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Qureshi, Y., Ali, U. & Sher, F.

Original citation & hyperlink:
Qureshi, Y, Ali, U & Sher, F 2021, 'Part load operation of natural gas fired power plant with CO2 capture system for selective exhaust gas recirculation', Applied Thermal Engineering, vol. 190, 116808.
https://dx.doi.org/10.1016/j.applthermaleng.2021.116808

DOI 10.1016/j.applthermaleng.2021.116808
ISSN 1359-4311

Publisher: Elsevier

Part load operation of natural gas fired power plant with CO_2 capture system for selective exhaust gas recirculation

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Abstract

This work investigates base and part load operation of natural gas combined cycle power plant integrated with post-combustion CO_2 capture plant and selective exhaust gas recirculation scheme. Decarbonizing of natural gas combined cycle power plant is complex due to the higher flue gas flow rate with the least CO_2 content ~3–4 vol.% with residual 20% O_2 and 77% N_2 content. Therefore, the effect of series, parallel and hybrid selective exhaust gas recirculation is examined, a concept where selectively CO_2 can be recycled back and mixed into the ambient air to the inlet feed of the compressor thereby reducing the flue gas flow rate and enhancing CO_2 content at the inlet of capture plant. The study is novel in a way that part-load performance at 80, 60 and 40% for parallel and hybrid scheme of selective exhaust gas recirculation is analyzed through process simulation in Aspen Plus for 606 MW commercial-scale natural gas combined cycle power plant coupled with an amine-based CO_2 capture plant. It is found that the simulation results of power plant and CO_2 capture plant model agrees well with the experimental results. Further, the performance results show the viability of base and part load operation of natural gas combined

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cycle power plant integrated with CO_2 capture plant by enhancing the CO_2 concentration for hybrid configuration to approximately 19 vol.%. For parallel configuration, CO_2 content increases to around 13–14 vol.% at 70% recirculation ratio in comparison to 6.6 vol.% for simple EGR at 35 % ratio. It is found that the selective exhaust gas recirculation offers more stable combustion by maintaining O_2 content at 19 vol. % at combustor inlets for parallel and hybrid cases and the flue gas flow rate reduces to 68 and 70%, respectively thus reducing the size of the capture plant. The specific reboiler duty for hybrid, parallel, and series configuration reduces to 3.19, 3.25, and 3.31 MJ/kg CO_2, respectively in comparison to 3.54 MJ/kg CO_2 for base case natural gas combined cycle power plant coupled with MEA-based CO_2 capture unit. Whereas for 80 to 40% load change, the specific reboiler duty drops from 1.78% to 1.14% for parallel and hybrid configurations, respectively. In conclusion, hybrid selective exhaust gas recirculation configuration shows less efficiency penalty from base load to 40%part load and results in a decrease in specific reboiler duty in comparison to parallel configuration. Therefore, the study is innovative in an aspect that part-load performance at 80, 60 and 40% is performed, and results show a similar pattern as of baseload operation.

Keywords:

Global warming; Natural gas combined cycle; Selective exhaust gas recirculation; Specific reboiler duty; Carbon capture and storage

Nomenclature

CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CFF	Constant fuel flowrate
CO_2	Carbon dioxide
DCC	Direct contact cooler
DoE	Department of energy
EGR	Exhaust gas recirculation
ENRTL	Electrolyte non-random two liquid
GHG	Greenhouse gases
HP	High pressure
HPP	High pressure pump
HRSG	Heat recovery steam generator
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
A-IGCC	Advance integrated gasification combined cycle
IP	Intermediate pressure
IPP	Intermediate pressure pump
L/G	Liquid to gas ratio [kg/kg]
LP	Low pressure
LPP	Low pressure pump
MEA	Monoethanolamine
MWe	Megawatts electric
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NO_X	Nitrogen oxides
PCC	Post-combustion CO_2 capture
SCT	Selective CO_2 transfer
SEGR	Selective exhaust gas recirculation
SO_X	Sulfur oxides

Symbols

D	Diameter (m)
G	Gas flow rate (kg/s)
m	Mass flowrate (kg/s)
n	Polytropic exponent
p	Pressure (bar)
R	Ideal gas constant (J/mol/K)
T	Temperature (K)
Us	Superficial velocity (m/s)
v	Specific volume (m^3/kg)
V_m	Molar volume (m^3)
μ	Kinematic viscosity (m^2/s)
ω	Acentric factor

1. Introduction

CO_2 is one of the main greenhouse gases (GHG) which is accountable for an increase in global warming. High impact on the global climate change has been observed due to the CO_2 emissions. The significant threat to climate change from increased levels of GHG emissions is imminent in the atmosphere [1]. GHG emissions have been predicted to increase by 28% by 2030, if no valid measures are taken [2]. International Energy Agency (IEA) [3] has reported that despite using mitigating strategies and recent control policies, GHG emissions will reach a level of 45 gigatonnes by 2035. This emission is related with 50% possibility of limiting the increase in average global temperature to 5.6 °C unless determined measures are taken to stabilize GHG concentrations at 450 ppm CO_2. The major source of anthropogenic CO_2 emanation is from fossil fuel-fired power plants. On the other side, fossil fuel plays an important role to meet an increase in energy demand, though to stabilize the CO_2 concentration in the atmosphere, carbon capture and storage (CCS) is becoming essential [4]. Romeo et al. [5] shows that for CCS technology CO_2 compression is a prerequisite operation, so by compression with intercooling energy requirements can be reduced. Romeo et al. [5] focuses on taking the advantage of intercooling heat and analyses the economic and energetic results using intercooling compression in the LP part of the steam cycle and indicated a reduction in 40% compression energy requirement with a 23% decrease in cost of electricity.

Globally, gas-fired power plants play a vital role in power production. Further, natural gas is one of the key contributors to fossil fuel consumption and regarded as a flexible source of energy on the domestic/commercial scale and play a significant role as a fuel for electricity generation in the power plant. Natural gas combined cycle (NGCC) is a state-of-the-art technology for power generation which increases the system efficiency. In addition, NGCC plants are regarded as highly efficient for electricity generation among other fossil fuel power plants [6]. However, an increase in CO_2 emissions to the atmosphere from the burning of natural gas results in serious environmental issue i.e., global warming [7]. Decarbonizing NGCC power plants using post-combustion technology is most challenging due to the high flow rate of flue gas with carbon intensity as low as ~3–4 vol.%. At same power production rate, CO_2 emissions from NGCC plant is less than half as compared to coal-fired power plant. However, still an unabated NGCC plant releases a significant amount of CO_2 into the atmosphere about 350 kg CO_2/ MWh [8]. PCC from NGCC power plant raises difficulties, as exhaust flue gases have relatively low CO_2 content and energy requirement is increased due to auxiliary equipment's and large size of the capture plant [9]. By revamping the capture plant, using exhaust gas recirculation (EGR) integrated with PCC has been indicated to be more feasible than a conventional NGCC plant [10, 11]. By employing EGR, the capital cost of CO_2 separation unit decreases as the amount of CO_2 increases in the exhaust of the gas turbine and reduces the flow rate of the flue gas at 35% EGR ratio [12, 13]. In the EGR process, a part of the flue gas leaving the heat recovery steam generator (HRSG) is recycled to the compressor inlet after cooling, thus substituting a portion of the air entering the gas turbine [14, 15].

However, this work emphasis on a novel option of selective exhaust gas recirculation (SEGR), a concept of selectively recycling CO_2 from the exhaust of gas-fired power plant back to the entering air stream of the compressor of the gas turbine thereby raising CO_2 content and reducing the flue gas flow rate [16, 17]. SEGR functions either in parallel or in series and enhances CO_2 concentration to around 13–14 vol.% well above 6.6 vol.% at about 35% EGR ratio. The minimum oxygen level in the combustor is 16 vol.% for 35% EGR while SEGR maintains O_2 concentration at approximately 19 vol.% [16]. Therefore, the problems associated with the combustion instability of EGR are minimized for the case of SEGR. **Fig. 1(a)** and **(b)** represents series and parallel SEGR scheme, respectively for CO_2 capture with NGCC power plant. However, parallel and series configurations have some other limitations. In the CO_2 capture plant, parallel configuration required high capture efficiency while in a series configuration, the large cross-section area of the absorber may be required, which is unrealistic in some cases [9, 16]. Therefore, any change (in **Fig. 1(a)** and **(b))** will lessen these limitations and thus improve the application of SEGR. In order, to overcome these drawbacks advanced hybrid SEGR configuration for CO_2 capture was optimized in this work which is a combination of series and parallel configuration.

Consumption of renewable energy sources is growing fast around the world; fossil fuels mainly coal will be the primary source of energy supply for the next coming years. The use of wind and solar energy sources will contribute to the changing energy load of power plants; however, any kind of energy storage system is not commercially available [18]. Thus, fossil fuel-based power plants will remain to generate more balancing energy in part load conditions to maintain flexibility in the operation [18]. Therefore, this work is novel in a way that part-load performance of the NGCC power plant integrated with SEGR for the parallel and hybrid case configuration is investigated.

The design method for modelling of NGCC plant integrated with PCC plant and SEGR performance is evaluated by utilizing Aspen Plus software. The baseload operation of NGCC plant coupled with amine-based PCC plant and SEGR in series, parallel and hybrid configuration is investigated. The optimization of the amine-based PCC plant depends on the optimal design of gas and coal power stations integrated with MEA absorption plant as described by Agbonghae et al. [19]. It was reported that model based on values of solvent circulation rates and CO_2 loading of large-scale amine-based PCC plant without techno-economic analysis may lead to suboptimal designs [19].

A significant barrier in the deployment of commercial-scale PCC plants is due to the increased capital and operating cost. Kawabata et al. [20] represented A-IGCC technology in which steam and flue gas from the gas turbine is utilized as a gasifying agent. The investigation revealed that increase thermal efficiency is obtained using pre-combustion CO_2 capture plant with IGCC system. Whereas in post-combustion capture plant with A-IGCC system 38.5% thermal efficiency is gained as compared to 50.6% without capture plant. The efficiency loss of around 9.9-15.2% is observed with the absorption of 81 mol% CO_2 [20]. In pre-combustion capture with an A-IGCC system excess heat at low temperature is not utilized which resulted in a decrease in plant efficiency. Canepa et al. [21] carried out a thermodynamic investigation of CCGT power plant integrated with a PCC plant through simulation using Aspen Plus. The simulation data of Gate cycle software is used for validation of CCGT power plant whereas the PCC plant is validated with pilot-scale data for large scale application of the power plant. In addition, the performance analysis of CCGT with and without capture plant is determined, and the energy penalty is estimated. The integration of the PCC plant with EGR indicates a decrease in energy requirement without major revamping in the power plant but does not determine the impact of part-load operations [21]. Turi et al. [22] performed a techno-economic investigation of NGCC power plant combined with two CO_2 membrane systems, i.e. CO_2 capture membrane for sequestration and selective exhaust gas recycle membrane to increase CO_2 content entering the gas turbine compressor. The investigation is performed for three membrane technologies of different permeability and selectivity, however, the two membranes are operating in a series configuration with the flue gas while parallel and hybrid configurations are not analyzed [22].

Diego et al. [8] conducted a techno-economic analysis of the parallel SEGR configuration with both CO_2 selective membrane and PCC plant working at 95 % capture efficiency. It was evaluated that overall, 90% CO_2 capture efficiency can be attained with 53% SEGR recycle ratio [8].Under these conditions in CO_2 capture plant, the amount of CO_2 in flue gas is restricted to 8 vol. % and oxygen level in the air enriched with CO_2 enters the combustor about 20 vol. % [9, 22]. The analysis of this study indicates that the economic benefits of the parallel SEGR system is reliant on selective membrane cost and auxiliary power consumption [9]. Herraiz et al. [16] carried out SEGR analysis where MEA solvent is used for the CO_2 capture plant while the rotary wheel packed with solid sorbent is used for selective CO_2 separation. The NGCC power plant model is integrated with gPROMS Model Builder while Aspen Plus is used for modelling of PCC process and CO_2 compression system. The results indicate that for series SEGR scenario, three different cases were investigated between various combinations of PCC and selective CO_2 transfer (SCT) efficiency (i.e., 31/95%, 48/90% and 58/85%) while sustaining overall efficiency of capture system at 90% [16]. In this instance, the CO_2 content was calculated in the flue gas which raises approximately to 13, 8 and 6 vol.%, respectively; although O_2 level at combustor inlet is around 18.92 and 20.22 vol.%, respectively [16]. For parallel SEGR, at 70% recycle ratio with (96/97%) PCC and SCT efficiency an overall 90% CO_2 capture efficiency was achieved. Thus, in this configuration amount of CO_2 in the flue gas reaches approximately 14 vol% and O_2 in the oxidant stream to 18.68 vol.% [9, 16]. Palfi et al. [23] work represents the continuation of Herraiz et al. [16] work using rotary gas adsorption unit for SEGR application. A minimum pressure drop is proposed in the unit to avoid derating of power output in the gas turbine. The configuration shows adsorption of CO_2 with selective porous material in a rotary wheel using air for selective recycling and regeneration. As the flue gas comes in contact with the solid material placed in a rotor which is operated at the reduced rotational velocity for CO_2 absorption. The desorbed CO_2 is conveyed into an air stream that flows counter currently to the flue gas.

The study of the part-load analysis of NGCC plant with CO_2 is reported in limited literature. Rezazadeh et al. [24] account for the performance viability of full and part load operations down to 60% gas turbine load without and with CO_2 capture. The solvent circulation rate is increased at 60% load; hence, to retain an overall 90% CO_2 capture, the lean loading is raised from its design value [24]. Further, the outcomes of without CO_2 plant operation revealed to be non-beneficial as steam turbine efficiency drop as compared to NGCC plant integrated with PCC plant or compression unit. Ali et al. [25] examined the co-firing of biomass and coal in a pulverized supercritical power plant coupled with PCC unit using Aspen Plus. The performance at part load (40, 60 and 80%) is compared to the baseload model, and analysis reveals a reduction in specific reboiler duty at the CFF case [25]. Jordal et al. [26] studied the steady-state part-load operations of the NGCC plant without and with PCC plant by considering two integration options for steam extraction. Firstly, steam is extracted from IP/LP crossover and LP superheater to supply heat duty to reboiler, and secondly, integration of 40% reboiler duty in HRSG, while remaining is obtained from IP/LP crossover. In HRSG, the triple pressure steam cycle is substituted by an individual pressure level for full and part load operation, which has an efficiency drop of 0.4% point [26].

The part-load analysis of NGCC with EGR and PCC plant has also been reported. Calderon et al. [27] evaluated the part-load functioning of NGCC with PCC plant integrated with EGR. The results indicate a decrease in the number of absorber trains and the efficiency is increased by 0.5 % point as CO_2 content is higher in the flue gas. This benefit is minimized as load changes from 100 to 50%, and the same efficiency is obtained at 50% load for both cases. The study does not report the effect of efficiency as well as the impact of part-load performance on SEGR. However, as discussed earlier, there is a lack of detailed part load analysis of commercial-scale NGCC plant integrated with MEA-based PCC plant for SEGR. In this study, the optimum design of series, parallel, and hybrid configurations for NGCC plant with SEGR are evaluated at baseload. This work is novel in the way that the part-load performance of SEGR with the parallel and hybrid configurations are analyzed, and quantitative analysis of key parameters is represented for the system. Further, the literature comparison of different SEGR works as reported in the literature is presented in **Table S.1** of the supporting information.

2. Material and Methods

2.1. Process description

The NGCC plant as indicated in **Fig. 1 andFig. *2*** comprises of two gas turbines with GE's 7FA.05 type of 420.6 MW_e power output, two HRSG units and a steam turbine that generates a power output of 185.9 MW_e. The air is compressed in a gas turbine compressor and it passes to a combustor where it is assorted with pressurized natural gas. The combust air-fuel mixture than expands in a turbine to produce power. The turbine exhaust gas then moves into the HRSG, where the remaining heat is retrieved to produce steam. The HRSG encompasses three pressure subsystems, i.e. high, intermediate and low pressure (HP/IP/LP). Feed water from each subsystem comprising of HPP, IPP and LPP pump passes to economizer from where it is boiled in the evaporator and superheated in the superheater. High-pressure steam from HP turbine mixes with an IP steam, and mixed steam passes into the reheater and expands in an IP turbine. The superheated steam extracted from IP/LP crossover and LP superheater mixes, de-superheated and enters the reboiler. The expanded steam from LP steam turbine enters the condenser and is pumped back to LP economizer through LPP. For NGCC power plant, the gas turbine operates at surplus air, the flue gas from the turbine contains low CO_2 concentration (3–4 vol. %) in comparison to coal-fired power plant exhaust gas (10–14 vol. %) [28-30]. Thus, the CO_2 is stripped from a large volume of exhaust gas in NGCC with approximately one-third CO_2 partial pressure than of coal flue gas [28].

The schematic diagram shows the absorber column in which the flue gas from the bottom enters counter currently and meets a lean amine solution entering from the top of the absorber as indicated in **Fig. 1 andFig. *2***. This leads to the treated flue gas low in CO_2 concentration to the water wash section to eliminate entrained MEA solvent hence, limiting the solvent emission into the atmosphere. The rich loaded solvent is pumped from the last stage of the absorber and after absorbing heat in a cross-heat exchanger from the lean solvent emitting from the reboiler. The rich MEA solution flows down the stripper and absorbed CO_2 is stripped off by an upward flowing stream from the reboiler. The lean solution is cooled in the cross-heat exchanger by a rich amine solution and sent to a lean MEA-based cooler prior to the inlet of the absorber. The steam at the top of the stripper is condensed in a condenser and fed back to the stripper as reflux while concentrated CO_2 is sent to the compression unit for transport and storage.

The suggested series, parallel, and hybrid configuration in this work utilizes the amine-based PCC plant and selective CO_2 transfer system to enhance the CO_2 content and reduce the flue gas flowrate by revamping with SEGR. The selective CO_2 transfer efficiency (SCT) is defined as the quantity of CO_2 that is excluded from flue gas and recycled with the air stream relative to CO_2 content in total at the entering SCT setup [16]. The SCT system is modelled in literature using various operating parameters, such as CO_2 selectivity, pressure drop, SCT efficiency, heat transfer flow rate and leakage levels. The input data is obtained from a design assessment of selective CO_2 transfer system utilizing structured solid material in a rotary wheel reported by Herraiz et al. [16]. Besides using rotary adsorption other options for removing CO_2 from flue gas proposed by Merkel et al. [31] is a selective CO_2 membrane. The separation in CO_2 selective recycle membrane is driven by the difference in CO_2 partial pressure in air and flue gas as air flows counter-currently to the flue gas near atmospheric pressure in permeate and retentate streams. In this study, the SCT system is modelled using a component splitter for separating CO_2 from flue gas before it is sent to the compressor feed as represented in **Fig. 1 andFig.** ***2***. The series configuration is modelled with SCT efficiency in which the entire portion of exhaust gas exiting the HRSG is passed to the PCC plant, and after pre-treatment in the PCC, CO_2 is partially eliminated.

A large portion of CO_2 content still exists in flue gas and subsequently sent to a CO_2 capture unit. The selective CO_2 is recycled back with ambient air to the inlet of the gas turbine compressor. While for parallel configuration, flue gas exiting the HRSG is split, and a fraction of flue gas is recirculated to the SCT setup. The CO_2 is selectively passed with ambient air stream into the feed gas compressor. Whereas a portion of non-diverted flue gas is sent to the PCC unit, which requires a higher CO_2 removal rate for overall 90% CO_2 capture rate [12, 16, 30]. **Fig. 2** represents the hybrid SEGR configuration. In a hybrid configuration, the portion of flue gas is directed towards the PCC plant operating at lower efficiency for CO_2 capture in comparison to parallel SEGR, whereas the diverted flue gas is sent to the SCT setup. The enriched CO_2 stream is recycled back to the compressor while the CO_2 depleted flue gas is emitted into the atmosphere.

2.2. Modelling approach

2.2.1. NGCC power plant configuration

A 606 MW NGCC power plant is simulated in Aspen Plus and validated with the model reported in the DOE/NETL results [32]. The flue gas from the HRSG is divided into two portions and sent to the PCC system and the other component of the splitter is recycled back by maintaining minimum of 16 vol.% O_2 to the inlet of the combustor. The input data for modelling of NGCC plant at base load operation is provided in **List of** Tables

Table *1*. Stodola law of cones as given in **Eq. (1)** estimates the steam specifications through the steam turbine at off-design conditions. Same temperature and efficiencies cannot be maintained at the part-load operation. For the steam turbine, Stodola law of cones equation is used for the respective efficiency while pressure ratio remain the same; however, individual pressure will decrease in the steam turbine [24, 25]. SEGR ratio to be employed is calculated by evaluation analysis of CO_2 concentration in flue gas, O_2 content at combustor inlet and by maintaining 90% overall CO_2 capture efficiency at varying SEGR ratios as indicated in **Fig. 3** Since an increase in SEGR ratio leads to higher CO_2 concentration, therefore the SEGR ratio is decided by maintaining 16 vol.% O_2 content at 90% capture efficiency.

$$\frac{m_{in}}{m_{in_{base}}} = \frac{\mu p_{in}}{\mu_{base} p_{in_{base}}} \sqrt{\frac{p_{in_{base}} v_{in_{base}}}{p_{in} v_{in}}} \sqrt{\frac{1-\left(\frac{p_{out}}{p_{in}}\right)^{\frac{n+1}{n}}}{1-\left(\frac{p_{out_{base}}}{p_{in_{base}}}\right)^{\frac{n+1}{n}}}} \quad (1)$$

where m is the steam mass flow, μ is the kinematic viscosity, p is the pressure, v is the specific volume, and n is the polytropic exponent. Further, the process conditions must be designed above a certain value to subdue the pressure drop along the pipeline for supplying the steam to the reboiler. The saturated steam is provided to the reboiler for solvent regeneration after conditioning of superheated steam derived from IP/LP crossover at 3.70 bar and assorted with LP superheater steam [33]. A valve operates at upstream of LP turbine to prevent overflow volume from the last stage of an IP turbine and provide adequate steam pressure to the reboiler and condensing temperature. Further, a portion of reboiler condensate is refluxed back to the steam turbine cycle.

2.2.2. PCC plant configuration

The PCC plant is operated by an MEA solvent for chemical absorption. The flue gas leaving the HRSG is cooled in a direct contact cooler (DCC) to 40 °C before entering the bottom of the absorber while water is retrieved through condensation of the exhaust gas stream. The flue gas pressure is slightly increased above atmospheric pressure by a fan to compensate for the pressure drop that varies from 147 to 490 Pa/m for packed columns in the PCC plant [34]. For the present research work, it is assumed that the flue gas contains negligible portions of NOx and SOx and hence neglected in the process analysis as natural gas is a cleaner fuel.

In the PCC plant configuration, generally two absorbers are employed providing flexibility in the operation during the part-load framework [12, 19]. A 30 wt.% aqueous MEA solution is used as a standard solvent which enters at 40 °C at the top of the absorber with lean loading value fixed at

0.25 mol CO_2/mol MEA [12]. The temperature of rich solvent exiting the bottom of the absorber is increased in a cross-heat exchanger, with a 10 °C hot/cold outlet approach temperature by using lean amine solvent leaving the reboiler. The reboiler operates at 1.75 bar to maintain a regeneration temperature below 120 °C to avoid degradation of solvent and to obtain required lean loading. The pump efficiency in the PCC plant is fixed at 75%, whereas the pressure of the amine solution is maintained at 3 bar. A study by Agbonghae et al. [19] shows the basis for optimum lean loading for CO_2 capture in NGCC plant while the rich solvent loading estimation is performed based on the optimum height of packed column for the absorber.

As the CO_2 concentration increases (25–30 vol.%) at the inlet of the compressor due to SEGR, the operation of the commercial gas turbines is to be affected under these conditions. This will cause a change in fluid dynamics of the turbo machinery, fluid properties (because of the increase in specific heat ratio as compressor ejection temperature decreases and turbine exhaust temperature increase), and heat transfer to the cooled turbine blades [22]. Thus, for this application, commercial gas turbine compressor and turbine geometry maybe redesign as well as a substantial redesign of the combustor will be required for complete fuel combustion with comparatively less O_2 concentration in the oxidant stream. However, at present a minimum of 16 vol.% O_2 content entering the gas turbine compressor is considered acceptable for flame stability and appropriate combustion efficiency [9]. It is assumed for the present research work that the similar results will be obtained if the redesign of gas turbine and combustor is available.

2.3. Modelling framework

The gas turbine is modelled using Peng-Robinson equation of state while PCC plant is modelled using the ENRTL property method to explain the physical and thermodynamic properties. For vapor state, Peng-Robinson equation of state as shown in **Eq. (2)**, is utilized with constants given in **Eq. (3-8)** while IAPWS-95 property package is used for the steam cycle. A multi-stream heat exchanger is employed for the HRSG unit. The gas and steam turbine power output are kept constant and regarded as the basis for the designing of the PCC plant with SEGR for all three scenarios of series, parallel, and hybrid case. CO_2 capture process using liquid MEA is a reactive absorption process. Therefore, the rate-based approach is more preferred for mass transfer and kinetic reactions as it provides higher reliability in comparison to the equilibrium approach [35].

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \tag{2}$$

$$a \approx 0.45724 \frac{R^2 T_c^2}{p_c} \tag{3}$$

$$b \approx 0.07780 \frac{RT_c}{p_c} \tag{4}$$

$$\alpha = \left(1 + \kappa\left(1 - T_r^{0.5}\right)\right)^2 \tag{5}$$

$$T_r = \frac{T}{T_c} \tag{6}$$

$$\kappa = 0.37464 + 1.54226\omega - 0.26992\omega^2 \tag{7}$$

$$\omega = \frac{p^{sat}}{p_c} \tag{8}$$

where p is the pressure of the gas, R is the ideal gas constant, T is absolute temperature, V_m is molar volume,ω is the acentric factor, a and b are constants for attractive potential and volume correction respectively. The ENRTL activity coefficient model is employed for the liquid phase while the Redlich-Kwong equation of state as shown in **Eq. (9)** is accounted for the vapour phase with constants whose formulae are shown in **Eq. (10-11)** [36, 37]. The principal reactions in MEA-based PCC involve chemistry of MEA-CO_2-H_2O solution. The equilibrium reactions accompanied by kinetically controlled reactions that explain the formation reaction of carbamate and bicarbonate are provided in **Table 2**.

$$p = \frac{RT}{V_m - b} - \frac{a}{\sqrt{T} V_m (V_m + b)} \tag{9}$$

$$a \approx 0.42748 \frac{R^2 T_c^{2.5}}{p_c} \tag{10}$$

$$b \approx 0.08664 \frac{R T_C}{p_c} \tag{11}$$

2.4. Model validation and verification

The validation of the model is performed to analyze the model under study to assure the performance of model and simulation against experimental and reported results. In order, to compare the results of selected parameters the model is tuned with the operating values of the pilot-plant and reported data. The model of NGCC plant employed is compared with an unabated case in DOE/NETL report [32] as indicated in **Fig. 4** while the CO_2 capture plant is validated with the experimental collection of data stated by Notz et al. [38] in which 13 variation studies are performed with 47 total experiments for pilot-scale CO_2 capture plant. The validation revealed that the design framework and operating variables such as lean and rich solvent loading, temperature characterization of absorber and stripper, and CO_2 capture level were in a good agreement. The calibrated model is run for all the experiments and results are presented in **Fig. 5** for the selected parameters. The packing type used for the absorber and stripper column is the Sulzer Mellapak 250Y structural packing.

The mean percentage absolute deviations for the specific reboiler duty, CO_2 capture rate, rich loading, and lean loading are 5.53, 2.51, 1.59 and 0.35%, respectively. The PCC plant is validated at a pilot plant scale, a scaleup of the capture plant is required to fit with a commercial scale NGCC power plant [39]. Therefore, for column sizing the diameter of the absorber is determined by using design parameters i.e., approach to maximum capacity (varies from 70-80% of the flooding point velocity) as shown in the **Eq. (12)** and maximum pressure drop (varies from 147 to 490 Pa/m, as MEA is moderately foaming) whereas, the height of absorber is adjusted by using 0.1m steps until the required capture efficiency is obtained. The stripper diameter is estimated using the same criteria while the height of the column is gradually increased by 0.1m until a marginal decrease in the reboiler duty (less than 0.05%).

$$D = \sqrt{\frac{4G}{\pi U_S}} \tag{12}$$

where D is diameter of the column, G and U_s is the flow rate and superficial velocity of the gas.

2.5. Selective exhaust gas recirculation

By using innovative SEGR scheme, CO_2 content can be escalated up to 19 vol% at the inlet of PCC plant by maintaining 16 vol.% O_2 concentration at the inlet of gas turbine combustor. In general, a selective CO_2 transfer system is used for selectively recycling CO_2 from the flue gas using different operation designs such as rotary adsorption and CO_2 selective membrane system. However, the present work provides SCT system using a component splitter which is modeled using Aspen HYSYS for removal of CO_2 from the flue gas prior to recycling back to compressor feed. Aspen simulation workbook provides an appropriate user interface to Aspen Plus and Aspen HYSYS models. Aspen Plus user interface directly interacts with the properties section, flow sheet variables (pressure, flow rate, temperature, and composition) by built-in Excel subroutine. After completion results are transferred to Aspen Plus user interface to use in next block in flowsheet and data are updated for excel subpages after any update in Aspen and Excel sheet. The overall CO_2 capture rate is defined as the quantity of CO_2 that is eliminated from the flue gas to the total quantity of CO_2 in the flue gas at the inlet of the capture plant. In series flow, the flue gas is passed through the PCC unit where a part of the CO_2 is removed and is then sent to a component splitter. By setting the split fractions in the component splitter, a large portion of CO_2 is removed, and the enriched CO_2 stream is recycled back to the compressor feed with the ambient air stream while CO_2 depleted flue gas is emitted into the atmosphere. The series configuration is modelled with selective CO_2 transfer efficiency SCT as defined in Section 2.1 and is indicated in **Eq. (13)**.

$$\text{SCT efficiency} = 1 - \frac{(mol\ CO_2)_{SCT\ system\ outlet}}{(mol\ CO_2)_{SCT\ system\ outlet}} \tag{13}$$

For parallel flow, flue gas is split into two fractions where diverted flue gas is sent to the component splitter while non-diverted flue gas is passed through CO_2 capture plant. By using a large SEGR ratio, the size of a CO_2 capture plant is substantially reduced as the flow rate of flue gas decreases with a considerable amount of CO_2 content is treated in both of the units. However, high selective CO_2 transfer efficiency and recirculation ratios are required. In an advanced hybrid SEGR technology, NGCC plant integrated between the PCC plant and SCT system is utilized for CO_2 capture. Hybrid SEGR technology exploits the benefits of a combination of series and parallel scheme using the SCT system to enhance CO_2 content and PCC plant as capture technology. The flue gas enters at low temperature in the SCT set-up at about 30 °C to minimize sensible heat transfer, and minimum temperature is assured at the entering gas turbine. For parallel SEGR, the temperature of diverted flue gas from HRSG is reduced in a DCC. Whereas in series SEGR the leaving flue gas from the absorber is cooled either in an additional DCC or in the absorber water wash section.

2.6. PCC plant performance at part load

The simulation of NGCC plant for part load operation at 80 ,60, 40%, are performed in Aspen Plus. By reducing fuel mass flow rate, the air requirement decreases, the gas turbine load is decreased. At each part load analysis, the temperature of flue gas is cooled to 40 °C at the inlet of the absorber by DCC while the 90% CO_2 capture rate is maintained by adjusting the L/G ratio. The part-load operation of a power plant is analyzed from 100 to 40% with a 20% interval for parallel and hybrid cases. While in series configuration CO_2 is removed partially from the flue gas of the PCC system and then passed into SCT system with reduced CO_2 content, therefore, a large cross-sectional area of the absorber may be required. The optimization of L/G ratio at all part loads considering reboiler temperature, specific reboiler duty, and auxiliary power the minimum net efficiency penalty is performed. The pressure at the top of a stripper is held constant at 1.62 bar as reduced pressure is not favored for part-load operations following high IP/LP crossover pressure design as discussed in Section 2.2.1. The extracted steam from the IP/LP crossover is given to reboiler and reduces the pressure because of decrease in mass flow to 87.39 kg/s. The upstream valve at the LP turbine must provide adequate condensing temperature and steam pressure to the reboiler and avoid excess volume flow out from the IP turbine. The steam pressure is maintained at 3 bar in the reboiler by an upstream throttle valve.

3. Results and discussion

3.1. Baseload performance

The CO_2 content increases drastically in the exhaust gas to about 19 vol% as compared to 5 vol% with a conventional air combustion. In the gas phase, a rise in CO_2 content results in a higher CO_2 absorption rate in the absorber due to the increase in mass transfer driving force as thermodynamic equilibrium is shifted towards rich CO_2 loading [9, 16]. This resulted in the decrease of the steam requirement for the solvent regeneration, thus reducing the specific reboiler duty for hybrid, parallel, and series configuration near to 3.19, 3.25, and 3.31 MJ/kg CO_2, respectively which is 6-8% lower in comparison to NGCC plant coupled with MEA-based CO_2 capture unit as indicated in **Fig. 6.** The effect of specific reboiler duty and various parameters for SEGR in series, parallel and hybrid coupled with PCC plant are listed in **Table 3**.

Fig. 7 indicates the CO_2 content effect on the specific reboiler duty. It is noticed that as the CO_2 concentration increases in the flue gas, the specific reboiler duty reduces, the reason behind this decline in specific reboiler duty is due to the increase in the partial pressure of CO_2 which effect the driving forces and thus facilitate more absorption of the CO_2 [39]. The total CO_2 content captured is higher at constant capture rate as the CO_2 concentration increases consequently lowering the specific reboiler duty. The energy requirement per kg of CO_2 capture reduces as CO_2 content increases from 4 to 18% resulting in the drop of specific reboiler duty from 3.54 to 3.19 MJ/kg CO_2. In the literature, Akram et al. [11] kept the constant solvent flow rate whereas varying the capture rate while in this study to accomplish the 90% CO_2 capture rate the flow rate of solvent is varied; however, specific reboiler duty trend is similar in both studies. The temperature of entering flue gas in the absorber affects the reboiler duty as revealed by Brigman et al. [40] that as the temperature dropped from 50 °C to 25°C, the specific energy requirement reduced by 20%.

However, in the present study entering flue gas temperature is kept constant at 40 °C for the purpose that the flue gas from the actual power plant will be hotter which is needed to be cool down at the absorber inlet. Thus, the cooling process also consumes energy; however, the temperature of flue gas varies with the location and design process of the power plant. Although, by process optimization of the power plant and PCC plant, the cooling requirements for the flue gas entering the absorber and reboiler duty can be optimized [11]. Another important factor which will affect the specific reboiler duty is lean and rich solvent loading. Normally, specific reboiler duty drop down when there is a rise in the solvent loading. Tobiesen et al. [41] reported that specific reboiler duty decreases from 11.20 GJ/Ton$_{CO2}$ to 3.70 GJ/Ton$_{CO2}$ where lean loading was increased from 0.18 to 0.37 mol CO_2/mol MEA, respectively. Less water vapour is required for higher rich loading which ultimately require less heat to vaporize the water [42]. This makes it one of the important contributing part in order to reduce the specific reboiler duty at higher CO_2 content.

Furthermore, the regeneration of solvent in the stripper is influenced by an increase in lean and rich solvent loading because of the higher CO_2 concentration in the flue gas. As the lean loading increases, it reduces the steam generation in the stripper, thus reduces the specific reboiler duty. The lowest specific reboiler duty could be attained if the highest rich solvent loading (0.44 mol CO_2/mol MEA) is maintained which is based on the solubility of CO_2 at thermodynamic equilibrium [38]. The flowrate of the CO_2 which is absorbed is similar to the desorbed, so that stripper design is alike for all cases due to the same fuel input and constant capture efficiency. However, some deviation at the stripper may occur in rich loading and solvent flowrate. Although, this study has followed the same optimization process as used by Agbonghae et al. [19] by keeping the lean solvent loading constant at 0.25 mol CO_2/mol MEA whereas, at higher rich loading it becomes easier to remove CO_2 content which ultimately reduces the specific reboiler duty.

SEGR configuration minimizes the flow rate of the flue gas, which is treated in the PCC plant with increased CO_2 concentration. For parallel and hybrid case, the flue gas flow rate reduces to 68 and 70%, respectively in comparison to the conventional MEA-based CO_2 capture plant as recirculation ratio is set at 70 and 76%, respectively for both cases and cooled to 30°C before recycling. As mentioned in **Table 4**, the flue gas flow rate passing through the CO_2 capture plant reduces to 208 kg/s for parallel and 197 kg/s for hybrid configuration, which is 30–32% of the base-case model. The CO_2 concentration which is recycled is limited by the O_2 content maintained at 16 vol.% at the combustor inlet. The amount of O_2 reduces in the CO_2 enriched air either by transferring O_2 from air to the flue gas or by the transfer of water vapor from flue gas to air as large proportion of air is substituted by the water vapor. By transferring 10% oxygen, the O_2 content will be reduced by approximately by 1 wt.% [19]. The CO_2 content increases by an excessive amount of water vapor transfer as surplus humidity is condensed in DCC.

Moreover, for different SEGR configurations, the CO_2 concentration increases in series SEGR operating at overall 90% CO_2 capture rate and SCT efficiency is varied at 92, 95 and 97%. The amount of CO_2 in flue gas reaches to 6.71, 9.93 and 12.91 vol. %, respectively in comparison to 3.90 vol.% for NGCC integrated with PCC without SEGR configuration. SEGR in parallel and hybrid configuration operating at overall 90% CO_2 capture rate, the flue gas CO_2 concentration reaches to around 14.73 and 18.23 vol. % respectively.

Fig. ***8*** shows an absorber temperature profile with respect to height. The temperature bulge at top of the absorber as the maximum amount of CO_2 is absorbed thus providing an increased driving force for mass transfer. The rate of CO_2 absorption decreases as temperature rises due to the fact that equilibrium shifts towards reagents. As CO_2 content increases the temperature bulge rises and results in a higher mass transfer rate. On the contrary, increased bulge temperature is not suitable for the absorption process as it decreases the rate of absorption.

For the hybrid scheme, the temperature increases to about 82 °C while 70–80 °C for parallel and series scheme as a result of the maximum heat of absorption where temperature bulge is near the top of the absorber. The temperature then starts to decrease because of the water vapor and lean solvent as shown in

Fig. *8*. Kvamsdal et al. [43] reported that the cooling effect and water vapor decreases at high L/G ratios. In a hybrid configuration, the CO_2 depleted gas leaves the top of absorber at approximately 70°C while for parallel and series configuration the temperature is around 60–65 °C. A large water wash section may be needed to cool down the temperature to 40 °C or ambient and to reduce the amount of MEA emissions. A random packing can be used for this purpose; however, additional details of the water wash section is not evaluated in the results described in the given **Table 3**.

One of the important factors which have an influence on PCC plant is L/G ratio. As the CO_2 content increases, the L/G ratio also increases, as an excessive quantity of solvent is needed to obtain a 90% CO_2 capture rate. As the L/G ratio rises the specific reboiler duty for solvent regeneration reduces as indicated in **Fig. 9**. At 6-12% CO_2 concentration for series configuration, the reported L/G ratio is 2.04 –3.78 while it increases to 4.13 to 4.91 at 14.73% and 18.23% CO_2 concentration in parallel and hybrid configurations, respectively. Agbonghae et al. [19] simulation results of NGCC power plant showed the measured L/G ratio is 1.50, 2.45 at 5 and 8% CO_2 concentrations, respectively which are nearly close to the values mentioned in **Table 4**. The auxiliary loads of the power plant are calculated from the DOE report [32] and SEGR system auxiliaries are assumed constant at approximately 11.2 MW to make the system more feasible and hence allowing the evaluation of net power output of the power plant. Further, the net power plant efficiencies are estimated and shown in **Table 4**.

3.2. Part-load performance

The net efficiency in the part-load operation of the power plant is evaluated from 100 to 40% load which reduces due to less flue gas flow rate and lower steam parameter. The net plant efficiency and associated efficiency penalty based on simulation investigation of NGCC plant at part load operation integrated with PCC is shown in **Table 5**. The net efficiency decreases at part load as anticipated by working the equipment at different loads from the base-load design point and the part-load efficiency drop by 2–3% point [44]. The net plant efficiency decreases from 49.01% at full load to 40.79% at 40% load for parallel configuration while 49.07% to 40.90% for hybrid configuration for the same load decrease. The net efficiency penalty refers to the difference between power plant efficiencies without and with PCC. The efficiency penalty at full load is around 8% points and reaches to 9.89% and 9.78% points for parallel and hybrid configurations down to 40% load. While the load drops, the efficiency penalty increases because of the throttling losses to maintain the pressure level in the reboiler necessary for the heat transfer as shown in **Fig. 10**.

For series SEGR, a higher temperature at gas turbine inlet is expected compared to parallel SEGR due to less air to the flow rate of flue gas ratio in the SCT system. Therefore, as the total quantity of flue gas passes through the system a higher sensible heat transfer rate occurs in series SEGR system. The ratio of specific heat increases with higher CO_2 content as the outlet temperature of the compressor decrease with an increase in the outlet temperature of the turbine. For cases with SCT efficiency greater than 90%, a higher exhaust gas temperature enters the HRSG.

The part-load performance for SEGR in series is not evaluated because of intricate SCT design and operation as the flue gas is firstly passed through PCC system and then sent to SCT system with decreased CO_2 content in the flue gas. That outcomes in a large size of PCC plant and CO_2 selective membrane area will also increase. Further, the efficiency for series SEGR is less in comparison to parallel and hybrid configurations, so the net efficiency penalty is higher for series configuration. The gas turbine inlet temperature also increases to around 30°C at 40% load operation relative to 1293°C temperature at base load operation while at each part load analysis, the behavior of specific reboiler duty is similar to base-load operation. The reduction in specific reboiler duty is due to decrease in logarithmic temperature difference in rich/lean cross heat exchanger and a rise in the rich CO_2 loading. In parallel and hybrid configurations, the specific reboiler duty drops down from 1.78% to 1.14%, respectively, from 80 to 40% load change. Although at all loads, the lean loading is fixed at 0.2 mol CO_2/mol MEA, the rich loading increases at part loads due to an overdesign of the absorber [25].

As a result, closer equilibrium approach and higher mass transfer is achieved. Further, the L/G ratio decreases from 4.13 at full load to 4.06 down to 40% with a reduction in heat duty and reduction in the CO_2 content in the flue gas from 14.73 to 14.54 for parallel configuration. Whereas for hybrid configuration, the L/G ratio decreases from 4.91 at 100% load to 4.76 at 40% load while CO_2 concentration decreases from 18.23 to 18.06 vol.% with reduction in solvent flow rate to 37.42% at 40% load as compared to 100% load.

Fig. *11* shows both parallel and hybrid cases for the reduction of specific reboiler duty and L/G ratio at 20% load intervals. In addition, the CO_2 concentration reduces at various part-load performances, as shown in

Fig. *12* due to the increased air to fuel ratio and any possible leakages in the air preheater. The air to fuel ratio increases down to 40% load to 35.17 from 34.04 on mass basis at base load while keeping constant pressure ratio in comparison to base-load operation. Furthermore, it results in the reduction of the flue gas flow rate to 64% at 40% load relative to the baseload. The steam extraction from the IP/LP crossover point experiences the reduction in the flow rate of steam through the LP turbine, thereby reducing the turbine power output [33].

However, sometimes it is preferable to operate NGCC power plant without PCC plant, for instance at peak hours with increased electricity rates or during maintenance time of the CO_2 capture plant. Generally, double-flow LP steam turbine is considered so it is necessary to design a steam turbine which can handle a varying steam flow rate. Rezazadeh et al. [24] discussed the performance viability of the NGCC power plant without and with PCC plant and its influence on the condenser pressure and efficiency of IP and LP turbine for different part load operations. It is reported in the literature that it is not useful to operate without PCC plant except during inevitable conditions, for instance, interruption in PCC plant operation or CO_2 compression train. Therefore, in this study at each load operation, the steam mass flow rate to the reboiler is estimated and it is found that approximately 40% of the total steam from IP/LP crossover is sent to the LP turbine maintaining 90% CO_2 capture rate in the PCC plant. It is observed that the total steam flow rate through LP turbine in triple pressure NGCC with 90% CO_2 capture is 123 kg/s and reduces to 87.40 kg/s for 40% GT load.

Table *6* shows the part-load operation of NGCC power plant integrated with PCC plant for parallel and hybrid schemes.

4. Conclusions

This work has exploited the use of series, parallel, and hybrid configurations for selective exhaust gas recirculation in the natural gas combined cycle power plant at base-load and part-load operation for parallel and hybrid arrangements. The results conclude that selective exhaust gas recirculation configuration anticipated in this work has increased CO_2 concentration, i.e. for hybrid, parallel, and series (97/90) configurations it reaches to 18.23,14.73 and 12.91 vol.% respectively, keeping below 16 vol. % oxygen level at the inlet of the combustor with an overall 90% CO_2 capture rate. Additionally, selective exhaust gas recirculation configuration for the parallel and hybrid case at 70% and 76% recirculation ratio reduces the flue gas flow rate by the 68% and 70%, respectively in comparison to the conventional air-based combustion hence smaller absorber diameter allowing a compact design of the CO_2 capture plant. For the part-load performance at 80, 60, 40%, the steam extraction was carried out at IP/LP crossover and results indicate the performance viability of part-load operation for the system under analysis. The overall CO_2 capture rate is maintained at 90% at various part-load operations down to 40% by calibrating lower values for the solvent circulation rate. This study quantitatively analyzes the performance of the MEA-based CO_2 capture plant integrated with selective exhaust gas recirculation in terms of reduction in specific reboiler duty to 6-8% at full and part load operation in comparison to air-based combustion at similar CO_2 concentrations. The investigation of the net plant efficiency without and with CO_2 capture at part-load performance shows that at baseload the efficiency penalty for parallel and hybrid configurations integrated with CO_2 capture is 8.35% and 8.29% point while increases to 9.89% and 9.78% point down to 40% load, respectively. Thus, the better performance of the hybrid configuration is obtained, leading to a decrease in the specific reboiler duty. By selecting whether selective exhaust gas recirculation in series, parallel or hybrid configuration, the selective CO_2 transfer efficiency plays a vital role and optimization should be performed to minimize the cost of the overall plant. Moreover, different promising solvents should be utilized for these case studies to evaluate energy efficiency values by performing simulation analysis.

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List of Tables

Table 1. Input parameters for the simulation of NGCC models at base load operation for NGCC power plant [32].

Parameter	Value
Gas turbine inlet temperature (°C)	1293
Gas turbine outlet temperature (°C)	612
Air inlet temperature (°C)	15
Compressor pressure ratio	17
Compressor isentropic efficiency (%)	79.50
Gas turbine isentropic efficiency (%)	90.51
Evaporation pressures in HRSG	

High pressure (HP) (bar)	162
Intermediate pressure (IP) (bar)	24
Low pressure (LP) (bar)	4
Fuel inlet temperature (°C)	38
Fuel inlet pressure (bar)	27.50
Isentropic efficiency of steam turbine	
HP (%)	88.03
IP (%)	92.37
LP (%)	93.67
Pump efficiency (%)	75

Table 2. Equilibrium and kinetically controlled reactions with its parameters [11, 34]

Reactions	Reaction Type	Rate Constant K	Activation energy E [kJ/mol]
$H_2O + MEAH^+ \leftrightarrow MEA + H_3O^+$	Equilibrium	---	---
$2H_2O \leftrightarrow H_3O^+ + OH^-$	Equilibrium	---	---
$HCO_3^- + H_2O \leftrightarrow CO_3^{2-} + H_3O^+$	Equilibrium	---	---
$CO_2 + OH^- \rightarrow HCO_3^-$	Kinetic	1.33E+17	5547
$HCO_3^- \rightarrow CO_2 + OH^-$	Kinetic	6.63E+16	107,420
$MEA + CO_2 + H_2O \rightarrow MEACOO^- + H_3O^+$	Kinetic	3.02E+14	41,264
$MEACOO^- + H_3O^+ \rightarrow MEA + CO_2 + H_2O$ (Absorber)	Kinetic	5.52E+23	69,158
$MEACOO^- + H_3O^+ \rightarrow MEA + CO_2 + H_2O$ (Stripper)	Kinetic	6.50E+27	95,384

Table 3. Operating parameters of the CO_2 capture process for investigated configurations.

Parameters	Air based combustion	SEGR Series (92/90)	SEGR Series (95/90)	SEGR Series (97/90)	SEGR Parallel	SEGR Hybrid
Overall CO_2 capture efficiency	90	90	90	90	90	90
CO_2-enriched stream at compressor inlet						
Temperature (°C)	15	27	27	27	25	28
Pressure (bar)	1.01	1.01	1.01	1.01	1.01	1.01
Mass flow rate (kg/s)	642	623	627	629	670	796
CO_2 concentration (vol.%)	0.03	0.63	4.01	7.09	9.20	13.76
O_2 concentration (vol.%)	20.73	19.92	19.48	19.23	19.33	16.60
Flue Gas at GT exhaust						
Temperature (°C)	612	911	912	913	860	754
Pressure (bar)	1.04	1.04	1.04	1.04	1.04	1.04
Mass flow (kg/s)	665	646	650	652	693	819
CO_2 concentration (vol.%)	3.90	6.71	9.93	12.91	14.73	18.23
Cross heat exchanger hot side temperature approach (°C)	10	10	10	10	10	10
MEA concentration (wt.%)	30	30	30	30	30	30
Lean solvent loading (mol CO_2/ mol MEA)	0.25	0.25	0.25	0.25	0.25	0.25
Condenser temperature (°C)	35	35	35	35	35	35
Stripper condenser pressure (bar)	1.62	1.62	1.62	1.62	1.62	1.62

Absorber						
Number of absorber	2	2	2	2	2	2
Absorber packing	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y
Absorber diameter (m)	12.88	12.88	12.88	12.88	11.23	10.60
Absorber height (m)	19.90	17.00	17.00	17.00	18.39	18.56
Stripper						
Number of stripper	1	1	1	1	1	1
Stripper packing	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y	Mellapak 250Y
Specific reboiler duty (MJ/ kg_{CO2})	3.54	3.39	3.33	3.31	3.25	3.19

Table 4. Designed results of the CO_2 capture plant for NGCC power plant configurations.

Parameters	Air based combustion	SEGR Series (92/90)	SEGR Series (95/90)	SEGR Series (97/90)	SEGR Parallel	SEGR Hybrid
Gas turbine power output (MW_e)	420.6	420.0	419.2	419.9	420.2	420.5
Gross power output (MW_e)	606.5	604.4	604.8	605.2	605.4	606.1
Net power output (MW_e)	553.1	539.7	540.1	540.5	540.7	541.3
Net thermal efficiency (%)	48.87	48.93	48.97	49.00	49.01	49.07
Recirculation ratio (%)	-	-	-	-	70	76
Flue gas temp at absorber inlet (°C)	40	40	40	40	40	40
CO_2 in flue gas (vol.%)	4.97	6.71	9.93	12.91	14.61	18.23
Liquid/gas ratio (kg/kg)	1.91	2.04	2.90	3.72	4.13	4.91
Rich CO_2 loading (mol CO_2/ mol MEA)	0.47	0.48	0.49	0.49	0.49	0.49
Flue gas at absorber bottom (kg/s)	665	646	650	651	208	197

Table 5. Net efficiency penalty for reference NGCC power plant with and without CO_2 capture at various GT loads.

Parameters	**GT load [%]**			
Net plant efficiency (%)	100	80	60	40
Reference NGCC (without CO_2 capture) (%)	57.36	55.24	52.71	50.68
NGCC+PCC (Parallel Configuration) (%)	49.01	46.56	43.72	40.79
Efficiency penalty (%-point)	8.35	8.68	8.99	9.89
NGCC+PCC (Hybrid Configuration) (%)	49.07	46.70	43.76	40.90
Efficiency penalty (%-point)	8.29	8.54	8.95	9.78

Table 6. Part loads operation of NGCC plant integrated with MEA-based PCC plant for parallel and hybrid configurations.

Parameters	GT load (%) for parallel case			GT load (%) for hybrid case		
	80	**60**	**40**	**80**	**60**	**40**
Gas turbine power output (MW)	336.5	252.9	168.9	336.5	252.9	168.3
Steam turbine power output (MW)	173.9	160.6	147.8	173.6	160.2	147.5
Gross power output (MW)	510.4	413.5	316.7	510.1	413.1	315.8
Flue gas flow rate (kg/sec)	586	509	427	708	612	515
Flue gas flow relative to full load (%)	87	76	64	89	77	65
Specific Reboiler duty	3.24	3.23	3.22	3.19	3.17	3.14
L/G ratio	4.11	4.09	4.06	4.89	4.80	4.76
Lean loading (mol CO_2/ mol MEA)	0.25	0.25	0.25	0.25	0.25	0.25
Rich loading (mol CO_2/ mol MEA)	0.49	0.49	0.49	0.49	0.49	0.49
CO_2 conc. at GT exhaust (vol.%)	14.67	14.61	14.54	18.17	18.12	18.06

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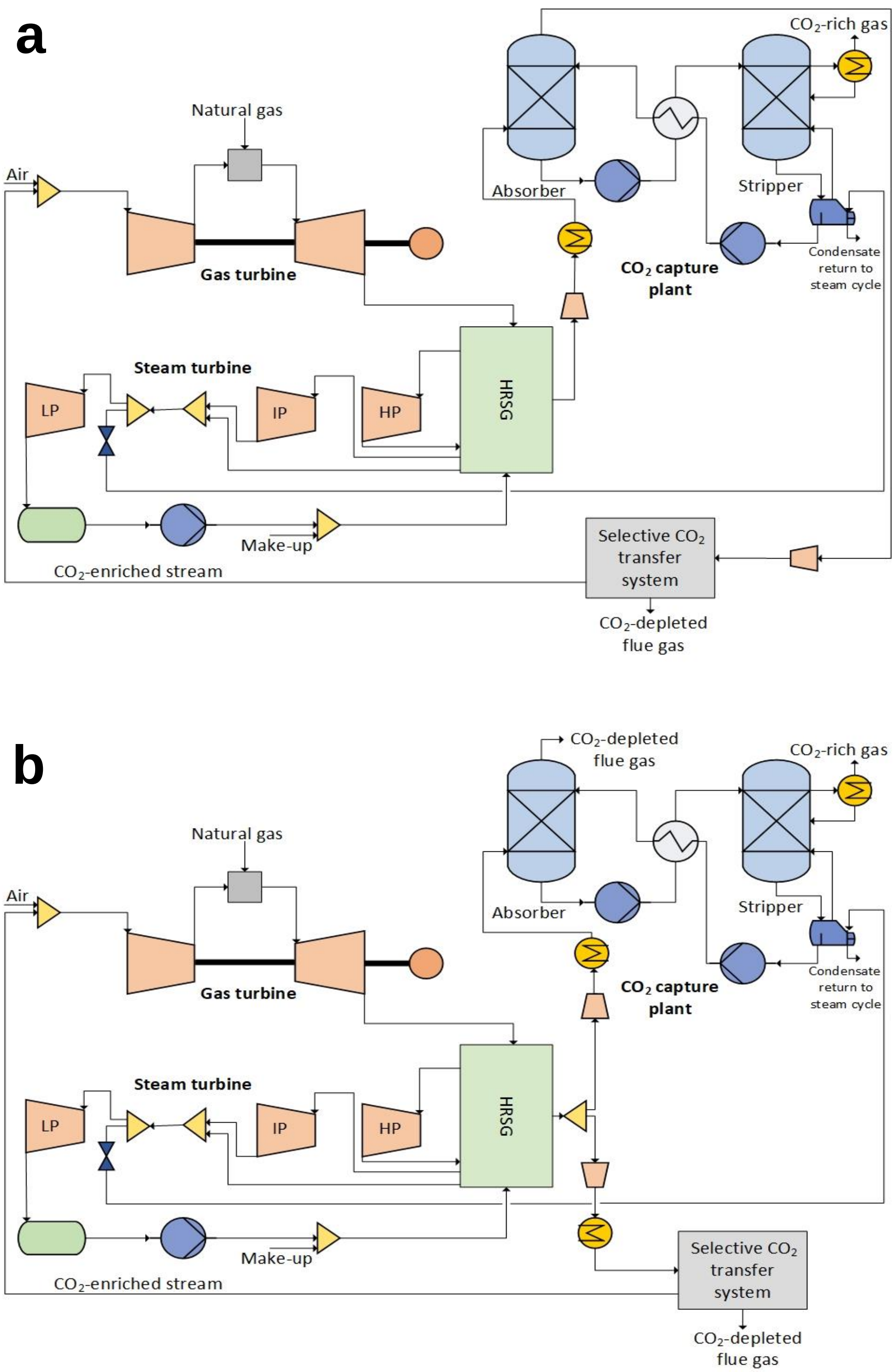


Fig. 1. SEGR schemes for CO_2 capture in NGCC power plants integrated with MEA-based CO_2 capture plant; **(a)** Series and **(b)** Parallel [16].

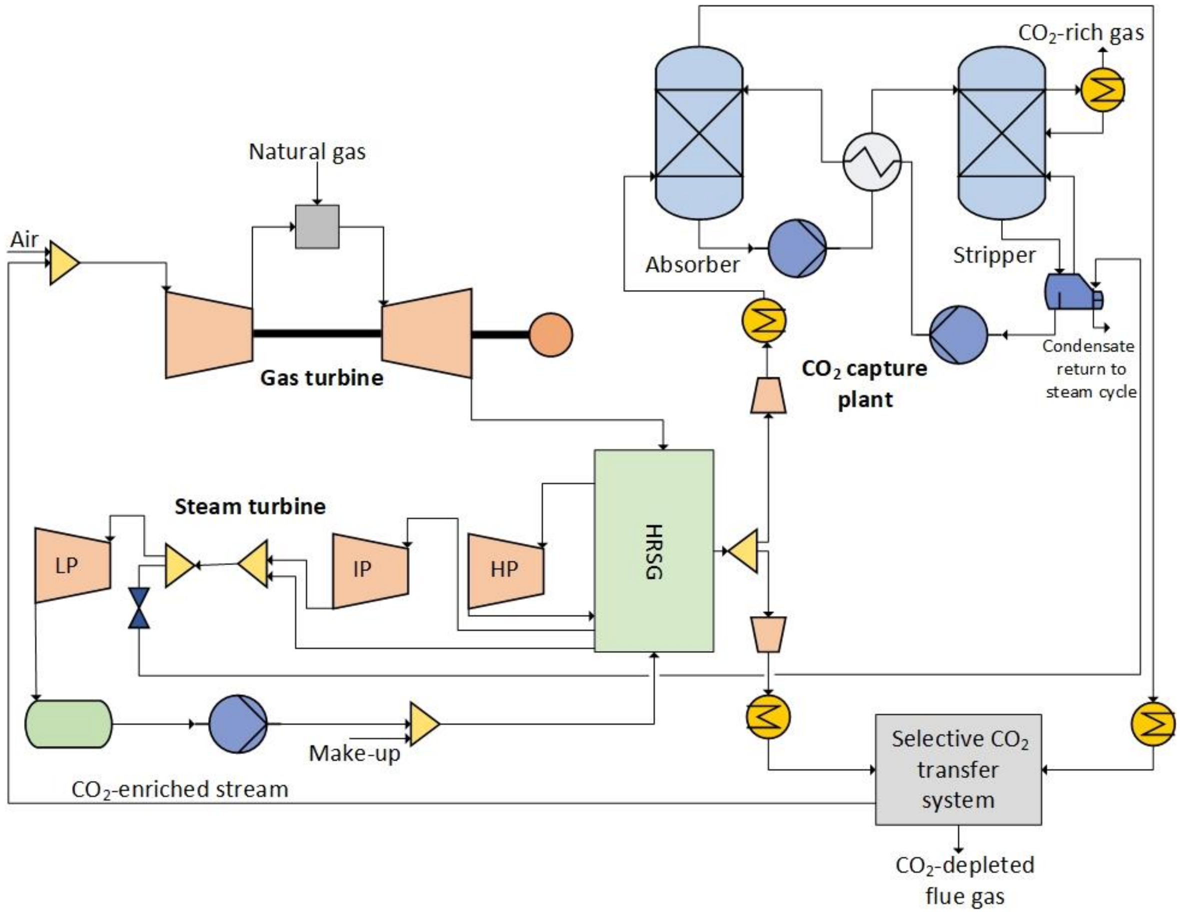


Fig. 2. Hybrid SEGR scheme for CO_2 capture in NGCC power plant integrated with MEA-based CO_2 capture plant [9].

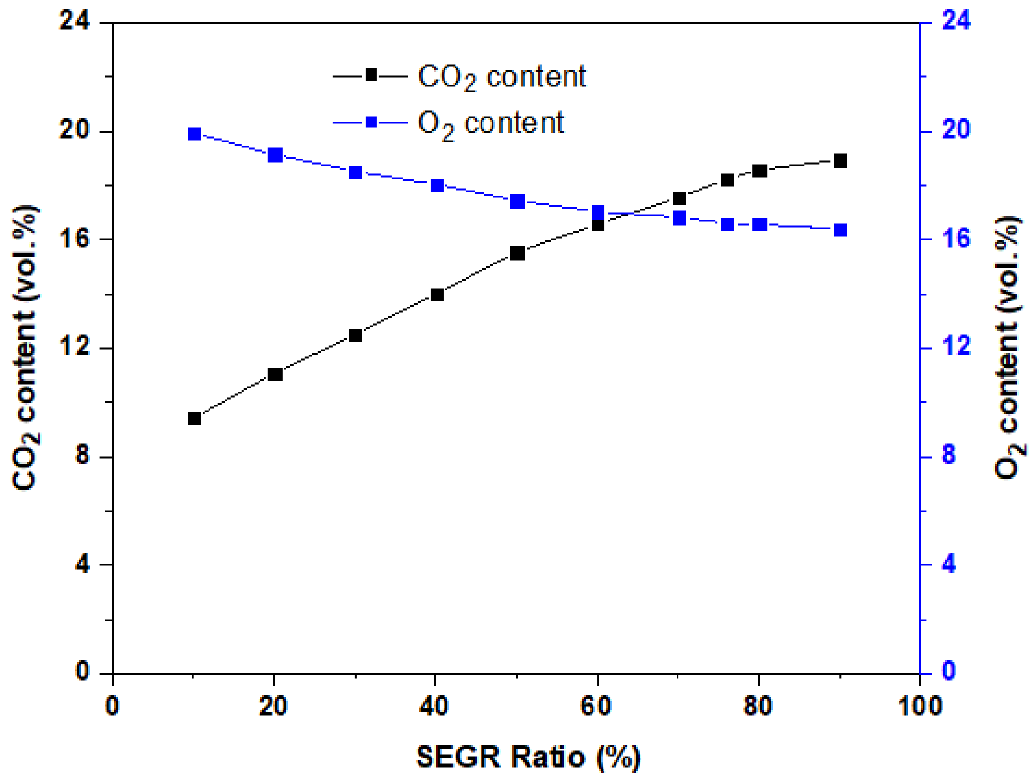
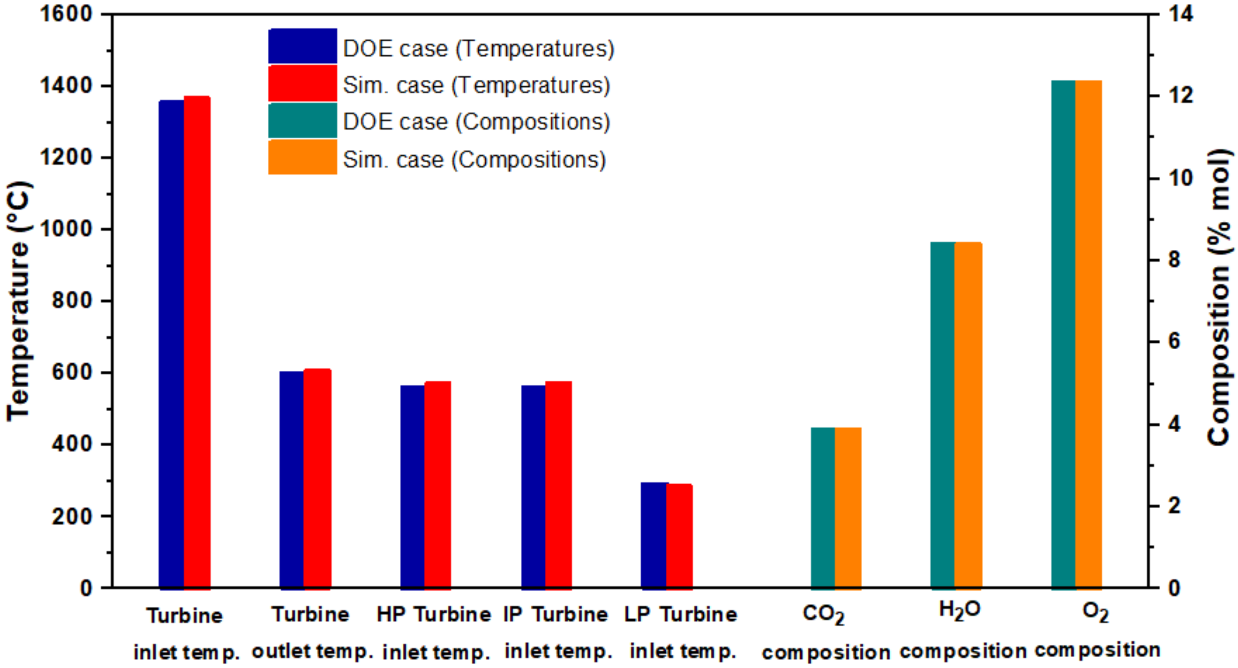


Fig. 3. Evolution of CO_2 content in the flue gas and O_2 concentration at the combustor inlet at 90% overall CO_2 capture efficiency of the system at multiple SEGR ratios for the hybrid SEGR configuration.



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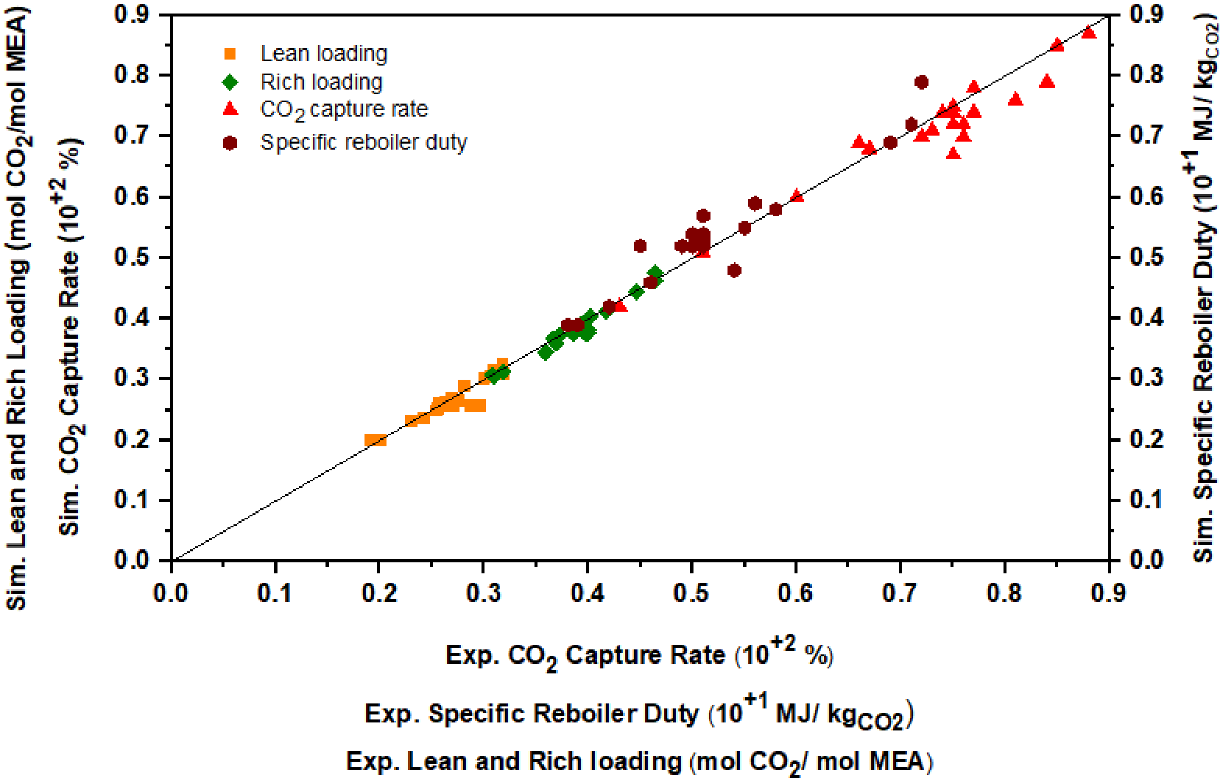
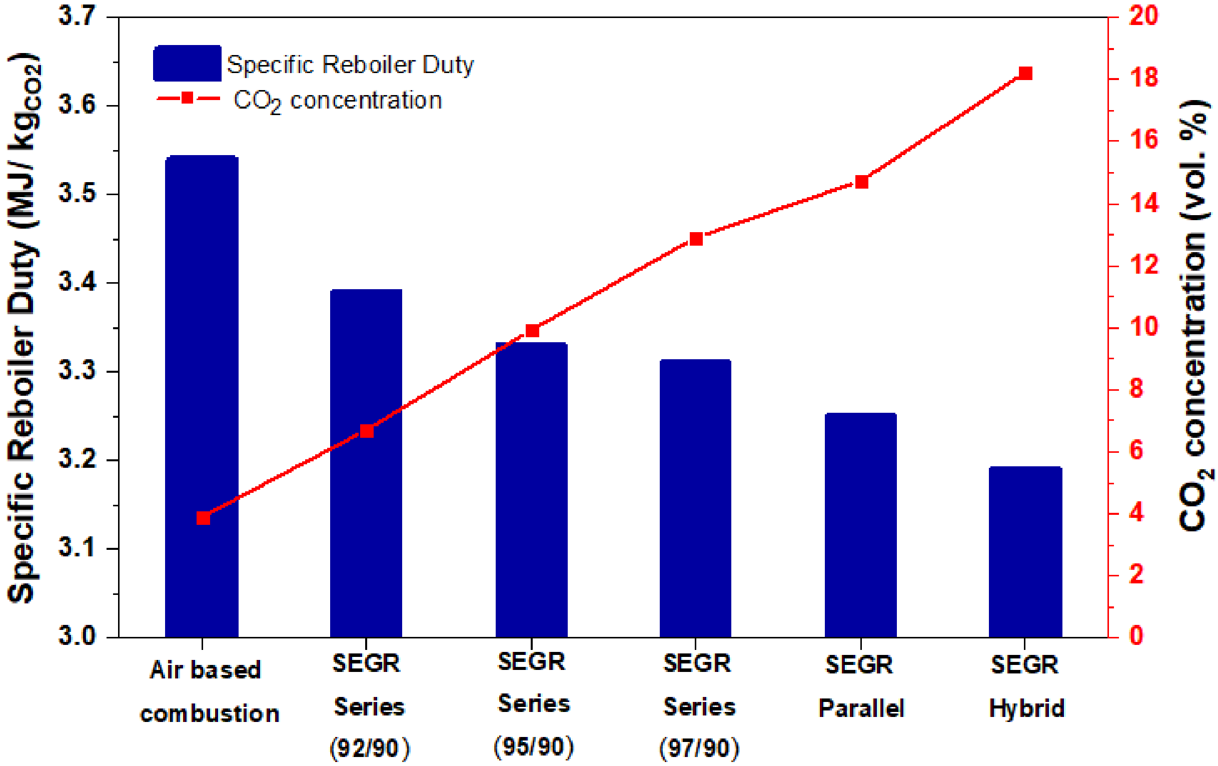


Fig. 5. Parity plot for lean and rich loading, CO_2 capture rate, and specific reboiler duty model results as a function of the experimental results.



SEGR series 92/90: selective CO_2 transfer efficiency 92%, and overall CO_2 capture efficiency 90%

SEGR series 95/90: selective CO_2 transfer efficiency 95%, and overall CO_2 capture efficiency 90%

SEGR series 97/90: selective CO_2 transfer efficiency 97%, and overall CO_2 capture efficiency 90%

Fig. 6. Specific reboiler duty and CO_2 concentration for SEGR in series, parallel and hybrid scheme compared to reference air-based combustion.

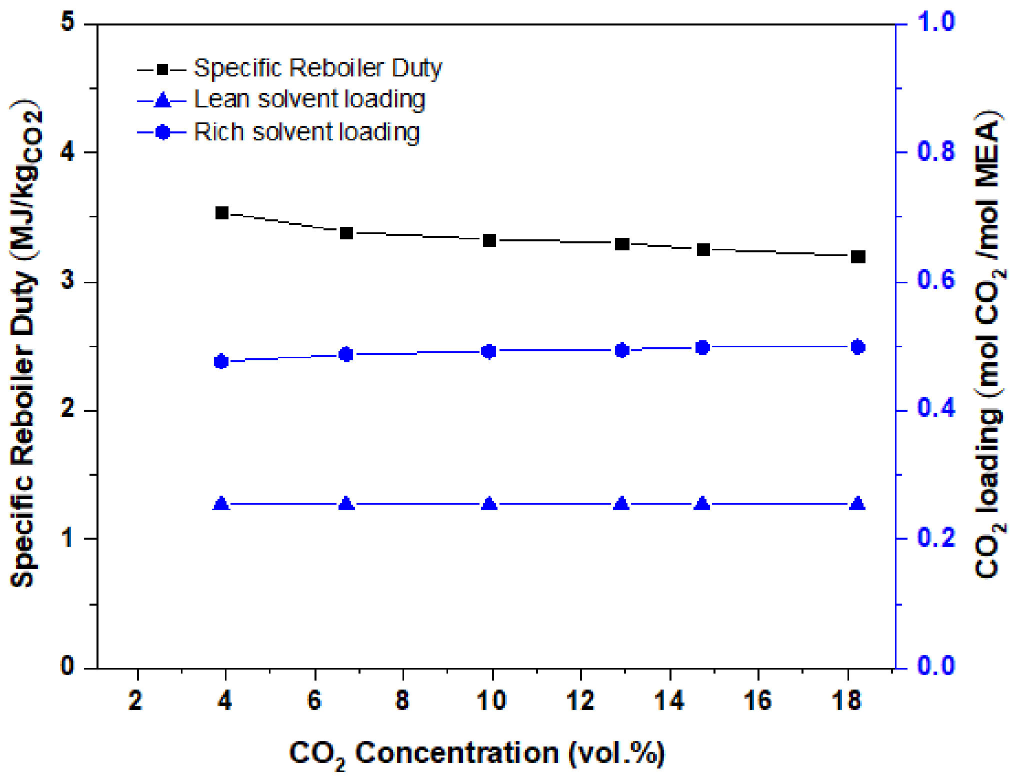


Fig. 7. Variation in specific reboiler duty and rich loading at constant lean loading as a function of the CO_2 concentration.

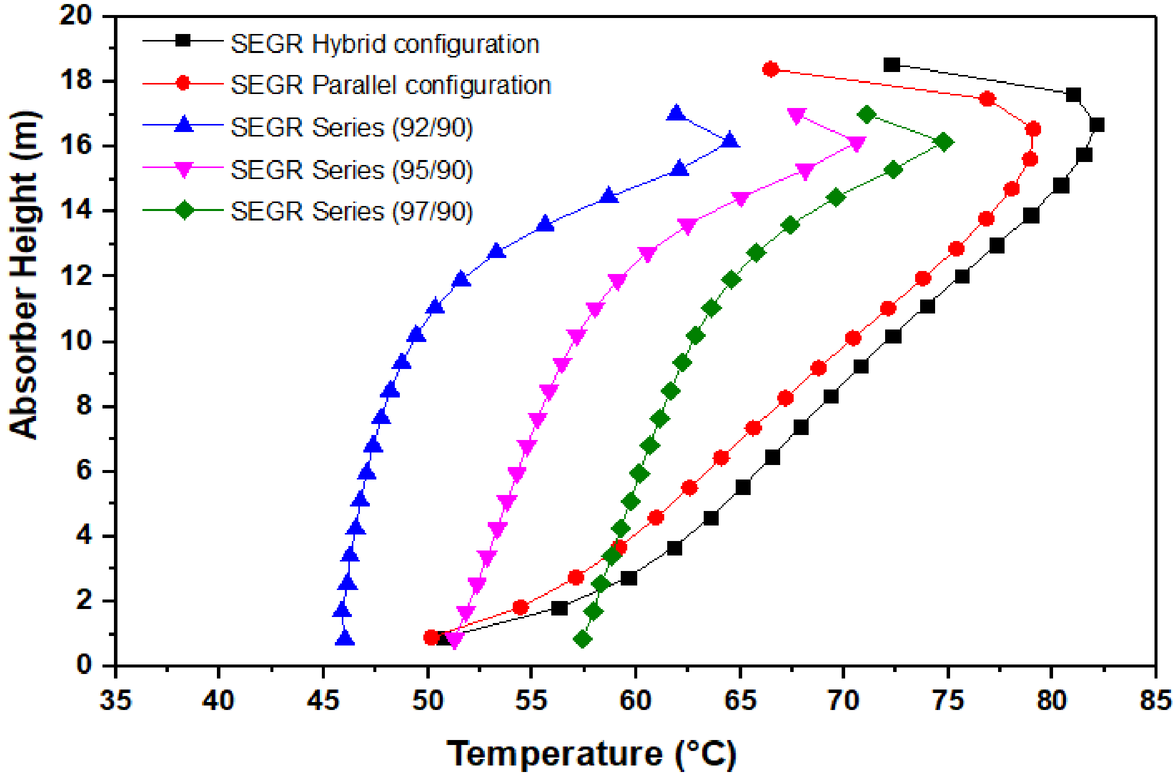


Fig. 8. Absorber temperature profile for different case studies at varying packing height.

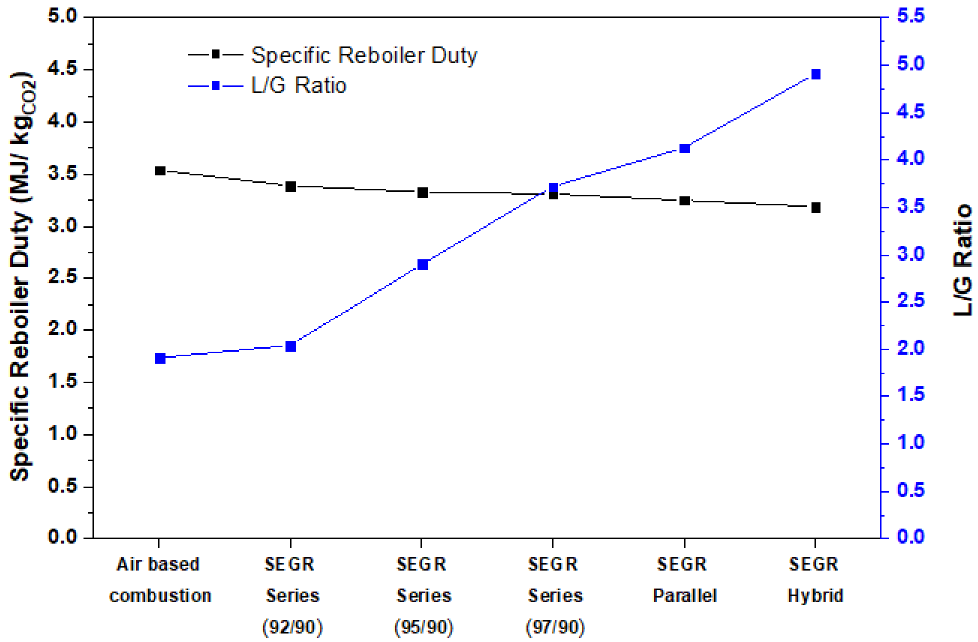


Fig. 9. Impact of different case studies on the specific reboiler duty and L/G ratio.

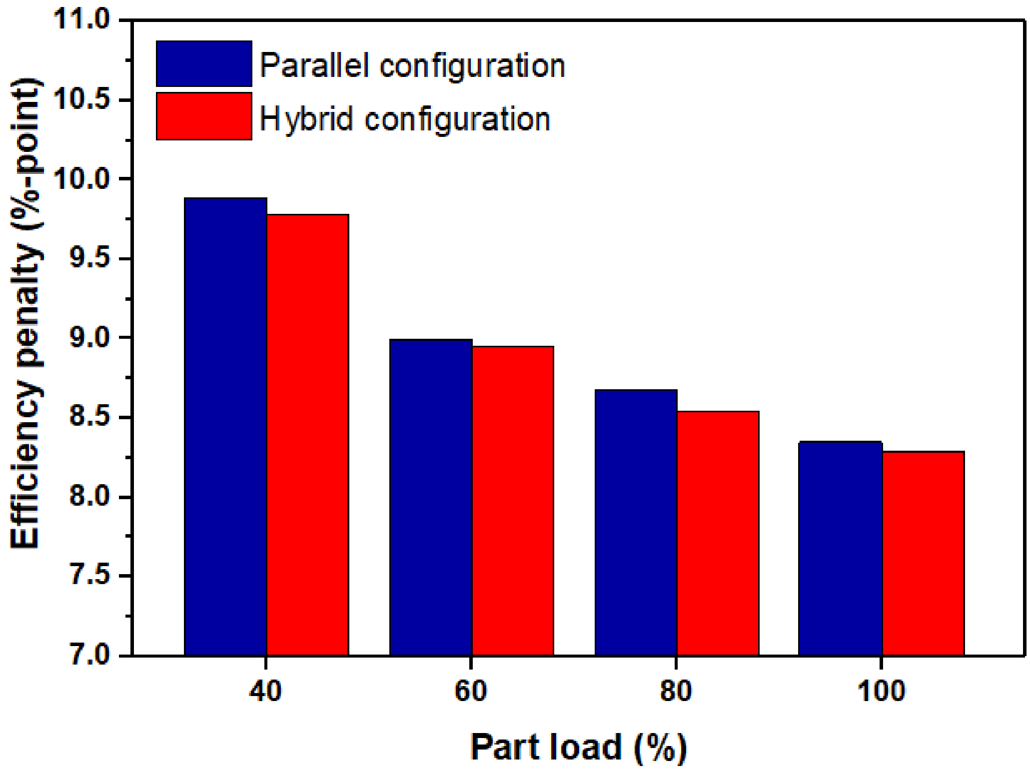


Fig. 10. Net efficiency penalty for parallel and hybrid configuration at part load operations.

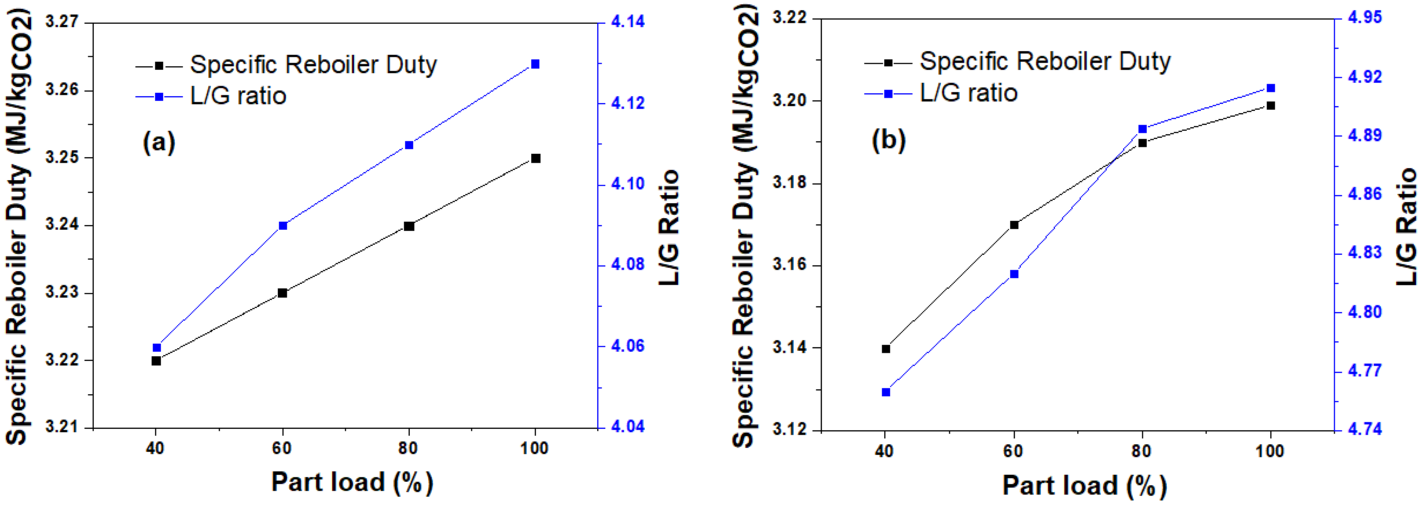


Fig. 11. Parallel (a) and Hybrid (b) Specific reboiler duty and L/G ratio in NGCC power plant at part load operations.

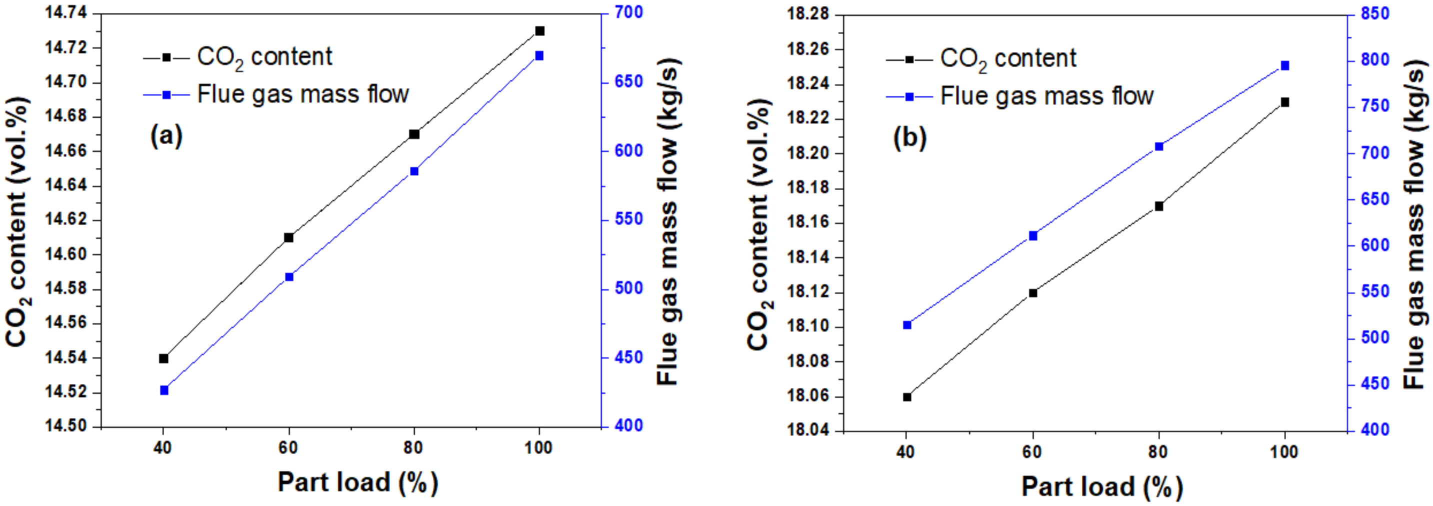


Fig. 12. Parallel (a) and Hybrid (b) CO_2 content in flue gas and flue gas mass flow in NGCC power plant at part load operations.