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The implications of delivering the UK's Paris Agreement commitments on the power sector

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Abstract

Through the 2015 Paris Agreement, the UK committed to keeping average global temperature rise to "well below 2˚C". Integrated Assessment Models show that this will require extensive greenhouse gas removal (GGR) from the atmosphere. For the EU, it is estimated that 20-70 Gt_{CO2} of cumulative GGR by 2100 is required, all from bioenergy with carbon capture and storage (BECCS). Depending on how the burden of GGR is shared, the UK would need to remove 2-6 Gt_{CO2} from the atmosphere. We apply a power systems planning model to determine how the electricity system would need to transition from 2015 to 2100 to meet the UK's Paris Agreement commitments. We find that until 2050, increased penetration of renewables, interconnection capacity and energy storage, alongside 15-17 GW of CCGT-CCS, is sufficient to stay on the required emissions trajectory. Between 2050 and 2100, however, the deployment of 7-26 GW of BECCS and 2-5 GW of direct air capture and storage (DACS) is crucial to provide the GGR required. A Paris-compliant UK electricity system will require £620-700 billion of capital and operational expenditure by 2100, 3-16% greater than the cost of achieving a decarbonised system. For the upper-bound GGR target, local biomass supply is insufficient, so imports are necessary. By 2100, up to 26% of annual demand is met by imported biomass. Such heavy dependence on imports may raise energy security concerns. Also, should biomass imports not be available in the required quantities, alternative (and more expensive) GGR methods will be necessary thereby increasing the cost of delivering a Paris-compliant system.

Keywords: greenhouse gas removal; power systems modelling; BECCS; direct air capture, DACS, Paris Agreement.

1. Introduction

Since the Industrial Revolution, rising anthropogenic greenhouse gas (GHG) emissions have led to planetary warming, and consequently climate change [1]. To mitigate against the devastating impacts of extreme climate change on natural and human systems [2], all nations – *via* the Paris Agreement [3] – have committed to keeping global average temperature rise well below 2˚C. Integrated Assessment Models (IAMs) have shown that decarbonisation pathways consistent with the Paris target rely on large-scale greenhouse gas removal (GGR) from

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the atmosphere [4]. GGR involves the direct or indirect removal of carbon dioxide (CO_2) from the atmosphere, thereby resulting in ‘negative emissions’. Several ‘technologies’ have been identified as potential sources of negative emissions; these include: afforestation/reforestation (AR) [5], bioenergy with carbon capture and storage (BECCS) [4]–[6], direct air capture and storage (DACS) [7], [8], soil carbon sequestration [5], [9], enhanced weathering of minerals [10]–[12] and ocean fertilisation [13], [14]. With the exception of AR, none of these GGR technologies (also known as negative emissions technologies (NETs)) have been deployed at commercial scale. There are several demonstration projects operational to prove the viability of BECCS [15] and DACS [16].

The United Kingdom (UK) Climate Change Act 2008 [17] mandates the reduction of economy-wide GHG emissions by 80% by 2050[†]. To achieve this, a virtual decarbonisation of the power sector is required [18]. To adhere to the Paris Agreement—to which the UK is committed, and seeks to align local climate legislation—however, deeper decarbonisation is necessary, including the deployment of NETs. The Committee on Climate estimate that 50 Mt_{CO2}/yr of negative emissions are needed (assumed to be from BECCS) to offset emissions from hard-to-decarbonise sectors by 2050 [19]. IAMs—which assess longer term decarbonisation pathways—estimate that the European Union (EU) would need to remove 20-70 Gt_{CO2} (median of 50 Gt_{CO2}) from the atmosphere by the end of the century[‡] [20]. To determine the UK-specific target, different sharing principles can be applied:

1. Equal distribution: the GGR target is shared equally between the 28 member countries of the EU. The UK would therefore need to remove approximately 1.8 Gt_{CO2} from the atmosphere by 2100.
2. Share of emissions: the GGR target is shared in proportion to the GHG emissions of the member country. The UK is responsible for 12% of EU emissions [21], therefore it would need to remove 6 Gt_{CO2} by 2100.
3. Equitable distribution: the GGR target is shared in proportion to the GDP of the member country. For example, the UK currently contributes 15% of the EU GDP [21], therefore it would need to remove 7.6 Gt_{CO2} from the atmosphere by 2100.

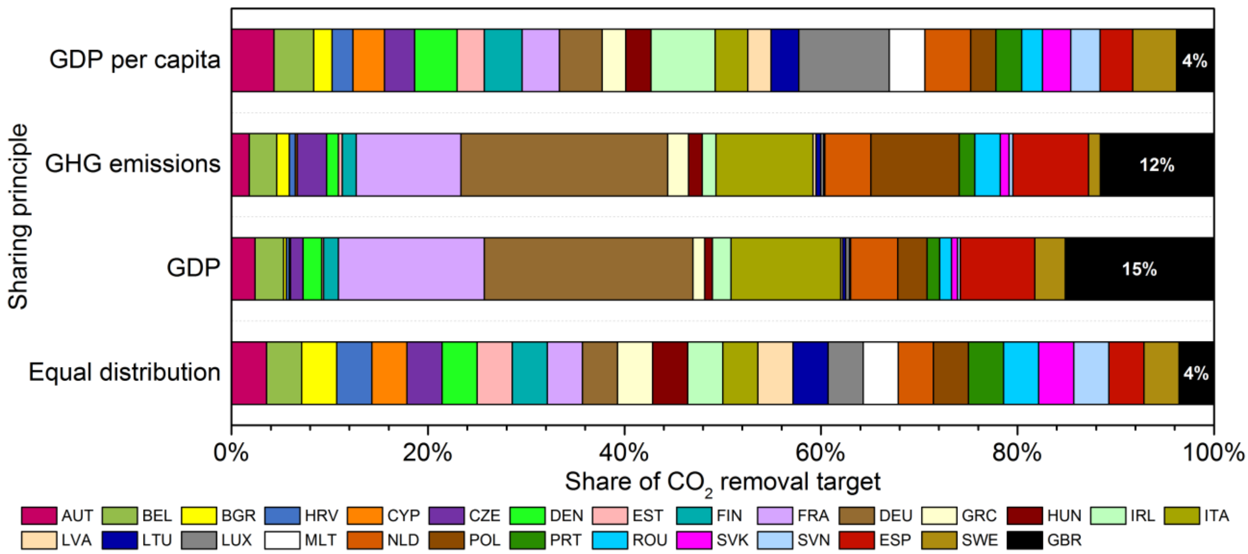

Fig. 1: Share of the EU CO_2 removal target to be allocated to the United Kingdom (GBR) relative to other member countries.

† This was based on a proposed global objective to keep temperature rise close to 2°C above pre-industrial levels (50% probability) [19].

‡ The estimates of the amount of GGR required regionally until 2100 to meet the Paris Agreement are obtained from four IAMs: IMAGE, MERGE-ETL, POLES and WITCH. All of these represent the EU as one or two geographic entities, and do not disaggregate the targets further to country-level [20].

4. Egalitarian distribution: the GGR target is shared such that the GDP per capita of each member country after the target is achieved is equal.

Fig. 1 illustrates the share of the GGR target that would be allocated to the United Kingdom (GBR) relative to other EU member countries if the above sharing principles are applied. Allocations based on sharing principles 3 and 4 are illustrated according to current GDP and population data [21]; determining how these may change is beyond the scope of this study. Climate equity warrants that the burden of mitigation action is distributed in accordance with responsibility for climate change [22], hence the focus on Principle 2. An equal distribution of the EU GGR target (principle 1) provides the lower-bound cumulative GGR that the UK—as a large historical emitter of GHGs—could be expected to provide. Therefore, we assess the implications of meeting the 1.8-6 Gt_{CO2} removal target (outlined by sharing principles 1 and 2) on the optimal design and operation of the UK electricity system until 2100, when the emissions targets are to be achieved.

2. Methods

2.1. The ESO-XEL modelling framework

To understand how the UK electricity system might transition during the remaining of the 21st century, we apply the *E*lectricity *S*ystems *O*ptimisation with capacity e*X*pansion and *E*ndogenous technology *L*earning (ESO-XEL). The ESO-XEL model is a mixed integer linear optimisation problem (MILP) that determines the least-cost capacity expansion and operation of a given electricity system, subject to a set of constraints:

- System-wide constraints: electricity demand, reserve and inertia requirements are satisfied; unmet electricity demand is restricted to 0.05% of annual demand and is significantly penalised at the value of lost load (estimated at £40,000/MWh). Maximum allowable CO_2 emissions from the electricity system are also specified according to the decarbonisation objectives discussed in section 1.
- Capacity expansion constraints: initial system design, and technology-specific build rates. Maximum deployment and lifetimes are defined exogenously.
- Technology-specific constraints: power generation, reserve and inertia provision capability; ability for flexible operation; and ramp-up and ramp-down times of each technology are specified.

The ESO-XEL model minimises the total system cost—the total capital cost (CAPEX) and operating cost (OPEX) invested into electricity generation—during the planning horizon considered, which is from 2015 to 2100 in 5-yearly time steps. Endogenous technology cost reduction is implemented in the model as technology-specific piecewise linear functions that define the reduction in the CAPEX of the technology at differents level of deployment in the system. The model formulation has been described previously [23], and a GAMS version is available as an open-source and open data model [24].

2.2. Data inputs and assumptions

In 2015, UK electricity system had a generating capacity of 90 GW: nuclear (9.6 GW), coal (21 GW), biomass (2.5 GW), combined-cycle gas turbines (31.5 GW), open-cycle gas turbines (1.3 GW), onshore wind (10 GW), offshore wind (5 GW), and solar photovoltaics (9.2 GW) [25]. The UK can also import electricity *via* 4 GW of interconnection capacity with France (2 GW), the Netherlands (1 GW), the Republic of Ireland (0.5 GW) and Northern Ireland (0.5 GW). Energy storage services are provided by 3 GW of pumped hydroelectric storage. This initial system design is defined exogenously in the ESO-XEL model. In addition to the existing power technologies in the system, combined cycle gas turbines with carbon capture and storage (CCGT-CCS), BECCS, DACS and battery storage (modelled as 100 MW lead-acid batteries) are made available for deployment in the model from 2020 onwards.

Electricity generation in the UK was 339 TWh in 2015, with final consumption at 303 TWh [25]. In this study, we assume a 1% year-on-year increase in electricity demand from 2015 until 2050 when it is 420 TWh/yr; and then subsequently after which it remains constant[§]. This is in line with projections of future demand [26]. Other data on technology-specific parameters are provided in Appendix A; fuel and carbon prices assumed are provided in Appendix B.

2.3. NETs in ESO-XEL

BECCS and DACS are the only NETs considered in this study due to their relative maturity and the direct implications of their deployment on the energy system. BECCS involves the firing of biomass in a power plant and sequestration of the resulting CO_2 emissions using carbon capture and storage (CCS) technology, usually in subsurface geological formations. As biomass is carbon neutral at harvest, BECCS can provide negative emissions, in addition to an electricity service (to meet demand). The amount of negative emissions obtained *via* BECCS is, however, highly-dependent on the supply chain, and type, of the biomass feedstock [27]. This is because raw biomass is heterogeneous and has high moisture content, therefore it must be dried, processed and pelletised into homogeneous fuel (pellets) before combustion in a power plant. Biomass processing and transport contribute additional CO_2 emissions to the fuel which can offset some or all of the negative emissions that would have been realised. The BECCS power plant considered in this study is an ultra-supercritical power plant with post combustion capture using MEA solvent. Biomass can be sourced from a range of local (municipal solid waste, waste wood and virgin biomass) and international sources (imported virgin biomass pellets from the EU and US); this is implemented in the model using the supply curve illustrated in Fig. 2.

CO_2 is present in very dilute concentrations in air (408 ppm). To extract CO_2 from air to form a high purity stream—as is done by DACS—therefore requires significant energy input. There are two archetypes of DACS currently being developed. The first, developed by Carbon Engineering Ltd., directly contacts air with a potassium hydroxide (KOH) sorbent to remove CO_2 as carbonate (K_2CO_3) [16]. The sorbent is then regenerated by reacting K_2CO_3 with calcium hydroxide ($Ca(OH)_2$). $Ca(OH)_2$ is obtained by hydrating calcium oxide (CaO), which is produced calcining calcium carbonate ($CaCO_3$) in a kiln at 900˚C. Due to the high temperature of the regeneration process, this DACS archetype (henceforth referred to as DACS-CE) cannot be operated flexibly. The second archetype of DACS being developed by Climeworks (DACS-CW) uses an amine-functionalised sorbent to capture atmospheric CO_2 at 100˚C [28]. The low-temperature of the capture process allows for the use of waste heat, and the modular nature of the technology allows for flexible operation of the DACS-CW plant. Both DACS technologies also require electricity for air separation, fans, liquid pumping and CO_2 compression [16], [28]. The operational and cost parameters of NETs implemented in the ESO-XEL model are provided in Appendix A.

3. Delivering the UK's climate change mitigation ambitions

Fig. 3 illustrates the optimal electricity generation capacity expansion and dispatch for the UK from 2015 to 2100 under three scenarios:

- Achieving a completely decarbonised electricity system by 2050, as legislated by the 2008 Climate Change Act (CCA) and retaining a zero-carbon system afterwards.
- Cumulative removal of 1.8 Gt_{CO2} by 2100, in line with the lower bound estimates from IAMs of GGR needed to meet Paris Agreement commitments (LB)
- Cumulative removal of 6 Gt_{CO2} by 2100, in line with the upper bound estimates from IAMs of GGR needed to meet Paris Agreement commitments (UB)

[§] Although UK electricity demand has been falling in recent years owing to improved energy efficiency, the electrification of other sectors (principally, heat and transport) is expected to result in demand growth of 0.5-1% in the near- to medium-term [26]. The upper-bound has been assumed in this work.

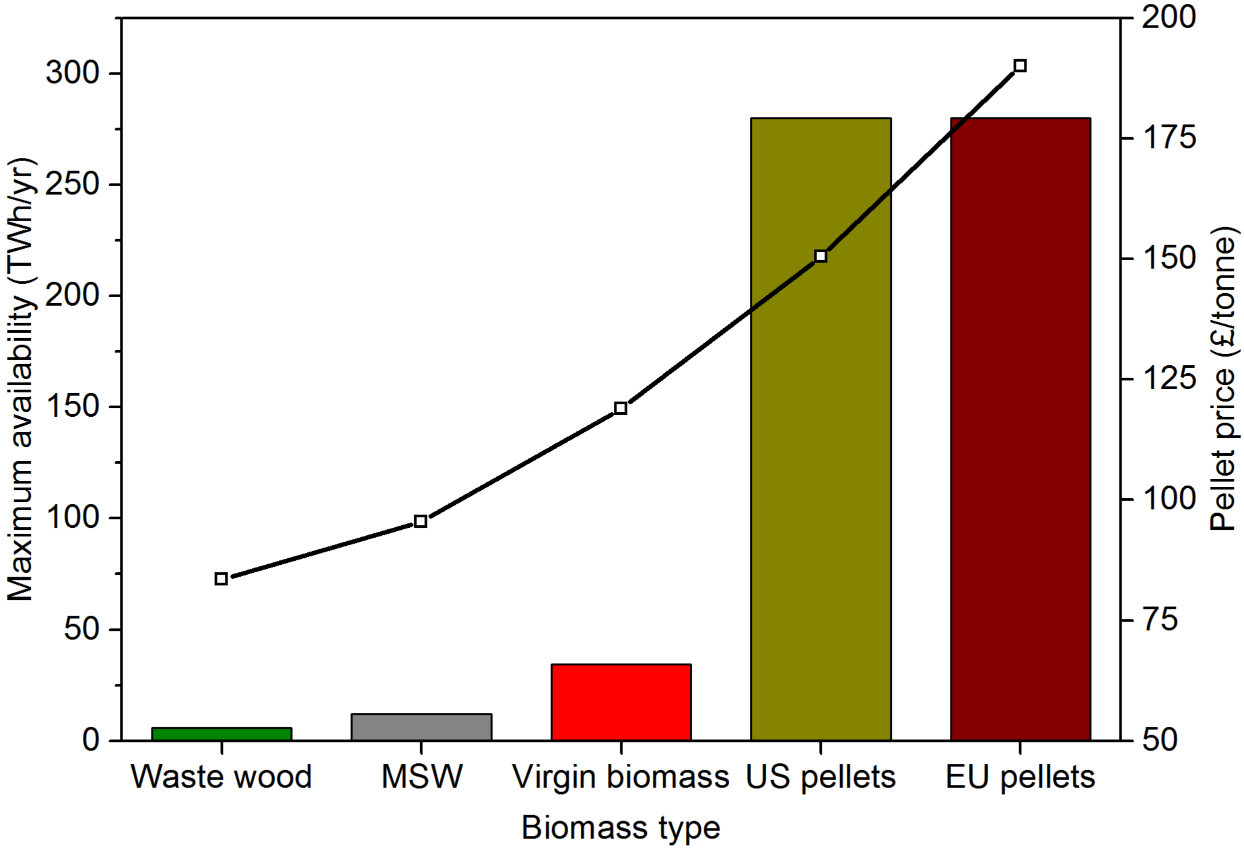

Fig. 2: Biomass supply curve showing the pellet prices and maximum power generation achievable from BECCS for a range of biomass types

3.1.1. A decarbonised electricity system

We observe that complete decarbonisation of the electricity system is largely achieved by increased penetration of intermittent renewables (iRES), *i.e.* solar PV, onshore and offshore wind technologies. Between 2015 and 2050, iRES generating capacity rises from 24 GW to 123 GW (from 25% to 60% of total generation capacity). Due to the relatively low energy density of iRES, however, they only satisfy 51% of demand in 2050. The increased reliance on iRES requires greater flexibility to compensate for their intermittency. This is satisfied by a tripling of pumped storage capacity to 9 GW**, increase in interconnection to 20 GW and addition of 7.5 GW of battery storage, all by 2050. This expansion in electricity import capacity is consistent with existing plans to add 7.3 GW of interconnection by 2022 [29]. Despite the increase in renewables' generation, significant thermal generation capacity remains deployed in the system to provide reserve and ancillary services. At peak iRES penetration (60% in 2045), thermal plants satisfy 17% of reserve capacity, with the rest being provided by pumped hydroelectric and battery storage.

** This is the maximum capacity of pumped hydroelectric storage that can be built, due to geographic constraints [24].

After 2070—when interconnection and some iRES capacity reaches their operational end-life, and CCS costs have reduced due to earlier deployment in the system—it proves cheaper to achieve zero-carbon electricity by deploying BECCS alongside abated and unabated thermal plants. That is, deploying BECCS (which also contributes to power generation) to offset the CO_2 emissions of gas plants is cheaper than building new iRES capacity and the associated energy storage and interconnection needed to accommodate the intermittency of iRES electricity supply. 4.5 GW of BECCS is deployed alongside 31 GW of CCGT, 22.5 GW of CCGT-CCS and 5.5 GW of OCGT by 2100. No DACS is deployed throughout the time period considered. A resurgence of nuclear deployment also occurs; after existing plants reach the end of their lifetimes in the 2030s, 16 GW of new build nuclear is added over the next five decades. Therefore, by the end of the century, iRES penetration is seen to fall to 35%. The total system cost rises from £62 billion in 2015 to £604 billion in 2100 (using a 3% discount rate for future cash flows).

3.1.2. Meeting the Paris Agreement commitment

Until 2050, the power generation mix needed to achieve the 1.8 and 6 Gt_{CO2} removal targets is the same as that needed to achieve a decarbonised electricity system (described in section 3.1.1). In all scenarios, carbon intensity is zero in 2050, with BECCS deployment at 1 GW. The deeper decarbonisation needed to meet the GGR targets occurs after 2060. To remove 1.8 or 6 Gt_{CO2} by 2100, BECCS deployment increases to 7 or 26 GW, respectively. This increased BECCS generation displaces CCGT generation from the system. CCGT capacity in 2100 falls from 32 GW (in a decarbonised electricity system) to 20-22 GW, when GGR targets are imposed. OCGT and CCGT-CCS capacities in system remain at similar levels to those described in section 3.1.1. Reduced CCGT generation means less negative emissions are required to offset gas-derived CO_2 emissions. Therefore, the negative emissions that would have been used as offset now contribute to the GGR target of the power sector. Some nuclear power plants are also displaced by increased BECCS deployment. For the lower (LB) and upper-bound (UB) removal targets, nuclear capacity in 2100 falls to 11 and 7 GW, respectively (compared to 12 GW when only zero-carbon electricity, not carbon-negative, is desired).

DACS is also seen to be deployed when the Paris targets are imposed on the system. For the LB target, deployment begins in 2075. 51 plants, each with the capacity to remove 1 Mt_{CO2}/yr from the atmosphere, are operational by 2100. These plants consume 18 TWh/yr, or 4% of annual electricity demand[††]. For the UB target, earlier DACS deployment is necessary. Between 2065 and 2100, 178 DACS plants are built. At peak deployment in 2085, 153 plants are operating and consuming 55 TWh/yr or 12% of annual electricity demand. In all scenarios where DACS is deployed, it is the Carbon Engineering archetype (DACS-CE) that is built, despite the inability of the technology to be operated flexibly. This does not mean that flexibility of DACS operation is not valuable to the system, but that cost is a more important driver of value (DACS-CE has lower CAPEX and OPEX than the modular and operationally-flexible DACS-CW).

The total system cost (TSC) rises to £624 billion and £699 billion for the LB and UB targets, respectively. This is a 3-16% increase in the TSC needed to achieve power system decarbonisation. The carbon intensity of UK-produced electricity (excluding imports) is also seen to be negative from 2075 and 2060, for the LB and UB targets, respectively.

[††] Although the bulk of energy input into DACS is heat, electricity is required for air separation, fans, liquid pumping and CO_2 compression. DACS operation therefore presents this additional electricity demand to the system.

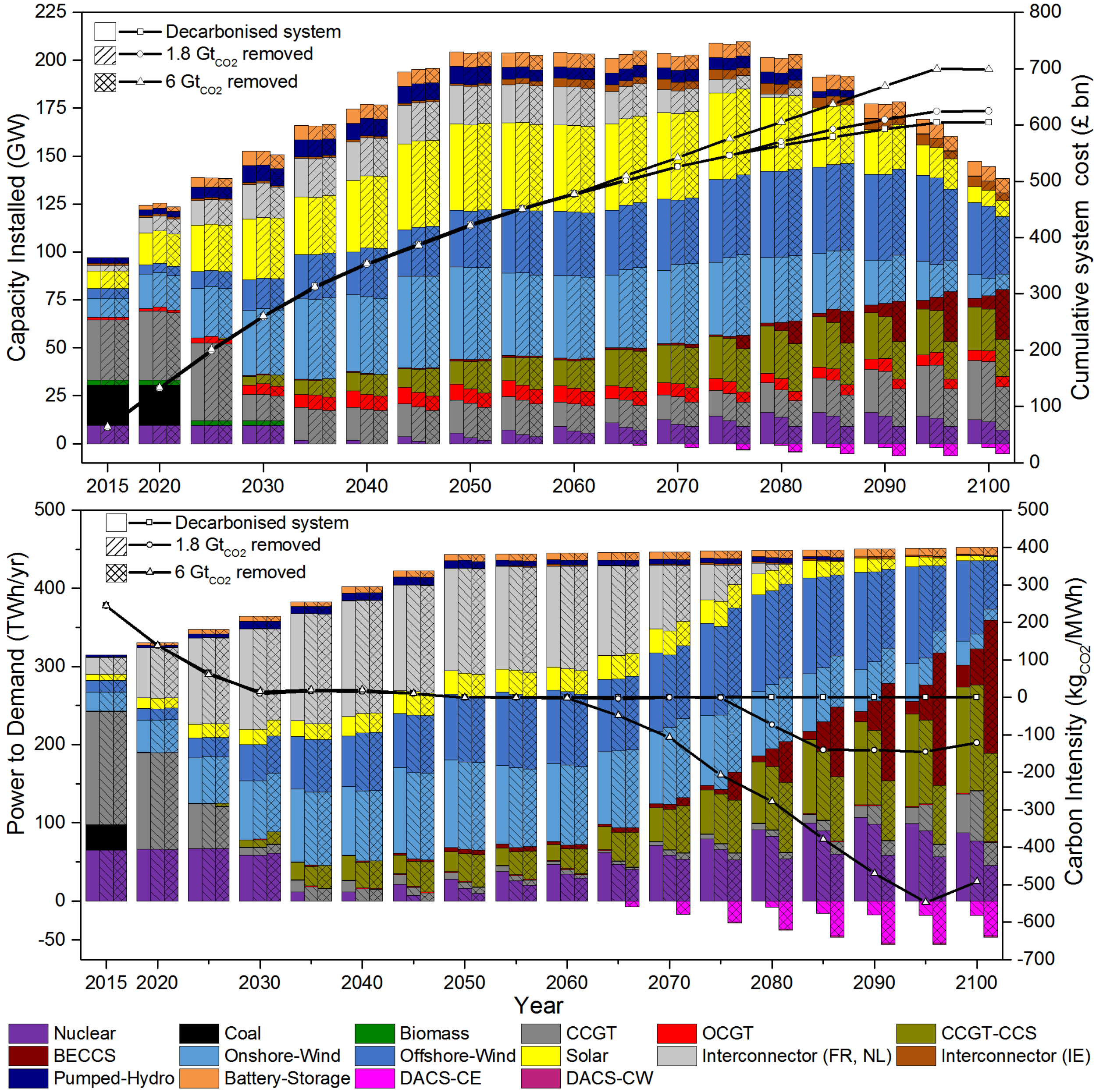

Fig. 3: Optimal power generation capacity expansion (above) and electricity dispatch (below) for the UK electricity system from 2015 to 2100 in three scenarios: achieving a decarbonized system by 2050 and maintaining zero-carbon afterwards (left, unshaded bars); achieving a zero-carbon system by 2050 and 1.8 Gt$_{CO2}$ of cumulative GGR by 2100 (middle, hatched bars); achieving a zero-carbon system by 2050 and 6 Gt$_{CO2}$ of cumulative GGR by 2100 (right, cross-hatched bars). The corresponding cumulative total system cost (above) and carbon intensity of electricity (below) for each scenario are also shown by the right vertical axes.

4. Discussion

Section 3 highlights the electricity systems transitions necessary to achieve different climate change mitigation targets in the UK. While these scenarios are theoretically possible, there are a range of factors that must be overcome before they can be realised.

4.1. Sociopolitical barriers to technology deployment

In all the scenarios discussed in section 3, there is significant deployment of CCS technology from 2030 onwards. 36 GW of CCGT-CCS and 8-27 GW of BECCS (cumulative) generation capacity is built by 2100. This highlights the importance of CCS—not just for negative emissions, but more so for the provision of dispatchable low-carbon power when coupled with gas-fired power plants (as has been previously shown [30])—in delivering a low- or negative-carbon power system. While the technology has been proven as technically viable in other parts of the world, it has failed to be demonstrated at commercial scale in the UK. Government support for CCS commercialisation has been withdrawn in the past, citing a lack of value for money and burdensome costs on consumers [31]. The lack of CO_2 transport and storage infrastructure, and the difficulty in allocating risks of first-of-a-kind CCS development between government and private sector has presented additional barriers to deployment [32]. For CCS to be realised in the UK at the scale shown in Fig. 3, these barriers must be overcome in the very near-term.

Nuclear power also features in all the scenarios discussed. As the existing stock of nuclear power plants reach the end of their operational lifetime, new capacity is built to, or beyond, contemporary levels. Although the UK has relied on nuclear power for electricity generation since the late 1950s, recent developments threaten the success of future projects. Higher safety requirements for power plants and reliance on private finance (as opposed to government borrowing at lower interest rates) to deliver projects have led to increased costs of nuclear plants in the UK [33]. New projects such as Hinkley Point C have been shown to provide only marginal value for money [34].

Lastly, while onshore wind development has not been banned in the UK, policy changes that ended new subsidies for onshore wind has since discouraged further deployment [35]. The scenarios discussed in section 3 see onshore wind capacity rising by a factor of 5, from 10 GW today to 48 GW by 2050. In the absence of policy changes, it may prove difficult to achieve the required levels of deployment of onshore in the necessary timeframe.

It is evident that significant sociopolitical barriers exist to achieving the least-cost system transitions illustrated in Fig. 3. Should these barriers not be overcome, achieving the UK's climate change mitigation objectives may prove more costly than necessary, or impossible altogether.

4.2. Electricity costs

Fig. 4 illustrates the average annual marginal cost of electricity generation from 2015 to 2100 when the Climate Change Act (CCA) and Paris targets are achieved. We observe that the cost of electricity generation rises similarly in all scenarios. This is due to the rising cost of thermal generation as the carbon price (see Appendix B) increases towards the end of the century. As shown in Fig. 3, gas-fired generation contributes 32-44% of annual demand by 2100. Higher carbon taxation on the resulting CO_2 emissions (including residual emissions from CCGT-CCS plants) drives up the marginal cost of gas generation. Therefore, independent of the emissions target that is to achieved, if fossil generation is dispatched in a system then carbon prices will determine the cost of electricity. The high marginal cost of BECCS plants due to the expensive biomass (see Fig. 2) also contribute to overall increased costs.

Currently, electricity prices are in the range of 50-60 £/MWh [36]. The costs shown in Fig. 4 only account for generation, and not transmission or distribution. Therefore it can be expected that should such scenarios materialise, electricity prices would be significantly higher than contemporary prices.

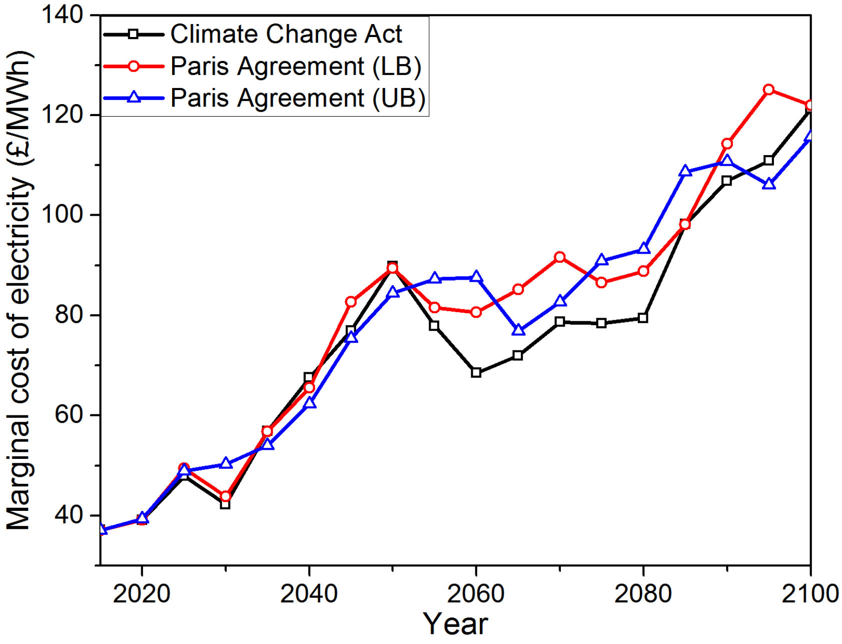

Fig. 4: Marginal cost of electricity from 2015 to 2100 when the Climate Change Act and Paris Agreement targets are met.

4.3. Energy security

Fig. 5 shows the proportion of annual electricity demand that is met by imported electricity (*via* interconnection) and imported biomass (after the local availability of MSW, waste wood and virgin biomass are exhausted). In all scenarios, reliance on imports increases sharply from 7% in 2015 to a peak of 37% in 2040. Whilst imported electricity has the benefits of being cheap and emissions-free (the current carbon accounting regime allocates emissions to the country of production not consumption), such heavy dependence on it may pose energy security concerns. After 2060, there is a sharp fall in the proportion of demand met by imports as interconnection capacity begins to reach the end of its lifetime (see Fig. 3), and old capacity is not replaced. Lost import capacity is compensated by new build CCGT-CCS and BECCS plants which are now cheaper due to cost reductions achieved from earlier deployment in the system.

For the CCA and LB targets, local biomass is sufficient to satisfy the demand of the 4.5 GW and 7 GW of BECCS plants installed, respectively. However for UB, 26 GW of BECCS is installed by 2100. Local biomass supply is insufficient to supply this increased BECCS capacity therefore imports are necessary. The proportion of annual demand reliant on imported biomass rises steadily from 0% in 2080 to 26% by 2100. Meeting higher estimates of the UK's Paris Agreement targets therefore would require extensive dependence on imported fuel which also raises energy security concerns. Lastly should imported biomass not be available in the required quantities (due to increased demand elsewhere), it may prove difficult to meet Paris commitments in a least-cost manner.

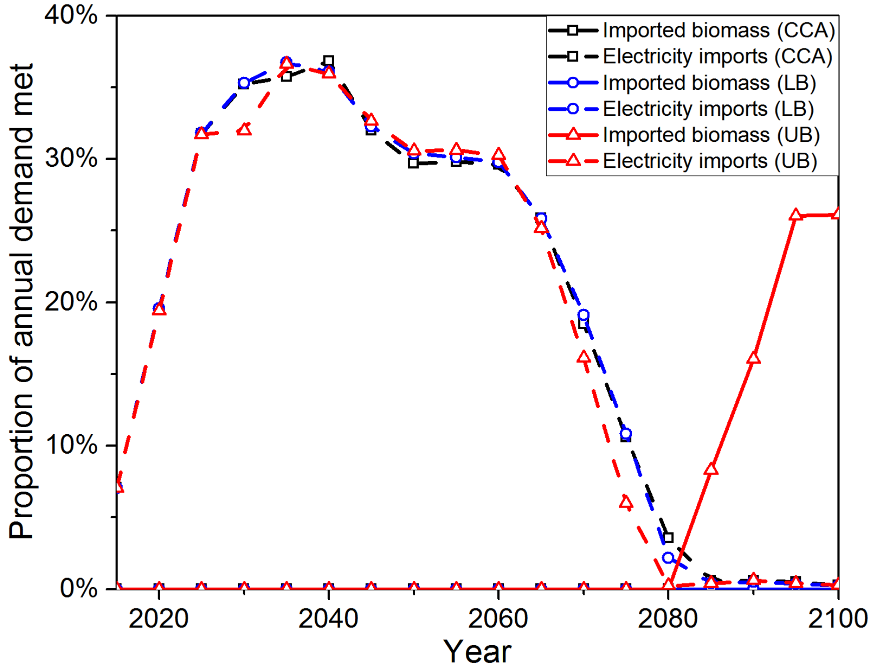

Fig. 5: Proportion of annual electricity demand met by electricity imports and imported biomass under Climate Change Act (CCA) and Paris Agreement targets (LB and UB)

4.4. Stranded assets

The least-cost pathway to completely decarbonise the electricity system has been shown to require increased penetration of iRES (discussed in section 3). Efforts to achieve GGR targets only begin after the system has been decarbonised. In Fig. 3, we observe this transition from a system dominated by iRES and flexible generation (imports) in 2050 to one increasingly dominated by BECCS and other thermal generators by 2100. However, while the share of demand of thermal generation falls with increased iRES penetration towards 2050, we observe that significant capacity of thermal generators (particularly CCGT plants) remains installed in the system. Between 2030 and 2050, share of demand met by CCGT plants is less than 5% in all scenarios, although 18 GW is available in the system. Therefore, CCGT plants are being significantly under-utilised but they are built to provide crucial reserve capacity and ancillary services.

Fig. 6 illustrates the capacity utilisation—the annual power output of a plant divided by its maximum possible power output— of CCGT, CCGT-CCS and BECCS power plants from 2015 to 2100. After 2025, CCGT utilisation remains below 20% till the end of the century, although it increases slightly from 2060 onwards as iRES penetration falls in the system. Similarly CCGT-CCS plants are being under-utilised until 2080 when utilisation rises above 40%. These plant load factors are significantly lower than designed for, therefore the plants will be unable to earn an economic return thereby creating stranded asset issues [37]. Despite the need for CCGT and CCGT-CCS plants in the system, the lack of economic viability of future CCGT and CCGT-CCS power plants will discourage investment in new build plants. This could result in a failure to meet emissions targets, or increased system costs if alternative technologies are deployed or investment is subsidised.

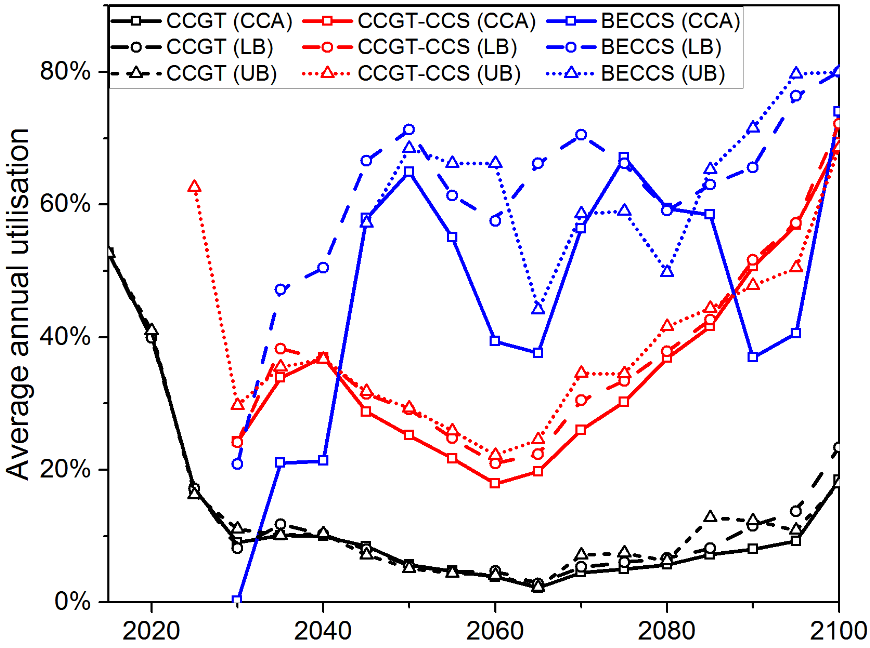

Fig. 6: Average capacity utilisation for CCGT, CCGT-CCS and BECCS power when Climate Change Act (CCA) and Paris targets are achieved

5. Conclusion

The UK needs to decarbonise its power system by 2050, and subsequently remove 1.8-6 Gt_{CO2} from the atmosphere by 2100 to achieve its Paris Agreement commitments. In this study, we find that the cost of achieving an electricity system that is consistent with the Paris target is 3-16% greater than the cost of achieving a zero-carbon system by 2050 (and maintaining it thereafter), as mandated by the 2008 UK Climate Change Act. The electricity systems transition necessary to meet the Paris target involves significant deployment of CCS technology from 2030, including up to 26 GW of BECCS as a source of negative emissions, and DACS. CCS has faced significant barriers to its deployment in the UK due to its costliness and a lack of CO_2 transport and storage infrastructure. To achieve the UK's climate change mitigation ambitions in a least-cost fashion, it is crucial that barriers to CCS deployment are overcome in the near-term. Increased deployment of nuclear and onshore wind are also critical for a Paris-compliant electricity system. Current policy that discourages expansion of existing onshore wind capacity, and the difficulties associated with establishing new nuclear plants including high costs of financing must be urgently addressed. In conclusion, while the cost of meeting the UK's Paris Agreement targets from the power sector is only modestly higher than the cost of a decarbonised system, there are significant sociopolitical barriers that must be overcome for the targets to be achieved.

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Appendix A. Technology-specific parameters

Table 1 provides the technical and cost parameters of the technologies considered in the ESO-XEL model; these are average values taken from [38]–[44], unless otherwise specified. Build rates are based on how fast capacity has historically been added into the system. The learning rate of each technology is the factor by which its unit cost falls for each doubling of cumulative installed capacity [23]. Technology rates assumed are taken from [45]–[48], except for DACS. Mature technologies have a learning rate of zero.

Table 1: Technology-specific parameters implemented in the ESO-XEL model. DACS technologies have negative capacities as they are consumers of power.

Technology	Plant efficiency	Unit capacity (MW)	Emissions (kg_{CO2}/MWh)	Build rate (GW/yr)	2015 CAPEX (£/kW)	Learning rate (%)
Nuclear	37%	600	0	0.36	4363	-1.0
Coal	42%	500	745.8	0	1439	0
Biomass	40%	500	284.4	0.4	2995	1.1
CCGT	53%	750	348.0	0.9	525	0
OCGT	39%	100	480.0	0.5	815	0
CCGT-CCS	46%	750	41.0	1.05	1838	4.5
BECCS	35%	500	-803.7	1	3800	1.1
Onshore wind	-	20	0	1.6	1421	12
Offshore wind	-	50	0	1.5	2731	20
Solar	-	10	0	1.5	646	23
Interconnection	52%	500	53-474*	1	930	0
Pumped hydroelectric storage	-	300	0	0.6	1087	1.4
Battery storage	-	100	0	0.5	771	19
DACS-CE [49]	-	-41	-2509.2	0.21	21190	9.0
DACS-CW [28], [50]	-	-68	-1500.0	0.34	12667	9.0

Appendix B. Fuel prices

Fig. 7 illustrates the range of fuel prices [39] and the carbon price [51]assumed in the ESO-XEL model.

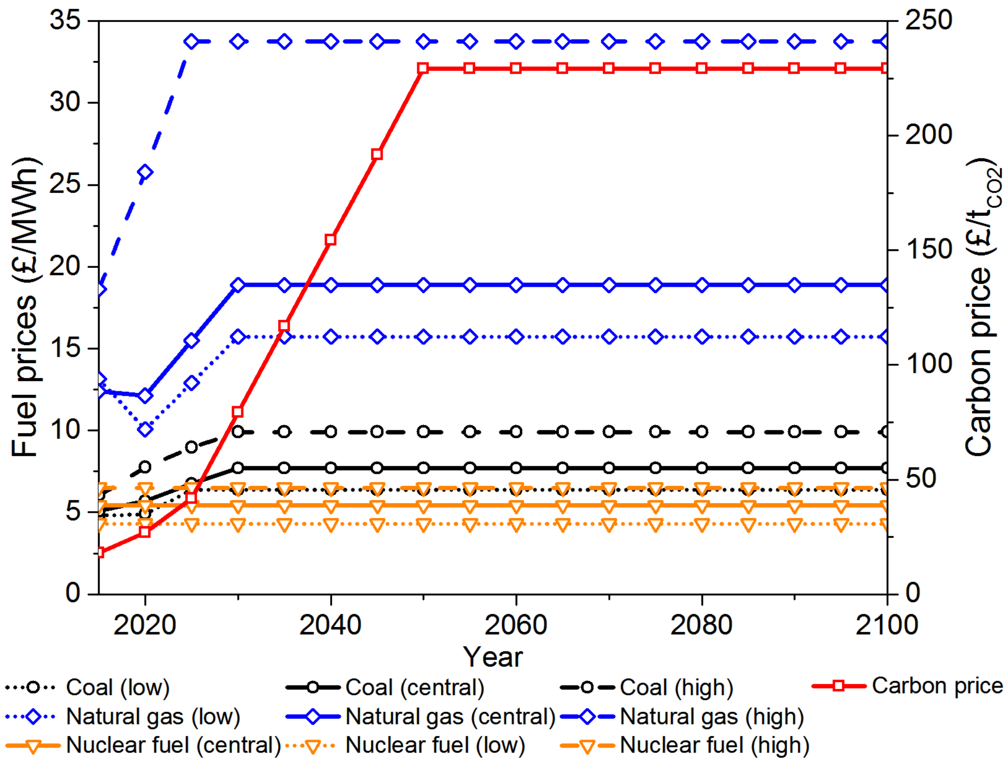

Fig. 7: Fuel and carbon prices in the ESO-XEL model

Appendix C. System-wide parameters

Table 2: System-wide parameters implemented in the ESO-XEL model

System-wide parameters	Value
Reserve margin	4% of peak capacity and 15% of intermittent generation
Inertia requirement	100,000 MW.s
Unmet demand limit	0.5% of annual demand
CO_2 transport and storage cost	10 £/t_{CO2}
Value of lost load	40,000 £/MWh
Transmission network losses	7.7% of annual demand
Discount rate for future cash flows	3%

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