Comparative Potential of Natural Gas, Coal and Biomass Fired Power Plant with Post - combustion CO_2 Capture and Compression

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Abstract

The application of carbon capture and storage (CCS) and carbon neutral techniques should be adopted to reduce the CO_2 emissions from power generation systems. These environmental concerns have renewed interest towards the use of biomass as an alternative to fossil fuels. This study investigates the comparative potential of different power generation systems, including NGCC with and without exhaust gas recirculation (EGR), pulverised supercritical coal and biomass fired power plants for constant heat input and constant fuel flowrate cases. The modelling of all the power plant cases is realized in Aspen Plus at the gross power output of 800 MW_e and integrated with a MEA-based CO_2 capture plant and a CO_2 compression unit. Full-scale detailed modelling of integrated power plant with a CO_2 capture and compression system for biomass fuel for two different cases is reported and compared with the conventional ones. The process performance, in terms of efficiency, emissions and potential losses for all the cases, is analysed. In conclusion, NGCC and NGCC with EGR integrated with CO_2 capture and compression results in higher net efficiency and least efficiency penalty reduction. Further, coal and biomass fired power plants integrated with CO_2 capture and compression results in higher specific CO_2 capture and the least specific losses per unit of the CO_2 captured. Furthermore, biomass with CO_2 capture and compression results in negative emissions.

Keywords: Biomass firing; exhaust gas recirculation; constant heat input; constant fuel flow rate

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1 Introduction

There is a wide consensus that human activities influence and cause global warming, which results in climate change due to greenhouse gas (GHG) emissions (Pachauri et al., 2014). Further, the major contributor of GHG has already crossed the limit of 400 ppm of CO_2 equivalent emissions into the atmosphere. The power generation sector is a major contributor of CO_2 emissions from combusting coal and natural gas. The application of carbon capture and storage (CCS) to thermal power plants or carbon neutral techniques should be adopted at a faster rate in order to mitigate the effect of global warming and to reduce the level of CO_2 emissions (IPCC, 2014). The technologies or techniques that can remove and/or reduce the large amount of CO_2 from the atmosphere should be a considerable part of the energy mix in order to limit the global temperature rise to 2 ^{o}C (Bhave et al., 2014). The post-combustion CO_2 capture using aqueous amines is the most developed process and it has already been demonstrated (Liang et al., 2015; Tontiwachwuthikul et al., 2013). The progress in research, development and demonstration in the post-combustion CO_2 capture can be found in the literature (Liang et al., 2015; Tontiwachwuthikul et al., 2013; Wang et al., 2011).

It is generally agreed that the most efficient and inexpensive means of reducing CO_2 emissions is by replacing coal with biomass and/or co-firing coal with biomass (Baxter, 2005). There is a growing evidence that bioenergy with carbon capture and storage will contribute to approximately half of the UK emissions targets (ETI, 2016; McGlashan et al., 2010). In the past, biomass was not used -in large scale power generation systems as a substitute for fossil fuels due to the low energy density, scarcity, considerable cost of transportation and its environmental impact (McIlveen-Wright et al., 2013). However, environmental concerns have renewed the interest in the use of biomass as an energy source for power generation (McKendry, 2002; Thornley, 2006; Thornley et al., 2008). As a result, Drax has converted and upgraded first of three coal boilers (with unit capacity of 645 MW) to use compressed wood pellets in the UK since 2013 (DRAX, 2016). Sustainably-grown biomass still emits the same amount of CO_2 during combustion; however, CO_2 is consumed during its growth (Demirbaş, 2003; Demirbas et al., 2009), which makes biomass a CO_2 neutral fuel. It is worth pointing that there is a time lag between the instantaneous release of the CO_2 due to the biomass burning and the eventual consumption of the released CO_2 by the newly grown biomass (McKendry, 2002). Further, if CCS is applied to sustainably-grown biomass, it would effectively result in negative CO_2 emissions (Eisentraut and Brown, 2012). Therefore, biomass usage results in no net CO_2 emissions when coal is replaced by sustainably-grown biomass and/or results in a reduction of the net CO_2 emissions when co-firing coal with biomass. To attain the projected biomass contribution to the electricity generation market, and to further reduce the CO_2 emissions, biomass will contribute to a considerable proportion towards commercial-scale power generation systems in the near future, as discussed in the literature (Faaij, 2006; Van den Broek et al., 2001). The major barriers to the demonstration and deployment of biomass for thermal power generation systems are the economics and sustainable biomass availability, rather than being of a technical nature (Bhave et al., 2014; Kraxner et al., 2014).

The use of biomass in thermal power generation systems may affect the system performance and efficiency due to the low heating value of biomass (McIlveen-Wright et al., 2011). However, biomass will result in additional benefits, such as lower SO_x emission, and negative emissions if CCS is applied. The techno-economic assessment and specific reduction in the CO_2 emissions for co-firing of coal and biomass in different types of technologies, including pulverized fuel firing, pressurized fluidised bed firing and atmospheric pressure circulating fluidised bed firing using the process simulator ECLIPSE have been reported in the literature (McIlveen-Wright et al., 2011; McIlveen-Wright et al., 2007; McIlveen-Wright et al., 2013). An energy analysis has been performed for the co-firing of biomass with coal in order to analyse the impact of the co-firing coal and biomass on the system performance (Mehmood et al., 2012). Similarly, a cost analysis and optimum plant size for co-firing of coal with biomass has also been reported (De and Assadi, 2009; Kumar et al., 2003).

There are studies in the literature (Abu-Zahra et al., 2007a; Abu-Zahra et al., 2007b; Aroonwilas and Veawab, 2007; Lawal et al., 2012; Mac Dowell and Shah, 2014) reporting the integration of the coal fired power plant with a CO_2 capture system based on parametric studies. In addition, other investigations (Cifre et al., 2009; Duan et al., 2012; Gibbins and Crane, 2004; Hanak et al., 2014; Hasan et al., 2012;

Khalilpour and Abbas, 2011; Lucquiaud and Gibbins, 2011a, b; Pfaff et al., 2010; Rao and Rubin, 2006; Romeo et al., 2008; Sanpasertparnich et al., 2010; Strube and Manfrida, 2011) have reported the integration of a CO_2 capture and CO_2 compression system to a coal fired power plant. The integration is based on comparing the parametric and sensitivity effects on the performance of the whole system in order to make coal based power plants as a favourable approach to be adopted for CCS. However, NGCC due to the higher efficiency is the most attractive option to be adopted for the integration to a CO_2 capture and CO_2 compression system in the present scenario of interest towards gas-CCS. Further, various studies (Botero et al., 2009; Jonshagen et al., 2011; Jonshagen et al., 2010; Li et al., 2011; SipÃķcz and Assadi, 2010) have reported that the NGCC with and without EGR to be an innovative approach when integrated with a CO_2 capture and compression system. However, comparison of different power plants based on the same power rating is not to be found in the literature on natural gas, coal and biomass firing.

1.1 Novelty

None of the above-mentioned literature has reported the impact of biomass on power plants integrated with a carbon capture technology. A techno-economic assessment of a standalone biomass fired power plant with two different kinds of CCS technologies, including PCC and oxy-fuel system, have compared the cost and emissions incentives to that of a coal fired power plant using IECM (Al-Qayim et al., 2015). IEA (2009) reported different case studies for the co-firing of biomass with coal for different technologies, including pulverised fuel firing, circulating fluidised bed firing and bubbling fluidised bed firing. Similarly, the same results as that of the IEA (2009) have been reported in (Domenichini et al., 2011). Benchmarking comparison of NGCC, coal and biomass fired power plants integrated with a MEA-based CO_2 capture plant has been reported (Berstad et al., 2011) with emphasis on the efficiency losses and specific CO_2 emissions for varying stripper operating pressure. It is found that coal and biomass power plants with CCS are more favourable targets from an energy point of view (Berstad et al., 2011). Berstad et al. (2011) compared NGCC, coal and biomass power plant integrated with CO_2 capture plant, however, the base power rating for each case varies. Further, it lacks the NGCC with EGR and this is an innovative approach to lessen the energy penalty. Furthermore, it is unsure whether maintaining the same fuel input or changing it by maintaining the same heat input will result in less penalty. In order, to have a comprehensive comparison of different power plant cases integrated with a CO_2 capture and compression system to have a meaningful understanding. The complete inclusion and reporting of each section of the power plant is seldom found in the literature, especially emission control technologies.

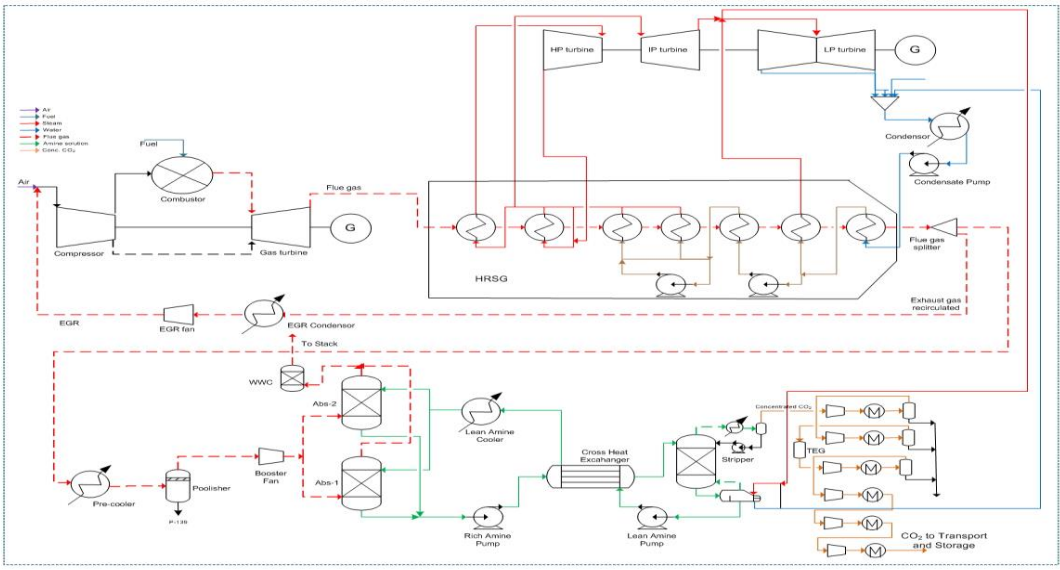

Figure 1 Basic schematic of the NGCC with EGR integrated with an amine-based CO_2 capture plant and CO_2 compression system.

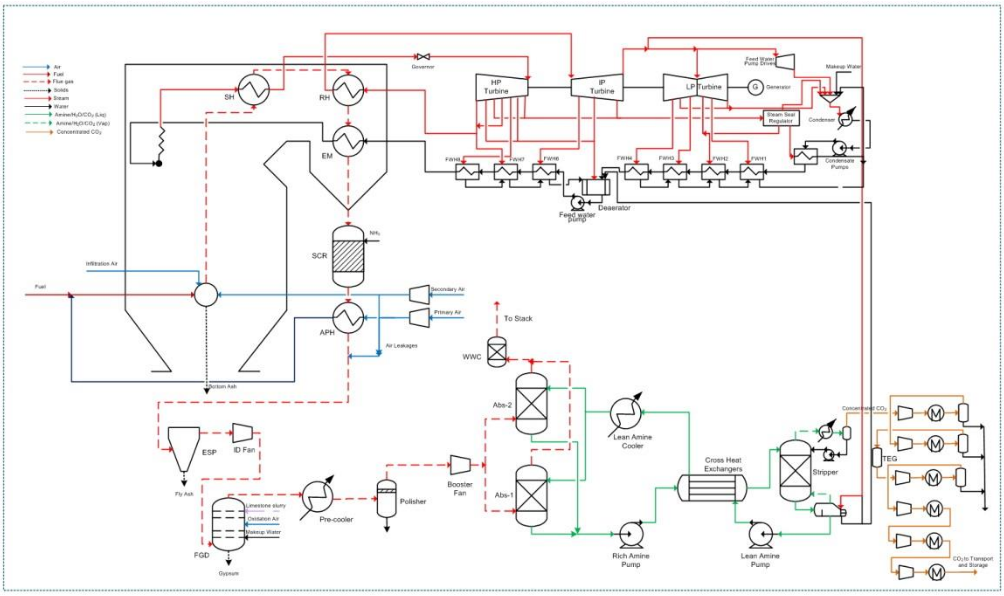

Figure 2 Basic schematic of the solid fuel fired power plant integrated with an amine-based CO_2 capture plant and CO_2 compression system.

In addition, the reported literature is limited in comparison to different power plant systems, including natural gas firing, supercritical coal and biomass fired; integrated with a CO_2 capture and compression system. It is clear from the above discussion that very limited work has been presented in the literature on the application of CCS towards the standalone biomass fired power plant and co-fired power plant. Therefore, the aim of this paper is to investigate and compare natural gas, coal and biomass fired power plants integrated with a CO_2 capture and CO_2 compression system and analyse the process performance in terms of efficiency, emissions and potential losses. In addition, different types of natural gas, coal and biomass fired power plants integrated with a CO_2 capture and CO_2 compression system are discussed and compared.

2 Process Configuration and Case Studies

Each of the natural gas, coal and biomass fired power plants can be sub divided into different case studies integrated with a CO_2 capture system and CO_2 compression unit and these are investigated in this paper. Natural gas fired power plant is sub divided into NGCC with and without EGR. Pulverised supercritical solid fuel fired power plant is divided into constant heat input and constant fuel flow rate for both coal and biomass.

Table 1 Input specifications for the NGCC models (U.S.DOE., 2013).

Parameter	Without EGR	With EGR
Gas turbine inlet temperature [Cifre, #31]	1487	1487
Gas turbine outlet temperature [Cifre, #31]	619	619
Air inlet temperature [Cifre, #31]	15	15
Flue gas temperature at HRSG exit [Cifre, #31]	88	106
Exhaust gas recirculation rate [%]	0	35
Pressure ratio	20	20
Compressor efficiency [%]	85	85
HP steam turbine efficiency [%]	88.9	88.9
IP steam turbine efficiency [%]	92.6	92.6
LP steam turbine efficiency [%]	94.0	94.0
Natural gas molar composition [%]		
CH_4	93.1	
C_2H_6	3.2	
C_3H_8	0.7	
iso-C_4H_{10}	0.4	
CO_2	1.0	
N_2	1.6	
Oxidiser composition at combustor inlet [%]		
N_2	77.32	78.99
O_2	20.74	16.54
Ar	0.92	0.94
CO_2	0.03	2.41
H_2O	0.99	1.13

2.1 Natural Gas Fired Power Plants

The natural gas fired power plant modelled is based on the Siemens 8000H frame gas turbine with ISO output of 275 MW from the gas turbine section as in the 2013 Report of the US Department of Energy (U.S.DOE., 2013). A schematic of the NGCC with EGR integrated to the CO_2 capture and compression system is shown in Figure 1. The pressure ratio of the compressor is 20 with a gas turbine inlet temperature 1487 ^oC and a gas turbine outlet temperature 619 ^oC. The bottom Rankine cycle consists of a triple pressure level single reheat cycle with a steam cycle specification of 16.5/566/566 MPa/^oC/^oC. The HRSG generates both main and reheat steam for the steam cycle. The flue gas temperature is 88 ^oC at the HRSG exit and it is then directed to the CO_2 capture system; the captured CO_2 stream is compressed through a CO_2 compression system. The specifications of the NGCC power plant modelled, along with natural gas and oxidizer compositions, are given in Table 1.

For NGCC with EGR, 35 % of the exhaust gas is recirculated to the compressor inlet of the gas turbine. The remaining 65 % of the flue gas is sent to the MEA-based CO_2 capture plant and the captured CO_2 is sent for compression through a CO_2 compression unit. For NGCC with EGR, the gas turbine inlet and outlet temperatures are the same as that of the NGCC without EGR; however, the flue gas exit temperature is 106 ^oC at the HRSG exit. The specifications of the NGCC with EGR are listed in Table 1.

2.2 Coal Fired Power Plant

The pulverised coal fired power plant modelled in this paper is based on supercritical pulverised coal cases reported in the 2010 Report of the US Department of Energy (Black, 2010). The pulverised coal fired power plant has a gross power output of 800 MW_e. A schematic of the coal fired power plant is shown in Figure 2 and it is integrated with a CO_2 capture system and CO_2 compression unit. For the supercritical case, the steam specification is 24.1/593/593 MPa/^oC/^oC and the steam generator is once-through with a super-heater, re-heater, economizer and air preheater (Black, 2010). The coal fired is bituminous type Illinois No. 6 coal, and its proximate and ultimate analysis with heating value is given in Table 2 for as-received and dry analysis. The air composition used for combustion is the same as given in Table 1.

In addition, to the primary and secondary air, infiltration air and/or air leakages are also accounted for as indicated in Figure 2. The Rankine cycle consists of three levels of steam turbines; high pressure, intermediate pressure and low pressure turbines. There are 8 feed water heaters, 3 upstream of the deaerator; heating the boiler feed water from the HP and IP turbines steam bleeds. The remaining 4 feed water heaters are at the downstream of the deaerator and LP turbine bleed steam is used for the boiler feed water heating. The condenser operates at a condensing pressure of 7 kPa with a corresponding saturation temperature 38 ^{o}C. In addition, the steam required by the MEA-based CO_2 capture plant is extracted from IP-LP cross-over and the condensate return from the MEA-based CO_2 capture plant is returned to the steam cycle at the deaerator.

Table 2 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

Further, the pulverised coal fired power plant is equipped with emission control technologies, including, the selective catalytic reduction (SCR) unit for NO_x removal, the fabric filters for particulate removal, the flue gas desulfurization (FGD) for SO_2 removal and the CO_2 capture unit for CO_2 removal. The flue gas from the economizer enters the SCR unit before preheating the air in the air preheater and then comes the fabric filters for removing the solid contaminants. Then the flue gas enters the FGD unit for SO_2 removal before it enters the CO_2 capture assembly.

2.2.1 Emission Control Technologies

The SCR unit uses ammonia with catalysts for the conversion of the NO_x pollutant into nitrogen and water. The SCR unit removes 86 % of the NO_x released during combustion with 2 ppmv of the ammonia slip at the end of the catalyst life. The number of active metals which can be used as catalyst, along with temperature ranges, can be found in the literature (Black, 2010; Veatch, 1996). The principal reactions involved in the SCR unit are as follows (Agbonghae, 2015; Veatch, 1996):

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O + heat \quad (1)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O + heat \quad (2)$$

The fabric filter removes any solid particulate contaminant carried away beyond the boiler assembly by the flue gas and works at 99.8 % efficiency. The same ratio of 80/20 percent split is applied between the fly ash and the bottom ash as reported in the 2010 Report of the US Department of Energy (Black, 2010). The FGD unit is a wet limestone forced oxidation process with gypsum as a by-product. The removal efficiency of the FGD unit is 98 % and it reduces the SO_2 content up to 10 ppmv (Black, 2010). The principal reactions involved in the FGD unit are as follows (Agbonghae, 2015; Veatch, 1996):

$$CaCO_3(s) + SO_2(g) + 0.5H_2O \rightarrow CaSO_3 \cdot 0.5H_2O + CO_2(g) \quad (3)$$

$$CaCO_3(s) + SO_2(g) + 0.5O_2 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O + CO_2(g) \quad (4)$$

2.2.1.1 CO_2 Capture Plant

The MEA-based reactive absorption and desorption are considered for the CO_2 capture from the flue gas at the CO_2 capture rate of 90 %. The flowsheet of the CO_2 capture unit is shown in Figure 2. The CO_2 capture unit consists of two absorbers and one stripper. The flue gas from the FGD unit is sent to the booster fan for the pressure increase before it is split into two streams and fed at the bottom of the absorber column. The flue gas is contacted with the lean amine solution in a counter-contact manner. The rich amine solution from the bottom of both absorbers is collected and pumped to the top of the stripper as a single stream after being heated through a cross lean/rich heat exchanger. The CO_2 is stripped from the amine solution and the uncondensed CO_2 stream from the condenser is sent to the CO_2 compression unit. The lean amine solution flows down the stripper column and is pumped back for recirculation to the top of the absorber. Further, there is a water wash section at the top of the absorbers to remove entrained droplets of the amine solution in the treated gas exiting the absorber columns.

2.3 Biomass Fired Power Plant

The components and details of the supercritical cases of the pulverised biomass fired plant are the same as that of the coal fired plant model explored in Section 2.2. The pulverised biomass fired plant model is also based on the 800 MW_e of gross power output. The boiler, steam cycle and emission control configuration is kept the same in order to have a thorough comparison of the coal and biomass firing systems. The biomass used is US forestry residue shipped in pellet form. The proximate and ultimate analyses of the biomass used, along with heating value, are reported in Table 2 in the form of an as-received and dry basis. Biomass has 24 and 88 % lower carbon and nitrogen, respectively, while 41 and 448 % higher hydrogen and oxygen, respectively, as compared to coal. Further, biomass has approximately 28 % lower calorific value compared to coal as reported in Table 2.

Due to these varying properties of the biomass, two case studies are performed, one based on constant heat input and the other based on constant fuel flow rate. In the constant heat input case, the flow of the fuel varies to maintain the same heat transfer from the flue gas to the water/steam in the super-heater, re-heater and economiser; while for the case based on the constant fuel flow rate, the fuel flow rate to the boiler is kept constant irrespective of the fuel type, whether coal or biomass, which results in varying heat transfer to the super-heater, re-heater and economiser. The case with constant heat input results in a large increase in the fuel flow rate due to with lower heating value of biomass. The case with a constant fuel flow rate results in a degradation of the total power output from the power plant due to the lower heating value of the fuel.

3 Modelling Strategy

The modelling of natural gas and solid fuel fired power plants are realized using the Aspen Plus process modelling software. The gas turbine and boiler are based on the Peng-Robinson with Boston-Mathias modification; the HRSG and steam side are based on IAPWS-95 property package. More details of the NGCC with and without EGR models can be found in Ali et al. (2016).

The theoretical air, excess air, air leakages and infiltration air for the constant boiler efficiency of 88 % are calculated based on recommendations found in the literature (Chou et al., 2012, 2014; Veatch, 1996). The ammonia required in the SCR unit is estimated based on the principal reactions given in Section 2.2.1, which shows that the ammonia required will be theoretically equal to the number of moles of NO_x present in the flue gas at the economiser outlet while keeping 2 ppmv of the ammonia slip into account. The limestone, O_2 and make-up water required in the FGD unit are estimated based on the principal reactions mentioned in Section 2.2.3. The assumptions made during the process modelling of the different parts of the solid fuel fired power plant, including the boiler, SCR, FGD, and steam cycle section can be found in the quality guidelines for energy process system studies provided by the US Department of Energy (Chou et al., 2012, 2014). However, a summary of the input specifications, irrespective of the solid fuel fired power plant type, can be found in Table 3.

Table 3 Summary of the input specifications for the solid fuel fired power plant.

Parameters	Value
Gross power output [MW_e]	800
Boiler efficiency [%]	88
Turbine thermal input [MW_{th}]	1705
Fabric filter efficiency [%]	99.8
SCR unit efficiency [%]	86
FGD unit efficiency [%]	98
Percent excess air [%]	15
Primary to secondary air split	0.235/0.765
Infiltration air to that of the total air [%]	2
Flue gas temperature at ESP inlet [Cifre, #31]	169

The MEA-based CO_2 capture plant model is based on second generation, rigorous rate based models. The model is based on the ENRTL-RK thermodynamic property package. The model has been extensively validated against experimental data and optimized (Agbonghae et al., 2014). The design data applied for the commercial-scale amine-based CO_2 capture plant used in this paper is given in Table 4, and this is based on the optimal design data reported by Agbonghae et al. (2014) for the commercial-scale coal fired power plant.

Table 4 Optimal design data for an amine-based CO_2 capture plant (Agbonghae et al., 2014).

Parameter	Value
Flue Gas Flowrate (kg/s)	821.26
Optimum Lean CO_2 loading (mol/mol)	0.2
Optimum Liquid/Gas Ratio (kg/kg)	2.93
Absorber	
Number of Absorbers	2
Absorber Packing	Mellapak 250Y
Diameter (m)	16.13
Optimum Height (m)	23.04
Stripper	
Number of Stripper	1
Packing	Mellapak 250Y
Diameter (m)	14.61
Optimum Height (m)	25.62
Specific Reboiler Duty (MJ/kg CO_2)	3.69

The CO_2 compression system modelled is a multiple-stage compression system with inter-stage coolers and knock out drums with the total stages being 6. The CO_2 compression system data for the inter-stage pressure is given in Table 5 and the final CO_2 compression pressure is set at 153 bar. The CO_2 compression system is modelled based on the Lee Kesler Plocker thermodynamic property package along with assumptions mentioned by the quality guidelines for energy process system studies provided in the US Department of Energy (Chou et al., 2012, 2014). The CO_2 stream cooling temperature is set at 30 ^oC and at the third-stage the CO_2 stream is dried with a tetra ethylene glycol (TEG) unit with a H_2O specification in the CO_2 stream specified at 20 ppmv. The pressure drop of 2 % is specified in the knock-out drums of the CO_2 compression system (Chou et al., 2012, 2014).

Table 5 CO_2 compression unit data (Black, 2010).

Stage	Outlet Pressure (bar)
1	3.6
2	7.8
3	17.1
4	37.6
5	82.7
6	153.0

4 Results and Discussion

4.1 NGCC with and Without EGR Results

The NGCC power plants with and without EGR integrated with the CO_2 capture and CO_2 compression units, and the key performance results are shown in Table 6. During the application of the EGR to the NGCC power plant, the steam cycle configuration and parameters are kept the same. The effect of the application of the EGR on the performance of the NGCC is clear from the results presented in Table 6. The EGR application results in 35 % decrease in air and flue gas flow rate. The EGR percentage of 35 % is selected based on the recommendation made by the 2013 Report of the US Department of Energy (U.S.DOE., 2013).

Table 6 Summary of the key performance results for the NGCC with and without EGR integrated to CO_2 capture and CO_2 compression units.

Case	NGCC	NGCC with EGR
Natural gas [kg/s]	29.2	29.5
Air [kg/s]	1177.1	771.1
EGR percentage [%]	0	35
Recirculated gas [kg/s]	-	398.8
Main steam [kg/s | bar | ^oC]	135 | 166.5 | 566	135 | 166.5 | 566
Reheat from furnace/boiler [kg/s | bar | ^oC]	98.5 | 24.8 | 566	98.5 | 24.8 | 566
Steam to stripper reboiler [kg/s | bar | ^oC]	110 | 5.2 | 338	108 | 5.2 | 338
Flue Gas Composition		
CO_2 [mol%]	4.16	6.53
H_2O [mol%]	8.90	9.22
N_2 [mol%]	74.23	75.76
O_2 [mol%]	11.83	7.59
Ar [mol%]	0.88	0.90
CO_2 Capture Plant	NGCC	NGCC with EGR
Flue gas, absorber inlet [kg/s]	1206.3	779.6
Lean MEA solution, absorber inlet [kg/s]	1193.8	1166.6

Rich CO_2 loading [mol/mol]	0.476	0.478
CO_2 captured [kg/s]	69.95	70.50
Specific reboiler duty [MJ/kg CO_2]	3.933	3.841
CO_2 Compression System	NGCC	NGCC with EGR
Total compression duty [MW_e]	20.76	20.94
Total intercooling duty [MW_{th}]	35.50	35.81

The EGR results in a 1 % increase in the fuel flow requirements which are due to the varying properties of the working fluid due to the EGR. Further the EGR results in a 57 % increase in the CO_2 molar composition in the exhaust gas. The increased CO_2 composition in the flue gas with its reduced flow rate, results in less solvent requirements and lower specific reboiler duty for the CO_2 capture plant. The solvent flow rate and specific reboiler duty decrease by about 2.3 % in comparison to the values obtained when there is no EGR. However, the amount of the CO_2 captured increases, which results in more specific CO_2 compression work as shown in Table S.1 of supplementary material. Further, detailed key performance results of the NGCC with and without EGR power plants integrated with CO_2 capture and CO_2 compression systems are shown in Table S.1 of supplementary material for more interpretation and explanation.

Table 7 Summary of the energy performance results for the NGCC with and without EGR integrated to CO_2 capture and CO_2 compression units.

Case	NGCC	NGCC with EGR
Fuel heat input, HHV [MW_{th}]	1528	1543
Total power, without steam extraction [MW_e]	800	800
Gas turbine power, with steam extraction [MW_e]	551	550
Steam turbine power, with steam extraction [MW_e]	163	160
Total power, with steam extraction [MW_e]	714	665
Power output without CO_2 capture and compression [MW_e]	785	782
Power output with CO_2 capture only [MW_e]	670	672
Power output with CO_2 capture and compression [MW_e]	650	651
Efficiency without CO_2 capture and compression [%]	51.40	50.60
Efficiency with CO_2 capture only [%]	43.89	43.50
Efficiency with CO_2 capture and compression [%]	42.53	42.15
Efficiency penalty with CO_2 capture only [%]	7.5	7.1
Efficiency penalty with CO_2 capture and compression [%]	8.9	8.5
Specific CO_2 emissions from power plant [g/kWh]	431	435
Specific CO_2 compression work [MJ/kg]	0.2968	0.2970
Specific losses per unit of CO_2 captured [%/kgs^{-1}]	0.11	0.10

The summary of the energy performance of the NGCC with and without EGR power plants integrated with CO_2 capture and CO_2 compression is shown in Table 7. Specific CO_2 compression work per unit of the CO_2 captured increases as the amount of the CO_2 captured also increases. It is evident that the net efficiency of the NGCC with EGR without CO_2 capture and compression systems decreases in comparison to the NGCC without EGR. This decrease is due to higher fuel flow rate requirements. Similarly, the net efficiency of the NGCC with an EGR power plant with and without CO_2 capture and compression decreases. However, the efficiency penalty of the NGCC with EGR is less in comparison to the NGCC without EGR due to the increased specific CO_2 emissions from the NGCC with an EGR power plant. Similarly, the specific efficiency losses per unit of the CO_2 captured decrease as more CO_2 is captured. This decrease is 9 % of the specific efficiency losses per unit of the CO_2 captured obtained through the NGCC power plant without EGR. Detailed energy performance results in the NGCC with and without EGR power plants integrated with CO_2 capture and CO_2 compression system are shown in Table S.2 of supplementary material for more interpretation and explanation.

Table 8 Summary of the key performance results for the pulverised supercritical coal and biomass fired power plants integrated with CO_2 capture and CO_2 compression systems for constant heat input and constant fuel flow rate cases.

Case	Constant heat input	Constant heat Input	Constant fuel flow rate
Fuel type	Coal	Biomass	Biomass
Coal [kg/s]	71.3	99.6	71.3
Total air [kg/s]	729	702	502
NH_3 injected [kg/s]	1.7	1.1	0.8
Slag + Fly Ash [kg/s]	6.9	0.7	0.5
Main steam [kg/s | bar | ^oC]	630 |242.3 |593	630 |242.3 |593	452 |242.3 |593
Reheat from furnace/boiler [kg/s | bar | ^oC]	514 |45.2 |593	514 |45.2 |585	367 |45.2 |593
Steam to stripper reboiler [kg/s | bar | ^oC]	223 |5.07 |296	230 |5.07 |296	163 |5.07 |296
Gypsum, moisture-free [kg/s]	9.6	0.1	0.1
Flue Gas Composition			
CO_2 [mol%]	13.28	14.35	14.35
H_2O [mol%]	15.48	14.17	14.18
N_2 [mol%]	68.05	68.28	68.28
O_2 [mol%]	2.37	2.38	2.37
Ar [mol%]	0.81	0.81	0.81
CO_2 Capture Plant			

Flue gas, absorber inlet [kg/s]	832	803	574
Lean MEA solution, absorber inlet [kg/s]	2403	2470	1743
Rich CO_2 loading [mol/mol]	0.479	0.480	0.480
CO_2 captured [kg/s]	152.0	157.1	112.1
Specific reboiler duty [MJ/kg CO_2]	3.686	3.673	3.634
CO_2 Compression System			
Total compression duty [MW_e]	44.90	46.46	33.18
Total intercooling duty [MW_{th}]	76.90	79.64	56.83

Table 9 Summary of the energy performance results for the pulverised supercritical coal and biomass fired power plants integrated with CO_2 capture and CO_2 compression systems for constant heat input and constant fuel flow rate cases.

Case	Constant heat input	Constant heat input	Constant fuel flow rate
Fuel type	Coal	Biomass	Biomass
Fuel heat input, HHV [MW_{th}]	1933	1933	1384
Steam turbine power, without steam extraction [MW_e]	800	800	574
Steam turbine power, with steam extraction [MW_e]	664	656	473
Power output without CO_2 capture and compression [MW_e]	758	758	536
Power output with CO_2 capture only [MW_e]	602	596	421
Power output with CO_2 capture and compression [MW_e]	557	549	388
Efficiency without CO_2 capture and compression [%]	39.22	39.30	38.70
Efficiency with CO_2 capture only [%]	31.16	30.82	30.40
Efficiency with CO_2 capture and compression [%]	28.84	28.41	28.01
Efficiency penalty with CO_2 capture only [%]	8.1	8.5	8.3
Efficiency penalty with CO_2 capture and compression [%]	10.4	10.9	10.9
Specific CO_2 emissions from power plant [g/kWh]	1092	1142	1293
Specific CO_2 compression work [MJ/kg]	0.2954	0.2957	0.2959
Specific losses per unit of CO_2 captured [%/kgs^{-1}]	0.053	0.054	0.071
Electricity output penalty [kWh/tCO_2]	257	262	228

4.2 Solid Fuel Power Plant Results

The pulverised fuel supercritical power plants are modelled for both coal and biomass firing based on the details provided in Sections 2 and 3. Both constant heat input and constant fuel flow rate cases are considered and the addition of the CO_2

capture and CO_2 compression system. The gross power output for constant heat input cases is set at 800 MW_e. The key performance results for standalone coal and biomass fired supercritical power plants integrated with a CO_2 capture and compression system with constant heat input and constant fuel flow rate cases are reported in Table 8 and the energy performance results for the cases are reported in Table 9.

4.2.1 Constant Heat Input Results

Constant heat input cases are performed for both subcritical and supercritical; coal and biomass fired power plants integrated with CO_2 capture and CO_2 compression systems. The CO_2 molar composition in the flue gas of the supercritical coal and biomass fired power plants is comparable with the CO_2 molar composition reported in the literature (Al-Qayim et al., 2015; Berstad et al., 2011; Black, 2010). Due to the lower sulphur content in the biomass, the FGD unit may not be required for the biomass-fired power plant with a CO_2 capture system and the requirement of the reduction of the SO_2 content before the CO_2 capture system can be met by a SO_2 polisher using an alkali wash. Similarly, due to the low ash content, the slag and fly ash produced by the biomass fired power plant is minimal, however, the true nature and properties of the slag and fly ash cannot be predicted by the present model. The key performance results are given in Tables S.3 and S.4 of supplementary material.

Due to the lower heating value of the biomass as discussed in Section 2.3, the fuel requirement increases by 40 %. At one end, the higher fuel flowrate requirement will disturb the boiler design, on the other end it will be an issue of logistics and supply of the sustainable biomass. A 800 MW_e bio-power plant operating with full capacity will require 500 tons biomass per hour equivalent to 17 lorries per hour with 30 ton each (Hetland et al., 2016). However, the CO_2 composition in the flue gas also increases by approximately 8 % with about 4 % decrease in the flue gas flow rate for the biomass case due to the higher O/C ratio in the biomass compared to the coal. Further, the biomass results in more CO_2 captured due to the increased CO_2 content in the flue gas, which results in increased CO_2 compression auxiliary loads. The net power output with CO_2 capture and CO_2 compression systems decrease by 1.5 %. A similar behaviour is observed for the net efficiency and this result in a slight increase in the efficiency penalty. Due to the higher specific CO_2 emissions from biomass fired power plants, there is a slight 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 as given in Table 9. The detailed energy performance results are given in Table S.5 of supplementary material for more interpretation and explanation. In addition, the flue gas composition at different locations of power plants integrated with CO_2 capture and CO_2 compression system are given in Table S.6 of supplementary material for more interpretation and explanation.

4.2.2 Constant Fuel Flow Rate Results

The constant flow rate case results in substantial de-rating of the gross and net power output from the power plants when fuel is switched from coal to biomass. The biomass firing results in approximately 30 % de-rating of the power output. However, if de-rating of the power plant is acceptable to the system, there is still a substantial decrease in the net efficiency of the power plant integrated with a CO_2 capture and CO_2 compression system by approximately 3 %. The efficiency penalty of the constant fuel flow rate cases is the same as that observed for the constant heat input cases, as the base power output considered for comparison is the de-rated power output and not 800 MW_e. The key performance results are given in Tables S.3 and S.4 of supplementary material for more interpretation and explanation. In addition, the flue gas composition at different locations of the power plants integrated with CO_2 capture and CO_2 compression system are given in Table S.6 of supplementary material for more interpretation and explanation.

The firing of the biomass results in an increase in CO_2 content by 8 % due to higher O/C ratio in biomass resulting in less dilution due to lower air flow requirements with approximately 31 % decrease in the flue gas flow rate. The solvent requirement to scrub the decreased flow rate flue gas also decreases by 30 %. The amount of the CO_2 captured also decreases, which results in a considerable increase in specific CO_2 compression work per unit of the CO_2 captured and specific losses per unit of the CO_2 captured. Due to the lower sulphur content in the biomass and lower biomass flow rate in comparison to what is required, the FGD unit may not be required for the biomass-fired power plant with a CO_2 capture system; instead the requirement of the reduction of the SO_2 content before the CO_2 capture system could be met by a SO_2 polisher using an alkali wash. As a result, the amount of the by-product, gypsum decreases enormously for the constant fuel flow rate cases when the fuel is switched to biomass. Similarly, due to the low ash content, the slag and fly ash produced by the biomass fired power plant is minimal, however, the true nature and properties of the slag and fly ash cannot be predicted by the present model. Detailed energy performance results are given in Table S.5 of supplementary material.

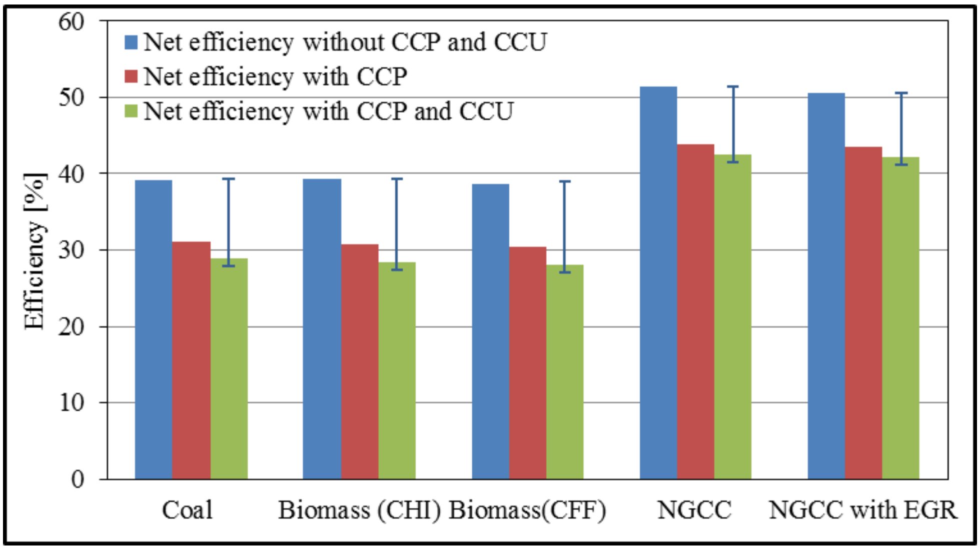

Figure 3 Net efficiencies and efficiency penalty of different power plant models integrated with CO_2 capture and CO_2 compression systems (where vertical bars indicate the efficiency penalty; CCP: CO_2 capture plant; CCU: CO_2 compression unit; CHI: Constant heat input; and CFF: Constant fuel flow rate).

5 Comparative Potential

The results and discussion presented in Section 4 for the different power plant cases modelled with CO_2 capture and CO_2 compression systems show that the standalone NGCC and/or NGCC with CO_2 capture and CO_2 compression system results in a higher net efficiency with the least CO_2 emissions. However, the least efficiency penalty due to the integration of the power plant with CO_2 capture and CO_2 compression systems is observed for the NGCC with an EGR power plant. This is due to the fact that for the NGCC with an EGR power plant, the auxiliary loads of the CO_2 capture system decrease due to the lower flue gas flow rate. The net efficiency of different power plants modelled, along with the efficiency penalty due to integration of the CO_2 capture and CO_2 compression systems, is shown in Figure 3.

Biomass fired power plants result in higher efficiency penalty along with higher specific CO_2 emissions. This is due to the low flowrate of the flue gas to the absorber with higher CO_2 concentration, the specific CO_2 emissions are higher and this results in higher specific CO_2 captured for the biomass fired power plants. Further, due to the higher concentration of the CO_2 in the flue gas of the biomass case, the CO_2 captured is higher, 157 kg/s for the biomass case in comparison to the coal fired, NGCC and NGCC with EGR having a CO_2 captured amount of 152, 69.95 and 70.50 kg/s, respectively. Thus, higher specific CO_2 emissions results in higher specific CO_2 capture, resulting in higher power requirement by CO_2 compressor system. The specific CO_2 emissions without capture and specific CO_2 captured for different power plant models are shown in Figure 4 where the hatched regions show the CO_2 captured. The coal and biomass fired power plants also shown higher specific CO_2 captured in comparison to NGCC and NGCC with EGR power plants. It is worth noting that if the biomass considered is sustainably-grown then it will result in zero CO_2 emissions and if the CO_2 capture is installed in negative CO_2 emissions. Further, coal and biomass power plants show the least specific losses per unit of the CO_2 captured. The specific losses per unit of the CO_2 captured for coal and biomass fired power plants with CO_2 capture and CO_2 compression systems are approximately half in comparison to the NGCC and NGCC with EGR integrated with CO_2 capture and CO_2 compression system.

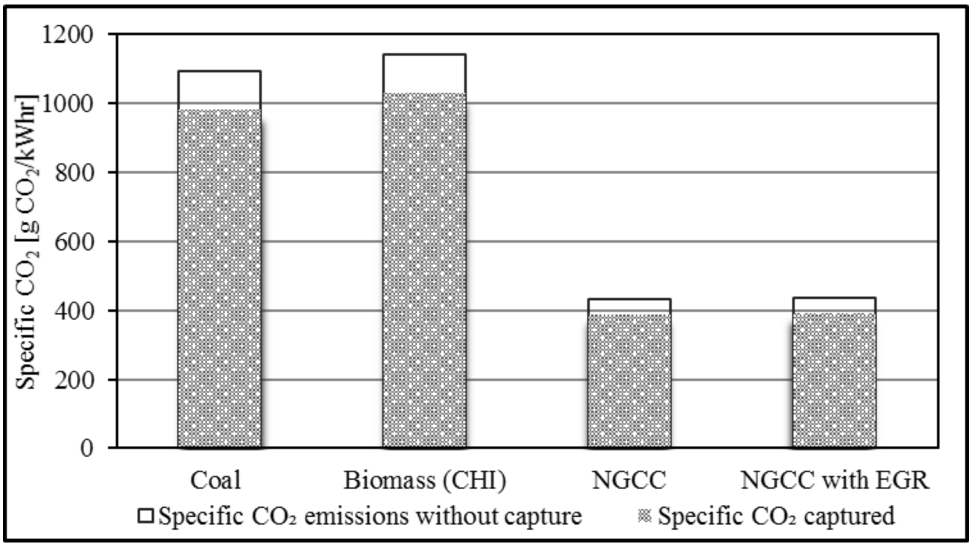

Figure 4 Specific CO_2 for different power plants through a CO_2 capture plant (where CHI is constant heat input and unhatched area shows the specific CO_2 emissions with CO_2 capture).

The power plant case with a constant fuel flow rate resulted in substantial power derating while the power plant with constant heat input case resulted in higher fuel flow rate requirements. From the specific CO_2 captured and specific losses per unit of CO_2 captured, the coal and biomass fired power plant with CCS are the most favourable options provided the changes required in the power plant due to fuel switch to biomass are ready to be adopted. However, in the present scenario of gas-CCS interest, NGCC coupled to CO_2 capture and CO_2 compression systems will be an attractive option to adopt due to the lower efficiency penalty.

7 Conclusions

This study has investigated the comparative potential of five different cases of power plants integrated to a MEA-based CO_2 capture system and a CO_2 compression unit for natural gas firing with and without EGR, supercritical coal and biomass firing for constant heat input and constant fuel flow rate cases. For consistency, the gross power output was maintained at 800 MW_e for most of the cases, except the CFF case, and the modelled and simulated results lead to the following conclusions:

- The biomass firing results in about 40 % increase in the fuel flow rate for the constant heat input case due to the lower heating value of the biomass and about 30 % derating of the power output for the constant fuel flow rate case.
- The FGD unit may not be required since the sulphur content in the biomass is less than coal and the limitation of removing the SO_2 to the required level can be simply achieved by the SO_2 polisher present in the CO_2 capture plant. Further, due to the low sulphur content in the biomass the by-product gypsum production decreases by 98.9 %.
- The NGCC and NGCC with EGR integrated with the CO_2 capture and CO_2 compression system shows higher net efficiency, 42.53 and 42.15 %, respectively, and the least efficiency penalty reduction of 8.9 and 8.5 %, respectively in comparison to the coal and biomass fired power plants integrated with a CO_2 capture and CO_2 compression system having higher net efficiency of 28.84, 28.41 % and efficiency penalty of 10.4 and 10.9 % respectively.
- Coal and biomass fired power plants when integrated with a CO_2 capture and CO_2 compression system, results in higher specific CO_2 capture due to the lower flowrate and higher concentration of the CO_2 in the flue gas and the

least specific losses per unit of the CO_2 captured of 0.053, 0.054 or 0.071 %/kgs^{-1}, respectively in comparison to the NGCC with and without EGR integrated with a CO_2 capture and CO_2 compression system having specific losses per unit of the CO2 captured of 0.11 and 0.10 %/kgs^{-1}, respectively. A standalone biomass power plant integrated with a CO_2 capture and CO_2 compression system will result in negative emissions if the biomass is sustainably-grown.

Nomenclature

Abs	absorber
APH	air preheater
CCP	CO_2 capture plant
CCS	carbon capture and storage
CCU	CO_2 compression unit
CFF	constant fuel flowrate
CHI	constant heat input
EGR	exhaust gas recirculation
EM	economiser
ESP	electro Static Precipitator
FGD	flue Gas Desulphurization
FWH	feedwater heater
GHG	greenhouse gases
HHV	higher heating value
HP	high Pressure
HRSG	heat recovery steam generator
ID	induced Draft
IECM	Integrated Environmental Control Model
IP	intermediate Pressure
LHV	lower heating value
LP	low Pressure

MEA	monoethanolamine
NGCC	natural gas combined cycle
RH	reheater
SCR	selective Catalytic Reduction
SH	superheater
WWC	water wash column
TEG	tetra ethylene glycol

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