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| Author(s) | Berstad, David; Arasto, Antti;<br>Jordal, Kristin; Haugen, Geir |
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# Parametric study and benchmarking of NGCC, coal and biomass power cycles integrated with MEA-based post-combustion $CO_2$ capture

David Berstad[a*], Antti Arasto[b], Kristin Jordal[a], Geir Haugen[c]

[a] *SINTEF Energy Research, NO-7465 Trondheim, Norway*
[b]*VTT Technical Research Centre Of Finland, P.O. Box 1000, FI-02044 VTT, Finland*
[c]*SINTEF Materials and Chemistry, NO-7465 Trondheim, Norway*

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## Abstract

A comparative study of MEA-based post-combustion $CO_2$ capture has been performed for NGCC, coal and biomass power cycles. With particular focus on overall electric efficiency and electricity output losses per unit of captured $CO_2$, the performance of the power cycles in consideration have been calculated and compared with respect to variation in desorber pressure in the capture process. For each of the cases, overall efficiency is rather insensitive to desorber pressure, as no major energy gains are obtained in the trade-off between steam extraction pressure, reboiler duty and $CO_2$ compression ratio. Whereas NGCC shows the lower efficiency penalty (7.2–7.4 %-units) at 90% $CO_2$ capture ratio, the coal and biomass cases still show lower specific electricity output losses per unit of captured $CO_2$ (20–25% lower than for NGCC), despite higher efficiency penalties. Hence, when considering specific $CO_2$ capture and compression work as comparison criterion, the coal and biomass plants turn out more favourable than NGCC, despite higher efficiency penalty.

Keywords: Post combustion; $CO_2$ capture; CCS; NGCC; coal; biomass; MEA.

## 1. Introduction

The necessity for $CO_2$ capture and storage (CCS) from thermal power plants as one of several important means to stabilise atmospheric $CO_2$ levels and curb global warming, has been widely and increasingly emphasised over the past years [1]. Reduction of the significant efficiency penalty that is intimately connected to $CO_2$ capture is a key challenge in the efforts towards low- or zero-emission fossil-based power generation.

For post-combustion capture of $CO_2$, a capital area of research is the quest for new or improved liquid solvents, with a complementary area of research being the design and optimisation of the absorption–desorption process in which the solvents are employed [2–5].

Condensation of low-pressure steam is usually assumed to be the source of heat for solvent regeneration in studies of desorption units, with a general assumption that the required amount of steam can be delivered from the power plant at a pressure matching the requisite regeneration temperature.

The purpose of the present study is to investigate interdependencies and trade-offs in post-combustion $CO_2$ capture between the selected capture process, power cycle and $CO_2$ compression process. Focus is on the sensitivity of overall energy performance when altering operation parameters in the capture process, desorption pressure in particular, which will impact both steam cycle and $CO_2$ compressor train.

## 2. Process configurations

MEA absorption–desorption of $CO_2$ is selected as capture process in this study, and will be applied to both natural gas combined cycle (NGCC), coal- and biomass-fired steam cycles with respective flue gas characteristics. Furthermore, four-stage $CO_2$ compression with inter-cooling and dehydration is assumed for all configurations.

### *2.1. Reference power plant cycles*

#### 2.1.1. Natural gas combined cycle plant

The natural gas-fired power plant in this study is an NGCC plant with a steam bottoming cycle. Nominal electric output is 385 MW from a LHV-based fuel input of 680 MW, resulting in an overall thermal efficiency of 56.6%. Gas turbine inlet temperature and pressure are 1226°C and 15 bar, respectively. Exhaust gas enters the heat recovery steam generator (HRSG) at 610°C and 1.05 bar. The bottoming process consists of three stages, where high-, intermediate- and low-pressure steam turbine inlet states are: 560°C, 111 bar; 560°C, 27 bar; and 324°C, 5.33 bar. Steam quality at the low-pressure turbine outlet is 91.9% and condenser inlet pressure equals 40 mbar. Exhaust gas state at the HRSG outlet is 96.8°C and 1.013 bar. Modelling and simulation is performed with PRO/II from SimSci-Esscor [6].

#### 2.1.2. Coal-fired plant

The coal-fired power reference plant in this study is a large-scale supercritical condensing power plant in a coastal location. Nominal electricity output of the plant is 522 MW. With 1270 MW bituminous coal fuel input, the reference case efficiency is 41.1%. The process is modelled with the Aspen Plus process simulator [7] as a generic power plant model. Main steam parameters assumed are: 560°C, 253 bar for primary steam; and 560°C, 160 bar for reheat steam. The condenser pressure is assumed to be 40 mbar. This power plant configuration represents normal existing coal fired condensing plant setup and performance in coastal locations in Northern Europe, for example in Finland.

#### 2.1.3. Biomass-fired plant

Representing the reference biomass power plant in this study is a modern condensing power plant fuelled with forest residues. The plant is an example of a biomass-fired power plant on the maximum capacity range in the light of regional biomass availability in forested areas in Northern Europe. This plant has 242 MW nominal electricity output with 596 MW fuel input, resulting in 40.7% efficiency for the reference case. It is, like the coal plant, modelled in Aspen Plus as a generic power plant model with modern steam parameters: 560°C, 164 bar for primary steam; 560°C, 57 bar for reheat steam; and condenser pressure equal to 40 mbar.

Summary of power and efficiency figures of the reference plants is found in Table 1. Also shown are respective flue gas compositions and $CO_2$ content for each power cycle. In addition to considerably lower $CO_2$ fraction, the $O_2$ content is also significantly higher for NGCC than for coal and biomass, due to air dilution for temperature moderation.

Table 1 Key figures for reference NGCC, coal and biomass power plants.

| | Unit | NGCC | Coal | Biomass |
|---|---|---|---|---|
| Fuel input (LHV) | $MW_{th}$ | 680 | 1270 | 596 |
| Turbine power output | $MW_{el}$ | 391 | 538 | 246 |
| Electricity consumption | $MW_{el}$ | 6 | 16 | 4 |
| Power island output | $MW_{el}$ | 385 | 522 | 242 |
| Net thermal efficiency | % | 56.6 | 41.1 | 40.7 |
| $CO_2$ emission rate | kg/s | 39.6 | 123 | 53.7 |
| Specific $CO_2$ emissions | $g/kWh_{el}$ | 370 | 849 | 798 |
| *Flue gas composition* | | | | |
| $H_2O$ | mol-% | 7.9 | 6.1 | 12.8 |
| $CO_2$ | mol-% | 3.9 | 14.6 | 15.0 |
| $N_2$ | mol-% | 74.6 | 75.8 | 69.8 |
| $O_2$ | mol-% | 12.7 | 3.4 | 2.6 |
| Ar | mol-% | 0.9 | n/a | n/a |

### *2.2. Post-combustion capture process*

The $CO_2$ capture process of this study is represented by an absorption–desorption cycle with MEA as solvent. Principal flow diagram of this process is displayed in Figure 1 and key data for the main process units involved are listed in Table 2. Exhaust gas from the various power cycles is cooled to 50°C and blown into the absorption columns. Scrubbed exhaust is extracted at the top of the absorber and emitted to the atmosphere, while the rich solution is pumped and heated in the rich-lean heat exchanger prior to entering the top of the stripping section. In the desorption column, heat from condensation of steam extracted from the steam power cycles releases $CO_2$ from the MEA solution. Captured $CO_2$ is extracted at the top of the desorber via the condenser and transported to the compressor train. The lean solution is recirculated to the absorption section of the process subsequent to cooling in the rich-lean heat exchanger.

Modelling and simulations of the $CO_2$ capture processes are performed with ProTreat [8], a gas treating process simulation tool that uses mass and heat transfer rates to model the towers used in amine-based processes, in contrast to using theoretical trays.

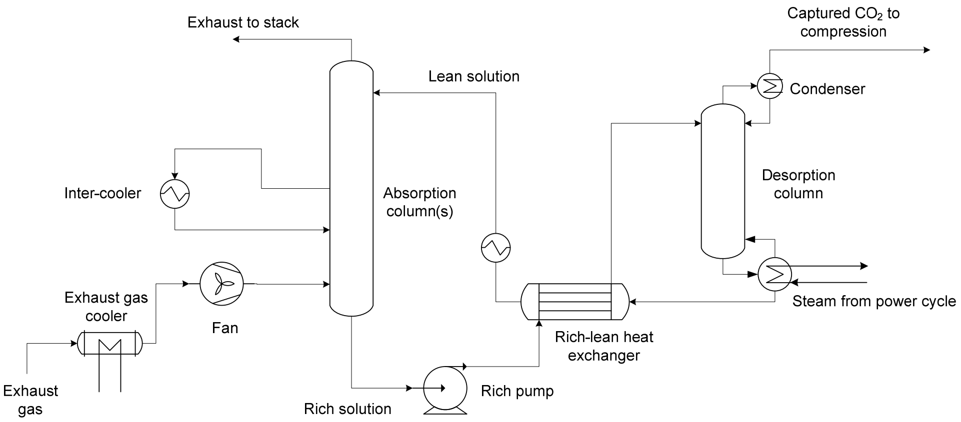

Figure 1 Flow diagram of the absorption–desorption $CO_2$ capture process with MEA as solvent.

Table 2 Main process parameters for the MEA absorption–desorption $CO_2$ capture process.

| | | Unit | NGCC | Coal | Biomass |
|---|---|---|---|---|---|
| Absorption columns | Number | | 2 | 2 | 1 |
| | Packing height | m | 16.0 | 16.0 | 16.0 |
| | Diameter | m | 12.5 | 12.5 | 11.5 |
| Desorption columns | Number | | 1 | 1 | 1 |
| | Packing height | m | 8.5 | 8.5 | 8.5 |
| | Diameter | m | 7.0 | 11.0 | 7.0 |
| MEA solution | Weight-% | % | 30 | 30 | 30 |
| | Lean loading | mol/mol | 0.250 | 0.270 | 0.270 |
| | Rich loading | mol/mol | 0.474 | 0.521 | 0.521 |
| Fan | Outlet pressure | kPa | 105.2 | 105.2 | 105.2 |
| | Efficiency | % | 85 | 85 | 85 |
| Rich pump | Efficiency | % | 75 | 75 | 75 |
| Rich-lean heat exchanger | Temperature approach | °C | 10 | 10 | 10 |
| | Pressure drop | bar | 0 | 0 | 0 |

### *2.3. $CO_2$ compression process*

In this study the compression process is assumed to consist of four stages, as shown in Figure 2. Parameters for each compression stage are listed in Table 3. Inter-cooling of the $CO_2$ stream to 25°C is performed downstream of each compression stage, followed by dehydration in knock-out drums. Relative inter-cooler pressure drop is assumed to be 3% of the inlet pressure.

As the number of compression stages is fixed and the captured $CO_2$ will be of varying pressure in the case studies presented in the following section, the pressure ratio distribution will not be identical for all cases. In the $CO_2$ compression model assumed in this study, the first two stages will have fixed pressure ratio equal to 3.5, while the third and fourth stages will have fixed outlet pressures of 80 and 200 bar, respectively. Hence, the pressure ratio of the third compression stage will vary with the pressure level of captured $CO_2$.

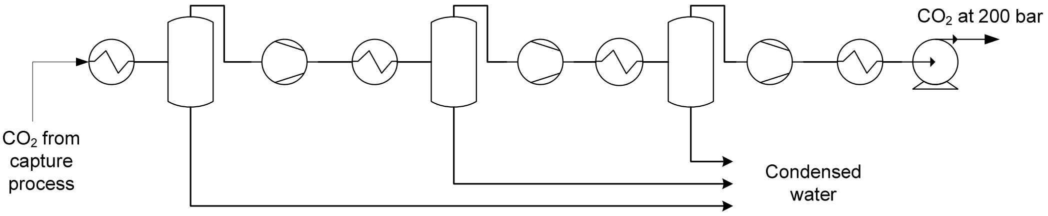

Figure 2 Flow diagram of the $CO_2$ compression process. The captured stream is compressed in three inter-cooled stages and subsequently pumped to export pressure (200 bar).

Table 3 Parameters for $CO_2$ compressor stages.

| Stage | Type | Pressure ratio | Polytropic efficiency |
|---|---|---|---|
| 1 | Gas compressor | 3.5 | 85% |
| 2 | Gas compressor | 3.5 | 80% |
| 3 | Gas compressor | 1.4–5.6 | 75% |
| 4 | Liquid pump | 2.5 | 75% |

## 3. Results and discussion

For each of the three power plant processes with post-combustion $CO_2$ capture, three different sets of operating parameters for the desorption process are investigated. Selected desorption pressure levels are: 1.24 bar (LP); 2.03 bar (MP); and 5.02 bar (HP). Main results from these case studies are listed in Table 4. As the maximum desorption temperature for MEA is normally assumed to be around 125°C, the HP case exceeds this limit by 17–19°C and is hence not considered as a viable point of operation. However, as the main focus of this study is on the energy performance as function of variation in operation parameters, it is still of interest to investigate the sensitivity of the overall models to such extreme desorption pressure levels.

Table 4 Main results from case studies for selected desorption pressure levels for the NGCC, coal and biomass power plants with post-combustion $CO_2$ capture and compression.

| | | NGCC | | | Coal | | | Biomass | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Case | Unit | LP | MP | HP | LP | MP | HP | LP | MP | HP |
| Desorber pressure | bar | 1.24 | 2.03 | 5.02 | 1.24 | 2.03 | 5.02 | 1.25 | 2.03 | 5.02 |
| Reboiler temperature | °C | 108 | 121 | 144 | 107 | 120 | 142 | 107 | 120 | 142 |
| Specific reboiler duty | $MJ_{th}/kg$ | 4.04 | 3.74 | 3.42 | 3.46 | 3.34 | 3.12 | 3.46 | 3.34 | 3.12 |
| Steam extraction pressure* | bar | 1.85 | 2.78 | 5.33 | 1.81 | 2.69 | 5.05 | 1.81 | 2.69 | 5.05 |
| Fuel input | $MW_{th}$ | 680 | 680 | 680 | 1270 | 1270 | 1270 | 596 | 596 | 596 |
| Power island output | $MW_{el}$ | 353 | 350 | 346 | 446 | 444 | 435 | 213 | 209 | 206 |
| Power, $CO_2$ compression | $MW_{el}$ | 13.6 | 11.5 | 8.3 | 41.9 | 35.4 | 25.5 | 18.3 | 15.4 | 11.1 |
| Power, auxiliaries | $MW_{el}$ | 2.7 | 2.8 | 3.0 | 3.5 | 3.6 | 4.4 | 2.9 | 3.1 | 3.7 |
| Net power output | $MW_{el}$ | 336 | 336 | 335 | 401 | 405 | 405 | 192 | 190 | 191 |
| $\eta_{th}$ incl. $CO_2$ compr. and aux. | % | 49.5 | 49.4 | 49.2 | 31.5 | 31.9 | 31.9 | 32.3 | 31.9 | 32.1 |
| Efficiency penalty from ref. case | % points | 7.15 | 7.26 | 7.42 | 9.55 | 9.21 | 9.20 | 8.37 | 8.72 | 8.57 |
| $CO_2$ capture ratio | % | 90.0 | 90.0 | 90.0 | 89.9 | 90.1 | 89.9 | 90.0 | 90.0 | 89.9 |
| Captured $CO_2$ flowrate | kg/s | 35.6 | 35.7 | 35.7 | 110.7 | 110.9 | 110.6 | 48.3 | 48.3 | 48.3 |
| Power, $CO_2$ capture and compr. | $MW_{el}$ | 48.6 | 49.4 | 50.5 | 122 | 117 | 117 | 49.8 | 51.9 | 51.0 |
| Specific $CO_2$ capt. and compr. work | MJ/kg | 1.36 | 1.39 | 1.42 | 1.10 | 1.06 | 1.06 | 1.03 | 1.07 | 1.06 |
| Specific $CO_2$ emissions | $g/kWh_{el}$ | 42 | 42 | 42 | 111 | 108 | 110 | 100 | 102 | 102 |

* Corresponds to a saturation temperature 10°C above the reboiler temperature

With the parametric variation of desorber pressure, overall efficiency varies with 0.3, 0.4 and 0.3 percentage points for each of the three plants. This indicates that the benefits from reducing the lost power consumption by extracting steam at lower pressure is to a large extent neutralised by the increased power requirement of $CO_2$ compression, and vice versa.

From the viewpoint of thermal efficiency reduction compared to reference case, the NGCC plant shows the best results with a best-performance efficiency penalty of 7.2 percentage points. For coal and biomass the corresponding figures are 9.2 and 8.4 percentage points, respectively. This difference in efficiency drop between coal and biomass on the one hand, and NGCC on the other, is mainly caused by the fact that the amount of $CO_2$ formed per unit of energy from fuel combustion is considerably lower for natural gas than for coal and biomass. In this work, these figures are 210, 349 and 325 $g_{CO2}/kWh_{th}$ for natural gas, coal and biomass, respectively.

Commonly, thermal efficiency penalty and decrease in power output compared to reference cases are regarded as key figures for evaluation of the energy performance of post-combustion $CO_2$ capture. These numbers provide a clear impression of the energy cost connected to integration of a post-combustion $CO_2$ capture cycle in power generation, but does not serve as an objective comparison criterion between different types of power plants with respect to the energy efficiency of $CO_2$ capture, as conditions and premises for capture inherently vary with type of fuel and power plant configuration. Instead, the figure of specific capture and compression work, the amount of electric energy lost per quantum of captured and compressed $CO_2$, can significantly enhance the understanding of penalties associated with post-combustion capture.

In Figure 3, the specific capture and compression work are plotted for the best-performance case for each type of power plant with $CO_2$ capture in this study. Also plotted is the reversible specific capture and compression work as function of $CO_2$ content of the flue gas. As can be observed, the specific capture and compression work is lower for the coal and biomass plants than for NGCC. This can be explained by the higher flue-gas concentration of $CO_2$ in the two former processes, increasing driving forces in the absorption process due to higher partial pressure, allowing higher effective loading of the MEA solution, as indicated in Table 2. As can be observed in Table 4, higher loading in the coal and biomass cases result in 9–14% lower specific reboiler duties than for NGCC. There are, however, indications that higher $CO_2$ fraction and thus more favourable capture conditions can be obtained by employing flue gas recirculation technology in NGCC plants [9,10]. A recirculation ratio of 30–40% may be realistic, potentially increasing the flue-gas $CO_2$ fraction to 6–7 mol-%.

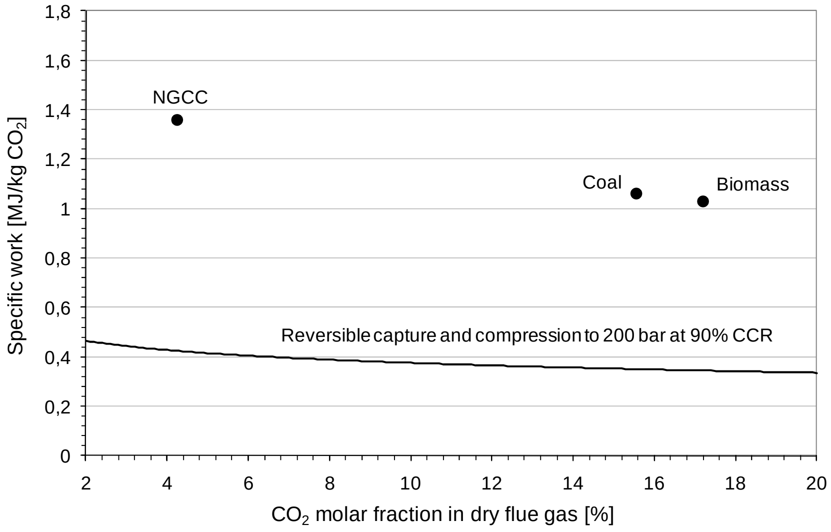

Figure 3 Specific capture and compression work for best-performance cases of NGCC, coal and biomass power plants with $CO_2$ capture. Plotted is also the reversible specific capture and compression power for 90% capture as function of dry flue-gas fraction of $CO_2$.

## 4. Conclusion

For each of the cases, overall efficiency of power generation with MEA-based $CO_2$ capture and compression to 200 bar export pressure is rather insensitive to selected desorber pressure, as no major gains are obtained in the trade-off between steam extraction pressure, reboiler duty and $CO_2$ compression ratio.

The NGCC power plant shows the lowest efficiency penalty when integrated with $CO_2$ capture. On the other hand, when considering the specific $CO_2$ capture and compression work, the coal and biomass plants turn out more favourable than NGCC, despite higher efficiency penalty. Hence, in a global perspective, coal and biomass plants such as those considered in this study are more favourable targets for post-combustion CCS from an energy point of view, as $CO_2$ is available at higher partial pressure than is the case for NGCC.

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