The role and value of negative emissions technologies in decarbonising the UK energy system

H. A. Daggash[1,2,3], C. F. Heuberger[2,3], and N. Mac Dowell[*2,3]

[1]Grantham Institute for Climate Change and the Environment, Imperial College London, Exhibition Road, London, UK
[2]Centre for Environmental Policy, Imperial College London, Exhibition Road, London, UK
[3]Centre for Process Systems Engineering, Imperial College London, Exhibition Road, London, UK

Abstract

The UK is committed to the Paris Agreement and has a legally-binding target to reduce economy-wide greenhouse gas emissions by 80% relative to 1990 levels by 2050. Meeting these targets would require deep decarbonisation, including the deployment of negative emissions technologies. This study, *via* a power supply capacity expansion model, investigates the potential role of bio-energy with carbon capture and storage (BECCS) and direct air capture and storage (DACS) in meeting the UK's emissions reduction targets. We show that to achieve power sector decarbonisation, a system dominated by firm and dispatchable low-carbon generators with BECCS or DACS to compensate for their associated emissions is significantly cheaper than a system dominated by intermittent renewables and energy storage. By offsetting CO_2 emissions from cheaper thermal plants, thereby allowing for their continued utilisation in a carbon-constrained electricity system, BECCS and DACS can reduce the cost of decarbonisation by 37-48%. Allowing some this value transferred to accrue to NETs offers a potential route for their commercial deployment.

Keywords: negative emissions technologies, BECCS, direct air capture

1 Introduction

Several studies have shown that the relationship between cumulative greenhouse gas (GHG) emissions and global warming is insensitive to the emission pathway (*i.e.* the time and rate at which emissions occur)[1,2]. Therefore, climate change risks and impacts can be mitigated by minimising historic emissions[3]. This

*Corresponding author: Tel: +44 (0)207 594 9298; E-mail: niall@imperial.ac.uk

has generated interest in the potential for large-scale greenhouse gas (GHG) removal from the atmosphere *via* negative emissions technologies (NETs). NETs, sometimes called carbon dioxide removal (CDR) technologies, are technologies that can remove CO_2, directly or indirectly, from the atmosphere[4,5]. A portfolio of technologies has been identified as viable options to deliver negative emissions at scale. These include: bio-energy with carbon capture and storage (BECCS)[5], direct air capture and storage (DACS)[6,7], afforestation/reforestation (AR)[8], ocean fertilisation[9,10], enhanced weathering of minerals[11–13], and biochar[8,14].

Through the Paris Agreement, most nations committed to keeping average global temperature rise to well below 2°C (above pre-industrial levels) by 2100[15]. Global decarbonisation pathways consistent with this target are reliant on the extensive deployment of NETs, usually BECCS[5]. The UNEP Emissions Gap Report 2017 states that NETs are necessary in addition to other mitigation options to manage possible overshoot of near-term GHG emissions targets. In the UK, the *Climate Change Act 2008*[16] (CCA) set a 2050 target to reduce economy-wide greenhouse gas (GHG) emissions by 80% relative to 1990 levels. Fig. 1 illustrates the projected reductions in sectoral emissions required to achieve this. The power sector must be essentially completely decarbonised by 2050[17].

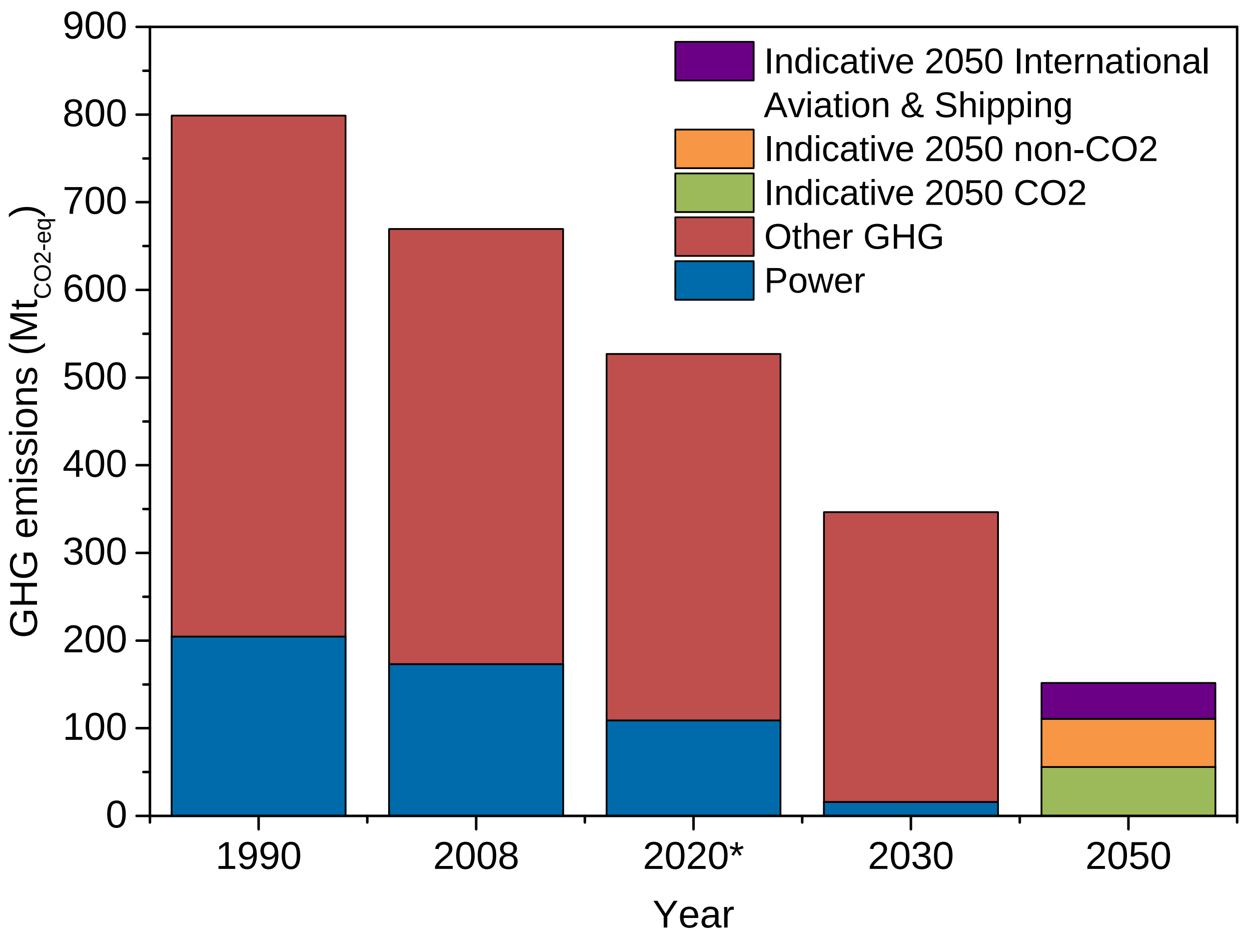

Figure 1: Power sector emissions in the context of UK greenhouse gas emissions (1990-2050). Figure adapted from CCC report.
*Assuming recommended implementation of measures proposed by the CCC[17].

To meet its commitments to the Paris Agreement, however, the UK requires deeper decarbonisation pathways (relative to the CCA target). Fig. 2 shows the sectoral emissions that must be achieved by 2050 to keep a 50% likelihood of keeping global temperature rise to 1.5°C by 2100. Approximately 50 Mt_{CO2}/y of negative emissions are needed by 2050 to offset CO_2 emissions from sectors with more difficult or expensive mitigation solutions, including aviation, shipping and transport[18].

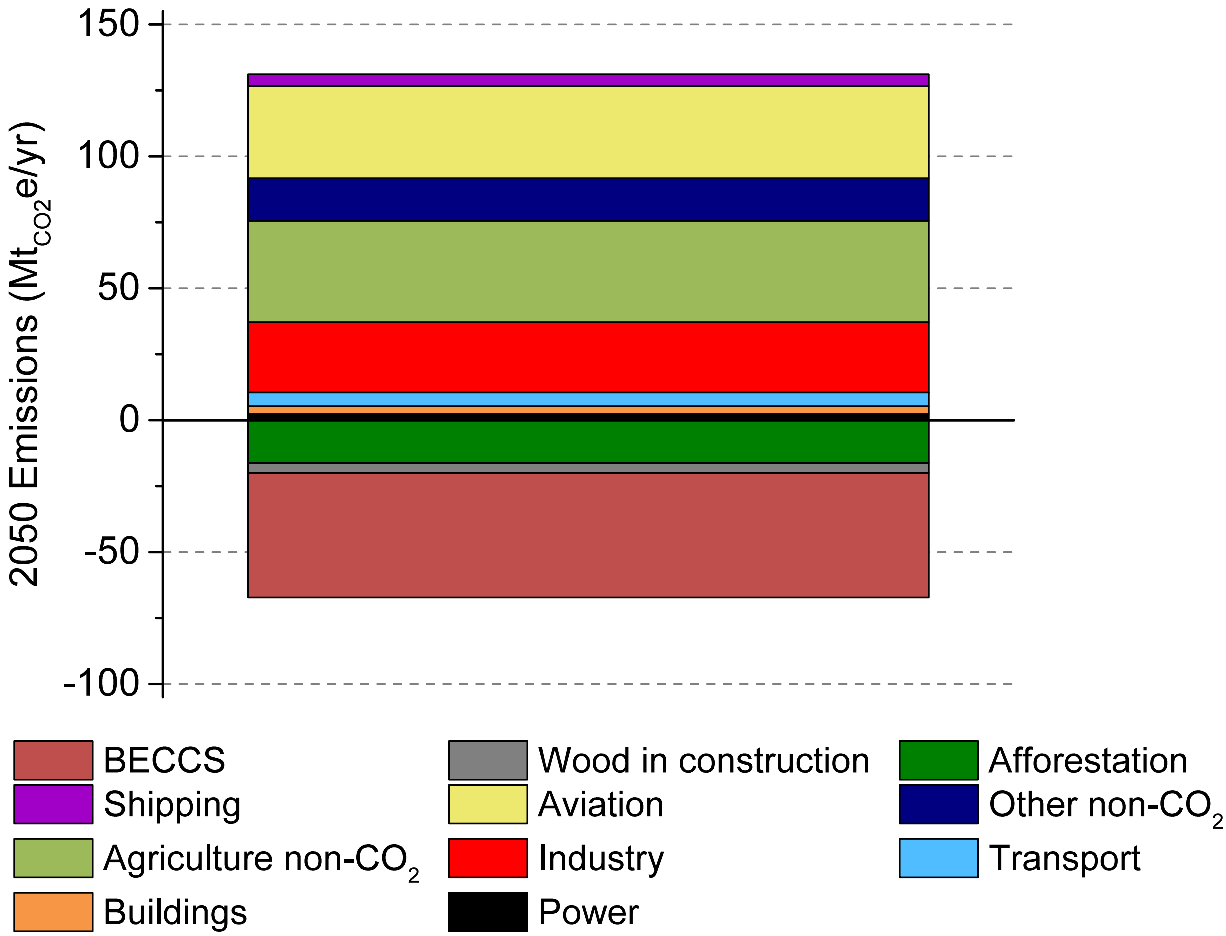

Figure 2: Residual UK greenhouse gas emissions in 2050 under the CCC's Max deployment scenario[18]. 92% GHG emissions reduction (relative to 1990 levels) is achieved by 2050. This is within the range of 86-96% suggested by the most ambitious paths available from global climate-economy models (which keep a 50% likelihood of 1.5°C in 2100 after overshooting). Figure has been adapted from the CCC report[18].

Whilst large-scale afforestation/reforestation has long been practised[19,20], BECCS[21] and DACS[22–24] are the only technological NETs being pursued at demonstration scale. These technologies are the focus of this study. Studies that have evaluated the negative emissions achievable through deployment of BECCS or DACS have considered them in isolation[25] and have neglected to consider the operation of these technologies within the broader energy system, and thus have not provided any insight into the extent to which they provide value to these systems, or the way in which they might operate therein. There is therefore a lack of understanding of the services they can provide and the incentives needed for each service (*e.g.*, power generation, CO_2 removal).

This study investigates the potential role for BECCS and DACS in achieving the: 1) 2050 UK power sector decarbonisation target decreed by the Climate Change Act 2008[16], and 2) negative emissions needed to be consistent with the Paris Agreement target, which is not legislated. It also quantifies the value added by BECCS and DACS to the UK energy system, and describes their operation within it.

Section 1.1 reviews the ongoing transition of the UK electricity system. Section 2 describes the Electricity Systems Optimisation (ESO) modelling framework used in this study and the parametrisation of NETs within the model. In section 3, possible decarbonisation pathways for the power sector, subject to different emission targets and the availability of NETs, are outlined. The value of negative emissions is discussed in section 4. Lastly, sensitivity analysis of the results presented to key modelling parameters is given in section 5 and we present some conclusions in section 6.

1.1 The UK electricity system

Fossil fuels have historically dominated the fuel mix for power generation in the UK and still provide the majority of power generation today. Fig. 3 shows that coal and gas contributed 53% of the fuel input for electricity generation in 2016. Imminent emissions reductions targets have spurred a transition to less-polluting fuels and renewable sources of energy[16,26,27]. Most notably, a planned phase-out of coal-fired plants by 2025[28] and an increase in the carbon price floor in 2015 (from £9/t_{CO_2} to £18/t_{CO_2}[29]) has led to a rapid decline in coal's share of generation. In 2016, coal supplied 9% of electricity, down from 22% in 2015[29]. This decline has been compensated by increased gas-fired and renewable electricity generation, the latter enabled by policies and incentives favouring renewable energy sources[27,30–33].

Total electricity supply to the UK was 357 TWh in 2016, including net imports via interconnectors[29]. The UK has 4.1 GW of interconnector capacity allowing trade with France (2 GW), the Netherlands (1 GW) and Ireland (1.1 GW)[34]. By source, electricity supply was: 40% gas, 20% nuclear, 15% non-thermal renewables (natural flow hydro, wind, solar, wave and tidal), 9% coal, 8% bio-energy (mostly from biomass co-fired with coal in Drax power station), 5% imports and 1% pumped hydro storage[29]. The rest is used by generators for their own plant works. Final electricity consumption was 304 TWh due to network losses (26 TWh) and consumption from within the energy industry (27 TWh)[29].

Although unabated gas plants—gas plants not equipped with carbon capture and storage (CCS) technology—emit less than half of the CO_2 of coal-fired plants, they still emit approximately 360-390 kg_{CO_2}/MWh of electricity generated[29]. As the UK seeks to transition to a decarbonised electricity system, unabated gas plants cannot continue to dominate the generation mix without being equipped with CCS and negative emissions to compensate for residual emissions from the CCS plants.

The variability in the supply of wind and solar energy poses challenges to the electricity system[36]. Limited transmission capacity and energy storage, and the relative inflexibility of base load generators (*e.g.*, nuclear plants) result in curtailment of power generation from intermittent renewable energy sources (IRES) during periods of surplus generation and low demand[37,38]. This is a necessary security measure required to maintain power system stability and operability, and to prevent equipment damage[39]. In the UK, constraint payments at an electricity price of £157/MWh are made to wind farms to curtail their generation[40]. In the absence of increased energy storage and flexibility in the electricity system, further penetration of IRES will see increased curtailment levels and hence, constraint payments. Approximately 2.7 GW of pumped hydroelectric energy storage (PHES) provide all the bulk electricity storage in the UK currently[29]. Although there are plans to increase this by up to 2 GW[41], long-term expansion of PHES is limited by geography. Current plans are to install 7.3 GW of additional interconnection capacity by 2022[34]. This will add further flexibility to the electricity system, which will serve to minimise curtailment.

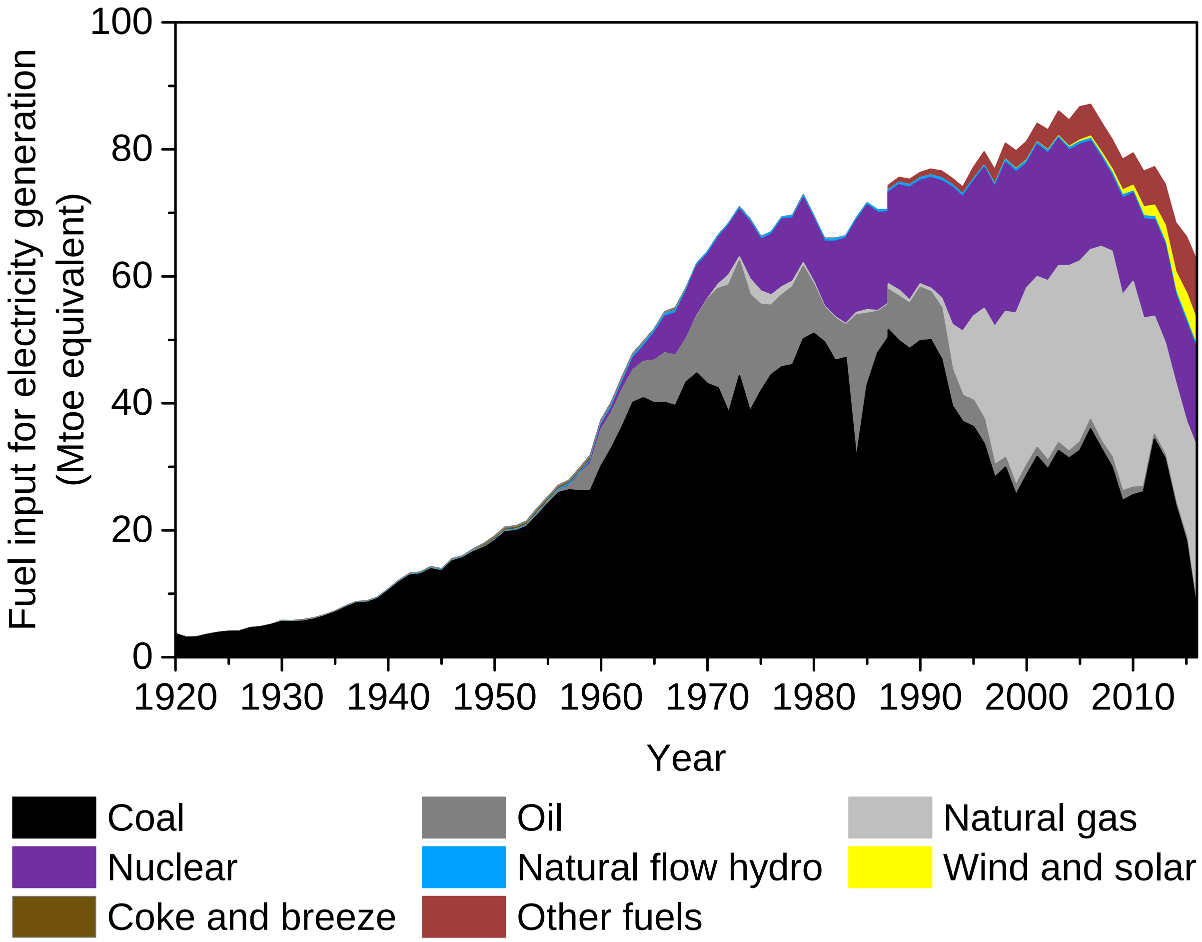

Figure 3: Fuel inputs for electricity generation in the UK from 1920 to 2016[35]. "Other fuels" include coke oven gas, blast furnace gas, waste products from chemical processes, refuse-derived fuels and other renewable sources including wind. Industrial hydro data are not available before 1951. Natural gas includes colliery methane from 1987 onwards.

The future role of nuclear power in the UK is threatened by its high upfront investment costs and lengthy construction times – the recently approved Hinkley Point C (HPC) plant will cost £30 billion and take 10 years to build[42,43]. Its long payback periods leave it susceptible to government policy changes that may reduce revenues hence financing is difficult to raise[42]. HPC has since been shown to provide marginal value-for-money for consumers, mainly due to large financing costs[44]. Increasing costs of the technology due to more stringent safety requirements further compound to the difficulties[45,46].

The above highlights some of the challenges that the UK faces as it seeks to transition to a low-carbon electricity system. This study will focus on the integration of NETs into the future electricity system, their impact(s) on the optimal system design, including how the challenges discussed can be avoided or overcome.

2 NETs in the electricity system

Within the electricity system, NETs can generate net negative CO_2 emissions to: 1) offset emissions from unabated and abated fossil generators, and/or 2) offset emissions from sectors that have more difficult or costly mitigation solutions. To meet the commitments to the Paris Accord, it is estimated that -47 Mt_{CO_2}/year from BECCS is needed by 2050 in addition to afforestation, to offset non-power sector emissions (shown in Fig. 2). Direct air capture of CO_2 and subsequent storage (DACS) has since emerged as another potential source of large-scale negative emissions. Both technologies are described in detail below.

Bioenergy with carbon capture and storage (BECCS)

Plants extract CO_2 from the atmosphere during their growth and convert it into carbohydrates *via* photosynthesis. When burned, the CO_2 captured is returned to the atmosphere hence net emissions from growth and combustion are zero. Biomass use for large-scale power or fuel production, however, requires processing due to its high moisture content and heterogeneous nature. Raw material and processed feedstock must also be transported to processing facility and the power plant, respectively. Land-use change (LUC), and in particular indirect LUC, may also be a significant contributor to GHG emissions, and these will likely need to be quantified on a case by case basis as they are dependent on a range of factors (location, type of land, *etc.*)[47–49]. These processes comprise the biomass supply chain and each contributes an additional energy input and carbon footprint that must be considered in the life-cycle emissions of biomass. Integrating a dedicated biomass-firing plant with CCS allows for CO_2 that would be otherwise released, to be captured and permanently sequestered, thereby can result in a net removal of CO_2 from the atmosphere (subject to sufficiently low supply chain emissions), *i.e.* negative emissions. As CCS capture efficiency is often around 90%, there are residual emissions from BECCS but the overall carbon balance is negative. Fig. 4 provides a simplified representation of the biomass supply chain from harvest to combustion in a power plant.

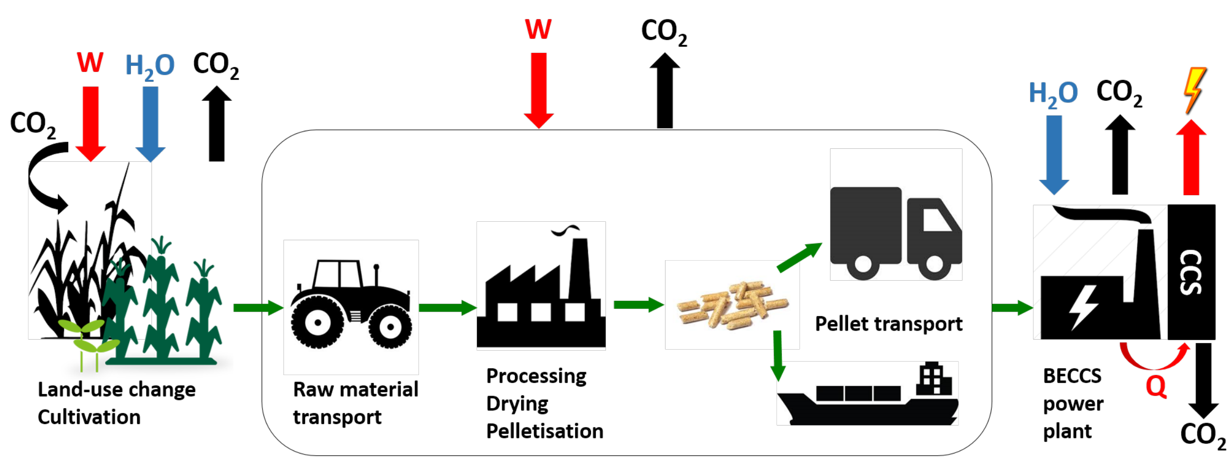

Figure 4: A simplified biomass supply chain from harvest to combustion in a BECCS power plant, showing inputs and outputs of CO_2, water (H_2O) and energy (W, Q) at different stages. This figure is adapted from[47,50].

A study on the resource efficiency of BECCS has shown that its potential for negative emissions is largely-dependent on the biomass supply chain[47]. In this study, Miscanthus with associated supply chain GHG emissions of 39.2 $g_{CO_2\text{-eq}}/MJ_e$ is assumed to be the feedstock to the BECCS plants; this is the mean value for a range of supply chains of UK-sourced Miscanthus[47]. These supply chain emissions are well below the sustainability limit in the UK (79 $g_{CO_2\text{-eq}}/MJ_e$)[51]. We assume an ultra-supercritical power plant with post-combustion CO_2 capture using conventional MEA and storage. Other technical features and costs of the BECCS plant are given in section 2.1.

Direct air capture and storage (DACS)

CO_2 can be removed directly from the atmosphere by contacting the air with a range of sorbents. The low atmospheric concentration of CO_2 (approximately 408 ppm[52]) means very large energy input and volumes of air are required to obtain a pure CO_2 stream. Commercial DACS technology manufacturers typically employ amine-functionalised sorbents[23,53,54] or wet-scrubbing systems with sodium or calcium cycling[7,22,55]. The archetype of DACS considered in this study uses a wet-scrubbing system with calcium cycling, because of its potential ease of scale-up. It is illustrated in Fig. 5. A potassium or sodium hydroxide solution captures CO_2 in air and stores it as a carbonate. Calcium carbonate ($CaCO_3$) is then calcined in a kiln to produce calcium oxide (CaO) and CO_2. Hydrated CaO is then used to regenerate the hydroxide solution for further CO_2 capture. The process description has been detailed previously[22,55] and will not be repeated here. The majority of the energy input into DACS – 6.1 $GJ_{th}/t_{CO_2\ captured}$ – is heat required for the calcination of $CaCO_3$ at 900°C. This is supplied *via* oxy-fired natural gas combustion, to avoid nitrogen (from burning in air) in the capture exhaust which would require a further separation step. Approximately 1.8 $GJ_e/t_{CO_2\ captured}$ is required for fans, liquid pumping, air separation (to provide oxygen for combustion) and CO_2 compression[55]. DACS technology description within the modelling framework used in this study is provided in section 2.1.

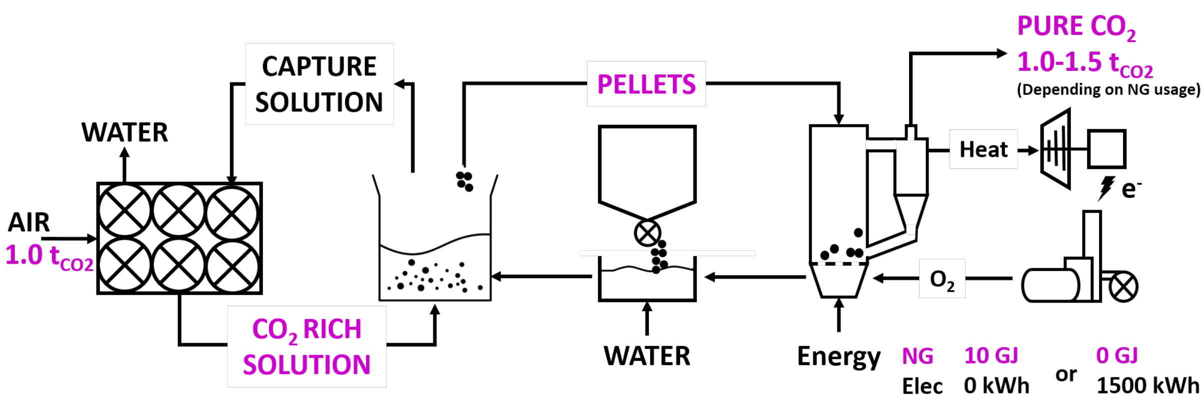

Figure 5: Simplified representation of a wet-scrubbing system for direct removal of CO_2 from the air, adapted from[22]. Capture solution is often sodium hydroxide (NaOH) or potassium hydroxide (KOH). Pellets of calcium carbonate are used to regenerate the capture solution.

2.1 Modelling

The Electricity Systems Optimisation (ESO) modelling framework used in this study combines capacity expansion planning and unit commitment model formulations to determine the optimal system design and hourly dispatch of electricity in the UK. This work assumed an exogenously imposed electricity demand, with an initial consumption of 304 TWh/yr[56]. A 1% year-on-year increase in electricity demand and an unchanged demand profile, illustrated in Fig. 16, are assumed throughout the planning horizon considered.

The ESO model assumes perfect foresight, and minimises the total system cost in the power supply system, *i.e.* the capital and operational expenditure, subject to the constraints below:

- Capacity expansion constraints: initial capacity available is specified; technology-specific lifetimes, maximum deployment (due to geographic or resource limits) and maximum build rates are specified.

- System-wide constraints: electricity demand is always met; 4% of peak load and 15% of intermittent power output must be available to provide reserve capacity; a minimum level of system inertia is maintained to provide frequency and voltage control services*; maximum annual carbon emissions from power generation are specified (discussed in section 1).

- Technology constraints: power, reserve and inertia provision capability; flexibility of generation/storage units; carbon emissions; and technology-specific ramping (up and down) times are all specified. Appendix 2 details the technology costs and operational parameters implemented in the model.

The ESO model is a mixed-integer linear optimisation problem (MILP). The mathematical formulation of the model has been described previously[57–59] and is accessible as an open-source and open data model[60]. The original ESO formulation does not include DACS technology, and has been adapted to do so. Appendix 1 details the changes made.

The MILP formulation does not allow for the direct calculation of shadow prices, as this is dependent on the algorithmic approach used to solve the model[61–63]. The shadow price associated with a particular constraint represents the increase in the optimal value of the objective (in this case, total system cost) per unit increase in the amount of resources available. In this study, the marginal cost of electricity (MC) has been estimated using the shadow price of the electricity balance constraint ($supply = demand$). Sensitivity analysis on the electricity demand (+/- 1 MW) was carried out to validate the MC estimates. The results of this are discussed in section 4.

The planning horizon considered is 2015 to 2050, when the decarbonisation of the electricity system is to be achieved. A discount rate of 3% is used for future cash flows. The UK is assumed to be a single node, hence transmission and distribution constraints have not being taken into account explicitly, but overall transmission losses are included (as 7.7% of demand).

The power generating technologies considered were: Nuclear, Coal, Combined Cycle Gas Turbines (CCGT), Open Cycle Gas Turbine (OCGT), CCGT with post-combustion CCS (CCGT-CCS), BECCS, Onshore Wind, Offshore Wind, Solar PV, and Interconnectors†. Pumped Hydroelectric storage and generic grid-level storage, parametrised as Lead-Acid Battery, were considered as energy storage technologies. Due to the large energy input needed for DACS, it is modelled as a net consumer of power, *i.e.* it contributes additional electricity demand to provide negative emissions. As BECCS and DACS have only been proven at demonstration scale, they are made available for deployment at scale from 2030 onwards in the model. All other technologies are available from 2015. Appendix 2 details the technology costs and operational parameters assumed.

2.1.1 BECCS

The reference BECCS technology assumed uses Miscanthus pellets fired in a 500 MW ultra-supercritical power plant with post-combustion capture using conventional MEA solvent (η_{net} = 35%)[64]. This plant provides approximately 0.80 t_{CO_2}/MWh of negative emissions[47]. The load factor range for stable generation is 30-85%, as for a conventional coal-fired plant. BECCS is yet to be developed at utility-scale, so costs cited in the literature are estimates. Eq. 1 was used to estimate the capital costs (CAPEX) of the BECCS technology considered. The CAPEX of an ultra-supercritical coal-fired plant with post-combustion CCS (£2368/kW[65]) was added to the cost of converting coal-fired generating units to full biomass-firing.

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*system inertia is the amount of kinetic energy stored in the spinning parts of synchronous generators

†The UK's current interconnectors with Europe were modelled as infinitely-flexible power generators, with limits on generation capacity.

This comprises modifications to fuel mills and boilers, and construction of pellet storage facilities; it is approximately £354/kW[66‡].

$$CAPEX_{\text{BECCS}} = CAPEX_{\text{Coal-CCS}} + CAPEX_{\text{Biomass-conversion}} \tag{1}$$

There are approximately 8.4 Mha of grassland available in the UK[67]. Excluding 6.1 Mha necessary for livestock production[68], there is 2.3 Mha of land potentially available for Miscanthus production. With average yield of 10 tonnes per hectare per year[69], 21 Mt of pellets can be produced locally (after taking into account the losses that occur during processing and transport). Locally-sourced Miscanthus raw material costs £49/tonne[70], however transport and processing increases the pellet cost to £118/tonne. This comprises majority of the operational costs (OPEX) for the BECCS plant. Appendix 2 details the additional costs and carbon emissions incurred along the biomass supply chain. Fig. 6 shows the contribution of the different supply chain processes to the final pellet price. Imported pellets are assumed to cost £190/tonne[71]. This higher cost has also been taken into account in the model when BECCS biomass demand exceeds domestic supply. CO_2 transport and storage costs of £10/t_{CO2}[72] have been assumed, although power plant and storage siting are not explicitly considered in the model. Other parameters considered are provided in Table 1.

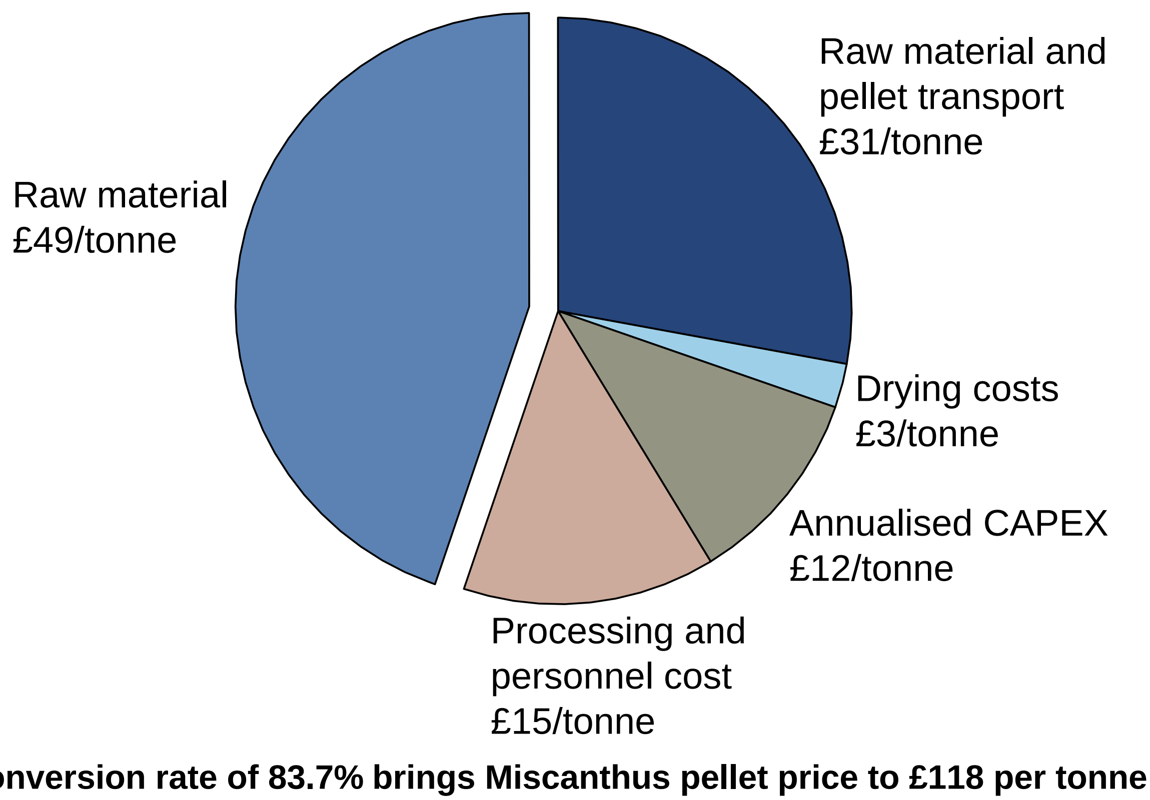

Figure 6: Cost composition of UK grown and processed Miscanthus pellets.

‡Based on £700 million conversion cost of three 660 MW units to full biomass-firing by Drax Power

2.1.2 DACS

The DACS process considered in this work is a hydroxide-based capture using calcium cycling to regenerate the capture solution. The regeneration requires the calcination of calcium carbonate ($CaCO_3$), which occurs at approximately 900°C. This does not allow for flexible operation as repeated cooling and heating of the kiln may threaten process stability. Therefore, it has been assumed that the plant is operated continuously at maximum CO_2 removal rate (utilisation factor of 100%). Based on the figures presented in section 2, a DACS plant removing 1 Mt_{CO_2}/y from the atmosphere requires 56 MW_e input. This is equivalent to a CO_2 removal rate of 2 t_{CO_2}/MWh consumed[55]. The bulk of the energy input to the air capture process, however, is high-grade heat to the kiln which is assumed to be supplied via oxy-fired natural gas combustion. Therefore the heat input does not contribute additional electricity demand to the system. DACS systems might potentially be composed of a number of small and modular CO_2 collectors[23,24]. Consequently, the cost of CO_2 collection, transport and storage is expected to be higher than for conventional power plants with CCS. This has been included as an added OPEX of £30/t_{CO_2}[74]. Other DACS technology costs were taken from the APS report[55].

Table 1: Description of BECCS and DACS in the ESO modelling framework. Note that DACS is a net consumer of power, therefore its unit capacity is shown as negative. DACS CAPEX[55] has been levelised against the electricity consumption of the plant only; heat consumption not included.

	BECCS	DACS
Unit capacity (MW)	500	-56
Efficiency (HHV basis)	35%	7%
Economic lifetime (years)	30	25
Plant load factor	30-85%	100%
Inertia potential (MW.s/MW)	10	-
CO_2 emissions rate (t_{CO_2}/MWh)	-0.8037	-2.022
CAPEX (£/kW)	2,721	33,074
Fixed OPEX (£/hour)	4229	-
Variable OPEX (£/MWh)	96-115	260
Start-up OPEX (£/hour)	4,000,000	-
CO_2 transport & storage (£/t_{CO_2})	10	30[74]
UK pellet costs (£/tonne)	118	-
Imported pellet costs (£/tonne)	190	-
Natural gas price (£/MMBTU)	-	3.74
Electricity price (£/MWh)	-	44

The description of the other technologies, fuel prices and carbon prices considered in this study are provided in Appendix 2. The ESO model was used to determine the least-cost optimal capacity expansion for the UK electricity system for the following scenarios:

- power sector decarbonisation by 2050 with: 1) no negative emissions technologies available to the system, *i.e.* "No NETs", 2) DACS technology, but not BECCS, available to the system, *i.e.* "DACS Only", 3) BECCS technology, but not DACS, available to the system, *i.e.* "BECCS Only"

- power sector providing 50 Mt_{CO_2} of negative emissions to meet commitments to the Paris Agreement (as in Fig. 2), *i.e.* "1.5°C system". Both BECCS and DACS are made available as the target cannot be met without NETs.

3 What might the future look like?

3.1 Zero emissions by 2050

3.1.1 No NETs

Figures 7 and 8 show the optimal capacity and electricity generation mix, respectively, to achieve power sector decarbonisation by 2050 for the scenarios discussed in section 2.1. We observe that complete decarbonisation of the electricity system – defined here as a carbon intensity of less than 10 kg_{CO2}/MWh – is achievable by 2050 without NETs. Such a scenario would see installed capacity increase by 208%, from 98 GW in 2015 to 301 GW in 2050, due to the extensive expansion of IRES and nuclear power. Solar dominates the capacity mix in 2050, making up 30% (90 GW), but satisfies only 11% of annual demand due to its low energy density. Offshore and onshore wind contribute 30% and 19% of demand, respectively. As the existing nuclear plants reach the end of their lifetimes in the next decade, 24 GW of new nuclear is added between 2030 and 2050 and its share of generation rises to 30% by mid-century.

Power plant utilisation factor, UF_i, is defined as the power output from a power plant i divided by the maximum possible power output during a given time period. Eq. 2 defines the annual utilisation factor for plant i.

$$UF_i = \frac{annual\ power\ output\ (MWh)}{plant\ capacity\ (MW) \times 24\ hours \times 365\ days} \tag{2}$$

The absence of negative emissions results in the underutilisation of unabated gas plants by 2050, as there is no CO_2 removal to compensate for their emissions. By 2050, UF_{CCGT} and UF_{OCGT} fall to <0.5%, despite having 29 GW of capacity installed. Unabated gas plants, however, provide 30% of the reserve capacity requirements in the system. Abated gas plants (CCGT-CCS) are also aggressively deployed from 2025, with 15 GW added over the next 15 years. $UF_{CCGT\text{-}CCS}$ decreases from 69% initially to 16% in 2050, as residual emissions from the CCS are minimised to meet the decarbonisation objective.

The dominance of IRES in this scenario leads to greater requirement for grid flexibility leading to increased energy storage and interconnector capacity installed. Storage service to demand peaks at 11 TWh/y in 2035 – a twofold increase from current levels. 9 GW of additional interconnector capacity are also built, with their share of electricity supply peaking at 18% in 2025, and subsequently falling to 4% by 2050. This is because electricity imports have an associated carbon footprint[75] which is attributed to the UK electricity system. As emissions targets become more stringent towards 2050, interconnection utilisation falls to minimise these associated emissions. Despite the increase in energy storage and flexibility services, incidences of curtailment still abound – 99 TWh/y (22% of demand) of IRES are curtailed in 2050. This is a lower-bound estimate as the model does not account for transmission congestion constraints.

While the *No NETs* system described is technically feasible, it is dominated by capital-intensive technologies. This is reflected in the large total system cost (TSC) – £307 billion of investment (CAPEX and OPEX) is needed in the power sector over 35 years. Fig. 10 illustrates the range of marginal costs of electricity (MC) for each scenario considered. In all scenarios, MCs are seen to be consistently higher than contemporary levels till 2050, when they peak. Peak MC is highest when no NETs are available to the system – it is approximately £200/MWh in 2050. This is because new IRES and energy storage capacity is required to provide an additional MWh of carbon-neutral electricity, as current capacity is maximally utilised. Underutilised (and cheaper) unabated or abated gas power plants cannot provide the electricity due to the decarbonisation constraint. The rapid expansion of IRES capacity must also be accompanied by expansion of transmission and distribution (T&D) networks, which incurs additional costs that are not

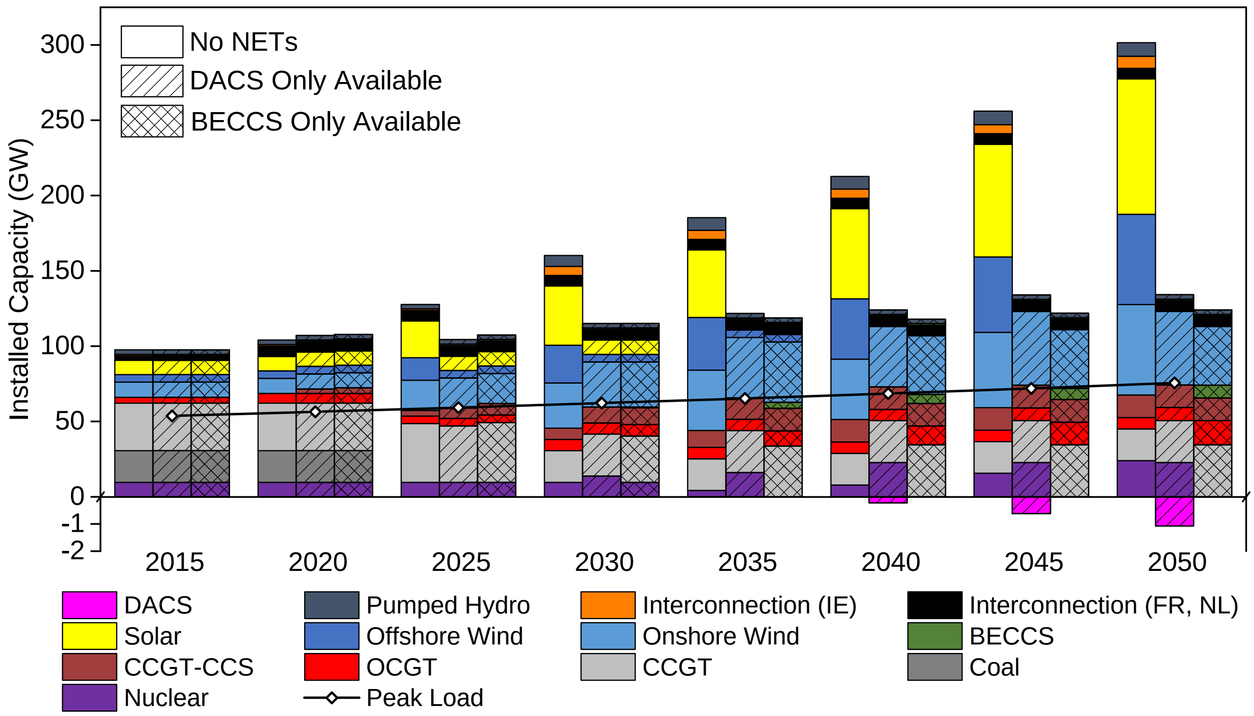

Figure 7: Optimal installed capacity mix for the UK, given the availability of negative emissions technologies for large-scale deployment.

included in the total system cost. Should constraint payments to IRES generators continue, curtailment will also contribute to additional costs.

3.1.2 DACS Available

The availability of direct air capture and storage is observed to reduce the cost of complete decarbonisation considerably. Despite the costliness of DACS, it is seen to be deployed from 2040 and to reduce the total investment needed to £193 billion (Fig. 9), 37% less than with *No NETs*. This is because the negative emissions from DACS allow for continued utilisation of cheaper thermal plants. DACS consumes 9.4 TWh/y (2% of projected annual electricity demand) by 2050 to provide 19 Mt$_{CO_2}$/y of negative emissions that offset CO_2 emissions from unabated and abated gas plants (shown in Fig. 13). The offset allows for increased gas utilisation; UF_{CCGT} doubles to 14% from 2040 to 2050 (period when DACS is operational), and $UF_{CCGT-CCS}$ increases to >70% in the same period—a fourfold increase from its utilisation when no NETs are available.

Increased power generation from gas plants also completely displaces the need for new Solar and Offshore Wind, with no new capacity built after the existing plants reach their end life. However, 49 GW of new Onshore Wind capacity is added by 2050. Consequently, IRES share of generation falls from 70% (when no NETs are available) to 36%, and energy storage requirements remain at contemporary levels. Reduced penetration of IRES also reduces flexibility needs with only 4 GW of interconnector capacity added. The availability of negative emissions to compensate for ‘imported emissions’, however, results in increased interconnector utilisation and hence reliance on electricity imports. Imports satisfy 9-18% of demand, up to three times its current share. The 24 GW of nuclear build after 2030 remains necessary to meet the bulk of electricity demand – 159 TWh/y by 2050 (35%). This share peaks at 39% in 2040 before falling slightly. Therefore to achieve power sector decarbonisation, a system dominated by firm and dispatchable low-carbon

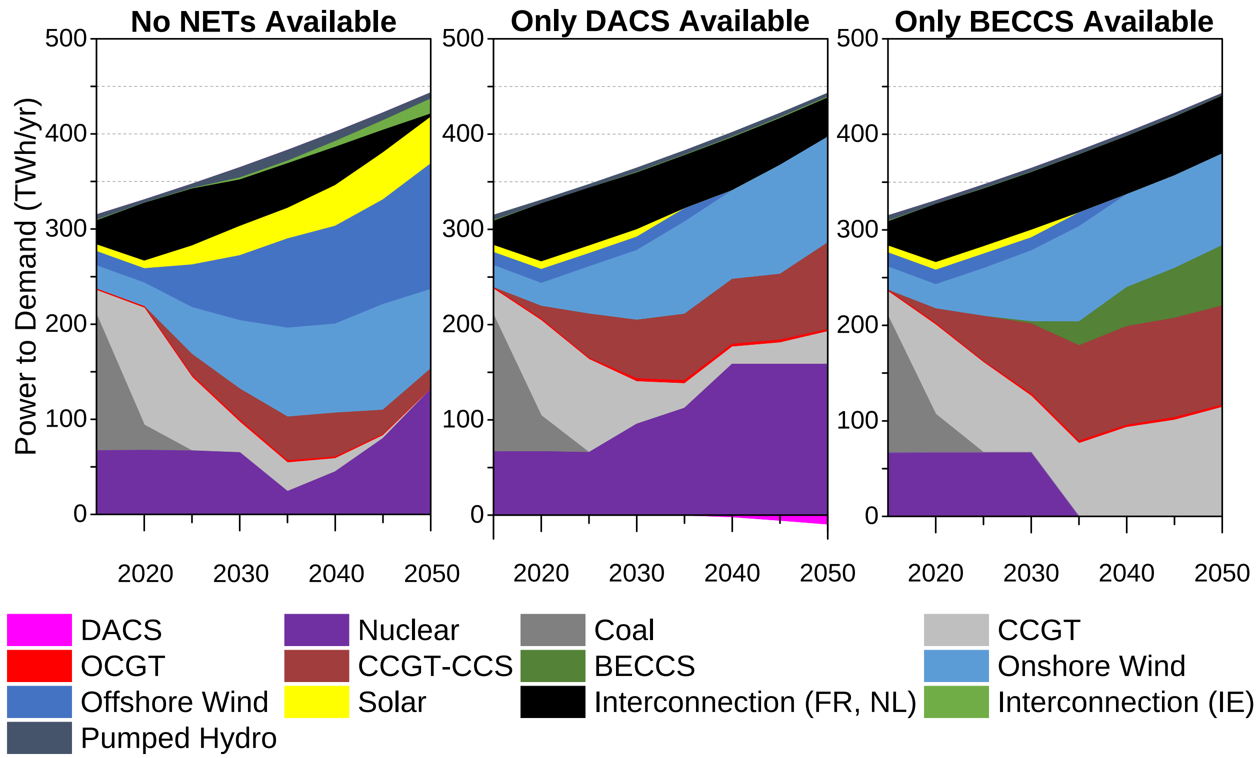

Figure 8: Optimal electricity generation mix for the UK from 2015 to 2050, when a zero emissions target is to be achieved, given the availability of negative emissions technologies for large-scale deployment.

generators with DACS to compensate for their associated emissions is significantly cheaper than a system dominated by IRES and energy storage.

Annual MCs are seen to be similar with and without DACS availability. Similar peaking at £206/MWh occurs in 2050, approximately four times the current average electricity cost of £47/MWh[76]. The high MC in 2050 occurs due to the large OPEX of DACS plants. A marginal increase in demand is satisfied by the increased operation of cheap thermal plants or imports (Nuclear and IRES are already maximally utilised) and DACS is needed to compensate for the resulting emissions, which in turn results in an added electricity demand.

The challenges surrounding social attitudes to land-based IRES[77], particularly Onshore Wind, will remain as installed capacity increases fivefold by 2050. Issues surrounding the feasibility of future conventional nuclear projects and CCS, discussed in section 1.1, also persist. Lastly, an increased reliance on electricity imports may also raise energy security concerns.

3.1.3 BECCS Available

When BECCS is made available to the system, total investment needed in the power sector by 2050 falls to £160 billion, a 48% decrease relative to the *No NETs* scenario. Therefore, BECCS deployment provides the greatest reduction in total system cost. We observe that 8.5 GW of BECCS capacity are built by 2050 to provide 51 Mt_{CO_2}/y of negative emissions. This offsets emissions from gas plants and interconnectors, thereby allowing UF_{CCGT} and $UF_{CCGT-CCS}$ to rise to 38% and 79%, respectively. In addition to the CO_2

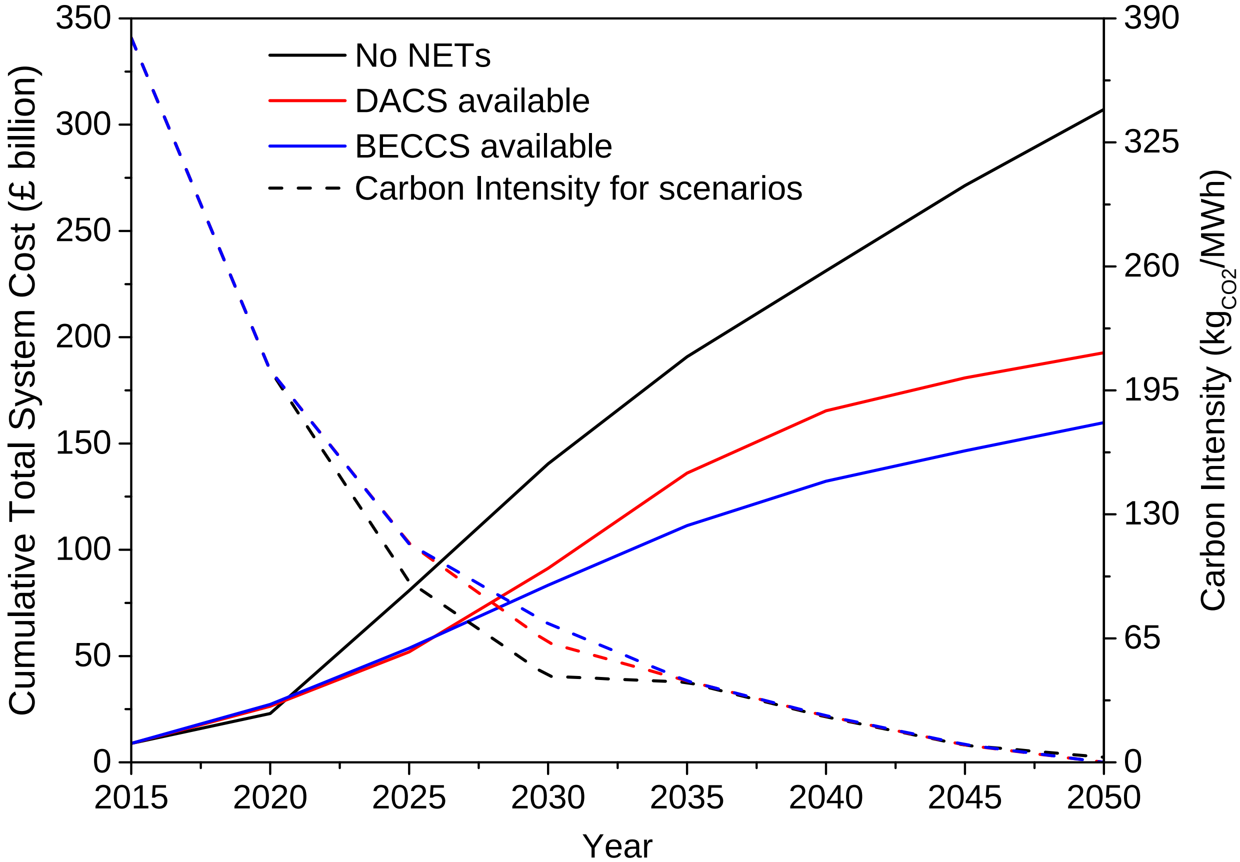

Figure 9: The cumulative total system cost of an optimal UK electricity system form 2015 to 2050, given the availability of negative emissions technologies for large-scale deployment.

removal service it provides, BECCS produces 63 TWh/y by 2050. Together, BECCS and gas satisfy 64% of demand: CCGT (26%), CCGT-CCS (23%), BECCS (14%) and OCGT (0.5%). Increased generation from thermal plants displaces more expensive low-carbon electricity generators from the system. No new Nuclear, Solar or Offshore Wind power plants are built after the existing fleet reach the end of their operational lifetimes. However, 39 GW of Onshore Wind is added by 2050, resulting in an increase of IRES penetration from 25% of capacity installed today to 31% in 2050. No added energy storage is needed to accommodate increased IRES penetration – 3 GW of pumped hydroelectric storage currently available however continue to provide 0.6% of demand.

The generation of 63 TWh/y of electricity by BECCS requires 12 $Mt_{pellets}$/y of fuel-grade biomass, assumed to be provided by Miscanthus in this work. Domestic Miscanthus supply – 21 $Mt_{pellets}$/y – can satisfy the biomass demand and more expensive pellet imports are not required. The necessity for a sustainable supply of biomass in order for BECCS to result in net removal of CO_2 from the atmosphere has been discussed at length elsewhere[47,78], and as such are not discussed further here.

In this scenario, MC consistently rises until 2050 when it peaks at £109/MWh, more than twice the current price. This is however approximately half of the MC observed in the *No NETs* or *DACS Only* scenarios.

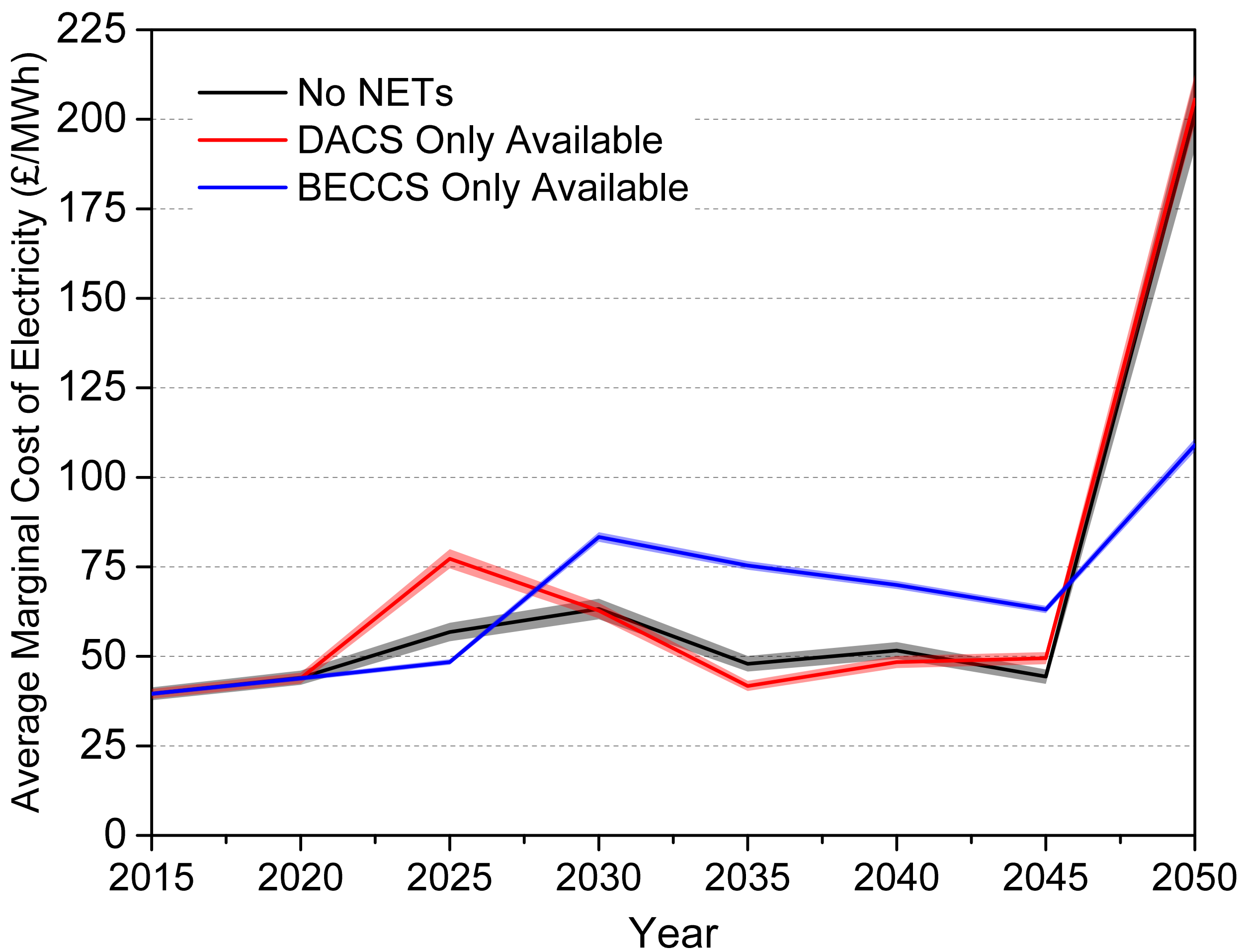

Figure 10: Average annual marginal cost of electricity in the UK depending on the deployment of BECCS or DACS in the system.

3.2 A "1.5°C system"

The emissions target for 2050 is adjusted to -50 Mt_{CO_2}/y in the model, so the UK can meet its commitment to the Paris Agreement[18], illustrated in Fig. 2. BECCS and DACS are also made available for deployment from 2015. All other model parameters remain unchanged. Fig. 11 illustrates the electricity supply mix necessary to meet this target by 2050. We observe that at least 93 Mt_{CO_2}/y of negative emissions are needed by 2050 – 43 Mt_{CO_2}/y compensates for the fossil generators in the system while the rest serves as available offset for other sectoral emissions. This is all provided by BECCS as it has cheaper abatement cost (£190/t_{CO_2}) compared to DACS (£390/t_{CO_2}), and can contribute to electricity supply.

To satisfy the CO_2 removal target above, approximately 23 Mt/y of Miscanthus pellets are needed by 2050. This is greater than current projections of domestic biomass availability, thus necessitating the import of potentially more expensive biomass. The optimal electricity generation mix needed to achieve the Paris Agreement target is shown in Fig. 11. This system requires £176 billion to be invested in the power sector from 2015 to 2050, a 10% increase compared to the *BECCS Only* scenario. BECCS capacity installed in 2050 increases from 8.5 to 15.5 GW as more negative emissions are required to meet the deeper decarbonisation target. The corresponding increase in generation displaces further unabated gas generation.

Consequently, less negative emissions are needed to offset ossil-derived emissions, thereby allowing more offset for non-power sectoral emissions. By 2050, unabated gas capacity is 46.8 GW, 3.8 GW less than installed capacity when mid-century decarbonisation is the objective. CCGT utilisation, UF_{CCGT} also falls from 38% to 31%.

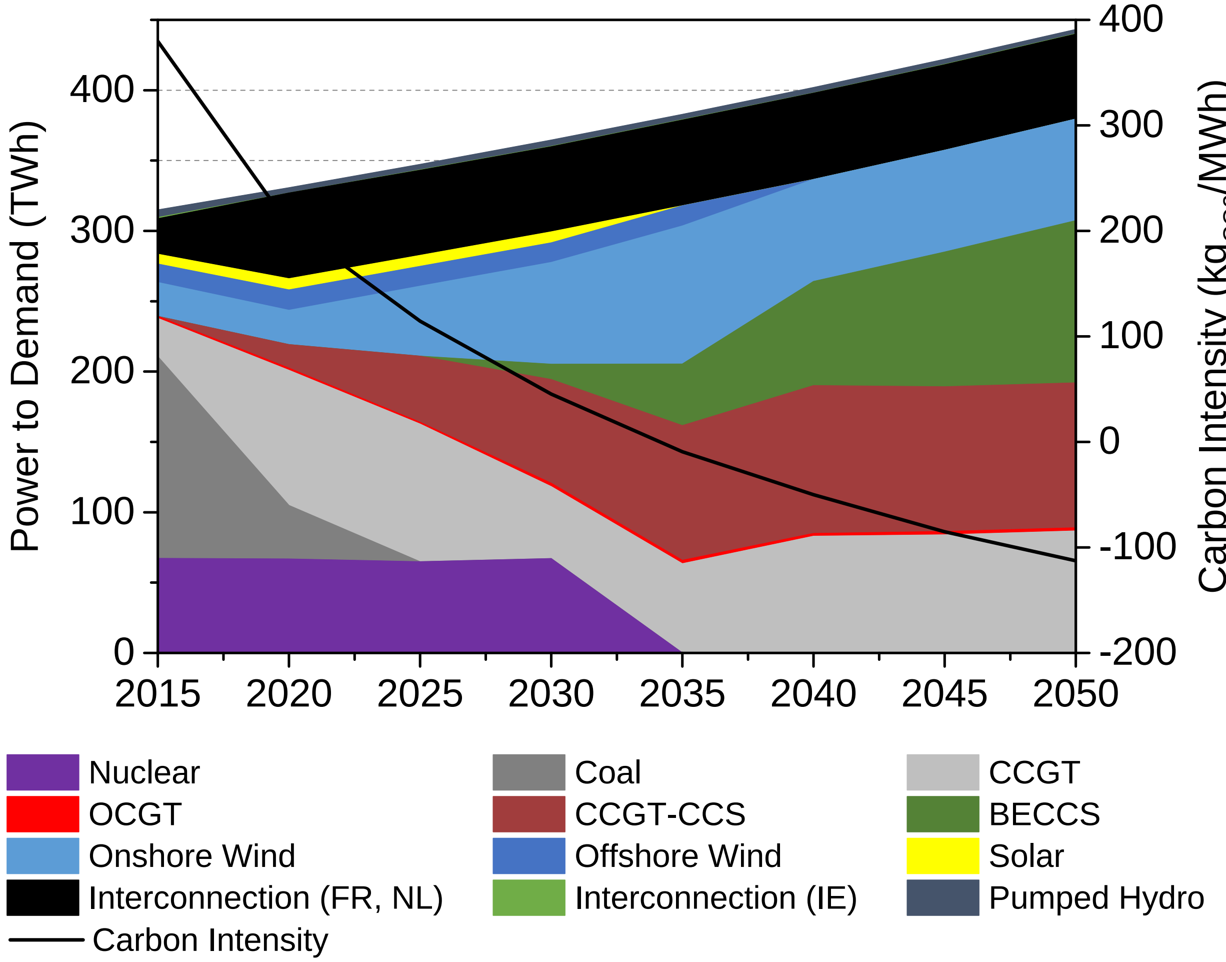

Figure 11: Optimal electricity generation mix for a UK electricity system consistent with the Paris Agreement target.

Nuclear, Solar and Offshore Wind are phased out as the existing power plants are not replaced at the end of their lifetime, while 30 GW of new Onshore Wind capacity is added by 2035. 15 GW of CCGT-CCS are deployed as in all scenarios previously discussed. Share of generation in 2050 is 26% BECCS, 23% CCGT-CCS, 20% CCGT, 16% Onshore Wind, 14% Imports, 0.7% Pumped Storage, and 0.5% OCGT. Therefore, should BECCS technology be available for deployment, it would need to supply more than a quarter of the UK's electricity demand to provide sufficient negative emissions for compliance with the Paris Agreement. Furthermore, such a scenario would see biomass and electricity imports meet approximately 16%[§] of demand, a threefold increase in import's share of generation today.

Onshore Wind features significantly in all the scenarios discussed, satisfying 16-36% of demand. More expensive Offshore Wind, however, is phased out in all but the *No NETs* scenario, as existing capacity is not

[§] 14% from interconnectors and 2% from imported biomass replaced after it reaches the end of its lifetime. Only lower cost IRES are therefore valuable to the system. The most recent auction in the UK saw falling costs of Offshore Wind[79]. In addition, public attitudes may favour unseen Offshore Wind farms over (new) onshore farms that disrupt landscapes. Reduced availability of Onshore Wind and cheaper Offshore Wind may therefore lead to the deployment of Offshore Wind in the future, contrary to what we observe here.

We also observe direct competition between BECCS and Nuclear, as BECCS deployment displaces the need for new nuclear plants in the system. Therefore, flexible carbon-negative generation to augment gas generation, and offset gas-derived emissions (from CCGT and CCGT-CCS), proves more valuable to the system than base load zero-carbon generation.

4 What is the value of negative emissions?

The reductions in system costs and marginal electricity costs achievable due to the availability of NETs have been shown to be significant, especially for BECCS. To quantify the value that each technology adds to the system, two metrics have been employed: the System Value[57] and the Value Transfer, as introduced in this work.

4.1 System value

The System Value (SV) metric quantifies the value of a technology, i, to the power system as the reduction in total system cost (TSC) caused by the deployment of the technology[57]. This is shown in Eq. 3. The reference year from which the reduction in TSC is calculated is 2050, when the decarbonisation objective is to be met.

$$SV_{i,k} = \frac{TSC_{i,k=0} - TSC_{i,k}}{k_i} \tag{3}$$

where TSC_k is the total system cost (TSC) in 2050 for a given deployment, k (kW), of technology i, and $TSC_{i,k=0}$ is the TSC in 2050 when technology i is not available to the system. As DACS is a net consumer of heat and power, k_{DACS} is the installed capacity required to meet its energy needs. An electricity-to-heat conversion factor of 45%[¶] was used to determine the installed capacity required to satisfy its energy input. Hence its SV is given in £/kW$_{\text{required}}$.

The available capacity of BECCS and DACS for deployment was increased until there was no marginal decrease in TSC. That is, should more of the technology be made available, it is not deployed as the resulting capacity mix is not cost-optimal. This limit is called the economic level of deployment (EL) of the technology, and is discussed in detail in our previous work[57]. The System Value curves for both BECCS and DACS are illustrated in Fig. 12. On initial deployment, BECCS has an SV of approximately £124,000/kW, three times that of DACS – £43,000/kW$_{\text{required}}$. As more BECCS is made available, the marginal reduction in TSC per installed capacity falls until BECCS reaches its EL. BECCS and DACS were found to have an ELs of 8.5 GW$_{\text{installed}}$ and 8.4 GW$_{\text{required}}$, respectively. As can be observed from Fig. 12, BECCS provides significantly greater value to the electricity system than DAC, though this gap does narrow substantially once more than 4 GW of capacity are installed.

4.2 Value Transfer

In section 3, we showed that the availability of both BECCS and DACS increased the utilisation of CCGT power plants. In the absence of NETs, they would have been constrained off the system owing to their CO_2

[¶]Efficiency of CCGT-CCS power plant

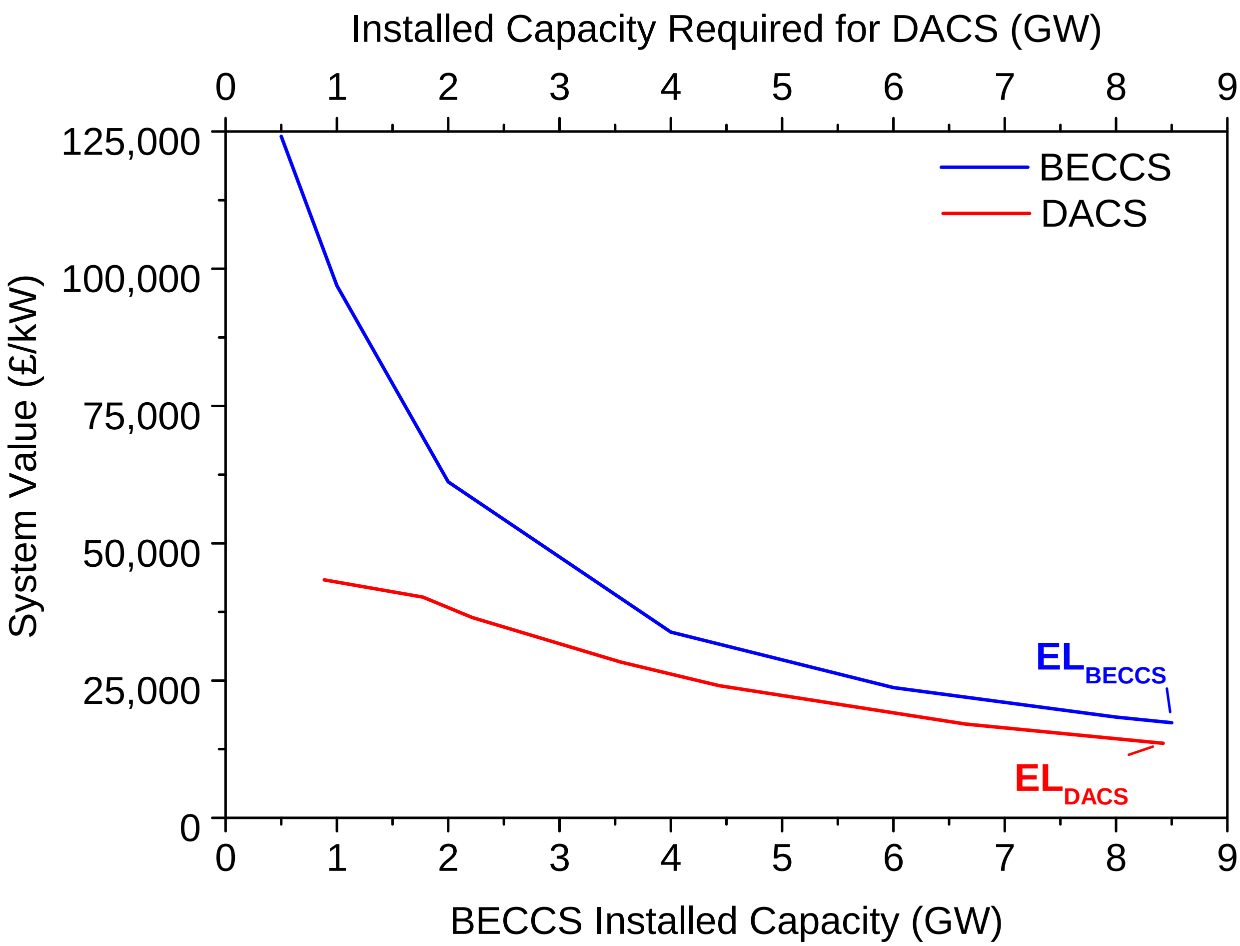

Figure 12: System value of BECCS and DACS to the UK electricity system. Their economic levels (EL) of deployment are highlighted.

emissions. Fig. 13 illustrates the contributions of different technologies to power sector emissions from 2015 to 2050 when NETs are available to the system.

It is observed that, with increasing availability of NETs, the asset utilisation of CCGTs is also substantially increased, whilst only marginal increases are observed for interconnection, OCGT and CCGT-CCS assets. In other words, the availability of NETs allows for increased revenue to be earned by those generation assets that would be otherwise constrained off the electricity grid owing to their carbon emissions. In order to fairly distribute the cost of providing this service, it is essential to allow some of that value to accrue to the NET facilities that are providing this service, thus reducing the societal cost of delivering negative emissions. In this section, we propose a proportional value transfer mechanism, and illustrate how it might be calculated.

Fig. 14 shows how CCGT utilisation factor (UF_{CCGT}) vary with different availabilities of BECCS technology. It is evident that higher UF_{CCGT} are associated with BECCS deployment. In the period 2015-2020, UF_{CCGT} peaks at approximately 35% due to the phase-out of coal plants, and in the absence of BECCS (i.e., the "No NETs" scenario), UF_{CCGT} falls to less than 5% by 2050. At maximum BECCS deployment, however, UF_{CCGT} is seen to be consistently higher than current levels, reaching 49% by 2050. To quantify the value of the emissions offset provided by BECCS to CCGT, a Value Transfer metric is used.

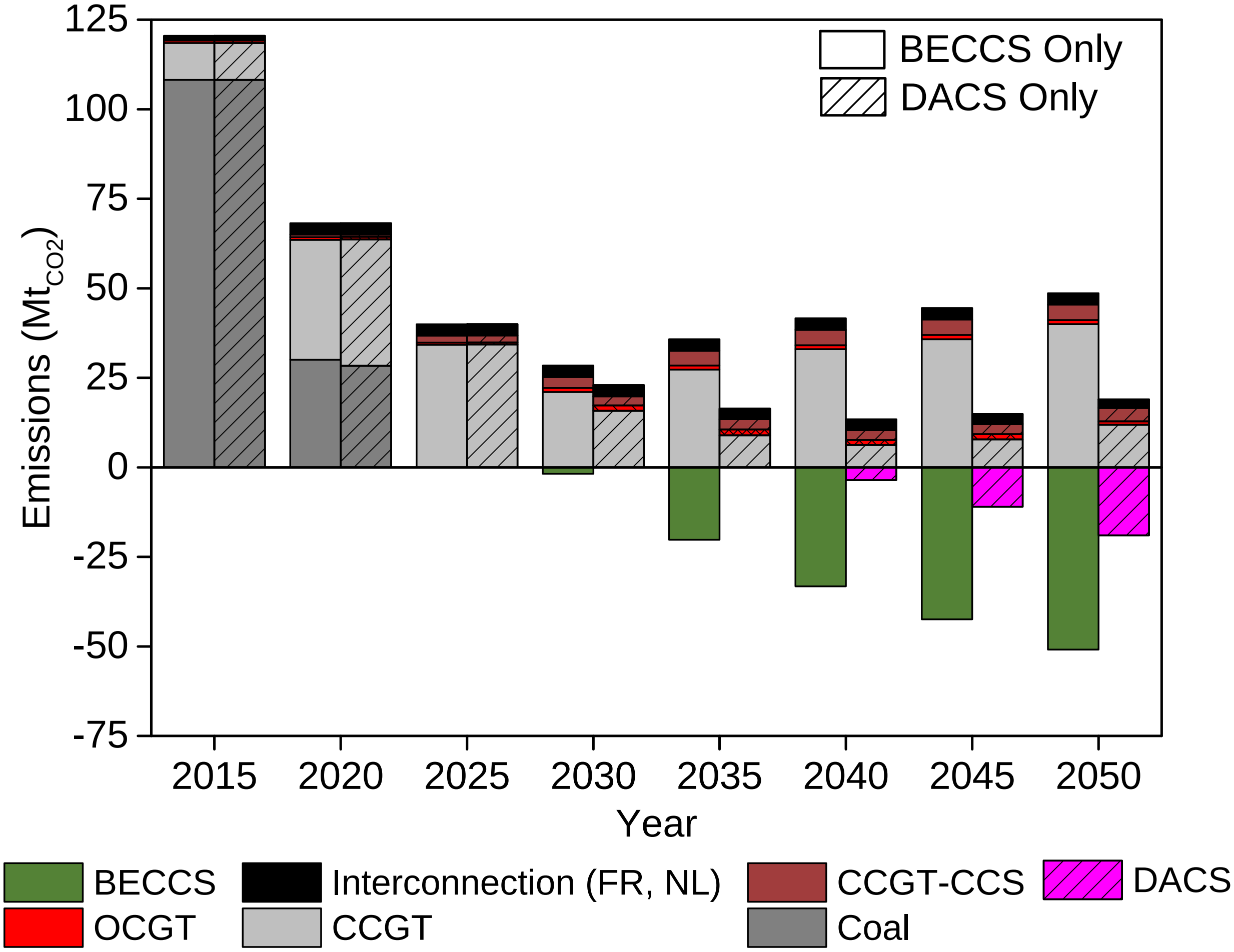

Figure 13: Carbon emissions by technology in a UK electricity system that achieves complete decarbonisation by 2050.

The Value Transfer ($VT_{i,j}$) metric, presented in Eq. 4, quantifies the value transferred to technology j by the increased operation of negative emissions technology i at deployment level d, $NE_{i,d}$. It has been defined as the change in revenue generated by technology j divided by the change in negative emissions provided by technology i.

$$VT_{\mathrm{i,j}} = \frac{R_{j,d} - R_{j,initial}}{NE_{i,d}} \tag{4}$$

where: VT is the value added to technology j plants by increased deployment of i; $R_{j,d}$ is the total revenue generated by j from 2015 to 2050 when i is deployed at capacity d; $R_{j,initial}$ is the total revenue generated by j when no negative emissions technologies are deployed in the system; and $NE_{i,d}$ is the total negative emissions provided by i at capacity d.

Revenue generated by j, R_j has been calculated as the sum of its revenue from electricity generation to meet demand and revenue from provision of reserve capacity. This is shown in the equation below:

$$R_j = \sum_{a,t} p2d_{j,a,t} \times MC_{a,t} + \sum_{a,t} r_{j,a,t} \times MRP_{a,t} \tag{5}$$

where t is time, discretised hourly; a is the year in which j is providing that service to demand; $p2d_{j,a,t}$ is the electricity generated hourly by technology j to meet demand at time t in year a (MWh/hr); $MC_{a,t}$ is

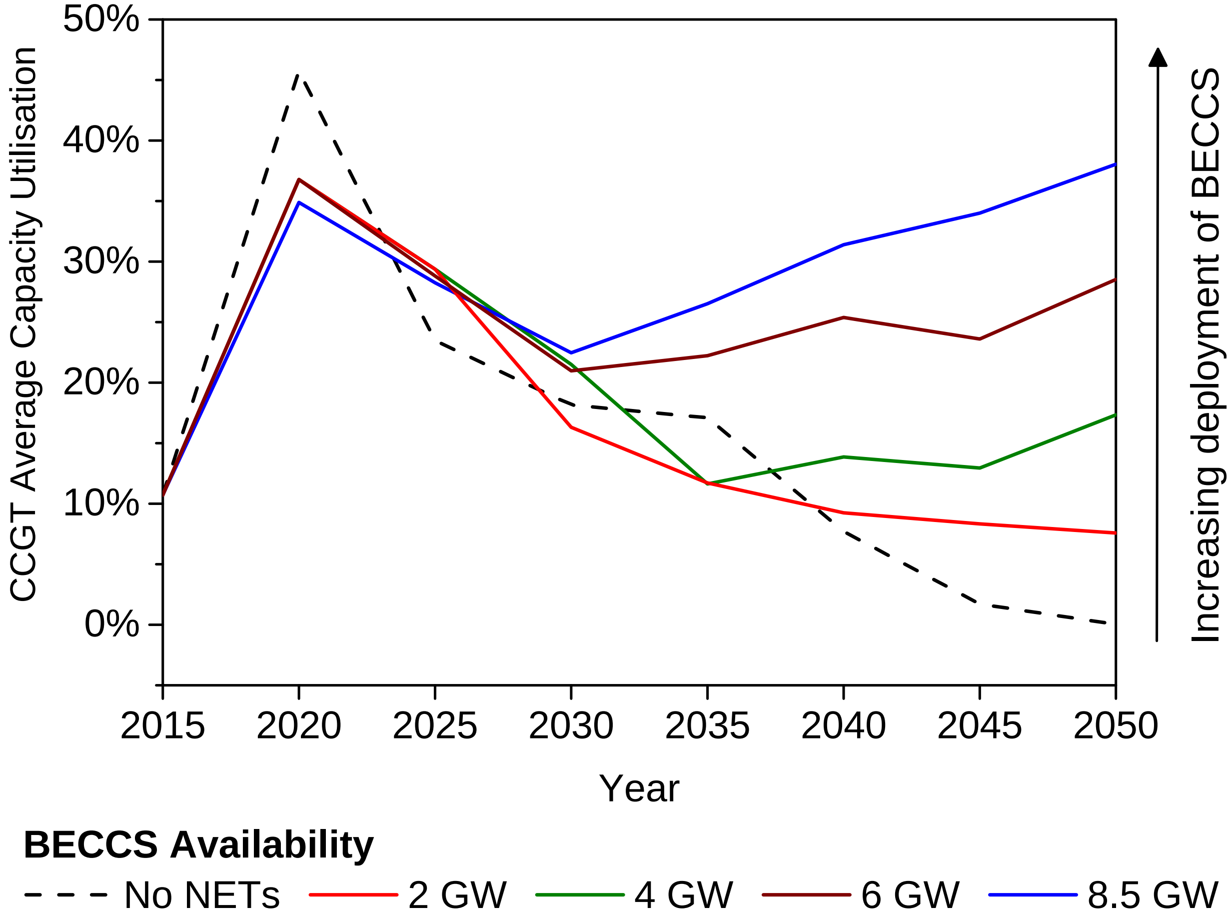

Figure 14: Variation in the utilisation factor of CCGT power plants with increased BECCS deployment in the electricity system.

the marginal cost of electricity (£/MWh) at time t in year a, derived as explained in section 2.1; $r_{j,a,t}$ is the reserve provided by j at time t in year a (MWh); and $MRP_{a,t}$ is the marginal cost of reserve at time t in year a (£/MWh).

Fig. 15 shows the variation in CCGT revenues and negative emissions provided with installed capacity of BECCS and DACS. $VT_{DACSOnly}$ and $VT_{BECCSOnly}$ were calculated to be approximately £460/t_{CO_2} and £230/t_{CO_2}. Therefore, per tonne of CO_2 removal, DACS accrues twice the value to CCGTs that BECCS does. From 2015 to 2050, £35 billion and £16 billion of additional revenue was generated by CCGTs when BECCS and DACS are deployed to their economic limit, respectively. VT_{DACS} is greater due to the higher MCs (illustrated in Fig. 10) and MRPs when DACS is deployed in the electricity system. In addition, BECCS ability to provide reserve reduces the need for CCGT reserve in the system. In a *DACS Only* scenario, CCGT reserve provision and MRP peak at 70% and £43/MWh, respectively, compared to 59% and £22/MWh, respectively, in a *BECCS Only* scenario. This results in larger CCGT revenues despite reduced operation (see Fig. 8). BECCS ability to provide reserve capacity in the system therefore reduces revenues generated by CCGTs.

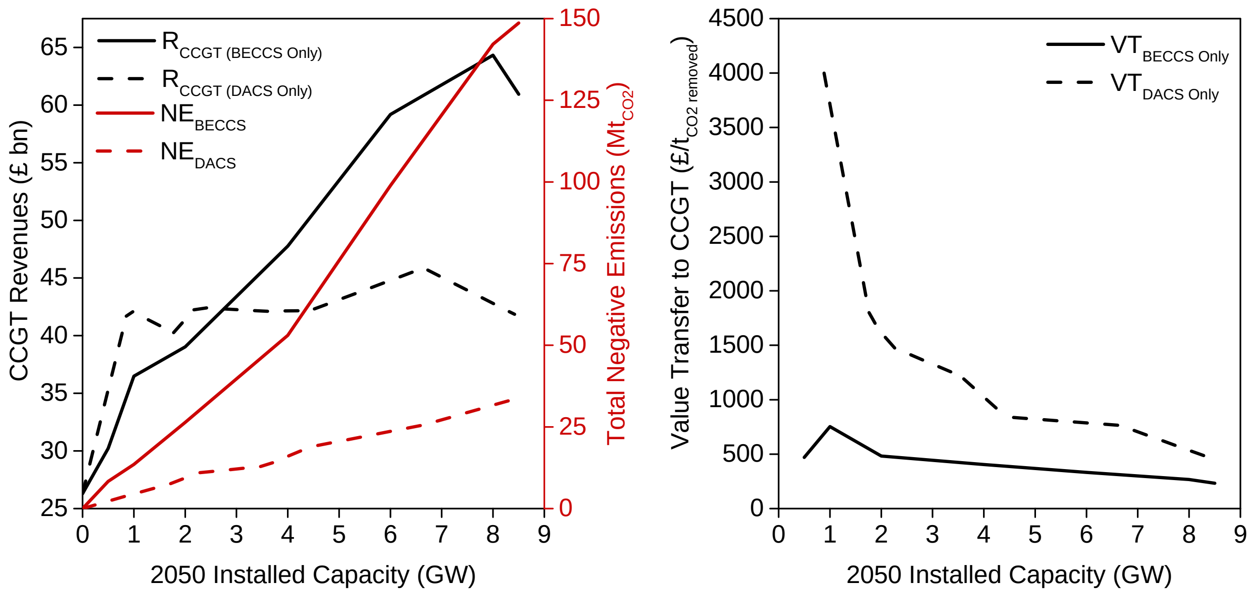

Figure 15: Variation in the total revenues generated by CCGT power plants and negative emissions provided with increasing deployment of BECCS and DACS (left). Value transfer from BECCS and DACS to CCGT power plants at different installed capacities (right).

4.3 Operation of BECCS within the electricity system

BECCS has been shown to provide three distinct services to the electricity system: power generation to meet demand, CO_2 removal from the atmosphere, and value transferred to CO_2 emitting assets that would be otherwise constrained off the electricity grid. As the value of, and thus appropriate compensation for, each service is likely to differ in value, it is important to understand the role of BECCS in the electricity system in which it is deployed. BECCS operation, described by its utilisation factor, UF_{BECCS}, is investigated to understand this role.

Fig. 16 shows the average hourly UF_{BECCS} and UF_{CCGT} in 2030 (when deployment begins) and 2050 (when decarbonisation is to be achieved) compared to the average annual hourly demand. In 2030, BECCS power generation is seen to fluctuate with hourly demand, *i.e.* it is load-following. CCGTs are observed to exhibit the same behaviour. BECCS is therefore operating to meet some electricity demand and provide some offset for CCGT emissions. The levelised cost of BECCS electricity is calculated to be £234/MWh (£64/MWh is contributed by biomass costs alone). Alternatively, the levelised CO_2 abatement cost (total investment in BECCS per tonne of CO_2 removed) is approximately £185/t_{CO_2}. These do not included the value it should accrue by providing a service to CCGT, discussed in section 4. In 2050, however, UF_{BECCS} is consistently at its maximum of 85%, hence it is operating base load. Therefore as the system emissions target tends to zero, BECCS transitions from load-following to base load behaviour, with the latter allowing for maximum CO_2 removal to meet the decarbonisation objective.

There is currently no incentive to support the deployment of NETs. The above analysis has, however, described the potential value that can be added by BECCS and DACS to the electricity system as a whole. In practice, this added value should accrue to the NETs in the form of a negative emissions credit, as discussed in previous work[78]. This has not been considered in this study.

Although the services to the electricity system provided by BECCS (electricity generation, reserve provision and negative emissions) and DACS (negative emissions) differ, they can both provide emissions offset that

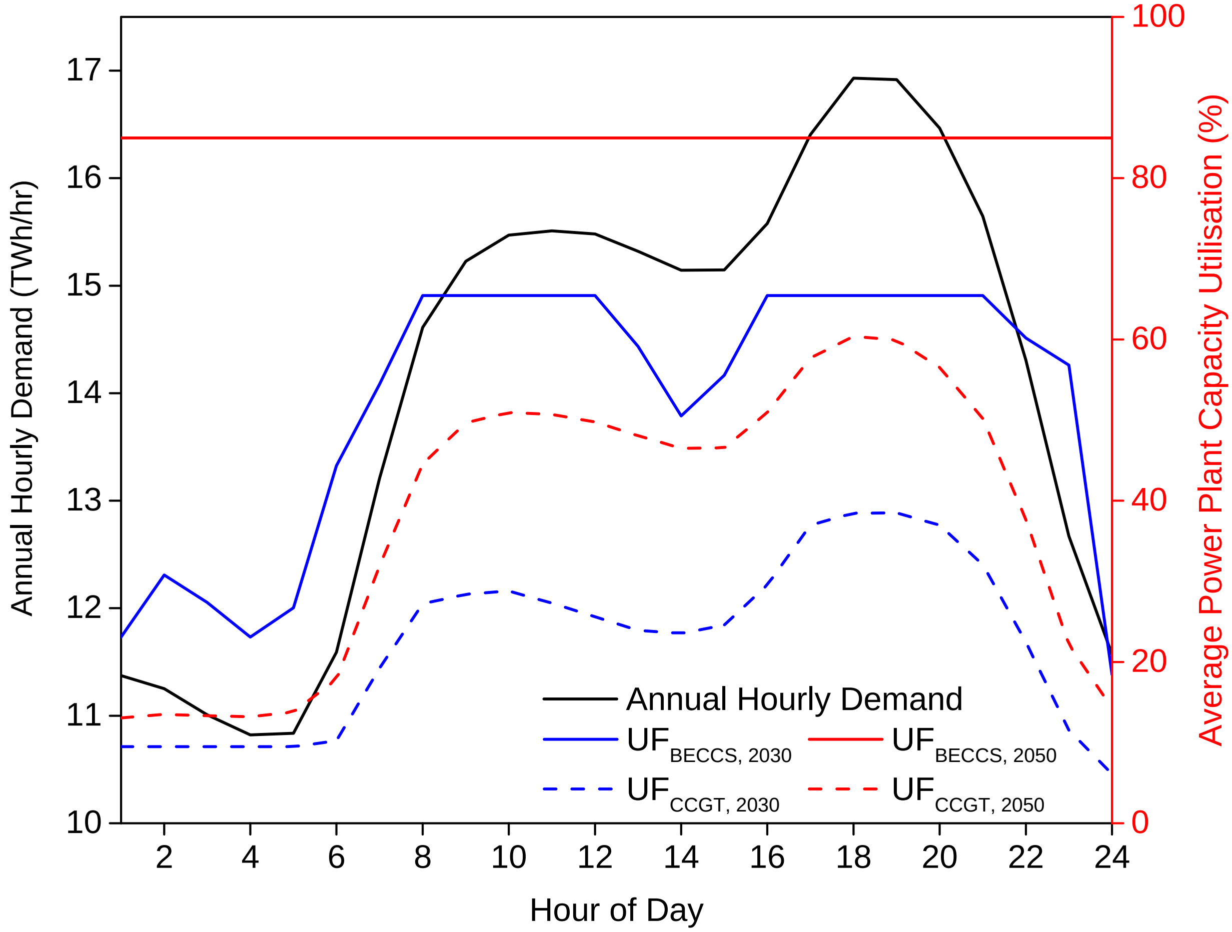

Figure 16: Variation in the average utilisation factor of BECCS plants in 2030 and 2050 with hourly electricity demand. The load factors are to be read of the right vertical axis (red), while the annual hourly demand is given on the left vertical axis (black).

allows for continued operation of cheaper unabated and abated thermal plants, especially CCGTs, and consequently drive down system cost. The Value Transfer metric, $VT_{i,j}$, discussed in section 4.2 shows that this continued utilisation translates into larger revenues for CO_2 emitting assets. The compensation of NETs by carbon emitters (at a price of $VT_{i,j}$) can potentially reduce the public burden of delivering negative emissions, *i.e.* reduce the negative emissions credit that needs to be provided for NETs' 'social service' of CO_2 removal.

5 Sensitivity analysis

The scenarios discussed in section 3 are dependent on the availability of CCGT-CCS technology, which is not currently deployed. In addition, estimates for BECCS and DACS technology costs have been used in the analysis. The influence of varying CCGT-CCS availability and NETs costs on the need for, and source of, negative emissions was investigated and is discussed below.

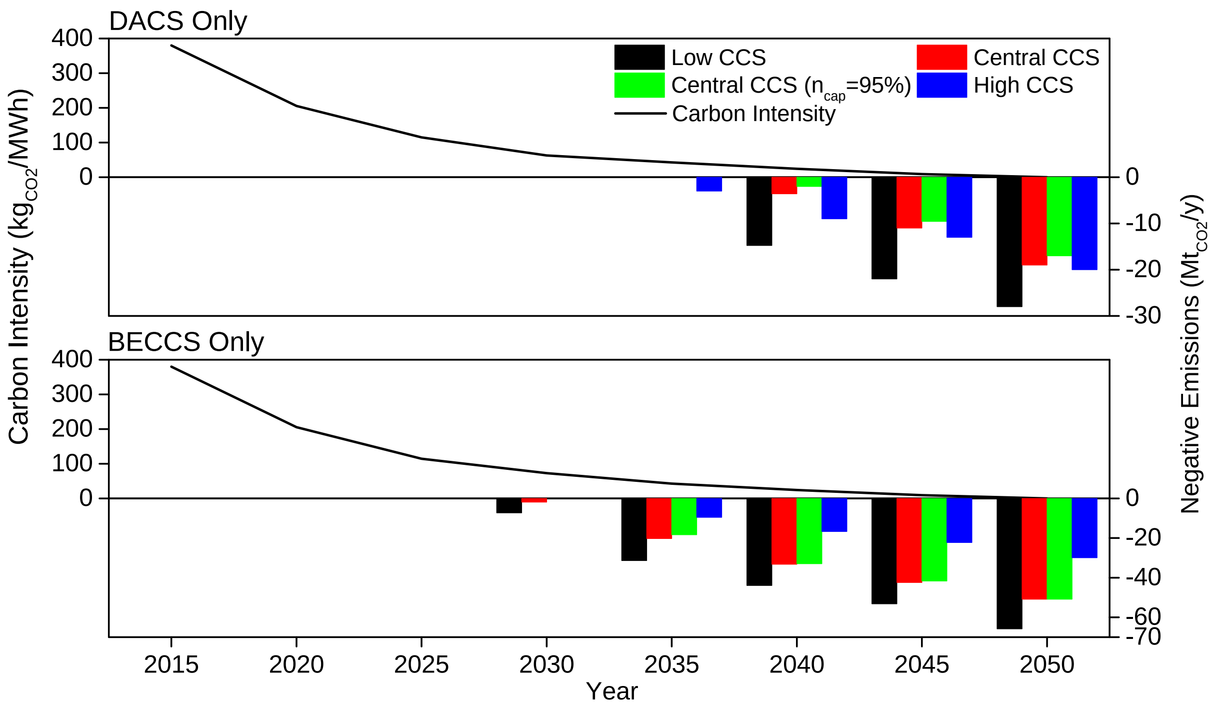

Figure 17: The variation in the amount of negative emissions deployed in the system from 2015-2050 with different CCGT-CCS availabilities, subject to a zero emissions target for the electricity system in 2050. Note that the vertical axis (negative emissions provided) has different scales for the *DACS Only* and *BECCS Only* scenarios.

5.1 CCS availability

CCGT-CCS contributes 15 GW to installed capacity in all the scenarios that achieve complete decarbonisation by 2050. It has been argued that the deployment of CCS technology presents a moral hazard to climate change mitigation as it allows for the continued consumption of fossil fuels [80,81]. It has also been shown that CCS can achieve capture rates of >90%, which is conventionally assumed, with limited efficiency penalty [70,82]. The amount of BECCS or DACS needed to decarbonise by 2050 at different CCGT-CCS availabilities and capture rates was investigated. Four scenarios are illustrated in Fig. 17: a) Low CCS (5 GW), b) Central CCS (15 GW), c) High CCS (45 GW), and d) Central CCS with $\eta_{\text{capture}} = 95\%$.

In the *DACS Only* scenario, increased CCGT-CCS availability initially reduces the need for negative emissions. However, at CCGT-CCS capacity of >15 GW (*Central CCS*), more CO_2 removal is needed to compensate for rising residual CCS emissions. Fig. 17 shows that DACS removes 1 Mt_{CO_2}/y more in a *High CCS* scenario, compared to a *Central CCS* scenario. This is because increased CCGT-CCS operation largely displaces Nuclear from the system, although CCGT generation is also reduced. As CCGT-CCS capacity increases from 5 to 45 GW, added Nuclear capacity decreases from 24 GW to 1.2 GW. In 2050, electricity demand met by Nuclear falls from 167 to 8 TWh/y; CCGT service to demand also falls from 66 to 16 TWh/y. Overall, CO_2 removal by DACS falls from 28 to 20 Mt_{CO_2}/y, from low to high CCS availability. Therefore, from a systems perspective, it is cheaper to operate more abated gas plants with DACS compensating for their residual emissions than to have a Nuclear-dominated electricity system. Furthermore, even at very high CCS availabilities, NETs are deployed in the optimal electricity system.

CCGT-CCS installed capacity is found to have greatest influence in the *BECCS Only* scenario. As capacity increases from 5 GW to 45 GW, negative emissions needed reduces from 66 Mt_{CO_2}/y to 30 Mt_{CO_2}/y in 2050. This is because increased CCGT-CCS generation displaces CCGT generation from the system – as CCGT-CCS capacity increases, CCGT generation falls from 164 to 42 TWh/y in 2050. Less emissions resulting from CCGT outweigh the increased residual emissions from CCGT-CCS, hence the need for negative emissions to compensate is reduced.

Increased capture rate, however, is found to have much less influence as a 5% increase in capture rate reduces the need for negative emissions by approximately 2 Mt_{CO_2}/y in the *DACS Only* scenario. In the *BECCS Only* scenario, the change is negligible. This occurs as reduced CCS emissions do not increase CCGT-CCS utilisation, rather cheaper CCGT plants produce 6 TWh/y more. The resulting CCGT emissions cancel out reduced CCS emissions, hence the need for CO_2 removal remains the same.

5.2 Scope for Cost Reduction

Thus far, we have evaluated the system with only one of BECCS or DACS available in any given scenario. However, given the relative immaturity of both technologies, and the potential for cost reduction, it is instructive to evaluate how they would interact in an electricity system if they were both available and competing. Thus, in this section, we present a sensitivity analysis quantifying the extent to which each technology would contribute to meeting a given negative emissions target should both technologies be available over a wide range of capital and operational costs.

5.2.1 CAPEX

Cost estimates in literature for DACS technology are for first-of-a-kind plants[23,24,55]. This is likely to reduce with increased R&D and deployment. The development of modular units for DACS[22,23] may also benefit from economies of scale, through mass production. Using the costs provided in Table 1, it was found that 87% of the investment in DACS was dedicated to CAPEX, with 17% for OPEX (Fig. 18). In contrast, investment in BECCS was made up of 60% CAPEX and 40% OPEX.

Fig. 19 shows the contribution of DACS to the UK's Paris Agreement target at different BECCS and DACS CAPEX. At current BECCS costs, $CAPEX_{DACS}$ must fall by a factor of 10 before its deployed for negative emissions. If the capital cost of DACS is reduced below 3500/kW_e[‖], DACS contributes 1-13% of -50Mt_{CO_2}/y target in 2050 (Fig. 2). At current cost estimates however, DACS remains uncompetitive with BECCS technology, even if $CAPEX_{BECCS}$ increases more than twofold from estimates in section 2.1.

5.2.2 Biomass cost

Miscanthus costs comprise the greatest contribution to $OPEX_{BECCS}$. Fig. 19 shows that despite a sixfold increase in Miscanthus raw material costs, BECCS is still the preferred source of all negative emissions. In addition to this increase, $CAPEX_{BECCS}$ must be >4000/kW (1.5 times the current CAPEX) for DACS to contribute to meeting negative emissions targets.

6 Conclusions

This study finds that, while power sector decarbonisation by 2050 is theoretically achievable without negative emissions technologies (NETs), this would require significant expansion of capital-intensive

[‖]Note that this is the capital costs of DACS levelised against its electricity consumption only, as discussed in section 2.1

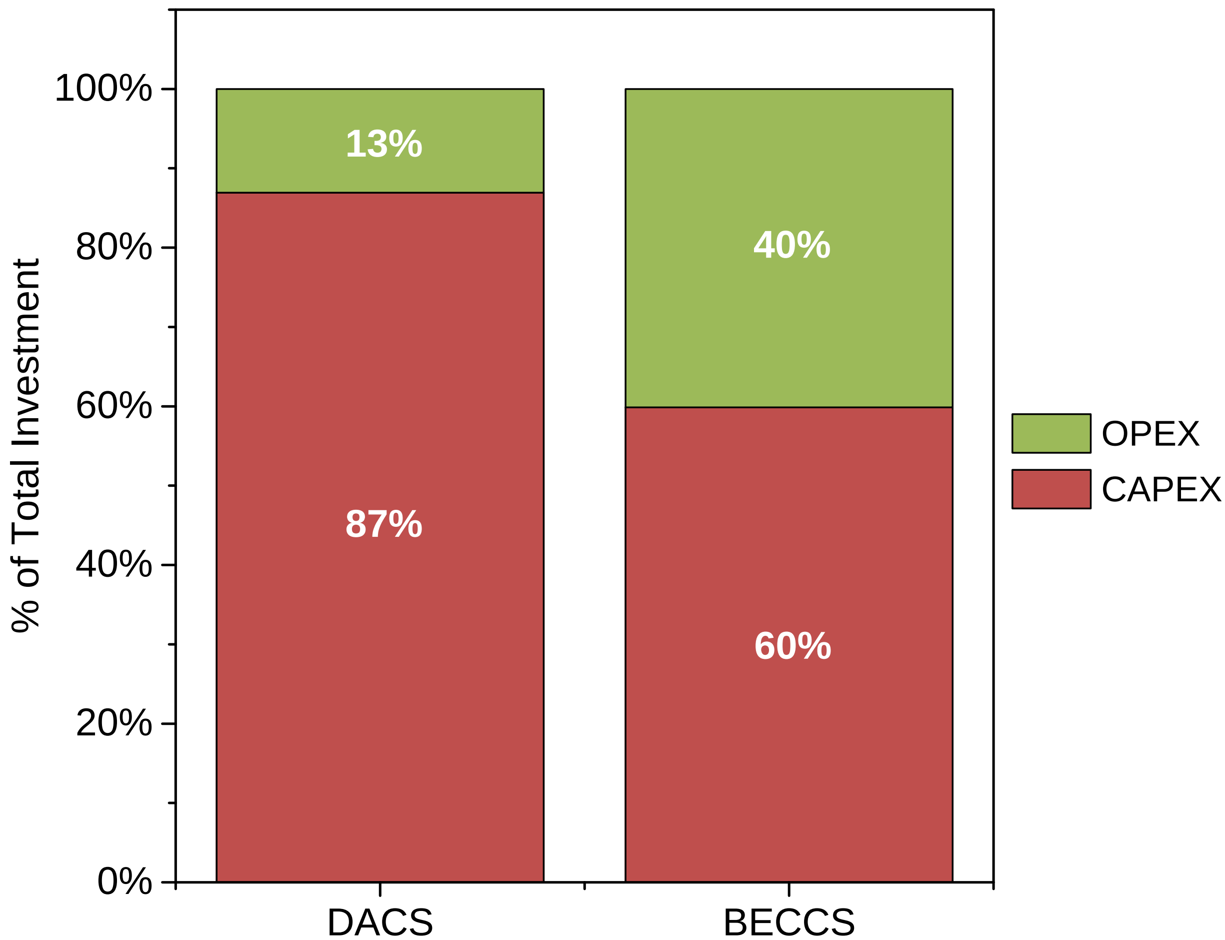

Figure 18: Contribution of CAPEX and OPEX to the total investment required for the operation of BECCS and DACS in the *BECCS Only* and *DACS Only* scenarios, respectively.

intermittent renewables and nuclear technologies. This results in a fivefold increase in electricity costs by 2050. Public acceptability is likely to hinder such a transition due to the lack of affordability of electricity. In addition, there are further sociopolitical barriers that must be considered. The large penetration of land-based IRES will require land dedicated to solar and onshore wind farms. Issues arising due to competition for land and social attitudes[77] must be overcome. Lastly, conventional nuclear technology faces challenges of large financing costs and long payback periods (discussed in section 1.1), which may dissuade from the pursuit of further projects[43,44]. Should NETs not be considered, it is unlikely for the decarbonisation target to be met.

Despite their relative costliness, NETs deployment could reduce total investment needed for electricity generation by 37-48% as their negative emissions allow for increased utilisation of cheaper CO_2 emitting generators within the system. BECCS provides the greatest opportunity for cost reduction. It is found to provide three times greater reduction in total system cost of the electricity system than DACS, per installed capacity. Whilst DACS still adds value to the system, its deployment will drive up electricity prices to levels seen in a *No NETs* system due to its large operating costs. A significant ramping of nuclear capacity installed is also needed. In contrast, BECCS deployment displaces the need for new nuclear plants as the services it provides – flexible carbon-negative generation to meet demand, reserve, and enable the continued utilisation of cheaper gas plants – are more valuable than the base load low-carbon generation offered by Nuclear.

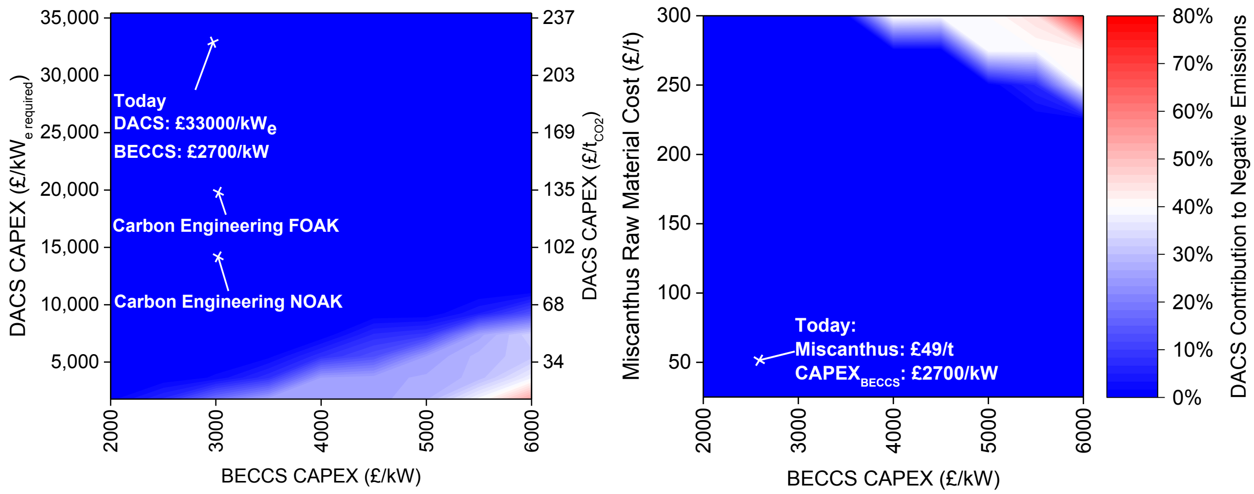

Figure 19: Contribution of DACS to the UK's negative emissions target at different biomass, BECCS and DACS costs.

Local grassland yield and availability is sufficient to satisfy the biomass demand for decarbonisation by 2050. However for the deeper decarbonisation pathways needed to be compliant with the Paris Agreement, 7% of biomass demand needs to be imported. The more stringent targets will also increase total electricity system cost by at least 10% (when BECCS is deployed).

The emissions offset that negative emissions provide for CO_2 emitting generators, especially CCGTs, has been observed to translate to larger revenues for CCGTs. In the absence of an incentive for negative emissions, a value transfer mechanism between NETs and CO_2 emitting assets could serve to reduce the public-borne cost of delivering negative emissions. This study concludes that NETs significantly reduce the cost of decarbonisation of the UK electricity system by 2050, and compensation by CO_2 emitting assets could offer a potential route to commercial deployment.

Declaration of interest

Declarations of interest: none.

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Appendix 1

The ESO-X model used in this work has been extended to include power-consuming negative emissions technologies, *e.g.* DACS. The mathematical formulation of the model, described here[58], has been adapted to include DACS. The equations changed are given below. Eq. 1-4 are newly added and are the basis of the analysis in this paper. The subsequent equations have been numbered to correspond with the labelling in the original model description[58]. An accessible version of the ESO-X model is available[60].

Table 2: Sets, parameters and variables added/updated in the ESO-X model

Type		Description	Unit
	i	all technologies considered in the system	-
	ig	power generating technologies, $ig \subseteq i$	-
	is	storage technologies, $is \subseteq i$	-
Set	t	time	hours
	a	planning period	years
	c	cluster set obtained using k-means clustering	-
	ne	negative emissions technologies, $ne \subset i$	-
	WF_c	weighting factor for cluster c	-
	$Disc_a$	discount factor in year a	-
	Des_i	unit capacity of technology i	MW/unit
	$Pmin_i$	minimum power output from technology i	%-MW
	$Pmax_i$	maximum power output from technology i	%-MW
	$CAPEX_i$	capital cost of tecnology i	£/unit
	Ems_i	carbon emissions from technology i	t_{CO_2}/MWh
Parameter	$OPEX_{i,a}$	operational cost of technology i	£/MWh
	$OPEXSU_{ig}$	start-up costs of technology ig	£
	$OPEXNL_i$	fixed operational costs of technology i	£/MWh
	$SEta_{is}$	storage roundtrip efficiency	%
	SE_a	annual system carbon emissions	t_{CO_2}
	$ImpElecPr_t$	import electricity price at time t of cluster c	£/MWh
	$VoLL$	value of lost load	£/MWh
	$UKNET_a$	UK negative emissions target in year a	t_{CO_2}
	$b_{i,a}$	number of units of technology i built in year a	-
	$d_{i,a}$	number of units of technology i installed in year a	-
	$u_{ig,a,c,t}$	number of units of technology ig starting up at time t in year a of cluster c	-
	$nets_{ne,a,c,t}$	number of units of DACS units ne operating at time t in year a of cluster c	-
	$p_{ig,a,c,t}$	energy output of technology ig to demand at time t in year a of cluster c	MWh
	$p2d_{ig,a,c,t}$	energy from technology ig to demand at time t in year a of cluster c	MWh
	$p2s_{ig,a,c,t}$	energy from technology ig to storage at time t in year a of cluster c	MWh
	$p2DACS_{ig,a,c,t}$	energy from generating technology ig to DACS at time t in year a of cluster c	MWh

Table 2: Sets, parameters and variables added/updated in the ESO-X model

Type		Description	Unit
	$p2is_{is,a,c,t}$	energy to storage technology *is* at time *t* in year *a* of cluster *c*	MWh
Variable	$s_{is,a,c,t}$	effective state of charge of technology *is* at the end of time *t* in year *a* of cluster *c*	MWh
	$s2d_{is,a,c,t}$	energy from storage technology *is* to demand at time *t* in year *a* of cluster *c*	MWh
	$s2r_{is,a,c,t}$	energy from storage technology *is* to reserve at time *t* in year *a* of cluster *c*	MWh
	$s2DACS_{is,a,c,t}$	energy from storage technology *is* to DACS at time *t* in year *a* of cluster *c*	MWh
	$slak_{a,c,t}$	unmet electricity demand at time *t* in year *a* of cluster *c*	MWh
	$DACSOPEX$	total operational costs of DACS technology	£
	$NEDACS_{ne,a,c,t}$	negative emissions provided by DACS at time *t* in year *a* of cluster *c*	t_{CO_2}
	$e_{ig,a,c,t}$	carbon emissions from technology *ig* at time *t* in year *a* of cluster *c*	t_{CO_2}
	tse_a	total system carbon emissions in year *a*	t_{CO_2}
	tsc	total system cost	£

Equations

$$nets_{ne,a,c,t} \leq d_{ne,a} \qquad \forall ne,a,c,t \tag{1}$$

$$\sum_{ig} p2DACS_{ig,a,c,t} + \sum_{is} s2DACS_{is,a,c,t} \leq nets_{ne,a,c,t} Des_{ne} Pmax_{ne} \qquad \forall ne,a,c,t \tag{2}$$

$$\sum_{ig} p2DACS_{ig,a,c,t} + \sum_{is} s2DACS_{is,a,c,t} \geq nets_{ne,a,c,t} Des_{ne} Pmin_{ne} \qquad \forall ne,a,c,t \tag{3}$$

$$NEDACS_{ne,a,c,t} = (\sum_{ig} p2DACS_{ig,a,c,t} + \sum_{is} s2DACS_{is,a,c,t}) Ems_{ne} \qquad \forall ne,a,c,t \tag{4}$$

$$\sum_{ig,c,t} e_{ig,a,c,t} WF_c + \sum_{ne,c,t} NEDACS_{ne,a,c,t} WF_c \leq SE_a + UKNET_a \qquad \forall a \tag{17}$$

$$p2d_{ig,a,c,t} + p2s_{ig,a,c,t} + p2DACS_{ig,a,c,t} = p_{ig,a,c,t} \qquad \forall ig,a,c,t \tag{21}$$

$$s2d_{is,a,c,t} + s2r_{is,a,c,t} + s2DACS_{is,a,c,t} \geq o_{is,a,c,t} Des_{is} Pmin_{is} \qquad \forall is,a,c,t \tag{30}$$

$$s2d_{is,a,c,t} + s2r_{is,a,c,t} + s2DACS_{is,a,c,t} \leq o_{is,a,c,t} Des_{is} \qquad \forall is,a,c,t \tag{31}$$

$$s2d_{is,a,c,t} + s2r_{is,a,c,t} + s2DACS_{is,a,c,t} \leq s_{is,a,c,t}SEta_{is} \qquad \forall is,a,c,t \tag{32}$$

$$s_{is,a,c,t} = s_{is,a,c,t-1} - s2d_{is,a,c,t} - s2DACS_{is,a,c,t} + p2is_{is,a,c,t}SEta_{is} \qquad \forall is,a,c,t>1 \tag{38}$$

$$\begin{aligned} tsc = \sum_{i} CAPEX_i b_{i,a} Des_i / Disc_a + \sum_{ig,a,c,t} (u_{ig,a,c,t} OPEXSU_{ig} WF_c)/Disc_a \\ + \sum_{ig,a,c,t} (OPEX_{ig,a} p_{ig,a,c,t} WF_c + OPEXNL_{ig} n_{ig,a,c,t} WF_c)/Disc_a \\ + \sum_{is,a,t} (OPEX_{is,a}(s2d_{ig,a,c,t} + s2DACS_{is,a,c,t}) WF_c + OPEXNL_{is} o_{is,a,c,t} WF_c)/Disc_a \\ + \sum_{i=InterImp,a,t} ImpElecPr_t p2d_{i,a,c,t} WF_c / Disc_a + \sum_{a,c,t} slak_{a,c,t} WF_c VoLL \\ + \sum_{ne,a} OPEX_{ne,a} (\sum_{ig,c,t} p2DACS_{ig,a,c,t} WF_c + \sum_{is} s2DACS_{is,a,c,t} WF_c)/Disc_a \end{aligned} \tag{44}$$

Appendix 2

System parameters

The base year for the ESO-X model is 2015. The annual demand and other system parameters are as provided in Table 3. We assume a 1% year-on-year increase in electricity demand. Although demand in the UK has fallen in recent years, increasing electrification of other sectors of the economy (heating and transport) is expected to result in rising demand[83,84].

Table 3: Data sources for system parameters assumed in the ESO-XEL model.

UK electricity system	Data source(s)
Hourly electricity demand	[85]
System inertia requirement	[86]
Capacity reserve for intermittent renewables	[87]
CO_2 emissions targets until 2050	[56]
Price of imported electricity	[88]
Power transmission and distribution losses	[89–91]
Value of lost load	[92]
Hourly availability of solar, onshore wind and offshore wind	[93–95]
Carbon price	[17]
CO_2 transport and storage costs	[72,74]

Fuel prices

Table 4: Data sources for fuel costs assumed in the ESO-X model.

Fuel cost	Data sources
Uranium (UO_2 fuel)	[96]
Coal	[97]
Natural gas	[97]

Biomass supply chain

The cost of biomass fuel is implemented using a supply chain. Two sources of biomass are considered: indigenous virgin biomass (Miscanthus is the grass considered) and pellet imports. For the local biomass, full supply chain (harvest, processing and pelletisation) emissions and costs are considered. For the imported biomass, transport costs from UK ports are considered. Tables 5- 7 detail the costs and associated CO_2 emissions of the biomass supply chain.

Table 5: Biomass supply and processing costs. Land availability is obtained from[98].

Biomass type	Raw material (£/tonne)	Pellet conversion rate	Pellet production cost (£/tonne)	Availability (tonne/ha yr)
Miscanthus	49[70]	83.7%[99]	17.86[100]	[69]
Imported pellets	159.5[71]	-	-	

Table 6: Cost of pellet plant

Pellet plant	
Unit capacity (tonnes/hr)	20[100]
Capital costs (M£/unit)	12[100]
Lifetime (years)	30[101]

Technology parameters

Table 7: Transportation costs and emissions assumed.

Transportation	Unit transport cost (£/t km)[101]	Unit emissions (kg_{CO_2}/t km)[101]
Truck	0.47	0.062
Rail	0.17	0.022
Ship	0.06	0.005

Table 8: Data sources for the technology costs and operational parameters implemented in the ESO-X model. Capital costs (average) and efficiencies are highlighted.

Technology	CAPEX (£/kW)	Efficiency (HHV)	Data sources reviewed
Nuclear	3673	37.0%	[102,103]
Coal (super-critical)	1237	42.2%	[72,102,104–114]
Dedicated biomass-fired	1590	40.0%	[103]
Combined cycle gas turbine (CCGT)	540	52.7%	[102,104,109,112,114–118]
Open cycle gas turbine (OCGT)	459	39.0%	[102,104,106,109,113–117]
Coal post-combustion CCS	2368	33.6%	[72,105–107,110,114,117,119–121]
CCGT post-combustion CCS	1187	45.5%	[102,107,108,110,117,120,121]
Bioenergy with CCS (BECCS)	2721	35.0%	[47,64,72,121–123]
Onshore Wind	1105	-	[93,102,103,115–117,124]
Offshore Wind	2600	-	[93,102,103,115–117,124]
Solar Photovoltaic (PV)	1157	-	[93,102?]
High-voltage direct current interconnection (HVDC)	1000	52%	[117,125,126]
Pumped hydro	1875	-	[102,121,127]
Lead-acid battery	1400	-	[128–131]
Direct air capture and storage (DACS)	33074	-	[55]