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Evaluation and Comparison of the Part Load Behaviour of the CO₂ Capture Technologies Oxyfuel and Post-Combustion

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Abstract

The rising share of fluctuating renewable energies increasingly demand flexible and part load operation of fossil-fuelled power plants with and without CCS. In this work the part load behaviour of the Oxyfuel and the post-combustion CO₂ capture processes are evaluated and compared. The net efficiency of the conventional hard-coal-fired power plant decreases from 45.2% at full load to 41.6% at 40% load. The net efficiency with post-combustion CO₂ capture using 7 m MEA as solvent decreases to 34.7% at full load and 30.2% at 40% load. The Oxyfuel process reaches in turn a net efficiency of 36.6% at full load and 32.3% at 40% load and shows therefore a benefit of 1.9%-points at full load compared to the post-combustion CO₂ capture with MEA. The efficiency advantage of the Oxyfuel process compared to the post-combustion CO₂ capture process remains constant at part load.

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1. Introduction

The ongoing climate change is a serious ecologic and economic challenge in the next decades. To limit the global temperature rise to 2 °C the IPCC (Intergovernmental Panel on Climate Change) recommends a reduction of greenhouse gas (GHG) emissions by 80% until 2050 compared to 1990 [1]. GHG emissions from coal-fired power plants can be reduced by increasing the energy conversion efficiency or by separating and withholding CO₂, commonly referred to as carbon (dioxide) capture and storage (CCS).

Although the contribution of renewable energies is growing significantly, fossil fuels such as coal will remain central to the world's energy supply during the next decades. The increased share of fluctuating energy sources like wind and solar power will lead to the need for flexible operation of power plants.

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Fossil-fuelled power plants too will have to operate more frequently in part load than in the past, the remaining power plants will have to provide larger amounts of balancing power to ensure grid stability and the number of load changes increases [2]. The Oxyfuel process and the post-combustion CO₂ capture (PCC) are two promising possibilities to reduce CO₂ emissions of coal-fired power plants with CCS and will also have to perform under this flexible operation in the future.

2. Processes Description

The Oxyfuel process and the PCC are both based on the conventional steam power plant process. In this section an overview of these processes will be presented before in section 3 the modelling work performed will be discussed in detail.

2.1. Conventional Hard-Coal-Fired Steam Power Plant Process

Conventional state-of-the-art hard-coal-fired power plants burn pulverised coal with air. The heat is transferred to a water steam cycle. The raw flue gas contains, besides nitrogen, CO₂, oxygen and water, as well as certain amounts of nitrogen oxides, fly ash (dust) and sulphur oxides. Therefore the flue gas treatment comprises a denitrification system, an electrostatic precipitator and a wet flue gas desulphurisation (FGD) unit.

The steam cycle comprises a super-heater and a re-heater. Power plants currently under construction have supercritical steam parameters. Feed water is pre-heated in up to nine feed water pre-heaters with steam tapplings from the steam turbine. The maximum overall net electric efficiency of such a hard-coal power plant is today approx. 46%. The reference power plant modelled in this paper reaches a net efficiency of 45.2 %.

2.2. Post-Combustion CO₂ Capture Process

In the PCC process CO₂ is absorbed from the flue gas of the conventional power plant by a chemical solvent in aqueous solution. The CO₂ content of typical hard-coal-fired power plants lies in the range of 12-15vol% (wet). The reduction of the CO₂ emissions is accompanied by a significant loss in electrical power output and a related net efficiency penalty of approx. 10%-pts. for processes using MEA [3]. In this paper 7 m MEA is used as solvent and causes a net efficiency penalty of 10.5%-pts. compared to the conventional power plant at full load. The retrofit of existing power plants with PCC is possible due to a low level of integration and downstream application. Furthermore, the PCC is already technically mature and applied routinely to gas purification applications, however, under substantially different boundary conditions.

Figure 1 shows the schematic of the PCC process. The flue gas of the boiler passes through the flue gas treatment, where it is cleaned and cooled, and then enters the absorber column at the bottom, in which the CO₂ is absorbed by a counter-current solution flow. The treated gas is released to the atmosphere, while the rich (CO₂-loaded) solution is gathered at the bottom and pumped to the desorber, passing the rich/lean heat exchanger (RLHX) where it is heated up, and enters the desorber column at the top with a temperature close to the desorber temperature level. In the desorber the absorbed CO₂ is stripped from the rich solution and the solvent is regenerated. The required heat duty is provided by a reboiler in which steam from the power plant is condensed and vapour (stripping steam) is generated. The counter-current vapour flow, consisting mainly of steam and CO₂, provides the necessary partial pressure difference and heat for desorption. At the head of the desorber the gas is led to the overhead condenser where the CO₂-

rich gas is cooled and the water vapour is condensed. The nearly pure CO_2 stream is compressed for transportation.

The lean solution is gathered at the reboiler and pumped to the top of the absorber closing the process cycle, passing the RLHX where it is cooled and preheats the rich solution. A detailed explanation of the process can be found in [3]. An overview of this process is given in [4].

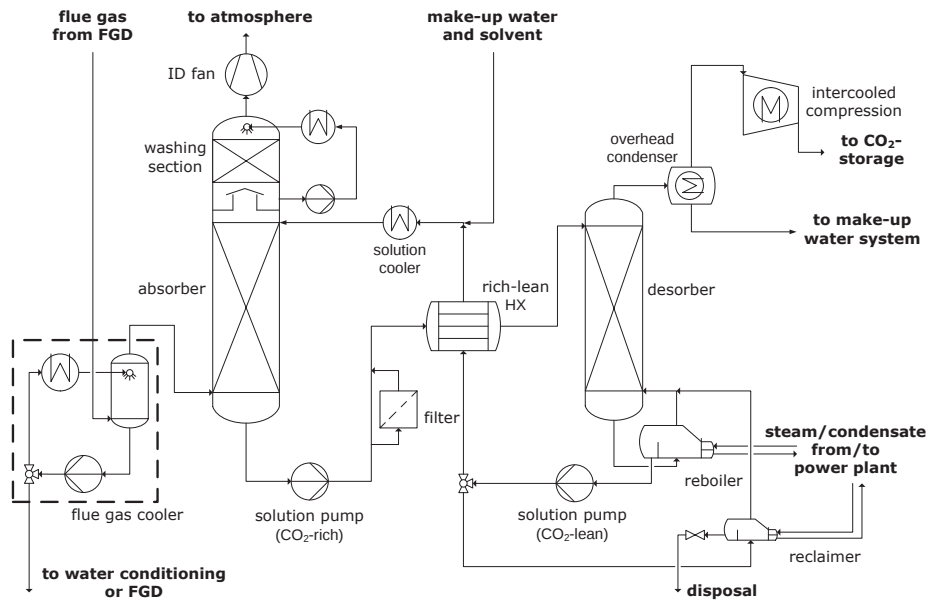


Figure 1. Schematic of a chemical PCC absorption process for CO_2 capture.

The target of the PCC is to reach a certain CO_2 capture rate, e.g., that 90% of the CO_2 emitted by the power plant is captured by the PCC. The CO_2 capture rate depends on the circulated solution flow rate and the working capacity (difference of lean and rich loading) of the solution. The solution flow rate, and therefore the L/G (mass ratio of solution and gas flow), can be controlled by the pumps in the process. Particularly the heat provided in the reboiler influences the loading of the lean solution while the rich loading is a result of the entire process. For this reason the working capacity of the solution is adjusted by the transferred heat.

The low pressure steam from the power plant is extracted from the intermediate pressure/low pressure (IP/LP) crossover section of the steam turbine. The reduction of the steam mass flow in the LP turbine leads to decreasing pressure there so that a pressure maintaining valve is used to provide the pressure level needed for heat transfer in the reboiler [5]. The power output of the power plant is reduced due to the reduced steam flow, the auxiliary power demand of the PCC, blowers and pumps, as well as the CO_2 compressor and the increased cooling water demand, which results in a higher demand of auxiliary power for the cooling water pumps.

2.3. Oxyfuel Process

The Oxyfuel process burns coal in an atmosphere of oxygen and recirculated flue gas and yields, as the nitrogen of the air is avoided, a flue gas with a high CO_2 content (approx. 80vol% (dry) for hard coal) [6].

The schematic view of the flue gas side of the Oxyfuel process configuration chosen is shown in Figure 2. Pulverised coal is transported by recirculated flue gas (primary flue gas recycle) to the boiler and burnt in an atmosphere of additionally recirculated flue gas (secondary flue gas recycle) and O_2 from a cryogenic air separation unit (ASU). The whole flue gas from the boiler passes a high-temperature electrostatic precipitator first, before partially branching out to the secondary flue gas recycle. The remaining flue gas, whereof a small portion serves as primary flue gas recycle, is cooled, desulphurised and treated in the gas processing unit (GPU). The GPU removes the impurities O_2 , N_2 and Ar by an one-staged partial condensation from the dried flue gas to receive a purity of the CO_2 stream larger than 96vol%. Including a cryogenic ASU with reduced oxygen purity of 95% and the compression of the captured CO_2 to 110 bar the net efficiency of the overall Oxyfuel power plant reduces by approx. 8-10%-pts. compared to the conventional power plant. In the work reported in this paper a net efficiency penalty of 8.6%-pts. is reached. A detailed overview of the Oxyfuel process can be found in [7].

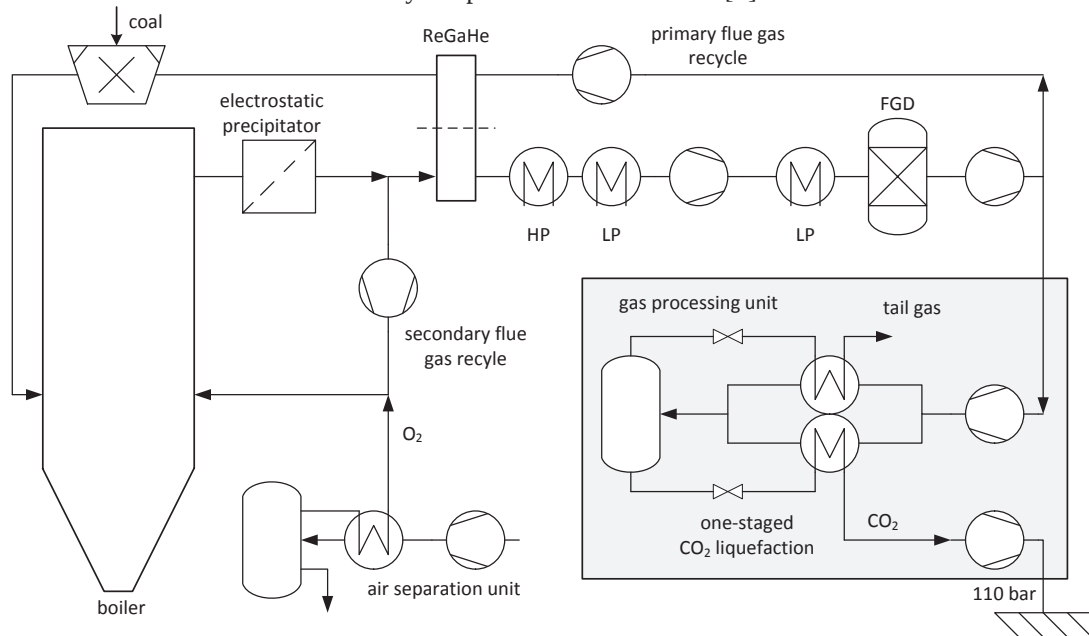


Figure 2. Simplified scheme of the flue gas path of the Oxyfuel process with a regenerative gas heater (ReGaHe), a wet flue gas desulphurisation unit (FGD) and heat transfer to low pressure (LP) and high pressure (HP) feed water.

3. Modelling

The most suitable simulation tools for the steady-state simulations of each sub-process are chosen, namely Ebsilon[®] Professional for the overall power plant and Aspen Plus[®] for the CO_2 separation processes. These tools are directly linked with each other during simulation using own-developed software extensions. The boundary conditions and component characteristics used in modelling the different processes are kept the same to allow reliable comparison.

The partial load of the power plant is defined as the heat input at part load divided by the heat input at full load. Operation below the once-through minimum load (approx. 40%) is not considered. All boundary conditions agree well with data obtained from manufacturers, operators and electric utilities, thus ensuring realistic results.

The specifications for CCS at each load are a capture rate of 90%, a CO₂ purity of at least 96% and the compression of the CO₂ to 110 bar.

3.1. Conventional Power Plant

Basis for the models are data of the concept study “Reference Power Plant North Rhine-Westphalia” [8]. The design of the reference power plant is close to the actual newly built power plants in Germany. The gross electric power output is 600 MW with live steam parameters of 600 °C and 285 bar, with reheat steam parameters of 620 °C and 59 bar and a condenser pressure of 40 mbar. Eight feed water pre-heaters are implemented and induce a feed water temperature of 303.4 °C. The pressure of the steam tapplings is optimised for the design point at full load. The pressure in the IP/LP crossover is 5.5 bar at full load.

The once-through steam generator is operated with sliding pressure. The air ratio λ is 1.15 at full load and increases to 1.4 at 40% load. The flue gas temperature downstream the economiser decreases from 380 °C at full load to 320 °C at 40 % load. A part of the high pressure (HP) feed water is led via a steam pre-heater bypass and is heated by heat displacement from the air downstream of the regenerative air pre-heater. The mill outlet temperature is 100 °C and is controlled by adding cold air to the mentioned pre-heated stream. The flue gas temperature behind the air pre-heater is maintained at 115 °C with a steam/air pre-heater that pre-heats the fresh air.

In part load the dry isentropic efficiencies of the steam turbine sections are calculated using characteristic lines in accordance with the corresponding mass flows. In the last stages of the LP turbine the influence of wet steam (Baumann Correlation) and exit losses are taken into consideration. The other turbomachinery (i.e., fans and pumps) is modelled using realistic characteristic diagrams.

Part load behaviour of all heat exchangers is implemented by a characteristic line for the heat transfer. The model of the regenerative heat exchanger considers a leakage which depends on the load. Pressure loss in part load is calculated using its dependence on mass flow and specific volume.

The composition of the hard coal is 66.1% carbon, 3.83% hydrogen, 6.6% oxygen, 1.6% nitrogen, 0.57% sulphur, 13.5% ash and 7.8 % water. The lower calorific value is 25.1 kJ/kg [9]. The temperatures of environment and coal are 15 °C. The cooling water temperature at the entrance of the condenser is 16 °C. The auxiliary power of the flue gas cleaning equipment is considered using specific power demands [9].

3.2. Post-Combustion CO₂ Capture Process

The overall process comprises the power plant, the PCC and the CO₂ compression. The design of the power plant island is kept the same as in the conventional plant. The PCC is retrofitted to the power plant, therefore the existing steam power process is modified as little as possible.

The PCC is modelled with AspenPlus®. The columns are modelled with detailed mass transport (rate-based) and chemical reactions. The columns, heat exchangers, pumps and fans are designed for the lowest overall net efficiency penalty at full load. The heat exchangers are designed and modelled with Aspen EDR. The flue gas flow is split in the PCC into two trains with an absorber diameter of 13.6 m and a desorber diameter of 7.9 m. The packing height in the absorber is 15 m and in the desorber 10 m. The RLHX is designed as plate heat exchanger for a logarithmic temperature difference of 10 K at full load. As reboiler a Kettle-type is used and designed for a temperature difference of 10 K between temperature of condensate and solution.

As solvent 7 m (30wt%) monoethanolamine (MEA) is used. The pressure at the top of the desorber is constant at 2 bar. The L/G is optimised in part load to reach the minimum net efficiency penalty, taking

into account the interface quantities: specific reboiler duty, reboiler temperature, cooling duty and auxiliary power.

The steam for the reboiler is extracted from the IP/LP crossover section. Retrofitting the steam extraction will decrease the pressure in the IP/LP crossover section. A pressure maintaining valve upstream of the LP turbine has to fulfil two functions: guarantee sufficient steam pressure for the reboiler and therefore sufficient condensing temperature, and prevent the volume flowing out of the last IP stage to exceed a certain level.

The CO₂ compression is modelled as two parallel trains with integrally geared compressors with six stages and five intercoolers. Single-train compressor operation starts when the CO₂ mass flow falls below 50%. [10].

3.3. Oxyfuel Process

Air pre-heating as a heat sink for the flue gas, like in conventional steam power plants, is not possible because of the ASU. Therefore, to transfer additional heat from the flue gas to the HP feed water, a LP bypass is installed. This decreases the flue gas heat losses. The primary flue gas recycle is reheated by a regenerative heat exchanger, see Figure 2.

The boiler model is divided into two zones [11]. The first zone models the radiation zone with a maximum steam temperature at the outlet of 470 °C that corresponds to the maximum allowable boiler membrane wall temperature. Slagging of heat exchangers in the second zone (convective zone) is avoided with flue gas temperatures below 1250 °C at its inlet. In part load the heat is split in the two zones the same way as in a conventional power plant. The recirculation rate is set to achieve the same ratio of flue gas volume flow to the full load volume flow in the boiler as in the conventional power plant. Flue gas temperatures at economiser outlet are the same as those in the conventional power plant. The mass flow of the primary recycle is reduced linearly to 75% at 40% load [11]. The oxygen ratio λ is kept constant at 1.15 for all loads to achieve better part load efficiency. As the recirculation rate is already fixed to set the distribution of heat in the boiler, the amount of oxygen is controlled by the ASU. Given the large impact of impurities in the flue gas on the efficiency of the CO₂ separation process an air ingress of 2 mass-% of the flue gas mass flow at boiler outlet is assumed.

To reach for the separated CO₂ purities larger than 96vol% the one-staged partial condensation in the GPU must be operated at approx. 30.5 bar and -45 °C. The condensed fraction yields the CO₂ stream and the vapour fraction the tail gas. The CO₂ stream and the tail gas are expanded partially to generate the required cooling power internally. The compressors upstream of the condensation (six stages, four intercoolers) and the final compression to 110 bar (three stages and inter-coolers) are designed in a two train configuration.

The cryogenic ASU delivers O₂ with the same purity of 95vol% for all load points. The actual separation process is modelled as a simplified black box while the adiabatic compressors are modelled with detailed characteristic diagrams. The heat (190 °C) of the compressed air at 4.6 bar is used for internal O₂ pre-heating to 140 °C. Three ASUs with two compressor trains each are necessary for the given power plant size.

4. Results

4.1. Conventional Power Plant

In part load the efficiency of the power plant decreases from 45.2% at full load to 41.6% at 40% load, shown in Figure 3, because of lower steam parameters, higher specific flue gas losses and higher specific

demand of auxiliary power. The auxiliary power is shown in Figure 3 as percentage of the gross electric output and is minimal at 80% load. The auxiliary power is mainly determined by the pumps and fans. The pressure loss in the system is reduced, but the efficiency of the turbomachines is reduced, too. This opposing effect leads to a minimum. The specific CO₂ emissions are 757.5 g/kWh at full load and increase up to 823.0 g/kWh at 40% load.

In full load the CO₂ content in the flue gas, shown in Figure 4, is 13.6vol% and reduces in part load due to higher air ratio and higher leakages in the air pre-heater. The flue gas mass flow is 566.6 kg/s at full load and reduces to 52.7% at 40 % load.

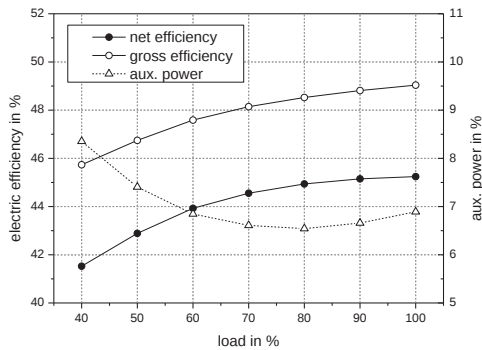


Figure 3. Efficiencies and auxiliary power of the conventional hard coal-fuelled power plant in dependence of the load.

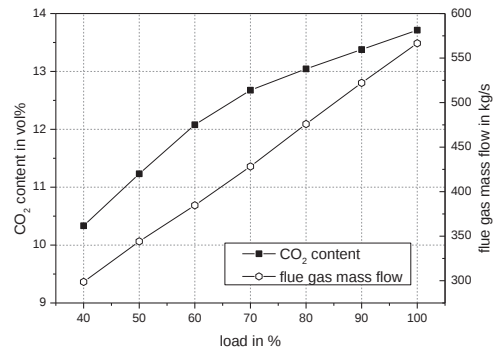


Figure 4. CO₂ content in flue gas and flue gas mass flow in the conventional power plant in dependence of the load.

4.2. Post-Combustion CO₂ Capture Process

The net efficiency of the process with MEA-PCC is 34.7% at full load and decreases to 30.2% at 40% load. Both the net and gross efficiency and the overall net efficiency penalty when using PCC, the difference between the conventional power plant and the power plant with PCC is shown in Figure 5. At full load the efficiency penalty is 10.5%-pts. and increases to 11.4%-pts. when reducing the load to 40%. The specific CO₂ emissions are 98.7 g/kWh at full load and 113.3 g/kWh at 40% load. The larger increase of the efficiency penalty is due to the higher throttling losses in the pressure maintaining valve to guarantee the pressure level necessary for heat transfer in the reboiler. Between 60% and 50% load the compressor operation is switched to single compressor operation, so that the specific power demand for compression decreases.

In Figure 6 the specific reboiler heat duty is shown. The optimised reboiler heat duty is 3.46 MJ/(kg CO₂) at full load. A higher L/G will increase the heat duty due to a higher demand to heat the solution to desorber temperature (latent heat). Otherwise, a low L/G will require a lower lean loading which requires more stripping stream to provide a lower CO₂ partial pressure. In part load the specific reboiler heat duty is reduced because of the decreasing logarithmic temperature difference in the RLHX and a higher rich loading. The rich loading is higher under part load because of an overdesign of the components absorber and desorber for that load, which induces a better mass transfer and closer approach to equilibrium, although the CO₂ content in the flue gas decreases. The logarithmic temperature difference decreases because of the oversized heat exchanger area at part load.

Figure 7 shows the specific reboiler heat duty for the regeneration of the solvent, the cooling duty and the specific auxiliary power of the PCC for the conditions with minimal overall net efficiency penalty (optimised L/G). The specific reboiler heat duty and cooling duty are reduced at part load because of the effects already explained. The specific auxiliary power is affected mainly by the turbo machines. The opposing effect of a lower pressure loss and a lower efficiency of the turbo machines leads to a minimum at about 60% load.

It is notable from Figure 8 that the minimal net efficiency penalty increases under part load. The L/G ratios of the net efficiency minima match the specific reboiler heat duty minima in Figure 6. With reduced load the optimised L/G shift to lower L/G. The lean loading for the optimised L/G is equal for the different loads.

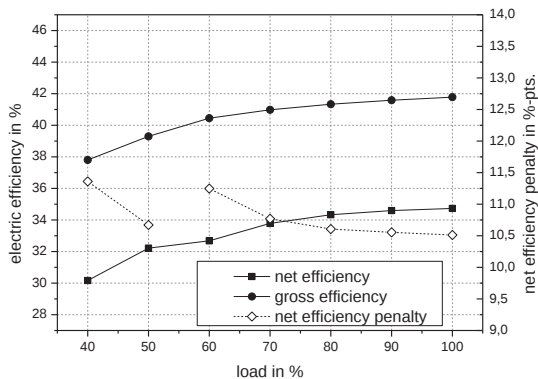


Figure 5. Net and gross efficiency and net overall efficiency penalty between the power plant with and without PCC in dependence of the load.

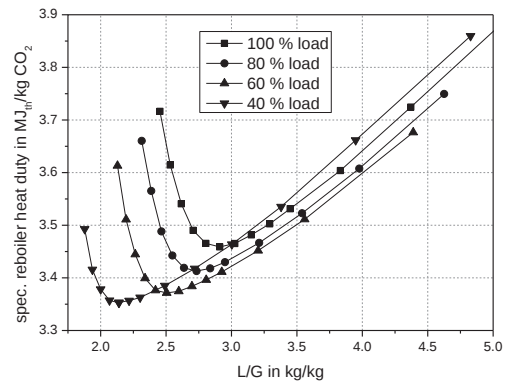


Figure 6. Specific reboiler heat duties for varying L/G and different loads.

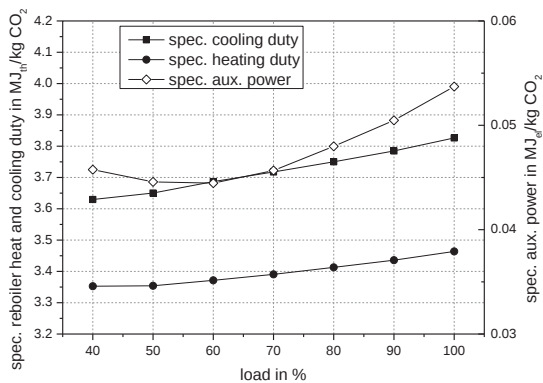


Figure 7. Specific reboiler heat and cooling duty and auxiliary power of the PCC in dependence of the load.

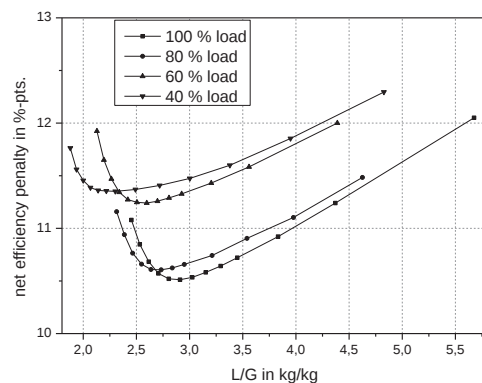


Figure 8. Overall net efficiency penalty for varying L/G and different loads.

4.3. Oxyfuel Process

Figure 9 compares the net and the gross efficiency of the Oxyfuel process with the conventional power plant. The efficiency loss grows constantly when reducing load. The specific CO₂ emissions are 94.1 g/kWh at full load and 106.4 g/kWh at 40% load. Depending on the mass flows of O₂ for combustion and the streams in the GPU, the compressors run at different efficiencies. At low load, parts of the compressor island are switched off as shown in Figure 10. This yields different specific energy consumptions for the loads depending on the characteristic lines of the compressor modules and their interconnections.

The recirculation rate is defined as the ratio of the recirculated flue gas mass flow (primary plus secondary recirculation) and the flue gas mass flow at boiler outlet. Although the absolute recirculation mass flows decrease with reduced load, the recirculation rate rises as Figure 11 shows. This is caused by the assumed design of the boiler that changes the volume flows of flue gas for part load the same way as in the conventional power plant. For a conventional power plant this means an increased air ratio at part load. As the oxygen ratio is maintained constant 1.15 for all loads in this Oxyfuel process, the increased recirculation rate causes a reduction in the O₂ concentration in the combustion atmosphere from 29vol% to 16.2vol% (Figure 12). The O₂ concentration falls below the O₂ concentration of a conventional air blown power plant at loads below 60%. This might impose the need for an optimised burner design and different feeding schemes of O₂ to the boiler than for a conventional power plant. The CO₂ concentration increases in accordance with the decreased O₂ concentration.

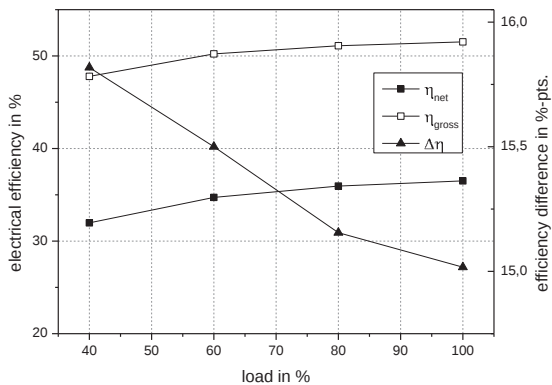


Figure 9. Electrical net and gross efficiencies of the Oxyfuel process and efficiency difference in dependence of the load.

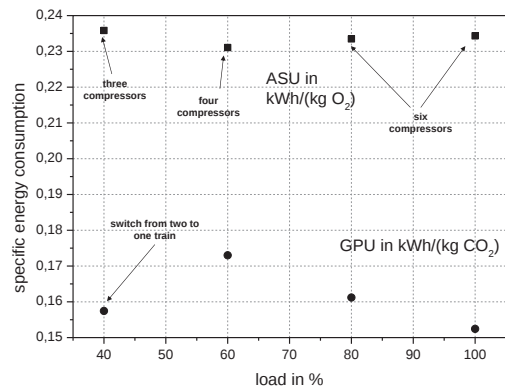


Figure 10. Specific electrical consumption of the compressors of the ASU and the GPU in dependence of the load. For part load some compressor modules are switched off.

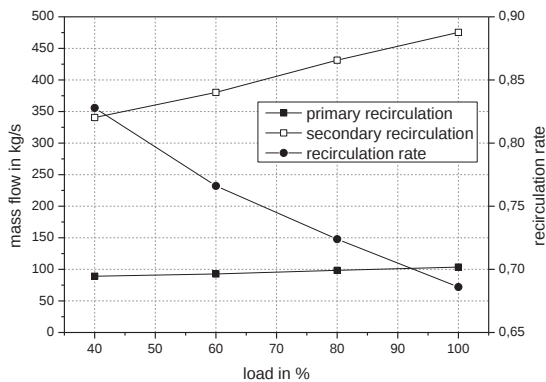


Figure 11. Absolute mass flows of primary and secondary recirculation and relative recirculation rate in dependence of the load.

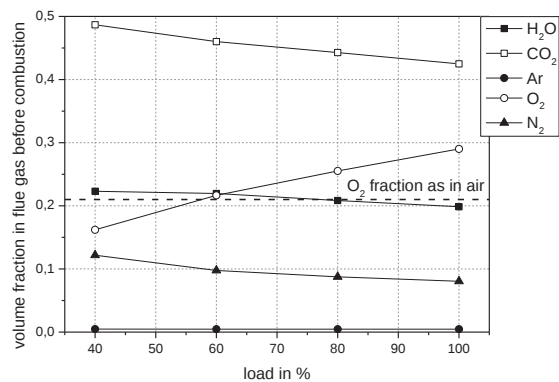


Figure 12. Volumetric concentrations in the mixture of recirculated flue gas and O₂ upstream of the combustion in dependence of the load.

The assumed air ingress mass flow as a constant fraction of 2% of the flue gas mass flow at boiler outlet, in combination with the relatively increased flue gas mass flows at part loads, yield increased N₂ concentrations in the combustion atmosphere (Figure 12) as well as in the flue gas at GPU inlet (Figure 13). This superposes the decreased residual O₂ concentration and results in a reduced CO₂ concentration at GPU inlet. Figure 14 shows that the purity of the CO₂ stream is kept at a constant level for all loads. The CO₂ stream contains the O₂ and N₂ according to their concentrations at GPU inlet.

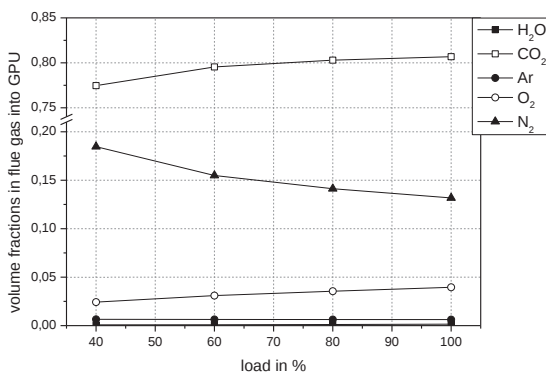


Figure 13. Volumetric concentrations of the dried flue gas from the boiler outlet treated by the GPU in dependence of the load.

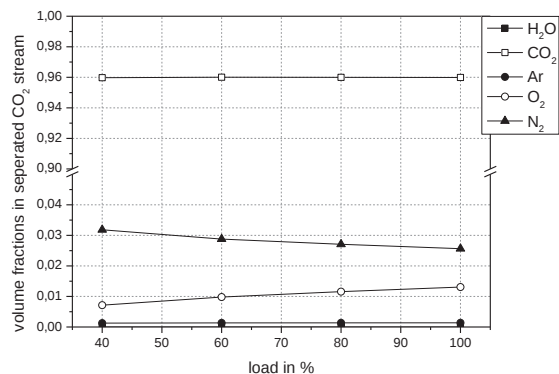


Figure 14. Volumetric concentrations in CO₂ stream in dependence of the load.

4.4. Comparison of the Processes

In Figure 15 the net efficiencies of the conventional power plant, the power plant with PCC using MEA as solvent and the Oxyfuel process are shown. The overall net efficiency penalty of the processes with CCS against the conventional power plant are also shown in Figure 15. The net efficiency of the Oxyfuel process in part load and full load is higher than the efficiency of the process with MEA-PCC. The increase of the efficiency penalty at part load in both processes is similarly. Related to the full load

no process has a specific advantage in the efficiency penalty at part load. Compared to the conventional power plant the losses of the PCC and the Oxyfuel process at part load are higher.

The PCC is at part load oversized and therefore the temperature difference in the heat exchangers decreased and a closer approach to equilibrium at the absorber outlet is reached. At part load the operation of the pressure maintaining valve to guarantee a pressure level necessary for the reboiler results in higher losses. The main decrease of the Oxyfuel process efficiency at part load is the reduced efficiency of the turbomachinery.

The process design like the choice of the solvent in the PCC or a different process scheme of the Oxyfuel process influences the efficiency in a huge manner. The focus in this investigation has been on processes that could be realised nowadays.

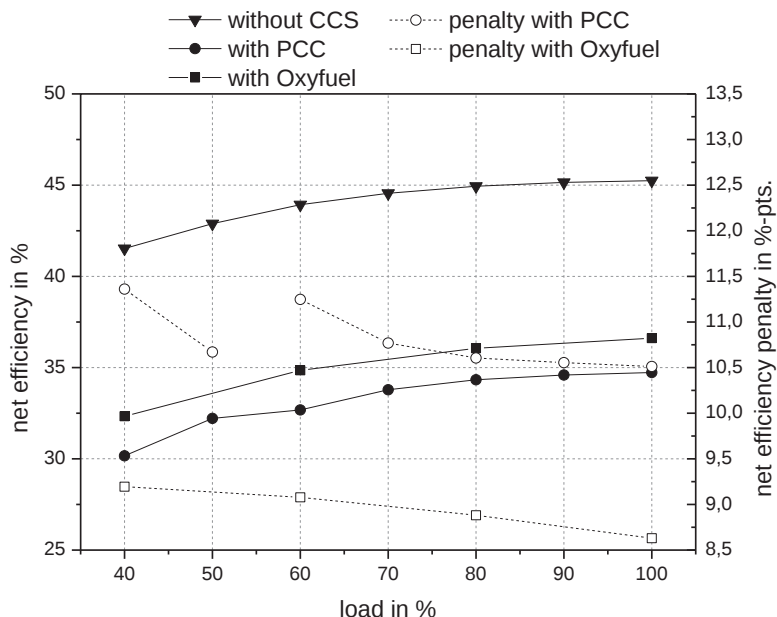


Figure 15. Net efficiencies of the power plant without CCS, power plant with PCC and Oxyfuel process and overall net efficiency penalty of the CCS processes against the conventional power plant in dependence of the load.

5. Summary and Outlook

The steady state part load behaviour of the CCS processes MEA-PCC and Oxyfuel has been evaluated under realistic and consistent boundary conditions. The overall net efficiency penalty of the Oxyfuel process is lower than that of the process with MEA-PCC.

The net efficiency penalty with post-combustion CO₂ capture using 7 m MEA as solvent increase from 10.5% at full load to 11.4% at 40% load. The Oxyfuel process reaches lower net efficiency penalties which increase from 8.6% at full load to 9.2% at 40% load. The difference of the net efficiency penalty between these two processes is not changing significant under part load.

The results presented here are used within the German DYNCAP research consortium to evaluate steam power plant processes with and without CCS under part load and serve as basis for development and validation of dynamic models, which are currently in development.

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