EPRG WORKING PAPER

The economic value of flexible CCS in net-zero electricity systems: The case of the UK

EPRG Working Paper 2308

Cambridge Working Paper in Economics 2336

Chi Kong Chyong, David M Reiner, Rebecca Ly, Mathilde Fajardy

Abstract

We build a unit-commitment optimisation model of a flexible combined-cycle gas turbine (CCGT) with solvent-based post-combustion carbon capture and storage (CCS). We derive the economic benefits of CCS with solvent storage for a 20-year investment (2030-2050) based on the expected long-term increase in carbon prices and the volatility of electricity prices. Drawing on National Grid's Future Energy Scenarios for the UK, our model shows that the CCGT-CCS plant profit is, on average, higher with solvent storage because of intertemporal arbitrage opportunities created by having this storage solution available. We find that the economic value of this intertemporal flexibility increases with greater electricity price volatility. Under high price volatility, the total return on investment (ROI) could reach 81-246%. In relative terms, this is much higher than the total ROI of the CCGT-CCS plant itself (7-64%). While there is an economic case for investing in flexible CCS with solvent storage, there are wider system benefits too. A flexible solvent storage solution should be seen in the context of the overall system 'flexibility' requirements of a low-carbon power system. On a cost basis, solvent storage represents just a fraction of the capital costs of more "mainstream" energy storage technologies, such as lithium-ion batteries or hydro pumped storage, while CCGT-CCS offers *firm* power. Overall, while seen as a rather technical solution, if abated fossil fuel generation is to be part of a future low-carbon power system having this flexibility adds economic benefits not just to operators but also improves overall system security and complements high shares of variable renewables on the grid.

Keywords Combined-cycle gas turbines, Carbon capture and storage, unit-commitment models, optimisation, flexible carbon capture, solvent storage

JEL Classification C61, Q47, Q48, Q52, Q55

Contact kc3634@columbia.edu
Publication April 2023
Financial Support N/A

The economic value of flexible CCS in net-zero electricity systems: The case of the UK

Chi Kong Chyong[a1], David M. Reiner*, Rebecca Ly*, Mathilde Fajardy*
[a]*Center on Global Energy Policy, School of International and Public Affairs, Columbia University & EPRG, University of Cambridge*
**Energy Policy Research Group, Judge Business School, University of Cambridge,*
Corresponding authors: kc3634@columbia.edu; d.reiner@jbs.cam.ac.uk

1. Highlights

- Solvent storage allows flexible CCS to obtain potentially higher profits from volatile low-carbon electricity markets
- Total return on investment (ROI) from solvent storage is much higher than the ROI of abated CCGT alone
- Cost of solvent storage is a fraction of the capital costs of many "mainstream" energy storage technologies while providing *firm* power
- Flexible CCS with solvent storage provides not just economic benefits to investors but improves overall system security and helps integrate variable renewables

2. Abstract

We build a unit-commitment optimisation model of a flexible combined-cycle gas turbine (CCGT) with solvent-based post-combustion carbon capture and storage (CCS). We derive the economic benefits of CCS with solvent storage for a 20-year investment (2030-2050) based on the expected long-term increase in carbon prices and the volatility of electricity prices. Drawing on National Grid's Future Energy Scenarios for the UK, our model shows that the CCGT-CCS plant profit is, on average, higher with solvent storage because of intertemporal arbitrage opportunities created by having this storage solution available. We find that the economic value of this intertemporal flexibility increases with greater electricity price volatility. Under high price volatility, the total return on investment (ROI) could reach 81-246%. In relative terms, this is much higher than the total ROI of the CCGT-CCS plant itself (7-64%). While there is an economic case for investing in flexible CCS with solvent storage, there are wider system benefits too. A flexible solvent storage solution should be seen in the context of the overall system 'flexibility' requirements of a low-carbon power system. On a cost basis, solvent storage represents just a fraction of the capital costs of more "mainstream" energy storage technologies, such as lithium-ion batteries or hydro pumped storage, while CCGT-CCS offers *firm* power. Overall, while seen as a rather technical solution, if abated fossil fuel generation is to be part of a future low-carbon power system having this flexibility adds economic benefits not just to operators but also improves overall system security and complements high shares of variable renewables on the grid.

JEL classification: C61, Q47, Q48, Q52, Q55

Keywords: CCGT, CCS, unit-commitment, optimisation, flexible carbon capture, storage

[1] Kong would like to thank Eduardo Italiani, a Research Assistant with the Center on Global Energy Policy at Columbia University, for his excellent help with redrafting this paper.

1. Introduction

In the context of meeting national net-zero targets, the increasing share of variable renewable energy (VRE) will impose constraints on the electricity system because of its intermittency. The costs of integrating VRE are strongly linked to the flexibility of the electricity system, in particular, the flexibility of other generators in the system (Heptonstall & Gross, 2021). Therefore, dispatchable fast ramping technologies are necessary to ensure the security of supply to meet intra-day demand variations (see, e.g., Lund et al. (2015) for a review of flexibility measures to enable high levels of VRE). Carbon capture and storage paired with either natural gas or bioenergy (BECCS) along with electrical storage technologies (e.g., lithium-ion batteries) are amongst the flexible solutions that have been discussed to support the massive roll-out of VRE (see IEA's Net Zero by 2050 scenario (IEA, 2021) as well as Brouwer et al. 2015; Gils et al., 2017; Després et al., 2017 ; Victor et al., 2018; Van Zuijlen et al., 2019; Zappa et al., 2019; Holz et al., 2021). However, the incentives to deploy flexible carbon capture and storage (CCS) on a gas plant will rely on the long-term evolution of the electricity price, its volatility and carbon price. For example, the higher the carbon price, the more profitable the deployment of CCS. But in some hours, when electricity prices are high relative to the cost of carbon emissions (e.g., due to scarcity events caused by high demand and/or low wind and solar electricity generation), incentives to capture CO_2 emissions will be lower.

Thus, the ability to maximise profits within the day lies in the CCS unit's capability to operate when electricity prices are low and switch off when electricity prices are high. If carbon prices are sufficiently low, the CCGT will vent the generated CO_2 when electricity prices are high. If carbon prices are high, the CCGT power plant must reduce its output to allocate electricity to CCS operations. The electricity penalty of flexible CCS can be shifted from periods of high electricity prices by storing the generated CO_2 to off-peak periods when electricity prices are lower. In short, having a dedicated CO_2 storage tank at the power plant fitted with CCS allows temporal arbitrage between low and high electricity price periods.

This switching ability is especially valuable as carbon price rises and electricity prices become more volatile. The CCGT can then capture extra profits by dispatching electricity instead of allocating the production to meet the CCS electricity penalty. The additional profit generated during these peak price hours increases with the level of electricity prices given constant within-day short-run marginal costs (e.g., fuel and carbon prices).

As discussed below, past studies have addressed the economic benefits of flexible carbon capture from shifting the electricity penalty to hours when electricity prices are lower. Still, to the best of our knowledge, none have looked at the contribution of flexible CCS incorporating the possibility of arbitrage between hourly electricity prices and daily fuel and carbon price dynamics. This upside economic potential lies in taking advantage of the dynamics associated with intra-day variation of electricity prices, daily fluctuations in fuel costs and the electricity penalty related to varying CO_2 capture.

We study the flexible operations of CCGT-CCS using an hourly plant-level unit commitment electricity production cost minimisation model to demonstrate the economic value of having a flexible CCS power plant. By exploring flexible CCS with storage, we allow CCS to be decoupled from the CCGT power plant in its operations. In this respect, a CCGT-CCS plant can maximise its profits by comparing the short-run marginal cost (SRMC) of CCGT (which includes fuel and carbon costs as well as variable running costs) to hourly electricity prices while the CCS unit minimises its auxiliary electricity penalty (electricity consumed to run carbon capture process at the CCGT-CCS plant) during the day. We expect that the volatility of electricity prices plays an important role in generating additional profit streams from flexible CCS operating in systems with large shares of variable renewables, thus justifying running CCGT-CCS in a flexible rather than in a baseload mode.

The rest of this paper is structured as follows. In the next section, we summarise key findings from the literature associated with our topic. Section 3 presents our research methodology, while Section 4 offers detailed discussions of obtained results. Finally, Section 5 outlines key messages and conclusions from our research as well as key assumptions and limitations and hence future research directions.

2. Literature Review

Net-zero energy systems require the electricity generation sector to be largely decarbonised and potentially provide negative emissions for hard-to-abate sectors (such as heat and energy-intensive industries). This, in turn, will require large increases in variable renewable electricity (VRE) generation (such as wind and solar) and, consequently, low-carbon dispatchable power (for a literature review of the need for flexible CCS in a 100% RES energy system, see, e e.g., Mikulčić et al. (2019)) and other flexible sources (e.g., electrical energy storage) to support a massive rollout of VRE. In what follows, we describe the two primary strategies adopted in the flexible CCS literature. We then examine the techno-economic perspective on the flexible operating strategies of CCS power plants. Finally, we briefly outline studies focusing on cost reduction strategies for CCS (e.g., arbitrage).

There are two types of flexible CCS discussed in the literature: (i) a flexible venting CCS system and (ii) a flexible storage CCS system. Works such as Rao & Rubin (2006), Ludig et al. (2011), Bruce et al. (2014), Errey et al. (2014), Manaf et al. (2016), and Singh et al. (2022) studied CCS processes of variable capture rates that optimise the marginal capture rate (tons of CO_2 captured over tons of CO_2 vented pre-capture) with respect to the additional cost of higher capture performance and electricity costs. Studies such as Domenichi et al. (2013), Mac Dowell and Shah (2015), Flø et al. (2016), Sanchez Fernandez et al. (2016), Khorshidi et al. (2016), and Cheng et al. (2022) looked at storing CO_2 inside the aqueous monoethanolamine (MEA) capture solvent during peak electricity prices and regenerated the solvent during off-peak windows. Other studies, e.g., Nimtz & Krautz (2013) and Oates et al. (2014), considered both strategies within a pulverised coal power plant. Finally, Kang et al. (2016) studied the effects of multiple CCS solvent trains in Texan and Indian electricity markets.

The techno-economic literature on flexible venting operation strategies for CCS has become increasingly granular in an effort to define the most optimal process control and market conditions. Rao & Rubin (2006) noted that previous studies had used a CO_2 capture rate of 90% with no apparent basis and thus conducted a cost optimisation of partially bypassing CCS. Their results indicated better economic performance at lower capture rates under existing market conditions. Furthermore, Ludig et al. (2011) and Bruce et al. (2014) found flexible CCS venting could be better implemented within markets with higher VRE source penetration. Errey et al. (2014) studied the cost drivers of this strategy and noted that a granular control of a flexible venting CCS decision framework would experience the maximal economic benefit. Manaf et al. (2016) provided an electricity and carbon price integrated model that optimised the solvent regenerator heat duty and, consequently, the energy penalty of the CCS. Lastly, Singh et al. (2022) studied this strategy across different electricity markets and noted that there is a need for predictive grid modelling. They also noted that flexible CCS plants would be viable on depreciated plants retrofitted with 30% cheaper CCS technology.

The possibility of CO_2-rich solvent storage improving operating profits, enhancing process flexibility, and reducing the CCS solvent regeneration energy penalty has also been explored (Jafari et al. (2022), Rua et al. (2020), Beiron et al. (2020), Szima et al. (2019), Mikulčić et al. (2019), Abdilahi et al. (2018)). For example, Mac Dowell & Shah (2015) and Cohen et al. (2011) found a relative increase in profits over inflexible systems by 10-16 % because of the electricity penalty savings during peak hours, when the CO2-rich solvent is stored instead of being regenerated. Chalmers et al. (2012) conducted a techno-economic analysis of a super-critical coal power plant with rich solvent storage in CCS to measure the short-run net cash flow based on the marginal cost of CCS and the electricity price. To maximise net cash flows, the rich solvent is stored when electricity prices are relatively high, and the stored rich solvent is regenerated during lower electricity prices. Studies exploring this strategy also agree that better profitability will come with the advent of VRE energy markets and carbon taxation (Singh et al. (2022), Cheng et al. (2022), Khorshidi et al. (2016), Luo and Wang (2016)).

With the added flexibility of both strategies, there is a need to control CO_2 capture storage and solvent regeneration. Unit commitment and economic dispatch (UCED) models have been developed by Cheng et al.

(2022) and Cohen et al. (2013). Cohen et al. (2013) used a UCED to study the energy and ancillary services value of flexible CCS operations in the US ERCOT market context. They found that und flexible CCS with solvent storage can reduce dispatch costs and provide substantial low-cost reserve capacity. Van Peteghem & Delarue (2014) developed an analytical optimisation framework and found that with well-defined peak and off-peak power prices solvent storage may improve the operation of CCS and lead to higher profits. Cheng et al. (2022) implemented a UCED to study the flexible CCS operating costs relative to inflexible CCS and no CCS in natural gas combined cycle power plants. Through their model, they also found that flexible CCS was most beneficial in comparison to the other scenarios under high carbon price scenarios.

On the other hand, Van der Weijk et al. (2014), using a European Electricity Market Model to simulate two coal-fired power stations with CCS, found that revenues were hardly affected by flexible capture rate (CO_2 venting) or solvent storage. Instead, they found that the main benefit of flexible CCS was an increase in reserve capacity provision. Their results regarding the limited impacts on revenue are specific to their assumptions about the fuel and carbon prices and generation mix they model but the benefit of flexible CCS on reserve provision is similar to findings by Cohen et al. (2013) and Craig et al. (2017a).

Zaman and Lee (2015) built a detailed post-combustion capture plant in gPROMS™ to simulate two flexible operating strategies – variable capture rate and solvent storage – and found both to be effective strategies that give the largest savings relative to the baseload operation. Their model is a detailed chemical engineering model which ignores market variables such as fuel cost (gas, electricity, and carbon price) and unit commitment decisions of the generating plant itself. Nevertheless, their findings are in line with those from the literature – flexible CCS operation has economic value. Similar results are obtained by Mechleri et al. (2017), where they optimise a CCGT-CCS system with solvent storage: high regeneration rates are observed during off-peak hours, whereas low regeneration rates and rich solvent storage are observed during peak hours.

To sum up, the existing literature suggests that: (a) the economics of CCS depends on granular process control, in particular, regenerator heat duties; (b) there is an economic benefit from running the CCS plant flexibly, especially in the context of systems with large shares of renewables and high price volatility.
Our contributions to the techno-economic and energy modelling literature are as follows:

- First, we have carried out a detailed techno-economic analysis based on a flexible CCGT-CCS model (Appendix 1) and combined it with our unit commitment, hourly economic dispatch model (§3.1) and apply this combined model to a case study of the role of flexible CCGT-CCS in different net zero scenarios for the UK. Most studies reviewed (e.g., Rao & Rubin (2006); Oates et al. (2014); Mac Dowell & Shah (2015); Mechleri et al. (2017) do not include unit commitment constraints. We also offer finer-grained analysis since we model UK net-zero scenarios with hourly granularity covering the full calendar years for 2030, 2040 and 2050.
- Second, we demonstrate how flexibility can compensate for investment costs by explaining economic drivers and the nature of this flexibility. To this end, using our model we run 72 simulations to gauge the trade-offs occurring in a flexible CCGT-CCS; in particular, we want to quantify trade-offs between price level vs price volatility impacts on the economics of a flexible CCGT-CCS plant.
- Finally, from an economic modelling perspective, our optimization model is formulated to reflect the flexibility of both CCGT and CCS and how they each respond to input costs and output prices, but the model can also be adapted to include other feed gases (e.g., biomethane) and other types of flexible CCS such as flexible carbon capture with solvent storage (our study), or a fixed carbon capture rate but with solvent storage. Compared to previous studies, the advantage of our model is that it offers the possibility of carrying out simulations of different carbon capture rates and different storage volumes to analyse the impacts on profitability and trade-off decisions. In addition, the specific decision variables for CCS can be turned off to recover a unit-commitment model for an unabated CCGT (without CCS), which would be useful in evaluating the cost of CO_2 avoided by comparing outputs with and without CCS.

3. Analytical framework

This section first presents a detailed formulation of our unit commitment and economic dispatch model applied to a CCGT-CCS plant with flexible CO_2 capture operations. We then discuss our scenarios, research design and main data inputs and assumptions.

3.1. Model Formulation

The model is set up as mixed integer linear program (MILP) and its objective is to maximise plant profit at hourly time steps subject to a set of constraints.

The set of all time periods in the modelling horizon *{1, ..., T}* is indexed by t.

3.1.1. Decision variables

		Units
q_t	Gross electricity output at time t	MWh(e)
$\hat{q}_t$	Net electricity output at time t	MWh(e)
i_t	Volume of rich solvent at time t	m^3
w_t	Volume of lean solvent at time t	m^3
u_t	Commitment status of the CCGT plant at time t (Binary variable =1 if committed, =0 otherwise)	n/a
v_t	Start-up status of the CCGT plant at time t (Binary variable =1 if starts up, =0 otherwise)	n/a
z_t	Shut-down status of the CCGT plant at time t (Binary variable =1 if shuts down, =0 otherwise)	n/a

3.1.2. Parameters – Prices and cost

P_t^{elec}	Electricity price in the day-ahead market in Great-Britain at time t	£/MWh(e)
P_t^{gas}	Natural gas price – NBP at time t	£/MWh(th)
P_t^{carbon}	UK Carbon price at time t	£/tCO_2
$Cost_t^{CO2_{TS}}$	Cost for CO_2 transport and storage	£/tCO_2
$cost^{VOpex}$	Variable operating cost of the plant	£/MWh(e)
$Cost^{SU}$	Cost of starting up	£/start
$Cost^{SD}$	Cost of shutting down	£/shut

3.1.3. Parameters – Carbon capture and storage

ε	Thermal efficiency (at LHV)	MWh (th)/MWh (e)
A	Carbon captured	tCO_2/m^3
B	Electricity penalty	MWh/m^3
ϵ	Emission intensity of the CCGT plant	tCO_2/MWh(e)
V	Volume of tank – Solvent storage	m^3
Y	Installed capacity of CCGT plant	MWh (e)
F	Maximum flow rate of solvent	m^3/h
$\bar{I}$	Maximum capture rate	% of total plant emissions

3.1.4. Parameters – Electricity generation

SU	Maximum ramp-up rate during start up	MW/h

SD	Maximum ramp-down rate during shut down	MW/h
RU	Maximum ramp-up rate when committed	MW/h
RD	Maximum ramp-down rate when committed	MW/h
$\underline{\mathrm{P}}$	Minimum stable generation	MW/h
$\overline{\mathrm{P}}$	Maximum power output	MW/h
L	Minimum down-time at the start of modelling horizon	h
G	Minimum up-time at the start of the modelling horizon	h
UT	Minimum up-time	h
DT	Minimum down-time	h

3.1.5. Objective function

The optimization problem seeks to maximise the following profit function, *Π*, of the CCGT plant:

$$\max_{\widehat{q_t}, i_t, w_t, v_t, z_t} \Pi = \sum_{t} [\widehat{q_t} P_t^e + i_t A (P_t^c - C_t^{TS}) - q_t (\epsilon P_t^{carbon} + \varepsilon P_t^{gas} + \mathrm{Cost}^{VOpex}) - v_t C^{SU} - z_t C^{SD}] \quad (1)$$

3.1.6. Constraints – Electricity output

Constraints (2-3) impose a requirement that electricity balances at each time period *t*. The net electricity output sold to the market and the electricity penalty required for carbon capture and compression is never greater than the installed capacity of the plant.

$$\forall t, q_t = \widehat{q_t} + w_t \mathrm{B} \quad (2)$$

$$\forall t, q_t \leq Y \quad (3)$$

3.1.7. Constraints – Carbon capture and storage

Constraint (4) ensures that the CCGT plant cannot clean more carbon than it generates for each time period t.

$$\forall t, i_t A \leq \bar{I}\, q_t \epsilon \quad (4)$$

It is important to note that by formulating constraint (4) as an inequality we allow the plant to capture emissions 'flexibly' instead of at constant rate, which would imply setting eq. 4 as an equality.

Constraint (5) describes the storage level of rich solvent, which is a function of inflows and outflows. The initial storage level is $s_0 = 0$.

$$\forall t, s_t = s_{t-1} + i_t - w_t \quad (5)$$

Constraint (6) sets the maximal capacity of stored rich solvent.

$$\forall t, s_t \leq \mathrm{V} \quad (6)$$

Constraint (7) imposes the condition that storage be empty at the end of the modelling period: all CO_2 captured has to be regenerated.

$$s_{t|t=T} = 0 \quad (7)$$

Constraints (8) and (9) set the limits of rich and lean solvent flow rates.

$$\forall t, i_t \leq \mathrm{F} q_t \quad (8)$$

$$\forall t, w_t \leq \mathrm{FY} \quad (9)$$

3.1.8. Constraints – Thermal generation

Equations (10) and (11) illustrate the capability of the CCGT plant to respectively ramp up and ramp-down.

$$\forall t, q_t - q_{t-1} \leq SU(2 - u_t - u_{t-1}) + RU(1 + u_{t-1} + u_t) \quad (10)$$

$$\forall t, q_{t-1} - q_t \leq SD(2 - u_t - u_{t-1}) + RD(1 - u_{t-1} + u_t) \quad (11)$$

According to constraint (12) the plant must produce at least the minimum stable generation level, which accounts for the level of spinning down reserve committed in the reserve market. Constraint (13) requires the plant to produce less than the maximum power output given committed spinning up reserve.

$$\forall t, q_t \geq u_t \underline{P} \quad (12)$$

$$\forall t, q_t \leq u_t \overline{P} \quad (13)$$

3.1.9. Constraints – Unit commitment

Equation (14) is the logical constraint related to the commitment status and start-up or shut-down status.

$$\forall t, u_t - u_{t-1} = v_t - w_t \tag{14}$$

Constraint (15) requires that the plant remain turned on for a minimum of UT hours when it is switched on.

$$\forall t \in [1 + G, T - UT + 1], \sum_{tt|tt \geq t}^{t+UT-1} u_{tt} \geq UT(u_t - t_{t-1}) \tag{15}$$

Equation (16) ensures that the unit is still turned on at the end of the modelling horizon if the number of hours by the end of modelling horizon is less than the minimum up-time.

$$\forall t \in [T - UT + 2, T], \sum_{tt|tt \geq t}^{T} (u_{tt} - [u_t - u_{t-1}]) \geq 0 \tag{16}$$

Following the same logic, constraints (17-18) require the plant to be turned off for a minimum of DT hours.

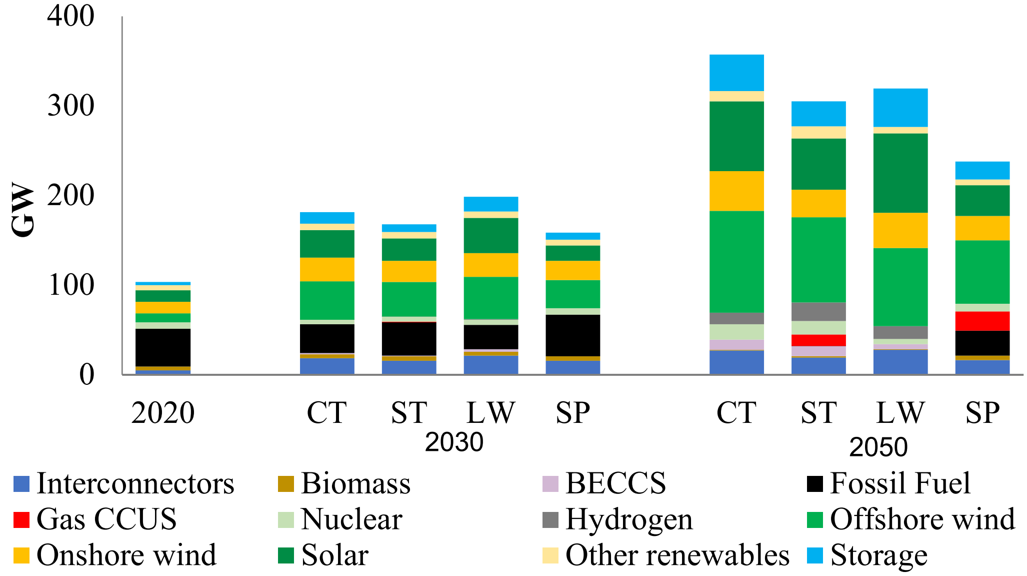
$$\forall j \in J(f), t \in [1 + L; T - DT + 1]: \quad \sum_{tt|tt \geq t}^{t+DT-1} u_{j,tt} \geq DT\left(u_{j,t-1} - u_{j,t}\right) \tag{17}$$

$$\forall t \in [T - DT + 2, T]: \quad \sum_{tt|tt \geq t}^{T} (1 - u_{tt} - [u_{t-1} - u_t]) \geq 0 \tag{18}$$

3.2. Scenarios and sensitivity analysis

We apply this model to the case of the energy transition in the UK. We calibrate our model to two National Grid Future Energy Scenarios (FES) – *System Transformation* (ST) and *Leading the Way* (LW) (National Grid ESO, 2021). The 2021 National Grid FES outline four alternative pathways for the UK's energy sector. Among the four FES, only the *Steady Progression* (SP) scenario does not meet the net zero target. FES envisage that gas CCUS will be required as early as 2030 in the ST scenario (0.80 GW) and by 2050 in both the ST (12.50 GW) and SP (21.50 GW) scenarios (Figure 1). We choose the LW scenario, as a sensitivity analysis, because the projected electricity and carbon prices under this scenario is the highest, while the ST scenario has the most ambitious CCUS plan and lower electricity and carbon prices (see Figure 2 and Annex A.2.2.). Therefore, contrasting the results from these two FES scenarios will highlight the importance of electricity and carbon price levels on the economics of flexible CCGT-CCS.

Figure 1 - Generation mix in FES 2021



Source: National Grid ESO (2021)

Thus, we run a total of 36 simulations of our model based on a 2x3x3x2 combination of five key dimensions:

(i) Two National Grid scenarios (ST and LW);
(ii) three spot years (2030, 2040 and 2050);
(iii) three sets of coefficients of variation for electricity prices (see Table 1); and
(iv) with and without the solvent storage option for the CCGT-CCS plant.

We model three spot years and therefore annual profits for 2031-2039 and 2041-2049 are estimated by linear interpolation from the 2030, 2040 and 2050 results in order to calculate the NPV of CCGT-CCS plants.
As we discussed in §2, the economics of flexible CCGT-CCS operation depends on the electricity price level, which in turn is a function of future generation mix, and importantly depends on price volatility. To address the latter factor, we assess the impact of the volatility of electricity prices on the profit function (1). We use three pairs of the coefficient of variation of electricity prices, as reported in Table 1.

Table 1: Sensitivity analysis: coefficient of variation inputs for electricity prices

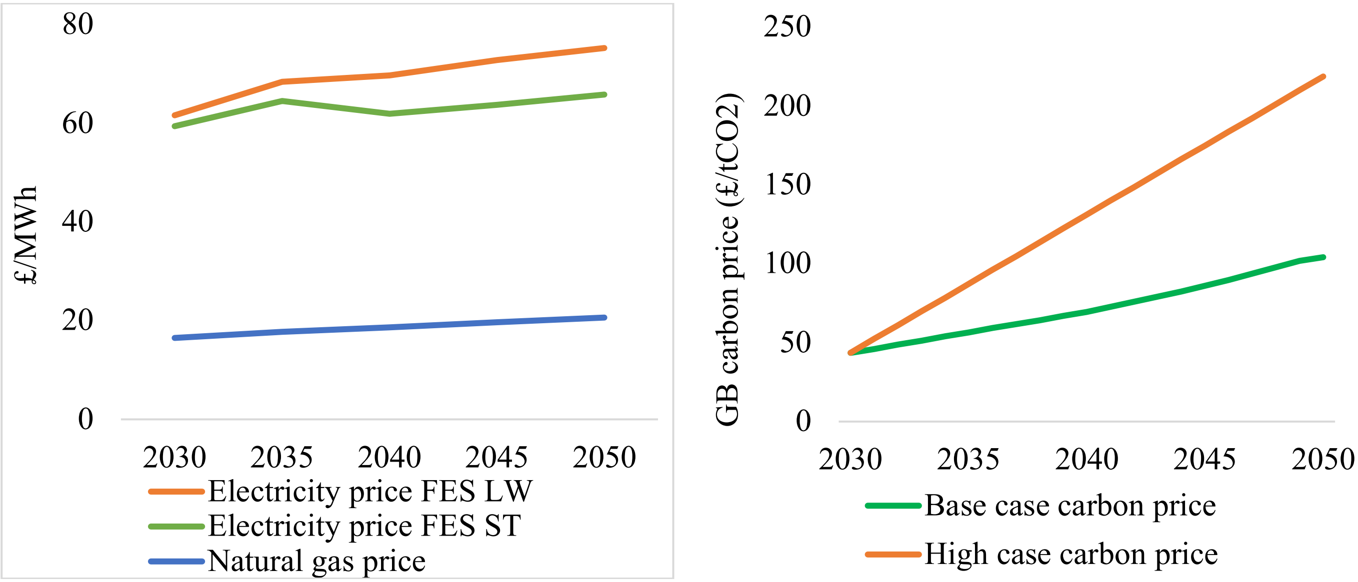
Baseline volatility: average 2012-2019 (without 2016)		**2016 volatility**		**Double 2016 volatility**	
Winter	Summer	Winter	Summer	Winter	Summer
0.311	0.264	0.723	0.844	1.446	1.687

Source: Own calculations based on Bloomberg day-ahead electricity prices in GB.

The average values for 2012 to 2019 without 2016 are used for the baseline (with and without the solvent storage). The other two sets of price volatilities are used to assess the impact of higher price volatility on the economic value of flexibility. In particular, 2016 offers an interesting case study of the effects of high electricity price volatility. That year, volatility was particularly high because of the constraints on the capacity margin resulting from two independent extreme weather events (Staffell, 2016). First, imports from France were reduced because of the shutdown of several French nuclear plants during the second half of 2016; since Britain is usually a net importer of electricity from France, the supply of French electricity was disrupted. Secondly, the French interconnector IFA

Link was damaged in November 2016, which halved its capacity. On top of that, the Brexit referendum in June 2016 led to a sharp fall in the value of the British pound.

Figure 2 – Projected electricity, carbon and commodity prices



Source: Electricity prices modelled based on generation data from National Grid, FES 2021 (see Annex A.2.2); all other data is from FES 2021.Notes: National Grid applies Base case carbon price to two FES scenarios– ST and CT, while the high carbon price case is applied to its LW scenario.

3.3. Using the model to quantify the economic value of flexible CCGT-CCS

To calculate the economic value of flexibility provided by the solvent storage option, we calculate the difference in the plant's net present value (NPV) with and without solvent storage. Calculations are carried out for the two FES scenarios and the three levels of electricity price volatilities, as discussed in §3.2. Thus, the NPV of the solvent storage is defined as follows:

$$NPV^{solvent} = \sum_{n=1}^{20} \left(\frac{\Pi_n^{with_{solvent}}}{(1+r)^n} - \frac{\Pi_n^{without_{solvent}}}{(1+r)^n} \right) - Solvent_{Capex} \qquad (19)$$

where Π_n is annual profit of the CCGT-CCS plant with and without the solvent storage calculated from equation (1), r is the discount rate (5%), and *Solvent_Capex* is the capital expenditure required for the solvent storage (see Appendix 1). To simulate the case without solvent storage we set the parameter V to zero.

Based on the model presented in §3.1, we can also calculate the NPV of the combined CCGT-CCS plant (eq. 20). These investment metrics will be used in our analysis in §4.3.

$$NPV^{CCGT-CCS} = \sum_{n=1}^{20} (\frac{\Pi_n^{CCGT-CCS}}{(1+r)^n} - CCGT_{CCS_{Capex}} \qquad (20)$$

It is worth noting that using the model we can simulate other interesting cases such as:

1. CCGT without CCS: set the parameter $\underline{I}$ (capture rate) to zero;
2. CCGT with CCS at constant capture rate: change the inequality constraint (eq. 4) to equality constraint. This will then force the model to capture carbon emissions at the rate defined by the parameter $\underline{I}$;

3. Hydrogen production (with and without CCS[2]) instead of electricity as final output.

We leave these possible cases for future research.

4. Results and discussion

In this section, we discuss key findings from the modelling. First, we present the results from our baseline scenario – FES ST. We then discuss results from our sensitivity analysis that focuses on the role of electricity price volatility as well as commodity (by comparing between various levels of price volatilities) and carbon price levels (comparing FES ST and FES LW price and cost levels). Finally, we present our NPV analysis of whether it is worth investing in solvent storage as a flexibility option, and discuss this solution in the context of the wider flexibility needs of a low-carbon electricity system.

4.1. Economics of CCGT-CCS flexibility with solvent storage

As discussed earlier, solvent storage allows the CGCT-CCS plant to arbitrage between electricity prices, fuel and carbon costs at various point in time (e.g., peak vs off-peak) and hence potentially improve its profit. Table 2 summarises the key statistics for the plant's operational decisions and achieved profits.

First, we can see that with the underlying assumptions about the generation mix, fuel and carbon prices, solvent storage improves annual profit marginally in 2030 but more significantly in later years with rising electricity prices and, especially, with rising price volatilities (Table *2*, line 6, 16 and 17). As we expected, the main driver of the economics of the solvent storage is to allow the plant to capture higher profits during peak hours – the increase in the average profit during peak hours (Table *2*, line 2) are much larger than the increase in average profit in all hours (Table *2*, line 1). The differences in maximum hourly profits (with and without the solvent storage, Table *2*, line 4) further highlights the importance of the plant's ability to optimise dispatch decisions to capture higher profit with the solvent storage. In this regard, the average "captured" price (defined as total revenue / total electricity sales) is higher with solvent storage than without it (line 14), while the average cost of generation is the same (line 15); that is, profit margin is higher with the solvent storage.

An interesting result is the difference for the lowest profits (Table *2*, line 3) – the plant's minimum profit is much lower with solvent storage than without the storage. The primary reason for this is that to capture higher peak period profits the plant then needs to clean up the accumulated CO_2 in the solvent storage tank in subsequent off-peak periods. This CO_2 cleaning up process consumes energy and therefore the additional fuel consumption at off-peak (low) electricity price periods pushes profitability down even further. This can also be seen by comparing the number of hours that the plant is sitting at the minimum stable generation (MSG) level (Table *2*, line 12) – with solvent storage, the plant generates at MSG level more often than without solvent storage. Further, while the plant is operating for more hours (Table *2*, line 11) with solvent storage, on average, it is generating less electricity. All these results highlight that solvent storage allows the plant to clean up the CO_2 accumulated in the storage during periods of low electricity prices, that is, when the opportunity cost of CO_2 clean-up is low. These dynamics can be seen in Figure 3 and Figure 4, which show examples of hourly decisions of the plant with and without solvent storage.

A final observation is that, as carbon price increases, the average capture rate also increases from 64% in 2030 to 87% by 2050 (Table *2*, line 9). This is in line with the finding in the literature that with a relatively low carbon price (in 2030 the carbon price in the FES ST is £32/tCO_2) flexible capture rate is more economic than fixed, steady-state capture (see e.g., Oates et al. (2014)). There is no impact of the solvent storage on the average capture rate suggesting that flexibility in CCS operation, in terms of capture rate, is a function of carbon price while flexibility associated with intertemporal CO_2 clean-up decisions (linked to the solvent storage) depends on electricity price volatility.

[2] See description of "Case 3: CO_2 capture from flue gas using MEA" in IEAGHG (2017).

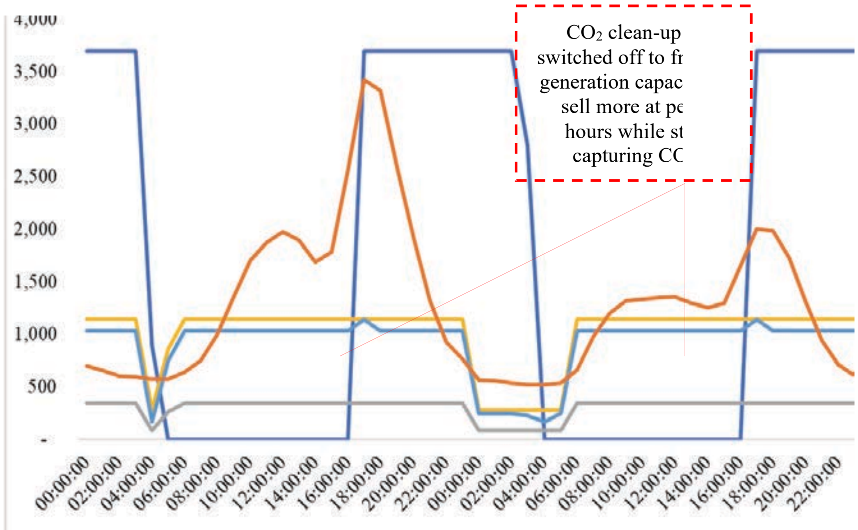
To sum up, with these intertemporal trade-offs, the annual profitability increases when the plant can shift the CO_2 clean-up process to other (off-peak) periods and thereby capture higher profits in peak periods.

Table 2: Plant's profit and operational characteristics – FES ST scenario

		2030		**2040**		**2050**	
		With storage	*No Storage*	*With storage*	*No Storage*	*With storage*	*No Storage*
	Profit						
(1)	Average hourly profit (all hours), £	14,909	14,908	11,377	11,329	13,201	13,068
(2)	Average peak hour profit, £	21,518	21,158	18,794	18,086	30,034	29,052
(3)	Min hourly profit, £	-4,135	449	-4,753	-1,000	-6,332	-2,277
(4)	Max hourly profit, £	46,268	45,895	68,312	56,666	185,571	161,847
(5)	CV of profit	49%	47%	80%	73%	172%	165%
(6)	Annual Profit, £Million	130.6	130.6	99.9	99.5	115.6	114.5
	Operational characteristics						
(7)	Gross generation, GWh	10,023	10,024	9,486	9,605	7,339	7,383
(8)	Net generation (electricity sales), GWh	9,296	9,297	8,554	8,661	6,618	6,658
(9)	CO_2 captured, ktCO_2 (capture rate)	2240 (64%)	2,240 (64%)	2,870 (87%)	2,906 (87%)	2,220 (87%)	2,234 (87%)
(10)	Energy consumed for CO_2 capture, GWh	727	727	932	943	721	725
(11)	Number of running hours	8,760	8,760	8,553	8,553	6,578	6,577
(12)	Number of hours gross generation @ MSG level	1	0	312	210	185	93
(13)	Average sales per running hour, MWh/h	1,061	1,061	1,000	1,013	1,006	1,012
	Costs and Prices						
(14)	Electricity "captured" price, £/MWh	59.6	59.6	62.6	62.4	74.4	74.1
(15)	Cost per MWh of sales, £/MWh	45.6	45.6	50.9	50.9	56.9	56.9
(16)	Average electricity price, £/MWh	59.4		61.9		65.8	
(17)	CV of electricity prices	11%		13%		37%	

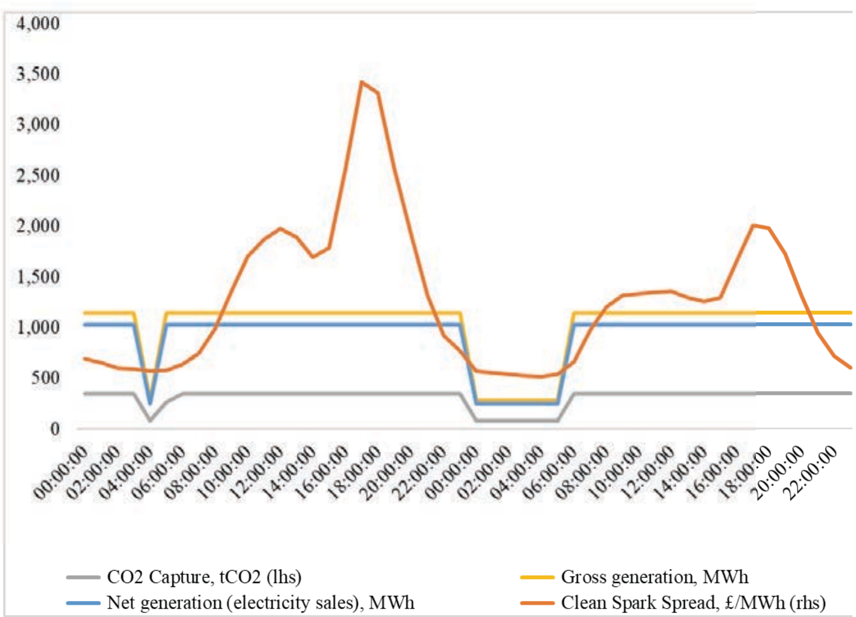
Notes: peak hours are 15.00-20.00; CV – coefficient of variation; MSG – Minimum stable generation

Figure 3 – A two-day example of hourly operational decisions: the case with solvent storage



Notes: this example reflects the operation of the plant for the first two days of Jan-2040.Clean spark spread refers to the variable margin of a gas plant, which is the price of electricity minus the cost of gas plus the cost of the emissions allowances needed

Figure 4 – A twc :orage



Notes: this example captures the operation of the plant for the first two days of Jan-2040.

4.2. Sensitivity analysis

The aim of this section is to answer three questions:

3. What is the impact of electricity price volatility on plant profits and operational decisions?
4. What is the impact of electricity price and carbon cost levels on plant profits and operational decisions?

For the first question, we focus on the FES ST with different price volatility assumptions and compare with the results from the baseline electricity price volatility reported in §4.1 (see also §3.2 for details of price volatilities). To answer the second question, we compare our results from the two scenarios – FES ST and FES LW. For the last question, we focus on FES ST and compare the results of the baseline prices with the results from the high price case (see Figure 2).

Table 3 reports key results from our price volatility sensitivity analysis including both the baseline scenario (i.e., results as in Table 2 'with solvent storage') as well as the two set of results using different price volatilities. All these results are shown for the case with solvent storage because we are interested in understanding the extra value that flexibility may bring under higher volatilities.

We can see that plant's annual profit (Table 3, line 6) is higher with higher electricity price volatility – the increase in profits ranges from 10% to 226% compared to profits under the baseline volatility scenario. The same mechanism is at play here as in the baseline volatility scenario – solvent storage allows extra electricity to be generated during peak hours while still capturing carbon emissions thereby keeping revenue higher (from selling more) and costs lower (from continued capture of carbon to avoid carbon cost penalty). The plant then cleans up the accumulated carbon in the solvent storage during off-peak hours.

Further, the impact of the solvent storage on profitability can be seen by comparing average and peak hour profits – higher volatility increases peak hour profit substantially more than the average profit for all hours (line 1 and 2). The positive impact on plant's profitability magnifies with higher electricity price volatility despite lower generation (Table 3, line 7 and 8). While the average electricity price is similar across all scenarios analysed, the 'captured' price is higher for higher volatilities – captured price could be twice the average price (Table 3, line 14 and 16). Therefore, the economic value of the solvent storage is its optionality – it captures the potential additional profit if and when electricity price becomes more volatile.

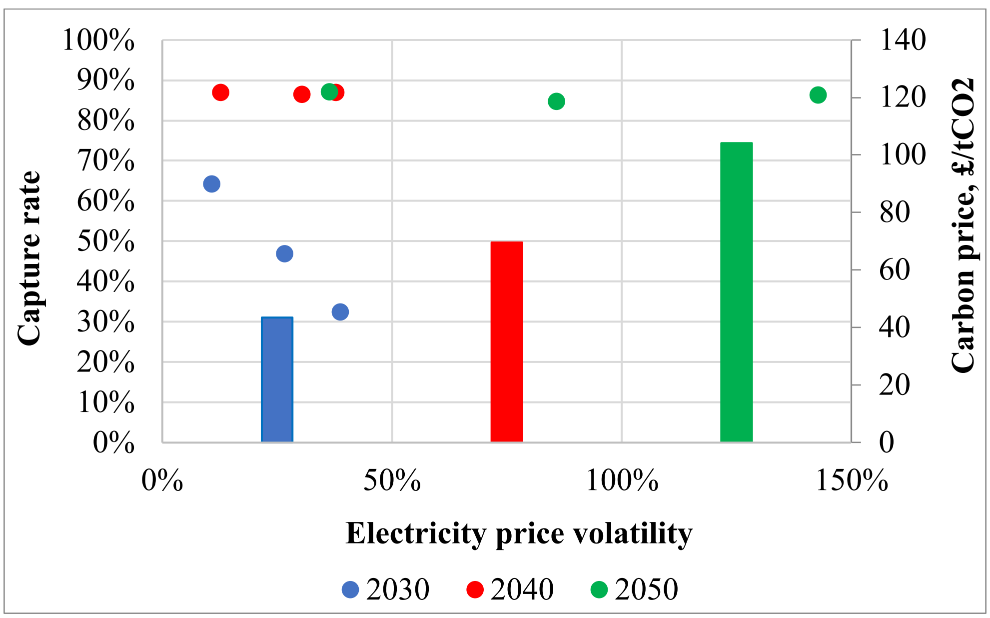
Lastly, as we noted earlier, the carbon price level and electricity price volatility have differing impacts on the capture rate. At a relatively low carbon price level (see Figure 5), increasing electricity price volatility (from 11% to 39%) reduces the capture rate from 64% to 32%. However, at a high carbon price level (e.g., £104/tCO2 in 2050) increasing electricity price volatility (from 37% to 143%) reduces the capture rate only marginally – from 87% down to 86%. In fact, it seems that the threshold for the carbon price to push the capture rate close to its capacity (90%) is above £45/tCO_2. Again, this finding is in line with previous studies in which, for example, Oates et al., (2014) estimated that at a carbon price of $40/t$CO_2$ and above a steady CO_2 capture rate is preferable and that the value of flexible CCS (i.e., flexible capture rate) decreases with CO_2 price.

Table 3: Plant profit and operational characteristics under various electricity price volatility assumptions (FES ST scenario)

		2030			**2040**			**2050**		
		baseline	*2016*	*2016 x 2*	*baseline*	*2016*	*2016 x 2*	*baseline*	*2016*	*2016 x 2*
	Profit									
1	Average hourly profit (all hours), £	14,909	16,372	21,024	11,377	13,772	19,623	13,201	23,742	42,971
2	Average peak hours profit, £	21,518	31,978	43,020	18,794	29,454	41,651	30,034	60,982	110,784
3	Min hourly profit, £	-4,135	-5,144	-6636	-4,753	-6,155	-7,007	-6,332	-10,290	-16,099
4	Max hourly profit, £	46,268	88,259	125,293	68,312	124,091	177,319	185,571	384,863	718,655
5	CV of profit	49%	101%	112%	80%	132%	129%	172%	213%	217%
6	Annual Profit, £Million	131	143.4	184.2	100	121.0	172.4	116	208.0	376.4
	Operational characteristics									

7	Gross generation, GWh	10,023	8,130	6,891	9,486	7,658	7,590	7,339	5,399	5,295
8	Net generation (electricity sales), GWh	9,296	7,700	6,640	8,554	6,911	6,845	6,618	4,883	4,780
9	CO_2 captured, ktCO_2 (capture rate,%)	2,240	1,324	775	2,870	2,302	2,296	2,220	1,588	1,587
10	Energy consumed for CO_2 capture, GWh	727	430	252	932	747	746	721	516	515
11	Number of running hours	8,760	7,500	6,438	8,553	6,991	6,974	6,578	5,075	4,946
12	Number of hours gross generation @ MSG level	1	456	484	312	342	315	185	435	378
13	Average sales per running hour, MWh/h	1,061	1,027	1,031	1,000	989	981	1,006	962	966
	Costs and Prices									
14	Electricty "captured" price, £/MWh	59.6	64.4	73.9	62.6	68.5	79.2	74.4	100.1	142.0
15	Cost per MWh of sales, £/MWh	45.6	45.8	46.2	50.9	51.0	54.1	56.9	57.5	63.2
16	Average electricity price, £/MWh	59.4	59.4	59.4	61.9	61.9	61.9	65.8	65.8	65.8
17	CV of electricity prices	11%	27%	39%	13%	30%	38%	37%	86%	143%

Figure 5 – Relationship between capture rate, electricity price volatility and carbon price (FES ST).



Notes: Carbon prices (right-hand side) are shown as three bars: blue bar is the carbon price in 2030, red bar – 2040, green bar – 2050; the three dots reflect the volatility in the baseline, 2016, and 2x2016 cases

Comparing the impacts of solvent storage on profits and operational decisions (Table 4), we see no striking differences between the results of the two FES scenarios. The impacts on profits are similar except for 2040 where the results indicate that solvent storage can improve annual profits in the FES ST scenario – by £0.4M – but not in FES LW (Table 4, line 6). This is because electricity prices are more volatile in ST versus LW (CV is 13% and 8% respectively). The results from this sensitivity analysis underscore the importance of price volatility as the main driver of the economics of solvent storage –the differences in electricity and carbon price levels (lines 16 and 18) do not impact on the ability of solvent storage to generate extra profit nor on plant's optimal dispatch. Further, solvent storage has no impact on capture rate (line 9, numbers in round brackets shows percentage point change in capture rate between the cases with and without solvent storage). This is consistent for both FES scenarios considered here (ST and LW). It reconfirms our earlier insight on the importance of price volatility and carbon price on the decision to use capture flexibly. This is somewhat expected because solvent storage is to allow intertemporal decision such as when to clean-up CO_2 whereas costs (carbon) and prices (electricity) affect current decisions such as how much to dispatch and capture.

Table 4: Impacts of solvent storage on plant profits and operational decisions under the FES ST and FES LW scenarios using the baseline volatility assumption

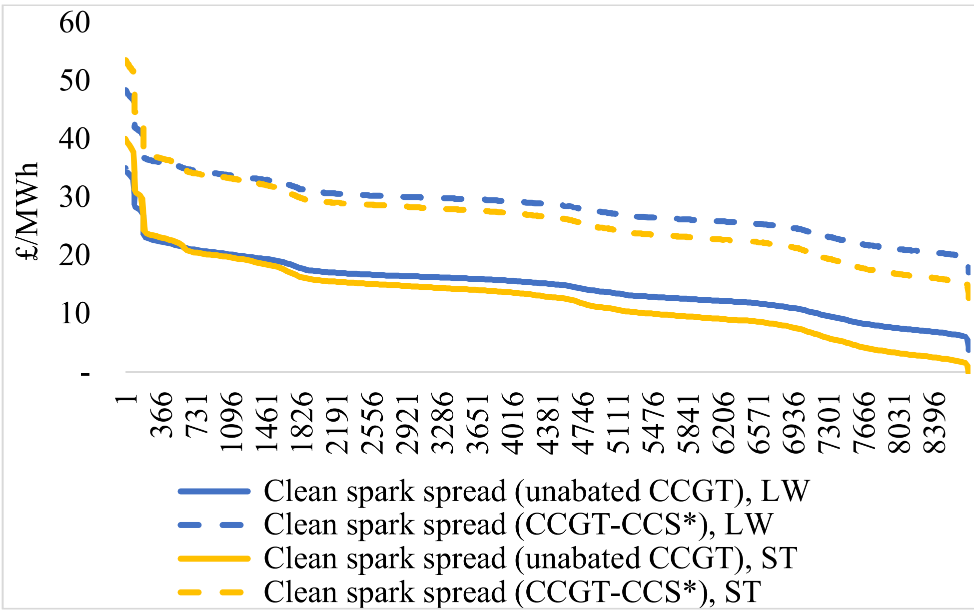
		2030		**2040**		**2050**	
		FES ST	*FES LW*	*FES ST*	*FES LW*	*FES ST*	*FES LW*
	Profit						
1	Average hourly profit (all hours), £	0	0	48	1	133	145
2	Average peak hours profit, £	359	377	708	4	983	1,086
3	Min hourly profit, £	-4,584	-922	-3,753	0	-4,056	-4,015
4	Max hourly profit, £	372	317	11,646	2,790	23,725	23,779
5	CV of profit, percentage points	2.2%	2.1%	6.4%	0.0%	6.7%	6.6%
6	Annual Profit, £Million	0.0	0.0	0.4	0.0	1.2	1.3
	Operational characteristics						
7	Gross generation, GWh	-1.1	0.0	-119.0	0.0	-44.5	-43.2
8	Net generation (electricity sales), GWh	-1.0	0.0	-107.2	0.1	-40.3	-39.0
9	CO_2 captured, ktCO_2 (change in capture rate, p.p.)	-0.3 (0.0)	0.0 (0.0)	-36.0 (0.0)	0.0 (0.0)	-13.5 (0.0)	-13.1 (0.0)
10	Energy consumed for CO_2 capture, GWh	-0.1	0.0	-11.8	-0.1	-4.3	-4.2
11	Number of running hours	0.0	0.0	0.0	0.0	1.0	-1.0
12	Number of hours gross generation @ MSG level	1.0	0.0	102.0	0.0	92.0	7.0
13	Average sales per running hour, MWh/h	-0.1	0.0	-12.5	0.0	-6.3	-5.6
	Costs and Prices						
14	Electricity "captured" price, £/MWh	0.0	0.0	0.2	0.0	0.3	0.3
15	Cost per MWh of sales, £/MWh	0.0	0.0	0.0	0.0	0.0	0.0
16	Average electricity price, £/MWh	59.4	61.6	61.9	69.7	65.8	75.2
17	CV of electricity prices	11%	8%	13%	8%	37%	30%
18	Carbon price, £/tCO2	43.5	43.5	69.6	131.1	104.1	218.7

4.3. Is it worth the investment – the NPV analysis

In this section, we report our NPV analysis by bringing together all the results from the preceding sections, including insights from the sensitivity analysis. We compute the NPV following eq. (19-20). Table 5 shows the results of these calculations. Key observations from these calculations as follows.

First, it is important to note that the NPV of the CCGT-CCS plant (without solvent storage) is consistently higher in the LW than in the ST scenario (except in the case of very high price volatility when the NPV under the ST is £698.6M in ST vs. 624.2M in LW, see Table 5). Figure 6 explains why – clean spark spreads (both assuming unabated and 90% capture rate) is higher in LW than in ST in 93% of the time when the spreads are positive.

Figure 6: Clean spark spread duration curves (baseline volatility)



*Notes: * assumes 90% capture rate; this chart shows only instances of positive clean spark spread ranged from largest to smallest for three spot years modelled – 2030, 2040 and 2050; in total there are 8760 hours (out of 26304 hours) in total when spreads are positive.*

Secondly, with the baseline electricity price volatility assumption, the NPV of the solvent storage is negative in both scenarios. While the solvent storage increases plant profitability (see Table 4), this increase in profits over the modelled horizon (2030-50) is not enough to cover the initial investment costs of ca. £8M (see Appendix 1 for details).

However, as mentioned previously, the economic value of solvent storage lies in taking the potential advantage of increased price volatility – under higher electricity price volatility assumptions (e.g., the 2016 volatility) the NPV of investing in the solvent storage would be positive, ranging from £6.4M-£7.3M. This represents total return on investment (ROI) of 81-92% (Table 5). In relative terms, this is much higher than the total ROI of the CCGT-CCS plant alone (7-23%). The NPV of solvent storage, under high price volatility scenarios, represents 3-11% of the plant's NPV while investment costs of the solvent storage is only 1% of total investment costs in CCGT-CCS plant (£8M for the solvent vs. £968M for the plant).

To sum up, investing in solvent storage to allow greater flexibility in plant operations has a non-negligible value in terms of return on investment – it delivers highly positive economic value under volatile electricity prices.

Table 5: NPV of the solvent storage and CCGT with CCS

	Baseline volatility		**2016 volatility**		**2016 x 2 volatility**	
	FES ST	*FES LW*	*FES ST*	*FES LW*	*FES ST*	*FES LW*

CCGT-CCS (No Solvent)	-165.2	115.8	67.9	222.2	698.6	624.2
Solvent storage	-2.4	-7.9	7.3	6.4	17.6	19.4
Total ROI for the CCGT-CCS (No solvent)	-17%	12%	7%	23%	72%	64%
Total ROI for the solvent storage	-31%	-100%	92%	81%	223%	246%

Notes: total ROI (return on investment) is defined as NPV divided by total capex.

To put this solvent storage flexible solution in the context of overall system ‘flexibility’ requirements for low-carbon power system, an investment of £8M allows the plant to add additional flexibility of 112MW of low-carbon generation capacity. Further, considering FES ST projection of 12.5 GW of gas CCS by 2050 this could mean an additional flexible low carbon ‘firm’ capacity of 1224 MW for a cost of just £86M, or £70/kW. This is a fraction of the capital costs for some of the “mainstream” energy storage technologies being discussed (see Table 6).

Table 6: CAPEX and other characteristics of solvent storage as a flexible solution compared with other energy storage technologies

	CAPEX (2050), £/kW			**Footprint, m^2**	**Roundtrip efficiency**	**Capacity, MW**	**Duration, hour**
	low	*medium*	*high*				
Lithium Ion Battery	164.6	197.6	230.5	908	85%	50	1
Hydro Pumped Storage	949.4	1,186.8	1582.4	250,000	75%	200	4
Compressed Air Energy Storage (CAES)	710.9	782.0	853.1	22,500	65%	200	4
Thermal Energy Storage	621.4	699.1	776.7	25,000	65%	200	4
Solvent storage* for post combustion CCGT-CCS plant	70	70	70	2,500**	100%	112	1***

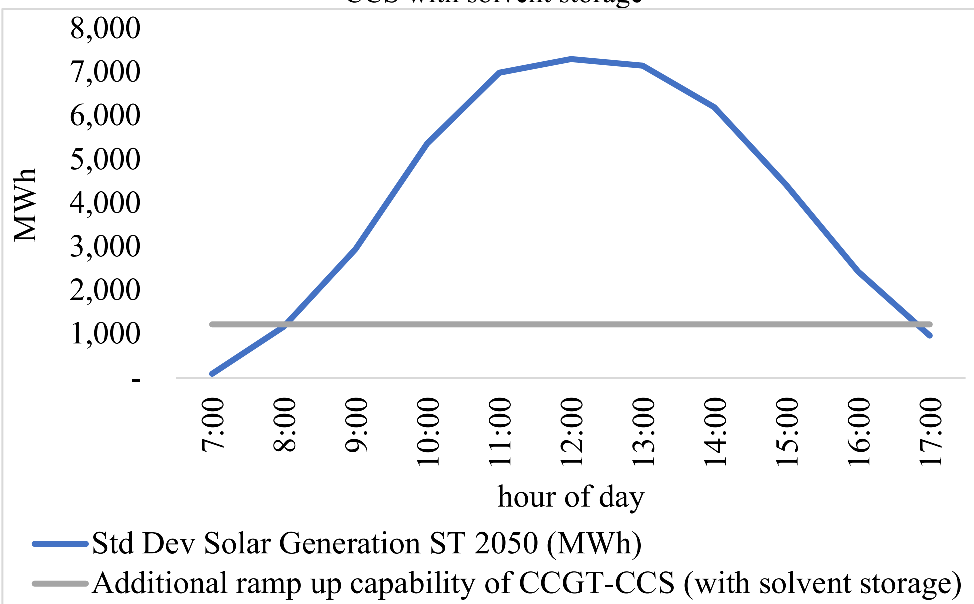
Source: Mott MacDonald (2018) for the first four options;
** Solvent storage option for CCGT-CCS is provided by Schnellmann et al., (2019); all costs are in £2018;*
*** two solvent storage tanks, each 3700m^3, are equivalent to two Olympic swimming pool with the following dimensions: length – 50m. width – 25m, depth – 3m;*
**** this assumes 90% capture rate at full plant design capacity (see Appendix 1 for details).*

Further, unlike the mainstream flexible storage technologies, the advantage of this additional capacity is its *firmness* – unlike storage, in that to produce energy it needs to be charged first, production decision of the CCGT-CCS with the solvent storage is independent of such considerations (for further discussion of the role of firm low-carbon electricity sources in deep decarbonisation of power generation see Sepulveda et al., 2018)). Further, while storage incur losses, the extra capacity of CCGT-CCS with solvent storage does not incur any extra losses beyond the standard loss associated with turning gas (thermal) into electric energy.

A second advantage, though of lesser importance in a low-carbon system, is that carbon intensity of energy production from storage is a function of the average carbon intensity of the power system itself; however, the solvent storage solution provides extra flexible production capacity at very low-carbon intensity – its intensity is capped at the plant’s capture rate (assumed 90%) or ca. 0.0348 tCO_2e/MWh-e. Moreover, the solvent storage solution does not take up much land area compared to some other large-scale storage solutions (e.g., hydro pumped storage, CAES). Of the four technologies, only lithium-ion batteries, with a production capacity of 50MW, have a smaller footprint (see Table *6*).

Lastly, related to the first point, the *firmness* of this additional capacity due to solvent storage should be seen in the context of inter-seasonality of energy production and demand. Taking FES ST as an example, solar generation capacity is expected to reach 57 GW, or ca. 20% of installed capacity, by 2050. Figure 6 compares the standard deviation (a measure of risk or changes in generation) of solar generation in February with the additional capacity of 1224 MW, assuming all CCS plants will have solvent storage. At noon, which is the peak hour for solar generation (at least in February in the UK), with the installed capacity of 57GW, the loss in solar generation production could reach 7,300 MWh. If all 12.5 GW of CCS is equipped with solvent storage, the extra capacity could cover 17% of the potential swing in solar generation without needing to switch off the capture unit and hence incurring carbon emissions (and cost). Further, it is clear from (Figure 7) that in 6 out of 11 hours of solar generation the extra capacity of CCGT-CCS could cover at least one-third of potential loss of solar generation, and at least in 4 hours covering half of the losses. This benefit relates to the findings of Van Peteghem & Delarue (2014), Cohen et al., (2013) and Craig et al., (2017b), all of whom found that one benefit of flexible CCS is an increase in reserve capacity provision. Thus, for a relatively small cost (Table *6*), solvent storage can act as a hedge against sudden changes in electricity balance at peak time and hence provide an option for taking advantage of sudden price spikes.

Figure 7: Standard deviation of solar generation in 2050 (FES ST) vs. additional ramp up capability of CCGT-CCS with solvent storage



Source: solar generation std. dev. is based on the EU Joint Research Centre (JRC) EMHIRES dataset (https://publications.jrc.ec.europa.eu/repository/handle/JRC106897); Notes: JRC EMHIRES provides hourly time series of solar generation capacity factors from 1986 to 2015 for the UK and other EU member states.

5. Conclusions

Large shares of renewable generation will be necessary in net-zero energy systems. The deployment of wind and solar will, however, impose constraints on the electricity system due to their intermittency, therefore more flexible electricity generators must participate. We have studied the case of a CCGT with CCS to assess the economic value of flexible carbon capture from the perspective of a unit-commitment model of a CCGT-CCS plant responding to day-ahead electricity market prices.

Our results support findings from past studies on the importance of flexible capture to the viability of CCS, regardless of the type of flexible post-combustion carbon capture technologies (variable capture or storage). Our unit-commitment model captures two arbitrage decisions: the decision to either vent the flue gas or to capture it, and then when the flue gas is captured, the decision to either regenerate the solvent or to store it for later regeneration. Each of these two trade-offs varies with two key inputs: the carbon price level and the intraday variation in electricity price. First, increasing carbon prices encourages the use of full carbon CO_2 capture (i.e., at the 90% design rate) as soon as the operational cost of CCS – made up of the electricity price and the cost of transport and storage – becomes sufficiently low compared to the carbon price. This trade-off is reflected in the modelling output, where the effective carbon capture rate rises from 2030 through 2050 due to the increasing carbon prices over this period. This finding is in line with previous estimates in the literature.

Secondly, the main contribution of our case study remains in the insights gained from exploring solvent storage dynamics at higher temporal resolution. Flexible carbon capture does not force the rich solvent (CO_2-loaded solvent) to be regenerated within an hour, i.e., as soon as the flue gas enters the CCS. Since the main component of the marginal cost of carbon capture is the auxiliary electricity penalty, flexible carbon capture allows time-varying solvent regeneration such that the rich solvent can be stored in a tank during peak hours to be regenerated when electricity prices will be lower. Storage enables the intertemporal arbitrage of electricity usage that eventually increases the profitability of the CCGT-CCS plant: the rich solvent does not have to be regenerated instantaneously but can be stored instead so that more electricity is dispatched and sold at peak hour prices. In the net-zero scenarios, the large shares of intermittent renewables will increase the volatility of electricity prices because of higher spikes during peak hours where the capacity margin is reduced, and low (or negative) electricity prices during off-peak hours with electricity surpluses. Despite the deployment of significant electricity storage capacity, the greater volatility of electricity prices in the next decades is expected to lead to a more profitable intertemporal arbitrage between peak and off-peak hours.

A high carbon price is necessary if the UK wants to profitably deploy fossil power plants with CCS: higher prices encourage the uptake of CCS as it becomes more profitable to capture the flue gas from the power plant rather than venting it. While there is little doubt that deploying CCS technologies relies on an increasing carbon price in the long run, the impact of carbon price on the present value of CCGT-CCS is more nuanced: if the carbon price is too high this will then reduce plant's profit margin and hence its investment case. This effect is especially important as we phase out fossil-fuel based generation because as fossil fuel disappear from the system, high carbon price will not translate into high electricity prices (carbon price being part of fossil plant's marginal cost). Our modelled FES LW is a clear example of this situation – the LW scenario has almost no fossil-fuel based generation and therefore even a very high carbon price will not have much effect on electricity price. Therefore, for the market setup envisaged by the LW scenario, investment in CCS will be feasible only in an extremely high electricity price volatility environment.

Thus, in this context of decarbonization, the volatility of electricity prices resulting from the deployment of large shares of renewables and expanding storage capacity will necessarily have an impact on the marginal profit of fossil peaking plants which will be able to ramp up during peak hours to meet the electricity demand. By allowing the carbon capture unit of fossil plants to be flexible with solvent storage, the operational profit is improved during peak hours since the postponed electricity penalty to off-peak hours where the electricity price is lower.

As a result, the economic value of solvent storage is to take the potential advantage of increased price volatility – under higher electricity price volatility assumptions the NPV of investing in the solvent storage would be positive, ranging from £5.3M-£8M. This represents total return on investment of 66-101%. In relative terms, this is much higher than the total ROI of the CCGT-CCS plant alone (12-45%). Thus, investing in the solvent storage to allow further flexibility for the plant operation has a non-negligible value in terms of return on investment – it delivers highly positive economic value under volatile electricity prices.

While there is an economic case for investing in flexible CCS with solvent storage for individual operators, the benefits of the solvent storage flexible solution should be seen in the context of overall system 'flexibility' requirements for low-carbon power system. An investment of £8M allows the plant to add additional flexibility of 112MW of low-carbon generation capacity, or £70/kW. As seen from Table 6, this investment would only be a fraction of the capital costs needed for "mainstream" energy storage technologies, such as lithium-ion batteries (£198/kW), CAES (£782/kW), or hydro pumped storage (£1,187/kW).

We have sought to shed light on the potential improvement in operational profit when both electricity generation and carbon capture are flexible. The implications of this case study are not, however, limited to natural gas as fuel for the CCGT. Indeed, our model is flexible, so several important and interesting case studies could (and should) be investigated.

First, it would be possible to model BECCS, especially with biomethane when used as a technical substitute for fossil natural gas with the same efficiency. Biomethane is considered carbon neutral and hence would not be penalised by the carbon price but biomethane does cost more than fossil natural gas. Therefore, an interesting case study would be to compare the economics of running an unabated CCGT using biomethane with a CCGT-CCS plant (with or without solvent storage) running on fossil gas.

Second, with a few simple changes to the input parameters we can simulate cases such as: (a) CCGT without CCS, (b) CCGT with CCS operating at constant capture rate, or indeed (c) hydrogen production (with and without CCS[3]) instead of electricity as final output.

Other potential improvements to our modelling approach could be carried out in future studies. We treated prices as exogenous variables in a unit-commitment framework, but prices can also be treated as endogenous, as a result of the merit-order stack and generation constraints of other operators in the electricity system. Moreover, we have not considered the impact of CCGT-CCS on electricity price levels: CCGT-CCS is at the high-end of the merit-order stack and will likely be the price-setting technology in the future because of its flexibility (see e.g., Davison, 2011; Brouwer et al. 2015; Gils et al., 2017; Després et al., 2017; Zappa et al., 2019).

Finally, we have assumed that flexible power plants will soften the price spikes but, depending on the structure of the market and legal enforcement, they could potentially exert market power by strategically withholding capacity at times of scarcity.

[3] See "Case 3: CO_2 capture from flue gas using MEA" in IEAGHG (2017)

5. References

Abdilahi, A. M., Mustafa, M. W., Abujarad, S. Y., & Mustapha, M. (2018). Harnessing flexibility potential of flexible carbon capture power plants for future low carbon power systems: Review. In Renewable and Sustainable Energy Reviews (Vol. 81). https://doi.org/10.1016/j.rser.2017.08.085

Bates, C., & Hill, T.A. (2018). CCUS technical advisory - Report on assumptions. Uniper Technologies

Beiron, J., Montañés, R. M., Normann, F., & Johnsson, F. (2020). Flexible operation of a combined cycle cogeneration plant – A techno-economic assessment. Applied Energy, 278. https://doi.org/10.1016/j.apenergy.2020.115630

BEIS. (2018). Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology – Benchmarking State-of-the-art and Next Generation Technologies (No. 13333-8820-RP-001). Department for Business, Energy & Industrial Strategy. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/800681/BEIS_Final_Benchmarks_Report_Rev_3A__2_.pdf

BEIS. (2020). *Electricity Generation Costs 2020.* UK Department for Business, Energy & Industrial Strategy. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/911817/electricity-generation-cost-report-2020.pdf

Brouwer, A. S., van den Broek, M., Seebregts, A., & Faaij, A. (2015). Operational flexibility and economics of power plants in future low-carbon power systems. *Applied Energy*, *156*, 107-128.

Bruce, A.R., Harrison, G.P., Gibbins, J. and Chalmers, H., 2014. Assessing operating regimes of CCS power plants in high wind and energy storage scenarios. *Energy Procedia*, 63, 7529-7540.

Chalmers, H., Gibbins, J., & Leach, M. (2012). Valuing power plant flexibility with CCS: The case of post-combustion capture retrofits. *Mitigation and Adaptation Strategies for Global Change*, *17*(6), 621–649. https://doi.org/10/cnzws3

Cheng, F., Patankar, N., Chakrabarti, S., & Jenkins, J. D. (2022). Modeling the operational flexibility of natural gas combined cycle power plants coupled with flexible carbon capture and storage via solvent storage and flexible regeneration. *International Journal of Greenhouse Gas Control*, *118*. https://doi.org/10.1016/j.ijggc.2022.103686

Chyong, C. K., & Newbery, D. (2022). A unit commitment and economic dispatch model of the GB electricity market–Formulation and application to hydro pumped storage. *Energy Policy*, *170*, 113213. https://doi.org/10.1016/j.enpol.2022.113213

Cohen, S.M., Rochelle, G.T. and Webber, M.E., (2013). Optimal CO2 capture operation in an advanced electric grid. *Energy Procedia*, 37, 2585-2594.

Cohen, S. M., Rochelle, G. T., & Webber, M. E. (2011). Optimal operation of flexible post-combustion CO2 capture in response to volatile electricity prices. Energy Procedia, 4. https://doi.org/10.1016/j.egypro.2011.02.159

Craig, M.T., Jaramillo, P., Zhai, H. and Klima, K., (2017a). The economic merits of flexible carbon capture and sequestration as a compliance strategy with the clean power plan. *Environmental S cience & T echnology*, 51(3), 1102-1109.

Craig, M.T., Zhai, H., Jaramillo, P. and Klima, K., (2017b). Trade-offs in cost and emission reductions between flexible and normal carbon capture and sequestration under carbon dioxide emission constraints. *International Journal of Greenhouse Gas Control*, 66, 25-34.

Davison, J. (2011). Flexible CCS plants–A key to near-zero emission electricity systems. *Energy Procedia*, *4*, 2548–2555. https://doi.org/10/fhpf56

Després, J., Mima, S., Kitous, A., Criqui, P., Hadjsaid, N. and Noirot, I., 2017. Storage as a flexibility option in power systems with high shares of variable renewable energy sources: a POLES-based analysis. *Energy Economics*, 64, 638-650.

Domenichini, R., Mancuso, L., Ferrari, N., & Davison, J. (2013). Operating flexibility of power plants with carbon capture and storage (CCS). *Energy Procedia*, *37*, 2727-2737.

Eager, D., Hobbs, B. F., & Bialek, J. W. (2012). Dynamic Modeling of Thermal Generation Capacity Investment: Application to Markets With High Wind Penetration. *IEEE Transactions on Power Systems*, *27*(4), 2127–2137. https://doi.org/10/f4c7m2

Errey, O., Chalmers, H., Lucquiaud, M. and Gibbins, J., 2014. Valuing responsive operation of post-combustion CCS power plants in low carbon electricity markets. *Energy Procedia*, 63, 7471-7484.

Fernandez, E. S., del Rio, M. S., Chalmers, H., Khakharia, P., Goetheer, E. L., Gibbins, J., & Lucquiaud, M. (2016). Operational flexibility options in power plants with integrated post-combustion capture. *International Journal of Greenhouse Gas Control*, *48*, 275-289.

Flø, N. E., Kvamsdal, H. M., & Hillestad, M. (2016). Dynamic simulation of post-combustion CO2 capture for flexible operation of the Brindisi pilot plant. *International Journal of Greenhouse Gas Control*, *48*, 204-215.

Gils, H.C., Scholz, Y., Pregger, T., de Tena, D.L. and Heide, D., 2017. Integrated modelling of variable renewable energy-based power supply in Europe. *Energy*, 123, 173-188.

Haines, M. R., & Davison, J. E. (2009). Designing carbon capture power plants to assist in meeting peak power demand. *Energy Procedia*, *1*(1), 1457–1464. https://doi.org/10/dvjgtz

Heptonstall, P. J., & Gross, R. J. K. (2021). A systematic review of the costs and impacts of integrating variable renewables into power grids. *Nature Energy*, *6*(1), 72–83. https://doi.org/10/ghm3xm

Holz, F., Scherwath, T., del Granado, P.C., Skar, C., Olmos, L., Ploussard, Q., Ramos, A. and Herbst, A. (2021). A 2050 perspective on the role for carbon capture and storage in the European power system and industry sector. *Energy Economics*, *104*, 105631.

IEA Greenhouse Gas Programme (IEAGHG) (2009) *Partial Capture of CO2*. Report *2009-TR02*, May. Retrieved 2 February 2022, from https://ieaghg.org/publications/technical-reports/reports-list/10-technical-reviews/977-2009-tr02-partial-capture-of-co2

IEA Greenhouse Gas Programme (IEAGHG) (2017), Techno-economic evaluation of SMR based Standalone (Merchant) Plant with CCS', Report 2017/02, February. https://ieaghg.org/exco_docs/2017-02.pdf

IEA (2021). *Net Zero by 2050 - A Roadmap for the Global Energy Sector.* Retrieved April 202, from https://www.iea.org/reports/net-zero-by-2050

IRENA. (2020). *Renewable Power Generation Costs in 2019*. International Renewable Energy Agency. https://www.irena.org/publications/2020/Jun/Renewable-Power-Costs-in-2019

Jafari, M., Botterud, A., & Sakti, A. (2022). Decarbonizing power systems: A critical review of the role of energy storage. In Renewable and Sustainable Energy Reviews (Vol. 158). https://doi.org/10.1016/j.rser.2022.112077

Kang, M.-K., Jeon, S.-B., Cho, J.-H., Kim, J.-S., & Oh, K.-J. (2017). Characterization and comparison of the CO2 absorption performance into aqueous, quasi-aqueous and non-aqueous MEA solutions. *International Journal of Greenhouse Gas Control*, *63*, 281–288. https://doi.org/10/gcj36k

Kim, I., Hoff, K. A., & Mejdell, T. (2014). Heat of Absorption of CO2 with Aqueous Solutions of MEA: New Experimental Data. *Energy Procedia*, *63*, 1446–1455. https://doi.org/10/ggwj2t

Khorshidi, Z., Florin, N. H., Ho, M. T., & Wiley, D. E. (2016). Techno-economic evaluation of co-firing biomass gas with natural gas in existing NGCC plants with and without CO2 capture. *International Journal of Greenhouse Gas Control*, *49*, 343–363. https://doi.org/10.1016/j.ijggc.2016.03.007

Ludig, S., Haller, M. and Bauer, N., 2011. Tackling long-term climate change together: the case of flexible CCS and fluctuating renewable energy. *Energy Procedia*, 4, 2580-2587.

Luo, X., & Wang, M. (2016). Optimal operation of MEA-based post-combustion carbon capture for natural gas combined cycle power plants under different market conditions. *International journal of greenhouse gas control*, *48*, 312-320.

Lund, P.D., Lindgren, J., Mikkola, J. and Salpakari, J., 2015. Review of energy system flexibility measures to enable high levels of variable renewable electricity. *Renewable and sustainable energy reviews*, 45, 785-807.

Mac Dowell, N., & Shah, N. (2015). The multi-period optimisation of an amine-based CO2 capture process integrated with a super-critical coal-fired power station for flexible operation. *Computers & Chemical Engineering*, *74*, 169–183. https://doi.org/10/f64f5z

Mac Dowell, N., & Staffell, I. (2016). The role of flexible CCS in the UK's future energy system. International Journal of Greenhouse Gas Control, 48. https://doi.org/10.1016/j.ijggc.2016.01.043

Mott MacDonald (2018) 'Storage cost and technical assumptions for electricity storage technologies', a report for BEIS. Available at: https://www.gov.uk/government/publications/storage-cost-and-technical-assumptions-for-electricity-storage-technologies (accessed March 2022)

Manaf, N.A., Qadir, A. and Abbas, A., 2016. Temporal multiscalar decision support framework for flexible operation of carbon capture plants targeting low-carbon management of power plant emissions. Applied Energy, 169, pp.912-926.

Mechleri, E., Fennell, P. S., & Mac Dowell, N. (2017). Optimisation and evaluation of flexible operation strategies for coal- and gas-CCS power stations with a multi-period design approach. *International Journal of Greenhouse Gas Control*, *59*, 24–39. https://doi.org/10/f93bgx

Mikulčić, H., Skov, I.R., Dominković, D.F., Alwi, S.R.W., Manan, Z.A., Tan, R., Duić, N., Mohamad, S.N.H. and Wang, X., (2019). Flexible Carbon Capture and Utilization technologies in future energy systems and the utilization pathways of captured CO2. Renewable and Sustainable Energy Reviews, 114, p.109338.

National Grid ESO. (2021). *Future Energy Scenario. https://www.nationalgrideso.com/future-energy/future-energy-scenarios*

Nimtz, M. and Krautz, H.J., 2013. Flexible operation of CCS power plants to match variable renewable energies. Energy Procedia, 40, 294-303.

Oates, D. L., Versteeg, P., Hittinger, E., & Jaramillo, P. (2014). Profitability of CCS with flue gas bypass and solvent storage. *International Journal of Greenhouse Gas Control*, *27*, 279–288. https://doi.org/10/f6c696

Rao, A. B., & Rubin, E. S. (2006). Identifying Cost-Effective CO2 Control Levels for Amine-Based CO2 Capture Systems. *Industrial & Engineering Chemistry Research*, *45*(8), 2421–2429. https://doi.org/10/c4b9bs

Rúa, J., Bui, M., Nord, L. O., & mac Dowell, N. (2020). Does CCS reduce power generation flexibility? A dynamic study of combined cycles with post-combustion CO2 capture. International Journal of Greenhouse Gas Control, 95. https://doi.org/10.1016/j.ijggc.2020.102984

Sakwattanapong, R., Aroonwilas, A., & Veawab, A. (2005). Behavior of reboiler heat duty for CO2 capture plants using regenerable single and blended alkanolamines. *Industrial & engineering chemistry research*, *44*(12), 4465-4473.

Sepulveda, N.A., Jenkins, J.D., de Sisternes, F.J. and Lester, R.K., 2018. The role of firm low-carbon electricity resources in deep decarbonization of power generation. Joule, 2(11), 2403-2420.

Singh, S. P., Ku, A. Y., Mac Dowell, N., & Cao, C. (2022). Profitability and the use of flexible CO2 capture and storage (CCS) in the transition to decarbonized electricity systems. *International Journal of Greenhouse Gas Control*, *120*, 103767. https://doi.org/10.1016/J.IJGGC.2022.103767

Schnellmann, M. A., Chyong, C. K., Reiner, D. M., & Scott, S. A. (2019). Deploying gas power with CCS: The role of operational flexibility, merit order and the future energy system. *International Journal of Greenhouse Gas Control*, *91*, 102838. https://doi.org/10/ggt552

Staffell, I. (2016). Q4 2016: Price Volatility Keeps Rising, *Electric Insights* https://reports.electricinsights.co.uk/q4-2016/price-volatility-continues-rising/

Szima, S., Nazir, S. M., Cloete, S., Amini, S., Fogarasi, S., Cormos, A. M., & Cormos, C. C. (2019). Gas switching reforming for flexible power and hydrogen production to balance variable renewables. Renewable and Sustainable Energy Reviews, 110. https://doi.org/10.1016/j.rser.2019.03.061

Van der Weijk, P.C., Brouwer, A.S., Van den Broek, M., Slot, T., Stienstra, G., Van der Veen, W. and Faaij, A.P., (2014). Benefits of coal-fired power generation with flexible CCS in a future northwest European power system with large scale wind power. *International Journal of Greenhouse Gas Control*, 28, 216-233.

Van Peteghem, T. and Delarue, E., (2014). Opportunities for applying solvent storage to power plants with post-combustion carbon capture. *International Journal of Greenhouse Gas Control*, 21, 203-213.

Van Zuijlen, B., Zappa, W., Turkenburg, W., van der Schrier, G. and van den Broek, M., (2019). Cost-optimal reliable power generation in a deep decarbonisation future. Applied Energy, 253, p.113587.

Victor, N., Nichols, C. and Zelek, C., 2018. The US power sector decarbonization: Investigating technology options with MARKAL nine-region model. *Energy Economics*, *73*, pp.410-425.

Weiland, R. H., Dingman, J. C., & Cronin, D. B. (1997). Heat Capacity of Aqueous Monoethanolamine, Diethanolamine, N-Methyldiethanolamine, and N-Methyldiethanolamine-Based Blends with Carbon Dioxide. *Journal of Chemical & Engineering Data*, *42*(5), 1004–1006. https://doi.org/10/frwstg

Wu, X., Wang, M., Liao, P., Shen, J. and Li, Y., (2020). Solvent-based post-combustion CO2 capture for power plants: A critical review and perspective on dynamic modelling, system identification, process control and flexible operation. Applied Energy, 257, p.113941.

Zaman, M. and Lee, J.H., 2015. Optimization of the various modes of flexible operation for post-combustion CO2 capture plant. Computers & Chemical Engineering, 75, pp.14-27.

Zappa, W., Junginger, M. and Van Den Broek, M., 2019. Is a 100% renewable European power system feasible by 2050?. Applied Energy, 233, pp.1027-1050.

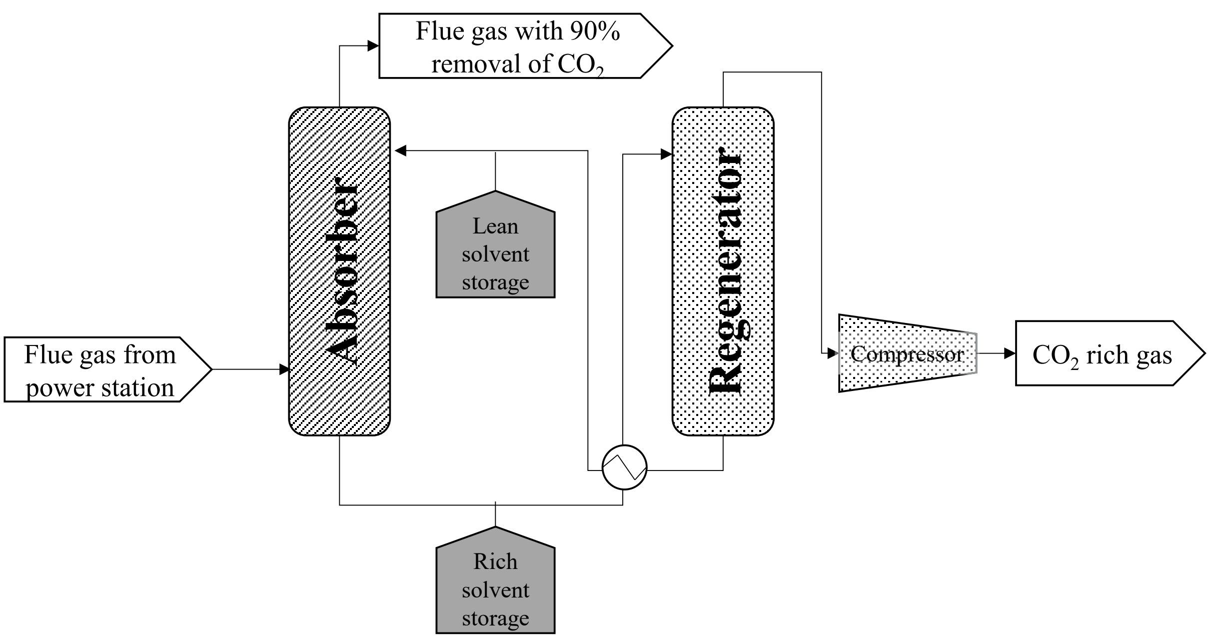
6. Appendix 1 – Description of post-combustion CCS with solvent absorption

A.1.1. General description of the CCS process

In this paper, we focus on a post-combustion CCS unit with solvent-based absorption as described in Schnellmann et al. (2019), which is a case study of a flexible CCS power plant. We use an amine solvent with 30 wt% MEA (monoethanolamine) to absorb CO_2 in the flue gas from the CCGT power plant. It is either vented or stays in a closed system to be transferred to the CCS unit. When the flue gas enters the CCS unit, it goes through the absorber where the lean solvent captures CO_2, then becomes the rich solvent with a concentration of 0.48 mol CO_2/mol MEA. Only up to 90% of the flue gas can be captured in the absorber, therefore the remaining 10% still must be vented. The rich solvent is stored in the rich solvent tank before CO_2 removal. Afterwards, it needs to be heated in the reboiler to be cleaned in the regenerator, where CO_2 is separated from the solvent. Once the solvent is cleaned, it is turned back into lean solvent at a concentration of 0.03 mol CO_2/mol MEA. The separated CO_2 is then compressed in the CCS unit to be further transported and stored outside of the unit. We do not address the issues of CO_2 transport and storage because these operations lie outside the capture unit, instead, we include a constant cost of transport and storage in the profit optimization.

The rich solvent storage is the key to providing the CCS flexibility characterized in this paper because the rich solvent can either be instantly regenerated within the hour that electricity is produced or stored in order to be regenerated later. The total volume of the solvent in the CCS unit is the capacity V of the rich solvent storage: if there are x m^3 of rich solvent stored, then V-x m^3 are stored in the lean solvent storage. As the two forms of storage are symmetric, we do not consider the lean solvent storage explicitly but focus instead on the inflows and outflows of the rich solvent storage tank. Thus, when we use 'storage' in this paper we refer to the rich solvent storage.

Figure A1.1 Schematic drawing of power plant with a post combustion unit



Source: (Schnellmann et al., 2019))

In our CCS unit, there are two main electricity-consuming processes: (i) the reboiler heat duty for regeneration and (ii) compression of CO_2. The reboiler heat duty refers to the energy used to (i) raise the temperature of CO_2-loaded solution to the boiling point, (ii) break the chemical bonds between CO_2 and absorption solvent, and (iii) generate water vapor to establish an operating CO_2 partial pressure needed for CO_2 stripping" (Sakwattanapong et al, 2005). Reboiler heat duty is variable because it depends on the volume of rich solvent processed (i.e., it depends on the amount of CO_2 captured). The increase of temperature is 10ºK for the reboiler heat duty, then uses 0.23 MWh/t CO_2 captured. The compression of CO_2 amounts to 15 kJ/mol CO_2 captured (~0.095 MWh/tCO2). In sum, the electricity penalty amounts to 0.326 MWh/t CO_2. For a CCGT power plant with a capacity of 1144.3MW[4], 90% capture rate and 0.348 tCO_2/MW emission intensity, if the electricity is produced at the rated capacity in baseload mode for 100% availability, then 359 tCO_2 is captured with CCS in an hour, that is 116 MWh of electricity penalty (or ca. 10% of electricity generated). All details on the calculations can be found below. For modelling purposes, it is nevertheless important to note that CCS can only capture or clean the solvent whenever the CCGT power plant is on because of the electricity penalty. Thus, electricity for CCS cannot be bought from the market but can only be used from the CCGT; and stored solvent cannot be cleaned whenever there is no electricity generation from the CCGT.

A.1.2. Calculations of technical parameters of CCS unit

Carbon captured by the solvent (tCO_2/m^3) = A

The amount of carbon captured per m^3 of solvent is derived from the difference in CO_2 loading in the MEA between rich loading state and lean loading state.

Carbon captured (A)	**0.09295**	**tCO_2/m^3 solvent**
Concentration of MEA in solvent (x_{solv})	0.30	wt%
Rich loading in solvent (α)	0.48	molCO_2/molMEA
Lean loading in solvent (β)	0.05	molCO_2/molMEA
CO_2 removal (Δ_{CO2}=α-β)	0.43	molCO_2/molMEA

$$A = D_{CO2} \times Molar\ mass\ CO2 \times x_{solv} / Molar\ mass\ MEA$$

<u>*Chemical data*</u>

Molar mass MEA	*61.08*	*g/mol*
Molar mass CO_2	*44.01*	*g/mol*
Density solvent	*1000*	*kg/m^3*

Electricity penalty (MWh/m^3) = B

The electricity penalty for the CCS unit includes both the electricity for the reboiler heat duty (B_{reb}) and the electricity for CO_2 compression (B_c).

Electrical penalty from reboiler heat duty (B_{reb})	**36.45**	**kJ/molCO_2**

$$B_{reb} = 0.75\eta Q$$

Reboiler heat duty (Q)	93.17	kJ/molCO_2
Temperature difference (Δ_T)	10	K

[4] Along with other technical parameters the assumption about 1144.3 MW of capacity of CCGT post combustion CCS comes from BEIS (2018).

Heat capacity of aqueous solvent[5] (C_p)	3.7	J/g.K
	0.114	kJ/(mol solvent.K)
Heat of absorption[6] (Q_R)	84.3	kJ/mol

$$Q = Q_R + \frac{C_P \Delta_T}{x_{solv} \Delta_{CO2}}$$

Carnot Efficiency (η)	0.522	
Turbine efficiency (T_C/T_H)	0.75	
T_C	298	K
T_H	623	K

$$\eta = 1 - \frac{T_C}{T_H}$$

Compression electricity (B_c)	**15**	**kJ/molCO_2**

The total electricity penalty is:
$B = B_{reb+}\ B_c$ =51.45 kJ/molCO_2 = 0.32 MWh/tCO_2 = 0.030185 MWh/m^3 solvent

Mass flow rate of solvent (m3/h) = F
In Schnellmann et al. (2019), the technical properties of the CCGT with 52% LHV and 90% capture gives a storage rate for CO_2 of 1.90 molCO2/s/MW. The change in CO_2 loading in the MEA is ΔCO_2 = 0.43 mol CO2/mol MEA, with a concentration of MEA in the solvent of 30 wt%. The molar mass of CO_2 is 61.08 g/mol so the amount of solvent needed to clean 1 mol of CO_2 captured is 0.473 kg. The mass flow rate of the solvent is therefore F = 0.473 kg/molCO_2 x 1.90 molCO_2/s/MW = 0.901 kg solvent/s/MW = 3.24 m^3 solvent/h/MW.

Volume of solvent storage tank (m^3) = V
The volume of the storage tank determines the degree of flexibility of the CCS. In our model, we assume that an empty tank can accommodate 1 hour of captured CO_2 (90% of total CO_2 produced) when the CCGT is producing at its maximum capacity Y. Because the flow rate of the rich solvent is equal to the flow rate of lean solvent, we also assume that a full storage tank can be emptied in 1 hour minimum. Therefore, we set V = F x Y = 3.24 m^3 solvent/h/MW x 1144.3 MW= 3707 m^3. For simplicity, we round the value to V=3700 m^3. We can double the flexibility of the CCS unit by doubling the volume of the storage tank. However, this will extend the time needed for solvent regeneration to a minimum of 2 hours.

7. Appendix 2 – Data inputs and assumptions

A.2.1. Techno-economic parameters of CCGT-CCS

The power generation data is calibrated based on Chyong and Newbery (2022) for CCGT power plants and the BEIS (2018) report on UK CCS technologies. The technical properties for the CCS unit come

[5] Weiland et al. (1997)
[6] Kim et al. (2014)

from Schnellmann et al. (2019) while CO_2 transport and storage assumptions are taken from Bates & Hill (2018).

Electricity generation and carbon capture

Thermal efficiency	ε	1.923	MW(th)/MW(e)
Emissions intensity	ϵ	0.348	tCO_2/MWh(e)
CCS capture rate	$\underline{I}$	0.90	tCO_2 captured/tCO_2 generated
Rich solvent storage capacity	V	3700	m^3
Installed capacity	Y	1144.3	MW
Carbon capture	A	0.09295	tCO_2/m^3
Electricity penalty	B	0.03019	MWh/m^3
Maximum flow rate of solvent	F	3700	m^3

Cost

Start-up cost	$Cost^{SU}$	54.48	£/start
Shut down cost	$Cost^{SD}$	1000	£/shut
Fixed OPEX for CCGT only	$Cost^{FixedOpex_{CCGT}}$	13,100	£/MW
Fixed OPEX for CCGT-CCS	$Cost^{FixedOpex_{CCS}}$	25,800	£/MW
Variable OPEX	$Cost^{VarOpex}$	4	£/MWh
CO_2 transport and storage	$Cost^{CO2_{TS}}$	23	£/tCO2
Solvent storage capex	Solvent_Capex	7.9	£M
CCGT-CCS plant capex	CCGT_CCS_Capex	968.3	£M

Thermal generation and unit commitment

Maximum ramp-up rate during start-up	SU	0.31 Y	MW/hour
Maximum ramp-down rate during start-up	SD	0.31 Y	MW/hour
Maximum ramp-up rate when committed	RU	3.44 Y	MW/hour
Maximum ramp-down rate when committed	RD	3.44 Y	MW/hour
Minimum stable generation (MSG)	$\underline{P}$	280	MWh
Maximum power output	$\underline{P}$	Y	MWh
Minimum up-time	UT	4	hours
Minimum down-time	DT	2	hours

A.2.2. Price forecasts

The reference time series that we use for the modelling are the day-ahead electricity prices in Great Britain, wholesale gas price trading at the National Balancing Point (NBP) and the UK carbon price. While gas and carbon prices are available in the FES, electricity prices are not forecasted by FES. Therefore, in order to derive a consistent electricity price time series we use FES projections of annual commodity prices (Table A. 1) as well as carbon prices (Table A. 2). The annual average gas prices are disaggregated into daily values using the normalised historical variations of NBP over 2012-2019.

Table A.2. 1: Wholesale annual average commodity prices

	2030	**2040**	**2050**
Natural gas, p/therm	48.3	54.6	60.4
Coal, $/tonne	68.7	72.0	74.9

Crude oil, $/bbl	64.5	66.2	65.6

Source: National Grid FES 2021

Table A.2. 2: Annual average carbon price (£/tCO2)

	2030	**2040**	**2050**
High case	43.50	131.08	218.66
Base case	43.50	69.60	104.15
Low case	32.31	40.78	72.44

Source: National Grid FES 2021; Notes: according to the 2021 FES, the base case carbon prices map on to the ST and CT scenarios, while the high case maps to the LW scenario, and the low case maps to the SP scenario.

The forecast of electricity prices for each of the four scenarios is decomposed in two steps: first, estimating the annual average, then fitting these annual averages for hourly variations.

The calculation of the annual average electricity price is based on the short-run marginal cost of electricity generation, i.e., the average of operational cost for all technologies weighted by their share in the generation mix. The forecast of the electricity generation mix is provided by National Grid FES 2021, the costs of generation in £/MWh come from BEIS[7] (2020) and IRENA[8] (2020) reports. For fossil fuel based generation, we add fuel costs to the operational costs using LHV values and fuel and carbon prices provided in National Grid FES 2021, as reported in the above tables.

For the second step, we need to develop a time series of daily electricity prices. We estimate the hypothetical electricity prices for 2030, 2040 and 2050 using the equation from Eager et al. (2012): $P_e = ae^{b(Installed\ capacity-load)}$, where a and b are parameters calculated based on historical data over 2012-2019 taken from Bloomberg terminal. Installed capacity values are derived from National Grid FES 2021. Load values are the FES annual averages fitted with normalised historical load profiles by season (Winter, Spring, Summer, High Summer, Autumn) and day type (weekday, holiday). Once we obtain these hypothetical electricity prices, we normalise them to fit the annual average electricity prices given in FES. Thus, the projected electricity prices are summarised in Table A.3 below.

The share of renewables will increase significantly in all FES scenarios, so we expect, ceterus paribus, to see increased price volatility under all scenarios. On the other hand, the National Grid scenarios assume a significant deployment of batteries by 2050, with 28.3 GW of electrical storage capacity in the LW scenario, 27 GW in the CT scenario and 17.8 GW in the ST scenario, and 16.4 GW in the SP scenario compared to 3.5 GW in 2020 (National Grid ESO, 2021). The ability of storage to smooth the electricity price curve by controlling the imbalances between supply and demand is not evaluated here as we do not model the whole electricity system. For this reason, we run a sensitivity analysis of our model for two levels of electricity price volatility –medium (calibrated to the 2016 volatility level) and high (double the 2016 volatility) – since we do not forecast the interaction between the intermittent generation from the renewables and storage capacity and their effects on electricity prices.

Table A.2. 3: Annual average electricity prices (£/MWh)

	2030	**2040**	**2050**
FES LW	61.65	67.44	69.74
FES ST	59.31	59.95	63.52
FES CT	61.02	62.36	64.18

[7] Cost of generation from coal, gas and nuclear taken from BEIS (2020)

[8] Cost of generation from biomass, hydro, wind, solar, waste and other renewables taken from IRENA (2020)

FES SP	55.11	60.71	65.85

Source: Own calculation based on National Grid FES (National Grid ESO, 2021) commodity, carbon prices, and generation costs from IRENA (2020) and BEIS (2020) .