Structural evolution of the UK electricity system in a below 2°C world

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Summary

We employ a national-scale electricity system model to determine the least-cost transition necessary to meet a given CDR burden in the UK. The results show that, while sufficient in the medium-term, a system dominated by intermittent renewable energy technologies (IRES) cannot deliver zero-carbon power or CDR at the scale required in a cost-effective manner. The marginal value of IRES for climate change mitigation diminishes with time, especially in the context of the Paris Agreement. Deeper decarbonisation instead requires a resurgence of thermal generation from bioenergy and gas (both with carbon capture and storage), and nuclear. Such a system is inherently centralised and will require maintenance—if not improvement—of existing transmission and distribution infrastructure. Current policy direction however encourages the proliferation of renewables and decentralisation of energy services. To avoid locking the power system into a future where it cannot meet climate change mitigation ambitions, policy must recognise and adequately incentivise the new technologies (CCS) and services (CDR) necessary.

Keywords: carbon dioxide removal, negative emissions technologies, Paris Agreement, BECCS, direct air capture, power systems modelling, climate change mitigation

Introduction

Climate change has become a mainstay of global political discourse since the 2015 Paris Agreement. Through the accord, all nations committed to keeping the increase in global average temperature to "well below 2°C above pre-industrial levels" by 2100, and pursuing further efforts to restrict it to 1.5°C. Integrated assessment models (IAMs)—climate-economy models that inform on the socioeconomic consequences of greenhouse gas (GHG) emissions—have estimated that cumulative anthropogenic GHG emissions (also known as the 'carbon

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budget') must be limited to 590-1240 $Gt_{CO_2\text{-eq}}$ between 2015 and 2100 to deliver the Paris accord (>66% probability).[1] Mitigation action (reducing the sources or enhancing the sinks of GHGs) pledged by countries in their nationally-determined contributions (NDCs), however, is insufficient to achieve this; even if NDCs are successfully implemented, the available carbon budget will be exhausted by 2045-2075.[2] Large-scale carbon dioxide removal (CDR) from the atmosphere is therefore critical to compensate for an exceedance of the 2°C carbon budget.[3] IAMs show that a cumulative 430-740 Gt_{CO_2} of CDR is necessary by the end of the century, beginning as early as 2020 and reaching 10-20 Gt_{CO_2}/yr in 2100.[3,4] This is largely achieved through land-based CDR* in the form of afforestation and reforestation (AR), and bioenergy with carbon capture and storage (BECCS).

Although other forms of land- and ocean-based CDR techniques are extensively discussed in the literature, they remain largely theoretical.[5,6] Direct air capture and storage (DACS)—the direct removal of CO_2 from the atmosphere using a range of sorbents—has emerged as another technological option for CDR, with several demonstration projects seeking to establish its commercial viability.[7] Studies that assess the CDR potential of BECCS and DACS technologies have been carried out in the context of isolation, therefore they fail to quantify their relative values within the broader energy system.

Majority of the cumulative CDR needed to satisfy the 2°C carbon budget by 2100 is provided by BECCS in six regions†: China (20-170 Gt_{CO_2}), the United States (10-140 Gt_{CO_2}), India (0-90 Gt_{CO_2}), the European Union (20-70 Gt_{CO_2}), Brazil (20-150 Gt_{CO_2}) and Russia (10-80 Gt_{CO_2}).[4,8,9] Owing to the formulation of IAMs, the European Union's (EU) CDR requirements are not further geographically-disaggregated. How and where this CDR burden should be achieved at national-level where climate policy is implemented, is therefore unknown, and the implications of these quotas on country-level energy system transformations is largely absent.

This study seeks to fill these gaps by: 1.) quantifying UK CDR requirements according to established fairness principles, and 2.) determining the electricity system transition necessary to meet those requirements, since scenarios obtained from IAMs attribute most, if not all, of CDR in the energy system to BECCS in the power sector.[4]

Burden-sharing to deliver the Paris Agreement

It has been established that the countries with the greatest responsibility for climate change and the capacity to address it differ greatly from those most vulnerable to its adverse impacts.[10,11] Consequently, international climate policy has emphasised the need for fairness in establishing the relative burden of action to be taken by governments to stabilise GHG concentrations at non-dangerous levels.[12] The *United Nations Framework Convention on Climate Change* treaty states that member parties should protect the climate system "on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities".[13] However, there is no objective definition of how fairness should be assessed within the context of international climate policy.[12,14] Several sharing principles have been proposed to equitably distribute the economic burden of climate change mitigation. Some of these principles, and their implications for the UK's climate change mitigation burden have been illustrated in Fig. 1 and are detailed in Table S1.

These burden-sharing principles seek to establish a politically-optimal distribution of responsibility for climate change mitigation. In reality however, CDR is more feasible in some countries than others due to bio-geophysical and socio-political factors, *e.g.* an abundance of bioenergy resources, availability of low-carbon energy or geological sinks for CO_2. Consequently, a cost-optimal distribution of the CDR burden may require cooperation between nations. This is not taken into account in this study. Despite the weaknesses of these interpretations of distributive fairness[18–20], the principles have been used to ascribe regional carbon quotas and determine the sufficiency of existing climate change mitigation commitments to achieve them.[12,20]

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*CDR is sometimes referred to as 'negative emissions'. The terms are used interchangeably throughout the text.

†The estimates of CDR required to be consistent with the Paris Agreement are obtained from four IAMs: IMAGE, MERGE-ETL, POLES and WITCH.[4] All of these represent the EU as one or two geographic entities.

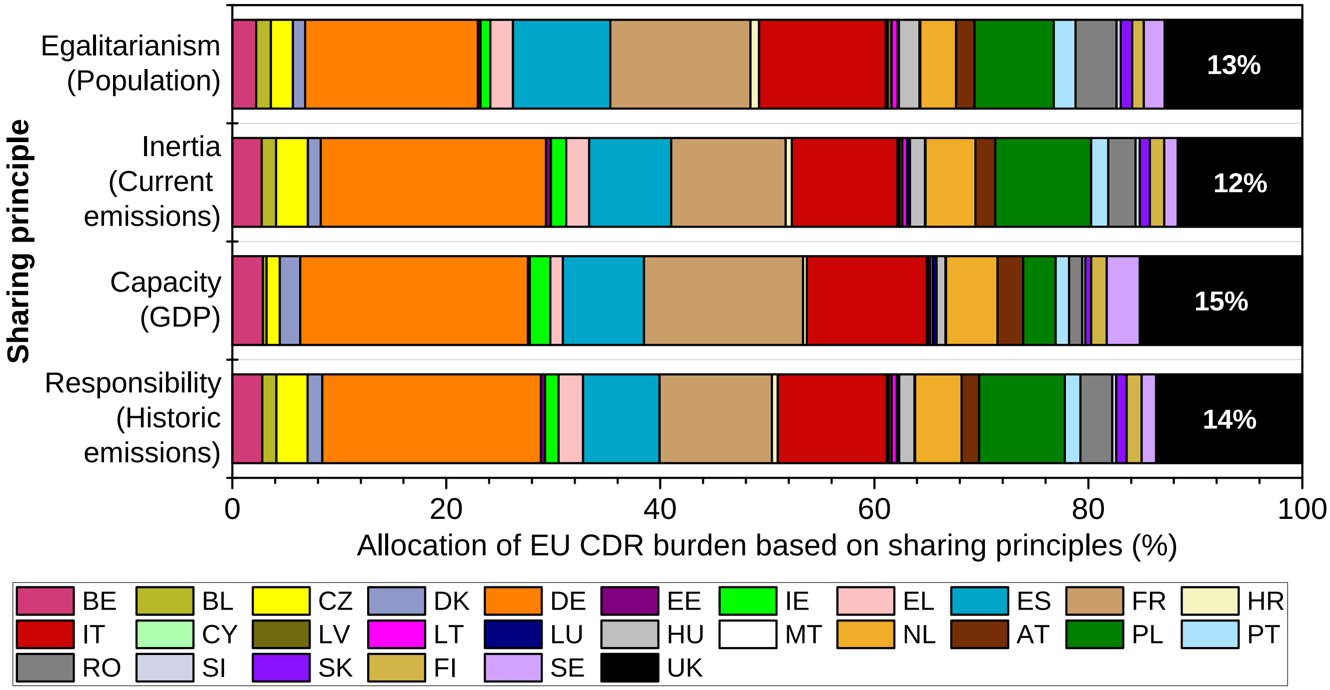

Figure 1: Allocation of the European Union's CDR burden according to proposed 'fairness principles'. Population and GDP data are obtained from Eurostat[15,16]; member states' historic greenhouse gas emissions are obtained from the European Environment Agency[17].

For the purpose of this study, we assume that the EU's CDR burden is allocated to member states in proportion to their responsibility for the climate change problem, *i.e.* based on their cumulative historic emissions. The UK is responsible for 14% of the EU's historic emissions (see Table S1); this corresponds to a cumulative CDR requirement of 2.8 to 9.8 Gt_{CO_2} by 2100. We subsequently analyse the implications of this scale of CDR on the UK's electricity systems transition.

Modelling framework

The national electricity system was modelled using the Electricity Systems Optimisation with capacity eXpansion and Endogenous technology Learning (ESO-XEL) in this study.[21] ESO-XEL is a mixed integer linear optimisation model that determines the least-cost evolution of a power system in five-yearly time steps, subject to a range of constraints: hourly demand is satisfied; grid reliability and operability are constantly maintained; until 2050, the maximum carbon emissions allowance for the system is restricted to the five-yearly power sector carbon budgets advised by the Committee on Climate Change (CCC)[22]; maximum build and ramping rates are specified per technology. Technology-specific cost learning is also implemented endogenously in the model *i.e.* capital costs are assumed to vary with additional capacity deployment, not with time. Although ESO-XEL treats the entire system as a single node, losses resulting from power transmission and distribution are accounted for. The mathematical formulation of the model has been defined previously[21], and is available as an open-access and open-data model.[23]

Model inputs

The technologies available for deployment in the ESO-XEL model, highlighted below, are available throughout the planning horizon considered (2015 to 2100). Their deployment is driven by the emissions constraints implemented in the model.

- Conventional fossil fuel generation from coal, open-cycle gas turbine (OCGT) and combined-cycle gas turbine

(CCGT) power plants. Interconnection with external electricity markets is modelled as infinitely-flexible power generation, with limits on generation capacity.

- Firm low-carbon generation from nuclear and biomass plants, and coal and CCGT power plants equipped with post-combustion carbon capture and storage (CCS). For CCS, we assume a conventional 90% CO_2 capture rate using monoethanolamine (MEA).[24]
- Intermittent low-carbon generation from solar photovoltaics (PV) and wind (onshore and offshore).
- Energy storage provided by batteries (parameterised as lead-acid type) and pumped hydroelectric storage (PHES).
- CDR from BECCS (which also contributes to power generation) and DACS, which is modelled as a power and heat consumer that provides atmospheric CO_2 removal at a cost[‡].

Two archetypes of DACS are currently being developed for commercial purposes, thus both were considered in the model. The first, DACS-CE, uses a hydroxide sorbent to remove CO_2 from air at a cost of \$94-232/t_{CO_2}; this is being developed by Carbon Engineering.[7] High-grade heat at 900°C (supplied by natural gas) is required to regenerate the capture solution[§]. Due to this high-temperature nature of the DACS-CE process, intermittent operation (say, due to variable energy supply) will lead to repeated heating and cooling of process equipment, which can be a source of efficiency loss or threaten process stability.[25] Thus inflexible operation—hence constant power and heat consumption—is assumed. The second, DACS-CW, is a modular technology that uses an amine-functionalised sorbent and low-grade heat to capture atmospheric CO_2 at a cost of \$600/t_{CO_2}; this is being developed by Climeworks.[26] This archetype can utilise waste heat at relatively low temperatures (100°C), so it is assumed to be suitable for flexible operation. Other costs of carbon capture *via* DACS that have been cited in the literature vary greatly (from \$30-1000/t_{CO_2}[27]), as they are based on a range of theoretical engineering approaches (*e.g.* deduced from separation efficiency[28]) or have considered only one aspect of the technology[29,30]. This uncertainty presented a challenge to this study.

The system parameters (demand evolution, initial system design, reserve and inertia requirements) and carbon prices assumed are detailed in Table S2; fuel costs assumed in the model are provided in Table S3; technological parameters (efficiencies, lifetimes, build rates, ramping rates, capital costs and learning rates) assumed are given in Table S7. Local and imported biomass sources are considered using a biomass supply curve; this is illustrated in Figure S1, and discussed in detail in Tables S4, S5 and S6.

Results

The 2008 Climate Change Act mandates an 80% reduction in economy-wide GHG emissions (relative to 1990 levels) by 2050.[31] This requires a virtual decarbonisation of the power sector by 2050.[22] For illustrative purposes therefore, we have compared the cost-optimal system transition needed to achieve a decarbonised electricity system by 2050, relative to a transition that meets the UK's purported CDR requirements by 2100. Accordingly, Fig. 2 presents the least-cost capacity expansion and electricity dispatch for the UK from 2015 to 2100 in three scenarios: 1) achieving and maintaining a zero-carbon electricity system from 2050 onwards, 2) providing 2.8 Gt_{CO_2} of CDR by 2100, and 3) providing 9.8 Gt_{CO_2} of CDR by 2100.

We observe that until 2050, the decarbonisation pathway for all three scenarios is approximately the same, *i.e.* carbon intensity falls to zero by mid-century independent of the emissions target imposed. This is largely achieved through extensive expansion of intermittent renewable generation capacity (wind and solar) from 24 GW to

[‡]DACS presents an additional electricity demand to the system. In periods of high IRES availability, excess electricity is able to be used by DACS for CDR.

[§]The heat required for regeneration is supplied *via* the oxycombustion of natural gas. The resulting CO_2 emissions are also captured and sequestered by the DACS plant.

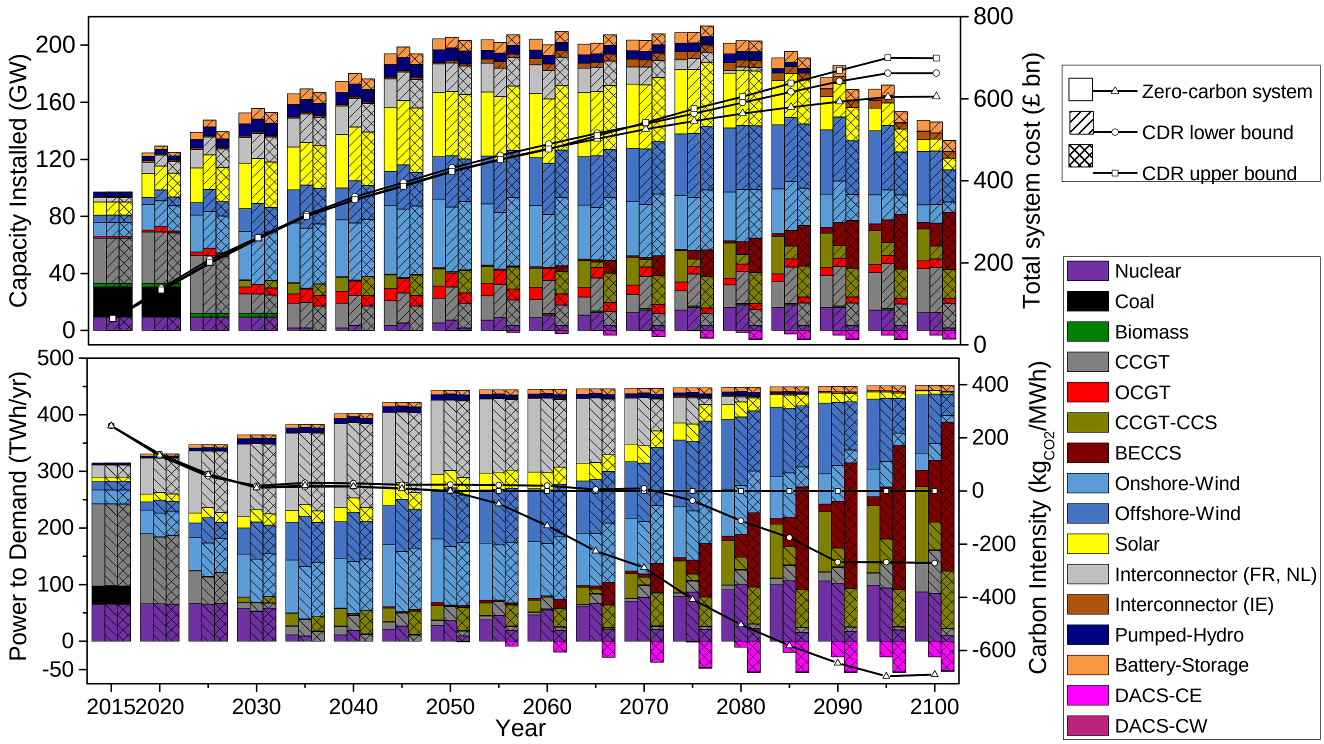

Figure 2: Least-cost power generation capacity expansion and electricity dispatch mix from 2015 to 2100 for the UK electricity system, as forecast by the ESO-XEL model, in three scenarios: achieving a zero-carbon system by 2050 (left); providing cumulative CDR of 2.8 Gt_{CO_2} by 2100 (middle); providing cumulative CDR of 9.8 Gt_{CO_2} by 2100 (right).

123-126 GW in 2050 (60-61% of installed capacity). The increasing variability of electricity supply in the system necessitates additional grid flexibility, consequently energy storage services and interconnection are expanded simultaneously. Pumped hydroelectric storage (PHES) deployment reaches its geographically-constrained maximum of 9 GW, with 7.2-7.5 GW of batteries built to supplement. Interconnection experiences similar rate of growth to renewables, with electricity import capability quintupling to 21 GW by mid-century. Concurrently, peaking gas power plants (OCGT) see a 550-670% increase in capacity installed to 8.5-10 GW, reflecting the need for faster generation output response to increasingly volatile power supply and, inherently, demand.

The proliferation of intermittent renewable energy sources (IRES) coupled with energy storage, however, is insufficient to reach net-zero emissions in a cost-effective manner. While coal is eliminated from the system after 2020, 38-41 GW of gas power plants, both unabated and abated (equipped with CCS), remain in the system to provide crucial ancillary services to maintain grid reliability, and/or dispatchable low-carbon power. Existing nuclear capacity (9.6 GW) is only replaced after it reaches operational end-life in 2030 in the 'Zero-carbon system' and 'CDR lower bound' scenarios; 1.8 GW of new build comes on-line in 2035 and peaks at 16-18 GW in the latter half of the century. In the 'CDR upper bound' scenario where existing nuclear is not replaced, CCGT-CCS deployment is seen aggressively from 2030 onwards, with a total of 15 GW built in 20 years; this highlights the need for dispatchable low-carbon electricity as renewables penetration rises in a carbon-constrained system. As CCS only captures 90% of gas-derived emissions, 0.5-1 GW of BECCS capacity is deployed to compensate for CCGT-CCS residual emissions.

Current global decarbonisation efforts largely seek to increase deployment of wind and solar power. The above shows that such a strategy is consistent with the cost-optimal pathway only up to a limit—in the case of the UK, this is until 2050. Beyond this limit, however, the optimal system design to either maintain a zero-carbon system or meet ambitious CDR burdens greatly differs.

Maintaining a zero-carbon system post-2050

Near- to medium-term decarbonisation objectives are satisfied by displacing fossil generation with IRES, as shown from 2020 onwards in Fig. 2. This is because, despite IRES' low energy density and intermittency—which require additional capacity, energy storage and grid flexibility to compensate—they provide the cheapest zero-carbon electricity. However, several factors conspire to reduce the relative competitiveness of IRES: rising demand[¶] and the retirement of old fossil and IRES power plants means there is a significant capacity shortfall that must be replaced quickly; even the modest learning rates assumed here (see SI) result in cheaper firm low-carbon power from CCS plants; exhaustion of storage and flexibility availability as interconnection and PHES are maximally deployed. Consequently, for the delivery of zero-carbon electricity, firm low-carbon thermal generation (complemented with some CDR from BECCS to offset residual emissions) proves cheaper than further expansion of IRES. From Fig. 2, we observe that IRES capacity falls by more than 50% to 58 GW, while firm low-carbon generation (nuclear, CCGT-CCS and BECCS) capacity rises from 18 to 40 GW, between 2050 and 2100. Total generation capacity, which peaks at 208 GW in 2075, also shrinks to 147 GW in 2100 due to the reduced reliance on IRES.

The challenges of gigatonne-scale CDR

The return to a system dominated by thermal power plants is accelerated when CDR targets are imposed because of the increased need for BECCS and DACS. For the lower- and upper-bound CDR requirements, annual CO_2 removal rate rises till the end of the century when it reaches a peak of 159 and 358 Mt_{CO_2}/yr, respectively. In 2100, the 16-40 GW of BECCS capacity installed requires 1.2-2.9 EJ/yr[‖] of bioenergy to provide 57-63% of annual CDR. Despite the energy intensive nature of DACS, it provides 46-61% of total CDR. This highlights the influence of increasing biomass costs as local supplies of waste and virgin biomass are exhausted, and import dependence rises (see SI). Increased BECCS costs and technology learning conspire to favour DACS deployment over a marginal increase in BECCS capacity. Although DACS-CE has limited learning potential (majority of the processes involved—absorption, calcination and compression—use mature technologies) and is unable to operate flexibly, it is the archetype of DACS that is deployed owing to its lower capital and operating costs (relative to DACS-CW). Inflexible operation limits DACS-CE's capacity to integrate into an IRES-dominated system, so it is likely that DACS deployment facilitates the resurgence of thermal generation in the system after 2050.

Meeting the required CDR commitments appears not to transgress any biophysical limits. However, the extent of their deployment poses other risks. Total system cost (capital and operating costs throughout the planning horizon) increases by 10-30%, relative to the 'Zero-carbon system', for the Paris Agreement-compliant systems. In the worst-case scenario, BECCS is required to generate 280 TWh_e/yr, equivalent to 55% of annual demand. Due to limited local bioenergy availability, 228 TWh_e/yr (81%) of BECCS generation relies on imported biomass. Such heavy import dependence will leave the power sector exposed to the volatilities of global supply chains and present energy security concerns. In addition, the large volumes of CO_2 need to be transported from 254 large-scale capture units (BECCS, CCGT-CCS and DACS plants) to suitable storage sites. Therefore, extensive CO_2 transportation networks are necessary as this amount of infrastructure is unlikely to be geographically-concentrated. Lastly, DACS deployment adds significant demand to the system. In the upper-bound scenario, DACS consumes 53 TWh_e/yr in 2100, equivalent to 13% of the annual demand. Fig. 2 shows the increase in DACS deployment required to meet more ambitious CDR requirements. From Fig. 3, it can be seen that greater electricity supply is needed earlier to satisfy this additional DACS demand.

[¶] Although UK electricity demand has been falling in recent years due to improved energy efficiency, the electrification of other sectors (transport, heating, *etc.*) is expected to result in demand growth.[32]

[‖] 100 EJ/yr is widely-cited as the global sustainable biomass production potential.[33]

The evolution of the electricity system in a post-Paris world

The cost of electricity generated from IRES has fallen dramatically in recent years, and this trend is expected to continue in the near future to the extent that subsidy-free IRES will be competitive with conventional generation technologies.[34] This, in addition to the need to decarbonise economies, has resulted in calls for 100% IRES-dependent electricity systems.[35–38] This study has shown that, in the long-term, such a system is not a cost-effective means to deliver either zero-carbon electricity or the Paris Agreement.

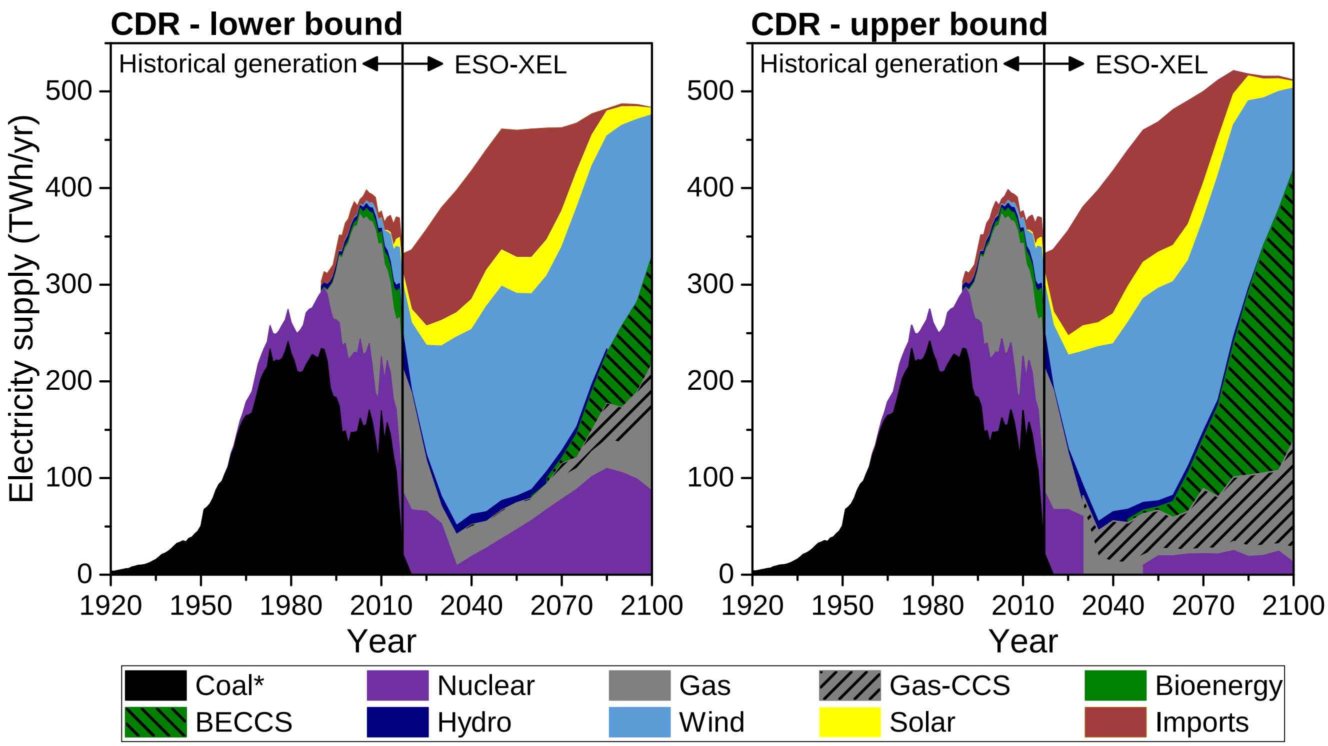

Figure 3: Evolution of the UK electricity supply from 2020 to 2100 (as projected by the ESO-XEL model) when CDR requirements consistent with the Paris Agreement are imposed. Historical data from 1920 to 2017 is also shown.

Fossil fuels, particularly coal, has historically dominated the fuel mix for power generation in the UK. Since the 2000s, several policies and legislation have been implemented to spur a transition to less-polluting fuels and renewable sources of energy.[31,39,40] Fig. 3 illustrates how the historical transition of electricity supply (from 1920 until 2017) compares with the projections obtained using ESO-XEL (until 2100). Two future transitions are apparent, with the first being imminent. Spurred by cheap IRES and an urgent need to completely decarbonise, the penetration of IRES—IRES available capacity relative to total system capacity—increases consistently until mid-century when it reaches a peak of 61%. Increased imports and energy storage compensate for the variability of IRES during this period. Fossil generation—which is from gas only as coal is eliminated from the system from 2020—is either abated with CCS or greatly reduced. Nuclear capacity is briefly eliminated from the system as existing power plants retire.

The second transition sees the deployment of significant BECCS and DACS capacity to meet rising CDR burden. Retirement of old fossil and IRES capacity, and rising electricity demand (due to electrification, DACS, economic/population growth *etc.*)[32] result in a significant capacity shortage. New CCGT-CCS, nuclear and some unabated gas capacity prove a cheaper generation portfolio to compensate for this shortage, compared to further expansion of IRES and energy storage. This is due to falling CCS costs (due to cost learning from earlier deployment), limited additional storage capacity (PHES and interconnection capacity exhausted) and the higher availabilities of thermal power plants. Therefore we observe the electricity system return to one dominated by thermal generation, although this is now dependent on bioenergy, nuclear and gas, as opposed to coal—the historically dominant fuel.

Shifting the conversation from low-carbon to negative-carbon

The ESO-XEL model assumes the perspective of a central planner. However most countries have enacted some form of liberalisation reform in their electricity markets. Investment decisions in power generation are therefore no longer centralised, but driven by risk/return prospects. Investment in immature technologies that are unable to meet market-rate returns are incentivised through favourable policies or legislation. In the past two decades, the increased urgency to decarbonise led to a raft of such incentives for renewable energy technologies. Broadly, renewable energy support (RES) is given in the form of: quota systems that allocation a proportion of generation to IRES (renewables obligation certificates, competitive tendering or bidding); incentives that lower cost of investment (tax credits or exemptions, soft or interest-free loans, *etc.*); additional payments for generation (feed-in tariffs, contracts-for-difference); carbon pricing to discourage fossil generation; and legislation discouraging CO_2-intensive generation (mandated carbon budgets, coal plant bans).[41,42]

This study has shown that despite the cost reductions in IRES—which are a result of some or all of the above incentives—their continued deployment (in the long-term) does not provide the least-cost pathway to the Paris Agreement. As subsidy-free IRES becomes commercially-viable, support should therefore be redirected to other technologies that are crucial to meeting long-term mitigation objectives, particularly CDR technologies. The services offered by BECCS and DACS in the electricity system are qualitatively different in type and value, and their incentivisation should reflect this. That is, whilst IRES are an important part of a transition to zero-carbon, they are unable to achieve deeper decarbonisation objectives that require a negative-carbon electricity system—this is only possible through CDR deployment. Therefore incentives given to IRES and CDR technologies should reflect their relative importance to deeper decarbonisation objectives at the given stage of the energy transition. Table 1 summarises these services and the instruments that could be used to monetise them. Common to both BECCS and DACS is the ability to provide an atmospheric CO_2 removal service, which is a public good that should be appropriately remunerated. In addition, they can provide CDR to compensate for GHG emissions from CO_2-emitting power plants or other sectors of the economy with more expensive or difficult mitigation options (such as heat or aviation). Here, BECCS or DACS would allow value to accrue to other assets by allowing them to operate and generate revenue in a carbon-constrained system. The purchase of 'negative emissions credits' by the assets so enabled can be used to share some of this value with BECCS and DACS.

Table 1: Potential incentives for services provided by BECCS and DACS

CDR techology	Services provided	Potential incentives
BECCS	Power generation	Wholesale electricity market, revenue support *e.g.* contracts-for-difference
	Ancillary services	Capacity market, ancillary services market
	Atmospheric CO_2 removal	Negative emissions credit
	CO_2 emissions offset for other power plants or sectors of the economy	Auction-able credit to CO_2 emitters
DACS	Atmospheric CO_2 removal	Negative emissions credit
	CO_2 emissions offset for other power plants or sectors of the economy	Auction-able credit to CO_2 emitters

Crediting negative emissions

The UK has recognised the social cost of carbon[43], and therefore recognised that emitting CO_2 to the atmosphere is imposing a public cost. CO_2 removal is consequently a public good, which could reasonably be expected to be compensated in line with the value of the avoided cost. We introduce the concept of a ’negative emissions credit (NEC)’ as a payment for the net removal of one tonne of CO_2 from the atmosphere. Building on previous work[44], a cash flow analysis was carried out to understand the effect of remuneration through NECs on the economic viability of first-of-a-kind (FOAK) BECCS and DACS plants. As BECCS also contributes to power generation, it is assumed that it receives revenues from electricity sales at the marginal cost of electricity of the system. Capacity utilisation throughout the operational lifetime of the plants is determined from the optimal electricity dispatch profile obtained using the ESO-XEL model .

For a FOAK BECCS plant, a NEC of £52/t_{CO_2} yields an internal rate of return of 4%, typical for regulated assets. Due to the greater cost of capture and the absence of any other revenue stream, DACS-CE and DACS-CW require NECs of £176/t_{CO_2} and £342/t_{CO_2}, respectively, to achieve a similar return. High-risk investments, such as those in nascent technologies, often demand higher returns; Fig. 4 shows that much higher NEC payments will be needed to achieve higher IRRs. Nascent technologies typically have IRRs of greater than 10%. Achieving such a return would require NECs of at least £86/t_{CO_2} and £223-443/t_{CO_2} for BECCS and DACS, respectively.

Revenue support for BECCS

In addition to providing negative emissions, BECCS can generate electricity to meet demand and provide ancillary services that help to maintain system reliability and operability. Owing to its added social utility (climate change mitigation), low-carbon electricity generation is often subsidised through feed-in tariff (FiT) or contract-for-difference (CfDs) schemes. Generally, both schemes guarantee stable revenues (at a pre-agreed tariff or ‘Strike Price’) for generators in a volatile wholesale market; FiTs target small or medium-scale renewable energy generators, while CfDs target utility-scale generators. In today’s paradigm, BECCS would—were it not for other barriers to deployment (lack of CO_2 transport and storage infrastructure, social acceptability of biomass use)—be eligible for such revenue support as it produces negative-carbon electricity that furthers mitigation. Fig. 5 illustrates the effect of a NEC and CfD-type incentive on the profitability of a FOAK BECCS plant.

In the absence of a NEC, BECCS would need a strike price guarantee of 133-188 £/MWh to achieve an IRR of 4-15%. If BECCS was recognised as a CDR technology solely and not remunerated for power generation, it would need a NEC of 166-234 £/t_{CO_2} to generate the same return on investment. Remunerating BECCS for the CDR service alone may well be more politically feasible, as that enables BECCS to compete directly in the electricity market, *i.e.* ‘subsidy-free’.

The above highlights that BECCS and DACS are not commercially-viable and need significant support before they can be deployed at the scale required. However, it is important to note that the NEC payments required by both technologies are comparable to the carbon prices assumed in IAMs at their time of deployment (2030 for BECCS, and 2050 for DACS).[3] In addition, the price guarantee required by BECCS is consistent with what is awarded to IRES through various support schemes.[41]

Discussion

Decarbonisation of the UK energy system has so far been driven by increased use of IRES, particularly wind and solar power which have experienced dramatic cost reductions. Consequently, entirely ‘wind, water and sunlight’ dependent power generation is being proposed as a long-term strategy that serves climate change mitigation ambitions at least cost. This study has however shown that the power system that can deliver the CDR burden consistent with the Paris Agreement, in a cost-effective manner, is dominated by thermal generation, mainly from bioenergy, gas (both with CCS) and nuclear power plants. Policies advocating for increasing penetration of IRES to near total levels therefore pose the danger of ‘lock-in’ to either an overbuilt power system or one incapable of

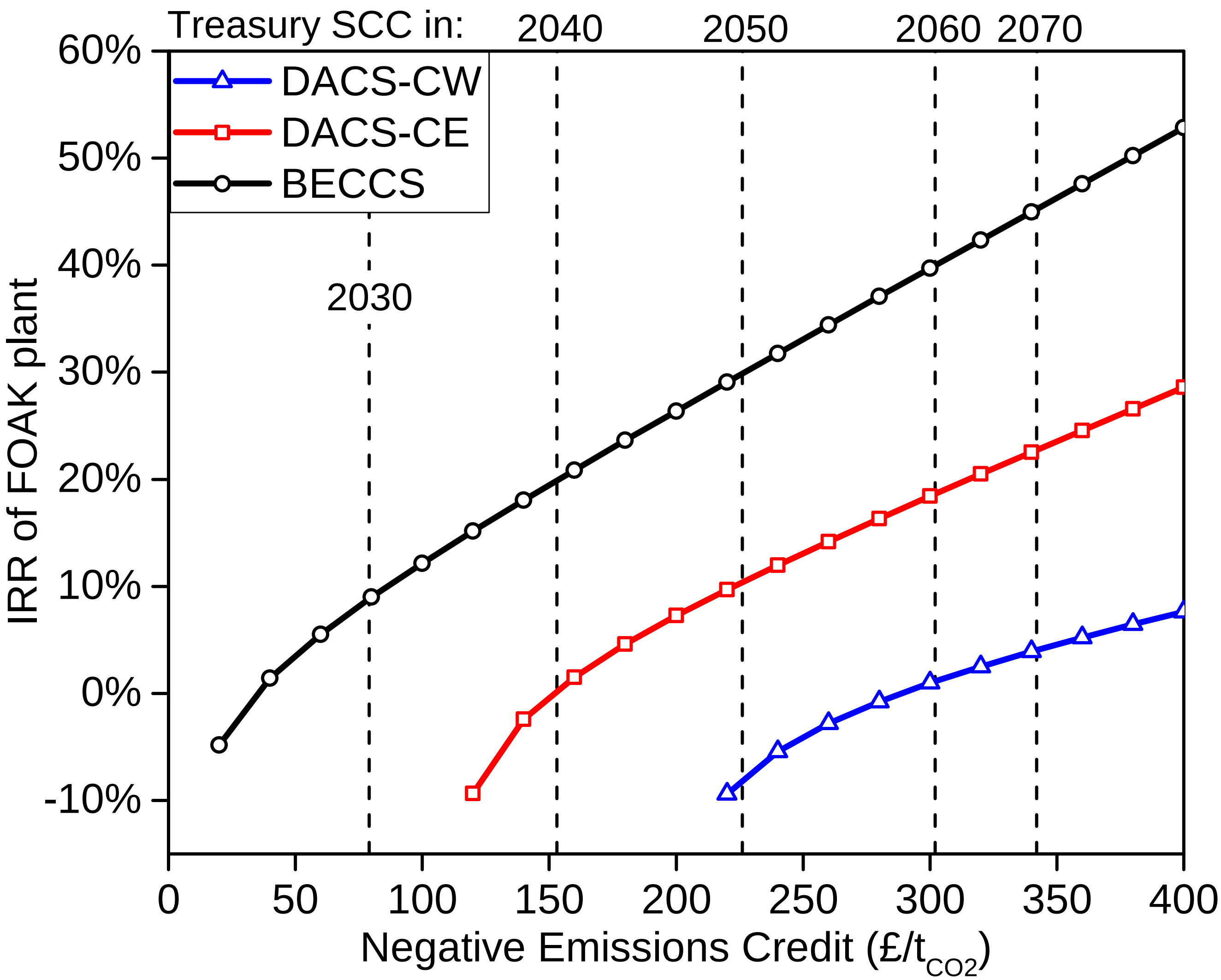

Figure 4: IRR on investment FOAK CDR technologies at different negative emissions credit payments. Dashed lines illustrate the social cost of carbon (SCC) in the years labelled, as projected by the UK Treasury.[43]

delivering sufficient climate mitigation.

Cheap IRES also allow for the viability of smaller-scale and isolated power systems, and even the participation of traditional energy consumers in power generation. Consequently, decentralisation is cited as a major feature of the climate change-induced energy transition.[45–47] However a system dominated by utility-scale thermal generation is inherently centralised and requires extensive transmission and distribution networks. Pursuing decentralisation efforts in the short-term may lead to the disintegration of infrastructure that appears to be critical in the long-term.

Although the potential value of BECCS and DACS for deep decarbonisation has been exhibited, several barriers—both techno-economic and socio-political—must be overcome for their commercialisation to be realised. Most notably, there exists few financial incentives for investment in the technologies. With the exception of voluntary carbon markets—whose traded volumes and price of carbon remain low[48]—, carbon pricing or emissions trading schemes do not credit CDR from BECCS or DACS. The lack of extensive CO_2 transport and storage infrastructure, or a credit for the sequestration of CO_2, further discourages investment. Significant BECCS and DACS deployment are likely to require international supply chains, owing to biomass trade and the asymmetric distribution of CO_2 storage sites. How accreditation for CDR should be apportioned to sectors or nations involved

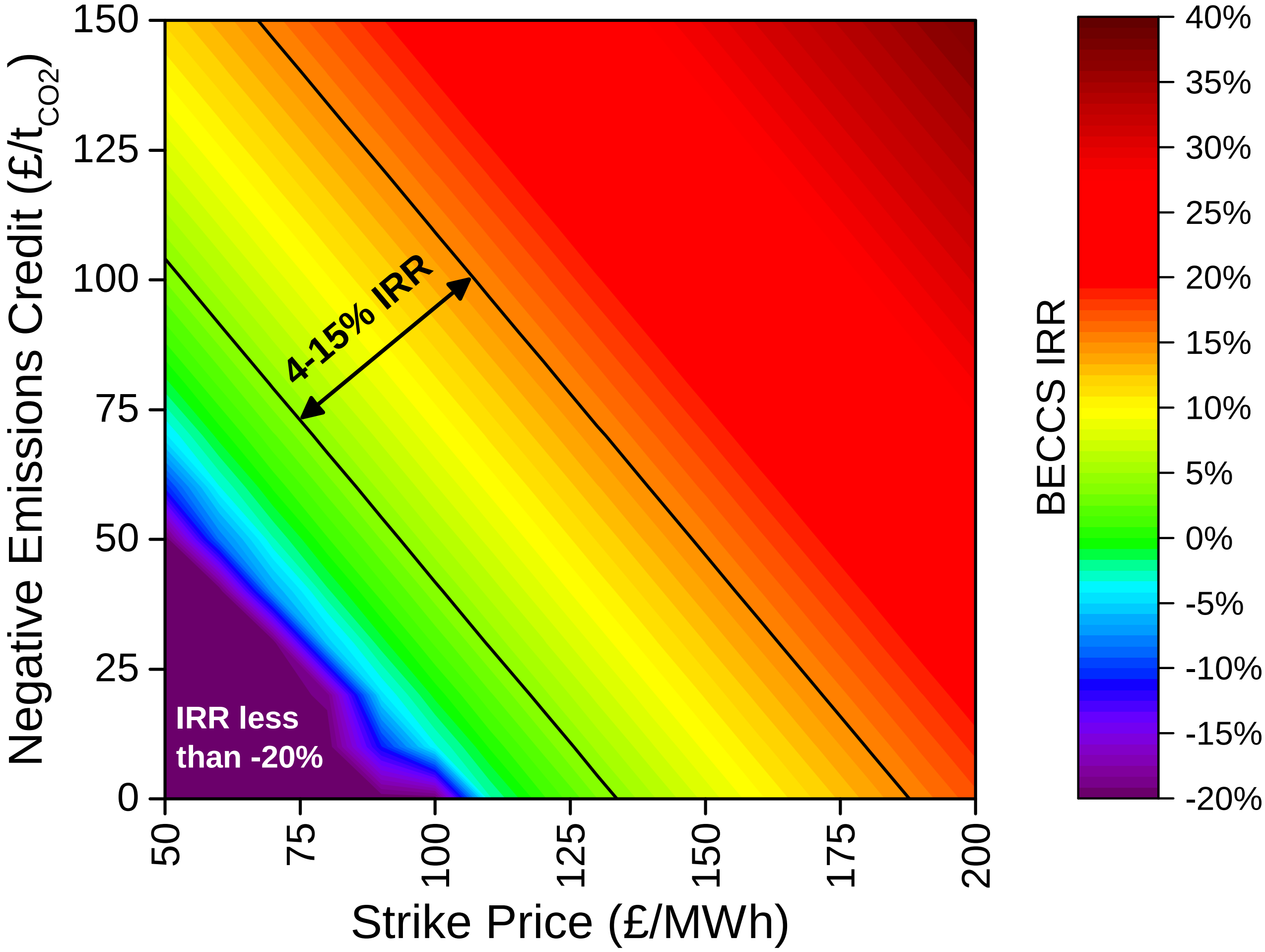

Figure 5: IRR on investment in a FOAK BECCS power plant when it is credited for power generation at a strike price, and credited for CO_2 removal *via* a negative emissions credit. For illustrative purposes, scenarios that result in very negative IRRs (below -20%) are simply shown by the black region.

in these value chains is yet unresolved. In the case of BECCS, certification schemes to guarantee the sustainability of the—domestic, but more so for the internationally-traded—biomass feedstock will be challenging due to the complexity of biogenic carbon accounting frameworks.[49–51] Finally, the perception of CDR as a moral hazard, on which focus will redirect support from other components of the mitigation toolbox[24], generates social acceptability concerns.[52]

Favourable policies and subsidisation mechanisms have been successfully resulted in IRES achieving grid parity. However, this study has shown that the marginal value of IRES deployment to deep decarbonisation efforts will diminish with time. Instead, new technologies (CCS with both gas and bioenergy) and services (CDR) are needed to achieve further climate mitigation. Whilst significant, the incentives required by these new technologies/services to achieve commercial viability are similar to those given to then nascent intermittent renewable energy technologies. Policy must therefore recognise their values in an increasingly carbon-constrained world, and adequately incentivise them to attract investment and encourage innovation.

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Author Contributions

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Declaration of Interests

The authors declare no competing interests.

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