ANALYSIS

Quantifying the value of CCS for the future electricity system

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Many studies have quantified the cost of Carbon Capture and Storage (CCS) power plants, but relatively few discuss or appreciate the unique value this technology provides to the electricity system. CCS is routinely identified as a key factor in least-cost transitions to a low-carbon electricity system in 2050, one with significant value by providing dispatchable and low-carbon electricity. This paper investigates production, demand and stability characteristics of the current and future electricity system. We analyse the Carbon Intensity (CI) of electricity systems composed of unabated thermal (coal and gas), abated (CCS), and wind power plants for different levels of wind availability with a view to quantifying the value to the system of different generation mixes. As a thought experiment we consider the supply side of a UK-sized electricity system and compare the effect of combining wind and CCS capacity with unabated thermal power plants. The resulting capacity mix, system cost and CI are used to highlight the importance of differentiating between intermittent and firm low-carbon power generators. We observe that, in the absence of energy storage or demand side management, the deployment of intermittent renewable capacity cannot significantly displace unabated thermal power, and consequently can achieve only moderate reductions in overall CI. A system deploying sufficient wind capacity to meet peak demand can reduce CI from 0.78 t_{CO_2}/MWh, a level according to unabated fossil power generation, to 0.38 t_{CO_2}/MWh. The deployment of CCS power plants displaces unabated thermal plants, and whilst it is more costly than unabated thermal plus wind, this system can achieve an overall CI of 0.1 t_{CO_2}/MWh. The need to evaluate CCS using a systemic perspective in order to appreciate its unique value is a core conclusion of this study.

Broader context

The structure and operation of our electricity system are expected to experience an unprecedented rate of change in the period to 2050 and beyond. The challenge of electricity planning is becoming increasingly complex, and requires us to consider not only economic performance but also environmental and security issues. As we transition from a system characterised exclusively by dispatchable power generation capacity to one with significant intermittent renewable power generation, technologies have to be evaluated on the basis of their impact on the electricity system as a whole and not only by their individual performance. It is important that goals for technology deployment do not conflate ends with means and that these goals do not compromise the security of the electricity system. carbon capture and storage applied to fossil fuelled thermal power plant (CCS) is observed to be a particularly important technology as it is able to provide dispatchable, low-carbon energy in addition to ancillary services vital to the operability of the electricity system. This work contrasts the potential contribution of CCS and intermittent renewables towards displacing unabated thermal power plants and reducing the overall carbon intensity of an electricity system. It shows that the combination of renewables and unabated fossil plants will not result in a sufficiently low carbon electricity system, when considering current global climate targets.

1 Introduction

The global energy landscape is changing substantially, motivated by the need to combat climate change. Investment in renewable

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energy has been in the vanguard of this system change rising from $60 to $200 billion annually from 2000 to 2013, while investments in fossil fuel using technologies continue to dominate by increasing from $500 to $1100 billion in the same period.[1] Over 86% of energy consumption is met by fossil fuels with only 2.2% from intermittent renewable sources such as wind and solar.[2] Due to immense capital investment and long asset lifetimes the energy system evolves slowly.[3] It is therefore likely that fossil fuels will remain vital to the global energy supply for the foreseeable future.[4] It is also recognised that

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fossil fuels cannot continue to be exploited as they have been,[5] with a significant fraction of the world's reserves now branded "unburnable".[6] However, the fossil fuels are themselves not "unburnable", rather the CO_2 released from their combustion is "unemittable", and in this context carbon capture and storage (CCS) is a unique proposition for decarbonising the power sector.

There is a growing consensus that CCS† is key to the low-cost decarbonisation of both the power and industry sectors, complementing renewable or nuclear power.[5,7–9] The IPCC finds that to achieve a 450 ppm CO_2-eq atmospheric concentration by the end of the century (2 °C warming), global mitigation costs are 138% higher without CCS power plants.[5] Similarly, the Low Carbon Innovation Coordination Group (LCICG) estimate that fully integrating CCS into the UK's energy system reduces costs between 2010 and 2050 by £100–500 billion ($\approx$1–5% of total system cost without CCS availability).[7,10] The additional value of CCS power plants in being able to generate carbon negative electricity via bioenergy CCS (BECCS) is also widely recognized.[5,7,11,12] Intermittent renewable energy sources (iRES), also referred to as variable renewable energy (VRE),[13] unquestionably has an important role to play in decarbonising the electricity system; it is not a case of "renewables or CCS", but "renewables and CCS". The key question which therefore arises is what mix of these sources provides the most value to the electricity system.

IRES can provide low-carbon electricity, however their power output depends on a fluctuating energy source (wind or insolation) which cannot be controlled. A sufficient level of balancing capacity‡ is required, since even with more iRES capacity installed than peak demand, electricity demand cannot be met at times where the energy source is unavailable. Balancing capacity can come from energy storage technologies, demand-side mechanisms, and conventional firm capacity such as nuclear or fossil fuel power plants. On a practical level, the increasing penetration of intermittent power generation is stressing the electric grid's operability to its limits and is increasing the requirements for reserve and frequency control.[15,16] The trilemma between carbon avoidance, cost, and security requires a delicate balance.[17,18]

CCS power plants have the advantage of being both low-carbon (typically 0.05–0.1 t_{CO_2}/MWh) and dispatchable. Previous studies have focused on the cost of CCS, but to the best of our knowledge no research has investigated the value provided to the energy system by CCS power plants. Generating technologies operating within the electricity system are required to comply with technical and socio-economic conditions. In addition to meeting environmental constraints, technologies also have to meet operational requirements ensuring security of supply and system operability. In order to assess the value of a given technology to the electricity system, it is crucial that the analysis is performed both for the costs of the technology individually and for the added cost imposed on the system by the introduction of an additional unit of capacity.

It is important to note that the first unit of a technology added to a given capacity mix has a different value than the nth unit. For example, the first capacity unit of wind power is extremely valuable to a system given its near-zero short-run marginal costs (SRMC) and its manageable impact on system operability and stability. In contrast, in a wind-rich generation mix, increasing the wind capacity further could actually increase system costs (i.e. negative value) and operational emissions owing to the requirement for back-up volume and their increased part-load operation.[19]

The central hypothesis of this paper is that these whole-systems issues must be taken into account when considering the design and evolution of an electricity system towards decarbonisation. However, this work does not aim to perform a complete whole-systems analysis, but rather to highlight the necessity of considering system synergies and to present the background of the integration problem in an illustrative example differentiating between intermittent and firm capacities.

The remainder of the paper is structured as follows. Section 2 reviews the value of reliable electricity supply, then Section 3 discusses core features and the role of CCS power plants in the capacity mix. Section 4 extends our view to the electricity system and how future trends will affect reserve, and operability requirements. We analyse the carbon intensity (CI) of different capacity units, as well as the CI and costs of an illustrative electricity system in Section 5 and conclude in Section 6.

2 What is the value of permanent electricity availability?

The cost of electricity is simply described by its price: £42/MWh in 2014 in Britain.[20] The value of having access to a reliable electricity supply is much greater, despite it being largely taken for granted in many societies. The Value of Lost Load (VoLL) is a measure of the damage caused to the economy by a loss of power supply.[21–23] This concept enables us to contrast the cost of electricity with its economic and societal value, and indicates the dependency of modern economies on reliable electricity supply.

Fig. 1 summarises the VoLL in Europe from the 1960s and gives some foresight to 2030. Historically this has been in the range of £2 000–4000/MWh, but recently studies have estimated values up to £15 000/MWh for the residential and £50 000/MWh for the service sector.[24,25] The UK Office of Gas and Electricity Markets (Ofgem) projects a VoLL value combining all sectors at £3000/MWh in winter 2015/16, and £6000/MWh in 2017/18.[26] There are a variety of approaches to calculate and measure the VoLL to a given society. For a comparison of measurement techniques see Ajodhia, Baarsma, de Nooij, and Leahy.[27–30]

The economic losses caused by power brown-outs and black-outs are two orders of magnitudes higher than the costs of electricity. This emphases the importance of ensuring that the new electricity generation technologies which are being deployed as part of the transition to a decarbonised energy system do not compromise the stability or resilience of the electricity grid.
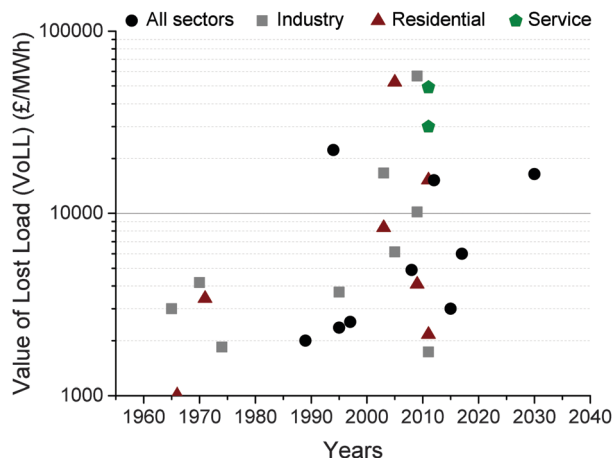
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† In the following we write CCS as shorthand for CCS-equipped power plants.
‡ In the UK electricity system, the capacity reserve margin is typically set to range between 5–10% of peak demand.[14]

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Fig. 1 VoLL values for the UK, data from ref. 24–27 and 104–107, and for other European countries.[108–113] Generally values for the service sector reveal a high electricity dependency since lost man-hours are permanently lost. The VoLL value for 2030 is a forecast for developed countries in general as opposed to developing countries where VoLL might be £3000/MWh.[107]

3 Carbon capture and storage – the flexible and low-carbon option

In addition to providing low carbon electricity, CCS-equipped power plants also have the key feature of providing flexible, dispatchable power, which will become increasingly important with the continued deployment of iRES.[31] Traditionally flexibility is understood on the process level of managing unit operations, and indicated by parameters such as ramping rates, up times, down times, and so forth. Consequently, it allows power plants to follow the load and to operate in sympathy with iRES.

More recently, flexibility from the perspective of the electricity grid, or system operator is becoming increasingly important. Here flexibility of a power plant is not simply the adjustment in power output but the ability to provide the required service to the electricity system at any given point in time. This feature is typically referred to as dispatchability. IRES, being only reactively controllable (*e.g.*, the output of a wind power plant can be turned down when the wind is blowing, but it cannot be increased beyond the available wind power at any given point in time), are non-dispatchable. The implications of this second perspective underpin this paper as it highlights how the value of a specific feature of a technology depends on the network the technology is operating within.

Increasing operational flexibility in CCS can impose constraints on the operation compared to conventional power plants.[32] The degree to which different variants of CCS technology (amine scrubbing, oxy-combustion *etc.*) can operate in a flexible manner is a function of the design and operability of the individual technology elements of which the CCS plant is composed. A restriction applicable to all CCS options is for example the part load behaviour of the CO_2 compressors (70% minimum stable load[32]) but other, limitations arise from the individual processes in pre-combustion, post-combustion, and oxy-combustion CCS. Crucial for oxy-combustion CCS are the ramp rates

(3% per minute) of cryogenic air separation units;[32] whereas for post-combustion processes the solvent regeneration or column design can become limiting factors.

Analyses of how to increase CCS power plant flexibility have historically been divided between options that reduce CO_2 removal and those which keep the CO_2 capture rate constant when operating off the nominal load point. Hydrogen storage for pre-combustion, liquid oxygen storage, solvent storage, or time varying solvent regeneration[33,34] for post-combustion or bypassing are currently the most studied techniques.[35–40] Strategies to overcome the operational limitations are ample (although not tested at large-scale) and we do see that CCS power plants can operate just as flexibly as their CO_2 emitting counterparts,[32,41–44] albeit potentially at the expense of greater capital cost.

Despite its technical strengths, a lack of understanding of the value which CCS power plants provides to a low-carbon electricity system has, to date, acted as a first-mover disincentive.[45] Although current deployment of CCS is mostly limited to the power generation and gas processing sector, industry (*e.g.* cement and steel industry) is also expecting movement towards CCS.[46,47] Cost reductions from experiences in the power sector may function as an enabler for the use of CCS in industrial decarbonisation. The IPCC suggests that limiting temperature rise requires an increase in CCS investment rates almost on par with renewables (+100% by 2029 compared to 2010), whereas unabated fossil fuels experience strong divestment (−20% by 2029 compared to 2010).[5]

The costs of electricity generation from CCS power plants in the UK expressed as Levelised Cost of Electricity (LCOE) are estimated between £70–150/MWh§ depending on technology type, fuel used and region.[48–51] The estimated LCOE of the only existing large-scale project (Boundary Dam in Saskatchewan, Canada) is calculated to range between £105–177/MWh depending on the cost of capital.[50]

The costs of CO_2 avoided are in the range of £20–70 per t_{CO_2}[52,53] for CCS power plants. Up front capital costs of a CCS power plant are estimated to be between 40–80% greater than those of an unabated plant.[54] However, these costs are expected to be substantially reduced as technology deployment moves from first-of-a-kind (FOAK) to nth-of-a-kind (NOAK).[49] The LCOE is projected to drop from £150/MWh in 2015 to just below £100/MWh in 2029 as a function of economies of scale, de-risking leading to reduced cost of capital and technological improvement.[55] Further, the IEA estimates a CAPEX reduction between 10–20% by 2035,[56] and the LCICG estimates a decrease of 30% by 2020.[10] Studies outside the UK anticipate a cost reduction of 5–20% by 2030, with a worldwide deployment of at least 100 GW.[57–59]

Although the importance of CCS is clear, only economic measures defined through coherent long-term policies can convince the industrial and energy end-use sectors to invest in and

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§ The International Energy Agency (IEA) estimates the LCOE for CCS power plants at £62–68/MWh in 2011;[48] DECC publishes figures of £90–130/MWh in 2013.[49] Bassi *et al.* identify a range of CCS LCOE of £70–80/MWh in 2015.[50]

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deploy this technology. Using technology prices or LCOE measures do not adequately value at the system level the production of dispatchable, low carbon power and these approaches can have major shortcomings evaluating system integration costs.[60] The overall value of a given technology to the electricity system can only be understood when technologies are assessed together, not in isolation.

4 System security and operability

Power stations do not only generate electricity, but a range of additional services which are essential for maintaining a permanent and stable supply across the system, including reserve capacity and frequency control. These additional services are mandatory for eligible power producers and indispensable for a reliable electricity supply. We identify three levels defining the system state. On the highest level, the total of installed generating capacity establishes system "adequacy" as the ability to meet peak load. The second level, system "reliability" is secured by a sufficient amount of reserve capacity, whereas on the lowest level inertia is required to ensure system "operability". Reserve capacity refers to the amount of power that is held by generators or energy storage technologies which is not being dispatched to serve the instantaneous electricity demand but can be called upon if necessary. Inertia refers to the kinetic energy stored in the spinning generators or rotors connected to the system which smoothes out imbalances and is important for frequency and voltage control.

The continuously changing level of demand requires the constant balancing of load¶ and generation in the electricity network. The system-wide variables defining the state of the grid are the generation, the load, the frequency, and interchanges.[61] A change in load, fluctuation of power output from the generators, as well as unplanned shut-downs of generators or interconnectors constantly disturb the balance on the electric grid.[61]

Restrictions for the operability of the network arise on the consumer-side where the frequency quality matters. In Europe, grid frequency must be maintained at 50 Hz ± 1%. This condition of the network is generally referred to as grid stability. The Rate of Change of Frequency (RoCoF) is manageably small (0.125 Hz·s^{-1} in 2014/2015[16]) as long as the level of system inertia, all inertia provided by the generators connected to the network, is sufficient. The definition of sufficient system inertia depends on the network size as well as the types of technologies in the capacity mix.[62] If the frequency fluctuates beyond the threshold of ±1% generating units may be automatically disconnected from the grid for safety reasons. In a worst case scenario the frequency drop causes a cascade effect where more and more generators are turned off-line resulting in a "frequency collapse", often with far-reaching impact.[61]

Various mechanisms for balancing the system are used to prevent the system from damaging black-outs, collectively known as "ancillary services". Rebours, Kirschen *et al.* provide an

overview of electricity system across Europe, the United States, and New Zealand comparing ancillary services in frequency and voltage control.[63,64] Despite the differences in nomenclature, all countries run balancing services on a reserve and frequency control level.

The maintenance and functionality of these services is indispensable for reliable electricity supply. However, not all types of power generators are technically capable of providing ancillary services. Depending on the energy conversion process, technologies can feature inertia-rich components (gas or steam turbines, rotational energy) or the potential to provide reserve (stored energy in chemical, potential and other forms). As both sides of the electric system, the supply and demand, are changing this will serve to further complicate the "balancing challenge".[65] Hence, grid stability is to become a limiting factor for an innovative electricity system transition,[15,66] and is indeed considered in current energy policies.[67] In the following sections we investigate how electricity generation and consumption changes and influences the balancing requirements specifically in the UK until 2050.

4.1 Europe's electricity systems

To begin with, we take one step further back from a regional to an international level and briefly discuss the position of the UK's electricity system within Europe. The distribution and of type of power plants across the European Union (EU) depend on a number of factors including indigenous resource availability, political interests and public acceptability. Every country is facing its own specific set of circumstances and is developing its own strategy.

We aggregate the technologies into three main categories: firm low-carbon (nuclear, hydro, bioenergy, geothermal energy, imports, and energy storage technologies), intermittent renewables (on- and off-shore wind and solar), and fossil fuels (coal, natural gas, and oil) with and without CCS. This specification emphasises pertinent features of the different fuel types in terms of capacities, operational constraints and environmental impact. Firm low-carbon generators provide dispatchable electricity at very low emission rates. Despite an increasing quality in weather forecasting, the source of intermittent power generation (wind or insolation) is inherently uncontrollable in time and intensity. Power generation from fossil fuels causes greenhouse gas emissions but can be adjusted quickly and operate flexibly. Fig. 2 summarises the shift in electricity generation by fuel over the past four years from 2010 to 2014 for selected European countries. Historically, power systems have been predominantly firm and controllable generation: a transition to systems dominated by iRES is unprecedented.

All European countries have moved towards renewables and a reduction in fossil fuels in recent years. However, it is also clear from Fig. 2 that they are all moving in different directions. Often the individual movements are only possible because they happen in conjunction with neighbouring systems. For example, Denmark (DK) as a relatively small country produces 30 TWh/year in almost equal parts from wind and fossil sources.[68] However, with a peak power demand of ~5 GW (relative to the UK

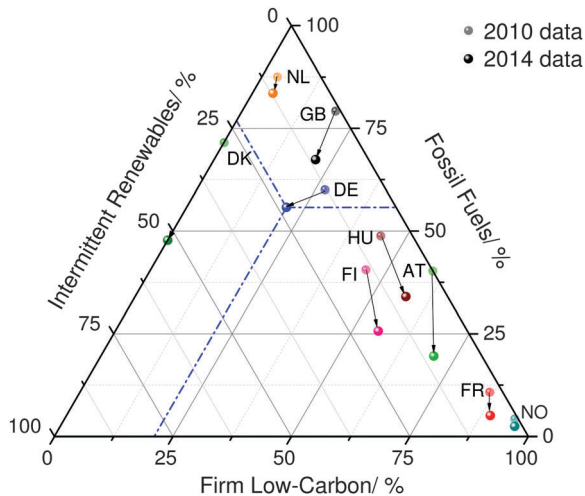¶ Here, the terms load (grid perspective) and electricity demand (system, market perspective) are used synonymously.

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Fig. 2 Electricity generation 2010–2014 in selected European countries, data from ENTSO-E.[114]
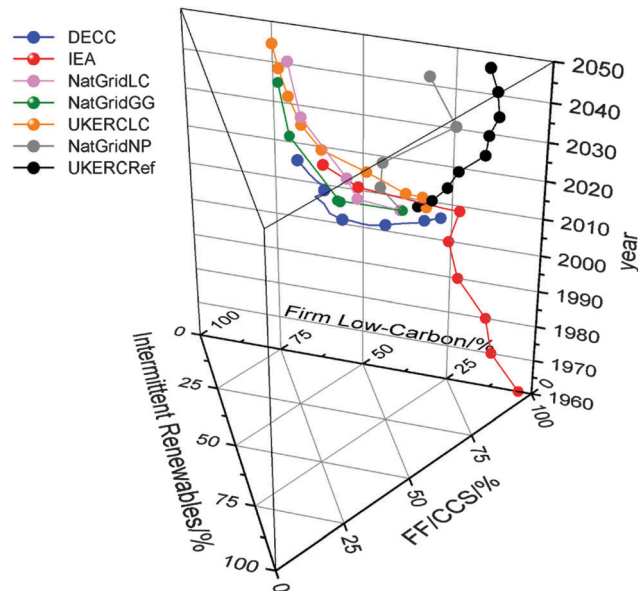

Fig. 3 Trajectories for electricity generation by fuel in a technology ternary, data from ref. 70, 72, 73 and 115. FF/CCS refers to fossil-fuelled generators with and without CCS, and firm low-carbon includes imports, which come predominantly from nuclear-rich France and hydro-rich Norway. Data is normalised to total electricity generation for each year or according to the time discretisation of the given set.

with ∼60 GW peak demand) 30% of inland generated electricity is exported and 30% of Denmark's consumption is met by imported electricity.[68] The possibility to operate an electricity system without firm low-carbon capacities highly depends on interconnections and regional sources.

4.2 Britain's electricity system in transition

4.2.1 Electricity generation mix. The rate at which we expect the UK's electricity system to change in the period from 2010–2050 is unprecedented.[69–72] Policies, environmental awareness, and system constraints push for a rigorous change of direction. To gain general understanding around which sources dominate electricity supply today and in the following decades we review seven scenarios on the UK's future electricity generation mix and visualise these in Fig. 3 and 4.

The data shows essentially two different types of scenarios. The first, including National Grid's "Low Carbon" (NatGridLC), and "Gone Green" (NatGridGG) scenarios, UKERC "Low Carbon" (UKERCLC), the DECC and the IEA data depict a clear transition through the ternary prism. The second, represented by the UKERC reference (UKERCRef) and the National Grid "No Progression" (NatGridNP) scenario, continues the path when making hardly any adjustments to the policies today.

Within the two branches, data is in overall agreement. Fig. 4 visualises the corresponding fuel mix for the different 2035/50 systems. There is a marked transition from an electricity system dominated by unabated fossil fuels to one in which a much larger role is played by nuclear and iRES. All scenarios in the "green" branch start including fossil power plants with CCS starting from 2019 to 2025. Power generation from unabated coal disappears in every "green" scenario by 2050, CCS gains ground and ultimately contributes 20% of electricity generation in the UK. These results are in agreement with other electricity projections by the IPCC.[5]

4.2.2 Electricity demand. From 2010 to 2050 predictions agree upon a general increase of approximately 35% in electricity demand due to its important link to the transport, building,
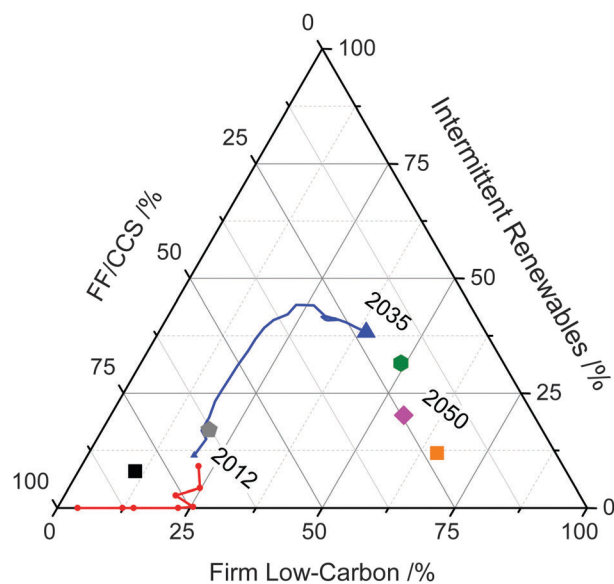

Fig. 4 Equivalent data as Fig. 3; transition of electricity generation by fuel for 1960 to 2012 according to the IEA, and 2012 to 2035 to DECC's reference scenario.[73] Remaining scenarios are shown with large markers for the respective 2050 fuel mix.

and end-use sector.[70,72,73] However, the sectoral share between residential, commercial and industrial (manufacturing) demand remains a 35/30/35% ratio.[70,72,73] Nevertheless, the hourly profile of electricity demand will change significantly over the coming decades. Introduction of new demand-side technologies (particularly electric vehicles and heat pumps) and wider trends

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(such as efficiency improvements and de-industrialisation) mean that the within-day variation in demand may increase, to the extent that peak load may increase at twice the rate of annual demand.[74]

4.3 Ancillary services

The role of ancillary services as tool to maintain supply reliability and grid stability is essential. When comparing power technologies it is again important to clearly differentiate between firm and intermittent generators. Conventional power generators such as fossil-based systems (or energy storage technologies) are referred to as firm capacities and due to the (theoretically) permanent and immediate availability of the energy source (fossil fuel for example), they can commonly meet reserve service requirements. Thermal power plants including synchronous generators are also inherently inertia-rich. On the other hand, intermittent generators such as wind power plants have a predictable but not dispatchable power output. Due to their intermittent nature they cannot be dispatched as demand occurs and chosen by ''economic criteria'' in contrast to conventional power generating technologies.[60] New concepts are being proposed to add reserve and inertia providing features to expand their portfolio of services. The subsequent sections examine how the changing electricity supply and demand affect the balancing requirements for reserve and inertia services.

4.3.1 Reserve requirements. The reserve services specify the amount of additional capacity that is needed to reliably operate an electricity system. A permanent system margin, as additional fraction of peak demand, secures power supply in the event of planned and unplanned outages. In the UK, National Grid's indicative level of adequate system margin is 20% above peak demand or 12–14 GW (based on approximately 60 MW peak demand).[75]

Additionally, back-up in the form of conventional capacity (or energy storage capacity) is required to compensate for the lack in firmness of intermittent capacities. Every GW of installed intermittent capacity necessitates the availability of additional firm capacity. Estimates for a sufficient level of back-up capacity range from 15–20% of the intermittent capacity[75,76] up to 50–100% to hedge against periods without wind.[77]

With growing penetration of iRES, correspondingly higher reserve levels will be needed to maintain the electricity supply reliability. Consequently, more back-up capacity is necessary to balance greater volumes of electric power, though used less frequently as it is displaced by iRES.

4.3.2 Inertia requirements. In the UK, large power generators have to provide mandatory frequency response to automatically balance supply-demand mismatch by increasing or decreasing their power output.[78]

The expected changes in generating capacity over the coming decades greatly influences the level of available system inertia. This property is measured in GW·s, indicating the power output that can be retained only by the kinetic energy stored in the on-line generators. Substituting synchronous generators (such as gas turbines, conventional coal and nuclear plants) by non-synchronous generators such as iRES reduces the total

system inertia.[79] Currently the level of system inertia in the UK is 360 GW s and is expected to shrink to 150 GW s in the period of 2024–2035,[16] in proportion to the rate of installation of iRES.[72] Subsequently, this causes a higher RoCoF, a general decrease in system stability, and increases requirements for a higher level of frequency containment.[16]

The consequences of a changing capacity mix are far-reaching for system reliability and operability. In the following section we outline the major effects different system configurations have on operational carbon emissions‖ and the energy economy.

In any future energy system, a sufficient amount of response capacity, energy storage technologies, interconnectors, or demand-side mechanisms are necessary to meet reliability standards.[15] In the absence of an inertia-based grid frequency control, these requirements will become the limiting factor for renewable power deployment.[80] Strategies which attempt to make use of intermittent power generation in frequency response propose ''synthetic inertia''** as a service for wind power plant. In this way, power generators which are traditionally almost inertialess can provide a similar service by rapidly increasing their power output from a part-load operation point.[16] However, this type of service cannot be monetarily valued as it is not yet specified by the Grid Code.

Although inertia is an essential feature of the electricity grid, there are at present no evident market incentives, apart from individually contracted agreements with the system operator, to promote high-inertial generator types. Renewables are often supported using a fixed premium for energy generated regardless of how useful this is to the system, which offers no reward for availability or dispatchability.[82] Furthermore, renewables can operate at the expense of conventional generators where support schemes include an export guarantee with preferential grid access.[83]

5 How clean is green? – systems analysis

5.1 Low-carbon and intermittent power generators

The major reason iRES and CCS power plants are considered in the technology mix today is their distinguishing characteristic of providing low-carbon electricity. In order to compare emissions from power systems including these technologies we define and investigate a hypothetical capacity unit for the provision of constant power through the year. Intermittent power generators such as wind farms cannot operate at full power continuously as they are limited by resource availability, and so they require back-up capacity to meet electricity demand continuously

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‖ Please note that in this context we refer solely to carbon emissions caused during operation of the power plants as opposed to life cycle emissions.

** Synthetic inertia refers to the addition of an electronic controller on the wind power generator side which is able to restrain power output and increase rapidly if needed. This power boost can then counteract a frequency excursion and reduce the RoCoF.[16,79,81] While, the inertial response from wind power generators has a positive effect on system inertia it only acts momentarily, if wind power is available, and might not be able to replace other security measures.[81]

over the year. Their average power output relative to their installed capacity is referred to as their capacity factor (CF). We assume that conventional fossil-based power generators running at full load have a capacity factor of 100%, meaning in one hour of operation a conventional power plant with capacity size of 500 MW for example can generate 500 MWh of electricity. On an annual average this is an acceptable assumption since base-load power plants operate at CFs of 85–90% due to down-time. Applying the same logic to intermittent power generators, a 500 MW wind farm for instance can provide CF_{Wind} 500 MWh in one hour, where the CF for wind generators varies over time and space, and inherently depends on the location of the power plant.

Fig. 5 illustrates the available wind resource across Europe according to the average annual CFs. As might be expected, the North Sea and the northern European countries register the highest wind speeds and consequently the highest CFs. Fig. 6 shows the capacity factor distribution in the selected European countries. The spread of CFs for central European countries is greater than for the northern countries such as Denmark (DK) or Great Britain (GB) which can generally rely on CFs between 25–30% onshore. Offshore CFs for the North Sea, which refers to the region most accessible for Great Britain and the Scandinavian countries, reach up to 45–50%.

Wind power generators alone cannot provide a full capacity unit in terms of firmness and availability (full load hours). Thus, in order to compare the effects on electricity generation costs and emissions of an operable electricity system, we combine wind with thermal power plants (with and without CCS) where the thermal power plants provide back-up capacity. The Carbon Intensities (CI) measured in t_{CO_2}/MWh for different system configurations are shown in Fig. 7. The CIs for the combined wind-thermal systems are calculated as described in eqn (1), where index i represents the different countries,
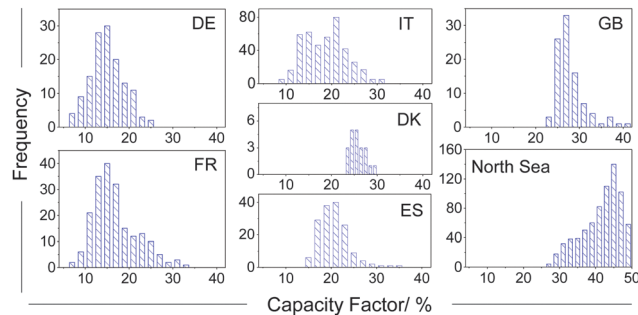

Fig. 5 Long-run capacity factors (CFs) averaged over 1995–2014 and aggregated across Europe.[116,117] The CFs determined from hourly wind speeds using the Renewables.Ninja database,[85] assuming 80 metre tall Vestas V80 2 MW turbines were installed at regularly-spaced locations on land and up to 250 km out to sea.

Fig. 6 Histogram of long-run capacity factors averaged over 1995–2014 and aggregated for selected European countries from data for single turbines by location.[116,117] The visualised data for the selected countries does not include offshore areas. The North Sea refers only to British territorial waters, and is presented on a different x-axis scale.

BU indicates the back-up capacity, and W wind power generators. In all cases, $CI_W = 0$ and annually averaged CFs for each country are derived from the underlying data in Fig. 6.

$$CI_{i,W+BU} = CF_{W,i}CI_W + (1 - CF_{W,i})CI_{BU} \qquad (1)$$

Although during operation there are no carbon emissions from pure wind power generators, a capacity unit comprising the available wind energy (regional CFs) shows only a marginally lower CI than purely conventional processes. Hence, the CI of the back-up capacity should be included when stating the emissions of wind power generators. The idea of "associated carbon" refers to the carbon implicitly emitted by "clean" electricity generators which require fossil-based back-up capacity.

We find that the CI of electricity coming from combined capacity where wind power generation is backed up by coal-fired power plants (subcritical or supercritical) still exceeds the CI of a conventional Combined Cycle Gas Turbines (CCGT) operating independently. Only a combination including CCS technologies can reduce the CI to sufficient levels below 0.1 t_{CO_2}/MWh when deployed on coal-fired power plants, and 0.05 t_{CO_2}/MWh for CCGT-CCS power plants, respectively. We note that the presented CI levels for power generation from CCS power plants are based on the conservative assumptions in the underlying IECM tool;[84] with state-of-the-art power plants and improved capture technologies, CI can potentially be reduced further. Additionally, balancing operation forces back-up power plants to operate off their design point, reducing efficiency and increasing CI further. This latter factor is not considered here, making the calculations presented in Fig. 7 an optimistic estimate for the CI of power generated from capacity composed of a combination of wind and unabated thermal power plants. The effect of a combined wind and solar power integration increases the CI for the results on combined capacities presented in Fig. 7. Since the CF for solar (PV) power generation in the UK is 1/3 the CF for on-shore wind (9% versus 29% annual average[85]), any mix of wind and solar will be worse than the presented example.

Adding capacity to a system does not only displace power generation, it also displaces power capacity. However, due to its intermittent output, the contribution of an increment of
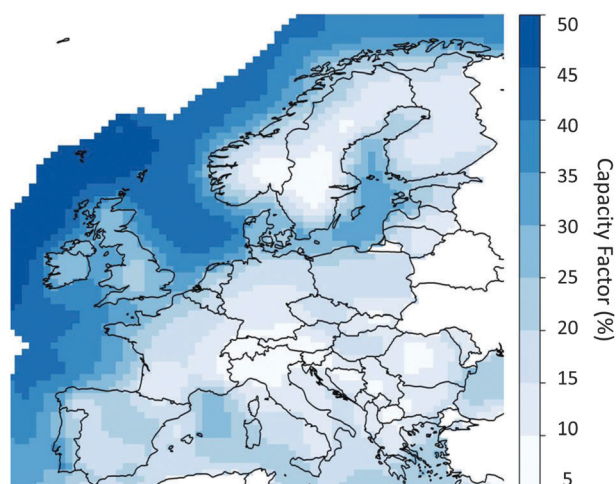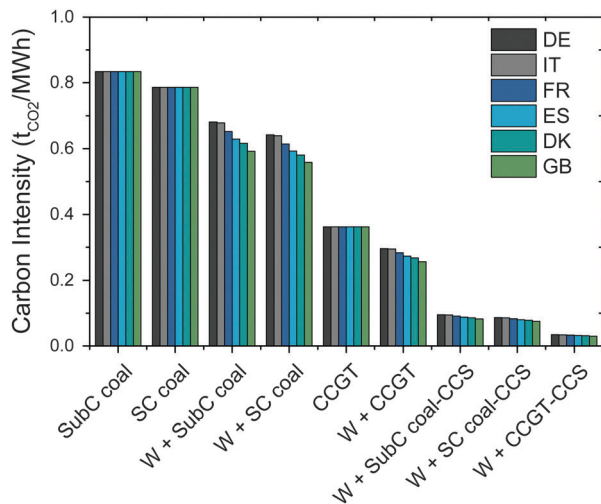
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Fig. 7 Carbon intensity for different system setups derived with the IECM tool.[84] "SubC coal" represents a subcritical coal power plant (gross electricity output 650 MW, net plant efficiency 37.84%), "SC coal" a supercritical coal power plants (gross electricity output 650 MW, net plant efficiency 40.16%), and CCGT a natural gas combined cycle power plant (gross electricity output 298 MW, net plant efficiency 50.33%). All CCS systems are set to capture 90% of flue gas CO_2. The energy penalty of post-combustion CCS (using a 30 wt% monoethanolamine solvent) reduces plant efficiencies to 27.11% (SubC), 29.84% (SC) and 43.41% (CCGT). The CF for on-shore wind (W) is set to the annual average for each country.[85]

electricity generation from iRES changes as a function of how much is present in a given system. The capacity credit (CC) quantifies the fraction of a generator's capacity that can be considered 'firm', and is available to be called on when most needed. This fraction also corresponds to the quantity of other generating capacity that is displaced by iRES, without compromising the system's ability to reliably meet peak demand.[86,87] Conventional power generators generally have a CC near 100% since they provide inherently firm capacity (not considering outage due to maintenance for instance). For wind power generators, the CC is a function of the wind penetration X_W, the percentage of installed wind capacity of total system capacity. This relationship is presented in Fig. 8 based on data from Gross et al.[75] and references therein. In a system where wind capacity contributes 5% of peak capacity, i.e., $X_W = 5\%$, the CC ranges between 16–31%, at $X_W = 20\%$ it decreases to 7–24%, dropping to 2–13% once the installed capacity reaches 50%. This is due to the wind power supply uncertainty increasing, leading to the "firmness of capacity" decreasing with the amount of capacity on the system.

5.2 System capacity and asset utilisation in wind and CCS integrated systems

In this section, we present the results of a thought experiment where we quantify the impact of extensive deployment of intermittent renewable electricity or CCS power plants into an electricity system initially composed of unabated thermal power plants. Our hypothetical system has a peak demand of 62.5 GW, analogous to current UK peak demand. We evaluate the contribution of each technology in increments of capacity towards a
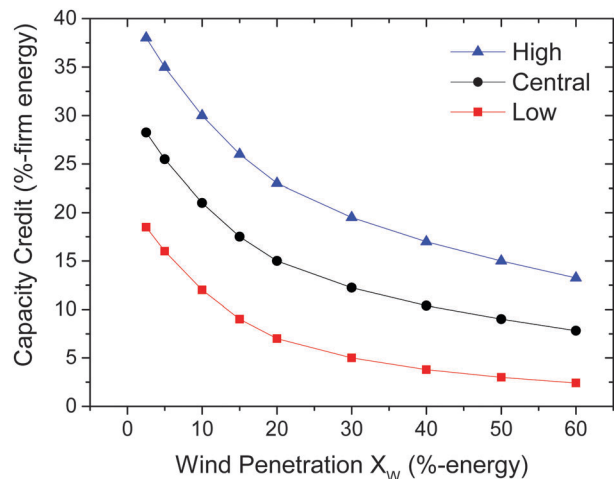

Fig. 8 Capacity credit of wind power generators, based on data presented by Gross et al.[75] and references therein. It can be observed that initial deployment of wind power can contribute between 17–37% of its firm capacity, but that this capacity credit reduces with increasing deployment.

Table 1 Input data assumptions for illustrative total system costs calculation. The CAPEX refers to NOAK power plants, and is annualised using a discount rate of 7.5% and a lifetime of 25 years for all technologies. The reported values are not shown to be real costs and are not intended for further use. Benchmark data is reported by the IEA and NREL[56,118–120]

Symbol	Unit	Thermal	Wind	CCS
CAPEX	£/kW	1000	2000	1700
Annualised CAPEX	£/kW·yrs	89.71	179.42	152.51
OPEX	£/MWh	50	0	55
Capacity factor/availability	%-Capacity	80	29	80
Carbon intensity	t_{CO_2}/MWh	0.78	0	0.11
Electricity demand	TWh/yrs		315	
Peak demand	GW		62.5	
System reserve margin	%-Capacity		10	

reduction in the cost and carbon intensity of the resulting system. The calculations provide insight on the difference between firm and intermittent capacities on the system configuration, cost, and CI. We define a low-carbon electricity system as one with an overall CI of less or equal then 0.1 t_{CO_2}/MWh. Table 1 provides the input data for the underlying calculations presented.

In our model system, we quantify the amount of thermal and wind capacity required to ensure a reliable electricity supply, meeting the annual electricity demand specified in Table 1. The underlying calculations refer to the half-hourly demand data for the UK for 2013.[88] Fig. 9(a) illustrates how the total amount of capacity increases with the level of wind capacity in the mix. Although wind capacity can displace some thermal capacity, in line with the CC of wind at that level of penetration, a system including 69 GW of wind capacity, i.e., sufficient wind to meet peak demand, would at most replace 7–22% of existing thermal capacity. This would have the effect of nearly doubling the total asset base required to reliably provide sufficient energy to meet peak demand. This represents an infrastructurally inefficient and capitally expensive system. A purely fossil based system meeting a peak demand of 62.5 GW with a standard reserve
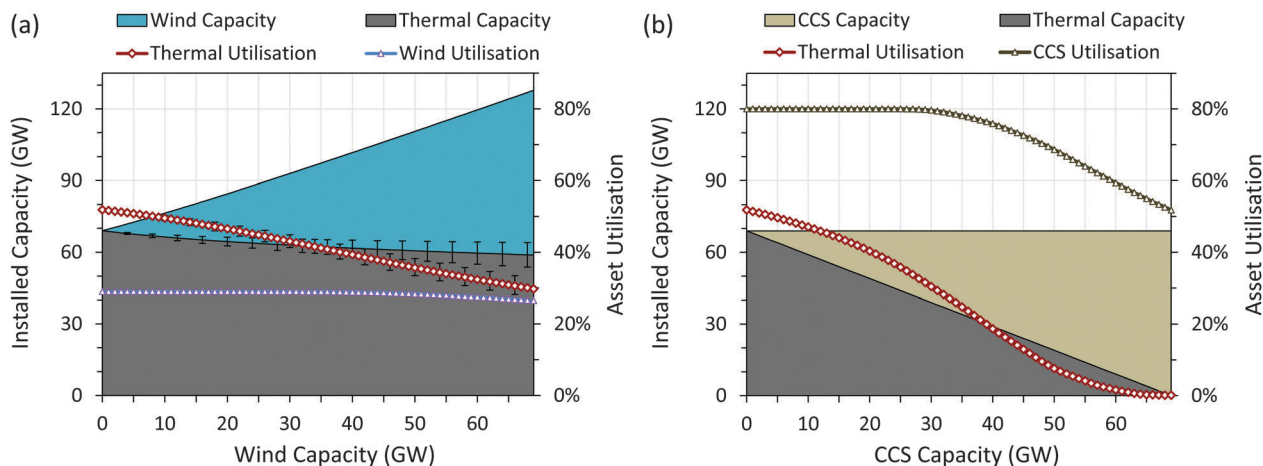
Fig. 9 Installed capacity mix and generator utilisation as a function of the amount of (a) wind and (b) CCS capacity. In (a), total capacity requirements nearly double for the maximum wind power deployment rate due to the necessity for sufficient back-up capacity. Data on wind availability is taken from ref. 116. The error bars indicate the spread referring to the low and high CC values from Fig. 8. Thermal utilisation decreases from initial 52% to 30% as electricity from wind power plants is favoured. Wind utilisation decreases from a maximum of 29% (CF) to 26% due to curtailment. In (b), the total amount of capacity remains constant. Thermal utilisation decreases as electricity from CCS power plants is favoured and thermal capacity is being substituted. CCS power plant utilisation initially equals the maximum availability and decreases according to the load-duration requirements.

margin of 10% would require a total of 69 GW thermal capacity. In a system composed of different types of thermal power plants, base-load units operate at high utilisation rates ($>80\%$) whereas peak load plant utilisation is generally low ($<10\%$). However, the utilisation of thermal power plants in such a system would average 52% meeting 315 TWh/year (utilisation = power output/installed capacity). The integration of wind causes a decrease in utilisation of the thermal asset, dropping from 52 to between 27 and 33%, as a function of the value of CC used at this level of wind penetration. As the rate of plant utilisation decreases, the associated business risk increases, which will in turn increase the cost of capital and consequently the price at which electricity must be sold. At the same time electricity prices become more volatile which requires more state aid and third party regulation.[89]

A system where CCS power plants are deployed for low-carbon electricity generation is illustrated in Fig. 9. Here, the total amount of capacity remains constant, as CCS power plants could displace thermal power plants on a one-to-one basis. The utilisation of the thermal capacity decreases as it is displaced by CCS-equipped capacity. Early CCS plants operate at 100% load until the installed CCS capacity is greater than 50% of peak demand. Only once this threshold is crossed would CCS capacity begin to become constrained off in the usual fashion, tending towards a final asset utilisation factor of 52%. Early adopters of CCS, however, could enjoy a first mover advantage of high utilisation rates, thus incentivising the creation of new markets and triggering further investment.

5.3 Electricity system cost and carbon intensity in wind and CCS integrated systems

The common LCOE calculation accounts for the life-time expenses and revenues levelised by the generated electricity from the respective technology. Eqn (2) summarises the LCOE structure as fraction of the total expenses over the total

electricity produced throughout the lifetime of an individual power plant (£/MWh). Operational expenses OPEX can be understood as the sum of operation and maintenance cost (O&M), fuel cost, and carbon cost. The nomenclature for eqn (2) and (3) are given below.

$$\mathrm{LCOE}_{i,t} = \frac{\left(\mathrm{CAPEX}_i + \sum\limits_{t=1}^{T} \mathrm{OPEX}_{i,t}\right)(1+r)^{-t}}{\sum\limits_{t=1}^{T} \mathrm{EG}_{i,t}(1+r)^{-t}} \qquad (2)$$

i, # power plant;
t, # years of power plant lifetime;
h, # hours of operation in year;
r, discount factor (%);
CAPEX, investment cost for power plant i (£);
D, decommissioning cost for power plant i in year t (£);
OPEX, operational expenses for power plant i total in year t (£), or per hour h (£/MWh);
EG, electricity generation by power plant i in year t, or per hour h (MWh).

The LCOE allows for a comparison of investment decisions as it contains key market parameters such as fuel cost, discount rates, or carbon cost. However, the LCOE metric assumes that generated electricity is a homogeneous product.[60] This is not the case for power generation through iRES which require back-up or energy storage capacity in order to provide electricity as reliably as conventional power plants. Thus the traditional concept of LCOE lacks a systems perspective when comparing the electricity generation costs iRES and firm generation technologies, as it does not account for the costs imposed upon firm power generators (such as increased cycling and start-up costs) imposed upon firm intermittent power generators.[90]

We address the shortcomings of the LCOE metric by proposing an alternative metric, the total system cost (TSC), and use
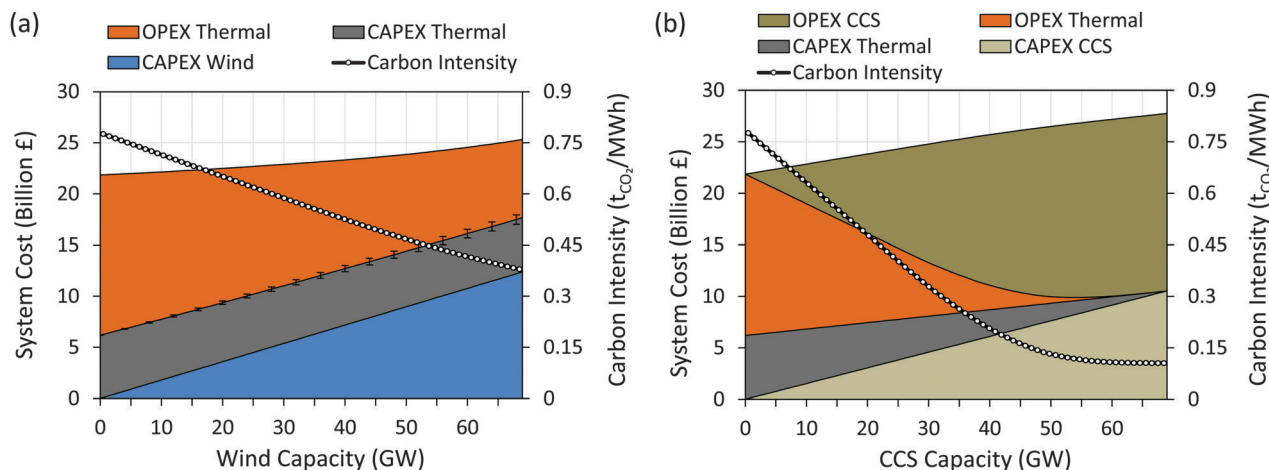
Fig. 10 Total system cost as sum of capital (CAPEX) and operational expense (OPEX) and the overall carbon intensity (CI) for (a) thermal–wind and (b) thermal–CCS integrated system. In (a), OPEX decreases with reduced fuel consumption and utilisation; CAPEX increase with wind power installation. The error bars indicate the sensitivity in thermal CAPEX referring to the low and high CC values from Fig. 8. The CI reaches 0.4 t_{CO_2}/MWh at the maximum wind power deployment. In (b), thermal CAPEX and OPEX decrease according to the increase of the respective CCS cost components. The system CI reduces to 0.1 t_{CO_2}/MWh at the maximum share of CCS-equipped capacity.

this to analyse two model systems – the first composed of wind and unabated thermal power plants, and a combination of CCS and unabated thermal power plants in the second. As described in eqn (3), the annualised total system cost (£) is an absolute measure including the capital and operational expenses of all power plants comprising the electricity system. It does not, however, consider the costs of power plant decommissioning. The OPEX factor (including O&M, fuel, carbon) accounts for the total quantity (TWh) of electricity generated over the year. This enables us to explicitly consider the additional costs associated with thermal power plant generation arising from iRES integration. For simplicity, we do not include system infrastructure costs such as transmission and distribution, however, this extension would further elucidate the system impacts of technology integration.

$$\text{TSC} = \sum_{i=1}^{N} \text{CAPEX}_i A_{t,r} + \sum_{i=1}^{N} \sum_{h=1}^{H} \text{OPEX}_{i,h} \text{EG}_{i,h}, \quad (3)$$

where the annuity factor is given by $A_{t,r} = (1 - (1 + r)^{-t})/r$, depending on the discount factor r and lifetime t of the corresponding power plant.

Fig. 10 presents the share of CAPEX and OPEX as it changes with the amount of wind (a), CCS capacity (b) in the system. On the secondary y-axis we also see the CI of the system configuration matching to each level of wind or CCS integration.

Fig. 10(a) illustrates how the additional capital cost of wind power generators is approximately balanced by the reduction in system OPEX arising from fuel consumption. Nevertheless, the total system cost increases by 16% for a maximum deployment of wind capacity. However, the increased deployment of wind power results in a significant reduction in system CI. The system CI reaches 0.38 t_{CO_2}/MWh at the maximum wind power integration, which equals a reduction of 50% as 50% of electricity demand is met by wind power generation. However, the overall

CI does not satisfy low-carbon electricity system requirements of 0.1 t_{CO_2}/MWh, and indeed is a higher CI than the unabated CCGT plant illustrated in Fig. 7. For the CCS integrated system in Fig. 10(b), total system cost increases by 30% at the maximum level of CCS deployment, replacing the thermal capacity entirely. However, the CI is very significantly reduced, resulting in a truly low carbon system with a CI of 0.1 t_{CO_2}/MWh.††

Fig. 11 compares the aggregate cost of carbon abatement for the illustrative thermal–CCS and thermal–wind electricity systems across their range of CI, and penetration of CCS and wind power plants, respectively. We find that initially the deployment of wind power generators can reduce the systems CI more cost effectively than the deployment of CCS. However, attempting to reduce the CI below 0.45 t_{CO_2}/MWh exclusively *via* wind integration causes a significant increase in the amount of total capacity installed and thus the cost of abatement. Indeed, the thermal–wind system cannot achieve a CI below 0.225 t_{CO_2}/MWh, even at 137 GW of wind in the capacity mix.

Considering the role of CCS, we find that 20 GW of CCS achieves the same amount of decarbonisation as the deployment of 44 GW of wind. Moreover, the deployment of 69 GW of CCS reduces the CI to 0.1 t_{CO_2}/MWh – something which is unachievable with the deployment of iRES alone. However, initially, deploying CCS has an increased marginal abatement cost over wind deployment. Therefore, in the context of this analysis, the cost-optimal solution is first the deployment of 44 GW of wind and the subsequent deployment of sufficient CCS to displace the remaining unabated thermal plant.

Note that this is a static analysis and so we have not assumed any change in cost of technology as it is deployed, consistent with

†† Analogous calculations for a case combining thermal and gas-fired power plants (CCGT) as firm and less carbon-intense generator increases total system cost by 3%, however, the CI of such a system could reduce at most to the CI of the gas-fired power plants of approximately 0.36 t_{CO_2}/MWh.
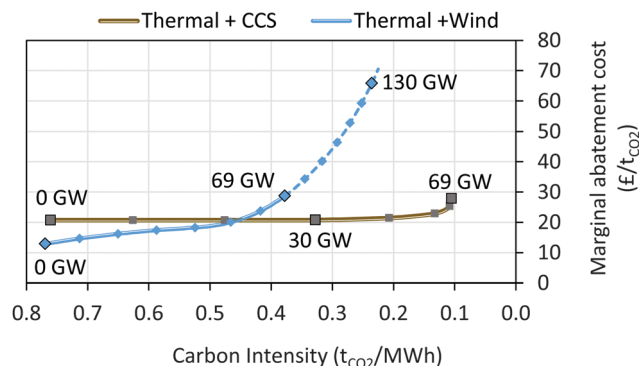
Fig. 11 Reduction in carbon intensity (CI) in the hypothetical thermal–CCS and thermal–wind systems. The continuous lines with markers refer to the systems in Fig. 9 and 10, where CCS and wind respectively are deployed up to a level of 69 GW. The dashed line for the wind capacity integrated systems represents the theoretical continuation of increasing wind capacity and thermal back-up in order to achieve a CI of 0.225 t_{CO_2}/MWh.

the NOAK plant cost assumptions presented in Table 1. Given that the wind industry is relatively mature, this is a reasonable assumption. However, in the case of the CCS industry, this is conservative, and one would expect significant cost-reduction to be observed as a result of increased deployment, and in particular as the marginal cost of developing transport and storage decreases.

5.4 Impact of energy storage technologies and demand-side management

The previous analysis is simplified as we analyse a two-technology system and do not consider technologies which complement generation from iRES, such as energy storage or demand-side management (DSM) technologies. The presence of energy storage technologies can reduce the need for firm back-up capacity and even out the power output from iRES in the intra-day or seasonal supply-demand mismatch.[65,91] Combining iRES with designated energy storage capacity could increase the capacity credit of intermittent power generation.

However, the value of storage resources will highly depend on its specific features (distributed/grid-level, storage duration, charging/discharging times/cycles, efficiency, *etc.*) and on the type of electricity system (level of intermittent/firm generators, reliability and operability requirements). Additionally, the presence of electricity interconnectors will play an increasing role in power balancing in future electricity systems, potentially turning connected energy systems into large storage reservoirs for one another.[92] DSM can increase the efficiency of electricity network usage and reduce requirements for electricity grid reinforcement and grid congestion.[93,94] Despite the positive effect of energy storage and DSM technologies on the balancing challenges, their implementation at scale is not currently technically and economically viable.[91,95–97]

Energy systems models that include energy storage and DSM technologies estimate an economic energy storage capacity deployment of approximately 4 to 15 GW for the UK, depending on type of storage, costs, as well as system and technology parameter.[98] The analyses find that an increase of iRES reduces

OPEX of thermal power plants due to reduced fuel cost. However, this reduction in thermal plant OPEX comes at the cost of an increased balancing cost.[93] The value of load following and flexible operation in power plants has been observed to increase in line with the level of intermittent power generation.[99] Studies analysing a realistic mix of generating technologies, find very similar levels of thermal capacity displacement (12%) and generation reduction (23–46% depending on level of iRES penetration) as the results of the thought experiment presented here.[100,101] A key advantage of the analysis presented here is that its simplicity provides insight to the significant difference between firm and intermittent capacity, the associated system integration challenges and the varying value that different technologies can bring to the challenge of decarbonising the electricity system.

6 Conclusion

We have discussed how the trends in electricity supply and demand together with environmental targets are pushing the electric system to its operational limits. Without a flexible and low-carbon transition technology which can provide electricity as well as sufficient balancing capacity to meet reserve and inertia demands system reliability could be endangered. Given the high value of electricity to our society, compromising on reliability would likely prove to be a costly mistake.

Our analysis indicates that, in the absence of CCS-equipped power plants, wind power provides a limited reduction in the carbon intensity (CI) of a given energy system. This statement comes with the caveat that wind power provides an initially cost-effective means for the first steps in decarbonising an energy system. Compared to electricity generation from unabated coal or gas power plants, the integration of wind power to a combined unabated thermal–wind capacity unit can reduce the CI by 18–30%. The integration of CCS technology, however, reduces emissions per MWh by 87–88%,‡‡ noting that this figure has the potential to improve in line with advances in capture technology.

We have presented the results of a thought experiment wherein we evaluated the environmental and economic impacts of decarbonising an electricity system composed initially of unabated thermal power plants with wind and CCS. We find that the installed wind capacity can only marginally displace thermal capacity due to its relatively low capacity credit. A high deployment of wind power capacity would increase total system cost by 16% and reduce the CI from 0.78 to 0.38 t_{CO_2}/MWh. However, such an electricity system contains nearly double the amount of capacity that would be needed as firm asset to secure supply. Intermittent renewables are able to displace thermal power generation, but cannot substantially displace thermal capacity. The savings in operational and fuel expenses for thermal power generators do not entirely compensate the capital costs

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‡‡ We assume a 90% CO_2 capture rate for all investigated CCS technologies, reducing absolute emissions by 90%. The net plant efficiency penalty caused by the CCS unit reduces annual power generation, resulting in an emission reduction per MWh of ≤90%.[84]

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added through the installation of wind power generators. Additionally, a reduced market access and distortion of traditional base load and peaking operation for thermal power plants could drive up the cost for electricity generation. In a system where CCS power plants are deployed, unabated thermal capacity can be replaced effectively, resulting in an energy system with generation capacity in line with demand. The option of extensive CCS deployment is estimated to increase total system cost by 30% and reduces CI to 0.1 t_{CO_2}/MWh. In comparison, a system integrating CCS faces a persistent increase in CAPEX and OPEX in proportion to the amount of CCS capacity installed.

The analysis has confirmed the hypothesis that the choice and integration of different power generating technologies significantly impacts system-level characteristics, such as the total amount of necessary capacity, total system cost, and carbon intensity. Investments in supposedly cheap technologies can entail unplanned expenses in areas such as grid stability but also miss the goal of reducing environmental damage. A feasible path of decarbonisation will likely require a combination of intermittent renewable energy and firm low carbon energy technologies. Emission reduction in the electricity sector will cause an increase in total system cost, and a least-cost path to decarbonisation will require the deployment of a portfolio of technological solutions.

Existing whole-system energy models only partly capture these effects as they must trade off breadth against detail. As a result, they often do not recognise the intermittency aspect of iRES or the operational feasibility from an electrical and network engineering perspective.[102] However, rigorous modelling including energy storage technologies, demand-side management, transmission and distribution has provided valuable insight to technology-specific operation and system impacts.[98–100,103]

We also conclude that it is not rational to assess the value of a technology to an electricity system in isolation. The provision of electricity is not a uniform service or product flow, but is characterised by its availability and controllability depending on the generation technology and the current system state.

Acknowledgements

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