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Operating flexibility of CO₂ injection wells in future low carbon energy system

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Abstract

Many studies in the literature optimise operation of individual components along the CCS process chain for base-load/design conditions. This fails to acknowledge the need for flexible operation of fossil CCS infrastructure in future low carbon energy systems, characterised by high shares of inflexible nuclear power and intermittent renewable power supply. In this environment CCS power stations are likely to load-follow in order to balance the electricity grid. This results in extensive ramping and part-load operation as well as large variations in CO₂ flows that are produced. Unless CO₂ flow balancing techniques are deployed within the power stations, the CO₂ transportation and storage (T&S) systems will need to accommodate these large fluctuations in feed-flows. This paper addresses an identified gap in the literature by exploring the issues associated with flexible operation of CO₂ T&S systems, as well as options to overcome these issues. A particular focus is laid on the operational flexibility of injection wells as the potentially least flexible part of the system.

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Keywords: CCS; flexible operation; CO₂ flow variability; CO₂ transportation & storage networks

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1. Introduction

Inherent to low-carbon electricity generation technologies are their very different capabilities and tasks in the energy system. While power from renewable sources is largely variable (i.e. wind and solar), nuclear plants provide clean and firm but inflexible power at low operational cost. Carbon capture and storage (CCS) fitted on fossil fuel-fired (or biomass-fired) power stations offers to provide firm and flexibly dispatchable power at low (or potentially negative) greenhouse gas (GHG) emissions. This makes the technology well suited for balancing electricity systems dominated by high penetrations of intermittent renewable energy supply and significant contributions of inflexible nuclear power.

This characteristic as a firm capacity provider with good load following capability stands in contrast to the majority of the literature, which focusses on investigating CCS technology at steady-state and design conditions.

After assessing operating regimes of CCS power stations and the likely variability of captured CO₂ streams feeding into future CO₂ Transportation & Storage networks this paper discusses the risks associated with variable operation of individual components along the CO₂ T&S process chain. Particular attention is given to CO₂ injection wells as the potentially least flexible component in the system. Finally, operating and design options are presented that allow mitigating or avoiding the risks associated with fluctuating CO₂ flow rates in the system.

2. Variable CO₂ flows in future low carbon energy systems

To assess the operating profiles of CCS power plants and the resulting variations in CO₂ flows feeding into future CO₂ Transportation and Storage (T&S) networks, a purpose-built Unit Commitment Economic Dispatch (UCED) model is run on a series of energy system scenarios.

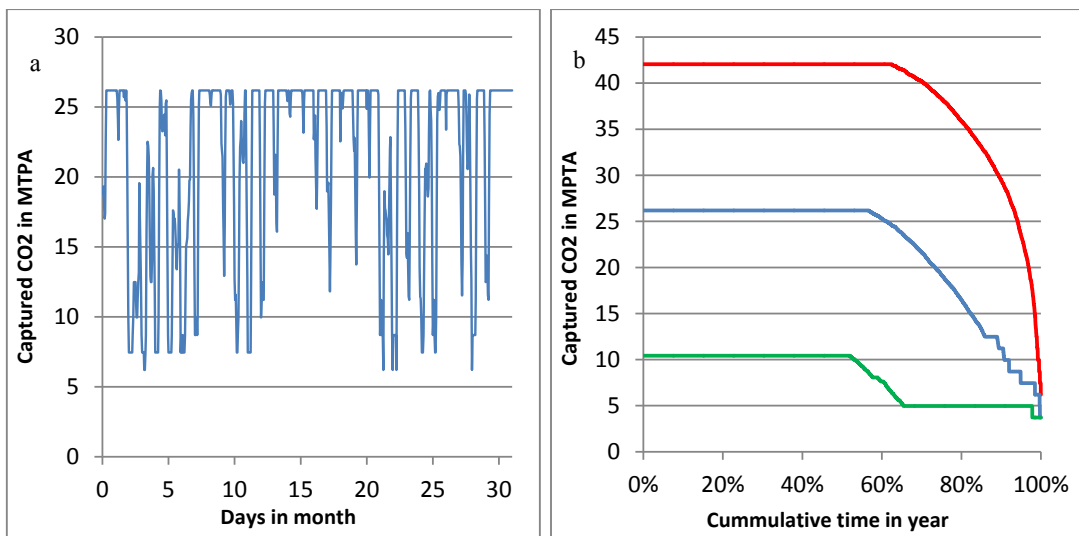


Figure 1.

- (a) CO₂ flows captured by CCS power stations over representative month of October in reference year.
 (b) Duration curve of captured CO₂ for 15GW (red), 30GW (blue), 45GW (green) of installed wind capacity in reference year.

The model, which was originally developed by Bruce [1,2,3], is run for a test system that is similar to plausible futures for the UK electricity system, including nuclear power capacity predictions of UK Government Department for Energy and Climate Change (DECC) [4] for 2035. Gas based capacity (Natural Gas Combined Cycle and Open Cycle Gas Turbine generators NGCC and OCGT) was added to the thermal power generation fleet to achieve a thermal capacity margin of 15% compared to the UK demand peak of 2002-2010. Highly accurate historical wind data and electricity demand data of the UK from 2004 from Bruce [1] and [5] serve as input data for the reference

scenario in this paper. The year 2004 represents an average windy year within a dataset containing data of 2002-2010 and is, therefore, suitable to provide an illustrative test case for this work. 30GW of installed wind capacity is assumed in the base case, with sensitivities of 15GW and 45GW installed capacity also considered.

9GW of CCS capacity has been implemented in the base cases corresponding to an annual average emission intensity of electricity generation of 100g/kWh, which represents a significant drop from around 420g/kWh in the UK in 2015 [4] on the way to an intended CO₂ emission intensity of around 65g/kWh by 2050 [4]. In the sensitivity cases, CCS capacity is adjusted to achieve a consistent annual average CO₂ emission intensity of around 100g/kWh. This leads to 14.4GW and 3.6GW of CCS capacity implemented in the 15GW and 45GW of installed wind capacity scenarios, respectively. Post-combustion capture (PCC) and a capture rate of 90% is assumed for CCS power stations. For further technical, economic and techno-economic input data the reader is referred to the appendix and to [1].

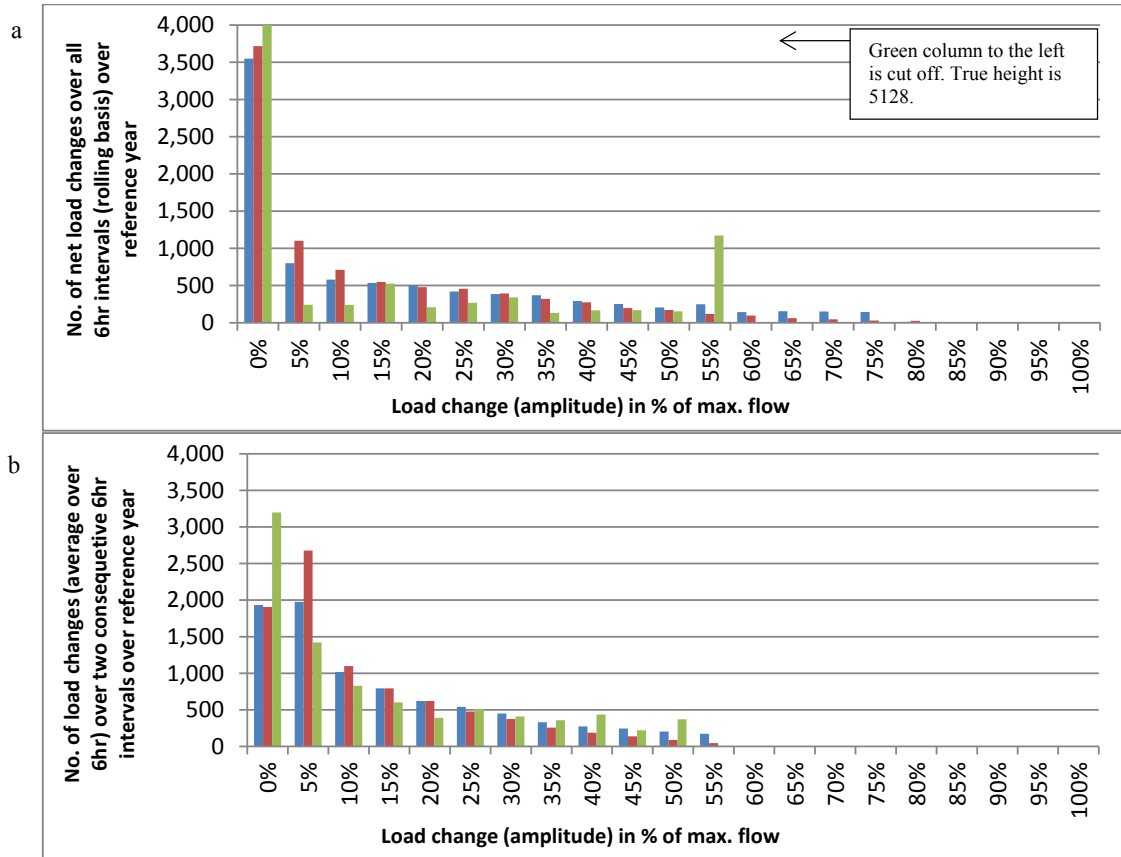


Figure 2.

- (a) Number and amplitude of net changes in CO₂ captured by CCS power stations over 6h intervals (on a rolling basis) over base year, for 15GW (red), 30GW (blue), 45GW (green) of installed wind capacity.
- (b) Number and amplitude of changes in average amount of CO₂ captured by CCS power stations over two consecutive 6h time intervals over the reference year (on a rolling basis), for 15GW (red), 30GW (blue), 45GW (green) of installed wind capacity.

Figures 1a-2b characterize the resulting CO₂ streams captured by all CCS power plants in the respective scenarios after the UCED model has been run to determine which power plants will be operated to meet demand on an hour-by-hour basis.

Figure 1a shows the time profile of the captured CO₂ (in Million Tons Per Annum, MTPA) over the representative month of October in the reference year. A pattern similar in nature to the electricity load profile can

be recognised, once corrections for part-load efficiency losses of the underlying power stations have been considered. Large fluctuations in produced CO₂ streams can be seen occurring on a daily basis.

Figure 1b shows the duration profiles of captured CO₂ flows at the inlet of a T&S network for 15GW, 30GW, 45GW of installed wind capacity. It can be seen that for 52-60% of the year (depending on wind capacity scenario) the CO₂ capture plants deliver the nominal amount of CO₂. For the rest of the year the capture plants deliver an amount of CO₂ between the nominal and a minimum level.

Figures 2a and 2b illustrate the variability of the CO₂ flows captured by the CCS power stations over the reference year. Figure 2a shows the number and amplitude of the net changes in captured CO₂ over all 6hr time intervals (on a 'rolling' basis) over the reference year for the base case as well as the sensitivity cases. It can be seen that 27% of all net load changes over 6hr periods in the base case are greater than 30% of the nominal flow, and 12% of all net load changes have an amplitude greater than 50% of the nominal flow.

Figure 2b shows the number and amplitude of the average changes in the amount of CO₂ produced by the CO₂ capture plants over two consecutive 6hr time intervals in the base case as well as in the sensitivity cases. Looking at the 6hr average of captured CO₂ flows it can be seen that still 25% of the load changes in the base case are greater than 25% of nominal flow and 10% of the changes have amplitude of at least 40% of nominal flow.

These results demonstrate that unless CO₂ flows are balanced within CCS power plants, CO₂ T&S networks will need to be able to accommodate significant and regular variations in feed-flows.

3. Issues associated with flexible operation along the CO₂ T&S system

Having highlighted the likely variability of CO₂ flows feeding into future T&S networks, the remainder of the paper focuses on discussing the issues associated with flexible operation of CO₂ T&S networks (e.g. regular ramping), as well as the operating and design options that exist to mitigate these risks. CO₂ T&S systems can be divided conceptually into 3 subsystems responsible for: transportation, injection and storage.

The means of transportation commonly considered are by pipeline and by ship. It is generally agreed that for longer distances and smaller quantities shipping is more cost efficient, whilst transportation via pipeline is more cost efficient for larger quantities and for smaller distances [6,7]. The following discussion takes transportation via pipeline as the baseline scenario. Many of the discussed issues and options are, however, applicable to systems based on ship transportation.

Pipeline based transportation systems frequently have booster stations along the system to ensure that pressures remain within certain design bounds throughout the network. Pipeline transportation is usually performed in single phase (either in gas or liquid/dense phase) to minimize operational difficulties. For the purpose of this study transportation in dense phase is taken as the reference case.

After a thorough literature review and interaction with the FEED study team of the White Rose CCS demonstration project in the UK [8], CO₂ injection wells have been identified as the components in the process chain that potentially have most difficulties with large and regular variations in CO₂ flow rates. These are, therefore, discussed in detail in the next section.

The following sub-sections give a brief overview of the limitations associated with flexible operation of the transportation and storage parts of the system.

3.1. Transportation system (pipelines & booster stations)

A significant aspect of pipeline flow assurance is typically concerned with ensuring single phase of the fluid. Multi-phase flow can lead to slug flow and accumulation of individual components of the mixture with characteristics that can endanger safe and continuous operation (e.g. corrosion, blockage of pipe [9]). Free water can lead to hydrate formation at low temperatures [10] which can clog flow paths and is difficult and time consuming to remove. Accumulation of certain volatile components such as H₂ and H₂S at bends of the pipeline can lead to increased corrosion and embrittlement of the material [11].

For ensuring safe and continuous operation of the pipeline at single phase flow, the fluid must be kept within certain pressure bands dictated by the pipeline design (e.g. pipeline strength) on the high end and by the phase

envelope of the mixture on the low end. Further, maximum flow limits must be respected to avoid fluid velocities that lead to excessive erosion [12].

Booster station compressors have ramp limits, maximum flow limits and surge limits. When several compressors are used in parallel their operation can be coordinated. When flow rates are dropping to low relative levels, compressors can be switched off sequentially in systems where multiple compressors are used, which increases the flow span over which the compression system can operate whilst respecting surge limits and avoiding CO₂ recycling.

3.2. Reservoir

Looking at CO₂ storage it is known that cyclic injection into saline aquifers can lead to halite precipitation in the near wellbore region that reduces injectivity significantly [8,13]. The water of the brine dissolves CO₂ and leaves behind salt precipitate in the pores when the water is pressed into the reservoir by the incoming stream of CO₂. Brine then pushes back to the near wellbore zone when injection of CO₂ has been interrupted or flow rate has been decreased. This phenomenon is particularly pronounced in stores in which the CO₂ plume migrates away from the near well bore due to its buoyancy [8]. Over many injection/shut-in cycles accumulation of halite precipitation can cause injectivity of the store to decrease. Although this phenomenon can be remediated through water wash intervention, restoring the full initial injectivity again once halite build up has started is difficult.

As a further constraint to flexible operation, near wellbore pressure levels need to be constrained during injection to avoid endangering caprock integrity. This automatically leads to maximum injection flow limits.

It should also be noted, however, that an appropriate storage site development can promote a store's ability to operate in a cyclic manner (e.g. wells are drilled in a manner that restricts the CO₂ plume to migrate away from the near wellbore region) [8].

4. Issues associated with regular CO₂ injection well cycling

As discussed in the previous section large components of a typical CCS system include the power stations with CO₂ capture facility, transportation pipelines, injection wells and reservoirs. A small, however, very central part of the system is the wellhead choke valve, which is located between the pipeline(s) and the injection well(s). It is used to control the pressure upstream in the pipeline and indirectly controls the flow rate into the injection well. The pressure downstream of the valve at the wellhead cannot be controlled directly but is governed by the reservoir pressure, the static pressure drop over the CO₂ column in the well, and the dynamic backpressure in the well when injecting CO₂, which is a function of the load and reservoir characteristics. When the pressures upstream and downstream of the valve differ, and the downstream pressure is lower there is a pressure drop taking place across the valve, which comes along with a Joule-Thomson (JT) cooling effect. If downstream pressures are low and the CO₂ at the wellhead is gaseous, for example at low loads due to a reduced backpressure in the pipe or due to low reservoir pressures, there is a phase change occurring across the valve. The CO₂ then at least partially flashes into the gaseous state, which leads to a very strong cooling effect and two-phase flow in the injection well (considerably higher JT coefficient and cooling effect of gaseous compared to liquid CO₂ [14]).

Figure 3b shows illustrative pressure drops and the resulting temperature of pure CO₂ flashing isenthalpic for example over the wellhead choke valve (no heat exchange with the environment is considered). It can be seen that a flash of CO₂ from 6°C and 42bar to 15bar leads to temperatures of around -28°C. This cooling effect is a major driver of the risks associated with regular injection well cycling.

4.1. Clathrate hydrate formation:

Clathrate hydrates are crystalline solid inclusion compounds in which small guest molecules (typically gases) are trapped in cages of hydrogen bonded water molecules [15]. Under high pressure and low temperature and a sufficiently high water concentration (i.e. with free water present in the flow) hydrates can form that consist of CO₂ molecules trapped in a water based lattice [16]. There are three known common hydrate structures (type 1, type 2, type H; [17]). Carbon dioxide usually forms type I hydrate structures [17].

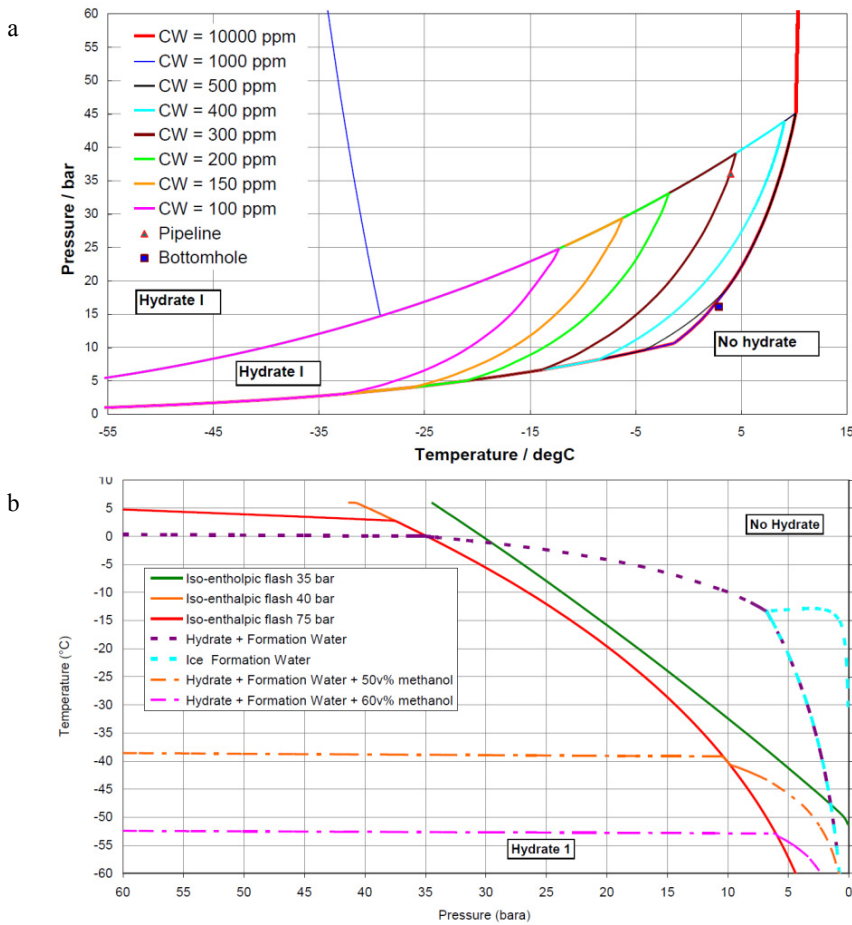


Figure 3. (a) Comparing JT Curves and Hydrate formation areas for different concentrations of condensed water (CW); (b) Hydrate Formation zones for different water concentrations [14].

Figure 3a illustrates for different condensed water (CW) concentrations in the CO₂ the pressure-temperature regions under which hydrates (class 1) can form (i.e. see within/to the left of solid lines). Figure 3b shows the temperature drop caused by an isenthalpic flash/pressure drop of pure CO₂ from 6°C and various pressures (see red, green, and orange solid lines; e.g.: over the wellhead choke valve however neglecting heat exchange taking place with the environment). The figure further shows the pressure-temperature areas in which hydrates can form when CO₂ comes into contact with formation water (in this example considered in development work for the Kingsnorth CCS demonstration project [14]) mixed with different concentrations of Methanol, which can be injected as a hydrate formation inhibitor. Looking at the isenthalpic flash curves in figure 2b (i.e. solid red, orange and green lines) it can be seen that the risk of low temperatures and hydrate formation is biggest when the pressure drop across the well head choke valve is largest. This happens at low loads (i.e. start-ups, shut-downs, continuous operation at low loads) when pressures downstream of the valve at the wellhead are low, due to the reduced (or missing) backpressures in the well.

When hydrates form they can plug flow paths and interrupt operation [18, 19], which can be very costly even for short amounts of time [8]. Once they have formed and clog flow paths they are difficult and time consuming to remove.

4.2. Cracking of cement and wellbore materials (JT-cooling):

When operating regularly in the two-phase region of the well (i.e. with flashing taking place across the wellhead choke valve due to low pressures at the well head; e.g. during cycling or continuous operation at low loads) the well completion (i.e. installation placed by engineers in the borehole to make the well ready for operation) material is exposed to large temperature variations. These thermal load and temperature changes have a significant effect on near wellbore casing, cement and formation stresses. Over time the steel, cement and rock will repeatedly expand and contract in volume and also relative to each other due to different thermal expansion coefficients [20]. This can create and enlarge fractures, fissures and radial cracking threatening the integrity of the well completion over the desired infrastructure lifetime [8,20,21].

4.3. Hydrogen induced embrittlement of well material:

When CO₂ flashes across the wellhead choke valve due to low pressures at the wellhead, the concentration of volatile components of the mixture in the gas phase increases. This can lead to problems related to increased concentrations of H₂S and H₂ that can lead to corrosion and hydrogen induced embrittlement of the well material [8]. Atomic hydrogen can penetrate into the well material and accumulate at cracks reforming to H₂ [22]. This will increase the local pressure in the material which can promote cracking of the material [22]. It also makes the material more susceptible to fatigue failure [23]. However, H₂ and H₂S are only expected in CO₂ flows from pre-combustion power plants [24]. For CO₂ from post-combustion power plants and oxy-fuel plants this phenomenon is not expected to represent a risk.

4.4. Oscillations and vibrations:

Vibrations can be classified into steady-state and dynamic transient vibrations of which the dynamic transient vibrations are usually more severe [25]. The increased requirement for ramping amplifies the risk associated with transient vibrations and oscillations. This is particularly the case when flashing happens across the wellhead choke valve as it leads to large changes in fluid velocity and density over the valve, or when operating the wellhead with pressures and temperatures close to the critical point [8].

4.5. Reduced lifetime due to cyclic thermal stresses:

The above effects can lead to reduced lifetimes of CO₂ injection wells. However, given the relatively few and recent projects injecting CO₂ into geological formations for storage there is, to the knowledge of the authors, no data publically available regarding lifetime reductions.

Reduced lifetimes of injection wells would directly lead to additional costs of the system. These would be incurred either through the need for additional maintenance efforts (e.g. more work overs), or the requirement for drilling and installing more wells for injection given their reduced lifetimes.

In the end, these additional costs need to be compared to the costs of mitigating the lifetime hampering processes and effects. This can be done either through balancing of CO₂ flows upstream in the network, or by enabling the wells to cope better with CO₂ flow variability.

5. Operating and design solutions to overcome CO₂ injection well cycling issues

Having outlined the issues associated with regular CO₂ injection well cycling this section presents options with which these issues can be overcome. They can be classified into operational and well completion design options. These are addressed in Sections 5.1 and 5.2 respectively. Section 5.3 then reviews reliability and costs for inflow control valves.

5.1. Operating solutions

5.1.1. Optimal start-up and shut-down time

During shut-in and at low loads when the backpressure in the well from CO₂ injection is either low or missing, a gas cap can develop at the wellhead (depending on depth and pressure of the reservoir). When passing through this state of the system during start-up and shut-down, CO₂ will flash across the wellhead choke valve, which comes along with the strong JT cooling effect that can endanger the integrity of the well.

During this transient phase the temperature of the completion material is dominated by the interplay of the heat exchanged with the CO₂ through convection, and the heat exchanged with the surrounding materials (e.g. casing, cement, rock) through conduction. There exists an optimum start-up and shut-down time that minimizes the temperature drop of the well material. This optimal time is a trade-off between allowing enough time for the heat-exchange with the environment to occur on the one hand, and limiting the time to avoid well completion and surroundings to be cooled off by the CO₂ on the other hand, as this would reduce the heat-exchange through conduction. [21]

However, this strategy is only suitable during start-up and shut-down operation and not when there is a need for continuous operation at low loads, when flashing is taking place across the wellhead choke valve, due to the small amounts of CO₂ supplied by the sources upstream in the network.

5.1.2. Addition of MEG or Methanol

Monoethyleneglycol (MEG) and Methanol are hydrate formation inhibitors. Their addition shifts the hydrate formation area of the mixture to higher pressures and lower temperatures. The substances can be added to the CO₂ mixture before injection in order to avoid the risk of hydrates forming in the injection well due to low temperatures [19,26]. It should be noted, however, that the continuous injection of MEG and Methanol during operation at low-loads when flashing is taking place across the well-head choke valve is likely to be economically unviable, particularly when injection is taking place off-shore.

5.1.3. Additional injection of nitrogen

In order to minimize flashing when a gas cap has developed at the top of the well, additional amounts of nitrogen can be injected. By increasing the total flow rate through the well and into the reservoir the backpressure in the well is increased. When injecting sufficient amounts of nitrogen single phase flow can be ensured at the wellhead, preventing flashing and avoiding the associated risks. Again, the additional injection of nitrogen over extended periods of time is likely to be economically infeasible, particularly for offshore operation.

5.2. Design solutions

Several design solutions exist that can be deployed to prevent flashing taking place across the wellhead choke valve and avoid associated risks. They all apply the same basic principle of increasing the backpressure in the well completion in order to prevent two-phase flow. Generally the options can also be combined in new tailor made designs. However, due to higher risks associated with more complex design solutions, and high costs associated with well interventions if they are required, a general consensus seems to be to design early CO₂ injection wells with as little complexity and related scope for failures as possible.

5.2.1. Downstream remotely actuated ball valve

Ball valves can be installed in the completion, for example at the lower end of the upper completion, which can be used to increase the backpressure in the upstream well at lower loads by controlling the flow rates. They can also be used to isolate the pressure in the upper well completion from the reservoir pressure during shut-in. In this way the formation of a gas cap at the wellhead can be prevented at all loads and the associated risks can be avoided. Ball valves can be remotely actuated [26]. As additional components in the well completion they add complexity and cost to the completion. Along with the increased complexity comes an inherent additional risk of failure [8,26].

5.2.2. Remotely actuated sliding sleeves

Similarly to ball valves sliding sleeves can be used to manipulate the flow through the well completion, and through individual isolated injection zones in the reservoir. This flow control again can be useful for controlling the backpressure in the upper completion at low loads or during shut-in. Sliding sleeves can be operated remotely, either electrically, hydraulically or in combination [27, 28]. They can have binary, multiple or continuous opening positions [27, 28]. Again, the increased complexity of the configuration leads to higher costs of the completion. The moving parts in the corrosive and exposed environment deep underground further represent a risk of failure inherent to the configuration [8,26].

5.2.3. Multilateral wells

Multilateral wells consist of a mother well and several well laterals branching off into different parts of the reservoir. ICVs (i.e.: Inflow Control Valves (e.g.: ball valves, sliding sleeves) can be used to control the flow of CO₂ through the individual well laterals. ICVs can currently, however, only be installed in the well's mother bore and not in the laterals [29]. Given the inherent reliability issues of moving parts (i.e. valves) in the well completion it might make sense to spread the risk by making several flowpaths available. Multilateral wells come, however, at a significantly increased cost, complexity and integrity risk of the configuration [8,27].

5.2.4. Dual or multiple tubing string completion

The multiple string completion consists of several tubing strings in the same wellbore casing. The tubing strings can be arranged in parallel or concentrically in another [26, 27]. They can be closed in and operated independently from each other [8]. This allows injecting CO₂ into two independent tubing strings with smaller effective diameters. The backpressure in the strings will increase due to a larger relative surface exposure of the CO₂ in two independent tubing strings leading to increased friction. This enables single phase operation at lower loads. At very low loads one tubing string can be shut-in, with operation in the remaining tubing string being closer to its respective design point, minimizing the operating loads at which flashing takes place across the wellhead choke valve.

5.3. Reliability and cost data for Inflow Control Valves

A major concern regarding the deployment of subsurface, remotely controllable ICVs is related to their reliability performance. The increased design complexity of well completions with ICVs increases the risks associated with failures. This is particularly due to the nature of ICVs as moving parts in the subsurface in a potentially corrosive environment where intervention and work-over costs are high. For example, rig hire for the White Rose CCS demonstration project was estimated at around 155,000-255,000£/day [30]. However, reliability data in the publically available literature is scarce. There is only limited data available:

- Mitchel et al. [31] state that when excluding the first installations in the statistics, the survivability rate of the ICVs installed in the Snorre (oil & gas) field in Norway is approximately 85% over a time period of approximately 10 years;
- Al-Khelaiwi [29] suggests that the 5-year survivability for the ICV system is currently 96% for the all-hydraulic control system; and
- Further, an average reliability of 90% was found for a large sample of intelligent wells (oil & gas wells) [28].

It must be noted, however, that this data has been gathered for ICVs operating in a significantly different environment. While the data represents ICVs installed in oil & gas extraction wells that are usually operated on a basis of several months or years [28,31], ICVs for CO₂ injection would face a considerably changed working environment and potentially much more frequent usage (e.g. daily: see variable flow rates in Figure 1a and associated discussion in Section 2). Further, due to the high intervention and work-over costs (particularly offshore) ICVs for CO₂ injection are likely to be required to operate largely maintenance free over the intended infrastructure lifetimes of 30-40 years in order to be economically viable. Whether this can be achieved with further technological advancements on ICVs is yet to be found.

Cost data on ICVs is similarly scarce in the literature. Several sources estimate the typical cost of integrating an ICV into a well completion over the large span of 0.5-2.1M\$ [29, 32, 33]. This suggests that the equipment costs for installing ICVs are relatively small compared to the overall costs of wells (costs for drilling and completing 3 wells for the White Rose project was estimated at 68.3M£ [34]; injection infrastructure capital costs at the Kingsnorth UK demonstration project were estimated at 94.3M£ in the central case within a FEED study [30]). The costs are however increased by a longer installation time required for installing the system (e.g.: around 0.5M\$/day [32]). The largest cost contributions could nevertheless be the increased insurance costs and/or increased work-over costs due to the potentially lower reliability of the system [8].

6. Alternative options to deal with CO₂ feed-flow variability: Balancing flows

There are other options to mitigate risks associated with large and regular fluctuations in CO₂ feed flows to the T&S system, which need to be considered as alternatives to making changes in the design and/or operation of CO₂ injection wells. They consist of reducing the flow variability by balancing CO₂ flows upstream in the system.

6.1. Interim CO₂ storage opportunities within power stations or T&S networks

To some extent CO₂ can be buffered in the transportation pipelines through line-packing. Line-packing refers to the action of increasing (decreasing) the pressure levels in the pipeline in order to 'pack' more (or less) of the fluid into the pipeline by compressing (decompressing) it. Line-packing is performed by controlling the flow out of the CO₂ T&S system by a downstream throttling valve (e.g. wellhead choke valve) in response to the given amounts of CO₂ feeding into the system. It can be used as an additional degree of freedom to smooth out CO₂ flow fluctuations for the downstream injection wells. The balancing capacity of this technique is determined by the length of the pipeline, by the maximum operating as well as minimum operating pressures of the pipeline (e.g. to sustain single phase flow), and by temperature and composition of the fluid amongst other things.

Further, there exists the option of storing CO₂ for balancing purposes either within the boundaries of the power plant once it has reached the required quality for export to the T&S, or along the CO₂ T&S system. This can be done in large tanks, or in underground geological formations dependent on the required scale or and storage capacity [8,35]. It should be noted that the highest effective working capacity for interim storage facilities can be achieved when there is a phase change taking place when emptying the store (from liquid/dense to gaseous). However, this phase change can come with a strong cooling effect (of the released CO₂ as well as of the tank) that might limit discharge flow rates and constrain the ability of the stores to balance CO₂ flows through the T&S networks.

6.2. Solvent storage in post-combustion capture (PCC) CCS power stations

Solvent storage at PCC CCS power stations would allow the decoupling of electricity produced by the power plant and CO₂ streams produced by the CO₂ capture plant for a certain amount of time, most likely a few hours. This is achieved by storing CO₂ intermediary within the solvent in a 'rich' solvent storage tank and delaying the energy intensive step of regeneration of the rich solvent to later points in time. Operation of the capture plant is maintained by feeding lean solvent from a dedicated lean solvent tank to the system. The time over which solvent storage operation can be continuously sustained before the need for regenerating rich solvent becomes apparent is determined by the capacity of the rich and lean solvent storage tanks (for more detailed explanation see [36, 37, 38]).

There are several studies in the literature that explore the economic viability of solvent storage [39, 40]. They all focus on using solvent storage as an energy arbitrage technique that allows achieving higher profits by boosting electrical output of the power plant when electricity prices are high by storing rich solvent, and delaying the energy intensive step of solvent regeneration to a later point in time. When electricity prices and with it the opportunity costs of selling less electrical power is low the step of regenerating stored rich solvent is performed. The literature suggests that solvent storage can lead to additional profits in jurisdictions with large and frequent fluctuations in electricity prices, particular for small storage tank capacities (Cohen [39] suggests optimal storage capacity for 15-30min of storage operation).

By storing CO₂ within the solvent in rich solvent containers, CO₂ flows exported from the capture plant to the T&S system can be smoothed out. The potential value of solvent storage as a CO₂ flow balancing option have, to the knowledge of the authors, not yet been fully explored in the literature.

6.3. Liquid oxygen (LOx) storage at oxy-fuel combustion and pre-combustion CCS power stations

Similarly to solvent storage there is a very energy intensive step, i.e. the production of pure oxygen in the Air Separation Unit (ASU) that can be decoupled to some extent from the main power generation process. This is particularly the case for many oxy-fuel combustion options and to a lesser extent for at least some pre-combustion capture power plant options. Several operating patterns could be considered. For example, the installation of an oxygen interim storage tank allows operating the ASU at high loads, producing significant amounts of pure oxygen and consuming large amounts of power from the electricity generation unit, while simultaneously running the power plant at low loads (e.g. minimum stable generation). In this way it is possible to sustain a substantial flow of CO₂ to the T&S system (e.g. 25-35% of maximum flow), while exporting only small amounts of power to the electricity grid, due to the ASU consuming large amounts if not all of the power locally produced by the power generation unit. Similarly, the ASU unit can be shut-down (ramped down) whilst running the power generation unit at higher load. By using previously stored liquid oxygen less power is consumed by the ASU while maximum fuel input is sustained. This boosts electricity output when required, for example at peak demand periods for balancing the electricity network, while the nominal feed flow rate of CO₂ to the T&S system is maintained. This characteristic makes oxy-fuel (and to a lesser extent pre-combustion capture) CCS power stations well suited for balancing CO₂ flows feeding into the T&S networks. The CO₂ flow balancing capacity of oxy-fuel power plants is limited by the available liquid oxygen storage volumes and the power consumption of the ASU.

As described by Capture Power [41], the White Rose oxy-fuel power plant design developed with financial support from the UK Government and others had a design minimum stable load level of ~25% of nominal power production. When the ASU is simultaneously ramped up to full load there is almost no power exchange with the electricity grid while significant (e.g. likely around 25-35% of nominal flow) CO₂ feed flow rates are maintained to the T&S system. This operational state can be sustained for around 8h before the design LOx storage vessel reaches full capacity for the design developed for this project.

6.4. Hydrogen storage at pre-combustion capture IGCC power stations:

Pre-combustion involves reacting a fuel with air (or oxygen) and/or steam to produce a synthesis gas (syngas) that is composed of carbon monoxide and hydrogen [42]. Once the carbon components are captured in an energy intensive process there remains a mixture of (nearly) pure hydrogen that is combusted in the power generation unit of the plant. Similarly to the methods above a hydrogen buffer tank can be used to decouple some of the more energy intensive aspects of the CO₂ capture process from the time of electricity generation. In particular, the 'CO₂ producing' step of CO₂ capture can be decoupled from the rest of the power generating unit, assuming that the plant is designed to allow this flexibility. This again allows CO₂ feed flow rates to the T&S networks to be less volatile by decoupling the operation of the gasifier and pre-combustion capture process from the delivery of electricity.

7. Conclusion

This paper begins with an exploration of the extent to which CCS power stations may be required to load follow, i.e. operate with variable electricity output, in future electricity system scenarios using a UK-based case study. The amount of load following will determine the variability of CO₂ flows that need to be accommodated by the future CO₂ T&S systems.

The analysis shows that across all considered scenarios there are significant and regular fluctuations of CO₂ flows that are produced by CCS power plants. By examining the fluctuations in captured CO₂ streams the study finds that 27% of all net changes over 6hr-periods in the reference scenario are greater than 30% of the nominal flow, and 12% of the changes are greater than 50% of the nominal flow. The analysis highlights the requirement for future CO₂ T&S networks to operate in a flexible manner. This finding stands in contrast to a limited amount of literature

available in the public domain investigating the ability of CO₂ T&S networks to respond to fast and frequent load changes.

The paper addresses this identified gap in the literature and discusses the risks associated with flexible operation of T&S networks, with a particular focus on the injection wells as the potentially least flexible part of the system. It further presents operating and design solutions for mitigating these risks. While operating costs of the operating solution for extensive cyclic operation, particularly for offshore operation seem economically challenging, the design options lack robust reliability data for their main components (i.e. inlet control valves) over the long term. Failing ICVs would lead to very high follow up costs for well interventions, particularly offshore.

Finally, further options are discussed to mitigate risks associated with CO₂ flow variability that consist of balancing CO₂ flows upstream in the networks through the use of interim storage options.

Although this paper outlines several options to allow successful design and operation of flexible CCS systems, it does not provide a complete analysis of the most cost-effective way of enabling the system to deal better with CO₂ flow variability. These costs in turn need to be compared to the additional costs of operating the system without making any special provisions for flexible operation (provided this is possible; higher costs associated with wear and shorter lifetimes of the equipment likely). Further, the costs of available energy (electricity) storage options should be considered as an alternative way to mitigate variable operation of CCS plants.

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Appendix

This section summarises further relevant technical, economic and techno-economic input parameters used for performing the UCED simulations.

The thermal generation fleet consists of nuclear power plants, Natural Gas Combined Cycle (NGCC) and Open Cycle Gas Turbine (OCGT) power stations. 15GW of nuclear capacity is assumed based on DECCs baseline scenario for 2035 [4]. Gas based capacity (i.e. from NGCC and OCGT power stations) is assumed to be 71.4GW. This corresponds to a thermal capacity margin of 15% compared to the peak demand in the available dataset (summarises data from 2002-2010). The divide of NGCC and OCGT capacity is determined in each scenario iteratively by the constraint for NGCC plants to have a minimum capacity factor of 40%. This constraint is set to avoid excessive provision of comparatively expensive NGCC capacity (compared to OCGT capacity) to provide relatively small amounts of power. The remainder of gas capacity is provided by OCGT generators. CCS is assumed to be fitted on the required amount of NGCC plants with highest full load efficiencies that allows reaching a CO₂ emission intensity of 100g/kWh in the respective scenarios.

Table 1 presents full load efficiency (LHV) data for the assumed thermal generation fleet. Nuclear efficiency data is taken from [1] and efficiencies for NGCCs and OCGTs are based on [43, 44]. Full load efficiency data for NGCC and OCGT plants is interpolated between the upper and lower limits to represent gradual technological advancements. Part load efficiency curves are based on [44].

Table 1. Efficiency data for thermal generation fleet.

Type	LHV efficiency range
Nuclear power plants	36.7%
Natural Gas Combined Cycles (NGCCs)	59.5 - 62.1%
Open Cycle Gas Turbines (OCGTs)	37.5 - 41.8%

15GW of minimum thermal load is assumed at each point in time, similarly to [1], in order to meet the requirements of operating reserve and to limit the rate of change of frequency (RoCoF) after a large generation outage. Reserve requirements are set to 3.5 standard deviations to cover any unexpected changes in demand-wind forecast uncertainty in 99.95% of the events. This corresponds to a reliability standard for security of supply of 3hr per year, using the Loss of Load Expectation risk metric [45]. Spinning reserve requirements are set to be 1.5 standard deviations based on [46].

Fuel costs and CO₂ prices are assumed as presented in Table 2. Further technical, economic and techno-economic data is based on [1].

Table 2. Fuel and CO₂ prices.

Natural Gas	23.2£/MWh _{th}
Uranium	3.0£/MWh _{th}
CO ₂	78.5£/kg

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