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Deploying gas power with CCS: The role of operational flexibility, merit order and the future energy system

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Keywords Carbon capture and storage; Flexibility; Combined cycle gas turbine (CCGT); Power plants; Electricity system; Amine solvents

JEL Classification L94, Q4

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Deploying gas power with CCS: The role of operational flexibility, merit order and the future energy system

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Abstract

Combined cycle gas turbine (CCGT) power plants are an important part of many electricity systems. By fitting them with carbon capture their CO_2 emissions could be virtually eliminated. We evaluate CCGT plants with different variations of post combustion capture using amine solvents, covering a range of options, including solvent storage, partial capture and shifting the energy penalty in time. The analysis is based on the UK electricity system in 2025. The behaviour of individual CCGT plants is governed by the plant's place in the merit order and to a lesser extent by CO_2 reduction targets for the electricity system. In the UK, CCGT plants built from 2016 onwards will emit ~90% of the CO_2 emissions of the whole CCGT fleet in 2025. The typical 'base case' CCGT plant with capture is designed to capture 90% of the CO_2 emissions and to operate dynamically with the power plant. Downsizing the capture facility could be attractive for low-merit plants, *i.e.* plants with high short-run marginal costs. Solvent storage enables electricity generation to be decoupled in time from the energy penalty associated with carbon capture. Beyond a few minutes of solvent storage, substantial tanks would be needed. If solvent storage is to play an important role, it will require definitions of 'capture ready' to be expanded to ensure sufficient land is available.

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1. Introduction

An increasing share of electricity supply is being met by renewable capacity, posing challenges for the power grid since wind and solar resources vary in time and space and their power output is difficult to predict. To compensate for that variability, electricity systems will require thermal power plants to be more flexible than previously, adjusting their power output more frequently, and over greater ranges to respond to large and sudden changes in power output from renewables. Flexible thermal generators, primarily combined cycle gas turbine (CCGT) power plants, ensure that the supply and demand of electricity remains balanced and thus provide valuable balancing services for electricity systems. Although the utilization of these plants will decrease, they will continue to be one of the last major sources of CO_2 emissions on the grid in decarbonized energy systems [1].

Many of these thermal power plants could be fitted with carbon capture and storage (CCS) technologies [2] – a step that could virtually eliminate the CO_2 emissions associated with the generation of electricity, while still providing dispatchable power in a flexible manner [3–6]. It comes, however, with an energy penalty. This, along with the additional equipment required and the adjustments that must be made to the design of the power plant adds cost. There are however opportunities for capital cost reductions and maximisation of the revenue they generate through technology modifications, and adjustments in power plant operating methodology. Reduction of the capital cost, as well as increased flexibility, could significantly increase the attractiveness of thermal power plants with CCS for deployment in a future electricity system [7]. A key question for technology developers is to understand how flexibility in the design and operation of new power plants with CCS or CCS-retrofits [8] can be exploited to maximise earned revenue and thus be able to attract interest and investment.

Currently, the most industrially relevant method of carbon capture is post combustion capture of CO_2 using amine solvents. This involves chemical absorption of CO_2 into an amine solvent in the 'absorber' and subsequent regeneration in the 'regenerator' by increasing the temperature. The regeneration releases high-purity CO_2, which is then compressed, ready for sequestration underground.

We evaluate the flexibility in design and operation of combined cycle gas turbine (CCGT) power plants with different variations of post combustion capture of CO_2 using amine solvents. We cover the full range of technological and a selection of operational options, beginning with the most frequent configuration, which we define as the 'base case'. In this configuration the capture facility is sized to capture 90% of the CO_2 emissions at peak power output and to operate dynamically with the power plant. The net capacity, *i.e.* the electrical output to the grid, will be smaller, compared to an equivalent plant without CCS, due to the energy penalty associated with carbon capture [9,10]. Research has shown that the addition of carbon capture does not significantly affect the ramp rates and raises the level of minimum stable generation only by a small amount [11,12].

A number of opportunities are available to diverge from this 'base case'. The vast majority of the energy penalty associated with capturing CO_2 is incurred when the rich solvent is regenerated. Therefore the penalty can be shifted in time by storing CO_2-rich solvent and regenerating it at a later time. A limited amount of storage is accessible by altering the lean loading of the solvent [13], but generally the addition of rich and lean solvent storage tanks is required. Access to storage increases the options for independently altering the capacity of particular units of the capture facility, *e.g.* the stripper. The energy penalty can be avoided altogether by by-passing the capture unit and venting the flue gas [14–18]. Accessing all these opportunities is based on operational decisions and three major design decisions:

1. **Capacity of the absorber** to process flue gas. Surplus flue gas must be vented.
2. **Capacity to store CO_2 as rich solvent**, enabling electricity generation to be decoupled from the energy penalty associated with capturing the CO_2. This can be done by (i) varying the lean loading of the solvent or (ii) adding rich and lean solvent storage tanks. When storage capacity is exhausted, the power output to the grid must be decreased or flue gas must be vented.
3. **Capacity of the regenerator and compressor**, affecting the rate at which CO_2-rich solvent can be regenerated. The size of the regenerator and compressor must be matched since storage of large volumes of CO_2 gas at low pressure is not practical, due to high capital cost. If storage is utilized, the size of the regenerator is not dictated by the size of the absorber.

A simple schematic diagram of post combustion capture is shown in Figure 1. The unit operations affected by decisions 1 to 3 are highlighted.

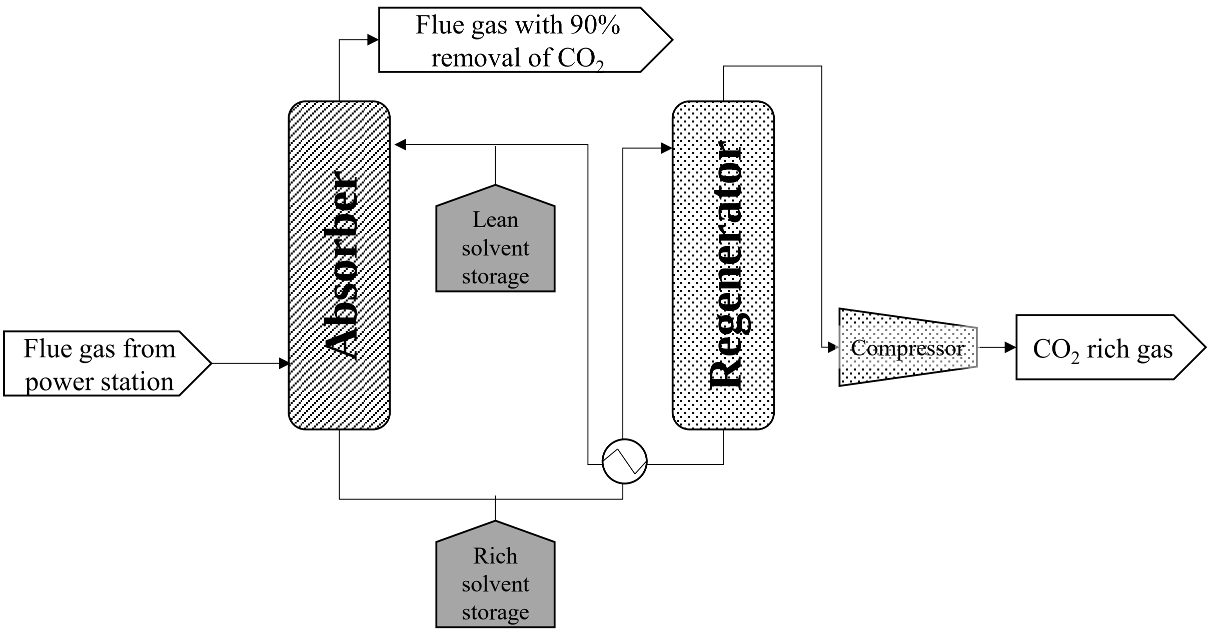

Figure 1. Schematic diagram of a power plant with a post combustion capture facility. The units affected by design decisions 1 (), 2 () and 3 () are highlighted.

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Depending on decisions 1 to 3, the need to reduce the net capacity can be lessened or even eliminated altogether. The net capacity of the power plant is the gross capacity minus the energy penalty associated with capturing CO_2 at peak power output. The energy penalty can be reduced by down-sizing the absorber and processing only part of the flue gas (design decision 1) or it can be avoided altogether at peak power output by shifting the energy penalty in time to periods of low power output (design decisions 2 and 3).

Since external factors, such as the generation mix on the grid are important, the evaluation is done in the context of different future energy scenarios.

2. Modelling

We evaluated CCGT power plants with different configurations of carbon capture in the year 2025 using a combination of the Energy Policy Research Group (EPRG) electricity system model and a general model of a CCGT power plant with CCS.

The outputs of the EPRG electricity system model, in particular the power output profiles, were used as inputs to the power-plant-scale model, to determine the behaviour of a general, single CCGT power plant with different configurations of CCS. To enable the coupling between the electricity system and this power-plant-scale model it was assumed that CCGT plants with CCS would fulfil the same role in the electricity system as conventional CCGT plants, *i.e.* as dispatchable power. This is reasonable since, by 2025, CO_2 prices are unlikely to have risen sufficiently to fundamentally alter plant economics. Furthermore only a small proportion of CCGT plants could be fitted with CCS in this time and they would therefore have a negligible effect on the behaviour of other plants in the electricity system.

2.1. Electricity System Model

The unit commitment and economic dispatch model optimises the scheduling of electricity supply for least cost at hourly intervals over the course of a year. It models the British (GB) electricity system at power plant level and includes major techno-economic constraints such as ramping, minimum up and down time and security of supply considerations (for details see Chyong *et al.* [19]). All generation plants were assumed to have no CCS and publicly available information for generation capacity and types was used. The model was calibrated to the generation mix in 2015 to derive 'unobservable' parameters, *i.e.* cost functions explaining the differences between modelling results and historical generation patterns for 2015. The model was then specified for four different Future Energy Scenarios (FES) for GB in 2025 developed by the UK system operator, National Grid: Two Degrees, Community Renewables, Consumer Evolution and Steady Progression [20].

Unlike previous FES editions, the current version focuses on two important aspects of a future electricity system: level of decentralization and speed of decarbonization. The focus on decentralization is an update to the FES scenario framework. It is largely to reflect the increasing importance of the decentralization trend in the energy industry brought about by cheaper small-scale (renewable) generation sources. Thus, the four FES scenarios are differentiated along those two aspects: the speed of decarbonization is assumed to be driven by policy, economics and consumer attitudes, while the level of decentralization reflects the developments in energy supply and how close it is to the end consumers. While all four scenarios see a rather ambitious roll out of renewable energy supply, only two of them – Community Renewables and Two Degrees – meet the UK's statutory 2050 carbon reduction target [21]. The approach to modelling the GB electricity system in 2025 is to follow the main assumptions developed in the four FES scenarios. Developments of the GB electricity system to 2025 based on these four scenarios are summarised in Table 1, below. FES also uses three commodity price scenarios (low, base case and high). For our modelling we chose the base case commodity price scenario with the four FES scenarios. By 2025, National Grid's base case commodity price scenario assumes that gas prices will rise by 26% which is reasonable given that 2025 is not far away and that gas markets are oversupplied in the period to 2025. It further assumes that the carbon price will rise to £35/tCO_2 and given the recent reforms of the EU ETS which recently drove up the EU ETS carbon price to *ca.* €20-25/tCO_2 this is also reasonable. Commodity prices are important for any modelling of energy markets, especially when there is inter-fuel competition between coal, gas and other fossil fuel generation technologies. However, GB's 2025 generation will have no coal on the system [22] and only nuclear, gas and biomass (along with some distribution-connected oil plants). So, in a sense, gas price and carbon costs are important but will not change the results of this research as the focus here is on different CCGTs with different efficiency levels and hence their place in the merit order.

Table 1. Input parameters to the electricity system model for the different Future Energy Scenarios. Non-biomass thermal renewables includes generation from anaerobic digestion, waste, landfill gas, animal biomass and sewage gas.

	2015	2025 (relative to 2015)			
		Community Renewables	**Two Degrees**	**Steady Progression**	**Consumer Evolution**
Gross Demand, TWh	299.7	315.4	309.4	327.5	328.1
Generation					
Wind, TWh	8.4	22.2	17.9	14.5	16.2
Solar, TWh	4.1	6.5	6.5	6.3	6.5
Hydro run-of-river, TWh	15.6	28.9	28.4	24.0	25.5
CHP, TWh	16.8	19.8	18.3	13.5	15.1
Non-biomass thermal renewables, TWh	2.0	0.0	0.0	0.0	0.0
Distribution connected oil, TWh	4.6	5.4	5.0	5.3	5.7
Other, TWh	215.6	131.9	111.8	162.8	170.1
Residual Demand, TWh	15.9	20.0	20.0	20.0	20.0
Prices					
Gas price, £/MWh(th)	299.7	315.4	309.4	327.5	328.1
Carbon price, £/tCO_2	32.5	100.8	121.6	101.2	89.1

We model thermal power plants (biomass, nuclear, oil and gas-fired) while treating all generation data in Table 1 (wind, solar, hydro, *etc.*) as exogenous to derive the residual demand. The outputs from the model are hourly generation profiles of each thermal power plant. The model optimises generation outputs from these plants such that total supply from all thermal power plants meets residual demand at least cost at hourly intervals.

2.2. Modelling at the Power Plant Scale

The model at the power plant scale considers the 'base case', described earlier, and any variations associated with operational decisions and the design decisions 1 to 3, also given earlier, *i.e.* absorber capacity, solvent storage and regenerator and compressor capacity. It assumes that the addition of carbon capture does not affect the power plant, except for the energy penalty incurred due to the extraction of steam or the use of electricity. The energy penalty, *i.e.* kJ per tCO_2, is assumed to be fixed across the range of possible power plant loads, which is a reasonable first-order estimate. The energy penalty is assumed to be made up of three major contributions [23]. The first is the heat required to raise the temperature of the solvent stream to the stripper temperature and the second is the heat required to balance the enthalpy of reaction associated with regenerating the solvent and releasing the CO_2 in the stripper. The final contribution is the electrical energy required to compress the CO_2, ready for sequestration. Other contributions, such as electrical energy to pump solvent between the absorber and the stripper, are negligible.

In this work, the amine solvent was assumed to be an aqueous solution of 30 wt% monoethanolamine (MEA). Solubility properties of CO_2 in the solvent were taken from Gabrielsen *et al.* [24]. The capture plant was assumed to operate with a lean solvent loading of 0.05 mol CO_2/mol MEA. The rich solvent loading was ~0.48 mol CO_2/mol MEA, in equilibrium with the flue gas entering the absorber, assumed to be at 40°C with a mole fraction of CO_2 of 0.05. Heat capacities for the solvent were taken from Weiland *et al.* [25]. The full equations for determining the energy penalty are described in Supplementary Information.

A CCGT power plant with CCS can operate in a number of different modes, depending on its power output to the grid and the capacity of its different units. A key variable of the power plant model is the power output to the grid at which the plant switches between having to vent CO_2 or store CO_2 in rich solvent and having spare capacity to regenerate CO_2 – which we label the 'threshold output'. Above this load, some or all of the CO_2 must be stored or vented. The threshold output is fixed for a particular plant and is given by:

$$\text{Threshold output (MW)} = (\text{Gross capacity (MW)} - \text{Energy penalty(MW)}) \qquad 1$$

The energy penalty is the energy required to capture 90% of the CO_2 emissions when the plant is operating at its gross capacity. For the base case plant there is never a need to store or vent CO_2. Holding the gross capacity of the plant constant, the net capacity of the plant can be increased, but it becomes necessary to vent CO_2 when the plant is supplying large amounts of power to the grid. Alternatively, CO_2 can be stored in rich solvent if storage capacity is available.

If the absorber is down-sized, corresponding to design decision 1, it is no longer possible to process all the flue gas when the plant is operating at peak power output. The maximum rate at which flue gas can be processed, $\mathrm{Rate_{flue}}$, expressed as MW equivalents, is fixed for a particular plant and is given by:

$$\mathrm{Rate_{flue,max}\ (MW) = Gross\ capacity\ (MW) * Absorber\ size} \qquad 2$$

where the absorber size is a fraction relative to the base case plant. Flue gas in excess of $\mathrm{Rate_{flue,max}}$ must be vented, while flue gas equal to or below this value can be processed. The rate at which flue gas is processed at a particular point in time is given by:

$$\mathrm{Rate_{flue}\ (MW) = MIN(Rate_{flue,max}\ (MW), Gross\ power\ output\ (MW))} \qquad 3$$

The gross power output is the sum of the net power output and any energy penalty incurred due to regeneration of solvent at a particular point in time. Whether the CO_2 in the processed flue gas can be captured depends on the rate at which solvent can be regenerated and on the availability of solvent storage.

The rate at which solvent can be regenerated depends on the regenerator capacity and the spare power available from the power plant. The spare power, $\mathrm{Power_{spare}}$, varies with time and is given by:

$$\mathrm{Power_{spare}(MW) = Gross\ capacity\ (MW) - Power\ output\ (MW)} \qquad 4$$

The maximum rate at which rich solvent can be regenerated, $\mathrm{Rate_{regen}}$, is therefore given by:

$$\mathrm{Rate_{regen,max}(MW) = Gross\ capacity * MIN\left(\frac{Power_{spare}}{Energy\ penalty}, Regenerator\ size\right)} \qquad 5$$

where the regenerator size is a fraction relative to the base case. If there is no solvent storage or the rich solvent tank is empty, the actual rate of regeneration, $\mathrm{Rate_{regen}}$, may be lower than $\mathrm{Rate_{regen,max}}$ and equal to the gross power output (sum of net power output and the energy penalty associated with that power output). If there is storage available and the rich tank requires emptying, $\mathrm{Rate_{regen} = Rate_{regen,max}}$.

If storage of rich solvent is available, the level of stored solvent (MWh), store, can range between 0 and $\mathrm{store_{max}}$. Storage is modelled as a mass balance:

$$\frac{d\text{store}}{dt} = \text{Rate}_{\text{flue}} - \text{Rate}_{\text{regen}} \qquad 6$$

When $\text{store} = 0$, $\text{Rate}_{\text{regen}} \leq \text{Rate}_{\text{flue}}$, while when $\text{store} = \text{store}_{\text{max}}$, $\text{Rate}_{\text{regen}} \geq \text{Rate}_{\text{flue}}$. When the plant is switched off, no power is produced and so no solvent can be regenerated. Any existing rich solvent is assumed to remain in storage. If $\text{Rate}_{\text{regen,max}} \leq \text{Rate}_{\text{flue}}$, excess flue gas must be vented. Under rare circumstances if $\text{regenerator size} > \text{absorber size}$, flue gas may be vented at the same time as CO_2, stored in rich solvent at an earlier point in time, is being regenerated.

The power plant model was used to determine the operation of a CCGT power plant supplying power to the grid, as per the power output profiles of the EPRG electricity system model. The power output profiles were the net power output of the CCGT plant with CCS. The power plant model was implemented in MATLAB. If storage capacity was available, this was initially empty on 1st January 2025. Results from the power plant model included the fraction of CO_2 captured over the whole year, the gross and net power output profiles, the venting profile and the storage profile. The gross power output profile is the sum of the net power output profile and any energy penalty incurred due to regenerating solvent.

3. Results

3.1. Electricity System Model

In total there are 43 CCGT plants with a combined installed capacity of 41.5 GW in 2025. This is based on the capacity in 2015, and the plants that are likely to be built by 2025. There is limited uncertainty in this due to the long lead time for building new plants. In 2025, electricity from CCGT plants accounts for 17.2%, 20.0%, 28.4% and 28.2% of total electricity generated in the Two Degrees, Community Renewables, Consumer Evolution and Steady Progression scenarios from National Grid respectively. A summary of key variables of the whole CCGT fleet in 2025 for the four different scenarios is shown in Table 2. The capacity factor of a power plant is the average power generated compared to the rated capacity.

The CCGT fleet exhibits similar behaviour in the Two Degrees and Community Renewables scenarios. These two scenarios are compatible with meeting the 2050 target that the UK has set for reducing greenhouse gas emissions by 80% below 1990 levels. The CCGT fleet exhibits similar behaviour in the Consumer Evolution and Steady Progression scenarios. These scenarios follow a slower decarbonisation pathway and utilised CCGT plants more heavily. This indicates that the behaviour of the whole CCGT fleet is governed more strongly by the stringency of the CO_2 emissions target than the precise manner by which it is achieved. In every scenario, the standard deviation of each of the variables was large, indicating that there is substantial variation in the behaviour of individual CCGT plants.

Table 2. Summary of key variables of the whole CCGT fleet from the EPRG electricity system model for four different scenarios in 2025 from National Grid. The mean and standard deviation (SD) for the whole fleet is given. Time refers to the average length of a single instance at a particular operating point, *e.g.* each time a power plant in the Two Degrees scenario was brought to its maximum power output, it spent 10 hours operating at this level. Total time is the sum of all the instances over the whole year.

	Two Degrees		**Community Renewables**		**Consumer Evolution**		**Steady Progression**	
Variable	**Mean**	**SD**	**Mean**	**SD**	**Mean**	**SD**	**Mean**	**SD**
Capacity factor	0.106	0.147	0.119	0.154	0.185	0.211	0.175	0.204
No. ramps (/year)	178	264	203	294	303	403	286	387
No. times switched off (/year)	23	28	34	31	31	32	31	32
Time at maximum power output (hours)	10	245	8	202	4	6	4	6
Time at minimum stable generation (hours)	10	16	7	12	7	11	7	11
Time switched off (hours)	262	998	182	766	166	645	171	656
Total time switched on (hours/year)	2259	3031	2346	2753	3273	3036	3162	3066
Total time switched off (hours/year)	6501	3031	6414	2753	5487	3036	5598	3066

The so-called merit order ranks available sources of electrical generation based on ascending short-run marginal cost of generation and the amount of electricity generated. We follow the convention that high-merit plants have the lowest short-run marginal cost, similar to convention of the Central Electricity Generating Board (CEGB). High-merit plants are therefore generally deployed first. Factors such as thermal efficiency and location influence the generation costs of an individual CCGT plant. The UK's heavy reliance on CCGT plants means that these plants span a wide range of the merit order. Figure 2 shows the merit order of the CCGT plants within the CCGT fleet, based on the average gas price assumed for 2025 (£19.98/MWh(th)) and a carbon price of £35.42/tCO_2 from the FES scenarios.

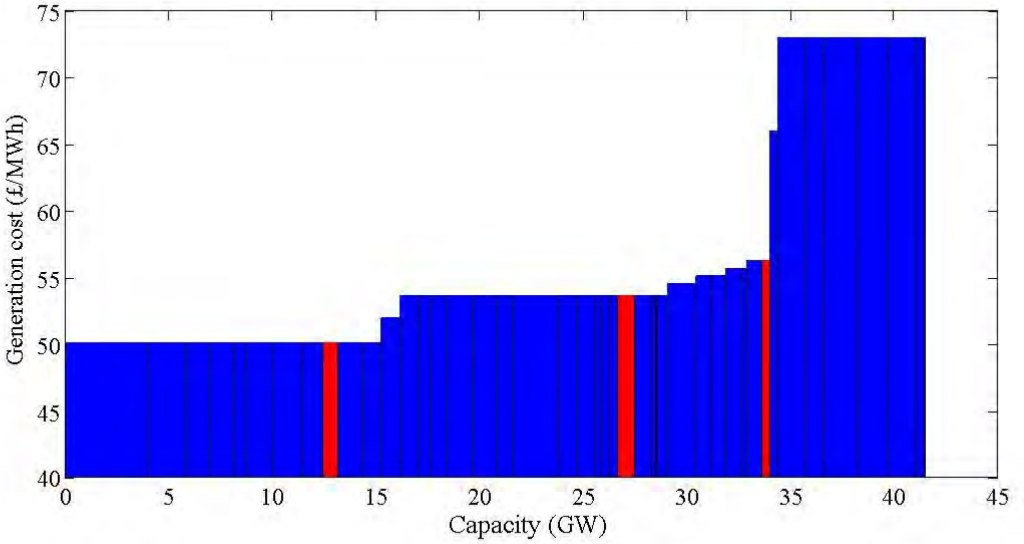


Figure 2. Merit order of plants in the CCGT fleet. The selected plants are marked red, from left to right they are (i) a 710 MW plant in New Keadby, (ii) an 805 MW plant in Damhead Creek, and (ii) a 401 MW plant in Corby.

Since the standard deviation of the variables of the whole fleet is large, the behaviour of three different CCGT plants with high-, mid- and low-merit were analysed further. The three selected plants are highlighted in Figure 2. From high- to low-merit, the plants were respectively: (i) a 710 MW plant in New Keadby, currently operated by SSE Ltd. and built in 2016, (ii) an 805 MW plant in Damhead Creek, currently operated by Scottish Power Ltd. and built in 2000, and (ii) a 401 MW plant in Corby, currently operated by Corby Power Ltd. and built in 1993. A summary of key variables from the EPRG electricity system model for these three different CCGT plants is shown in Tables 2a-c.

Figure 4 shows sample power output profiles of these three plants from 8th to 18th January and 10th to 20th July 2025. These are consecutive periods of ten days with the highest and lowest levels of intermittent renewable (wind and solar) generation respectively. The wind and solar profiles for the Two Degrees scenario are shown in Figure 3, with the selected time periods highlighted. The other scenarios had the same solar and wind patterns, but they were adjusted from 2015 using different scaling factors, as described in Section 2.1.

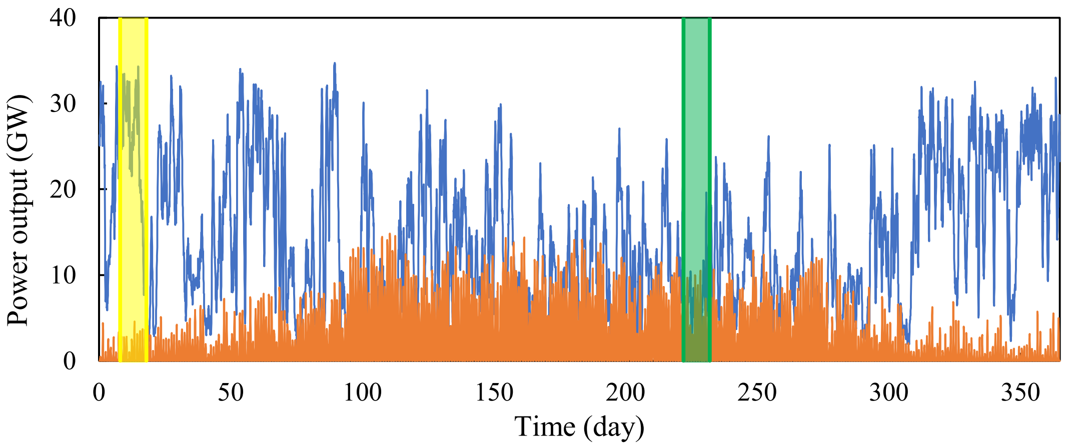


Figure 3. Assumed solar (——) and wind (——) generation in 2025 for the Two Degree scenario. Highlighted are the ten consecutive days with the highest ( ) and lowest levels ( ) of intermittent renewable generation.

The point at which a CCGT plant sits in the merit order has a significant effect on its behaviour. Tables 3a-c and Figure 4 show that the low-merit plant has a low capacity factor, spending most of the time at minimum stable generation, providing spinning reserve, or switched off. Occasionally during periods of high demand or limited supply of intermittent renewables, it ramps up to higher power outputs for a short period of time. The high-merit plant spends longer times above minimum stable generation, ramping frequently. High-merit CCGT plants have capacity factors up to ~ 0.42 for the scenarios meeting the 2050 target for CO_2 emissions and ~ 0.58 for the other scenarios. Individual plants in the two scenarios meeting the 2050 targets have similar power output profiles. The same plants are utilized more heavily in the two other scenarios with a slower decarbonization pathway. This demonstrates that the behaviour of individual CCGT plants depends mainly on the emissions target and is less sensitive to the precise manner by which it is achieved.

Table 3a. Summary of key variables for the 401 MW plant in Corby (a low-merit plant), from the EPRG electricity system model for four different scenarios in 2025 from National Grid.

Variable	**Two Degrees**	**Community Renewables**	**Consumer Evolution**	**Steady Progression**
Capacity factor	0.005	0.007	0.016	0.015
No. ramps (/year)	0	0	4	1
No. times switched off (/year)	3	5	8	7
Time at maximum power output (hours)	40.3	42.7	1.3	2.0
Time at minimum stable generation (hours)	40.3	42.7	37.3	44.7
Time switched off (hours)	1719.8	1214.9	822.9	917.9
Total time switched on (hours/year)	161	256	531	499

Total time switched off (hours/year)	8599	8504	8229	8261

Table 3b. Summary of key variables of the 805 MW plant in Damhead Creek (mid-merit plant) from the EPRG electricity system model for four different scenarios in 2025 from National Grid.

Variable	Two Degrees	Community Renewables	Consumer Evolution	Steady Progression
Capacity factor	0.031	0.050	0.104	0.095
No. ramps (/year)	66	68	164	135
No. times switched off (/year)	15	30	36	41
Time at maximum power output (hours)	1.8	2.2	2.2	2.3
Time at minimum stable generation (hours)	6.9	9.2	9.5	9.7
Time switched off (hours)	474.5	235.6	164.7	150.1
Total time switched on (hours/year)	710	1222	2501	2306
Total time switched off (hours/year)	8050	7538	6259	6454

Table 3c. Summary of key variables of the 710 MW plant in New Keadby (high-merit plant) from the EPRG electricity system model for four different scenarios in 2025 from National Grid.

Variable	Two Degrees	Community Renewables	Consumer Evolution	Steady Progression
Capacity factor	0.394	0.414	0.578	0.554
No. ramps (/year)	630	697	864	822
No. times switched off (/year)	21	42	2	6
Time at maximum power output (hours)	3.2	3.5	4.8	4.6
Time at minimum stable generation (hours)	10.0	7.0	5.8	6.3
Time switched off (hours)	25.5	30.8	35.5	28.7
Total time switched on (hours/year)	8225	7466	8689	8588
Total time switched off (hours/year)	535	1294	71	172

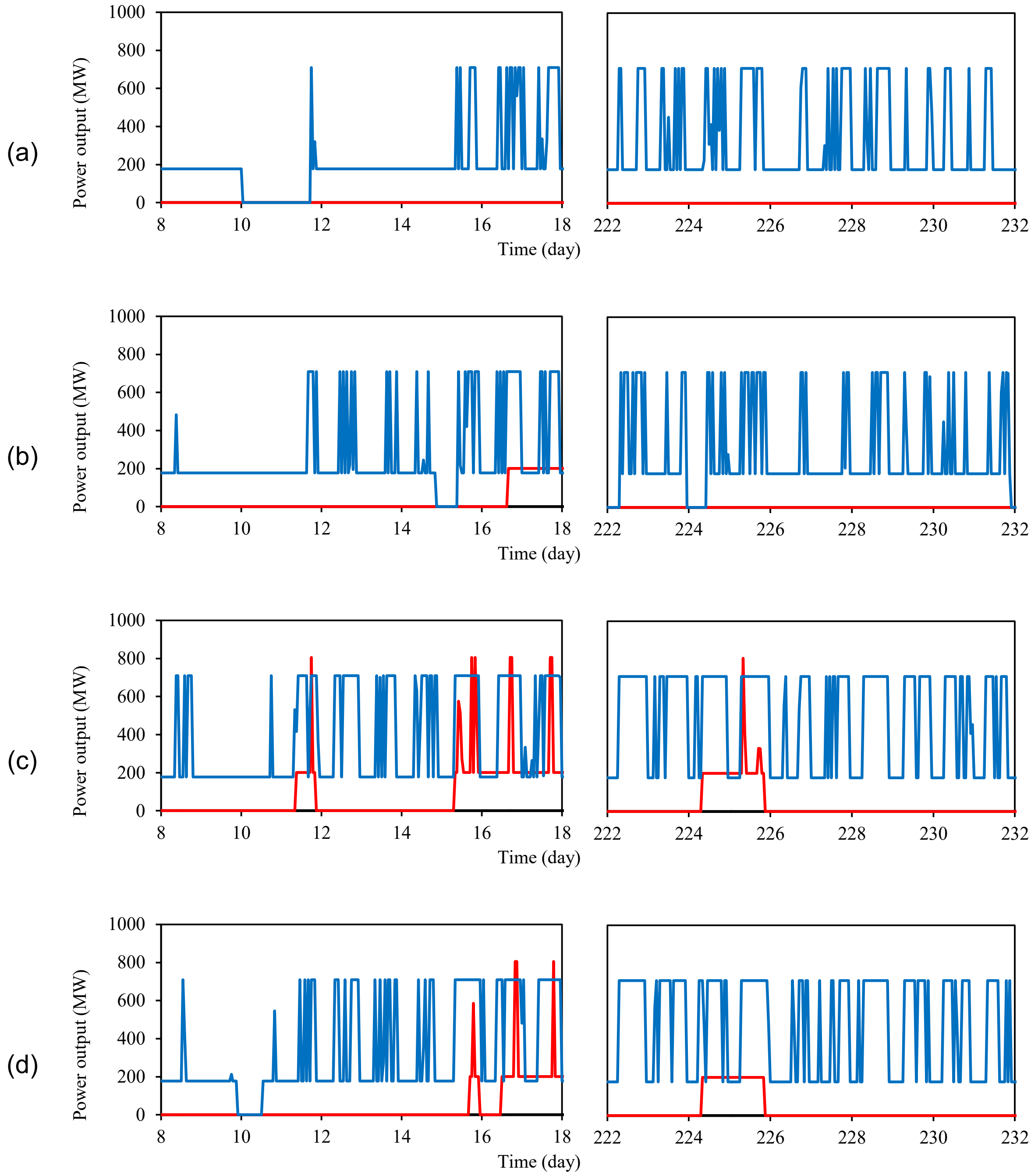


Figure 4. Sample power output profiles of low- ( ), mid- ( ), and high-merit ( )CCGT power plants in each of the four different future energy scenarios: (a) Two Degrees, (b) Community Renewables, (c) Consumer Evolution and (d) Steady Progression. For the low-, mid- and high-merit plants, the maximum power output of the plants was 401, 805 and 710 MW respectively.

For a CCGT power plant the maximum possible capacity factor is ~ 0.9, accounting for downtime required for maintenance. In reality, capacity factors of CCGT plants are lower and vary significantly, which has a significant effect on the distribution of annual CO_2 emissions across the fleet. High-merit plants are dispatched more frequently and therefore have higher capacity factors and annual CO_2 emissions. Figure 5 shows the contribution of each CCGT plant to the CO_2 emissions of the whole CCGT fleet for the case of the Two Degrees scenario.

The three selected plants are highlighted in Figure 5. The total emissions in 2025 for the Two Degrees scenario are ~ 17MtCO_2. As expected, high-merit plants are responsible for the vast majority of CO_2 emissions.

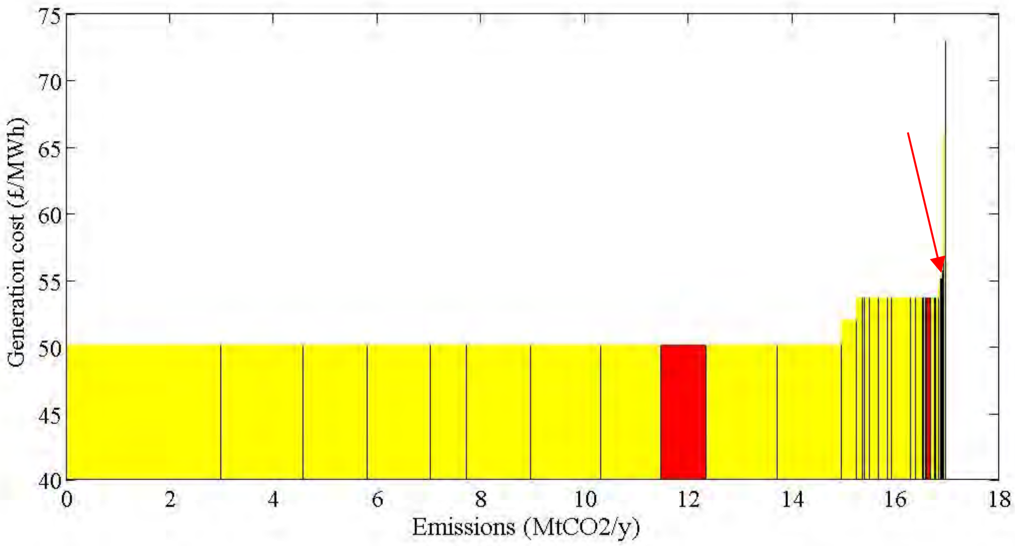


Figure 5. Contribution of different CCGT plants to the CO_2 emissions of the whole CCGT fleet. The selected plants are marked red. The location of the low-merit plant is indicated with an arrow.

3.2. Power Plants with CCS

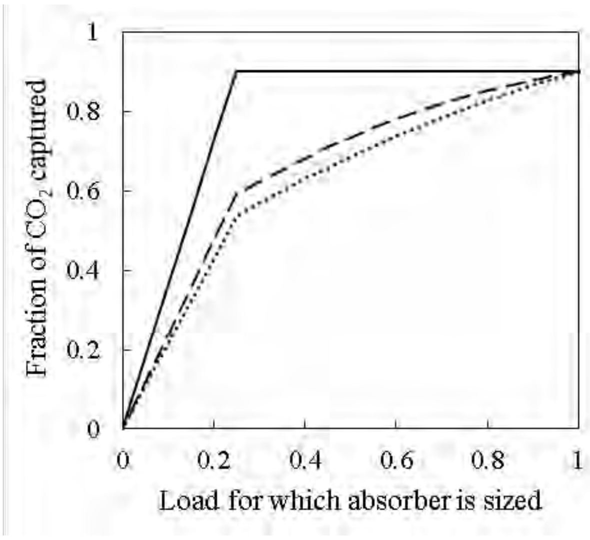
Based on the power plant model, the energy penalty associated with carbon capture is estimated to decrease the net power output of a CCGT power plant by ~ 6.5 percentage points. The relative contributions of heating the solvent, balancing the enthalpy of reaction and compressing are 0.12, 0.59 and 0.29 respectively.

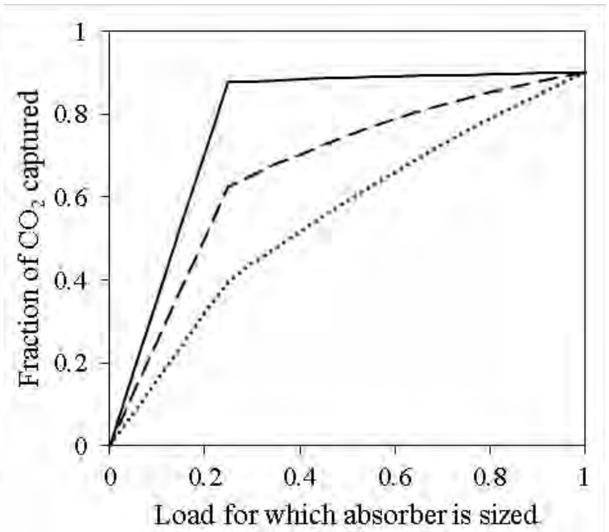
The impact of the different design decisions given in Section 2.2 on the proportion of CO_2 captured was evaluated by operating the different power plant designs to match the power output profiles shown in Section 3.1. Results from the Two Degrees and the Steady Progression scenario are used to illustrate the effect of different CO_2 reduction targets. The results from Community Renewables are similar to Two Degrees, while the results from Consumer Evolution are similar to Steady Progression.

For the 'base case' plant, 90% of the CO_2 emissions are captured and the capture facility is operated dynamically with the power plant. This means that the net capacity is the gross capacity minus the energy penalty associated with capturing CO_2 at peak power output.

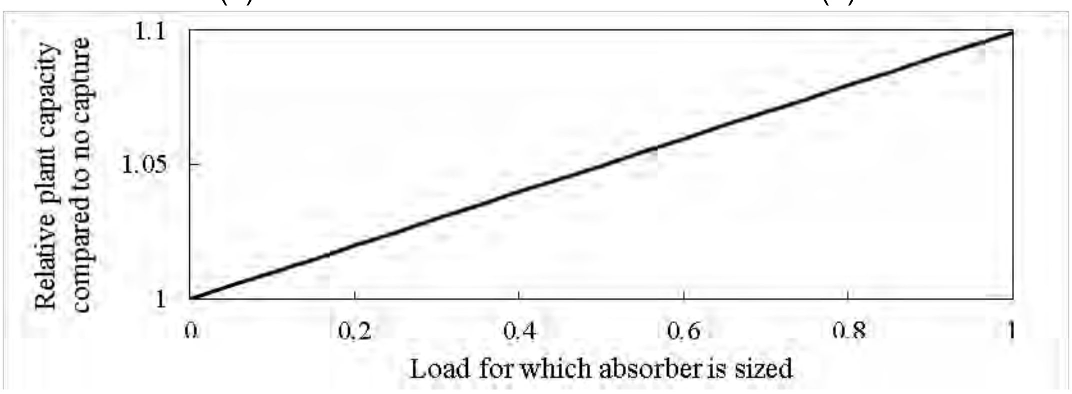
The first design decision is to specify the size of the absorber. Following the lines in each of the figures from right to left, Figure 6 (a) and (b) shows the fraction of CO_2 captured in 2025 as the absorber's capacity to process flue gas is decreased. The point where the lines cross x = 1 corresponds to the 'base case' plant. In the absence of storage, the energy penalty associated with carbon capture cannot be shifted in time, meaning that the remainder of the carbon capture system (regenerator, compressor) has to be sized to the same capacity as the absorber. As the size of the carbon capture system is decreased, the capacity of the power plant can also be decreased due to a reduction in the maximum energy penalty, as seen in Figure 6 (c).

As the size of the absorber is decreased, the fraction of CO_2 captured decreases. For all plants there are two linear regions with a steeper gradient below the point of minimum stable generation (MSG). MSG is at a load factor of 0.25. Low-merit plants able to retain greater levels of capture for the same absorber size and the change of gradient is more pronounced. For the Two Degrees scenario, sizing the absorber to process the volume of flue gas produced at MSG leads to a 0, 31 or 36 percentage point reduction in the amount of CO_2 captured compared to the base case for the low-, mid- and high-merit plants respectively. For the Steady Progression scenario, the reductions are 2, 27 and 50 percentage points respectively. The scenario therefore has a particularly strong impact on the high-merit plants.





(a) (b)



(c)

Figure 6. Fraction of CO_2 captured with the absorber sized based on the flow of flue gas at different loads. Results are shown for the low- (——), mid- (— —) and high-merit (......) plants in the (a) Two Degrees and the (b) Steady Progression scenario; (c) the required capacity of the power plant, relative to the same plant with no capture.

Rather than requiring an increase in the gross capacity of the power plant, all the flue gas could instead be vented when the plant is operating at maximum power output, leaving no spare heat or electricity available for regenerating the amine solvent. This is equivalent to retrofitting an existing CCGT plant with CCS, while keeping the net capacity of the plant the same. This is an operational rather than a design option. Under these circumstances, with a full-size absorber, the fraction of CO_2 captured is unchanged for the low-merit plant and drops from 90% to 71% and 58% for the mid- and high-merit plants respectively in the Two Degrees scenario. The fraction of CO_2 captured drops to 89%, 71% and 39% for the low-, mid-, and high-merit plants respectively in the Steady Progression scenario. This corresponds, in Figure 7, to the starting point of each curve along the y-axis. The choice of scenario mainly impacts the high-merit plant.

To reduce the amount of CO_2 released, CO_2 could be stored in the solvent, with the rich solvent being regenerated at a later time, decoupling electricity generation from the energy penalty associated with carbon capture. This is possible because the vast majority of the energy penalty is associated with regenerating the solvent. Storage capacity can be made available by allowing the loading of CO_2 in the lean solvent to rise or by increasing the inventory of solvent and adding rich and lean solvent tanks. The former is an operational decision, while the latter is the second design decision. Figure 7, moving from left to right in each of the sub-figures, shows the increase in rate of CO_2 captured as storage capacity is added. In the simulations, it was assumed that on 1st January the storage capacity was empty. The amount of storage was defined in terms of the number of hours of peak power output that could be sustained with 90% capture of CO_2 emissions. The low-merit plant hardly operates at peak power output, so it has a very high capture rate regardless of the storage capacity. For the other plants, addition of storage capacity improves the rate of carbon capture, but with diminishing returns.

It is helpful to convert storage capacity to a required volume of tank. For a CCGT plant without carbon capture with methane as fuel, a thermal efficiency of 59% (LHV) and 90% capture, CO_2 must be stored at a rate of 1.90 mol CO_2/s/MW. The molar mass of MEA is 61.08 g/mol and if the solvent is a 30 wt% aqueous solution of MEA, this gives 0.204 kg solvent/mol MEA. For a change in loading of MEA of 0.43 mol CO2/mol MEA between the lean and rich state, 0.473 kg solvent circulates for every mole of CO_2 captured. The mass flow rate of solvent is therefore 0.473 × 1.90 = 0.901 kg solvent/s/MW. Given a density of ~ 1000kg/m^3 [26], this is equivalent to 3.24 m^3 solvent/h/MW. The required volume for each of the two tanks (rich and lean solvent) for the three plants (401, 805, 710 MW) is therefore ~1300, 2600 and 2300 m^3 per hour of storage capacity for the low-, mid-, and high-merit plants respectively. For comparison, the volume of an Olympic swimming pool is ~ 2500 m^3. Allowing the lean solvent concentration to increase is unlikely to give storage capacity for more than a few minutes.

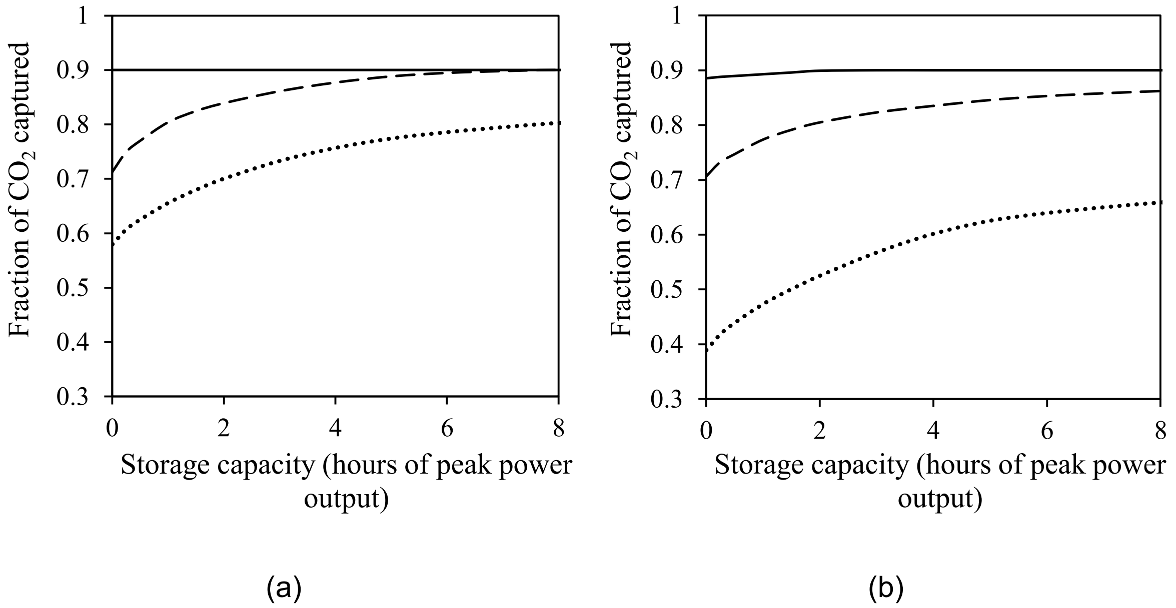


Figure 7. Fraction of CO_2 captured for different solvent storage capacities for the low- (——), mid- (— —) and high-merit (......) plants. Results are shown for the (a) Two Degrees and the (b) Steady Progression scenario.

From Figure 7 it is clear that for the high- and mid-merit plants, the addition of further storage capacity beyond ~ 4 hours leads to negligible further improvement in the fraction of CO_2 captured. This is because the increased storage capacity is not used effectively. This is illustrated in Figure 8, which shows the tank profile for the high-merit plant with 8 hours of storage capacity in the Steady Progression scenario. For a large fraction of the time period, the rate at which solvent can be regenerated is too low, meaning that there is often insufficient time to completely regenerate the solvent between periods of peak power output.

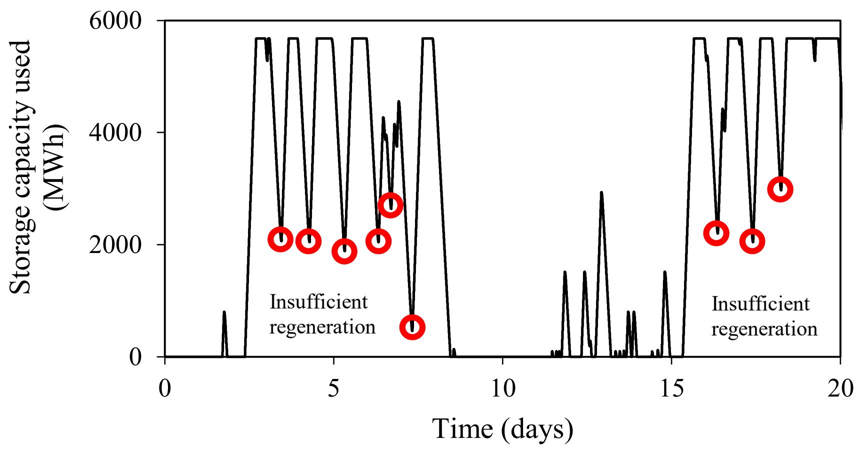


Figure 8. Level of solvent storage for the high-merit plant with 8 hours of storage capacity between 1st and 20th January 2025 in the Steady Progression scenario. Periods where there is insufficient regeneration are indicated.

To alter the rate at which solvent can be regenerated, the size of the regenerator and the compressor can be changed. This is the third design decision. Figure 9 and 10 show the impact of altering the size of the regenerator and the compressor for the high-merit plant. Increasing the capacity of the regenerator and compressor to 125% of the original capacity leads to a small improvement in the fraction of CO_2 captured. Decreasing the capacity of the regenerator and compressor means that the maximum fraction of CO_2 captured is lower and this is reached at a lower storage capacity. A decrease from 100% to 75% has only a limited impact on the fraction of CO_2 captured for small levels of storage capacity. Reductions in regenerator size beyond this have a substantial impact.

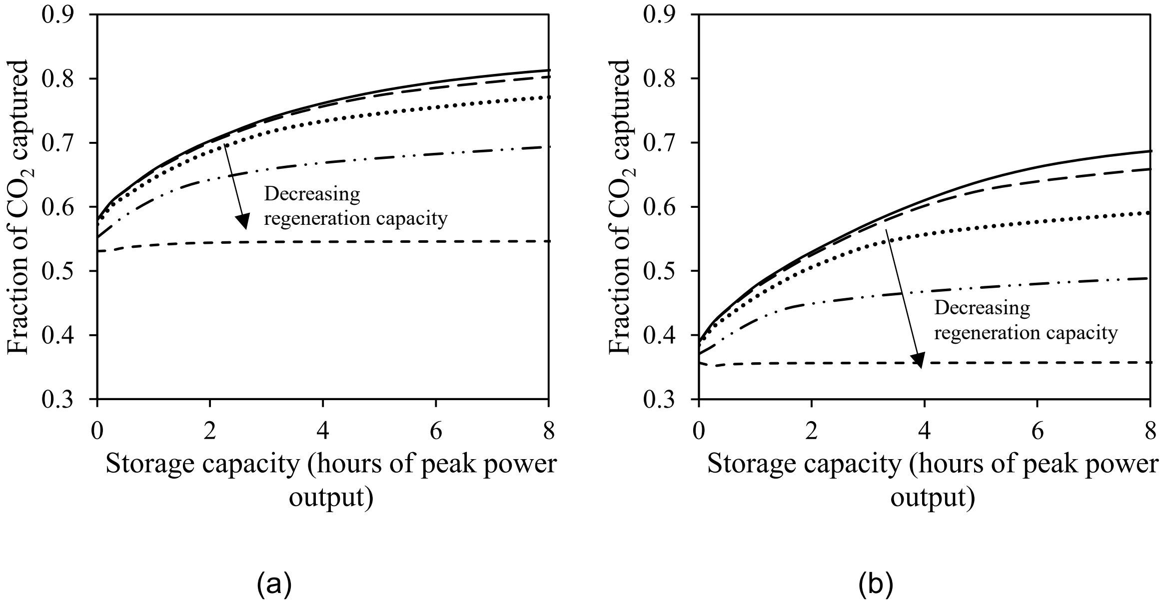


Figure 9. Fraction of CO_2 captured for different regenerator and solvent storage capacities for the high-merit plant with capacity to regenerate (i) 125% (——), (ii) 100% (— —), (iii) 75% (……), 50% (iv) (— · ·) and 30% (v) (- - -) of the rich solvent generated when the plant is operating at maximum power output. Results are shown for the (a) Two Degrees and the (b) Steady Progression scenario.

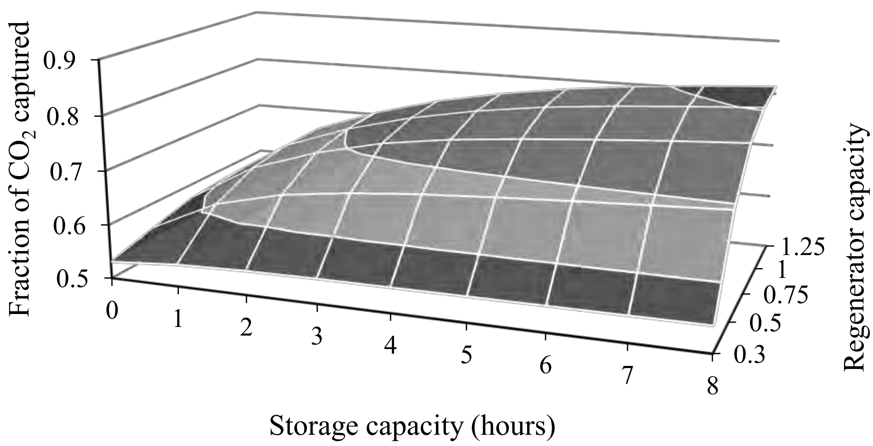


Figure 10. Fraction of CO_2 captured for different combinations of regenerator and compression capacity and solvent storage for the high-merit plant. These results are for the Two Degrees scenario.

There are further operational options that are not dependent on the three main design decisions. The most significant is the option of running the regenerator more than required at low loads to reduce the lean loading of the solvent and therefore being able to capture more than 90% of the carbon dioxide emissions in the absorber.

4. Discussion

4.1. Electricity System Model

Since the scenarios are for 2025, the results of this paper are particularly relevant for the design of the first few new CCS plants or CCS retrofits to existing plants that may be constructed in the UK in the mid to late 2020s.

The main aspect of a future energy scenario for 2025 affecting the behaviour of the whole CCGT fleet of the UK, and also the behaviour of individual plants, is the target for CO_2 emissions. A trajectory of emissions in line with achieving the 2050 target, *i.e.* National Grid's Two Degrees or Community Renewables scenarios, leads to a lower utilization of CCGT plants compared to slower decarbonization pathways, *i.e.* National Grid's Consumer Evolution and Steady Progression scenarios. Exactly how the target is achieved, whether in a centralized or decentralized manner, by a smaller growth in demand, or by greater wind or solar generation has a small impact.

The behaviour of an individual CCGT power plant is far more sensitive to its place in the merit order than the CO_2 emissions target. The UK has CCGT plants that operate all across the range of the merit order. High-merit plants ramp frequently between low and high levels of power output. Low-merit plants peak occasionally, often only a few times a year when both wind and solar generation are very low. Assuming sufficient financial incentives to make the economics of a CCGT plant with CCS cost neutral compared to no capture, the most important factor to understand is where a plant sits or will sit in the merit order. The place in the merit order is mainly governed by the thermal efficiency and therefore the age of a power plant as well as its location. A plant's location matters to its financial results: both gas prices and electricity transmission charges are location-specific. To deal with electricity transmission congestion some plants may be incentivised to locate at specific sites or in particular regions. A CCGT plant located close to a gas source, *e.g.* LNG import terminal or UKCS terminal, will pay lower gas transmission charges than those further away.

In terms of reducing CO_2 emissions, from a system perspective it is clear that the high-merit plants are the most pressing to address. For the Two Degrees scenario, the top 11 plants are responsible for ~ 90% of the emissions in 2025 and this is similar in the other scenarios. These are plants that have been built since 2016 or are scheduled to be built by 2025. Ensuring that these new plants are not simply 'capture ready' on paper, but are truly ready to operate flexibly with capture units in the energy system of 2025 and beyond will be critical to any successful further decarbonization of the power sector.

4.2. Power Plants with CCS

The typical base case CCGT plant with post combustion capture runs dynamically with the power plant and is sized to capture 90% of the CO_2 emissions. There are a number of design and operational modifications available that have an impact on the flexibility and the capital and operating costs of the plant and the capture facility. The ability to decouple power generation from the energy penalty is the key reason for the many possible design and operational variations of post combustion capture using amine solvents.

For low and mid-merit plants, it is possible to decrease the capacity of the carbon capture facility, while retaining reasonable CO_2 capture. Sizing the absorber to process flue gas and CO_2 generated at minimum stable generation (MSG) (25% load), keeps the fraction of CO_2 captured above ~ 70%. For all the CCGT plants, the fraction of CO_2 captured rises steadily up to MSG as the capacity of the capture facility is increased. After this point it still increases steadily, but at a slower rate, *i.e.* there is a change of gradient at MSG. To enable comparison, the net power output profile was fixed from the electricity system model. As the size of the carbon capture system is decreased, the capacity of the power plant can also be decreased due to a reduction in the maximum energy penalty. In reality, gross capacity will be set by the turbines available, which are sold in certain sizes by manufacturers. Once a set of turbines has been selected, adjustments, *e.g.* changing the absorber size, alter the net capacity.

Unless the power plant is over-sized to compensate for the energy penalty associated with capture, adding storage capacity, increases the fraction of CO_2 captured since it enables the generation of electricity to be decoupled from the energy penalty. Beyond a few minutes of storage it would be necessary to build two substantial solvent storage tanks, one for rich solvent and a second for lean solvent. To comply with the EU CCS Directives, all new power plants with a capacity greater than 300 MW must be ‘capture ready’. This Directive (and the resulting national regulations) focussed on the need to leave sufficient land available on site for future carbon capture equipment. If power plant operators want to leave the option of solvent storage open, the potential size of these tanks should also be taken into account. The required volume of tank is estimated to be ~1300, 2600 and 2300 m^3 per hour of storage capacity for the low-, mid- and high-merit plants respectively. For up to 10 hours of storage, assuming a height of 15m, the diameter of the tanks would be ~ 33, 50 and 44m respectively. These are substantial sizes and will require that definitions of ‘capture ready’ are expanded to ensure that sufficient space will be available for two storage tanks. It may double the amount of land required.

When sizing storage tanks, it is important that there is sufficient time between periods of peak output to empty the tank completely so that the full volume can be used effectively. An increase in the capacity of the regenerator and the compressor means that a rich solvent tank can be emptied more quickly during periods of low load. Larger tanks are only more valuable if the tank is constantly varying from completely empty to completely full. The key statistics 'Time at peak power output' and 'Time at MSG' together with the capacity of the regenerator and compressor are valuable for estimating a reasonable size of tank. The average time at MSG and at peak power output depends mainly on where the plant sits in the merit order and to a lesser extent on the CO_2 reduction target. There is little value in storage capacity greater than the volume of rich solvent generated over a period of time equivalent to the 'Time at peak power output'. It should be possible to regenerate a full tank over a period of time equivalent to the 'Time at MSG'. As an illustration, in Figure 9, for the same storage and regeneration capacity, the high-merit plant in the Steady Progression scenario has a lower rate of CO_2 capture than the same plant in the Two Degrees scenario. This is because the average time at peak power output is longer (4.6 *vs.* 3.2 hours) and the time at MSG is shorter (6.3 *vs.* 10.0 hours).

None of the design options discussed here are likely to have a significant impact on downstream transport and storage infrastructure. The one exception is an increase in the regeneration capacity, which would increase the maximum flow rate of CO_2 fed into a pipeline.

For most of the design options, the decision on whether carbon capture is attractive and which variation to adopt is a trade-off between various capital and operating costs. These considerations are location specific, heavily dependent on external factors such as fuel and carbon prices and also influenced by whether a new plant is under consideration or retro-fit of an existing plant is planned.

5. Conclusions

The behaviour of the CCGT fleet and of individual CCGT plants in future electricity systems will be influenced by CO_2 reduction targets. The behaviour is less sensitive to the manner in which the reduction is achieved. More important for the behaviour of individual CCGT plants, however, is its location in the merit order. High-merit plants ramp daily between peak power output and minimum stable generation, while at the other extreme, low-merit plants operate as peaking plants only a few times per year. From a system perspective, high-merit plants should be addressed first since they contribute the majority of the CO_2 emissions. Plants built from 2016 onwards are likely to produce ~ 90% of the CO_2 emissions of the whole CCGT fleet in 2025.

The typical base case CCGT plant with a post combustion capture facility using amine solvents is designed to capture 90% of the CO_2 emissions and for the capture facility to operate dynamically with the power plant. The design and operation is however quite flexible, mainly because the energy penalty associated with carbon capture can be decoupled from electricity generation by adding rich and lean solvent storage tanks. Downsizing the capture facility could be attractive for low- and mid-merit plants since capture rates greater than ~ 70% can be obtained even when the capture facility is sized to process only the flue gas at minimum stable generation. Beyond a few minutes of solvent storage, substantial storage tanks are needed. Altering the size of the regenerator and compressor is another design option. Ensuring that tanks are sized so that they can be utilized well is important. This is governed by the typical power output profile and the rate at which solvent can be regenerated. If solvent storage is to play an important role, it will require, for a start, that definitions of 'capture ready' are expanded to ensure that sufficient space will be available for storage tanks.

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