Techno-Economic Process Design of a Commercial-Scale Amine-Based CO_2 Capture System for Natural Gas Combined Cycle Power Plant with Exhaust Gas Recirculation

Usman Ali[a,1], Elvis O. Agbonghae[b], Kevin J. Hughes[a], Derek B. Ingham[a], Lin Ma[a], and Mohamed Pourkashanian[a]

[a]Energy 2050, Energy Engineering Group, Faculty of Engineering, Level 1, Arts Tower, University of Sheffield, S10 2TN, UK

[b]Research and Development Division, Nigerian National Petroleum Corporation (NNPC), E.P.C.L. Life Complex, P.M.B. 5373, Eleme, Rivers State, Nigeria

Abstract:

Post-combustion CO_2 capture systems are gaining more importance as a means of reducing escalating greenhouse gas emissions. Moreover, for natural gas-fired power generation systems, exhaust gas recirculation is a method of enhancing the CO_2 concentration in the lean flue gas. The present study reports the design and scale-up of four different cases of an amine-based CO_2 capture system at 90 % capture rate with 30 wt. % aqueous solution of MEA. The design results are reported for a natural gas-fired combined cycle system with a gross power output of 650 MW_e without EGR and with EGR at 20, 35 and 50 % EGR percentage. A combined process and economic analysis is implemented to identify the optimum designs for the different amine-based CO_2 capture plants. For an amine-based CO_2 capture plant with a natural gas-fired combined cycle without EGR, an optimum liquid to gas ratio of 0.96 is estimated. Incorporating EGR at 20, 35 and 50 %, results in optimum liquid to gas ratios of 1.22, 1.46 and 1.90, respectively. These results suggest that a natural gas-fired power plant with exhaust gas recirculation will result in lower penalties in terms of the energy consumption and costs incurred on the amine-based CO_2 capture plant.

Keywords: Exhaust gas recirculation; Natural-gas power plant; Process design; Economic analysis

1. INTRODUCTION

The escalating emissions of anthropogenic greenhouse gases is driving a transition towards a low-carbon energy mix in order to tackle the worsening effects of global warming and climate change [1]. Irrespective of the higher penetration of variable renewable power, fossil fuelled thermal power stations will continue to have a major share in the global energy mix needed to meet increasing power demand. However, to reduce the CO_2 emissions from fossil fuelled power generation systems, carbon abatement technologies need to be integrated with commercial-scale power generation systems, and of the various approaches the post-combustion CO_2 capture (PCC) offers some advantages [2]. Reactive absorption using alkanolamines, as one of the PCC technologies, is gaining more importance as the baseline

[1]Corresponding author: Tel.: +44(0) 745 716 0679
E-mail address: chemaliusman@gmail.com (Usman Ali)

technology for CO_2 capture due to its maturity [3, 4]. Currently, the major focus of the ongoing research is to reduce the amount of energy consumed in the regeneration of the solvent.

Research and development activities regarding solvent-based post-combustion CO_2 capture, with focus on the reduction of the energy consumption of the system, are being demonstrated worldwide through pilot-scale PCC [5-10]. In addition, PCC technology is near commercialization around the globe; demonstration of the integration of the PCC technology to a commercial-scale fossil-fuel power generation system, include the SaskPower Boundary Dam CCS Project, Canada, [11] the Peterhead CCS Project, United Kingdom, [12] and the ROAD CCS Project, Netherlands [13].

In addition, most of the reported studies in the literature involve process modelling studies of PCC systems. Process modelling and simulation can save time consuming experimental investigations as it can predict reliable results if the thermodynamic and kinetic packages used in developing the process models are rigorous and of high fidelity [3]. In the literature, there are several studies that discuss the design, operation and optimization of the PCC process using equilibrium-based models [14], rigorous rate-based models [15-18], and simplifications of rate-based models [19]. Yang and Chen [15] have simulated experimental case studies with equilibrium and rate-based models and have demonstrated the superiority of the rate-based model for predicting better results. Canepa and Wang [18] have reported the design of CO_2 capture plants for NGCC, however, economic implications are only considered for the lean loading and reboiler duty. Agbonghae et al. [16] reported the techno-economic process design of commercial-scale CO_2 capture plants for coal and natural gas fired power plants. Berstad et al. [17] have performed a comparative study for the design of the CO_2 capture plant for coal, biomass and natural gas fired power plants, however, it lacks an economic analysis. The exhaust gas from NGCC power plants is lean in CO_2 content, which results in a major penalty when an NGCC power plant is integrated with an amine-based CO_2 capture plant [20-22]. One way of enriching the exhaust gas from a natural gas-fired power plant is through exhaust gas recirculation (EGR) [23]. EGR offers many advantages in terms of enhanced CO_2 content in the exhaust gas and a reduced flue gas flow rate to the PCC system [10, 24]. However, it also has some limitations in terms of the maximum amount of the exhaust gas that can be recirculated without causing oxygen starvation at the combustor inlet, thus resulting in issues with combustion stability as reported in the literature [25, 26]. Following these limitations, the literature reports the design, operation and optimization of an amine-based CO_2 capture system integrated with NGCC in EGR mode and a comparison of the performance of the system without EGR [27-32].

1.1 MOTIVATION AND NOVELTY

In the literature there are various studies [27-32] that report the integration of an amine-based CO_2 capture plant with NGCC at 40 and 50 % EGR with little or no information about the actual design of the amine-based CO_2 capture plant. These studies report the heat exchanger network design [27-29] for various options for the steam extraction, the effect of the EGR on the thermodynamic properties of the turbo machinery, [28, 29] cost savings, [27] and a comparison of the process system performance with a humidification system, the supplementary firing and the external biomass fired boiler [30-32].

The process design of an amine-based CO_2 capture system for a commercial-scale NGCC in EGR mode and its comparison with a system without EGR, but without explicitly considering the techno-economics during the process design, can be found in the literature [33-37]. Sipöcz and Tobiesen [37] reported that a single absorber and a single stripper with heights 26.9 m and 23.5 m, respectively, can service a NGCC plant 410.6 MW_e (gross) without EGR. For a NGCC plant with a capacity 413.5 MW_e (gross) and with an EGR 40 %, they reported absorber and stripper heights 23.6 m and 21.2 m, respectively, and with a reduced specific reboiler duty 3.64 MJ/kgCO_2 for the NGCC with EGR compared to 3.97 MJ/kgCO_2 for the NGCC without EGR. They also reported the comparative plant economics for different cases, without considering it during the design stage. As reported by Agbonghae et al. [16], their design dimensions appear unrealistic as they cannot accommodate the quoted amount of flue gas. Also, as discussed by Agbonghae et al. [16], the reported design results by Biliyok and Yeung [34] and Biliyok et al. [33] of 4 absorbers with 10 m dimeter and 15 m height; and a single stripper with 9 m diameter and 15 m height was most likely based on the design for an off-shore application as reported in the literature [20, 38]. For a 40 % EGR, with a corresponding 40 % reduction in the flue gas flow rate, they reduced the number of absorbers to 3 without explicitly mentioning their design dimensions. Furthermore, Canepa et al. [35] reported that 2 absorbers with 9.5 m diameter and 30 m height, and a single stripper with 8.2 m diameter and 30 m height as the design results of an amine-based CO_2 capture plant for a NGCC power plant 250 MW_e (gross). When Canepa et al. [35] applied an EGR 40%, with a reduced flue gas flowrate, the height of both the absorber and stripper remained unchanged, although the specific reboiler duty was reduced. Also, the design results reported by Luo et al. [36] did not explicitly mention the reduction in the height of the absorber and stripper when an EGR 38 % was applied to the NGCC plant with a capacity 453 MW_e (gross). Table S.1 in the supplementary material, reports the design results for the different cases both with and without EGR as elaborated in the above discussion.

It is clear from the above discussion that the work presented in the open literature lacks a detailed techno-economic process design of the amine-based CO_2 capture plant for an on-shore based commercial-scale natural gas-fired power plant, both with and without EGR. Also, the effects of the EGR on the process design results need to be investigated by varying the EGR ratio on the same basis as that of the NGCC power plant. The already published literature have mostly presented the design results of the CO_2 capture system for an EGR percentage 40 %, [33-35, 37] with the exception of the paper by the Luo et al. [36]. Therefore, the focus of this paper is an amine-based CO_2 capture plant which can service an on-shore based commercial-scale natural gas-fired power plant in EGR mode. Further, the theme of this present study is to optimally design an amine-based CO_2 capture plant for the NGCC without EGR and NGCC with EGR at varying EGR ratios. Also, the sensitivity of the EGR ratio has been checked for the design and/or scale-up of the commercial-scale amine-based CO_2 capture plant for NGCC. The philosophy is to implement the rigorous rate-based process model for the process design of the amine-based CO_2 capture plant by considering both the process variables and economic parameters during the process design.

2. PROCESS LAYOUT AND MODELLING STRATEGY

2.1 PROCESS LAYOUT

A 650 MW_e (gross) NGCC plant is modelled in Aspen HYSYS and the process model results are compared with the results published in the 2013 Report of the US Department of Energy [39]. This report investigated the NGCC plant in three different configurations: NGCC without CO_2 capture, NGCC with CO_2 capture, and NGCC in EGR mode with CO_2 capture. The gas turbine modelled in this paper is an F-frame GE gas turbine (GE 7FA.05) with a gas turbine inlet temperature 1359 ^oC, a gas turbine outlet temperature 604 ^oC and a pressure ratio 17. The bottom Rankine cycle is a triple pressure level single reheat cycle with steam cycle specification of 16.5/566/566 MPa/^oC/^oC. Further, the heat recovery steam generator (HRSG) generates both the main and the reheat steam for the steam cycle. The natural gas and air composition, along with input parameters used in the model are given in Table 1, and the basic schematic of the NGCC is shown in Figure 1. The various sections of the NGCC, including the gas turbine, steam turbine and HRSG, are indicated by bounded rectangles in Figure 1.

For the NGCC with EGR, part of the exhaust gas is recirculated back to the compressor inlet to enhance the CO_2 concentration in the flue gas that is directed towards the CO_2 capture system in the present study. As previously stated, the EGR results in a reduced flue gas flow rate with an increased CO_2 concentration, which is of two-fold benefit for the integration of the NGCC in the EGR mode with the amine-based CO_2 capture system. The EGR loop consists of the condenser and the recirculation fan to boost the pressure of the recycle stream to the compressor inlet pressure. The exhaust gas from the HRSG exit is split and a portion of the exhaust gas is recirculated and the remainder is sent to the amine-based CO_2 capture system. In the US Department of the Energy Report [39], the total capacity of the NGCC in EGR mode was 615 MW_e (gross) at an EGR percentage of 35 %. The decreased capacity is due to the auxiliary loads of the EGR loop and the amine-based CO_2 capture process. For the NGCC in EGR mode, the gas turbine inlet temperature 1363 ^oC and gas turbine outlet temperature 615 ^oC is maintained. The flue gas temperature at the HRSG exit is 107 ^oC and the configuration of the three pressure levels with a single reheat of the steam cycle remains the same. The input parameters for the NGCC in EGR mode are summarised in Table 1, and the basic schematic of the NGCC with EGR is shown in Figure 1 where the EGR section is indicated by the green dashed rectangle. The higher temperatures observed in NGCC with EGR in comparison to the NGCC without EGR, are due to the higher heat capacity of the working gas stream as a result of the increased CO_2 concentration in it.

A schematic of the amine-based CO_2 capture plant shown in Figure 1 and it is bounded by the dotted blue rectangle. The CO_2 capture plant consists of the two columns; absorber and stripper, cross heat exchanger, cooler and pumps. The flue gas enters the bottom of the packed column absorber and it is contacted in a counter current manner with the downward flowing monoethanolamine (MEA) solvent. The resulting treated gas is low in CO_2 content and it passes through the water-wash section to remove traces of entrained MEA. The CO_2 loaded solvent from the bottom of the absorber is pumped and further heated in the cross heat exchanger with the lean amine coming from the stripper reboiler. The rich solvent is heated in the stripper by the upward flowing steam, leading to its regeneration to the lean amine solution; the lean amine solution is cooled down by heat exchange with the rich amine solution in the cross heat exchanger and by the lean amine cooler before re-entering the top of the absorber. The concentrated CO_2 from the condenser of the stripper is dried, compressed and sent to a CO_2 storage site.

2.2 MODELLING DETAILS

For the NGCC, the gas turbine is modelled using the Peng-Robinson equation of state and the combustor is modelled on the basis of the Gibbs free energy minimization. The steam cycle is modelled using the NBS steam property package. Further, the HRSG is modelled as a multi-stream heat exchanger. For the present study, the EGR percentage is not only fixed at 35 %; rather two more cases of the NGCC in EGR mode with ±15 % of the reported EGR percentage of 35 % are modelled and the design of the amine-based CO_2 capture system is done for an EGR percentage of 20, 35 and 50 %. It is assumed that combustion stability issues do not arise when the EGR percentage is 50 %, and technical modifications of the combustor are available to deal with those issues already mentioned in Section 1. The power output of the gas turbine is considered as the basis for the techno-economic process design of the amine-based CO_2 capture plant. For the EGR cases, the steam turbine power is also fairly constant for the three cases investigated. Although there is a drop in the flue gas flowrate with an increase in EGR, this is compensated by the increase in the flue gas temperature. Thus the total enthalpy of the flue gas will be about the same for all the cases and hence the steam generated in the HRSG will be almost the same.

The amine-based CO_2 capture plant is modelled using the Acid Gas thermodynamic property package. This is an integral functionality of Aspen and it is based on the Electrolyte Non-Random Two Liquid (Electrolyte NRTL) thermodynamic property package for the liquid phase properties. The Peng-Robinson thermodynamic equation of state was used for the vapour phase properties. The number of principal reactions involved in the reaction chemistry as defined in the literature [10] are as follows:

$$H_2O + MEAH^+ \leftrightarrow MEA + H_3O^+ \tag{1}$$

$$2H_2O \leftrightarrow H_3O^+ + OH^- \tag{2}$$

$$HCO_3^- + H_2O \leftrightarrow CO_3^{2-} + H_3O^+ \tag{3}$$

$$CO_2 + OH^- \rightarrow HCO_3^- \tag{4}$$

$$HCO_3^- \rightarrow CO_2 + OH^- \tag{5}$$

$$MEA + CO_2 + H_2O \rightarrow MEACOO^- + H_3O^+ \tag{6}$$

$MEACOO^- + H_3O^+ \rightarrow MEA + CO_2 + H_2O$ (7)

Reactions (1) to (3) are equilibrium reactions describing the chemistry of the MEA and CO_2 solution, while reactions (4) to (7) are kinetically controlled, and describe the formation of the carbamates and bicarbamates. In addition, the correlations used for the mass transfer and interfacial area estimation is the Bravo-Fair correlation [40] which is already built-in into Aspen. Similarly, for the pressure drop estimation the vendor correlation for the particular packing was employed.

2.3 MODELLING STRATEGY

In general, the design of absorber and stripper columns is well described in the literature [41-43]. However, the process design of packed absorber and stripper is not a straightforward process. It is a hit and miss trial procedures until the optimum design variables that can meet the specific design conditions and/or targets are arrived at. These design targets are defined by the hydrodynamic parameters of the packed column, specifically the maximum pressure drop that can be tolerated and the approach to the maximum capacity of the column [41-43]. The design and scale-up optimization of the amine-based CO_2 capture plants for the base case NGCC, with a power output of 650 MW_e, and NGCC with EGR percentage at 20, 35 and 50 %, are designed and optimised by the procedures defined by Agbonghae et al., [16] which can be referred to for more details. The design and/or scale-up strategy, with a process simulation tool, can be described by the following interlinked steps:

i. Model validation at the pilot-scale level.
ii. Selection of the process and economic parameters.
iii. Process performance bounds/criteria.
iv. Techno-economic process sensitivity analysis.

The model validation at the pilot-scale is performed in order to ascertain if the model is capable of representing the performance of the system under consideration, and the model results are compared with the experimental results. The model is tuned with the experimental data and the design values of the pilot-plant, and the results of the selected parameters are compared. The model of the amine-based CO_2 capture plant is validated against two sets of reported experimental data. The first experimental set of data used for model validation was reported by Akram et al. [10] in which EGR was implemented to study the behaviour of the pilot-scale CO_2 capture plant. The second experimental set of data used for model validation was reported by Notz et al. [9] who reported 13 variation studies with a total of 47 associated experiments for the pilot-scale CO_2 capture plant. From these, the variation study in which the CO_2 concentration in the flue gas was varied is considered for the model validation. The process model validation results at the pilot-scale level for the amine-based CO_2 capture plant are presented in Section 3.

The process and economic variables selected for the present study are presented in Tables 2 and 3, respectively. These process and economic variables remain fixed during the sensitivity analysis. The present design is for MEA strength of 30 weight % aqueous solution and the CO_2 capture rate is fixed of 90 %, a common basis for these types of study. In most of the reported studies in the open literature, 30 wt. % aqueous monoethanolamine (MEA) was taken as the base line solvent for comparison with various blends and/or new solvents; therefore it is generally considered as the benchmark solvent for the PCC technology. The lean loading is fixed at an optimum value of 0.2 mol CO_2/mol MEA [16], and the absorber inlet temperatures are fixed at 40 ^oC. The amine section pump efficiencies are fixed at 75 % and the maximum pressure for the amine solution around the circuit is 3 bara. The costing is performed with the Aspen Economic Analyzer, which is an integral part of Aspen, through the economic analysis tab. It is important to mention here that the cost estimated in terms of capital expenditure of the plant (CAPEX), and operating expenditure of the plant (OPEX) do not include ancillary equipment costs which may be part of the actual system based on hazard and operability studies [16]. However, if recommendations in the literature [44, 45] are properly applied for the economic analysis; the associated uncertainty with the economic analysis results will be reduced. The optimum design variables are those which results in the least OPEX. Further, to confirm the optimum point for each variable, the total annualized expenditure is estimated with a scale-up in the CAPEX and a scale-down in the OPEX. The total expenditure (TOTEX) is given by the following equation [16]:

$$\mathrm{TOTEX} = X_1(\mathrm{OPEX}) + X_2(\mathrm{CAPEX})\left[\frac{i\,(i+1)^n}{(i+1)^n - 1}\right] \tag{8}$$

where i is the interest rate and n is the service life of the plant, already defined in Table 3. Further, X_1 and X_2 are the scaling factors used to define the three cases:

- Case A: X_1 =1.0 and X_2 = 1.0
- Case B: X_1 =1.0 and X_2 = 1.5
- Case C: X_1 =0.5 and X_2 = 1.0

In addition, the interest rate is fixed at 10 % for the service life of 20 years and the equipment material selected is stainless steel. The utilities cost for steam, electricity and cooling water for the estimation of the economic parameters are listed in Table 3. Two process performance bounds are recommended in the literature when estimating the diameter of packed column for the specific liquid and the gas flow rates. The pressure drop across the height of the packing in the columns should not exceed 20.83 mm of H_2O per meter of the packing for amine systems, [42, 43] and the approach to the maximum capacity should not exceed 80 % of the flooding velocity [42, 43]. These process performance bounds are designed to achieve 90 % separation of the CO_2 and the column height is estimated for achieving this amount of separation.

The main question that requires an answer is the following: in order, to implement the techno-economic process analysis for the design and/or scale-up of the validated pilot-scale amine-based CO_2 capture plant to a commercial-scale amine-based CO_2 capture plant, which can service on-shore based validated NGCC of 650 MW_e (gross) capacity. Further, the implementation of the EGR is investigated. In addition, the design and/or scale-up of the above case are extended to the NGCC with EGR with three different EGR percentages of 20, 35 and 50 %. In total, four case studies are investigated, each consisting of a commercial-scale CO_2 capture plant which can service NGCC. The first case of a commercial-scale CO_2

capture plant is for NGCC without EGR. For the other cases, the design and/or scale-up of a commercial-scale CO_2 capture plant are obtained for 20, 35 and 50 % EGR operated NGCC. The design and/or scale-up of these cases are obtained provided the above mentioned process performance bounds are met for the specified process and economic parameters.

3. MODEL VALIDATION

3.1 NGCC and NGCC with EGR

As stated in Section 2.1, the model results of the NGCC were compared with the results obtained from the Report of the US Department of Energy [39]. Also, the results for the NGCC with an EGR percentage of 35 % are available in the same report and hence they are also compared. The model results are summarised in Table 4. Further, the model results for the NGCC with EGR percentages at 20 and 50 % are also presented in Table 4. The percentage absolute deviation for any of the variables presented in Table 4 is less than 3.2 and 4.1 %, for NGCC without EGR and NGCC with 35 % EGR percentage, respectively. Thus, the model results are in good agreement with the data in the report of US Department of Energy; hence, the flue gas can be confidently linked with the amine-based CO_2 capture plant for its design and scale-up. The CO_2 composition in the flue gas for the NGCC with EGR is increased by a factor 1.3, 1.6 and 2.1 in comparison to the CO_2 composition in NGCC without EGR for an EGR percentage of 20, 35 and 50 %, respectively. The flue gas flow rate, which is to be treated in the amine-based CO_2 capture system, is also decreased by the same percentage when the exhaust gas recirculation is applied. In addition to the above, the authors have reported in the literature [24, 46] a sensitivity analysis for the EGR stream on the performance of the gas turbine.

In addition to the model validation against the published data, a second law analysis of thermodynamics is performed for the NGCC cycle in order to visualize the effect of the EGR on the novel thermodynamic cycle. The second law analysis is summarised in Figure 2 in the form of the temperature-entropy (TS) diagram of the NGCC both with and without EGR. The different locations for the estimation of the temperature and entropy of the working fluid are labelled in Figure 2, and the various locations selected are as follows: (a) compressor inlet, (b) compressor outlet/combustor inlet, (c) combustor outlet/turbine inlet, (d) turbine outlet/HRSG inlet, (e) HRSG out, and (f) compressor inlet for the EGR stream. The TS diagram for the NGCC with EGR is a semi-closed thermodynamic cycle as part of the exhaust gas is recirculated to the inlet of the compressor. It is clear from Figure 2 that the change in the composition of the fluid due to the EGR, the working stream properties changes at the each location and thus affects the entropy at those corresponding locations.

Details are also provided in Table 4 of the auxiliary loads in order to show the losses in different sections of the system. Thus, allowing the estimation of the total net power output of the power plant. For the estimation purposes, the auxiliary loads are divided into two classes; one which can be directly measured and the other which are fixed based on the Report of the US Department of Energy [39] and are termed as other auxiliary loads in Table 4. The measurable auxiliary losses consist of the condensate pump and boiler feed water pump loads. The other fixed losses consist of the pumps load for water circulation, cooling tower fan loads, selective catalytic reduction losses, gas turbine and steam turbine auxiliaries loads and miscellaneous loads. For the NGCC with EGR, the additional loads of the EGR recirculation fan and the EGR coolant recirculation pump losses are also included in the above mentioned auxiliary loads. The difference between literature reported and model predicted value of the net power output for 35 % EGR case, is due to the fact that the literature reported value consider losses in CO_2 capture plant for that particular case.

3.2 AMINE-BASED CO_2 CAPTURE PLANT MODEL VALIDATION AT PILOT-SCALE

The process model validation of the pilot-scale amine-based CO_2 capture plant is performed for two pilot-plants. The first one is a pilot-plant designed to remove 1 ton per day of CO_2 based on the MEA and it is located at the Pilot-scale Advanced Capture Technology (PACT) facilities, the UKCCS Research Center, Sheffield, UK. The experimental and model results have been presented with full details by Akram et al. [10] and therefore are not discussed in this paper. The experimental investigation performed by Akram et al. [10] was focused on the exhaust gas recirculation for the micro gas turbine and the capture of CO_2 from the CO_2-enriched flue gas. The range of the CO_2 composition in the flue gas investigated varies from 5.5 mol% to 9.9 mol% which covers the wider operating range for commercial-scale NGCC with EGR, and the packing employed in the absorber and stripper is the random INTALOX Metal Tower Packing (IMTP25). The mean percentage absolute deviation for the specific reboiler duty, rich and lean loadings and rich and lean solvent concentrations are 2.0, 2.4, 0.2, 1.9 and 0.1 %, respectively. These indicate that the model results are in good agreement with the experimental results.

Further, the model is validated against the extensive pilot-scale experimental results reported by Notz et al. [9]. The model was tuned and ran for the boundary conditions for all the 47 experiments and the model results for the selected parameters are presented in Figure 3. The packing employed in this pilot-scale absorber and stripper is the structured Sulzer Mellapak 250Y.

It is observed that the mean percentage absolute deviations for the rich loading, specific reboiler duty and CO_2 capture are 2.6, 5.0 and 0.6 %, respectively. The absorber and stripper temperature profiles, as shown in Figures 4 and 5, respectively, for the set of experiments designated as Set E, and this variation study is focused on the variation of the CO_2 composition in the flue gas ranging from 3.6 to 13.4 mol% with the liquid to gas ratio maintained at 2.8. It is evident from Figures 3, 4 and 5 that the model results are in good agreement with the reported experimental results.

Having validated model results against experimental results for the two pilot-scale experimental investigations, especially with emphasis on the results for the CO_2 enhanced flue gas from the gas-fired MGT or burner, the process model can be used with confidence to predict the design and/or scale-up of the amine-based CO_2 capture plant.

4. DESIGN AND/OR SCALE-UP FOR A COMMERCIAL-SCALE AMINE BASED CO_2 CAPTURE PLANT

The design and/or scale-up of the amine-based CO_2 capture plant is performed for the four cases already discussed; one for the base case, the NGCC without EGR and with NGCC capacity 650 MW_e, and three cases for the NGCC with an EGR percentage of 20, 35 and 50 %. The conditions of the flue gas in terms of the process parameters, flow rates and composition for all these four cases for which the amine-based CO_2 capture plant is to be designed and/or scaled-up, is tabulated in Table 4. The input specification for the commercial-scale amine-based CO_2 capture plant in terms of the process parameter inputs and techno-economic variables are listed in Tables 2 and 3, respectively. The commercial-scale amine-based CO_2 capture plant is modelled and optimized for the Mellapak 250Y and the lean amine loading is fixed at 0.2 mol CO_2/mol MEA [16]. The summary of the design results for the amine-based CO_2 capture plant for the four different scenarios is shown in Table 5 and the detailed process design results and process economic results can be found in Table S.2.

4.1 COMMERCIAL-SCALE AMINE-BASED CO_2 CAPTURE PLANT FOR NGCC WITHOUT EGR

The process design results for the amine-based CO_2 capture plant for the commercial-scale NGCC without EGR are given in Figure 6. The design results are estimated for the liquid to gas ratio in the range from 0.94 to 1.04 at the CO_2 capture rate of 90 % and lean amine loading of 0.2 mol CO_2/mol MEA. The selected parameters presented here, which are affected by the liquid to gas ratio variation, are the packed heights of the absorber and stripper, the specific reboiler duty, the steam flow rate to the reboiler and the cooling water flow rate to the condenser and the lean amine cooler in the amine-based CO_2 capture plant. It is evident from Figure 6 (a) that the absorber packed height varies mainly as a function of the liquid to gas ratio. The variation of the absorber packed height around the optimum point varies both with increasing and decreasing the liquid to gas ratio around that point. The absorber packed height increases sharply as a function of the liquid to gas ratio when the liquid to gas ratio is decreased below an optimum point of the liquid to gas ratio. Also, there is a gradual decrease in the absorber packed height as a function of the liquid to gas ratio when this increases beyond the optimum point of the liquid to gas ratio. However, this decrease is less distinct and cannot be considered for the selection of the optimum point. Further, the stripper packed height is less affected by the variation of the liquid to gas ratio as seen from Figure 6.

In addition, the specific reboiler duty decreases with the reduction of the liquid to gas ratio without identifying the optimum location and this is observed for the absorber packed height as a function of the liquid to gas ratio. Also, the decrease in the steam requirement and cooling water requirement for the amine-based CO_2 capture plant, as shown Figure 6 (b), is observed with the reduction of the liquid to gas ratio. However, this decrease is not sharp and does not result in the location of the optimum design parameters alone. Also, the steam requirement is directly dependant on the specific reboiler duty, and hence does not result in the optimum design parameters for the relevant minimum specific reboiler duty. However, from Figure 6 (a), it is clear that the optimum point appears to be at the liquid to gas ratio of about 0.95.

However, if the process economic results for the same range of liquid to gas ratio is considered then the optimum location for the process design of the amine-based CO_2 capture plant can be better assessed. The economic results are presented in Figure 7, including the CAPEX, OPEX and TOTEX for different liquid to gas ratios. The TOTEX is estimated for three different cost scenarios as discussed in Section 2.2. It is evident from Figure 7 (a) that the CAPEX increases abruptly with the reduction of the liquid to gas ratio below a certain optimum value, and this increase is due to the sharp increase in the absorber packed height. Similarly, the OPEX also increases with the decrease in the liquid to gas ratio below a certain optimum point, and this is due to the increased CAPEX associated with the maintenance cost. Further, the OPEX increases with the increase in the liquid to gas ratio, beyond an optimum point, and this is due to the increased utilities requirement. The optimum location of the liquid to gas ratio from the minima of the OPEX is 0.96 and this results in the absorber packed height 16.47 m, stripper height 29.73 m and specific reboiler duty 3.83 MJ/kgCO_2. This optimum point is also verified by the minima of the TOTEX for the three different cases of the TOTEX as shown in Figure 7 (b). A summary of the optimum design results can be found in Table 5 and the detailed optimum process design is presented in Table S.2. However, the literature [37] reported a minimum liquid to gas ratio of 0.68, with an absorber height of 26.9 m and stripper height of 23.5 m. Further, it should be kept in mind that Sipocz and Tobiesen [37] reported that the design is for the NGCC power plant with a capacity of 410.6 MW_e. Conversely, the design results reported by Biliyok et al. [33] and Biliyok and Yeung [34] are of constant absorber height 15 m, with the number of absorbers as 4. In addition, the maximum NGCC power plant capacity is 453 MW_e as reported by Luo et al. [36], with absorber height 25 m and the specific reboiler duty 4.54 MJ/kg CO_2. It can be concluded that the economic analysis is also an important parameter to reach the optimum design dimensions for the design and/or scale-up of commercial-scale amine-based CO_2 capture plant.

4.2 COMMERCIAL-SCALE AMINE-BASED CO_2 CAPTURE PLANT FOR NGCC WITH EGR

The process design results for the amine-based CO_2 capture plant for the commercial-scale NGCC with EGR at three different EGR percentage cases, 20, 35 and 50 %, are presented in Figure 8. The results for the EGR cases are similar to those reported for the amine-based CO_2 capture plant for the commercial-scale NGCC without EGR. The design results are estimated for the CO_2 capture rate 90 %, lean amine loading 0.2 mol CO_2/mol MEA and liquid to gas ratio in the range 1.20 to 1.25 for 20 % EGR percentage, 1.40 to 1.60 for 35 % EGR percentage, and 1.80 to 2.00 for 50 % EGR percentage. The selected parameters presented here, which are affected by the liquid to gas ratio variation, are the same as those in the NGCC without EGR which includes; packed heights of the absorber and stripper, specific reboiler duty, steam flow rate to the reboiler and cooling water flow rate to the condenser and lean amine cooler in the amine-based CO_2 capture plant. From Figure 8 (a), it is clear that the absorber packed height increases abruptly with the reduction of the liquid to gas ratio below an optimum point for different cases of the EGR ratio. In addition, there is a less distinct decrease in the absorber packed height with the increase of the liquid to gas ratio beyond an optimum point of the liquid to gas ratio.

Further, the stripper packed height and specific reboiler duty follows the same general trend as discussed for the NGCC without EGR. The steam flow requirement and cooling water requirement are shown in Figure 8 (b). In addition, the steam flow requirement and cooling water flow requirement follow the same general trend as discussed for the NGCC without EGR. Hence, the optimum point for the liquid to gas ratio, based on the process analysis alone for different EGR cases, is 1.21, 1.45 and 1.88 for the 20, 35 and 50 % EGR percentages, respectively.

Nevertheless, if the process economic analysis is performed for a similar range of liquid to gas ratio for each of the EGR ratios, then the optimum location can be better estimated. The CAPEX and OPEX variation as a function of the liquid to gas ratio is presented in Figure 9 (a) and the TOTEX variation as a function of the liquid to gas ratio is presented in Figure 9 (b) for varying EGR ratios. It is evident from Figure 9 that the true optimum for the amine-based CO_2 capture plant can be better approximated by considering the process economic analysis. Based on the minima of the OPEX, the optimum liquid to gas ratio for different EGR ratios are 1.22, 1.46 and 1.90 for the 20, 35 and 50 % EGR percentages, respectively. A summary of the optimum design results can be found in Table 5 and the detailed optimum process design is presented in Table S.2.

However, for the reported literature design dimensions, the minimum absorber height as mentioned by Sipocz and Tobiesen [37] is 23.6 m for a single absorber at the EGR percentage of 40 % for NGCC operating at 413.5 MW_e. Although, the absorber heights reported by Biliyok et al. [33] and Biliyok and Yeung [34] are 15 m, however, the number of absorbers are 3 for both of the studies at 40 % EGR percentage for the 440 MW_e NGCC power plant. Similarly, the minimum specific reboiler duty reported is 3.64 MJ/kg CO_2 which is at 40 % EGR percentage for the 440 MW_e NGCC power plant [37]. A comparison of the design results for amine-based CO_2 capture plant as reported in the literature for NGCC, both with and without EGR, is presented in Table S.1.

Finally, it is observed that with an increase in the EGR ratio, the absorber and stripper packed height, specific reboiler duty and associated steam flow requirement, CAPEX, OPEX and TOTEX decreases, as can be observed from Table S.2.

5. CONCLUSIONS

This study has investigated a techno-economic process design of a commercial-scale amine-based CO_2 capture plant for NGCC with EGR leading to the following conclusions:

- Instead of employing a process design analysis alone, a combined process economic analysis is an essential requirement for reaching the optimum design variables for commercial-scale amine-based CO_2 capture plant.

- The optimum design results for the commercial-scale amine-based CO_2 capture plant are reported for a commercial-scale NGCC without EGR for a gross power output of 650 MW_e. This resulted in the optimum liquid to gas ratio being 0.96 for the structured Mellapak 250Y packing with a CO_2 capture rate of 90 % and CO_2 composition of 3.91 mol% in the flue gas.
- When a 20 % EGR percentage is applied to the same plant, the optimum liquid to gas ratio is 1.22 for the same packing and CO_2 capture rate. However, the CO_2 composition of the flue gas is increased to 5.13 mol%.
- The optimum liquid to gas ratio for the NGCC with 35 % and 50 % EGR are 1.46 and 1.90, respectively, with the CO_2 composition in the flue gas now being 6.20 and 8.19 mol%; provided that any modification in the combustor if required of the gas turbine is available for the 50 % EGR percentage equipped NGCC.
- The carbon capture from the existing or new natural gas-fired power plants will work to reduce greenhouse gases by minor variation to the present cycle in the form of EGR, which will result in fewer penalties in terms of the energy consumption and the cost incurred in comparison to a natural gas-fired power plant without EGR. The wide adoption of carbon capture, especially for fossil-fuelled power plants, will result in a better energy mix for the future low carbon economy.

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Supporting Material

Table S.1: Comparison of the design results for amine-based CO_2 capture plant as reported for NGCC with and without EGR.

	Canepa et al.[35]		**Biliyok et al.[33]**		**Biliyok and Yeung[34]**		**Sipocz and Tobiesen[37]**		**Luo et al.[36]**	
Power plant type	without EGR	with EGR	without EGR	With EGR	without EGR	With EGR	without EGR	With EGR	without EGR	With EGR
Power plant size (MW_e) Gross	250	250	440	440	440	440	410.6	413.5	453	453
Gas turbine output (MW_e)	-	-	-	-	287.7	287.6	-	-	295.03	294.64
Flue gas flow rate (kg/s)	-	-	693.6	416.1	693.6	416.1	639.6	370.28	660.54	408.75
Liquid flow rate (kg/s)	720.46	675.6	721.7	675.2	721.6	675.3	-	-	1128.19	1036.81
Exhaust gas recirculation, EGR (%)	0	40	0	40	0	40	0	40	0	38
Liquid to gas ratio (mol basis)	2.29	3.32	1.314	-	1.31	2.09	0.68[a]	-	1.79	2.71
CO_2 in flue gas (mol%)	4.1	7	3.996	6.61	3.996	6.61	4.4	7.8	4.4	7.32
CO_2 capture rate (%)	90	90	90	90	90	90	90	90	90	90
MEA concentration (kg/kg)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	-	0.325	0.325
Lean loading (mol/mol)	0.3	0.3	0.2343	0.3	0.234	-	0.132	0.128	0.32	0.32
Rich loading (mol/mol)	0.456	0.466	0.4952	-	0.4945	-	0.473	0.486	0.461	0.472
Number of absorber	2	2	4	3	4	3	1	-	-	-
Absorber Packing	IMTP no.40	IMTP no. 40	Mellapak 250X	Mellapak 250X	Mellapak 250X	Mellapak 250X	Mellapak 250	Mellapak 250	IMTP no. 40	IMTP no. 40
Absorber diameter (m)	9.5	8	10	-	10	-	9.13	6.87	19.81[c]	16.6[c]
Absorber packed height (m)	30	30	15	-	15	-	26.9	23.6	25	
Number of stripper	1	1	1	-	1	-	1	-	-	-
Stripper packing	Flexipack 1Y	Flexipack 1Y	Mellapak 250X	Mellapak 250X	Mellapak 250X	Mellapak 250X	Mellapak 250	Mellapak 250	Flexipack 1Y	Flexipack 1Y
Stripper diameter (m)	8.2	8	9	-	9	-	5.5	3.8	10.2[c]	9.8[c]
Stripper packed height (m)	30	30	15	-	15	-	23.5	21.2	15	-
Specific reboiler duty	4.97	4.68	3.992	3.726	4.0003	3.724	3.97	3.64	4.54	4.31

(MJ/kgCO_2)										
Stripper pressure (bar)	1.62	1.62	1.5	-	1.5	-	1.92[b]	1.92[b]	2.1	-

[a]L/G ratio reported was in mass basis.

[b]Regenerator temperature of 122 ^oC was reported.

[c]Diameter was estimated through the reported cross sectional area.

Table S.2: Detailed results summary for the amine-based CO_2 capture plant for four different scenarios of the NGCC.

	NGCC without EGR	**NGCC with 20 % EGR**	**NGCC with 35 % EGR**	**NGCC with 50 % EGR**
Gross power plant size [MW_e]	650.7	622.5	621.3	622.5
Gas turbine power output [MW_e]	418.1	419.9	418.7	419.9
Steam turbine power output [MW_e]	232.6	202.6	202.6	202.6
Exhaust gas recirculation rate [%]	0	20	35	50
Natural gas flow rate [kg/hr]	84161	84260	84815	85450
CO_2 in flue gas [mol%]	3.91	5.13	6.2	8.19
Flue gas flow rate [kg/s]	1029.7	783.9	652.8	499.2
Recirculated gas flow rate [kg/s]	-	196.0	351.7	499.2
Optimum liquid flowrate [kg/s]	988.5	956.3	953.1	948.4
Optimum liquid to gas ratio [kg/kg]	0.96	1.22	1.46	1.9
Lean CO_2 loading [mol/mol][16]	0.2	0.2	0.2	0.2
Optimum rich CO_2 loading [mol/mol]	0.480	0.485	0.487	0.489
Absorber				
Number of absorber	2	2	2	2
Absorber packing	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y
Absorber diameter [m]	15.00	13.61	12.75	11.39
Optimum absorber height [m]	16.47	15.75	15.43	15.31
Stripper				
Number of stripper	1	1	1	1
Stripper packing	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y
Stripper diameter [m]	9.20	9.06	9.02	9.00
Optimum stripper height [m]	29.73	29.46	28.67	27.88
Duty				
Specific reboiler duty [MJ/kg CO_2]	3.83	3.82	3.77	3.71

Specific condenser duty [MJ/kg CO_2]	1.65	1.51	1.50	1.48
Cross heat exchanger duty [MW]	135.6	149.8	157.3	224.3
Lean amine cooler duty [MW]	60.5	87.1	92.1	105.3
Lean amine pump duty [kW]	25.1	25.1	25.6	37.6
Rich amine pump duty [kW]	72.3	72.4	72.4	72.5
Capital and Operating Costs				
CAPEX [M £]	116.3	116.1	115.6	115.3
OPEX [M £/yr]	60.3	38.5	31.4	31.2
TOTEX [M £/yr]	74.0	52.1	45.0	44.8

Table 1: Input specifications for the NGCC model [39].

Parameter	Without EGR	With EGR
Gas turbine inlet temperature [^oC]	1359	1363
Gas turbine outlet temperature [^oC]	604	615
Air inlet temperature [^oC]	15	15
Flue gas temperature at HRSG exit [^oC]	88	107
Exhaust gas recirculation rate [%]	0	35
Pressure ratio	17	17
Compressor efficiency [%]	85	85
HP[a] steam turbine efficiency [%]	88	88
IP[b] steam turbine efficiency [%]	92.4	92.4
LP[c] steam turbine efficiency [%]	93.7	93.7
Fuel inlet temperature [^oC]	38	38
Fuel inlet pressure [MPa]	2.76	2.76
Natural gas calorific value [MJ/kg]	47.22	47.22
Natural gas molar composition [%]		
CH_4	93.10	
C_2H_6	3.20	
C_3H_8	0.70	
iso-C_4H_{10}	0.40	
CO_2	1.00	
N_2	1.60	
Air molar composition [%]		
N_2	77.32	
O_2	20.74	
Ar	0.92	
CO_2	0.03	
H_2O	0.99[d]	

[a]HP - high pressure.

[b]IP - intermediate pressure.

[c]LP - low pressure.

[d]Relative humidity of ~60 %.

Table 2: Input specifications [16] for the amine-based CO_2 capture plant.

Parameter	Value
MEA concentration [kg/kg]	0.3
Lean amine loading [mol CO_2/mol MEA][16]	0.2
CO_2 capture rate [%]	90
Flue gas temperature at absorber inlet [^oC]	40
Lean MEA temperature at absorber inlet [^oC]	40
Rich amine pump efficiency [%]	75
Lean amine pump efficiency [%]	75
Rich amine pump discharge pressure [bara]	3.0
Lean amine pump discharge pressure [bara]	3.0
Cross heat exchanger hot side temperature approach [^oC]	10
Cross heat exchanger pressure drop [bar]	0.1
Lean amine cooler pressure drop [bar]	0.1

Condenser temperature [^oC]	35
Stripper condenser pressure [bara]	1.62
Cooling water temperature rise [^oC]	5

Table 3: Economic analysis assumptions [16] used for techno-economic design of an amine-based CO_2 capture plant in Aspen.

Parameter	**Value**
Costing template	U.K.
Steam cost [£/ton]	17.91
Cooling water cost [£/m^3]	0.0317
Electricity cost [£/MWh]	77.5
Service life, n [yrs]	20
Interest rate, i [%]	10
Equipment material	316L stainless steel

Table 4: Validation of the model results for NGCC without EGR and NGCC with EGR percentage at 35 % and extended model results for the NGCC with EGR percentages at 20 and 50 %.

Parameters	**NGCC without EGR**		**NGCC with EGR**			
			35%	**35%**	**20%**	**50%**
	DoE [39]	**Model**	**DoE [39]**	**Model**	**Model**	**Model**
Gas turbine power output [MW_e]	420.8	418.1	418.6	418.7	419.9	419.9
Steam turbine power output [MW_e]	229.6	232.6	196.6	202.6	202.6	202.6
Total gross power output [MW_e]	650.7	650.7	615.2	621.3	622.5	622.5
Exhaust gas recirculation [%]	-	-	35	35	20	50
Condensate pump load [kW_e]	416	420	268	270	268	271
Boiler feed water pumps load [MW_e]	4.5	4.5	4.5	4.5	4.5	4.5
EGR auxiliary loads [kW_e]	0	0	677	684	452	905
Other auxiliary loads[39] [MW_e]	11.5	11.5	14.3	14.3	14.3	14.3
Total net power output [MW_e]	634	634	595	602	603	603
Turbine inlet temperature [^oC]	1359	1368	1363	1366	1360	1387
Turbine outlet temperature [^oC]	604	608.6	615	617	612	637
Recirculated gas flow rate [kg/s]	-	-	347.5	351.7	196.0	499.2
Flue gas flow rate [kg/s]	1029.7	1029.7	667.6	652.8	783.9	499.2
Flue gas molar composition [%]						

CO_2	4.04	3.91	6.07	6.20	5.12	8.19
O_2	12.09	12.38	8.29	7.95	9.9	4.33
N_2	74.32	74.42	74.96	74.87	74.38	75.87
Ar	0.89	0.88	0.90	0.89	0.89	0.90
H_2O	8.67	8.42	9.78	9.94	9.52	10.58

Table 5: Design results summary for the amine-based CO_2 capture plant for four different scenarios of the NGCC.

	NGCC without EGR	NGCC with 20 % EGR	NGCC with 35 % EGR	NGCC with 50 % EGR
Gross power plant size [MW_e]	650.7	621.1	621.3	622.5
Gas turbine power output [MW_e]	418.1	419.9	418.7	419.9
Exhaust gas recirculation Rate [%]	-	20	35	50
CO_2 in flue gas [mol%]	3.91	5.12	6.2	8.19
Flue gas flow rate [kg/s]	1029.7	783.8	652.8	499.1
Optimum liquid/gas ratio [kg/kg]	0.96	1.22	1.46	1.9
Optimum rich CO_2 loading [molCO_2 /mol MEA]	0.480	0.485	0.487	0.489
Absorber				
Number of absorber	2	2	2	2
Absorber packing	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y
Absorber diameter [m]	15.00	13.61	12.75	11.39
Optimum absorber Height [m]	16.47	15.75	15.43	15.31
Stripper				
Number of stripper	1	1	1	1
Stripper packing	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y
Stripper diameter [m]	9.20	9.06	9.02	9.00
Optimum stripper height [m]	29.73	29.46	28.67	27.88

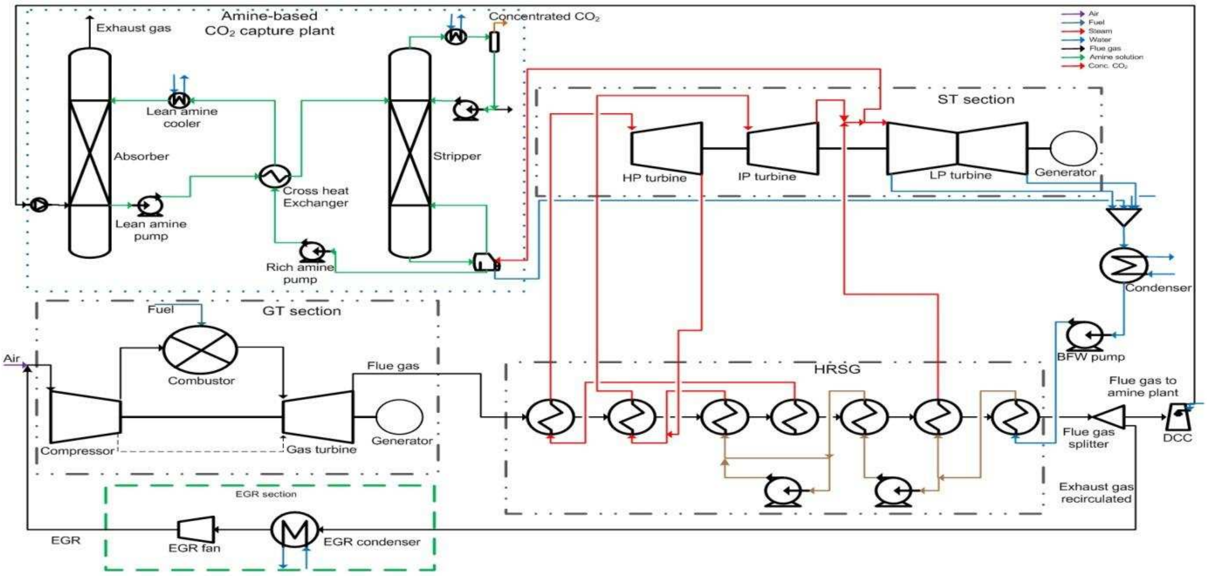

Figure 1: Basic schematic of the NGCC with EGR integrated with an amine-based CO_2 capture plant.

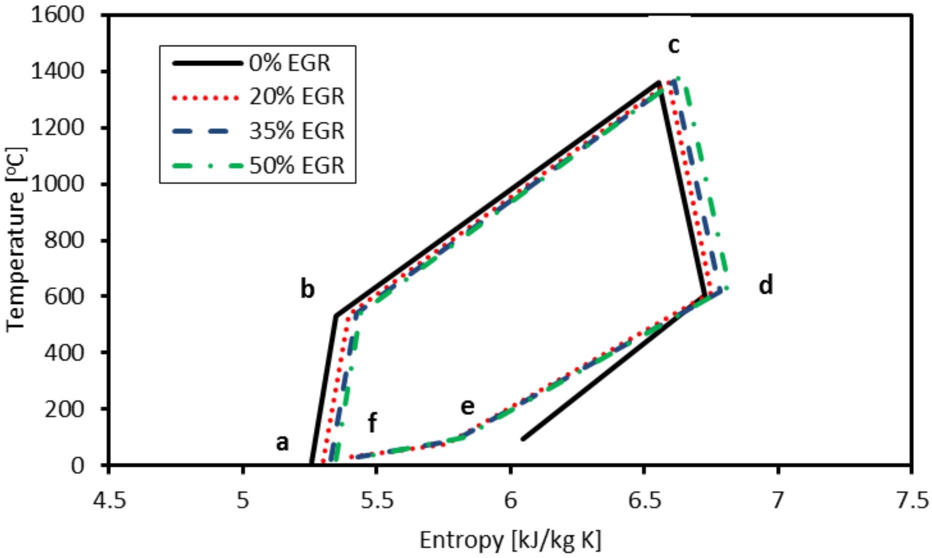

Figure 2: Second law analysis of the NGCC with and without EGR where (a) compressor inlet, (b) compressor outlet/combustor inlet, (c) combustor outlet/turbine inlet, (d) turbine outlet/HRSG inlet, (e) HRSG out, and (f) compressor inlet for the EGR stream.

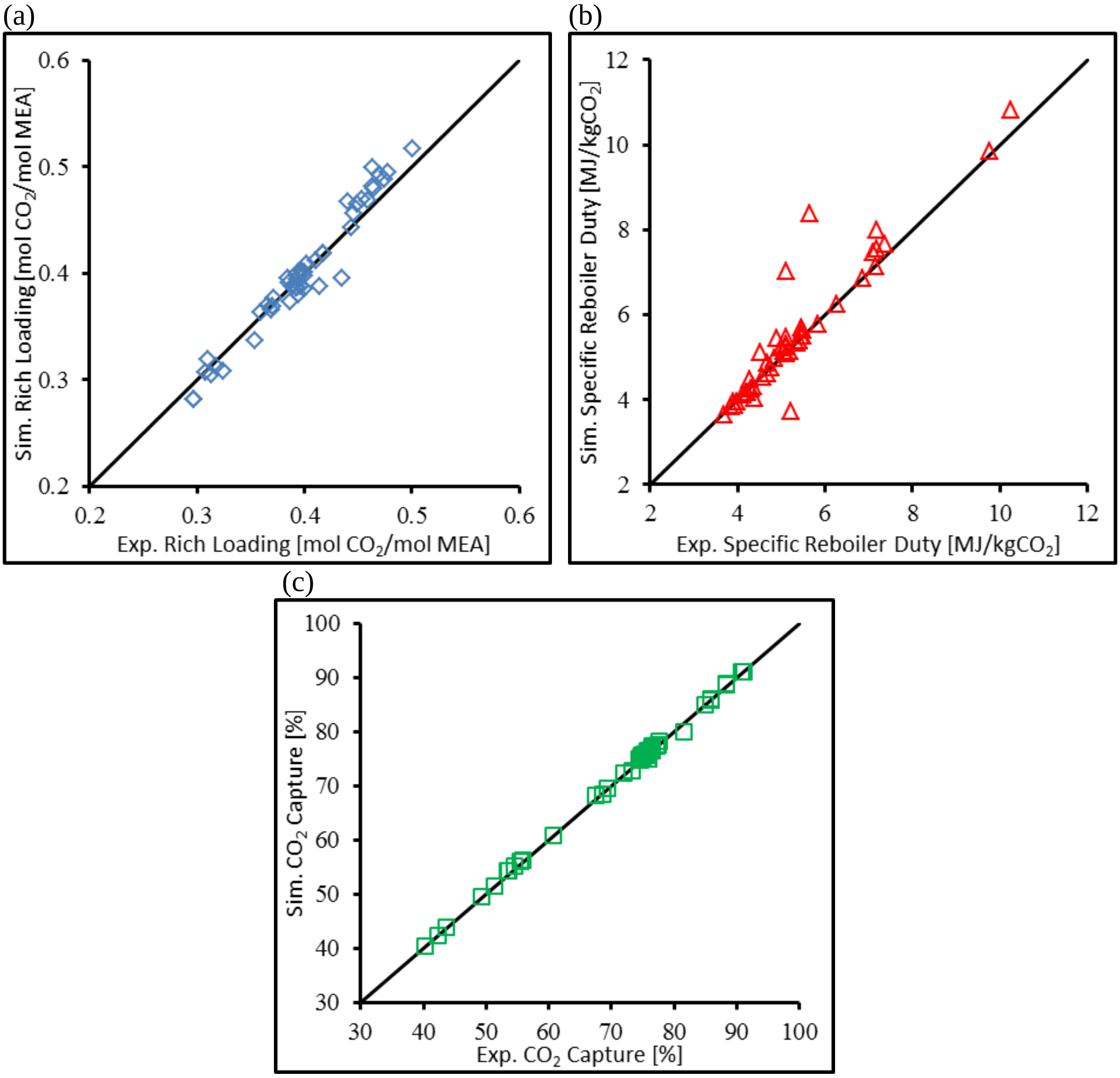

Figure 3: Model results as a function of the experimental results reported by Notz et al. [9] (a) Parity plot for rich loading; (b) Parity plot for specific reboiler duty; and (c) Parity plot for CO_2 capture.

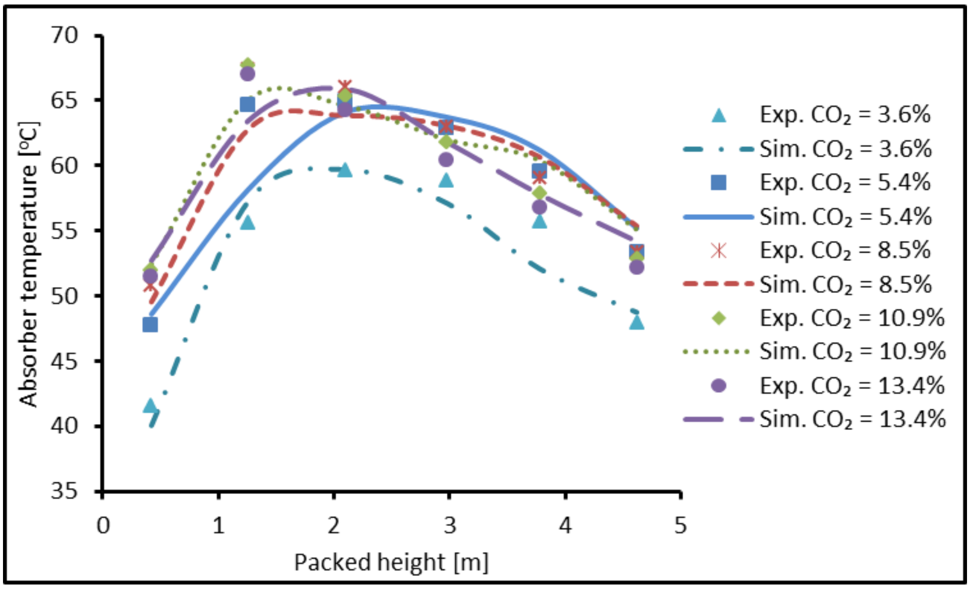

Figure 4: Model results as a function of the experimental results for the absorber temperature profiles reported by Notz et al. [9] for the set of experiments designated as Set E, reporting the variation of CO_2 composition in the flue gas.

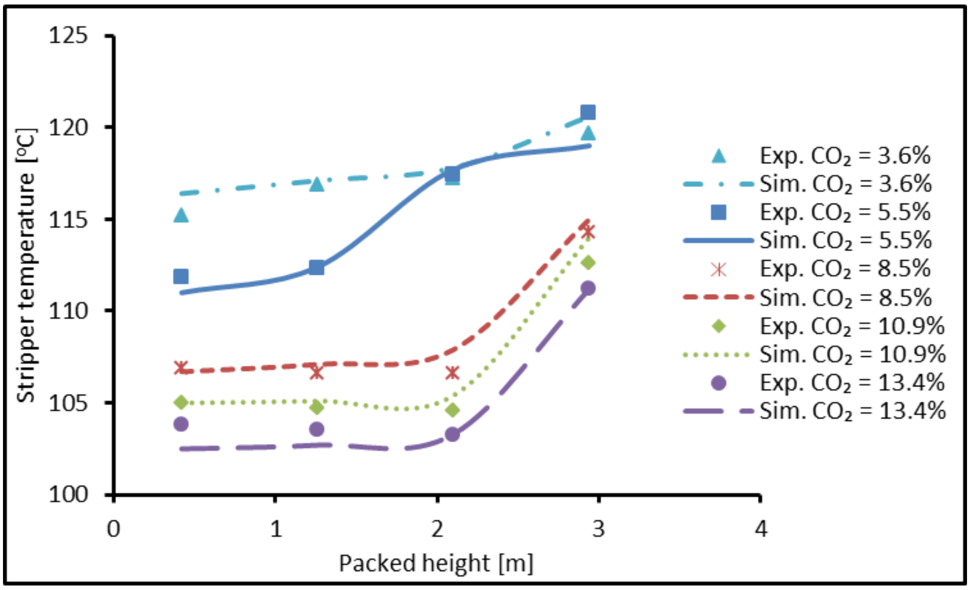

Figure 5: Model results as a function of the experimental results for the stripper temperature profiles reported by Notz et al. [9] for the set of experiments designated as Set E, reporting the variation of CO_2 composition in the flue gas.

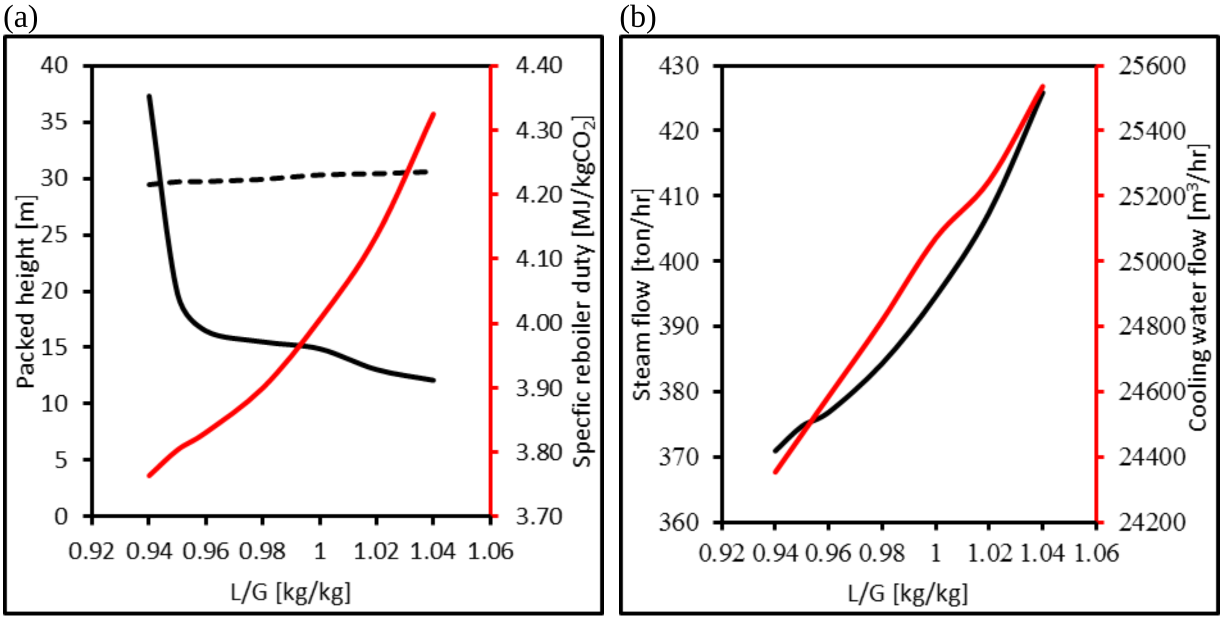

Figure 6: Process design results for the amine-based CO_2 capture plant for the NGCC without EGR. (a) Variations of absorber packed height (black solid line), stripper packed height (black dashed line) and specific reboiler duty (red solid line) as a function of the liquid to gas ratio; and (b) Variations of steam flow requirement (black line) and cooling water requirement (red line) as a function of the liquid to gas ratio.

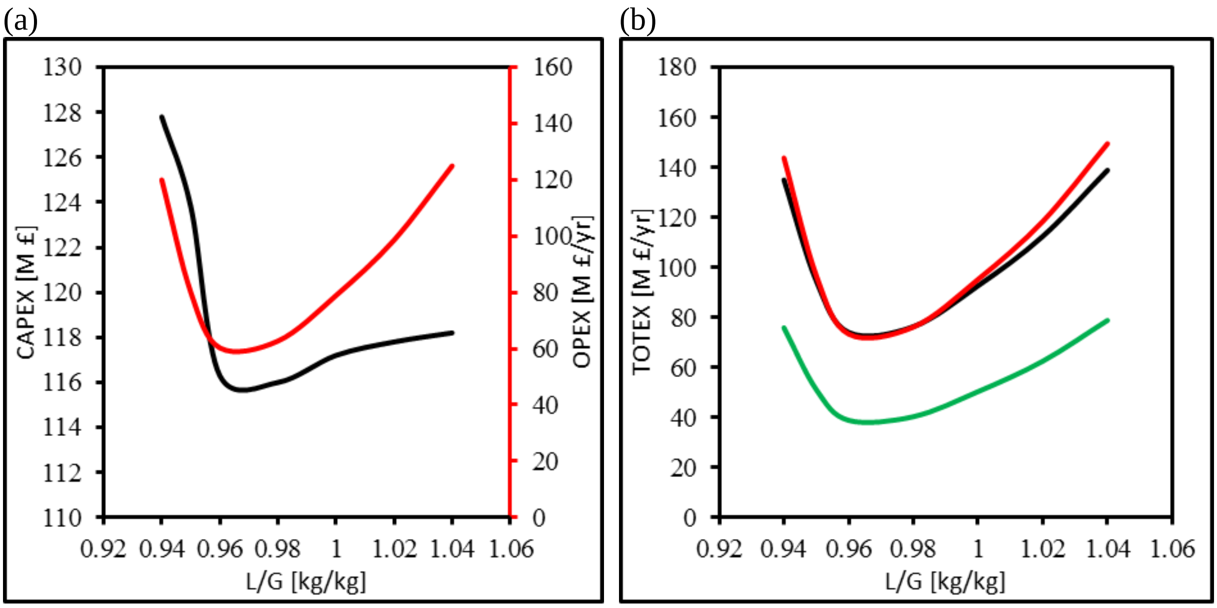

Figure 7: Process economic results for the amine-based CO_2 capture plant for the NGCC without EGR. (a) Variations of the CAPEX (black line) and OPEX (red line) as a function of the liquid to gas ratio; and (b) Variation of the TOTEX as a function of the liquid to gas ratio for three different cases as Case A (black line), Case B (red line) and Case C (green line).

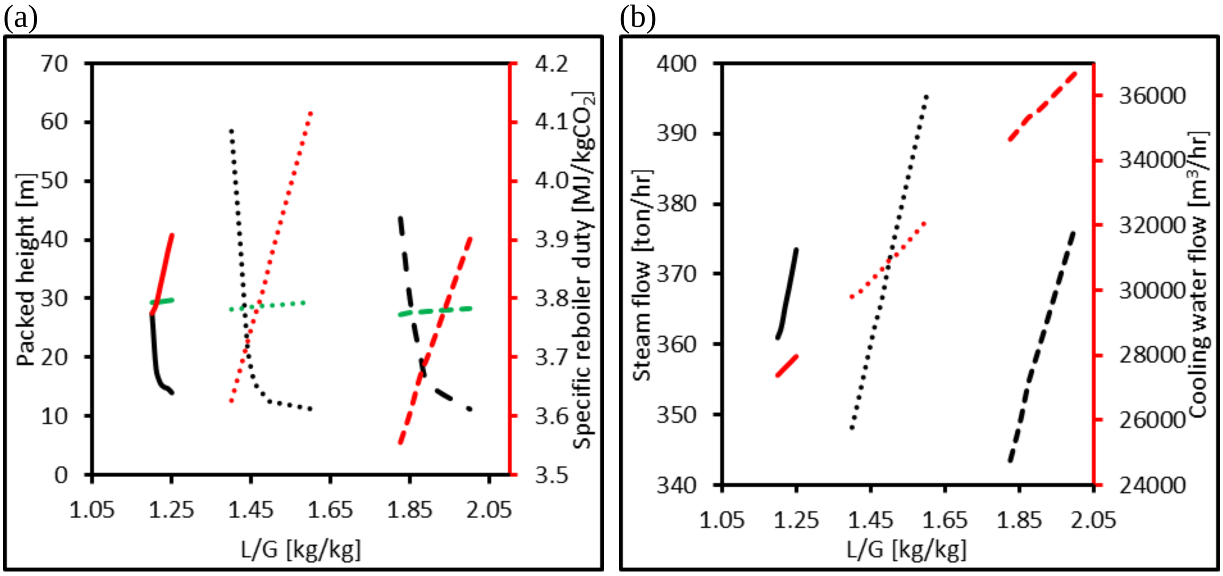

Figure 8: Process design results for the amine-based CO_2 capture plant for the NGCC with EGR (20 % EGR: Solid lines; 35 % EGR: Dotted Lines; and 50 % EGR: Dashed Lines). (a) Variations of absorber packed height (black lines), stripper packed height (green lines) and specific reboiler duty (red lines) as a function of the liquid to gas ratio; and (b) Variations of steam flow requirement (black lines) and cooling water requirement (red lines) as a function of the liquid to gas ratio.

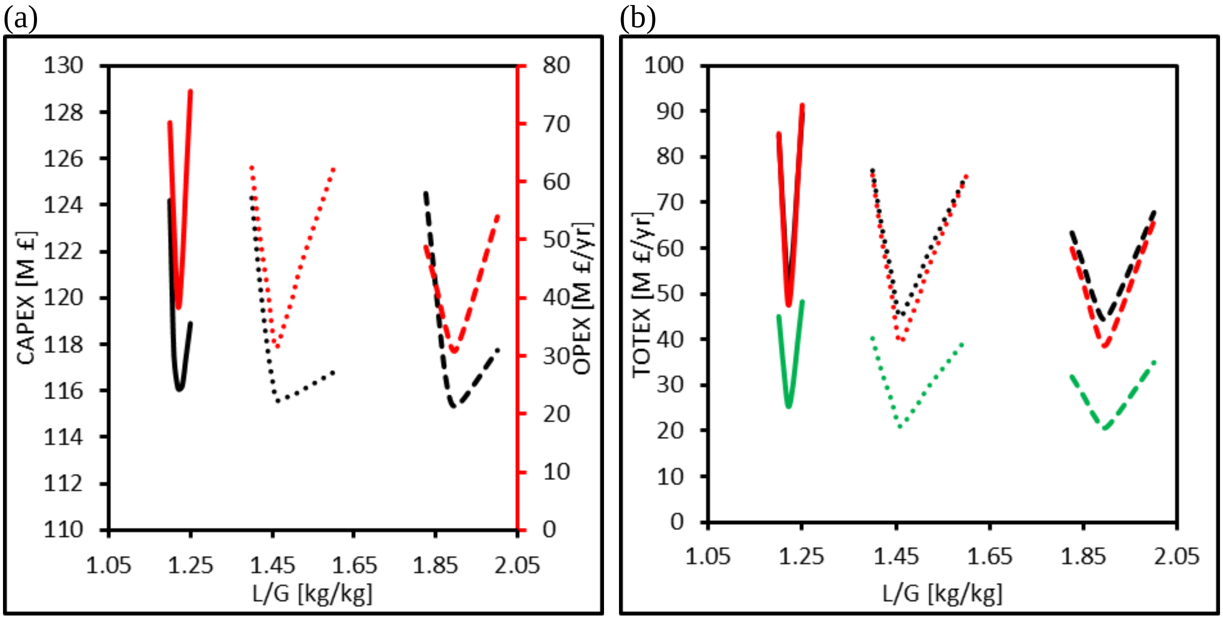

Figure 9: Process economic results for the amine-based CO_2 capture plant for the NGCC with EGR (20 % EGR: Solid lines; 35 % EGR: Dotted Lines; and 50 % EGR: Dashed Lines). (a) Variations of the CAPEX (black lines) and OPEX (red lines) as a function of the liquid to gas ratio; and (b) Variation of the TOTEX as a function of the liquid to gas ratio for three different cases as Case A (black lines), Case B (red lines) and Case C (green lines).