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Modeling and Evaluation of a Coal Power Plant with Biomass Cofiring and CO₂ Capture

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Additional information is available at the end of the chapter

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Abstract

Coal-fired power plants are the largest source of anthropogenic carbon dioxide (CO₂) emissions into the atmosphere, with more than 9.5 billion tonnes of CO₂ emitted annually. In order to mitigate the emissions of CO₂ from coal-fired plants, several measures were proposed, such as increasing the efficiency of the plants, cofiring biomass with coal, and capturing and storing CO₂ deep underground. Among these measures, the use of biomass, which is considered one of the most cost-effective renewables and, in addition, carbon neutral, combined with CO₂ capture and storage will play an important role toward reducing the fossil-based CO₂ emissions. In this study, we investigated in detail the performances of pulverized coal combustion plants with direct cofiring of biomass and integrated with an amine-based postcombustion capture technology. All the systems were modeled and simulated using the process simulation software Aspen Plus. The results indicate that cofiring 10% of biomass in a coal-based power plant only slightly affects the energy performance of the plant, reducing the net efficiency by 0.3% points. The addition of an amine capture system to both the coal-fired and biomass cofiring plants further reduces the efficiency of the plants by more than 10% points. Analyzing the effect of various CO₂ capture process parameters on the heat, solvent and cooling water requirements, and on the overall plant performance, it was found that the concentration of amine in the solution is the most important parameter. The results showed that the net electrical efficiency increases for systems using higher amine concentrations. Further, we investigated the effect of systems with lower heat requirement for solvent regeneration on the plant gross/net power output and also analyzed the plant performances under a flexible CO₂ capture efficiency.

Keywords: pulverized coal combustion, biomass cofiring, postcombustion CO₂ capture, chemical absorption, monoethanolamine, Aspen Plus simulation

1. Introduction

Among fossil fuel power plants, coal-fired ones are the largest source of anthropogenic carbon dioxide (CO_2) emissions, emitting to the atmosphere more than 9.5 billion tonnes of CO_2 each year [1]. The emissions of CO_2 from coal-fired power plants can be reduced by increasing the efficiency of the plants (1% increase in efficiency reduces CO_2 by 2–3%), cofiring carbon neutral fuels (e.g., woody biomass), and/or capturing CO_2 and storing it in geological formations. The capture of CO_2 can be realized by means of three main approaches [2], namely: postcombustion capture, in which the CO_2 is separated from the flue gas after combustion; oxy-fuel combustion, the combustion takes place in nearly pure oxygen resulting in a flue gas stream consisting mainly of CO_2 and water from which the CO_2 can be easily separated; and precombustion, in which the CO_2 is removed from the fuel before combustion. Among these technologies, postcombustion CO_2 capture is the most advanced one that can be relatively easily integrated into existing or new power plants without altering the combustion process. Currently, postcombustion capture with chemical absorption using an aqueous amine (e.g., monoethanolamine, MEA) solution is the most selected process, offering high capture efficiency and selectivity.

Biomass, as one of the most cost-effective renewables and, in addition, carbon neutral, can also contribute toward reducing fossil-based CO_2 emissions. Furthermore, biomass cofiring in existing or new coal-based power plants is an effective means of producing electricity from biomass at higher conversion efficiencies and lower costs [3]. In addition, cofiring biomass with coal can reduce the emissions of sulfur dioxide (SO_2) and, in some cases, nitrogen oxides (NO_x) [4]. Currently, biomass cofiring is used in over 240 power plants (most of which are located in Europe) [5]. The majority of these plants employ direct cofiring in pulverized coal (PC) boilers. Fluidized bed (bubbling and circulating) boilers and grate-firing boilers have also been used. The share of biomass used in the fuel mix is, in most cases, less than 10% on energy basis.

The impact of cofiring different types of biomass on the technical and economic performances of the PC plants, with and without postcombustion capture, was investigated by a number of studies [6–10]. All studies suggest that the use of cofiring in PC combustion systems will have a negative impact on the overall technical and economic performances of the plants. For example, in the work conducted by the US DOE's National Energy Technology Laboratory [6], biomass (hybrid poplar) was directly cofired with bituminous coal (Illinois no. 6) at different ratios, ranging between 15% and 100% on a mass basis. The results showed that the net electrical efficiency decreases with the increase of cofiring ratio. For plants with 15, 30, and 60% biomass share in the fuel mix, the net efficiency decreases by approximately 0.2, 0.4, and 1.1% points, respectively, in comparison with the reference plant without cofiring, while for the case with 100% biomass firing the efficiency penalty is significant, i.e., 2.7% points. Further, it is worth mentioning that, because of the lower overall efficiency of cofiring plants, the total CO_2 emissions, expressed in kg/MWh of power generated, are higher. However, if biomass is considered as a carbon neutral fuel, then the net CO_2 emissions to the atmosphere decrease with the increase of biomass cofiring ratio. For example, a 550 MW_e (net) supercritical coal-fired

power plant with a net efficiency of 40.7% (on a lower heating value (LHV) basis) has a carbon intensity of about 800 kg CO₂/MWh. For cases with cofiring, the total CO₂ emissions increase to 813 kg/MWh with 15% biomass cofiring, 826 kg/MWh with 30%, 866 kg/MWh with 60%, and to around 985 kg/MWh with 100% biomass firing. However, if the net CO₂ emissions are calculated, then they decrease to 746 kg/MWh with 15% biomass cofiring, 692 kg/MWh with 30%, 530 kg/MWh with 60%, and 0 kg/MWh for the case with 100% biomass firing.

Integration of amine capture systems to coal-based plants leads to significant energy penalties [11]. The efficiency of coal-fired as well as biomass cofiring plants can be reduced by more than 10% points as a result of CO₂ capture by means of, for example, a MEA-based chemical absorption process [6, 12–14]. The reduction of power output is mainly caused by the extraction of large quantities of steam from the steam cycle of the power plant for amine solvent regeneration (~65% of total energy penalty) and the auxiliary power consumption for the compression of the CO₂ product (~25%) [15]. As mentioned earlier, compared to coal-fired plants, the plants with cofiring depending on the cofiring ratio, have efficiencies up to 1% points lower. In addition to this, the overall energy penalty in cofiring plants with CO₂ capture is higher, and the resulting cost of electricity is also higher than that of coal-fired plants [6, 10].

Although several studies investigated the impact of amine-based postcombustion CO₂ capture on the energy performance of cofiring plants, none of them investigated the effect of the CO₂ capture process parameters on the performances of the cofiring plants. In this study, we investigated in detail the technical performances of PC power plants with direct cofiring of biomass and integrated with an amine-based postcombustion capture technology. Aspen Plus process simulation tool was used for the modeling and simulation. First, we estimated the performances of coal-fired plants with/without cofiring and with/without CO₂ capture. Then we analyzed the effect of various CO₂ capture process parameters on the heat duty of the reboiler, solvent flow rate necessary to capture 90% of the CO₂ from the flue gas, and cooling water requirements. Further, we investigated the effect of absorption processes with lower heat requirement for solvent regeneration on the gross and net power output of the plants, and also analyzed the plant performances under a flexible CO₂ capture efficiency operation.

2. Process description

2.1. Feedstock

The composition and heating values of the fuels used in this study are shown in **Table 1**. Bituminous coal (Illinois no. 6) was selected as the base fuel. It has a lower heating value of ~29.5 MJ/kg (dry basis, db), a low moisture content of 11.1% (as received, ar), and a relatively high ash content of 10.9% (db). It is further characterized by having high sulfur content of 2.8% (db). The biomass selected for cofiring cases is hybrid poplar with a moisture content of 50% (ar) and a lower heating value of about 18.5 MJ/kg (db). Its ash (1.5% db) and sulfur (0.03% db) contents are very low. In this study, we assumed that hybrid poplar prior to be fed into the boiler was dried to 10% using a fluidized-bed drying system [6].

	Bituminous coal Illinois no. 6 [13]	Hybrid poplar [6]
Moisture (% ar)	11.12	50.00
Ash (%)	10.91	1.48
Carbon (%)	71.73	52.36
Hydrogen (%)	5.06	5.60
Oxygen (%)	7.74	40.16
Nitrogen (%)	1.41	0.37
Chlorine (%)	0.33	–
Sulfur (%)	2.82	0.03
Higher heating value (MJ/kg)	30.53	19.63
Lower heating value (MJ/kg)	29.45	18.46

Table 1. Composition and heating values of coal (Illinois no. 6) and biomass (hybrid poplar) used in this study (by weight, db).

2.2. Power plant

The power plant is a supercritical PC-fired power plant designed to operate with main steam conditions at 242 bar/593°C and steam reheating at 42.4 bar/593°C. In this study, the reference plant (coal-fired, without carbon capture) generates 550 MW_e net power at an efficiency of about 40.7% (LHV).

Figure 1 shows a simplified layout of the power plant without CO₂ capture. From the boiler, the flue gas is sent to a gas cleaning system consisting of a selective catalytic reduction (SCR) for NO_x control, a baghouse (BH) for fly ash removal, and a limestone-based flue gas desulfurization (FGD) unit for SO_x removal. An air preheater (APH) is placed between the SCR and BH units. The primary air after exiting the APH is mixed with the fuel prior to entering the boiler while the secondary air was directly sent to the boiler.

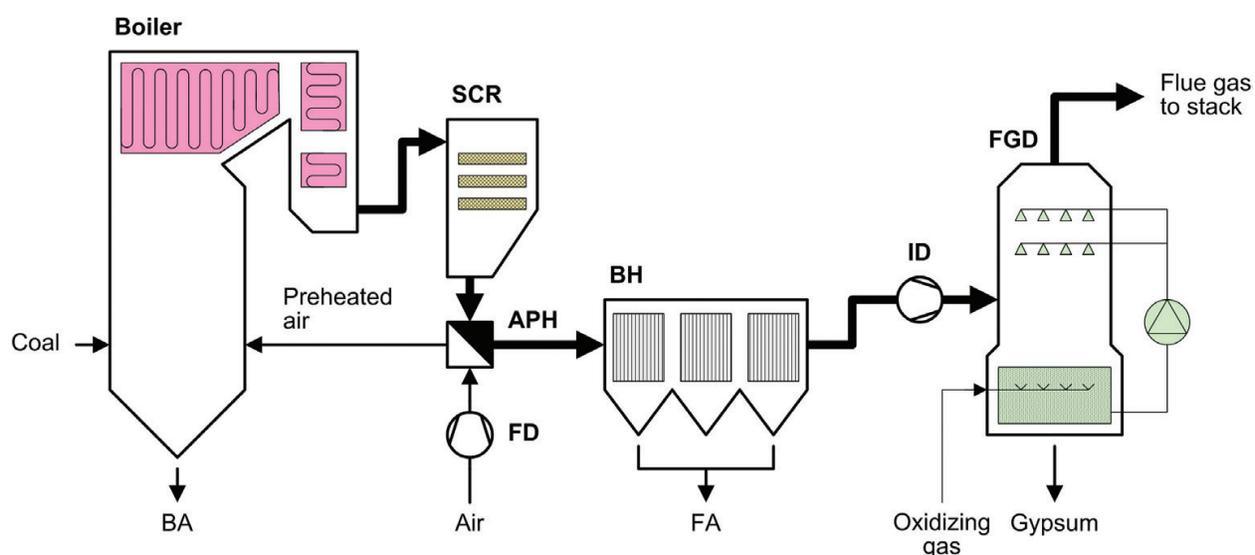


Figure 1. Layout of a pulverized coal-fired power plant (adapted from [16]).

The STEAMNBS (NBS/NRC steam table) property method was selected to model the water-steam cycle in Aspen Plus. The flowsheet was built mainly with the COMPR and HEATER blocks. For example, to model a HPST, two COMPR units were connected in series. The stream exiting the first unit was split into two, one directed to the second unit, and the other one was sent for feedwater preheating. The amount of steam extracted for feedwater preheating, the steam required to drive the boiler feed pump turbine, the steam required for the solvent regeneration and condensate used for desuperheating in carbon capture cases, and the cooling water requirement in the condenser were controlled within the program by means of several Design Spec functions.

The assumptions used for the modeling and simulation of the power plant are presented in **Table 2**.

Parameter	Value
Boiler section:	
Operating pressure (bar)	1.01
Boiler efficiency (% LHV)	91.2
Primary/secondary air (%)	23.5/76.5
Infiltration air (% of FG exiting the APH)	1.6
Air leakage in APH (%)	5.5
Ash distribution, BA/FA (%)	20/80
FG outlet temperature, boiler/APH (°C)	350/170
O ₂ content in FG at the APH outlet (mol%)	2.5
PA/FD/ID fans pressure ratio (-)	1.10/1.04/1.08
Fans isentropic/mechanical efficiency (%)	80/95
BH:	
FA removal efficiency (%)	100
Pressure drop (bar)	0.014
FGD:	
SO ₂ removal efficiency (%)	98
Limestone purity (wt%)	80.4
Limestone slurry, solid/liquid (%)	30/70
Excess sorbent for SO ₂ removal (%)	4
Excess O ₂ for oxidation (%)	135
Pressure drop (bar)	0.034
FG outlet temperature (°C)	57.2
Steam cycle:	
Live steam pressure/temperature (bar/°C)	242.3/593.3
Reheated steam pressure/temperature (bar/°C)	45.2/593.3
IP/LP crossover pressure (bar)	9.3
Condenser pressure (bar)	0.069

Parameter	Value
Boiler FW temperature (°C)	291.4
ST isentropic efficiency, HP/IP/LP (%)	83/88/93
ST mechanical efficiency (%)	99
Generator efficiency (%)	98.5
FW and condensate pump hydraulic/mechanical efficiency (%)	85/99.6
Steam extraction pressures for FW preheating (bar)	76.9/49.0 ^(a) , 21.4/9.5 ^(b) , 5.01/1.32/0.58/0.24 ^(c)
Number of FWHs, HP/LP (including deaerator) (-)	3/5
Temperature difference in FWHs (hot outlet—cold inlet) (°C)	5.56
Pressure drop in FWHs (cold-side) (bar)	0.34

^(a)Steam from HPST to FWHs 8 and 7.

^(b)Steam from IPST to FWH 6 and deaerator.

^(c)Steam from LPST to FWHs 4-1.

Table 2. Main assumptions for the simulation of the reference plant (without CO₂ capture) [6, 12, 13, 16, 17].

The power requirements of various subsystems in the power plant, such as solids handling and processing, emission control and other plant auxiliaries, are given in **Table 3**.

Parameter	Value
Coal handling and milling (kWh/t coal)	17
Biomass handling, processing, and drying (% of biomass heat input)	3.1
Ash handling (kWh/t TA)	30
SO ₂ sorbent handling and reagent preparation (kWh/t limestone slurry)	15
BH unit (kWh/t FA removed)	5
FGD unit (kWh/t SO ₂ removed)	325
ST auxiliaries (MW _e)	0.4
Condenser auxiliaries (% of heat rejected)	1.2 ^(a)
Miscellaneous BOP (MW _e)	2 ^(b)
Transformer losses (% of gross power)	0.3

^(a)Includes power consumption by circulating water pumps, ground water pumps, and cooling tower fans.

^(b)Includes power consumption by plant control systems, lighting, heating, ventilating, and air conditioning.

Table 3. Power consumption of various subsystems in the power plant [6, 13].

The power plant model developed in Aspen Plus was validated against the data from the NETL studies [6, 13]. The validation of the steam cycle parameters (i.e., mass flow rates, temperatures, and pressures of steam) is shown in **Figure 3**. As can be observed, the results are in good agreement with the reference [13]. The calculated steam turbine power output was

589.21 MW_e and the gross power output was 580.37 MW_e, which is very close to the reference value of 580.40 MW_e. **Table 4** compares the simulation results on the performance of coal-fired and biomass cofiring plants with the reference data [6, 13]. The deviation between the reference and the present results for the coal-fired case is insignificant. For the biomass cofiring case, with 10% heat input, the results are within the values reported in the reference [6].

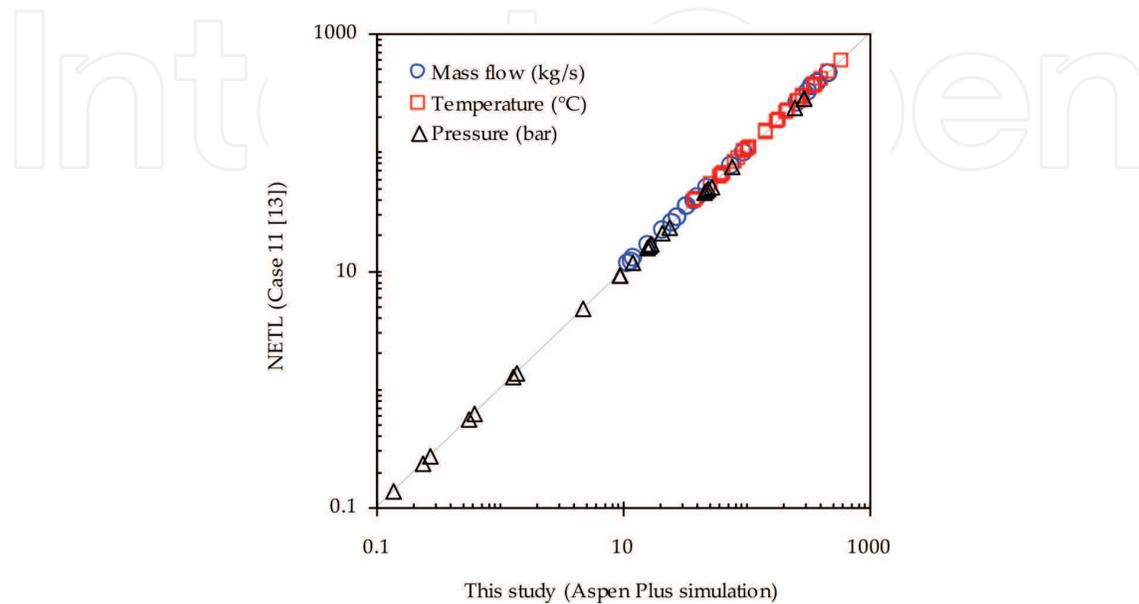


Figure 3. Validation of the water/steam parameters of the supercritical steam cycle.

2.3. CO₂ capture and compression

A simplified process flow diagram of the MEA-based chemical absorption process for CO₂ capture used in this study is shown in **Figure 4**. The flue gas after pretreating in a direct contact cooler (DCC), with reduced temperature and low impurities level, enters the absorber column where it contacts, countercurrently, with the aqueous amine solution (30 wt% MEA and 0.25 mol CO₂/mol MEA loading) introduced from the top of the column. The CO₂ from the flue gas reacts with the absorbent forming a CO₂-rich solution (~0.49 mol CO₂/mol MEA), which is then pumped to the desorber column via a lean/rich heat exchanger (HX). The clean

Case study	Coal-fired		Biomass cofiring		
	NETL ^(a)	This study	NETL ^(b)	This study	NETL ^(c)
Biomass share (% heat input)	0	0	6	10	13
Net plant efficiency (% LHV)	40.73	40.67	40.54	40.35	40.32
Fuel consumption (kg/MWh)	337.7	338.2	375.8	403.5	423.4
CO ₂ emissions (kg/MWh)	802.0	803.0	812.6	821.4	825.8

^(a)Case 11 [13].

^(b)Case PN4 [6].

^(c)Case PN3 [6].

Table 4. Comparison of plant performance without CO₂ capture.

flue gas exits the absorber and is further washed in a water washing section in order to remove any amine residues. In the desorber, the CO₂ is released from the liquid absorbent as a result of the heat provided by the LP steam in the reboiler. The CO₂-lean solution is then sent to the absorber column for the next cycle. The CO₂ product stream from the desorber column is further compressed, dehydrated, and transported to a storage site. The main assumptions used to model and simulate the capture and compression process are presented in **Table 5**.

In Aspen, the ELECNRTL (electrolyte nonrandom two-liquid model with Redlich-Kwong equation of state) property method was selected for the simulation of the absorption process. The chemical reactions taking place during the absorption process are as follows:

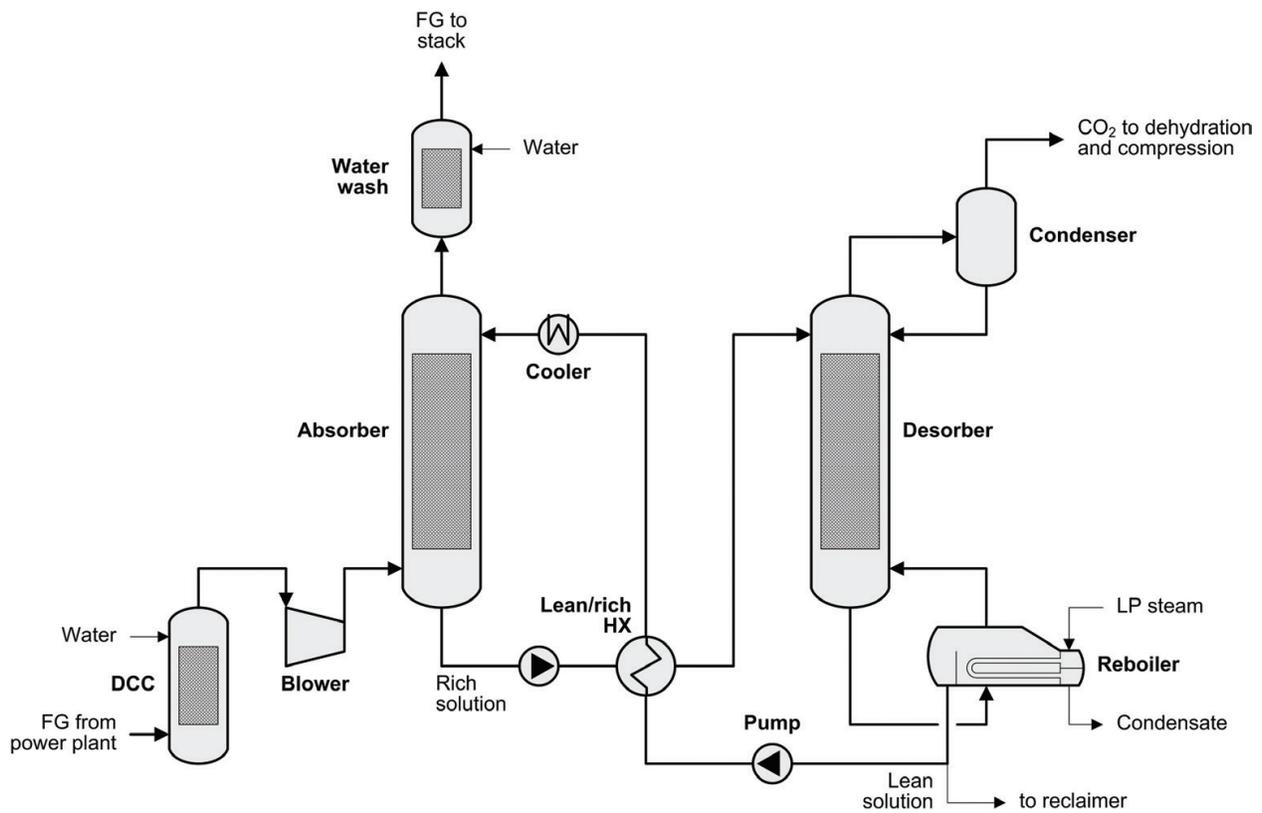


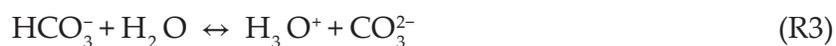
Figure 4. Process flow diagram of the chemical absorption process for CO₂ capture from flue gas.

Parameter	Value
CO ₂ capture:	
CO ₂ removal rate (%)	90
MEA concentration (wt%)	30
CO ₂ loading, lean/rich (mol CO ₂ /mol MEA)	0.25/~0.49 ^(a)

Parameter	Value
FG/lean solvent temperature at the absorber inlet (°C)	~45 ^(a) /40
Lean/rich HX temperature difference (hot outlet—cold inlet) (°C)	5
Reboiler temperature difference (°C)	10
Operating pressure, absorber/desorber (bar)	1.0/1.7
Pressure drop, absorber/desorber (bar)	0.14/0.20
Number of equilibrium stages, absorber/desorber (-)	18/12
Booster fan pressure ratio (-)	1.1
Booster fan isentropic/mechanical efficiency (%)	85/95
CO ₂ compression:	
Final delivery pressure/temperature (bar/°C)	110/30
Number of compression stages (-)	7
Compressor pressure ratio (-)	1.8
Compressor isentropic/mechanical efficiency (%)	80/95
Intercoolers outlet temperature (°C)	30
Intercoolers pressure drop (% of inlet stream)	2

^(a)Calculated.

Table 5. Main assumptions for the simulation of the CO₂ capture and compression process [13, 14, 16, 18].



For these reactions, the equilibrium constants were calculated with the following equation:

$$\ln(K_{ech}) = A + B/T + C \ln(T) + DT \quad (1)$$

in which, T is the temperature (K) and the coefficients A , B , C , and D are given in **Table 6** for each reaction.

To determine the loading of the solution (mol CO₂/mol MEA), Eq. (2) was applied:

$$\text{Loading} = \frac{[\text{CO}_2] + [\text{HCO}_3^-] + [\text{CO}_3^{2-}] + [\text{MEACOO}^-]}{[\text{MEA}] + [\text{MEA}^+] + [\text{MEACOO}^-]} \quad (2)$$

where the components in the numerator represent moles of all CO₂ species in the solution, whereas the components in the denominator represent moles of all MEA species.

The following unit operation blocks were used to develop the process flowsheet: RADFRAC columns were used to model the absorber and desorber columns using 18 and 12 equilibrium

Reaction no.	A	B	C	D
1	-3.038325	-7008.357	0	-0.00313489
2	231.465	-12092.1	-36.7816	0
3	216.049	-12431.7	-35.4819	0
4	-0.52135	-2545.53	0	0
5	132.899	-13445.9	-22.4773	0

Table 6. Coefficients from Eq. (1) for the calculation of the equilibrium constants in the CO₂-MEA system.

stages, respectively [16]. For the modeling of the flue gas blower a COMPR block was used. For cooling and heating purposes, several HEATER blocks were employed. The desorber condenser was modeled with a FLASH2 block.

For the development of the compression model, three unit operation blocks were used, namely, COMPR for compression, HEATER for cooling of the product stream, and FLASH2 for excess liquid removal. As specified in **Table 5**, the CO₂ product stream from the capture unit was compressed to 110 bar in a multistage compressor using seven compression stages with intercooling to 30°C.

The modeling results of the capture and compression model are presented in **Table 7**. These are compared with other sources. As can be seen, the results are in good agreement with the values reported in the open literature for conventional absorption/desorption processes with 30 wt% MEA. In this study, the minimum reboiler heat duty of 3.5 MJ/kg CO₂ captured was obtained for the lean loading of 0.25 mol CO₂/mol MEA. The solution leaving the absorber column had a loading of 0.49 mol CO₂/mol MEA. In the simulation, the liquid to gas mass flow rate ratio used was about 3.9, and the lean solvent requirement was about 20 kg/kg CO₂ captured. The total CW needed to cool (i) the FG before entering the capture unit, (ii) the lean solution after exiting the lean/rich HX, and (iii) the CO₂ product stream in the compression train was estimated at about 71 kg/kg CO₂ captured. The specific energy requirement was estimated at about 110 kWh/kg CO₂ captured of which more than 75% were consumed by the compression unit. Furthermore, it was found that the specific steam used for solvent regeneration was 1.45 kg steam/kg CO₂ captured, which is in agreement with the values reported in [13, 21]. For example, in reference [21] about 1.42 kg steam/kg CO₂ captured were used for the case with the steam extracted at 9 bar from the IP/LP crossover pipe and 1.47 kg steam/kg CO₂ for the case with steam extracted at 3 bar from the LPST.

2.4. Integration of CO₂ capture with power plant

The amine capture unit requires significant amounts of energy for solvent regeneration. This energy is usually provided by the steam extracted from the main power plant. It can also be delivered by, for example, an additional boiler in which steam is generated at sufficient quality and quantity necessary for regeneration [9, 22]. However, this measure would be more costly than that of direct extraction from the plant. In this study, the required steam for solvent regeneration is extracted at 9.3 bar from the crossover pipe between the

Study	This study	Abu-Zahra et al. [19] ^(a)	CAESAR [14]	Liu et al. [20]
L/G mass flow rate ratio (-)	3.87–3.92	3.48/4.83	4.05	2.75
Lean loading (mol CO ₂ /mol MEA)	0.25	0.24/0.32	0.26	0.23
Rich loading (mol CO ₂ /mol MEA)	0.49	0.48/0.49	0.48	0.54
Reboiler heat duty (MJ/kg CO ₂ captured)	3.5	3.89/3.29	3.73	4.6
Lean solvent requirement (kg/kg CO ₂ captured)	20	19.3/26.9	21.8	15.7
CW requirement (kg/kg CO ₂ captured)	70.1–71.4	106/103	61.7	
Power consumption (kWh/kg CO ₂ captured)	109		129.0	84.4 ^(b)

^(a) Values refer to the baseline/optimum case.
^(b) Only the energy used for CO₂ product compression.

Table 7. Main parameters of the capture and compression process for 90% CO₂ capture with 30 wt% MEA.

intermediate pressure and low pressure turbine. It is first expanded in an auxiliary turbine, desuperheated, and then enters the reboiler (**Figure 5**). Since the MEA solvent is regenerated at ~121°C, and the reboiler temperature approach is assumed to be 10°C, the conditions of the saturated steam before entering the reboiler are 132°C/2.86 bar. As will be further shown in this study, depending on the MEA concentration and other process conditions, approximately half of the steam from the IP/LP crossover will be extracted, and thus significantly reducing the gross power output. From the reboiler, the resulting condensate is pumped to 9.2 bar to the deaerator. The reboiler condensate can also be returned to one of the LPFWHs, provided that the temperature level is close to that of the condensate. In reference [16], with the same steam cycle, it was shown that the most appropriate location for the condensate reinjection is the deaerator.

2.5. Plant performance indicators

The performances of plants with/without cofiring and with/without MEA-based postcombustion CO₂ capture were evaluated using the following plant performance indicators:

Net plant efficiency, η_{net} (%):

$$\eta_{\text{net}} = \frac{W_{\text{net}}}{\dot{m}_C \cdot LHV_C + \dot{m}_B \cdot LHV_B} \quad (3)$$

Efficiency penalty due to cofiring and/or carbon capture, $\Delta\eta_{\text{net}}$ (% points):

$$\Delta\eta_{\text{net}} = \eta_{\text{net,ref}} - \eta_{\text{net,cofiring and/or CCS}} \quad (4)$$

Specific fuel consumption, SC_{fuel} (kg/MWh):

$$SC_{\text{fuel}} = \frac{(\dot{m}_C + \dot{m}_B) \cdot 3600}{W_{\text{net}}} \quad (5)$$

Specific CO₂ emissions, SE_{CO_2} (kg/MWh):

$$SE_{\text{CO}_2} = \frac{\dot{m}_{\text{CO}_2} \cdot 3600}{W_{\text{net}}} \quad (6)$$

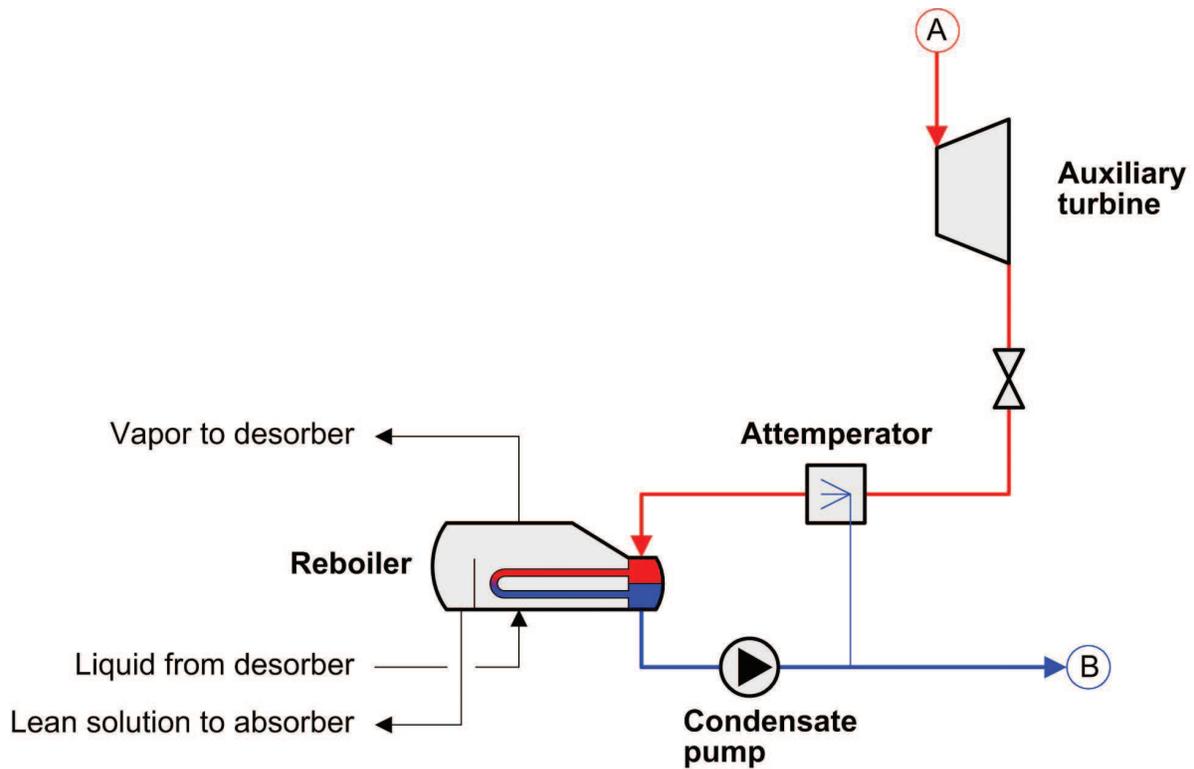


Figure 5. Integration of the steam with the stripper reboiler.

Net CO₂ emissions, NE_{CO_2} (kg/MWh):

$$NE_{CO_2} = \frac{\dot{m}_{CO_2} \cdot 3600}{W_{net}} \quad (7)$$

Here, \dot{m}_c is the flow rate of coal entering the plant (kg/s), \dot{m}_b is the flow rate of raw biomass entering the plant in the case with cofiring (kg/s), LHV_C and LHV_B are the lower heating values of coal and, respectively, biomass (MJ/kg), $\eta_{net,ref}$ is the net efficiency of the reference plant, without cofiring and without CO₂ capture (%), $\eta_{net,cofiring \text{ and/or } CCS}$ is the net efficiency of the plant with biomass cofiring and/or with CO₂ capture (%), \dot{m}_{CO_2} is the total flow rate of CO₂ generated (kg/s), $\dot{m}_{CO_2,c}$ is the flow rate of CO₂ generated only from coal combustion (kg/s), and W_{net} is the plant net power output (MW_e), which is obtained after subtracting the plant auxiliary power consumption.

3. Results and discussion

3.1. Performance of coal-fired and biomass cofiring plants with CO₂ capture

Simulation results of the investigated plants with/without biomass cofiring and with/without MEA-based postcombustion carbon capture are summarized in **Table 8**. As can be seen, the reference coal-fired power plant has a net electrical efficiency of 40.67% and releases 803 kg CO₂/MWh. The results further show that the performances of the plant with cofiring are slightly derated in comparison with the coal-fired plant. Cofiring 10% of biomass in a supercritical coal-based plant leads to a reduction in efficiency to 40.35% (i.e., 0.33% points efficiency

penalty compared with coal-fired case). This reduction is mainly attributed to the fact that the biomass fuel considered in this study has a lower calorific value and significantly higher moisture content, and the energy needed for its processing and drying is substantial. However, one can also note that cofiring biomass has a positive effect on the ash and SO₂ flow rates reducing the power demand of subsystems associated with their removal. The specific CO₂ emissions from the cofiring plant are estimated at 821.4 kg CO₂/MWh. But if considering only the emissions resulted from coal combustion, then they decrease to around 740 kg CO₂/kWh.

The addition of a MEA-based postcombustion CO₂ capture system significantly reduces the energy performance of both plants. For the coal-fired power plant with 90% CO₂ capture rate, the net efficiency drops to 30.47% (i.e., an efficiency penalty of 10.21% points with respect to

CO ₂ capture	No		Yes	
Cofiring	No	Yes	No	Yes
Fuel input:				
Coal (kg/s ar)	51.69	46.60	51.69	46.60
Biomass (kg/s ar)		14.67		14.67
Heat input (MW _{th} LHV)	1352.80	1354.98	1352.80	1354.98
Power generated/consumed:				
ST output (MW _e)	580.37	580.37	485.07	483.26
Coal handling and milling (MW _e)	-3.16	-2.85	-3.16	-2.85
Biomass handling, processing and drying (MW _e)		-4.20		-4.20
PA/FD/ID fans (MW _e)	-9.83	-9.91	-9.83	-9.91
BH and ash handling system (MW _e)	-0.61	-0.57	-0.61	-0.57
FGD and limestone handling/reagent preparation (MW _e)	-3.89	-3.51	-3.89	-3.51
CO ₂ capture and compression (MW _e)			-43.03	-43.69
Condensate pumps (MW _e)	-0.80	-0.80	-0.42	-0.41
Condenser auxiliaries (MW _e)	-7.65	-7.65	-8.07	-8.14
Miscellaneous BOP, ST auxiliaries and transformer losses (MW _e)	-4.20	-4.20	-3.90	-3.90
Total auxiliary consumption (MW _e)	-30.14	-33.69	-72.93	-77.19
Overall plant performance:				
Net power output (MW _e)	550.22	546.68	412.14	406.07
Net plant efficiency (% LHV)	40.67	40.35	30.47	29.97
Efficiency penalty (% points)		0.33	10.21	10.70
Specific fuel consumption (kg/MWh)	338.2	403.5	451.5	543.2
Specific CO ₂ emissions (kg/MWh)	803.0	821.4	107.2	110.6
Net CO ₂ emissions (kg/MWh)	803.0	739.3	107.2	0

Table 8. Performance of PC plants with/without cofiring, with/without CO₂ capture.

the reference plant) while for the cofiring plant the net efficiency decreases to 29.97% (i.e., an efficiency penalty of 10.7% points) after integrating the CO₂ capture and compression process. As can be noted from the table, the capture and compression process consumes more than 55% of the total auxiliary load. The results further show that in order to generate the same amount of energy, the systems with carbon capture should use 35% more fuel than the reference plant without capture. The CO₂ emissions reduce to 107.2 kg CO₂/kWh in case of coal-fired and to 110.6 kg CO₂/kWh in case of cofiring. For the cofiring case, if we assume that all the CO₂ resulted from the combustion of coal is captured from the plant, then the net CO₂ emissions would be zero.

3.2. Effect of operating parameters on CO₂ capture process

One of the main objectives of this study is to investigate the effect of different process parameters on the energy, solvent, and CW requirements in the CO₂ capture process. The effect of the MEA concentration in the solution (20–40 wt%), the FG temperature at the absorber inlet (40–50°C), the lean solvent temperature at the absorber inlet (30–50°C), the temperature difference in the lean/rich HX between hot outlet and cold inlet (5–10°C), and the stripper operating pressure (1.5–1.9 bar) were investigated. **Figure 6** shows the simulation results on the effect of different process variables on the heat, solvent, and CW requirements in the CO₂ capture process with respect to the base case (30 wt% MEA, 45°C FG inlet temperature, 40°C lean solvent temperature, 5°C lean/rich HX temperature difference, and 1.7 bar stripper operating pressure). For all simulation cases, the CO₂ capture rate was fixed at 90%. As shown, the concentration of MEA is the most important parameter with great effect on the heat, solvent, and CW requirements. Operating the capture unit with a lower MEA concentration (20 wt%) leads to a significant increase of the reboiler heat duty (>12% more compared with the base case), solvent requirement (>35%), and CW requirement (>30%). This is because as the MEA concentration decreases more solvent needs to be fed into the absorber column to remove 90% of CO₂ from the FG stream. The increased solvent flow rate then leads to higher cooling requirements. Further, the temperature of the rich solution entering the desorber column is lower, which needs more heat for solvent regeneration. Contrary to this, increasing the MEA concentration from 30 wt% (base case) to 40 wt% results in a decrease of the reboiler heat duty (>9%), solvent flow rate (>17%) and CW requirement (>17%). It should be mentioned, however, that the use of more concentrated solutions can lead to higher corrosion rates and increased amine emission from the system. In addition, the reboiler temperature increases for cases operating with higher MEA concentrations, which can also lead to thermal degradation of the solvent.

From **Figure 6**, it can be further noted that the FG inlet temperature has almost no effect on the heat requirement, solvent flow rate, and CW requirements. The same was also observed when varying the lean solvent temperature and only influencing the CW requirements. The use of solvent at lower temperatures than that of the base case (40°C) increases the CW requirements by more than 20%. This increase is mainly used in the lean solvent cooler. The temperature difference in the lean/rich HX and the operating pressure of the stripper were found to influence only the heat and CW requirements. If the lean/rich HX is operated with a larger temperature difference, then the rich solvent before entering the desorber column is cooler and, in consequence, more heat is required for solvent regeneration, and since the lean solvent

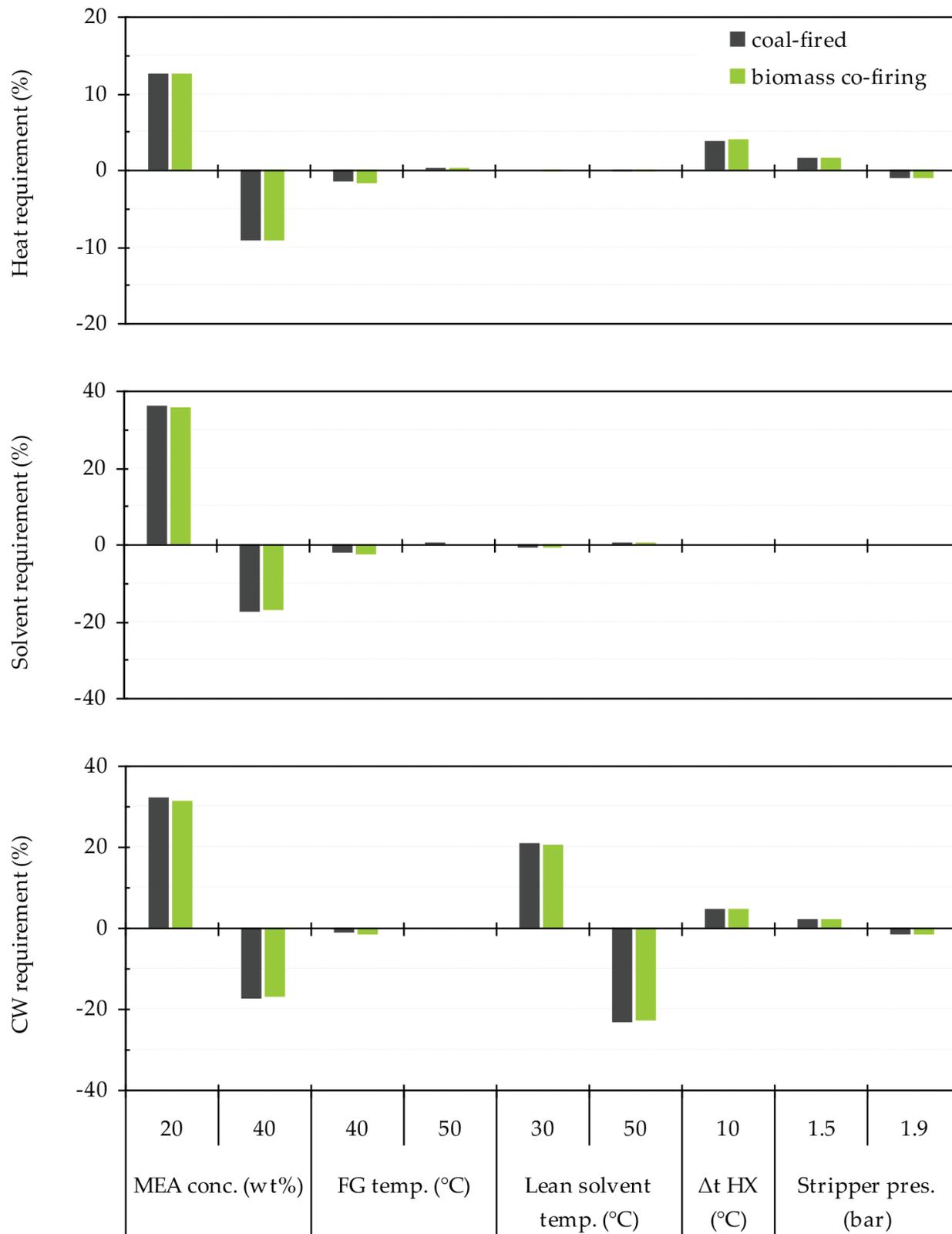


Figure 6. Effect of different parameters on the heat, solvent, and CW requirement in the CO₂ capture process with respect to the base case.

leaving the HX is warmer, then more CW is required to cool the stream to 40°C. Furthermore, operating the stripper at lower pressure leads to higher heat requirement and CW consumption. However, increasing the pressure from 1.7 bar (base case) to 1.9 bar reduces both the reboiler duty and the CW requirement, and in addition, the energy consumption for the compression of CO₂ is also reduced.

3.3. Effect of MEA concentration

As was shown earlier, the concentration of MEA in the solution can significantly influence the CO₂ capture process requirements. Therefore, it is necessary to investigate its effect on the plant performance. **Table 9** presents the simulation results for the coal-fired and cofiring cases using different MEA concentrations in the capture process. As can be seen, increasing the concentration of MEA has a positive effect on the plant energy performance. For coal-fired cases, the net electrical efficiency increases from 29.56% with 20 wt% MEA to 31.13% with 40 wt% MEA, i.e., an improvement of 1.57% points. It can be noted that the power demand of the CO₂ capture and compression process in all three cases is almost the same and only slightly decreases with the increase of amine concentration. This is because the solvent flow rate decreases and leads to lower pumps work. The amount of steam required for solvent regeneration decreases from about 180.5 kg/s, representing 57.1% of the total IP/LP crossover with 20 wt% MEA, to 145.4 kg/s, i.e., 46% of the IP/LP steam with 40 wt% MEA. For the cofiring cases, the electrical efficiency is 0.5% points lower than that of coal-fired cases. As noted, the gross power output is lower because the amount of steam extracted for solvent regeneration is higher in the cofiring cases. For example, the amount of extracted steam in the cofiring case with 20 wt% MEA is about 4 kg/s higher than that of the coal case. Moreover, the auxiliary power consumption in the cofiring cases with capture is higher, by approximately 4.2 MW_e, which is mainly consumed by the biomass processing system. The results further show that the solvent flow rate, the CW requirement, and the heat requirement for solvent regeneration for the cofiring plants with CO₂ capture are slightly higher than the values for coal cases.

CO ₂ capture (90%)	No	Yes		
MEA concentration (wt%)		20	30	40
Coal-fired cases:				
Cross power output (MW _e)	580.37	473.78	485.07	493.74
CO ₂ capture and compression (MW _e)		-43.27	-43.03	-42.95
Other auxiliary loads (MW _e)	-30.14	-30.61	-29.89	-29.61
Net power output (MW _e)	550.22	399.90	412.14	421.19
Net plant efficiency (% LHV)	40.67	29.56	30.47	31.13
Solvent requirement (kg/s)		2995.1	2202.9	1819.7
CW requirement (kg/s)		10218.1	7739.0	6400.0
Heat requirement (MW _{th})		434.3	385.8	349.7
Steam requirement (% of total IP/LP)		57.1	50.7	46.0

CO ₂ capture (90%)	No	Yes			
MEA concentration (wt%)			20	30	40
Biomass cofiring cases:					
Gross power output (MW _e)	580.37	471.95	483.26	492.01	
CO ₂ capture and compression (MW _e)		-43.93	-43.69	-43.59	
Other auxiliary loads (MW _e)	-33.69	-34.23	-33.50	-33.20	
Net power output (MW _e)	546.68	393.80	406.07	415.22	
Net plant efficiency (% LHV)	40.35	29.06	29.97	30.64	
Solvent requirement (kg/s)		3051.8	2248.9	1859.3	
CW requirement (kg/s)		10526.2	8013.7	6636.3	
Heat requirement (MW _{th})		442.3	393.4	356.8	
Steam requirement (% of total IP/LP)		58.2	51.7	46.9	

Table 9. Effect of MEA concentration on the energy performance of coal-fired/biomass cofiring plants with CO₂ capture.

3.4. Effect of heat requirement

In this section, the effect of the heat requirement for solvent regeneration on the power plant gross output was investigated. The simulation results are presented in **Figure 7**. The heat duty of the stripper reboiler was varied between 3.5 MJ/kg CO₂ captured (base case) and 2 MJ/kg CO₂ captured. The results showed that for the chemical absorption systems with heat requirement of 3.5 MJ/kg CO₂ captured, the gross power output of the plant decreases by more than 16% compared with the reference plants without CO₂ capture and the steam extracted from the IP/LP crossover amounts to ~50% of the total flow rate. In comparison, for systems with reduced heat requirement, for example, of 2 MJ/kg CO₂ captured, the power output decreases by only 9%, and the proportion of steam extracted is reduced to less than 30%. The amount of steam extracted for solvent regeneration is reduced from 1.45 kg steam/kg CO₂ captured (base case) to about 0.85 kg steam/kg CO₂ captured for the case with 2 MJ/kg CO₂ captured.

Figure 8 shows the effect of a capture system with lower heat requirement for solvent regeneration on the net power output and efficiency of the biomass cofiring plant. The simulations were carried out using the Cansolv technology for CO₂ capture with the following specific requirements: 2.48 MJ/kg CO₂ reboiler heat duty and 33.3 kWh/t CO₂ power duty [23]. It should be noted here that this technology is currently used at the SaskPower Boundary Dam power plant in Canada being the first commercial scale postcombustion carbon capture project [11]. The simulation results show that the net power output of the biomass cofiring plant integrated with the Cansolv capture technology would increase to about 428 MW_e, which is 5.3% higher than that of the plant using conventional MEA system. Compared with the reference biomass cofiring plant without carbon capture, the efficiency penalty due to CO₂ capture reduces to 8.79% points in case with Cansolv.

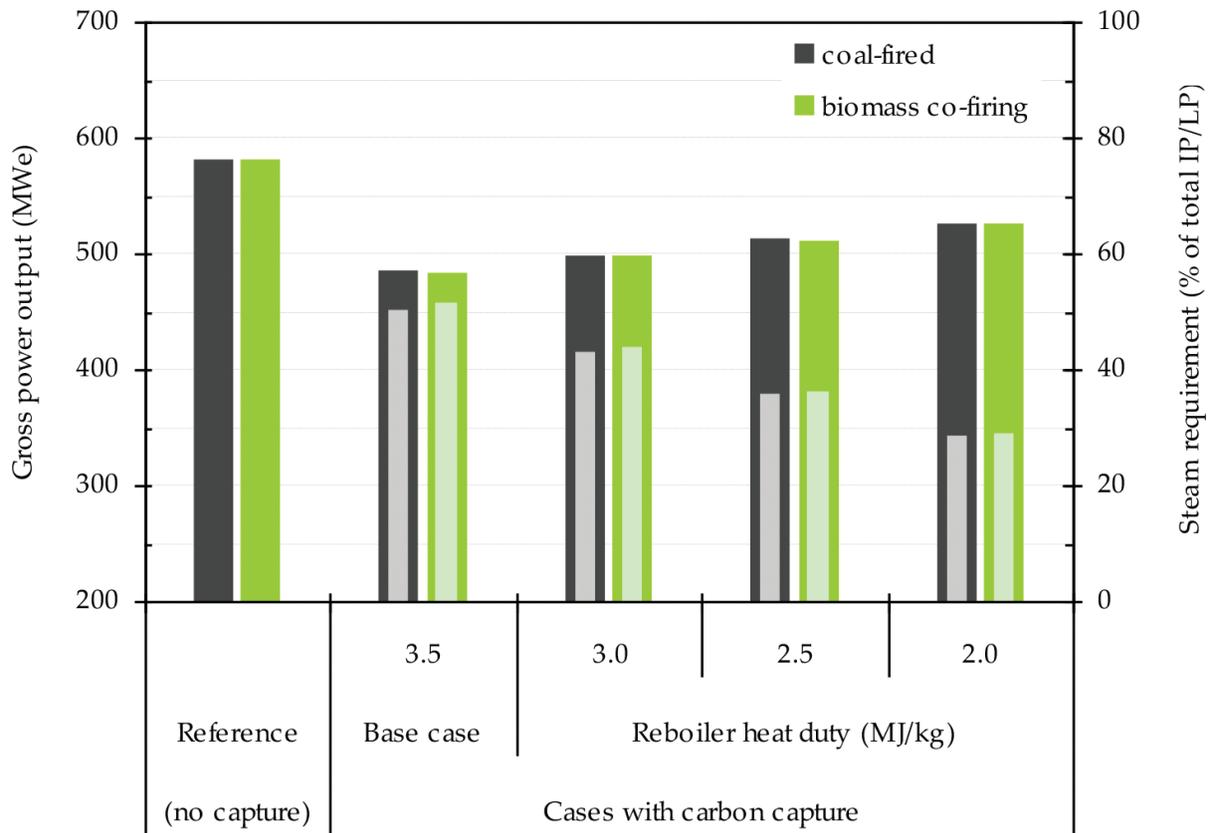


Figure 7. Effect of the reboiler heat duty on the gross power output (bars with a lighter color show the percentage of steam extracted from the IP/LP crossover).

3.5. Effect of CO₂ capture efficiency

To investigate the effect of the capture efficiency on the performances of coal-fired and biomass cofiring plants, the FG exiting the FGD unit was split into two streams, one directed to the capture unit and the other one sent directly to the stack. The amount of FG sent to the absorber column of the capture system varied between 100% and 56% of the total mass flow in order to achieve capture rates of 90–50%. In another configuration (not considered here), all the FG can be sent to the capture unit; however, in this case, the power requirements and cooling duties of the plant would increase.

The simulation results presented in **Table 10** show that the gross power output of both the coal-fired and biomass cofiring plants increases by ~9% as the capture efficiency decreases from 90 to 50%. This is primarily due to the fact that the quantity of steam extracted for solvent regeneration from the steam cycle is significantly lower (by ~45%) and, therefore, more steam is available for power generation. The net power output of the plants increases by more than 15% and the net electrical efficiency is 4.6% points higher than that of the case with 90% CO₂ capture. While the energy performances improve with a decrease in the capture rate, the plants specific CO₂ emissions increase from around 110 kg/kWh to more than 450 kg/MWh.

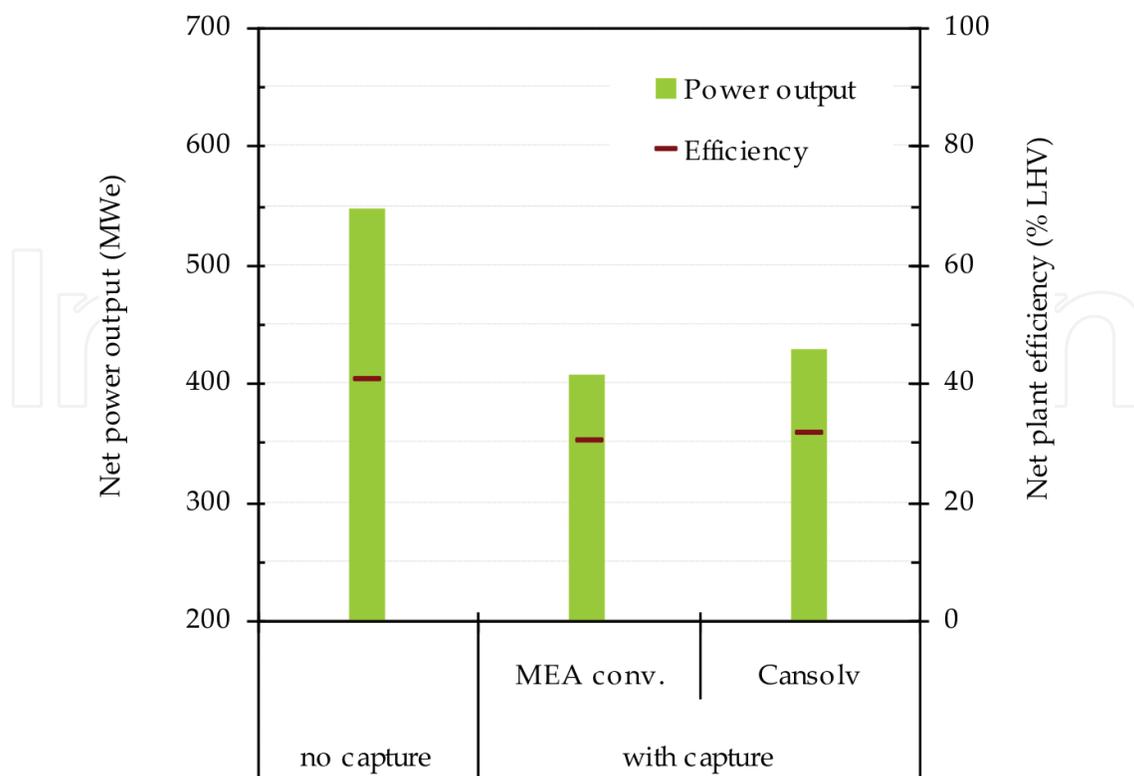


Figure 8. Effect of the capture system with lower reboiler heat duty on the net power output and efficiency of the biomass cofiring plant.

Overall capture efficiency (%)	90	80	70	60	50
FG to capture unit (% of total FG)	100	89	78	67	56

Coal-fired cases:

Gross power output (MW _e)	485.07	495.43	506.11	517.00	528.11
CO ₂ capture and compression (MW _e)	-43.03	-38.25	-33.47	-28.70	-23.91
Other auxiliary loads (MW _e)	-29.89	-29.92	-29.95	-29.97	-30.00
Net power output (MW _e)	412.14	427.26	442.69	458.33	474.21
Net plant efficiency (% LHV)	30.47	31.58	32.72	33.88	35.05
Solvent requirement (kg/s)	2203	1958	1713	1469	1224
CW requirement (kg/s)	7739	6878	6020	5160	4299
Heat requirement (MW _{th})	386	343	300	257	214
Steam requirement (% of total IP/LP)	51	45	39	34	28
Specific CO ₂ emissions (kg/MWh)	107	207	299	386	466

Biomass cofiring cases:

Gross power output (MW _e)	483.26	493.75	504.63	515.71	527.00
CO ₂ capture and compression (MW _e)	-43.69	-38.83	-33.98	-29.13	-24.27
Other auxiliary loads (MW _e)	-33.50	-33.52	-33.54	-33.56	-33.58

Overall capture efficiency (%)	90	80	70	60	50
FG to capture unit (% of total FG)	100	89	78	67	56
Net power output (MW _e)	406.07	421.40	437.11	453.02	469.17
Net plant efficiency (% LHV)	29.97	31.10	32.26	33.43	34.63
Solvent requirement (kg/s)	2249	1999	1749	1499	1249
CW requirement (kg/s)	8013	7122	6231	5341	4450
Heat requirement (MW _{th})	393	350	306	262	219
Steam requirement (% of total IP/LP)	52	46	40	34	29
Specific CO ₂ emissions (kg/MWh)	111	213	308	397	479

Table 10. Effect of CO₂ capture efficiency on the performances of coal-fired and biomass cofiring plants with CO₂ capture.

4. Conclusions

In this study, we investigated in detail the effect of biomass cofiring and carbon capture on the plant performances. For cofiring cases, 10% of heat input was substituted with hybrid poplar used as the biomass fuel. When carbon capture was considered, the plants were integrated with a MEA-based postcombustion capture technology. The plant's submodels, i.e., the boiler and flue gas cleaning section (deNO_x, deDust, deSO_x), the steam cycle, and the CO₂ capture and compression process were all modeled and simulated in Aspen Plus software. The simulation showed the following:

- (i) The addition of a MEA-based capture system to a supercritical coal-fired plant reduces the net plant efficiency to 30.47% (with 90% CO₂ capture rate), i.e., an efficiency penalty of 10.21% points compared with the reference plant without capture. The plant specific CO₂ emissions were decreased to 107.2 kg/MWh and the avoided emissions were 86.6%. Compared with these figures, the net efficiency of the plant with cofiring, after capturing 90% of the CO₂, decreases to 29.97%, i.e., an efficiency penalty of 10.7% points. Lower efficiency of the biomass cofiring plant with CO₂ capture of 0.5% points compared with the coal-fired plant with CO₂ capture is mainly due to the additional power demand for biomass processing and drying. Because of the lower performances and higher flue gas CO₂ flow rates, it was calculated that the plant specific CO₂ emissions were 110.6 kg/MWh. However, taking the biomass as carbon neutral and assuming that all the fossil-CO₂ is captured than the plant would have ~0 net CO₂ emissions.
- (ii) Among the investigated parameters that may affect the CO₂ capture process, it was found that the MEA concentration greatly influences the performances of the capture unit. For capture systems, operating with lower MEA concentrations, a higher reboiler heat duty, solvent flow rate, and CW requirement were achieved. However, the use of higher MEA concentrations, although lowers the consumption of steam, solvent, and CW, can lead to corrosion, solvent degradation, and higher amine emissions. The concentration of MEA also influences the energy performance of the plant. The results showed that the net efficiency increases as the MEA concentration increases. For the case

with 40 wt% MEA, the net efficiency of both the coal-fired and biomass cofiring plants improves by ~0.7 and ~1.6% points compared with the cases of 30 and 20 wt% MEA in the solution, respectively. The steam requirement reduces by ~9 and ~20% compared with 30 and 20 wt% MEA cases, respectively.

- (iii) The heat requirement for solvent regeneration in conventional MEA-based capture systems significantly affects the gross power output of the plant and, in consequence, the overall plant energy performance. It was found that the gross power output increases with decreasing the heat duty of the reboiler. For both the coal-fired and biomass cofiring plants with 90% CO₂ capture and an assumed heat requirement of 2 MJ/kg CO₂ captured, the gross power output increases by ~8.5% compared with the base case, while the steam requirement decreases by more than 40%. Lower reboiler heat duty of chemical absorption systems can be achieved by, for example, using an improved process configuration (e.g., absorber intercooling, lean vapor compression, split-stream, etc. [24–26]) and/or solvents with better characteristics [18, 23, 26–28].
- (iv) In addition, we analyzed the effect of the CO₂ capture efficiency on the overall performances of both the coal-fired and biomass cofiring plants. In this case, only a part of the flue gas stream was treated in the capture unit (with a fixed 90% capture rate), and the rest was sent directly to the stack. The results showed that the gross power output of the plants increases with decreasing the capture efficiency. Capturing less CO₂ from the plant requires less steam to be extracted for the solvent regeneration and, consequently, more steam is available for power generation. Furthermore, for lower capture rates, the net power output improves since the auxiliary power demand of the capture and compression process decreases. However, reducing the capture rates would negatively affect the plants CO₂ emissions, generating significantly more CO₂ into the atmosphere, which in case of biomass cofiring will be lower compared with coal-fired if only the net CO₂ emissions would be considered.

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Nomenclature

APH	Air preheater
BA/FA/TA	Bottom/fly/total ash
BH	Baghouse
BOP	Balance of plant
DCC	Direct contact cooler

FD	Forced draft
FG	Flue gas
FGD	Flue gas desulfurization
FWH	Feedwater heater
HHV/LHV	Higher/lower heating value (MJ/kg)
HP/IP/LP	High/intermediate/low pressure
HX	Heat exchanger
ID	Induced draft
PA	Primary air
PC	Pulverized coal
SCR	Selective catalytic reduction
ST	Steam turbine
ar	As received
db	Dry basis
\dot{m}	Mass flow rate (kg/s)
NE	Net emissions (kg/MWh)
SC	Specific consumption (kg/MWh)
SE	Specific emissions (kg/MWh)
W	Power (MW)
$\Delta\eta$	Efficiency penalty (% points)
η	Efficiency (%)

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