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Performance viability of a natural gas fired combined cycle power plant integrated with post-combustion CO_2 capture at part-load and temporary non-capture operations

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Abstract

Natural gas combined cycle (NGCC) power plants fitted with carbon capture and storage (CCS) technologies are projected to operate as mid-merit plants in the future of the decarbonised energy market. This projection stems from an inherent characteristic of the NGCC plants of being flexible in operation and able to rapidly change their output power. Therefore, it is expected that the NGCC-CCS plants will continue to operate flexibly for a range of operational loads; and therefore compliment the intermittent electricity generation of other low carbon plants to securely maintain the quality of electricity supply. This study aims to evaluate the performance of a triple pressure NGCC power plant fitted with a post combustion CO_2 capture plant (PCC) at power plant part loads, and assess the effect of the temporary shutdown of the PCC plant. Steady state simulations of the integrated plant at part loads were performed, as well as the integrated plant in non-capture operating mode. These demonstrated that the PCC steady state performance is viable at part loads down to 60%. However, operation in non-capture mode revealed a negative impact on the steam turbine performance, especially on the low pressure (LP) and intermediate pressure (IP) cylinders, as well as the cold end. Suggesting that it is not beneficial to operate in the non-capture mode, regardless of inevitable situations where the PCC or the CO_2 compression unit trip.

Keyword: combined cycle power plant, post-combustion CO_2 capture plant, part load operation, non-capture operation, steam turbine, liquid and vapour distribution

1. Introduction

To effectively reduce energy-related CO_2 emissions up to 2050, global electricity networks are expected to have to incorporate many different low carbon power generation technologies [1]. The likelihood and timelines to utilise different low-carbon power generation options, e.g. renewable resources and nuclear vary for different types of technology. However, given the differing rates at which new low carbon plants can be commissioned, and the risks associated with them, e.g. intermittencies associated with renewable energy resources, it is likely that fossil-fuelled power plants, renewables and in some countries nuclear will co-exist for a significant period and so it is important to reduce greenhouse gas emissions from fossil-fuelled power plants. Therefore, early deployment of fossil-fuelled plants equipped with carbon capture and storage (CCS) technology, or retrofitting existing ones, will help to mitigate the risk to energy security imposed by the technical and economic uncertainties in renewable and future nuclear plants, whilst still contributing to decarbonisation. Indeed, CCS may well increase the likely contributions of fossil-fuelled power plants to electricity generation in the future, compared with scenarios without CCS. This advancement also requires fossil-fuelled power generation fitted with CCS to be flexible, in terms of power output to efficiently match the varying demands of the electricity network [2].

Favoured in climate change mitigation strategies due to its low CO_2 emission rate per unit of energy produced, relative to other fossil fuels, natural gas is expected to account for a significant proportion of the future electricity generation market. Furthermore, natural gas power plants are well-positioned for flexible operation, due to the speed with which they can follow the electricity network demands.

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Having the quickest start-up/shut-down rates amongst fossil-fuelled plants, natural gas power plants are thus ideally suited to accommodate needs for variable power output in the future of the decarbonised electricity market. Furthermore, natural gas plants are relatively easy to build and do not suffer from some of the key limitations of alternative means of accommodating variable demand, e.g. limited availability of sites for pumped storage. Thus, it is likely that these plants will not operate continuously at full load [3,4] especially as the marginal cost of electricity generation is relatively high for natural gas plants. If stringent CO_2 reduction strategies are to be pursued [5], a suitable carbon capture technology route, e.g. post combustion CO_2 capture based on chemical absorption, will be an indispensable part of such power plants. Therefore, the suitability of these plants to operate in peak power, and especially mid-merit markets should be assessed at the design stage by carefully evaluating their part load behaviours and responses, and the implications of them being decoupled temporarily from the CO_2 capture plant. The present paper focusses on mid-merit power generation.

There is a limited amount of information available on the additional constraints that limit the power plant flexibility with PCC, in terms of start-up; shut down and part load performances [3]. To improve the flexibility of fossil-fuelled power plants fitted with PCC, the following suggestions have been evaluated and published in the public domain:

- Application of solvent storage to postpone the solvent regeneration process to a later time, allowing the power plant to increase or decrease load as per its original ramp up/down rates; [4-11]
- Temporary shutdown of the CO_2 capture plant in order to benefit from fluctuating electricity prices by avoiding the need for steam supply for solvent regeneration [4,7,9,11]
- Varying the CO_2 capture rate with respect to electricity market price and cost related to the CO_2 emissions [4,7,10,11]

Although the above mentioned alternatives allow the plant to generate extra power, or operate with their original ramp up/down rates when required, all of them require extra capital investment in terms of additional equipment or over-sized capacity of some major units [3,12]. In contrast, although there are limits to its flexibility constrained by design, operation and control of the chemical processes involved, the post combustion CO_2 capture process is capable of following the load of the power plant via using advanced control systems [2,3,13]. A key factor will then be to impose appropriate operational procedures on the capture plant performance at times when flexible operation is necessary [2,4]. Having satisfied this requirement, another aspect that needs to be fulfilled before delivering flexibility in power generation with PCC in place is the operability of the power plant in general, and the low-pressure (LP) steam turbine section in particular at times that the CO_2 capture unit is temporarily shut down. Since no steam is required for solvent regeneration, such conditions correspond to a substantial increase in the steam flow available at the LP turbine cylinder. This option requires the balance of the plant to be appropriately designed and sized to accommodate the increased steam flow in the LP turbine and the cold end i.e. condenser. Moreover, the generator must be sized accordingly to handle the extra electricity generation during non-capture operation [4,11,14].

This paper focuses on the particular case of a natural gas combined cycle (NGCC) power plant, which is favoured for its high efficiency and low capital costs, operating with a post combustion CO_2 capture plant using aqueous monoethanolamine (MEA) as its solvent. The performance viability is assessed of the NGCC and PCC at power plant part loads, for two process options of with and without CO_2 capture. The first aim is to verify whether and how the PCC plant will operate at power plant part loads and identify key process parameters that must be taken into consideration for a stable and efficient operation. In addition, the performance of the NGCC at part load while integrated with the capture plant is important especially at its key process interface with the capture plant, i.e. the steam supply interface. Furthermore, the performance of the NGCC plant, especially the LP steam turbine, during non-capture operation will be studied since there will be a considerable amount of steam available at the LP turbine inlet. Issues required to be considered in the NGCC plant in case of non-capture operation are addressed. Moreover, the potential impact on the performance of the IP steam turbine section and the condenser during the non-capture operation will be discussed.

In Section 2, an overview of a reference NGCC power plant with no CCS option at full and part loads is presented to simulate the operation of such plant in the actual electricity market. Section 3 covers the methodology applied to size a full-scale PCC unit based on a validated rate-based CO_2 absorption/desorption model. Section 4 presents the simulation of the PCC unit at power plant full and part load. The methodology applied to simulate the CO_2 compression unit and the calculations related to its electricity consumption at part load are covered in Section 5. The simulation results of the NGCC plant fitted with the PCC at full and part load are presented in Section 6, and finally, the discussion on the results and operational procedures required for the non-capture operation are presented in Section 7.

2. Standard NGCC configuration and performance study

This section provides an overview of the reference NGCC power plant with no CO_2 capture facility that operates at full and part load. The focus is on the main features related to the variability of performance parameters at part load, and the impact of part load operation on the plant net efficiency. Based on the information provided in this section, the impact of the PCC integration on the NGCC performance will be evaluated.

A nominal 650 MW natural gas combined cycle (NGCC) power plant is modelled in Aspen Plus V8.4. The power plant comprises two General Electric 7 Frame (GE 7F.05) gas turbines (GT), two triple pressure levels with single reheat cycle heat recovery steam generators (HRSG) and one condensing steam turbine (ST) in a multi-shaft arrangement. The net power output of the plant is 634 MW when fed with natural gas with the input parameters defined in Table 1. The modelled NGCC in Aspen is a replica of the plant originally defined and modelled by DoE/NETL [15] using GT-PRO and THERMOFLEX simulating software [16]. Applying GT-PRO for combined cycle power plant simulations reflects a realistic performance of existing technologies, and the results can be considered highly reliable at both full-load and part-load operations [17].

Table 1: Input data for NGCC power plant simulation [15]

Parameter	Value
Inlet air flow rate [tonne/hr]	3623
Compressor pressure ratio [-]	17.05
Compressor polytrophic efficiency [%]	85
Inlet air temperature [°C]	15
Fuel inlet pressure [MPa]	2.76
Fuel inlet temperature [°C]	38
Fuel composition [vol. %]	
Methane (CH_4)	93.1
Ethane (C_2H_6)	3.2
Propane(C_3H_8)	0.7
n-Butane (C_4H_{10})	0.4
Carbon Dioxide (CO_2)	1.0
Nitrogen (N_2)	1.6
Fuel lower heating value (LHV) [MJ/kg]	47.22
Gas turbine entry temperature [°C]	1360
Flue gas composition [mol. %]	

N_2	74.39
O_2	12.37
CO_2	3.905
H_2O	8.434
Ar	0.895
Steam turbine efficiency HP/IP [%]	88.03 – 92.37
Steam turbine efficiency LP [%]	93.67
Condenser pressure [kPa]	4.8
HRSG pressure drop[kPa]	3.6

To reduce the load of a gas turbine in a combined cycle arrangement, the fuel and air mass flows must be simultaneously decreased while maintaining a high turbine exit temperature to ensure high steam cycle efficiency. Reduction in the gas turbine load leads to the reduction of pressures and mass flow rates in the water/steam cycle. The preferred method to control a combined cycle at part loads down to 50% is the sliding pressure control mode. This method ensures good utilisation of the exhaust energy and therefore relatively higher efficiency at part loads. Below 50% load, the live steam pressure is held constant by means of the steam turbine inlet valves that introduce considerable throttling losses and thus higher stack losses [19].

For the study in hand, NGCC part load calculations have been based on purely sliding pressure operation down to the 60% load of the GT. The reason for this limit is that although for combined cycles in general the minimum technical load is around 40-50% of the design capacity, at lower loads, the impact on the cost of electricity is more pronounced, as the cost for fuel consumption represents a significant portion in the economics of a NGCC plant [3]. Moreover, the minimum load for a stable and efficient operation of the main air compressors is generally around 70%-75% [3]. The NGCC part load simulations revealed that the inlet air mass flow rate at GT 60% load is nearly 75% of that at the GT full load.

The full and part load simulation of the NGCC plant at ISO conditions replicated in Aspen Plus are presented in Table 2. The power plant part loads are defined according to the gas turbine load varying from 100% to 60% as indicated in Table 2.

Table 2: full and part load simulation of the reference NGCC power plant

GT load [%]	100	90	80	70	60
GTs output [MWe]	420.80	380.80	339.60	298.00	256.40
ST output [MWe]	229.7	224.1	215.4	206.5	195.7
Gross plant power output [MWe]	650	604.9	555.0	504.5	452.1
Gross power output relative to full-load case [%]	100	93	85.35	77.46	69.4
Auxiliary power consumption [MWe]	16.5	16.5	16.3	16	15.8
Net plant power output [MWe]	633.5	588.4	538.7	488.5	436.3
Net power plant electrical efficiency	57.25	56.75	55.84	54.86	53.67
Flue gas flow rate [tonne/hr]	3706.82	3481.80	3313.52	3021.30	2783.88
Flue gas flow relative to full-load case [%]	100	93.93	89.40	81.50	75.10
N_2	74.39	74.4	74.41	74.43	74.45
O_2	12.37	12.39	12.43	12.48	12.55
CO_2	3.905	3.896	3.88	3.856	3.822
H_2O	8.434	8.417	8.386	8.34	8.275
Ar	0.895	0.895	0.895	0.895	0.895
Total steam flow to LP turbine [tonne/hr]	579.54	558.96	532.35	507.20	480.12

3. PCC plant configuration and performance study

A standard PCC unit using MEA was modelled in Aspen Plus V.8.4 to capture 90% of the CO_2 emitted from the aforementioned 650 MW NGCC plant at 100% load operation. Figure 1 gives a schematic overview of the complete NGCC-PCC plant with a CO_2 compression unit, with the CO_2 capture plant outlined by the dashed rectangular box. The developed PCC model is a scaled-up version of a validated rate-based model of the CO_2 absorption/desorption using 30 wt. % MEA developed by Rezazadeh et al. 2015 [22]. The validation of the CO_2 capture model at pilot-scale was performed using the results of two sets of pilot plant experiments of the CO_2 absorption via MEA solvent with two different types of packing, i.e. Sulzer Mellapak 250Y and Sulzer BX, carried out at the Laboratory of Engineering Thermodynamics in TU Kaiserslautern, Germany [23,24]. The model results showed a good agreement with the experimental data, and the comparison of the simulation results and the experimental data for the two packing material are provided by Rezazadeh et al. 2015 [22] . Notz et al. [23], and Mangalapally and Hasse [24] provide details of the pilot set-up and the experimental results.

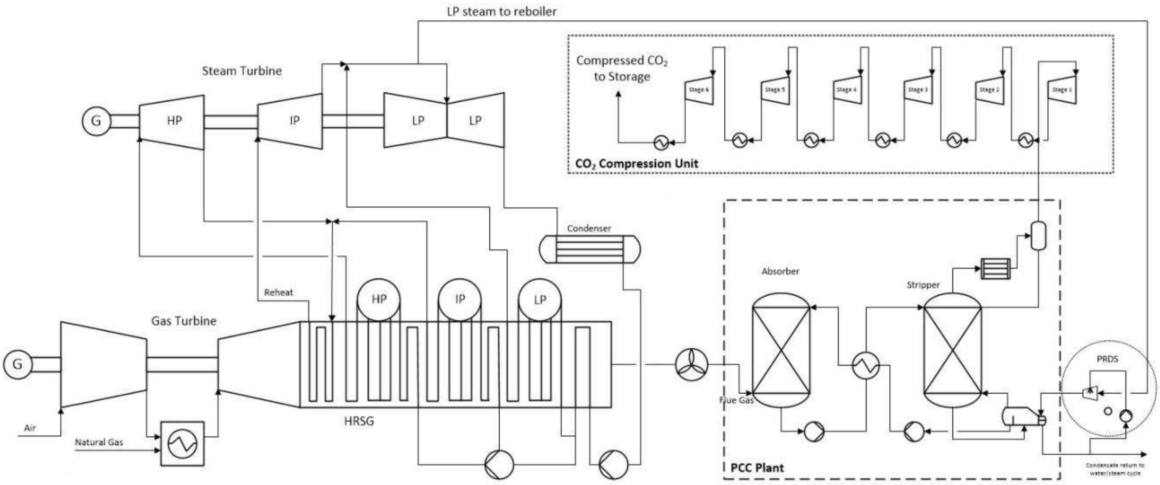

Figure 1: schematic overview of a NGCC-PCC plant including CO_2 compression unit

Based on the knowledge gained from several studies on large-scale post-combustion CO_2 capture plants [25-28], and chemical engineering principles [29-31], the process configuration, equipment sizes and energy requirement of the PCC to remove 90% CO_2 emitted from the 650MW NGCC power plant were determined. The capture plant is designed under the assumption that the NGCC flue gas is free from NO_x and SO_2. The selected absorbent is an aqueous solution of 30 wt. % MEA with the lean CO_2 loading of 0.21. The selected lean loading is based on the optimisation study performed by Agbonghae et al. 2014 [27], for MEA-based PCC applications for NGCC plants. The rich CO_2 loading is also calculated based on the optimum absorber packed column height for such application [27]. The liquid to gas mass ratio corresponding to the 90% capture rate at the design load was calculated to be 1, using the following equation [27]:

$$F_{\mathrm{Lean}} = \frac{F_{\mathrm{FG}} x_{\mathrm{CO_2}} \varphi_{\mathrm{CO_2}}}{100z(\alpha_{\mathrm{rich}} - \alpha_{\mathrm{lean}})} \left(\frac{M_{\mathrm{MEA}}}{44.009} \left[1 + \frac{1 - \omega_{\mathrm{MEA}}}{\omega_{\mathrm{MEA}}} \right] + z.\alpha_{\mathrm{Lean}} \right) \tag{1}$$

Where F_{Lean} is the mass flow rate of the lean solvent, F_{FG} is the mass flow rate of the flue gas, $x_{\mathrm{CO_2}}$ is the mass fraction of CO_2 in the flue gas, $\varphi_{\mathrm{CO_2}}$ is the percentage of CO_2 in the flue gas that is recovered, M_{MEA} is the molar mass of MEA, α_{rich} and α_{lean} are the lean and the rich solvent CO_2 loading, respectively, ω_{MEA} is the mass fraction of the MEA in the unloaded solution, and z is the number of equivalents per mole of the amine (z is 1 for MEA). [27].

Once the stream conditions have been determined, the diameters of the absorber and stripper columns were estimated. The column diameter is a function of the liquid and gas flow rates and their densities

[32]. To design the PCC plant, two absorber and two stripper columns were considered. The design principle to determine the diameter is based on the flooding limitations and the highest economical pressure drop to ensure a stable operating condition with proper liquid and gas distributions. Recommended pressure drop for packed columns ranges from 147 to 490 Pa (15 to 50 millimetres water) per meter packing [31]. Besides, the gas load corresponding to the maximum operating capacity should in general be 5 to 10% below the flooding point [33]. In addition to the liquid and gas flow properties, the latter parameter is sensitive to the type of packing [33]. To ensure a reliable operation, the diameter of the absorber column was then fine-tuned to ensure a 70-75% approach to flooding for the Sulzer Mellapak 250Y packing. This value corresponds to that of the pilot scale validated model. A similar method was applied for the stripper column. In the validated model, the approach to flooding of the stripper column was 30-35%. Table 3 summarises the Geometrical details of the Sulzer Mellapak 250Y packing.

Table 3: Geometrical details of columns packing [18,29]

Packing Geometry	Sulzer Mellapak 250Y
Surface area [m^2/m^3]	256
Void fraction [%]	98.7
Packing factor [1/m]	66
Side dimension corrugation [m]	0.0171
Corrugation angle [°]	45
Crimp height [m]	0.012

In general, columns with very large diameters are not recommended. To date, the maximum diameter for an absorber column under operation is 18.2 m (60 ft) reported by Reddy et al. [34]. The absorber diameter in this work was calculated to be 15 m. Table 4 summarises key input parameters for the CO_2 capture plant simulation.

Table 4: input data for PCC process simulation

Parameter	Value
Number of Absorber columns	2
Absorber column diameter [m]	15
Absorber column height [m]	20
Absorbent	MEA
Absorbent concentration [wt.%]	30
Absorber column pressure (top stage) [kPa]	101.6
Treated gas temperature at absorber exit [◦C]	35
Lean solvent temperature at absorber inlet [◦C]	40
Flue gas temperature at absorber inlet [◦C]	40
Flue gas pressure at absorber inlet	1137.6
Number of Stripper columns	2
Stripper column diameter [m]	9
Stripper column height [m]	20
Stripper column pressure (top stage) [kPa]	172.4
Stripper condenser temperature [◦C]	35
Lean/rich stream heat exchanger approach temperature [°C]	5

4. PCC performance at part loads

Steady state simulations of the PCC plant at the power plant full and part loads were carried out in Aspen Plus using the respective flue gas characteristics specified in Table 2. For all load cases, the flue gas is assumed to be cooled down to 40°C prior to entering the absorber column. At part loads, the liquid to gas ratios were adjusted to maintain the CO_2 capture rate at 90%. The details of the PCC simulation at part loads are provided in Table 5.

Table 5: PCC plant process simulation at part load operations

GT load [%]	100	90	80	70	60
CO_2 capture efficiency [%]	90	90	90	90	90
CO_2 captured [tonne/h]	2x103.17	2x96.60	2x91.35	2x82.80	2x75.63
Specific reboiler duty [MJ/kg CO_2]	3.64	3.65	3.66	3.70	3.70
Liquid to gas mass ratio	1.00	0.985	0.980	0.972	0.963
Lean solvent CO_2 loading	0.21	0.21	0.21	0.21	0.21
Rich solvent CO_2 loading	0.4761	0.4764	0.4766	0.4770	0.4773
Absorber fraction to flooding [%]	0.73	0.69	0.65	0.59	0.54
Absorber average pressure drop [Pa/m]	221.6	189.3	169.7	140.2	118.7
Stripper fraction to flooding [%]	0.33	0.31	0.30	0.27	0.24
Stripper liquid hold-up [m^3]	3.71	3.60	3.52	3.37	3.24
Reboiler energy requirement [MW_{th}]	104.6	97.8	93.0	85.2	77.6
Solvent temperature at Stripper bottom stage [°C]	117.4	117.4	117.4	117.4	117.4

4.1. Steam requirements for solvent regeneration

The main thermodynamic interface between the NGCC and PCC is the large amount of steam required for solvent regeneration. The extraction point chosen in this study is the favoured location by several studies, i.e. IP/LP crossover pipe where the steam is available at a pressure close to that required at the reboiler. [13,35-37]

In this work, a 10°C approach temperature is assumed in the reboiler to ensure reliable operation and avoid polymerisation of carbamate ions, i.e. thermal degradation of the solvent. Given an equilibrium solvent temperature of 117.2°C at the bottom of the stripper for all load cases, a saturated steam at 250 kPa is constantly required in the reboiler. When assuming 10% pressure losses in the branch pipe from the crossover pipe to the reboiler inlet, the minimum pressure required at the extraction point is calculated to be 275 kPa, given the stripper pressure at all load cases is held constant. The extracted steam is assumed to be routed to the reboiler section via a combined pressure reducing with de-superheating system (PRDS). The water required for de-superheating is provided by recycling a portion of condensate from the reboiler outlet on the hot side. This integration is defined by a dotted circle in Figure 1. This method has two benefits, first, by recycling a portion of the condensate at the temperature close to the steam saturation temperature, the sensible heat required to heat up the de-superheating water is minimised; second, a portion of total steam required is complimented by the evaporation of the condensate in the de-superheater, resulting in lesser steam extraction. Calculations revealed that approximately 13% of the steam required in the reboiler is provided by the evaporation of the recycled condensate. For all load cases, the extracted steam flow rate and parameters associated with the PRDS are provided in Table 6.

Table 6: PCC steam requirements for solvent regeneration at full and part loads

GT load [%]	100	90	80	70	60
Total steam required in both reboilers [kg/hr]	345.2	322.8	306.9	281.2	256.3
Steam pressure at reboiler [kPa]	250	250	250	250	250
Steam temperature at reboiler inlet [°C]	127.4	127.4	127.4	127.4	127.4
Total steam extracted from the IP/LP crossover pipe [tonne/hr]	301.2	281.2	268.1	246.3	224.1
Steam pressure at extraction point [kPa]	337	323	310	295	279
Steam temperature at extraction point [°C]	284.80	286.60	283.10	279.30	282.80
Condensate water required for de-superheating [kg/hr]	44	41.6	38.8	34.9	32.2

4.2. PCC auxiliary consumption

The auxiliary consumption includes the electricity required to run solvent circulating and make-up pumps, cooling and make-up water pumps, the flue gas blowers and any other rotary equipment involved in the process, with the flue gas blowers as the major consumer. Table 7 provides the PCC electricity consumption at various loads.

Table 7: CO2 compression unit electricity consumption at full and part loads

GT load [%]	100	90	80	70	60
PCC electricity consumption [MWe]	15.9	15.3	14.5	14.1	13.3

5. CO_2 compression

The produced CO_2 with high purity, i.e. > 98 mol. % CO_2, is expected to be compressed to 11 to 15 MPa to be transported for storage [3,38]. This is achieved by means of a multi-stage compression train with intermediate cooling, and then followed by a pump as a final step to deliver the CO_2 product in liquid phase for storage [3].

It is confirmed that the compression process does not add a specific constraint on the integrated plant capabilities to operate flexibly and change loads, as the compressors ramp rates, depending on their types, vary in the order of a few seconds [3]. However, similar to the GT main air compressors, at low loads, i.e. less than 70% of the design load, a portion of the compressed CO_2 must be recycled to maintain the unit operability at the expense of higher auxiliary electricity consumption.

CO_2 compression consumes a great deal of electricity to operate that needs to be supplied by the power plant [39]. To calculate the CO_2 compression auxiliary power consumption, a six-stage centrifugal compression unit with intermediate coolers was modelled in Aspen Plus V8.4. The validity of the CO_2 compression model has been ensured by comparing its results with data available in the public domain [15]. The compression train is outlined in Figure 1 by a dotted rectangular shape. Table 8 summarises the auxiliary power consumption of the CO_2 compression unit at various loads.

Table 8: the energy requirement of the CO_2 compression unit at plant full and part load operations

GT load [%]	100	90	80	70	60
CO_2 compression electricity consumption [MWe]	18	16.9	15.8	14.5	13.2

6. Integrated NGCC-PCC part-load performance

Table 9 provides the performance details of the NGCC plant fitted with the PCC at part loads which are evaluated by relating the data from the CO_2 capture and compression units to the reference NGCC plant data at each load.

Table 9: Design and off-design loads of the NGCC power plant with CO_2 capture plant

GT load [%]	100	90	80	70	60
GTs output [MWe]	420.80	380.80	339.60	298.00	256.40
ST output [MWe]	184.7	180.0	173.4	168.2	160.7
Gross plant power output [MWe]	605.5	560.8	513.0	466.2	417.1
Auxiliary power consumption [MWe] (Inc. power plant + capture plant + compression plant)	52.4	50.3	48.0	45.9	43.4
Net power plant power output [MWe]	553.1	510.5	465	420.3	373.7
Total power loss due to PCC integration [MWe]	79	76.3	72.3	66.9	61.5
Net Plant Thermal efficiency [%]	50.10	49.37	48.33	47.33	46.1
Efficiency penalty [%-point]	7.15	7.38	7.52	7.54	7.59

7. Results and discussion

The first part of this section is dedicated to evaluate the PCC performance at part loads in terms of overall energy consumption and solvent circulation rate. In addition, hydraulics of the absorber and stripper columns in terms of pressure drop, packing wettability and mass transfer efficiency are explored. In the second part, the impact of the PCC integration on the NGCC at part loads in terms of the net power output and net efficiency penalty are evaluated. Accordingly, the impact of the integration on the steam turbine at part loads is described. Finally, the drawbacks of the non-capture operation on the performance of the NGCC especially on the steam turbine are investigated.

7.1. PCC performance evaluation

7.1.1. Energy requirement

Steady state performance of the PCC at the part loads has been simulated, and the results presented previously in Table 5. At each load, the liquid to gas ratio was adjusted to maintain the CO_2 capture efficiency at 90%, by which the liquid to gas ratio was reduced to nearly 0.96 at the GT 60% load from its value of 1.00 at the full load. The reduction in the flue gas and circulating solvent flow rates at part loads results in lower electricity consumption. This effect is more pronounced at the GT 60% load where the auxiliary power consumption reduced by nearly 18% compared to the full load operation. However, the specific energy required for the solvent regeneration does not follow the same trend at part loads. Although the energy required in the reboiler in general decreases, the reboiler specific energy increases. This is partly due to the change in the liquid to gas ratio from its design value, and partly because of the increased rich solvent CO_2 loading at part loads.

The rich solvent CO_2 loadings at part loads are provided in Table 5. Despite a counter-intuitive behaviour that might have been expected due to the relatively lower CO_2 composition in the flue gas at part loads, the slight increase in the solvent CO_2 loading at the end of the absorption process might be due to the improved efficiency in the absorber column. The improved efficiency in the absorber simulation is attributed in the relatively smaller height equivalent of a theoretical plat (HETP) at lower loads. As presented in Table 10, the average HETP of the absorber column at the GT 60% load is reduced by 5.6% compared to that of the full load.

Table10: Design and off-design loads of the NGCC power plant with CO_2 capture plant

GT load [%]	100	90	80	70	60
Absorber column average HETP [m]	0.420	0.414	0.410	0.402	0.396

Generally, For structured packings such as Sulzer Mellapak 250Y, HETP increases with liquid and vapour loadings, and the load effect on the HETP is more due to liquid rather than vapour loads [30]. Furthermore, at higher liquid flow rates, more gas is entrained down the bed, causing efficiency to drop. Due to the structural characteristics of structured packings that limit lateral movement of fluids, at higher gas flow rates, more gas will be carried downstream, which is unfavourable for column efficiency [30,40]. At part loads, the flue gas and circulating solvent flow rates are simultaneously reduced, while, the liquid load reduction is more pronounced to maintain the CO_2 capture rate at 90%. This might be a reason for the improved efficiency, i.e. lower HETP, and hence higher CO_2 rich loading at lower GT loads. All above statements are valid under the assumption that the absorber packed column is evenly wet and uniformly distributed at all loads.

For a fixed lean solvent CO_2 loading, a higher rich solvent CO_2 loading requires more energy to strip the CO_2 and thus regenerate the solvent. Despite the lean CO_2 loading being a fixed design parameter at all loads, the rich CO_2 loading increased at part loads. To retain the lean CO_2 loading at the bottom of stripper column, more specific energy is therefore required in the reboiler.

7.1.2. Column hydraulics

The reduction in the flue gas mass flow rate is the major challenge that a CO_2 capture plant experiences at power plant part loads, as this is a crucial design value for the PCC. The hydraulics of the absorber and stripper columns should therefore be suitable to withstand various operational conditions. To examine the operability of the PCC at part loads, a number of operational parameters were considered for detailed evaluation.

7.1.2.1. Liquid distribution

The process design of the PCC is at the NGCC full-load operation. This means that the CO_2 capture plant is designed for the highest possible flue gas and circulating solvent flow rates. As described in section 3, sizing of packed columns at their design points was achieved by maintaining the column fractional approach to flooding at a reasonable level of 70-75%. Thus, the risk of flooding in the columns at part loads is not a concern, whereas, the risk of poor irrigation, and uneven flow distribution (maldistribution) and hence dry patch formation is more prominent.

Uneven flow distribution affects the packed column efficiency [30]. It occurs when the liquid and/or vapour flows are low and when less liquid is delivered to some areas than to others, causing a drop in mass transfer [30,41]. For an absorber to operate properly, the lean solvent flow rate entering the column must be high enough to effectively wet the packing to facilitate the mass transfer between the gas and liquid streams [42]. The minimum superficial liquid flow rate ($L_{\mathrm{sfr}_{\mathrm{min}}}$) that is required to wet the packing effectively is calculated using the following equation [42]:

$$L_{\mathrm{sfr}_{\mathrm{min}}} = MWR.\rho_{\mathrm{L}}.\alpha \tag{2}$$

Where, MWR is the minimum wetting rate of the absorber packing, ρ_{L} is the solvent density entering the absorber column, and α is the surface area to volume ratio of the absorber packing. The superficial liquid flow rate at each load case ($L_{\mathrm{sfr}_{\mathrm{load}}}$) is calculated using the following equation [42]:

$$L_{\mathrm{sfr}_{\mathrm{load}}} = \frac{L_{\mathrm{mol}_{\mathrm{load}}}.M_{\mathrm{MEA}}}{A_{\mathrm{Abs}}} \tag{3}$$

Where, $L_{\mathrm{mol}_{\mathrm{load}}}$ is the molar flow rate of the lean solvent at various GT loads, M_{MEA} is the solvent molecular weight, and A_{Abs} is the absorber column cross sectional area. Figure 2 shows the variation of the absorber column superficial value at various loads and their comparison with the minimum value.

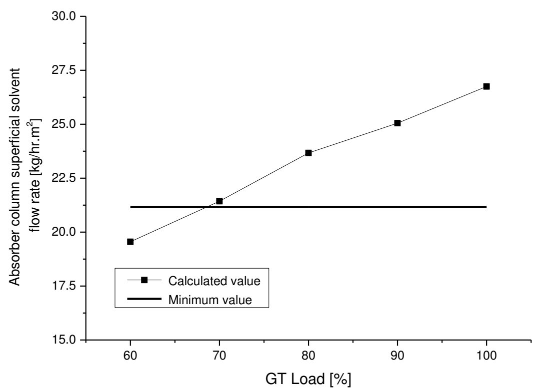

Figure 2: Absorber column liquid superficial value at various GT loads in comparison with its minimum value

The comparison confirmed there is sufficient liquid flow to wet the packing using the current design conditions up to 70% of the GT load, whilst the absorber operation at GT 60% load is at the risk of under wetting. One solution to mitigate this risk is to increase the lean solvent flow rate to meet the minimum requirement. Calculations showed that the lean solvent mass flow rate must increase by approximately 6% to maintain the minimum liquid load in the absorber column at the GT 60% load. To maintain the CO_2 capture rate at 90%, a solution is for the lean solvent CO_2 loading at this particular case to increase to 0.23 from the design value of 0.21.

7.1.2.2. Vapour distribution

Reduction in the flue gas flow rate at part loads results in the reduction in its velocity through the packed bed which will promote the risk of uneven vapour distribution in the absorber column. In general, the packing pressure drop places a resistance in the flue gas path that helps spread the vapour radially. If the pressure drop is too low, the flue gas will tend to channel through the bed, leading to poor mass transfer [30]. There is a common practice to design a packed column for a pressure drop not smaller than 15 mm of water per meter of packing height. When there is a likelihood of foaming, this value must be reduced [31]. Simulations showed that the pressure drop of the absorber packed column is in the range of 22 to 12 mm of water per meter of packing, where the lowest pressure drop corresponds to the 60% GT load. The packing material used in the absorber is the sulzer Mellapak 250Y which is categorised as a low-pressure gauze packing with a very low operational pressure drop [18]. Thus, the uneven vapour distribution in the absorber column at the 60% GT load is less likely to be a risk with the applied packing material.

7.1.2.3. Column operability

There is a reliable region for packed columns to operate at variable liquid and gas flow rates. Kister [30] defined an operational curve for packed columns and suggested that for a reliable operation at various liquid and gas flow rates, the absorber and stripper column efficiencies must be independent of gas and liquid flow rates, while the column pressure drop uniformly increases with gas flow rate. Thus, for absorber and stripper columns to cope with power plant part loads, their efficiencies should not vary with load changes. To verify this, the efficiency characteristic curves of the absorber and stripper columns operating at various loads is plotted and shown in Figure 3. The vertical axis is the average HETP of the column as the efficiency representative, and the horizontal axis is the GT load. As shown, the HTEP demonstrates a constant trend at various loads, confirming that both absorber and stripper columns operate reliably at part loads down to 60% GT load.

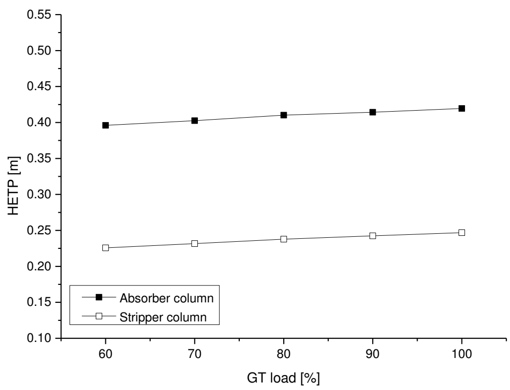

Figure 3: Absorber and stripper columns average HETP at various GT loads

There are other parameters that may be studied to confirm a reliable operation of PCC plants at part loads that are beyond the scope of this study. for example, the higher oxygen content in the flue gas at part loads has a potentially negetive impact on the solvent degradation rate and the unit operation. it is therefore worthwhile to study and seek alternative inhibitors to protect the unit against likely corrosion and degradation risks at part loads where O_2 content in flue gas increases [3].

7.2. NGCC performance evaluations

7.2.1. Net plant efficiency

Based on the simulation results of the NGCC at part loads while fitted with the PCC, the net plant efficiency of the NGCC-PCC plant and the associated efficiency penalty are calculated for various loads and presented in Table 11. As expected, the net plant efficiency of the reference NGCC at part loads drops by 2-3% points [3] as a result of operation of the equipment at loads different from their design point.

Table 11: the net plant efficiency for reference NGCC and NGCC-PCC plant at various GT loads

Net plant efficiency	**GT Load [%]**				
	100	**90**	**80**	**70**	**60**
Reference NGCC [%]	57.25	56.75	55.84	54.86	53.67
NGCC+PCC [%]	50.10	49.37	48.33	47.33	46.09
Efficiency penalty [%-point]	7.15	7.38	7.51	7.53	7.58

Likewise, the net efficiency of the NGCC-PCC plant is reduced at part loads. The efficiency penalty associated with the integration of the PCC and NGCC increases by reducing the GT load, which is due to inefficiencies associated with the CO_2 desorption in the stripper column. Also, for the NGCC-PCC plant, the reduction of the steam turbine efficiency is more pronounced at lower loads. In fact, the significantly light-load operation of the steam turbine at part loads promotes the rate of the efficiency drop. In this study, the efficiency of the CO_2 compression unit was assumed constant for all load cases. In practice, compressors efficiency will reduce with reducing the load which will have an additional impact on their auxiliary power consumption, and thus on the net plant efficiency and the efficiency penalty.

7.2.2. Steam turbine performance

By studying the LP steam pressure at the IP/LP crossover pipe presented in Table 6, it is evident that the pressure requirement of the steam to be extracted can be met for all load cases. In addition, the evaluations confirmed that the throttling loss associated with the steam extraction is minimal as the pressure of steam in the IP/LP pipe is close to that required in the reboiler. To reach a part-load capability below 60% GT load, a higher design crossover pipe pressure would be required. For example, in a study performed by Pffaf et al. [14] on a greenfield coal power plant, a design pressure of 700 kPa was suggested for the crossover pipe if part-load capability of 40% is required. A reduction of 50kPa on the design pressure of IP/LP crossover pipe results in nearly 0.2% point gain in the plant net efficiency at the expense of restricted part-load operation [14]. Therefore, it is useful to identify an efficient part-load limit with IP/LP pressure evaluations. In this work, the efficient part-load limit is around 60% as the crossover pressure at this load rate has a marginal difference with the minimal required pressure at the interface point.

7.3. Impact of non-capture operation

NGCC plants equipped with PCC must be designed to operate with variable steam extraction rates, possibly down to zero, to adjust both desired CO_2 capture efficiency and power output whenever required. There are conditions in which it is economically beneficial to operate without PCC, for example at times of high electricity demand. Also, there are conditions where operation without CO_2 capture is inevitable, for example during an interruption in the operation of the PCC or the CO_2 compression unit. In either case, the steam which is otherwise used for the solvent regeneration must be utilised in the LP turbine to generate electricity. This means that nearly double the amount of steam is available to enter to the LP turbine cylinder at power plant full load operation. This will have a considerable impact on the performance of the steam turbine in general and on the LP and IP turbines and the cold end in particular.

In coal power plants, the impact of variable steam flow rates through the LP turbine is manageable via using a synchronous self-shifting (SSS) clutch that entirely disconnects one of the LP steam turbines depending on the heat required in the PCC plant [43]. While in NGCC plants, usually only one double-flow LP steam turbine is used and therefore there is no flexibility in terms of possibility to shut down an LP turbine [43].

It is worth to note that the design of LP steam turbines capable of operating under large variations of steam flow is a not a new technology, and examples of such turbines can be found in combined heat and power (CHP) plants [42,44]. To shed light on the requirements and performance of an LP steam turbine operating with large variations of steam flow, it is useful to review some of the steam turbine theories. At any given load, the steam turbine has approximately constant volume flow. This helps the velocity vectors to remain unchanged and so does the efficiency [45]. The steam mass flow through the steam turbine at any off-design, e.g. operation without the PCC, can be calculated using the Law of Cones [46]:

$$\frac{\dot{m}_{\mathrm{s}}}{\dot{m}_{\mathrm{s},0}} = \frac{\bar{V}.p_{\mathrm{a}}}{\bar{V}_0.p_{\mathrm{a},0}}\sqrt{\frac{p_{\mathrm{a},0}.v_{\mathrm{a},0}}{p_{\mathrm{a}}.v_{\mathrm{a}}}}\sqrt{\frac{1-\left[\frac{p_{\mathrm{w}}}{p_{\mathrm{a}}}\right]^{\frac{n+1}{n}}}{1-\left[\frac{p_{\mathrm{w},0}}{p_{\mathrm{a},0}}\right]^{\frac{n+1}{n}}}} \tag{4}$$

Where, $\dot{m}_{\mathrm{s}}$ is the steam mass flow, p is the pressure, v is the specific volume, $\bar{V}$ is the average swallowing capacity, and n is the polytropic exponent. The suffix 0 is the design point, suffixes a and w denote at the ST inlet and outlet respectively. For the condensing LP turbine, where the pressure ratio is low and the ratio of swallowing capacity is almost 1, the above equation can be simplified as below and used to determine the relation between the live steam pressure and steam mass flow rate [47]:

$$\frac{\dot{m}_{\mathrm{s}}}{\dot{m}_{\mathrm{s},0}} = \sqrt{\frac{p_{\mathrm{a},0}.v_{\mathrm{a},0}}{p_{\mathrm{a}}.v_{\mathrm{a}}}} => \frac{p_{\mathrm{a}}}{p_{\mathrm{a},0}} = \left[\frac{\dot{m}_{\mathrm{s}}}{\dot{m}_{\mathrm{s},0}}\right]^2 \frac{\rho_{\mathrm{a},0}}{\rho_{\mathrm{a}}} \tag{5}$$

Where, ρ is the steam density. If the NGCC plant operates at full load while the PCC is shut down, the steam mass flow rate to the LP turbine cylinder increases by 108%. Using equation (5), it is estimated the inlet pressure of the LP turbine will consequently increase from 337 to nearly 700 kPa. This will have an impact on the IP turbine too, since the exit pressure at the IP outlet increases, and the steam volumetric flow decreases substantially by approximately 52%, leading to an efficiency impact. One suggested solution to minimise the impact of the non-capture operation is that during the PCC shutdown, the power plant operates at a lower load with the net power output equivalent to that of the power plant full load operation while integrated with the CO_2 capture plant [14]. In this work, the suggested part load operation to minimise the impact of the PCC shut down will be at the GT load of nearly 85%. Nevertheless, for this option, the IP/LP crossover pressure will increase to 627 kPa.

In addition to the above, the condenser back-pressure will rise as a consequence of the increased steam flow, if the cooling water mass flow rate is kept constant at the expense of higher outlet temperature. However, in the case of environmental limitations leading to the higher outlet temperature being not viable, the heat load rise in the cold end demands more cooling water which results in higher electricity consumption in the cooling water system, given the cooling water pumps are capable to operate at higher mass flow rates. Moreover, some provisions must be considered in the steam turbine generator to handle the surplus electricity generations. All these scenarios will definitely have a negative impact on the efficiency. If an NGCC power plant is designed to operate in a CO_2 capture integrated scheme, it is not beneficial to operate in a standalone mode, apart from emergency periods mentioned earlier.

8. Conclusion

Steady state simulation of a natural gas combined cycle power plant and a post combustion CO_2 capture unit were carried out in Aspen Plus V8.4. Simulations were made at full and part loads for two process options with and without CO_2 capture. The considered option to provide the heat for the solvent regeneration was the steam extraction at IP/LP crossover pipe for all cases. Part load cases were studied at GT load of 90, 80, 70 and 60%. The results confirmed the performance viability of the NGCC-PCC plant at full and part loads down to the 60% load. By adjusting the solvent circulation rate to lower values, except for the GT 60% load, the CO_2 capture with 90% capture rate was achievable at part loads. The study of the absorber column hydraulics showed that in order to have a reliable operation at the 60% load, the minimum liquid load required in the absorber packed column led to an increase of 6% in the circulating solvent flow rate. A suggested solution to retain the CO_2 capture rate at 90% at this load is to increase the lean solvent CO_2 loading to 0.23 from its design value of 0.21.

Simulation results confirmed that there is sufficient steam available at the IP/LP crossover pipe to provide the steam required for the solvent regeneration at part loads up to 60% GT load. Moreover, the study of the IP/LP crossover pressure showed that the throttling loss related to the steam extraction is minimal as the pressure of the steam in the crossover pipe is close to that required in the reboiler. However, to reach a part load capability below the 60% GT load, a higher design pressure for the crossover pipe would be required. An analysis of net plant efficiency for the two process options revealed that at full load, the efficiency penalty associated with the CO_2 capture operation is 7.15% point at full load and will increase to 7.6% point at 60% GT load.

The study of the absorber column performance and the mass transfer efficiency revealed that at part loads, due to relatively lower load of gas and liquid in the column, the mass transfer efficiency slightly improves and leads to a slightly higher rich solvent CO_2 loading at the column discharge. This improvement however showed a negative effect on the stripper performance in terms of the specific energy required by the reboiler.

An evaluation was made to study the impact of non-capture operation on the LP steam turbine. the results showed that if the NGCC plant operates at full load while the PCC is off, the steam flow available at the LP turbine increases by 108%, which will result in an increase on the LP turbine inlet pressure from 337 to nearly 700 kPa. The increase on the LP inlet pressure will affect the IP turbine as well, leading to the turbine efficiency drop. To minimise the impact of non-capture operation, it is suggested to operate the power plant at a lower load with the net power output equivalent to that of the NGCC full load operation while fitted with the PCC unit [14]. Specifically for this study, calculations showed that the suggested part load operation to minimise the impact of non-capture operation will be at the GT load of nearly 85%.

In addition to the IP and LP turbine performance, the non-capture operation will affect the condenser operating pressure due to the rise of the coolant temperature as a consequence of the increased steam flow, leading to a drop in the plant net power output. Moreover, to make the plant capable of operating without capture, some provision must be considered in the steam turbine generator to handle the surplus electricity generation. These evaluations suggest that if an NGCC plant is designed to operate in a CO_2 capture integrated scheme, it is not beneficial to operate in a standalone mode, apart from inevitable situations such as CO_2 capture plant or CO_2 compression unit trip.

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