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Controlling Capture Plants to avoid CO_2 Emissions penalties during Peak Load Demand

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Abstract

With the introduction of more and more renewables into the electricity system, pressure is mounting on the thermal power plants to operate in more flexible ways. In order to capture maximum emissions at the lowest cost, capture plants integrated with the power plants has to follow the operational regimes of the parent power plant. Therefore, capture plants has to be flexible enough to deal with the load variations on the power plants to meat grid demands.

A test campaign has been carried out at the PACT 1tpd CO_2 capture pilot plant to investigate capture plant flexibility in relation to power plant load variations. Monoethanolamine (40 wt.%) solvent was used to capture CO_2 from gas turbine representative flue gases containing around 5% CO_2. Pressurised Hot Water (PHW) is used to regenerate the solvent in the reboiler. Four Capture plant flexibility scenarios i.e. start-up, minimum stable generation, no-stripping and over-stripping, are investigated. No-stripping tests were performed to mimic the unavailability of steam for stripping over varied periods of time by stopping PHW flow to the reboiler. The results indicate that Specific Reboiler Duty (SRD) increased by 8.7% when the PHW stoppage time was 30 mins. Longer the PHW stoppage time, the longer it takes to recover the capture plant to the original steady state and higher the difference between the steady state capture efficiency and the average capture efficiency over the test period.

For over-stripping tests, stripper pressure was reduced to 0.4 barg from the original value of 0.5 barg for a varied period of time followed by no-stripping. It was observed that longer the over-stripping period, longer the recovery time. The results indicates that SRD increased by 36% when the over-stripping time was increased to an hour.

In conclusion, it is possible to maintain 90% overall capture efficiency, if the solvent is over-stripped for a long enough period, but reboiler duty will be increased. Optimisation of the capture process under these scenarios would be required in order to achieve a commercially-optimised balance i.e. minimum increase in SRD costs while achieving a capture efficiency that also minimises CO_2 emission costs.

Keywords: Dynamic operation, Carbon capture, CCGT, over-stripping
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1. Introduction:

UK Government has committed to reduce greenhouse gas (GHG) emissions by 80% by 2050 from a 1990 baseline and has highlighted the role of Carbon Capture Utilisation and Storage (CCUS) in reducing greenhouse gas emissions in its "Clean Growth Strategy" (Clean Growth, 2018). Costs associated with achieving the 80% reduction in GHG emissions will reduce by approximately £30bn per year if Carbon Capture and Storage (CCS) is included in the UK's energy system (Day, 2015). Without CCS, estimated cost to meet greenhouse gas emission limits will almost be doubled (BEIS report, 2019).

It is relatively difficult to make large emissions reductions in some sectors such as small and mobile sources and agriculture. Therefore, it is expected that large point sources of emissions such as power plants will have to achieve near-zero emissions (Davison, 2011). Separating CO_2 from large emissions sources using amines is one of the best available technologies at the moment. The technology has been applied in the industry for many decades but mainly on clean gases such as gas sweetening plants. The beauty of the technology is that it can be applied to wide range of gas sources and can be retrofitted to existing power plants.

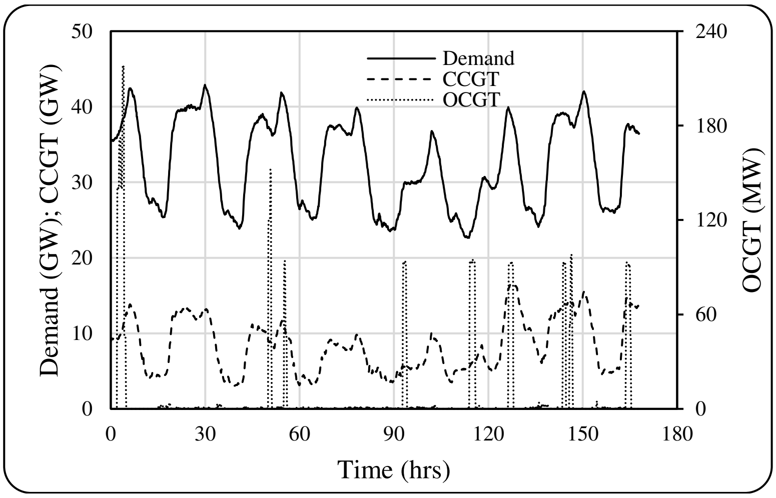

Figure 1: Variations in demand and load on Open and Combined Cycle Gas Turbines (OCGT & CCGT) (National Grid: https://www.gridwatch.templar.co.uk/)

Figure 1 plots total electrical demand and load variations on OCGT and CCGT power plants in the UK for a period of one week, from 12PM on the 18th to 12PM on the 25th of February 2020. The data is downloaded from the National Grid website which presents live data. The plot indicates that total electricity demand is around 40GW which peaks at 7PM, while lowest demand is around 5AM. It is evident from the plot that gas turbine power plants play a key role in balancing the power demand by load variations. OCGT power plants particularly go under sudden start-ups and shut downs. It is not possible to achieve deep reductions in emissions by abating only base load plants (Davison, 2011). This necessitates the need for flexibly-operated power plants and thus capture plants integrated with the power plant would have to be designed to accommodate these same variations. A recent review study of gas fired power plants flexibility by Gonzalez-Salazar et al. (2018) highlights that gas turbine power plants are more efficient and flexible as compared to coal. They have discussed different types of gas turbine power plants and their operational flexibility regimes in detail.

Intermittent renewables cannot supply very rapid responsive power to meet any sudden shortfalls in energy supplied to the grid due to fault conditions. This is normally done by thermal power plants, but when relatively few of these are operating much-reduced reserves are available. If Natural Gas Combined Cycle (NGCC) power plants integrated with Post Combustion Capture (PCC) plants can provide a bigger boost than normally possible this could be a major benefit in reducing the risk of grid frequency drops and consequent load shedding.

In future, requirements of flexible operation from power stations integrated with carbon capture plants will be highly increased (Spitz, et al. 2019). As many of the CCS plants integrated with power plants will have to operate at low load factors, costs will increase at an increasing rate as the emissions are reduced (Davison, 2011). Flexible operation of capture plant can be beneficial depending upon the price of electricity and cost of CO_2 emissions (Ziaii et al. 2009). Due to volatile electricity price, however, the profits have a strong correlation to it (Husebye et al. 2011). There are a number of studies on the flexible operation of CCS plants (Cohen et al. 2011; Kang et al., 2011; Lawal et al., 2012; Gaspar and Cormos, 2012; Harun et al., 2012; Dowell et al., 2013; Mac Saimpert et al., 2013; Domenichini et al., 2013; Lucquiaud et al., 2014; Mac Dowell and Shah, 2014; Errey et al. 2014; Gaspar et al. 2016; Mac Dowell and Staffell 2016; van de Haar, et al. 2017; Tait et al. 2018; Bui et al., 2018; Rua et al. 2020; Bui et al. 2020).

Tait et al. (2018) recently studied the response of capture plant to dynamic scenarios representative of pulverised coal plant operation. The scenarios studied include power output maximisation, frequency response, power output ramping and control of capture efficiency. They have highlighted that CO_2 capture efficiency during dynamic operations can be controlled by real-time control of solvent capacity by manipulating solvent flow rate and/or reboiler heat input (Tait el al. 2016). Mac Dowell and Shah, (2014) presented technical and economic analysis of different modes of flexible operation (solvent storage, exhaust gas venting and time-varying solvent regeneration) by mathematical modelling of a coal power plant integrated with a capture plant.

Cohen et al. (2011) highlighted by comparing flexible and inflexible capture plants that a flexible capture plant can maintain significant CO_2 emissions reductions while increasing annual profits by up to 10% by increasing power output while reducing capture rate (CO_2 venting). However, at high CO_2 prices, the benefit diminishes but a solvent storage system of 15-30 minutes per day capacity may be incorporated into the plant design to take advantage of the reduced stripping during peak load demands. Chalmers et al. (2012) developed methods for first order screening analysis of flexible operation of a coal fired power plant retrofitted with a post combustion capture plant and by performing quantitative analysis they concluded that option of storing rich solvent can be attractive on a short-run basis.

Errey et al. (2014) demonstrated the value of CO_2 capture plants by varying capture efficiency in response to changes in electricity selling price. Mac Dowell and Staffell (2016) investigated various capture plant operational strategies to maintain an average CO_2 capture efficiency close to 90% to capitalise on volatile electricity selling price.

Gaspar et al. (2016) developed a control scheme, based on Relative Gain Array analysis combined with open-loop dynamic sensitivity analysis, to investigate the performance of CO_2 capture process for industrially-relevant operational scenarios. They highlighted that shortage in the steam supply in the reboiler may represent a critical operational bottleneck. However, van der Haar et al. (2017) pointed out that power plants can respond faster to electricity demand variations by varying steam flow to integrated capture plant instead of load variations in the furnace.

Recently, Bui et al. (2020) presented data on three flexible scenarios i.e. effect of steam flow rate, time-varying solvent regeneration and variable ramp rate. Two modes of time-varying solvent generation are describes as peak (high electricity price) when steam flow to reboiler is reduced for maximum power production and off-peak (low electricity price) when steam is used for maximum solvent regeneration. Based on the results, they have recommended that in order to meet target cumulative capture rate, capture performance and duration of both of the modes of operation, peak and off-peak, needs to be coordinated.

Montañés et al. (2017a & b) presented and validated transient data of different operational parameters from 80 TPD CO_2 capture plant at Technology Centre Mongstad (TCM) by varying flue gas flow, solvent flow and reboiler duty set points. The set point of flow rate of flue gas feed was varied from 80% to 67% and back to 80% while the solvent flow was reduced by 8%. They observed long dead times for CO_2 product flow and concluded that the system acts as a buffer to step changes in flue gas flow and that the response is slower at lower operating loads. Montañés et al. (2017c) simulated dynamic interaction between a commercial power plant and capture plant and evaluated the performance of decentralised control structure at different gas turbine ramp rates. They have shown that power plant stabilizes a lot faster than integrated capture plant. Stabilisation time of the capture plant main process variables increases when CO_2 capture rate is controlled as compared to controlling L/G ratio. They concluded that, in a day ahead power market, load following capability of the integrated capture plant is not affected significantly if control structure for process operation is suitably selected.

He and Ricardez-Sandoval (2016) simulated different dynamic scenarios in integrated power and capture plant including step and ramp changes in reboiler energy input, step changes in natural gas flow to the power plant and scheduled steam consumption profile in the reboiler.

Kvamsdal et al. (2018) validated a two-level nonlinear model predictive control using experimental data from TCM plant and used the model to optimise thermodynamic performance of the plant and cost of electricity. They highlighted that accuracy and response time are better controlled with the model as compared to manual operation. Ceccarelli et al. (2014) analysed various load following scenarios of an existing commercial CCGT plant retrofitted with a CO_2 capture plant and concluded that during start-up operation only there may be additional CO_2 losses which can be limited by appropriate design strategies.

Mangiaracina et al (2014) demonstrated solvent storage concept at Brindisi pilot plant using four different modes of operation. Later on, Flø et al. (2016) evaluated different dynamic scenarios including load following, exhaust gas venting, varying solvent regeneration and solvent storage, by modelling Brindisi pilot plant and stated that solvent storage provides flexibility of maintaining CO_2 capture rate over 24 hr period but at added capital costs. Exhaust gas venting and variable solvent generation on the other hand are limited by solvent capacity to maintain CO_2 capture levels.

Post-combustion capture (PCC) plants linked to flexibly-operated natural gas combined cycle (NGCC) plant need to do three main things to accommodate flexible NGCC plant operation in a grid with a high content of intermittent and variable renewables:

1. Capture during a planned start-up with solvent flowing in advance (normal) or gas flowing in advance (unplanned start-up)
2. Operation at NGCC minimum stable generation, typically reduced gas flow (70% of design flow and 50% of design CO_2 concentration)
3. Provide primary responsive power by stopping/reducing steam extraction (no-stripping)

During peak load demand it is required to divert most of the power produced to the consumer and thus less/none will be available for stripping the solvent in the capture plant resulting in increased emissions of CO_2 as indicated by Bui et al. (2020). This could have financial penalties depending upon the regulations of the country. In order to compensate for the increased CO_2 emissions during a planned extended no-stripping period, which might be used for commercial reasons to obtain more power at periods of high electricity selling prices, it may be useful to over-strip the solvent for a period of time prior to no-stripping. So there is a possibility of 4^{th} case where solvent is over-stripped.

Above literature study highlights that there is a lot of work, both experimental and modelling, going on the flexibility of capture plant integrated with gas turbine power plants. Different flexible operational regimes are explored and evaluated at different scale and plant set ups. However, in the knowledge of the authors, there is no experimental data available in open literature on the above mentioned operational scenarios particularly comparison of variations in CO_2 emissions and reboiler duty as a function of no stripping and over stripping operation of the capture plants. In order to investigate the behaviour of capture plants during power plant load changes, the above-mentioned flexibility scenarios have been tested at the PACT pilot plant. The results presented here cannot be directly used for scale up purposes as they are plant configuration, equipment design and operational parameters dependent. However, the trends presented here provide an important insight into the future capture plants flexibly issues and can be used to further enhance studies in this area.

Before going into the details of the scenarios and results acquired, it is necessary to describe the facility.

2. Materials and Methods:

The pilot scale CO_2 capture plant at PACT is capable of capturing 1tpd CO_2. A simplified flow diagram of the plant is shown in Figure 2. Equipment specifications are given in Table 1. The plant is equipped with two absorbers, a stripper, a reboiler, a cross exchanger, a carbon filter and a water wash. Two absorbers are installed in series to increase residence time and contact between liquid and gas. Each of the absorbers is equipped with two beds of Flexipak 350X structured packing, 3m each. Total packed height, therefore, is 4 beds of 3 m each, so totalling 12 m, with liquid re-distribution at each bed.

For this test campaign, air with CO_2 injection, rather than real flue gas, was used. A blower is used to drive the gas through the plant. Flow rate of the solvent can be controlled by variable speed drives as well as pneumatic control valves. The tests were performed under gas turbine conditions so the CO_2 concentration in the absorber entry gas was kept close to 5%, except for 'minimum stable generation' runs. Solvent used was 40% Monoethanolamine (MEA).

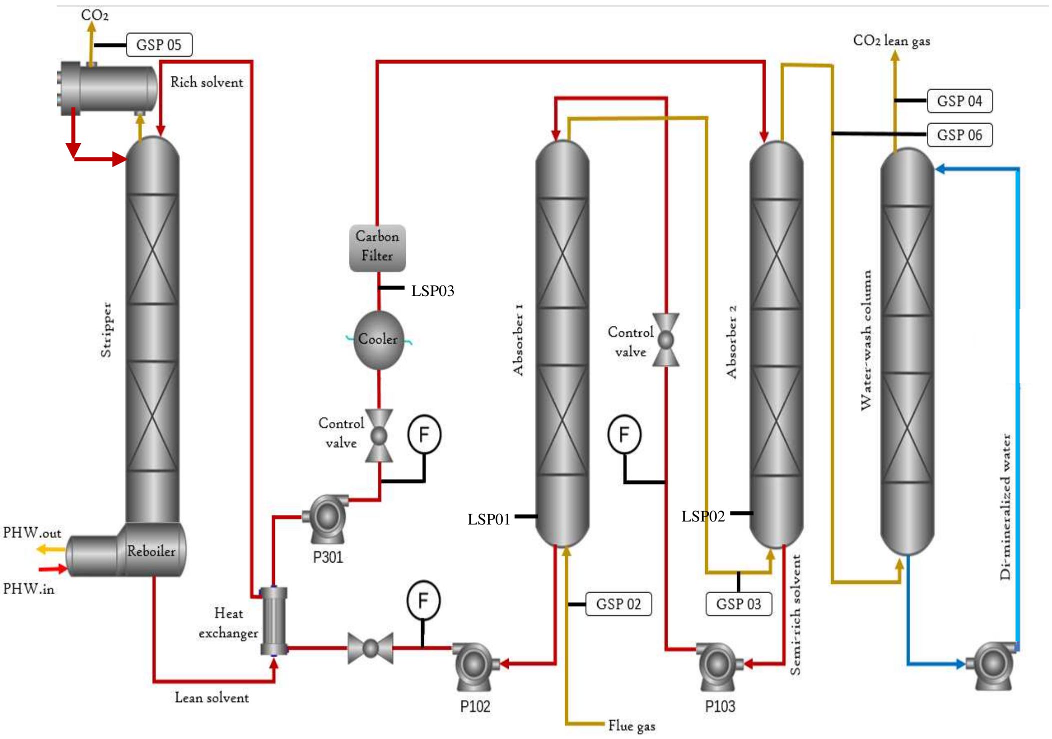

Figure 2: Simplified flow diagram of the PACT CO_2 capture plant

Gas analysis is performed at 6 different locations in the plant. Sampling lines are located at the Absorber 1 inlet, Absorber 2 inlet, Water wash inlet and outlet, and Stripper outlet. The gas samples are extracted from the plant using isokinetic sampling probes and routed to the FTIR through heated filters, heated sampling lines and a heated cabinet housing solenoid for sample switching. The entire sampling system is heated up to 180ºC to avoid condensation.

For offline measurements, solvent samples were collected from the plant for analyses by titration methods. Locations of gaseous and liquid sampling points marked on the plant in Figure 2 are illustrated in the following table 2.

Table 1: Absorber and stripper specifications

Specifications	Absorber 1	Absorber 2	Stripper	Water wash
Diameter (mm)	250	250	300	300
Packing model	Flexipak 350X	Flexipak 350X	IMTP25	IMTP25
Packing type	Structured	Structured	Random	Random
Total Packing height (m)	6	6	7.5	7.5
Packed beds	2	2	1	1
Temperature measurements	12	12	9	-

Table 2: Description of sampling points labelling in Figure 2

Label	Location on the plant	Label	Location on the plant
GSP02	Gas entering absorber 1	LSP01	Rich solvent
GSP03	Gas entering absorber 2	LSP02	Semi-rich solvent
GSP04	Gas leaving water wash	LSP03	Lean solvent
GSP05	CO_2 leaving stripper		
GSP06	Gas entering water wash		

The PACT pilot plant uses Pressurised Hot Water (PHW) instead of steam for solvent stripping in the reboiler. Capture plants integrated with power plants will normally take steam from the power plant to regenerate the solvent in the reboiler. The heating medium used for this purpose during this study was PHW instead of steam due to its ease of operation and better control. Based on the heat transfer coefficients and specific enthalpies per unit mass (kJ/kg), rate of heat transfer with PHW is expected to be slower than that with steam. However, volume based specific enthalpies (kJ/m^3) of PHW is lot higher than steam. Due to this reason, during start up from cold the behaviour of PHW will be different as compared to that of steam. However, once the solvent is heated up to the operational temperature, the effect of rate of heat transfer is not expected to be significant as relatively small amount of energy is required to keep the solvent at the specified temperature in the reboiler. On the positive side, temperature control is better and heat transfer is more uniform with PHW as compared to steam which is beneficial as research systems need precise control over operational conditions.

Parameters controlled for different scenarios under consideration are presented in table 3. A 3-way pneumatic valve is provided at the PHW entry to the reboiler to control the flow of PHW to the reboiler. The PHW supply to the reboiler can be stopped by any of the two methods (i) bypassing the reboiler via the 3-way valve (ii) stopping the PHW supply boiler. In the first case PHW circulates in the loop at the set point temperature and can be diverted to the reboiler whenever required. In the second case, the temperature of the PHW drops depending upon the length of the stoppage time.

Stripper pressure is controlled by a pneumatic control valve which maintains pressure by venting excess CO_2. The pressure is measured by a pressure transducer installed after the condenser which sends 4-20mA signal to the control valve via Programmable Logical Controller (PLC) to control the pressure to a given set point. The set point can be changed on the PLC HMI or data logging station.

Flue gas and solvent flow rates are controlled by varying motor speeds using variable speed drives by providing a set point on the data logging system or on the PLC HMI. Flow rate of injected CO_2 is controlled by a pneumatic control valve by providing set point on the PLC HMI.

Table 3: Control parameters for scenarios under study

Description	Flue gas flow	Flue gas composition	PHW flow	Stripper pressure	Solvent flow
Unplanned start up					x
Normal start up	x				
Step change in flue gas flow and composition	x	x			
No stripping			x		
Over stripping followed by no stripping			x	x	

2.1 Measurements:

CO_2 flow at the inlet is measured by a thermal mass flow meter, while the flow rate of gas into the absorber is measured by a pitot type flow meter. Solvent flow rate alongside density is measured by Coriolis flow meters. Gas composition for mass balance calculations is measured at the inlet and outlet of the absorber, along with temperature and pressure. A Gasmet DX4000 FTIR is used for gas analysis, which sequentially tests samples from each of the locations. The sequence and sampling time is user defined and can be changed in the FTIR software as and when required. For these tests, gas compositions at Absorber 1 inlet (GSP02) and Absorber 2 outlet (GSP06) were used for overall capture efficiency calculations. See Figure 2 and Table 2 for sampling point locations.

It is essential to monitor the solvent streams in real time to get good understanding of the plant behaviour during dynamic operation. During these tests Raman Spectroscopy probes were installed to monitor the solvent but one of the probes did not work properly. Therefore, for indications of loading variations during these dynamic scenarios, correlations between solvent density and loading were developed. It has been shown that liquid density has a very low correlation with solvent concentration while has the strongest correlation with CO_2 loadings (Bui et al., 2014). The idea has been used for correlating CO_2 loadings to liquid density by (Bui et al. 2016) during flexible operation of CSIRO's Loy Yang capture plant.

Similar idea has been used in this study to correlate CO_2 loadings with online density measurements. This does not provide accurate values of CO_2 loadings, however, it provides very important insight into the variation of CO_2 loadings during dynamic operation of the capture plant. As the solvent concentration and temperature of the rich and lean streams are different, two independent correlations are developed for the individual streams by using loadings measured by titrations and densities measured by Coriolis flow meters. The data used to develop the correlations using linear fit Excel function is shown in Figures 3a and 3b. Following correlations were found for the rich and lean loadings, respectively.

$$\text{Rich } CO_2 \text{ loading (mol/mol)} = 0.002^* \rho_{rich} - 1.8588 \quad (1)$$

$$\text{Lean } CO_2 \text{ loading (mol/mol)} = 0.0025^* \rho_{lean} - 2.4733 \quad (2)$$

Where;

ρ_{rich} = Density of rich stream

ρ_{lean} = Density of lean stream

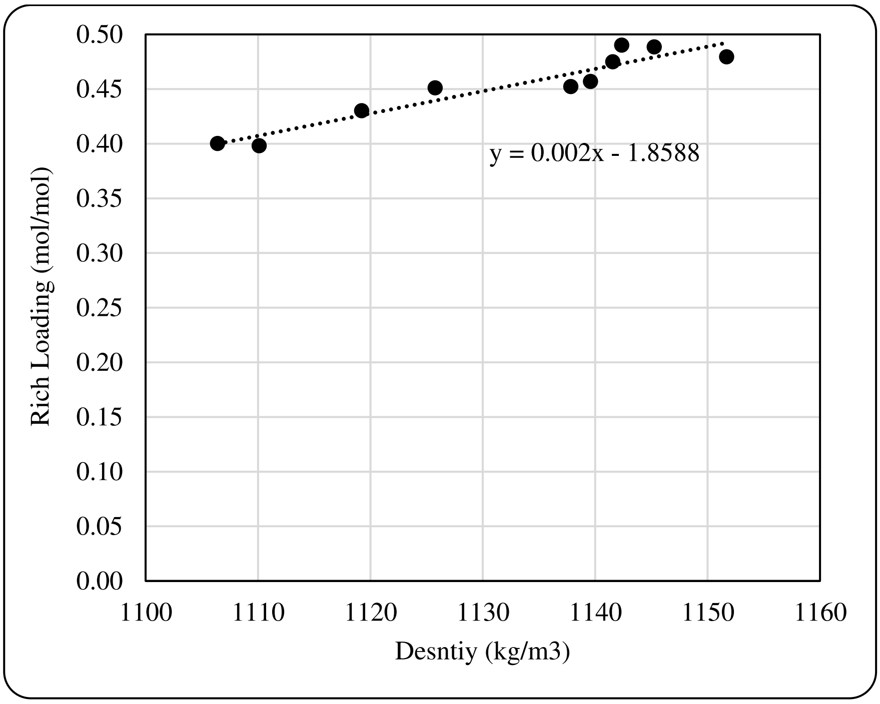

Figure 3a: Rich loading vs. solvent density correlation

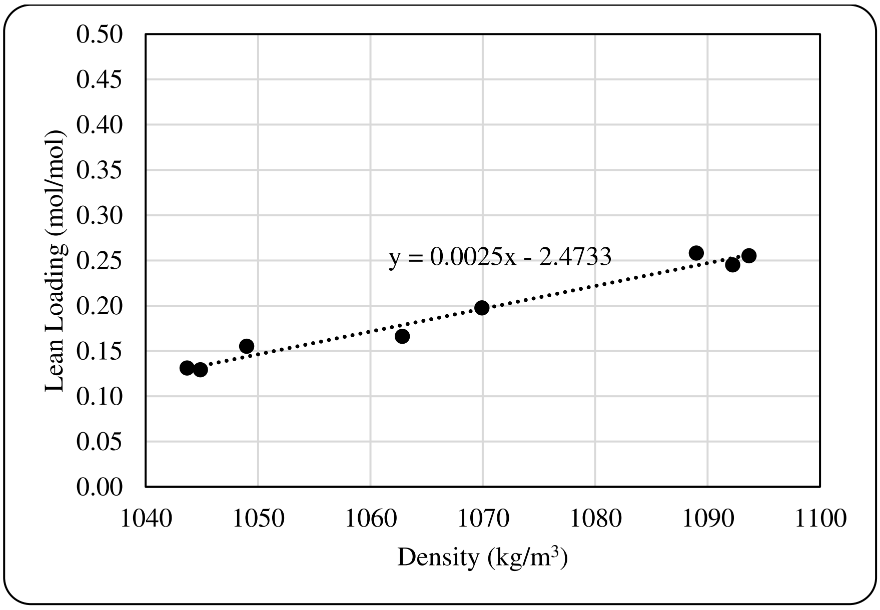

Figure 3b: Lean loading vs. solvent density correlation

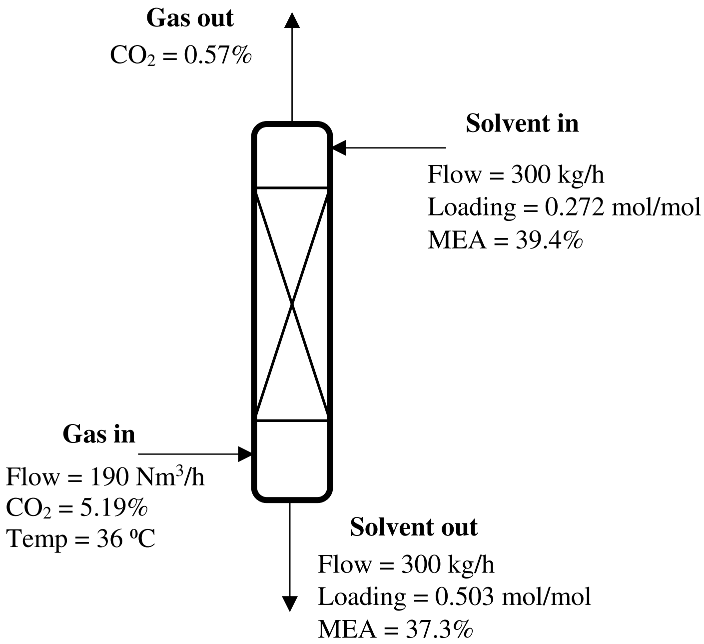

Figure 4: Absorber mass balance

2.2 Calculations:

For all the tests reported here, capture efficiency is calculated based on the gas analysis, temperature and pressure measurements at the inlet of Absorber 1 and at the outlet of Absorber 2. The gas flow rate was measured at the entry to Absorber 1. The flow rate of the gas at the outlet of Absorber 2 was calculated by mass balance. Mass balance closure for one of the steady runs is shown in Figure 4. Comprehensive data for the mass balance closure over a wide range of operational conditions is not available as all the dynamic tests were started from very close (same set points) steady state conditions. Gas flow rate at the outlet of the absorber is not measured. Due to very high water content in the stream, it was not possible to procure a suitable flow meter. Temperature, pressure and composition is measured for both of the inlet and outlet gaseous streams but flow rate is measured only for the inlet stream. The flow rate for the outlet gas is calculated by mass balance assuming that N_2 and O_2 pass through the absorber unreacted.

Specific Reboiler Duty and the amount of CO_2 captured is calculated from the energy used in the reboiler and the amount of captured CO_2 as follows (Akram et al. 2016).

Energy used in the reboiler is calculated from the temperature of the Pressurised Hot Water at the inlet and outlet of the reboiler and its flow rate by using Equation 3.

$$Q = M * C_p * (T_{in} - T_{out}) \qquad (3)$$

Where, Q = energy consumption, kJ/h; M = mass flow rate of the PHW, kg/h; C_p = specific heat capacity of PHW, kJ/kg.K; T_{in} = inlet temperature of the PHW, ◦C; T_{out} = outlet temperature of the PHW, ◦C.

The amount of CO_2 captured was calculated using Equation 4.

$$M_{CO2} = (n_{CO2in} - n_{CO2out}) * MW_{CO2} \qquad (4)$$

Where, M_{CO2}= mass of CO_2 captured, kg/h; n_{CO2in}= moles of CO_2 entering the absorber; n_{CO2out} = moles of CO_2 leaving the absorber; MW_{CO2} = molecular weight of CO_2.

The energy consumption per unit mass of CO_2 captured (MJ/kgCO_2), also referred to as SRD, is calculated from Equation 5 using values calculated in equations 3 & 4.

$$SRD = Q/M_{CO2} \quad (5)$$

3. Results and discussions:

Dynamic tests were undertaken for four different scenarios:

1. Start up
2. Minimum stable generation - step change in flue gas flow and CO_2 concentration
3. No-stripping (PHW stoppage)
4. Over-stripping (by lowering stripper pressure) followed by no-stripping (as in scenario 3)

3.1 Start-up:

When not in baseload operation, NGCC plants will normally start up and run to full power to meet expected demand for a network dispatch period (typically a multiple of 30 minutes), defined by grid operational needs. This will be an entirely predictable event, against supply and demand requirements estimated a day ahead and usually based on a bid to supply at a given price. In this case a full-scale PCC plant can be prepared in advance to receive flue gases and capture CO_2.

Note that NGCC plant will not usually be asked to provide un-forecasted rapid secondary response by starting up quickly and if required only the gas turbine component could do so and only certain plants would be suitable. This would normally only be in response to a fault condition and so would take place infrequently, therefore an immediate start to capture is not required. Nonetheless, it would be feasible to initiate capture quickly, if necessary sending flue gases to the stack until the PCC unit was ready to receive them.

Simple cycle gas turbine plants, used for meeting peak load demands, need lower CAPEX and have shorter construction period. They also have lower efficiency and thus higher specific emissions. Therefore, decarbonising these plants is essential. However, an auxiliary boiler will be required for heating up the solvent in these plants. This will also be the case in combined cycle plants during peak load periods. Therefore, these start-up scenarios are applicable to simple cycle GTs (SCCT) due to unavailability of steam from the power plant and to CCGT plants during peak loads when all the steam is required for steam turbines to generate maximum possible power.

CCGT plants have a frequent hot starts. If down time is less than 16 hrs, a CCGT plant will have hot start. Typical base load plant have around 13 hot starts per annum while typical intermediate and cycling plants will have 77 and 360 hot starts, respectively, per year Ruchti et al. 2012).

For the start-up, two scenarios were tested.

1. Unplanned start-up: Flue gas flowing first, then solvent circulation
2. Normal start-up: Solvent circulation first then flue gas flow

In both of these scenarios, solvent was heated before circulation mimicking the situation of the capture plant having to start up quickly, also termed as hot start. Pre-heating the solvent avoids time lapsed during heating up phase where solvent could be fully loaded due to no stripping taking pace and resulting in higher amounts of CO_2 going through the stack.

3.1.1 Unplanned start-up

For the first case, gas flow and CO_2 concentration were stabilised before starting hot solvent circulation. Solvent was heated up prior to circulation by PHW. This scenario is designed to mimic restart of capture plant after a short shut down. This could be due to a number of reasons including capture plant maintenance and repair, technical issues or peak load demand for a short period while power plant was operational. Before starting the capture plant, flue gas will be emitted to atmosphere resulting in increased amount of emissions during that period. The situation can also arise when penalty for CO_2 emissions outweighs the price of electricity where revenue from the sale of extra electricity is higher than the payment for extra CO_2 emissions (Delarue et al. 2012).

Figure 5 plots variation in capture efficiency during the test. It can be seen from the plot that gas flow started well in advance of the solvent flow. It took some time for the gas flow and CO_2 concentration to stabilise due to heating up of the pipes. The figure shows that capture efficiency went to close to 100% as soon as solvent flow was started. Capture efficiency was close to 100% for an hour after the start of flue gas flow, then started dropping, due to solvent saturation. The capture efficiency dropped to around 82% before started increasing again. Average capture efficiency over the test period of around two and half hours remained around 94.5%. This translates into 2 kg (4.4%) less CO_2 emissions over that if the plant was operated at steady capture efficiency of 90%. The higher amount of CO_2 captured (>90%) can be used to offset the emissions during capture plant shut down period or flue gas venting during peak electricity demand.

The plot also shows variation in solvent temperature during the test, measured by a RTD inserted into the middle of the reboiler. The solvent temperature followed the same trend as the stripper pressure. The temperature of the solvent in the reboiler was around 108°C. As the stripper pressure increases, the boiling point of the solvent also increases, resulting in an increase in solvent temperature.

Tait et al. (2018) presented two start up scenarios but both of them are based on the concept that steam for solvent regeneration is extracted from the power plant. In one of the scenarios, low-pressure steam turbine is allowed to reach full load before any steam is extracted while in the other steam is extracted as soon it becomes available. In the first scenario, CO_2 capture efficiency stays low for prolonged period and plant takes several hours to reach the desired capture efficiency. However, when steam is introduced into the reboiler at an early stage as in the latter scenario, drop in capture efficiency is smaller and the plant reaching steady state more rapidly.

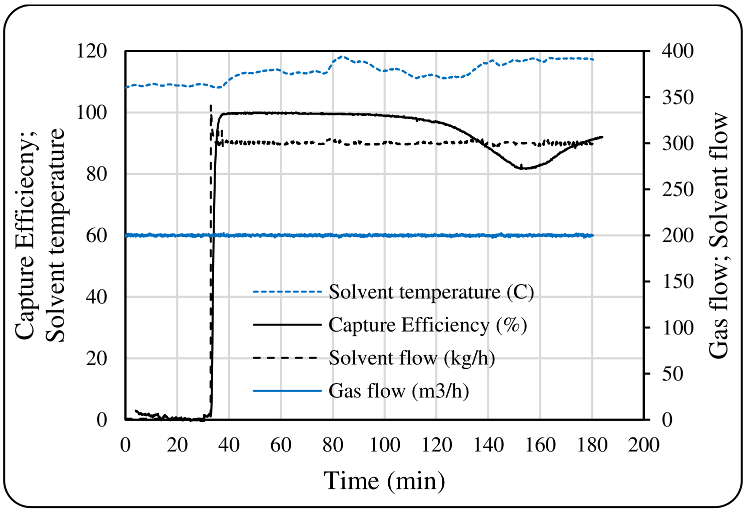

Figure 5: Variation in capture efficiency and solvent temperature with time during unplanned start up

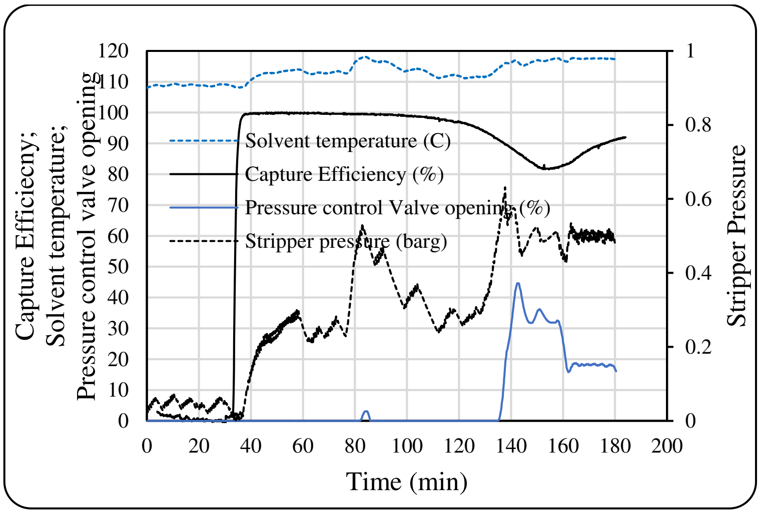

Figure 6: Stripper pressure variation during unplanned start-up

During current study, solvent was preheated before circulation, therefore, needing auxiliary source of heat as it will require to be warmed up before steam from the power plant becomes available. As can be observed from Figure 6, stripper pressure started increasing soon after the solvent circulation was introduced. However, it took around one hr and 40 minutes for the pressure to reach the set point resulting in pressure control valve to open to let the product gas flow through. This implies that even if solvent is preheated, there will be a considerable delay in CO_2 being available for compression and transport. Minimum capture efficiency in this case was above 80%, as opposed to 33% and 70% for the two start up cases tested by Tait et al. (2018), indicating that preheating the solvent reduces CO_2 emissions and thus lower emissions penalties or increased profits if selling carbon credits.

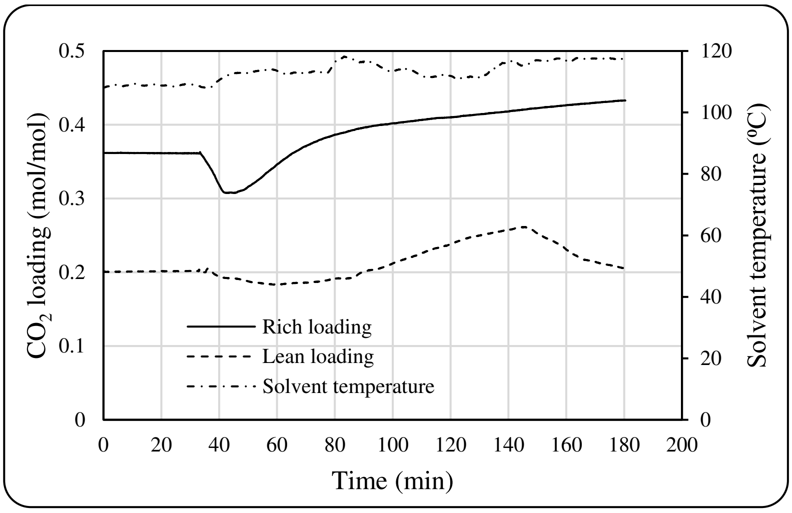

Figure 7: Loadings variation during unplanned start-up

Figure 7 plots CO_2 loadings for both the rich and lean streams. The plot shows that at the start of solvent circulation, rich loading was around 0.36 mol/mol. This is because the solvent was left in the plant partially-stripped on the previous day so that the solvent in the absorber sump has higher loading than that in the reboiler/stripper sump. Loading of the solvent in the stripper sump dropped as the solvent was preheated without being circulated. As the solvent circulation started, rich loading dropped due to mixing with lean solvent from the stripper/reboiler. The lean loading also dropped as the solvent was being heated up and started stripping. After few minutes of gas flow, rich loading started to increase while lean loading started increasing after some delay. Both of the rich and lean loadings had increasing trend due to absorption of CO_2 from the flue gas. After 140 mins of start-up, lean loading started to drop. This was due to increase in solvent temperature as a result of rise in stripper pressure as can be observed in Figure 6.

3.1.2 Normal Start-up

In order to ensure minimum emissions of CO_2, solvent flow has to be started before flue gas is available from the power plant. Therefore, for the normal start up scenario, hot solvent circulation was started before flue gas flow. This sequence ensures that when GT starts, flue gas goes to absorber and CO_2 is captured by circulating lean solvent. This way the emissions of CO_2 will be minimal. However, auxiliary boiler will be required to heat up the solvent before steam is available from the power plant (IEAGHG, 2012).

Figure 8 plots operational conditions against time for the test. In this case the solvent temperature was higher than the previous case as the stripper was already hot and quickly pressurised to 0.5 barg. The plot shows that all the parameters were steady soon after the plant start up. Capture efficiency was close to 100% for some time after the start up as in the previous scenario. This was because the solvent was lean to start with. The capture efficiency then started dropping as the solvent became saturated.

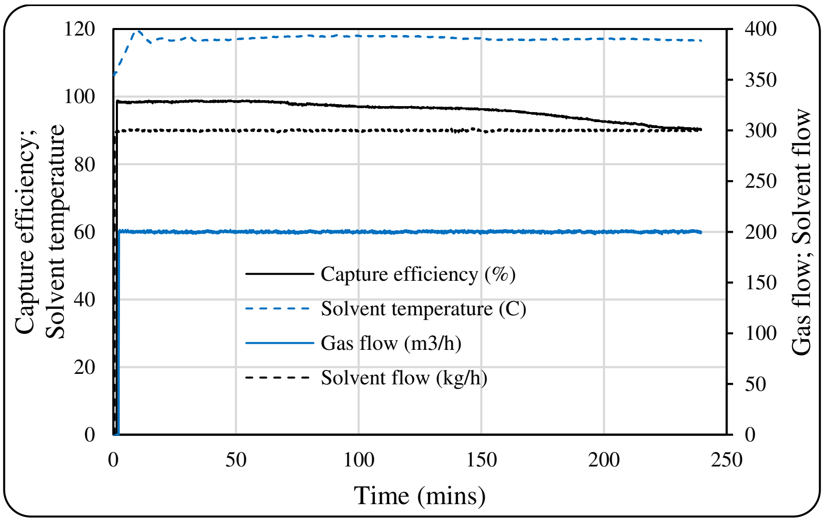

Figure 8: Capture efficiency variation during normal start-up

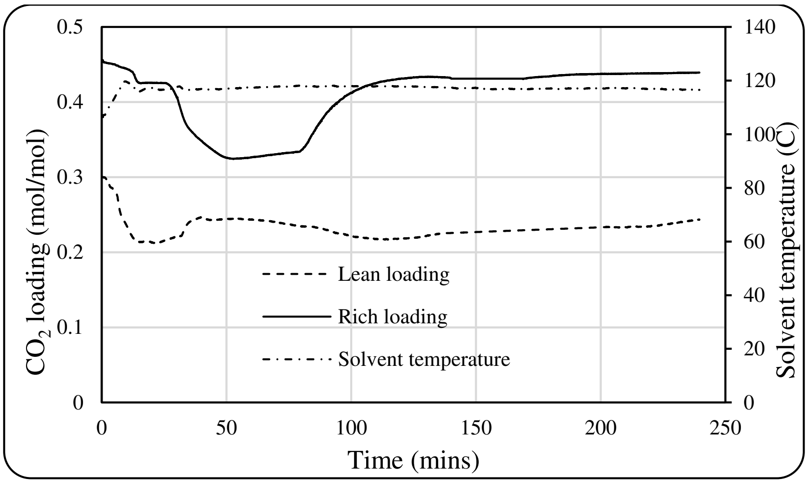

Figure 9: Loadings variation during normal start-up

The data indicates that capture efficiency was above 90% for more than three hrs of the start of gas flow. Average capture efficiency over the test period of around four hours remained around 96%. This translates into 5 kg (7.2%) less CO_2 emissions over that if the plant was operated at steady capture efficiency of 90%. The higher amount of CO_2 captured (>90%) can be used to offset the emissions during capture plant shut down period or flue gas venting during peak electricity demand. The figures indicate that capturing CO_2 as soon as flue gas is available has higher incentive in terms of emissions but may require extra investment for a source of energy for stripping or solvent storage.

Figure 9 plots rich and lean loadings for the tests. Both are stable after around two hrs although at the start there are variations due to mixing of lean and rich solvent as well as absorption of CO_2 from the gas.

3.2 Step change in gas flow and CO_2 concentration

In order to meet environmental limits of NO_x and CO emissions, GT has to operate at or above minimum load, generally 30-50% higher than base load production (IEAGHG, 2012). Load reduction on power plant down to 60% of the base load results in slightly lower efficiency, only 2-3 percentage points (IEAGHG, 2012). The response of the PCC plant to this condition is determined by plant design. In particular, for NGCC plants expected to operate for extended periods in this condition, the PCC unit might have two absorbers, with one specifically designed for the Minimum Stable Generation (MSG) mode when, for single shaft GTs with inlet guide vanes fitted, the air flow could be expected to be approximately 70% of the design value and the firing rate approximately 35%-70% of the design value.

By contrast, for a single 100% flow absorber operating at reduced gas flow the L/G ratio may not be able to be reduced significantly and so the energy consumption per tonne of CO_2 captured will be greater than the design value. Against that, the capture rate will be able to be higher. In addition, the actual value of electricity, at times when it makes sense to operate a NGCC plant at MSG, is obviously low, possibly even negative. So fewer MW sent out is not a major penalty – provided CCS incentives allow for this reality and don't provide artificial incentives for efficiency to generate more MW that are not really wanted.

For this scenario, a step change was introduced into the flue gas flow and CO_2 concentration. The flue gas flow was dropped to 70% of the original flow and the CO_2 concentration was dropped to around 50% of the original value while the rest of the parameters were maintained. The situation arises during MSG when air flow is reduced to 70% of the design value and the firing rate approximately 35% of the design value.

For this test it is considered that the power plant is running at MSG but capture plant is still running as normal with consistent solvent flow and steam for solvent regeneration available at the same conditions from the bottoming cycle or from an auxiliary boiler as in the case of CCGT or SCGT, respectively.

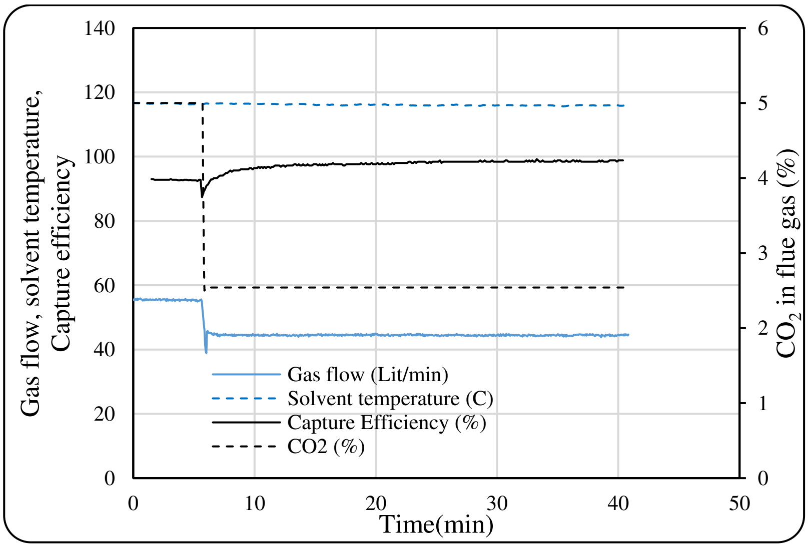

Figure 10: Variation in capture efficiency with step change in flue gas to MSG values

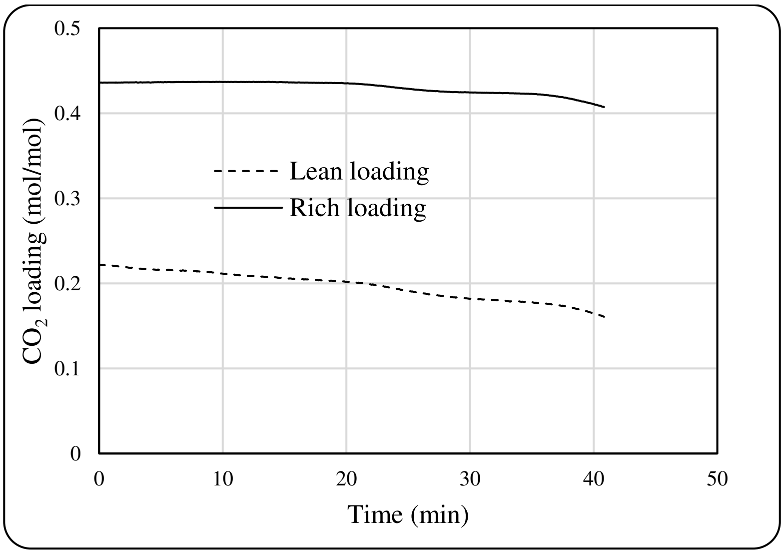

Figure 11: rich and lean loadings during flue gas and CO_2 step change

Dropping flue gas flow rate results in higher L/G ratio. Also contact time between the liquid and gas is increased due to lower velocity of the gas through the column. Also drop in CO_2 concentration to half dropped the CO_2 flow to the absorber by 60% as gas flow rate was also less, resulting in reduced driving force for absorption. Results of the test are presented in Figures 10 and 11. Capture efficiency increased to nearly 100% (Figure 10) while CO_2 loadings (Figure 11) dropped due to lower CO_2 gradient. However, no significant change was observed in the other parameters such as solvent temperature, stripper pressure etc.

The tests duration was around half an hour corresponding to a typical MSG duration on a NGCC plants. The average capture efficiency over the test period remained 97.6% resulting in capturing more than 8% extra CO_2 during the test period compared with 90% capture efficiency.

CO_2 loadings can be maintained by adjusting solvent circulation rate or steam supply to stripper but no effort was made to achieve this in this test. The idea is to maintain maximum capture efficiency for capturing maximum amount of CO_2 which can either be used to offset for the higher emissions during peak load demands or can be sold as carbon credits depending upon the price.

3.3 No-stripping:

Capturing and compressing carbon dioxide requires energy, giving a reduction of somewhere between approximately an eighth (for gas) and a quarter (for biomass) in the plant's electricity output. But part or all of this electricity can be restored just as quickly as the old coal plants used to be able to boost, and, unlike the coal plants, is available even when the CCS plants are running most economically, at full load. And not only is the power available for the primary response period of around 30 seconds: if needed it can continue to be supplied for however long it takes for additional secondary response generation capacity to come on line. For shorter and more limited boosts CO_2 capture would not even need to be interrupted. In real emergencies capture might have to be stopped for up to a few hours. But, since total long-term CO_2 emissions are what matters for climate change, the relatively small extra amounts of CO_2 that would then be released can be made up by additional capture at other times, when electricity is abundant or even in surplus, to meet the required annual targets.

Thus, post-combustion capture offers a valuable capability to stabilise the grid and avoid power cuts like the one in the UK in August 2019, when rapid primary response power is needed. This capability is much greater than that for conventional power plants or those with other forms of capture that cannot be cut off very rapidly in the same way to allow more electricity to be exported.

This feature can save the consumer significant amounts of money and provision for its inclusion in plant designs and use when needed should be encouraged in CfD contracts. This is probably best done by a regulatory-type provision, analogous to the Grid Code specifications for primary response capability applied in the past to UK coal power plants, linked to an appreciation of the increased value for this electricity supply compared to others.

In general, allowing flexibility in the level of capture from all CCUS installations rather than specifying fixed levels at all time is important to reduce costs to consumers and to minimise overall UK CO_2 emissions. For climate purposes CO_2 emissions can be averaged over decades. Yearly or longer averaging to allow optimisation of capture level (and initial plant design) to suit varying market and weather conditions, or an equivalent adjustment in the assessed amount of clean output for payments, is therefore very important. Costs will be saved by not needing to over-invest to meet only occasional requirements and emissions will be reduced by encouraging higher levels of capture when conditions permit.

For an example of the response of the capture plant to interruptions in heating to the reboiler, no-stripping tests were performed to mimic the unavailability of steam for stripping over varied periods of time. This situation could arise due to increased demand of electricity where most/all of the steam is diverted to the power terrain and no steam available for stripping of the solvent in the capture plant. The scenario also mimics the capture bypass where flue gas is emitted to atmosphere and all the available steam is used to produce electricity. According to Chalmers et al. (2009a&b) capture bypass is valuable if electricity price is 2-3 times higher than the cost of CO_2 emissions.

In order to mimic the situation, the PHW flow to the reboiler was stopped for these tests for varied amount of time: 3.5 mins, 5 mins, 10 mins and 30 mins. Figure 12 shows the variation in capture efficiency, stripper pressure and solvent temperature over the test period. For simplicity, the data is plotted only for one tests when PHW was stopped for 30mins.

The plots show that longer the PHW stoppage time, higher the variation in stripper pressure. When PHW is stopped, the stripping process is reduced although some stripping still happens due to the residual heat in around 450 litres of hot solvent in the reboiler. Due to the reduction in the stripping process, the stripper pressure starts to drop. The longer the PHW stoppage time, the lower the minimum stripper pressure.

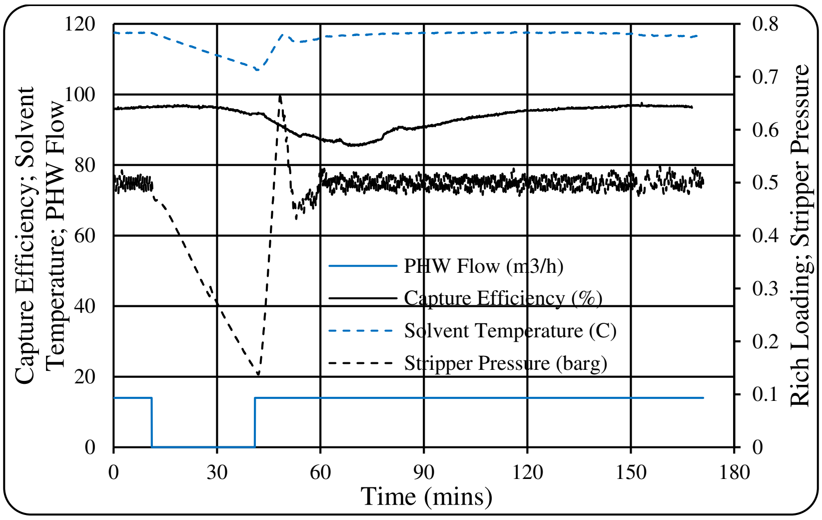

Figure 12: PHW stopped for 30 minutes

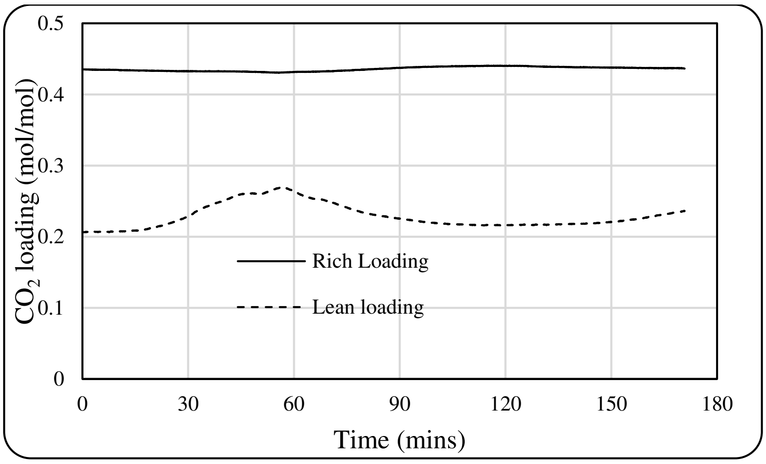

Figure 13: CO_2 loadings data for 30 mins PHW stoppage

Figure 13 plots CO_2 loadings for the test presented in Figure 12. It can be observed that lean loading started to increase few minutes after the PHW was stopped. The loading increased from 0.2 mol/mol to 0.27 mol/mol, an increase of around 35%. However, it took some time for the loading to start dropping after PHW circulation was started. Rich loading did not change much. There was a slight increase in the rich loading but much later than the increase in lean loading.

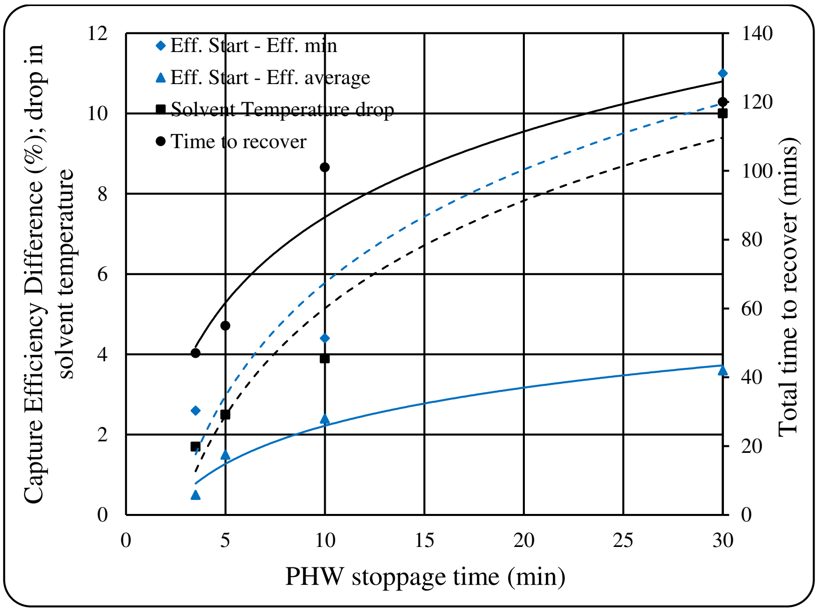

Figure 14: Impact of PHW stoppage time on capture efficiency variation

Figure 14 plots different parameters against time for all the four test cases described in Table 4. The parameters plotted in Figure 14 are defined as below.

Eff.start = Starting efficiency = Capture Efficiency when PHW flow was stopped
Eff.min = Minimum capture efficiency achieved during the test when no PHW
Total time to recover = Time from PHW stoppage to capture efficiency becoming equal to Eff.start
Eff.average = Average capture efficiency over the period defined as "total time to recover"

Table 4: Results of no–stripping tests [*averaged over the test period "Total (mins)]

PHW stoppage (mins)	Eff. Start	Eff. Min	Eff. Av.	Total (mins)	*Captd. CO_2 (kg/h)	*SRD MJ/kg
3.5	92.0%	89.4%	91.5%	47	17.06	5.3
5	89.0%	86.5%	87.5%	55	17.98	4.86
10	90.0%	85.6%	87.6%	101	16.96	5.04
30	96.0%	85.0%	92.4%	120	16.62	6.29

The data indicates that longer the PHW stoppage time, longer it takes to recover the plant back to original condition when PHW was stopped. It took around two hrs for the plant to get back to normal after 30min PHW stoppage time, more than double it took when PHW stoppage time was 5 mins. Also, the difference between capture efficiency at the start (Eff. Start) and the minimum capture efficiency (Eff. Min) increases with increase in PHW stoppage time. The difference (Eff. Start – Eff. Min) was more than 4 times higher for 30 min stoppage time as compared to that for 5 min stoppage time. Moreover, the difference between the capture efficiency at the start and the average capture efficiency also increases with increases in PHW stoppage time. The difference (Eff. Start – Eff. Av.) was more than double for 30 min stoppage time as compared to that for 5 min stoppage time.

Solvent temperature measured by inserting a RTD into the middle of the reboiler observed to have increasing trend with increase in PHW stoppage time. The temperature was dropped by around 10 ºC when PHW was stopped for 30 mins. The temperature drops due to two reasons. Firstly, there is no heat input to the reboiler and secondly, due to drop in stripper pressure resulting in more evaporation. The impact of drop in stripper pressure on the solvent temperature drop is clear in Figure 14 where it can be noted that drop in solvent temperature in the case of 30 min PHW stoppage time is well above the trend line whereas that for 10 min PHW stoppage time is well below it indicating increased level of evaporation as a result of drop in stripper pressure due to prolonged PHW shut down.

3.3.1 Change in SRD and captured CO_2:

Figure 15 shows percentage change in SRD and extra CO_2 emitted as a function of PHW stoppage time. For both of the parameters percentage values are calculated with respect to the respective values for the steady state operation for that specific test before PHW was stopped. Both of the parameters, SRD (MJ/kg_{CO2}) and CO_2 emissions (kg/h), presented here are averaged over the test period. The plot also shows absolute extra CO_2 emissions (kg) over and above the emissions which would have been emitted if the plant was operated at steady state throughout at the same conditions as was before PHW was stopped.

The figure indicates that SRD increases with increase in PHW stoppage time. The SRD increased by 8.7% when the PHW stoppage time was increased to 30 mins. However, it is clear from the plot that the increase in SRD is not linear with PHW stoppage time.

Emissions of CO_2 increase with increase in PHW stoppage time, as shown in Table 4. The figures indicate that CO_2 emissions are higher than the original steady state values for all the cases tested. For a 30 min PHW stoppage time, 3.3 kg more CO_2 was emitted over the test period which is around 9% higher than that would have been emitted if plant was operated at steady state without PHW interruption.

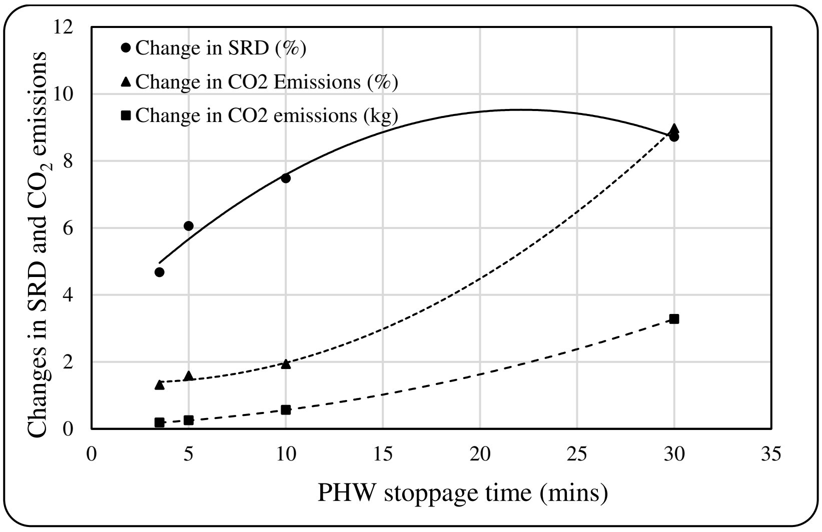

Figure 15: Changes in Specific Reboiler Duty and CO_2 emissions with PHW stoppage time

3.4 Over-stripping followed by no-stripping

This scenario was focussed on over-stripping the solvent before turning off the PHW flow. It is, to some extent, based on variable solvent regeneration where CO_2 is allowed to accumulate in the solvent during peak load demands and is regenerated when electricity price is low (Mechleri et al. 2017; Bui et al. 2020). This might be used if the need for an interruption in steam flow was predictable, which would not be the case for primary response duties but would be known if a temporary boost was required for commercial reasons during periods of high electricity prices. Such a boost period could be relatively long, with the minimum time corresponding to one charging period, so 30 minutes currently in the UK. In the future, though, this period might be reduced to facilitate real-time pricing signalling, as is the case already in other markets e.g. ERCOT (Electric Reliability Council of Texas).

On actual plants, a range of means could be used for over-stripping, such as using higher temperature steam or increasing steam flow. However, in this case only the stripper pressure was lowered for over-stripping, being dropped to 0.3 or 0.4 barg from the original value of 0.5 barg for a varied period of time before shutting down PHW. Data is plotted in Figure 16. For simplicity, data is shown for only one test when stripper pressure was dropped to 0.4 barg for 60 mins followed by PHW stoppage for 30 mins. The figure plots variation in capture efficiency, solvent temperature and stripper pressure during the test period. As can be observed from the figure, capture efficiency increased when the pressure was lowered due to decrease in boiling point of the solvent. Drop in boiling point results in enhancement in stripping resulting in capturing more CO_2. Capture efficiency dropped sharply after around 30 minutes of PHW stoppage, from 95% to around 75% within 25 minutes, before increasing again as a result of energy input after PHW was restarted. It took more than 3 hrs for the plant to get back to original conditions as was before the disturbance.

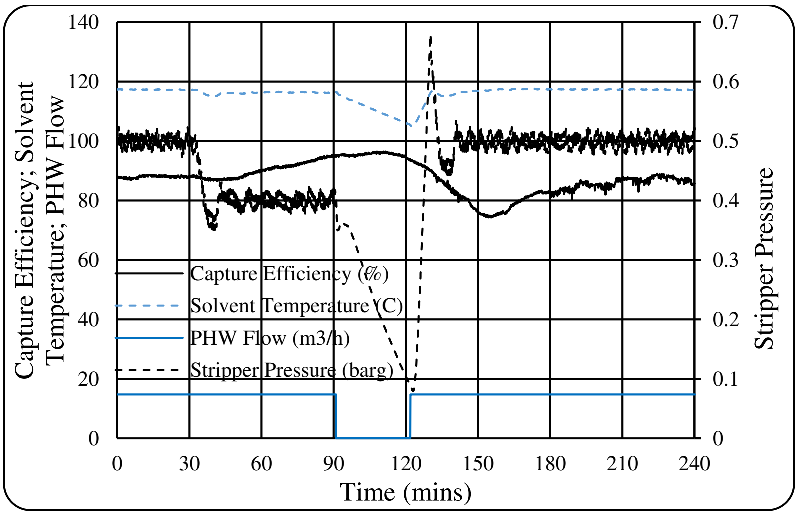

Figure 16: Stripper pressure dropped to 0.4 barg for 60 mins followed by PHW stoppage for 30 mins

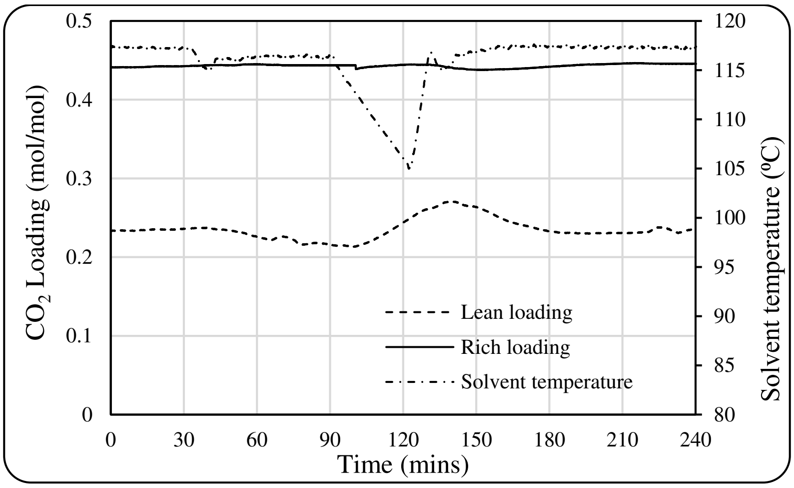

Figure 17: CO_2 loadings for Stripper pressure dropped for 60 mins followed by PHW stoppage for 30 mins

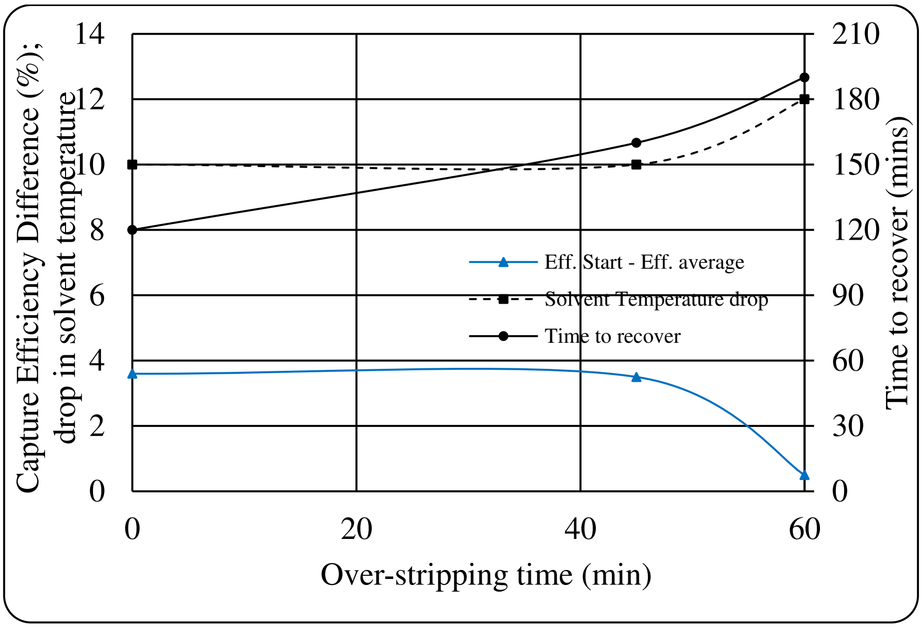

Figure 18: The impact of over-stripping on capture efficiency

Table 5: Results of over–stripping followed by no-stripping tests (pressure dropped to 0.4 barg)

Over-stripping (mins)	PHW stoppage (mins)	Eff. Start	Eff. Max	Eff. Min	Eff. Av.	Total (mins)
0	30	96.0%	-	85.0%	92.4%	120
45	30	90.0%	96.0%	82.0%	86.5%	160
60	30	88.0%	96.0%	74.3%	87.5%	190
45	15	87.5%	94.8%	87.5%	90.3%	210

Figure 17 plots rich and lean loadings for the test presented in Figure 16. Lean loading has shown a higher dependence on the changes in stripper conditions. Lean loadings dropped soon after reduction in the stripper pressure but rose sharply after 10 mins of PHW stoppage.

However, when the PHW was turned back again, lean loading started to drop but with a delay of around 20 mins. However, rich loading on the other hand did not change much.

Figure 18 plots comparison of data for the over-stripping tests, also shown in Table 5. The parameters in this figure have the same definition as in the no-stripping section, Figure 14. The plot indicates that for the same PHW stoppage time, a longer over-stripping period results in longer recovery time. Also, longer the over stripping period, longer it takes for the plant to get back to normal conditions. The time may be different for other plants as it is influenced strongly by the liquid hold-up in the plant (van de Haar et al. 2017). Moreover, for the same over-stripping period, a longer PHW stoppage results in lower average capture efficiency.

3.4.1 Change in SRD and CO_2 emissions:

Figure 19 shows the percentage change in specific reboiler duty vs over-stripping period for a fixed PHW stoppage time of 30 minutes. The figure indicates that the higher the over-stripping time, the higher the increase in SRD. The SRD increased by 36% when the over-stripping time was increased to an hour. The regeneration of solvent at non-optimal condition away from design point results in a significant increase in the reboiler duty resulting in relatively lower cycle efficiency (Zangrilli et al. 2014).

Emissions of CO_2 drop with increase in the over-stripping period as shown in Figure 19. All the data in these figure is averaged over the test period. The figure indicates that CO_2 emissions are higher than the original steady state values, for all the cases tested. For an over-stripping period of one hours, CO_2 emissions are only 0.5 kg (3%) more than the original case. However, this is at the cost of 36% increase in SRD.

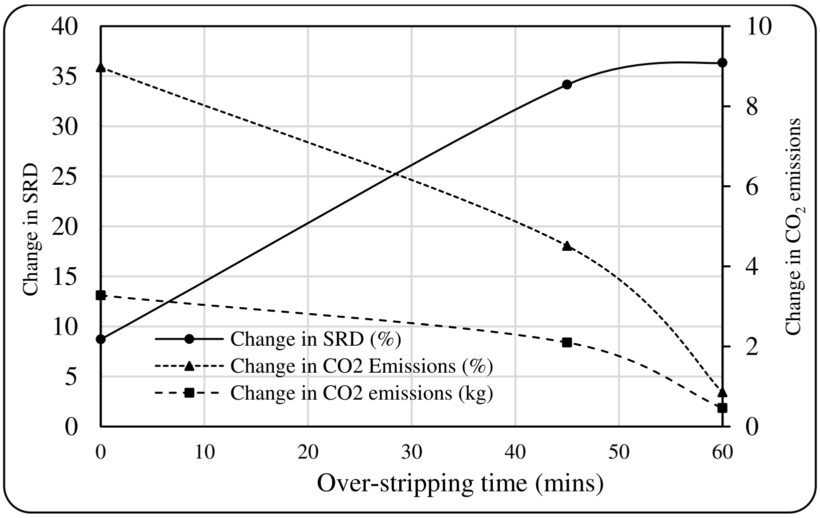

Figure 19: Change in SRD with over-stripping time

The results highlight that controlling the capture plants to maximise profits in response to load variations is an optimisation problem between reduction in SRD and maximising CO_2 capture. In order to achieve optimised plant performance to capitalise on fluctuating electricity selling price by variation in reboiler steam input, a robust process control system is required for the implementation of these operational strategies (Mac Dowell and Staffell, 2016).

4. Conclusions:

Flexible operation of a PCC plant to respond to typical commercial load changes on an NGCC power plant has been investigated at pilot scale. Satisfactory operation for planned start-up is achieved, as expected, by commencing solvent flow before flue gas is produced. For (likely infrequent) unplanned starts, capture also can be started as soon as solvent is available.

For unplanned interruptions of solvent regeneration to get a power boost to meet grid fault conditions, emissions of CO_2 increase due to unavailability of steam during peak demand.

For planned interruptions for commercial reasons, it is possible to compensate for increased emissions during that period by solvent storage and solvent over-stripping to avoid excess penalties for increased emissions to atmosphere. Solvent over-stripping tests have shown that if the solvent is stripped for a long enough period of time it is possible to maintain 90% overall capture efficiency, but at the cost of increased reboiler duty. Adjustment of the plant under these scenarios would be required in order to achieve a commercially-optimised balance i.e. minimum increase in SRD costs while achieving a capture efficiency that also minimises CO_2 emission costs.

5. Acknowledgement:

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