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Renewables, nuclear, or fossil fuels? Scenarios for Great Britain's power system considering costs, emissions and energy security

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HIGHLIGHTS

- We compare a large number of cost-optimal future power systems for Great Britain.
- Scenarios are assessed on cost, emissions reductions, and energy security.
- Up to 60% of variable renewable capacity is possible with little cost increase.
- Higher shares require storage, imports or dispatchable renewables such as tidal range.

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ABSTRACT

Mitigating climate change is driving the need to decarbonize the electricity sector, for which various possible technological options exist, alongside uncertainty over which options are preferable in terms of cost, emissions reductions, and energy security. To reduce this uncertainty, we here quantify two questions for the power system of Great Britain (England, Wales and Scotland): First, when compared within the same high-resolution modeling framework, how much do different combinations of technologies differ in these three respects? Second, how strongly does the cost and availability of grid-scale storage affect overall system cost, and would it favor some technology combinations above others? We compare three main possible generation technologies: (1) renewables, (2) nuclear, and (3) fossil fuels (with/without carbon capture and storage). Our results show that across a wide range of these combinations, the overall costs remain similar, implying that different configurations are equally feasible both technically and economically. However, the most economically favorable scenarios are not necessarily favorable in terms of emissions or energy security. The availability of grid-scale storage in scenarios with little dispatchable generation can reduce overall levelized electricity cost by up to 50%, depending on storage capacity costs. The UK can rely on its domestic wind and solar PV generation at lower renewable shares, with levelized costs only rising more than 10% above the mean of 0.084 GBP/kWh for shares of 50% and below at a 70% share, which is 35% higher. However, for more than an 80% renewable generation share to be economically feasible, large-scale storage, significantly more power imports, or domestic dispatchable renewables like tidal range must be available.
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1. Introduction

There is wide agreement in the climate science community that global greenhouse gas emissions must be reduced by at least 80–90% by 2050 in order to avoid severe climate change [1]. The UK government has put into place ambitious legislation to reach this goal with the 2008 Climate Change Act, which stipulates an economy-wide 80% emissions reduction by 2050, relative to 1990. Much work has been conducted on possible configurations of the UK's energy system on that basis, and on cost-effective pathways to achieve such configurations (e.g. [2–4]). A common theme (mirrored by work for other countries, e.g. [5]) is that first, the electricity sector must be largely emissions-free, and second, significantly more electricity will be needed to help decarbonize other sectors (such as heating and road transportation). Renewable energy is seen as one key source of low-carbon energy, and policies are therefore in place to support its deployment. While there is some recent uncertainty around the strength of policy

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commitments in the wake of the European Union's 2030 renewables target, which is binding only at an EU level [6], the deployment of renewable power generation has been steadily advancing, and this trend is likely to continue both in the UK and globally [7].

The deployment of renewable energy in the UK can be seen in the light of climate change mitigation, but also as part of a desire to balance affordability with energy security [8]. To achieve these goals, energy system models are crucial tools to produce high-level scenarios, providing broad guidance on what mix of technologies is more desirable or cost-effective under a given set of assumptions and policy choices. A recent example for the UK is the UK Energy Research Center (UKERC) scenarios for the 2050 energy system [4]. However, large-scale energy system models do not incorporate the necessary degree of spatial and temporal detail to examine different ways in which different mixes of renewables with existing technologies could be achieved [9]. There has therefore been increasing interest in using spatially and temporally explicit models to examine systems with higher shares of renewables in greater detail (e.g. [10]). While energy system models are one approach to generating scenarios, there are two main approaches for managing them: one where a small set of (often narrative) scenarios are carefully crafted [11], and the other, where a large number of scenarios are generated computationally and analyzed for salient features. Examples of the latter approach are the Modeling to Generate Alternatives method [12] or the scenario discovery methods developed at RAND [13].

Here, we investigate the three contrasting objectives for the future UK energy system: within a common model framework, how well does a future power system based on different combinations of technologies work in terms if its total system cost, its greenhouse gas emissions, and its energy security? A particular focus is on systems with high shares of wind and solar PV, and approaches, such as storage, to improve the cost and reliability of such systems. This investigation is performed by combining a newly developed cost-optimizing model with high resolution in space and time with the ability to generate and analyze a large number of scenarios. Generation technologies are grouped into three classes: renewables, fossil fuels, and nuclear. The scenarios are grouped by a key narrative (e.g., "deployment of carbon capture and store (CCS)" or "large-scale solar imports"), and within each of these groups, a number of different combinations of the three technology classes are explored. The approach used here improves on existing large-scale energy system models in three ways. First, it goes beyond single representative time slices to a full year of data. Second, it disaggregates the GB power system into 20 zones and considers transmission between the zones. This means that possible transmission bottlenecks as well as the spatial correlation of wind and solar power can be considered. Third, it can run and analyze a large number of models while varying one or a few key parameters, in order to explore the solution space.

The paper proceeds as follows. A literature review section discusses other work with similar aims or methods. It is followed by the description of methods (for more detail on these, also refer to the Supplementary material), and the results. The next section discusses sensitivity analyses as well as weaknesses of and possible improvements to the approach taken here, and is followed by a concluding discussion on the significance of the results obtained.

2. Literature review

The analysis presented here builds on three classes of existing work. The first class consists of large-scale scenarios of the entire energy system, often derived from optimization models, which attempt to describe various feasible energy system transition scenarios under a range of different assumptions. In the UK, the MARKAL model has been for many large-scale modeling exercises in support of the policy process [14], superseded more recently by the TIMES model [4]. These models depict the entire energy system and assess scenarios based on high-level constraints, such as the costs of technologies, or the expected deployment speed and potential. Large-scale scenario models, even when assessing futures with high shares of renewable energy, also must take simplifications to deal with computational tractability and data availability. A common simplification is to match output with demand annually or for a small set of time slices rather than for real (e.g. hourly) time series [15].

The second class is work that models 100% renewable energy systems (but often focusing on electricity only), attempting to complement large-scale analyses from the first class with more detailed considerations of renewable energy's technical feasibility (sometimes leaving aside economic considerations). For example, Connolly et al. [16] shows that a 100% renewable Ireland is technically possible using 1-hourly simulation with the EnergyPLAN model, but does not discuss the costs of this. Likewise, Heide et al. [17] discuss requirements for storage if Europe were to be powered with renewables, using detailed renewable resource data and modeling, but also leaving aside transmission network and economic considerations. Lund and Mathiesen [18] show similarly that a 100% renewable Denmark is physically possible with several caveats, including the necessity of a widely coordinated approach and requiring either large-scale biomass or hydrogen deployment. Costs for an intermediate target in 2030 are considered, but not the 2050 endpoint.

Scenarios from these first two groups of studies disagree significantly on the importance and feasibility of key technology groups such as nuclear power or fossil fuels with CCS. These disagreements are partially driven by differing levels of detail on technical feasibility and partially by how strongly economic considerations are included (e.g. via cost minimization) [19]. The third and final class consists of more recent attempts to synthesize approaches from both previous groups, combining (1) more spatial and temporal detail based on measured or modeled renewable resource data, and (2) modeling these constraints in the context of economic capacity planning.

One of the ways for renewables integration is large-scale storage, and as this is only possible with sufficient temporal detail, it has served as a driver for more detailed models. Budischak et al. [20] evaluate cost-minimal combinations of wind, solar and grid-scale storage for the northeastern United States, which can be considered a similar scale as a single European country. They find that with grid-scale storage of between 9–72 h and 50–60 GW throughput (which is about double the average demand in the studied system), and with renewables generating three times as much as actual demand, it is possible to meet demand 99.9% of the time at costs comparable to today (with assumptions for 2030 technology costs). A different modeling approach is to link different models, taken for example by [21], who discuss a framework which iteratively solves the TIMES long-term optimization model followed the EnergyPLAN short-term operational model to better consider the influence of fluctuating renewables on capacity planning. Using average daily renewable capacity factors and demand data for Portugal, they show that in cases with low storage availability, combining both models led to substantially different installed capacities compared to TIMES on its own. An alternative to storage is increased interconnection to balance meteorological conditions across space. Haller et al. [22] assess a high renewables future by modeling 19 zones across Europe and the possibility for interconnection and storage using a selection of 49 six-hourly time slices, finding that adequately deployed grid extensions and storage technologies enable renewables shares up to about 60% at an electricity cost increase of only 0.8-1.2 Euro-cent/kWh. Huber et al. [23] use the MERRA reanalysis to analyze the variability of solar PV and wind for given installed capacities across Europe, finding that a geographically large power system has lower flexibility requirements, particularly for high penetrations of wind power.

In addition to the two approaches to integrating renewables discussed above (storage and network expansion), supply and demand flexibility is a third important approach, achievable through new technologies such as the smart grid and large-scale demand response. First, overall demand may shift, for example efficiency gains leading to lower total demand. Second, the shape of the demand curve may change, for example due to large-scale demand response [24] or to additional sectors (heating and transport) becoming electrified. Together, these two effects may significantly change the future demand curve. However, it is also well-known that despite negative marginal abatement costs for many efficiency improvements, these measures face non-cost barriers preventing their implementation [25]. The Green Deal in the UK, for example, has not been widely adopted despite the potential cost savings for homeowners. For these reasons, the potential for change in the magnitude or the shape of demand is not further considered in the present work, except in form of a proxy (see Fig. 7). Qualitatively, it is clear that large-scale active demand response would improve renewables-heavy systems in terms of both their reliability and cost [26]. Thus, this study particularly emphasizes the first two options (storage and transmission extensions), as well as considering supply-side flexibility (in the shape of dispatchable solar imports and the use of flexible fossil fuel generation to balance renewables). Finally, all of these approaches benefit from a larger geographic scale (particularly wide-scale transmission interconnections), but the focus here is on the situation in the UK assuming no large-scale European supergrid is in place beyond some possibility for solar imports.

3. Methods

We consider a stylized space of combinations between nuclear, fossil fuels and renewables, and examine combinations of these with respect to their levelized costs, emissions intensity, and energy security. The fossil fuel group represents a mix of baseload (coal), mid-merit (combined-cycle gas turbine) and peaking (open cycle gas turbine) plants, which are the current backbone of the power system. Renewables encompass onshore and offshore wind, rooftop and large-scale solar PV, tidal range and stream, as well as the existing capacity of hydropower (pumped storage is considered a storage technology and is not grouped with renewable generation). Finally, nuclear is often seen as a potential large-scale source of low-carbon electricity. The mix of generated electricity in the UK in 2013 was about 61.2% fossil fuels, 13.2% renewables, and 23.9% nuclear, with 1.8% of other sources [27]. The potential contribution of bioenergy, including co-firing in fossil plants, is not taken into consideration in this stylized set of technologies, because the barriers for this technology's deployment appear more substantial than for other technologies. While PV and wind power are already being deployed at a large scale, the availability of large-scale bioenergy in the UK is less certain; there is a large number of competing technologies and the market potential of any of them is uncertain. There is also a need for further technology development, and questions of land use and environmental impact [28]. The exclusion of bioenergy can be considered a conservative assumption: it would act as a dispatchable technology (or even a storage technology) for balancing purposes, thus reducing the system costs of high renewables penetrations. One of the scenario groups (A4, see Table 1) uses the potential large-scale tidal power deployment to examine the effect of a renewable power source both domestic and dispatchable.

Table 1
Main scenario groups considered. For all scenarios the currently installed UK-EU interconnector capacity and currently installed UK grid is assumed, except where otherwise noted. The interconnector capacity is not included in computing the share of renewables, fossils and nuclear.

Scenario	Description
A1	Wind and solar deployment with current grid
A2	A1 + Significant grid expansion
A3	A1 + CCS deployed
A4	A1 + Tidal stream and range deployed
A5	A1 + Large-scale solar imports
A6	A1 + Grid-scale storage
B1-6	All A scenario groups, permitting up to 5% unmet demand
C1-5	For each A scenario group, take the 90% renewable and no nuclear case from the parameter space, and allow grid-scale storage deployment with a range of grid-scale storage costs (here, C1 and C6 are identical, so C6 is left out)
D1-6	For each A scenario group, take the 90% renewable and no nuclear case, and perform a set of cost sensitivity runs
E1-6	For each A scenario group, take the 50% renewable and no nuclear case, and perform a set of cost sensitivity runs
F5	For A5, run a range of allowed solar import capacities

The results are obtained with the Calliope tool, a linear programming framework for spatial–temporal energy system optimization. Calliope is designed from the ground up to address several perceived shortcomings in existing energy system models by focusing on spatial and temporal explicitness, openness and transparency, and the ability to compute and compare a large number of scenarios [9]. The objective function is to minimize system cost, which results in the most techno-economically feasible system given the provided constraints. All model equations and their implementation are described in detail in the model documentation [29], and more detail on the modeling approach is given in the Supplementary material. As shown in Fig. 1, the spatial resolution of the model is 20 zones, based on the National Grid transmission system [30]. Transmission constraints are derived from published power flows across the boundaries of these zones [31]. The wind and solar resource are modeled based on hourly observations from the NASA MERRA reanalysis [32], whose gridded data are aggregated to the 20 model zones. The wind resource is modeled with the Virtual Wind Farm model described in Staffell and Green [33], by extrapolating MERRA wind speeds to a hub height of 80 m and using the aggregated power curves of the five most common turbine models in the UK. This yields an average load factor of 31.2%, which is higher than the UK's historic average of 27.7% because of the higher proportion of offshore zones. The solar resource is modeled based on Ridley et al. [34] and Huld et al. [35], and validated on a monthly basis against PVGIS outputs for selected sites [36]. Rooftop and large-scale PV are treated separately, with large-scale PV having slightly higher efficiency, and assuming 1-axis tracking. Hydro power plants, as well as tidal range and stream, are assumed as always available (a simplifying assumption, but realistic for tidal range systems with two linked pools). In order to decrease computational complexity, the model time resolution is reduced from 8784 to 550 time steps, with a method that keeps important days of low wind availability at hourly resolution, resampling the rest of the time series to daily resolution. More detail on the methods and assumptions described above can be found in the Supplementary material.

Fossil and nuclear technology costs are derived from DECC data for *n*th of a kind plants [37] or for plants commissioned after 2025 such as tidal range and stream or CCS plants [38]. Renewable energy costs are for plants commissioned in 2020 [38]. Both the resource and cost data for desert solar imports are as described in Pfenninger et al. [39]. Component cost estimates for grid-scale storage technologies are taken from Budischak et al. [20]. Cost

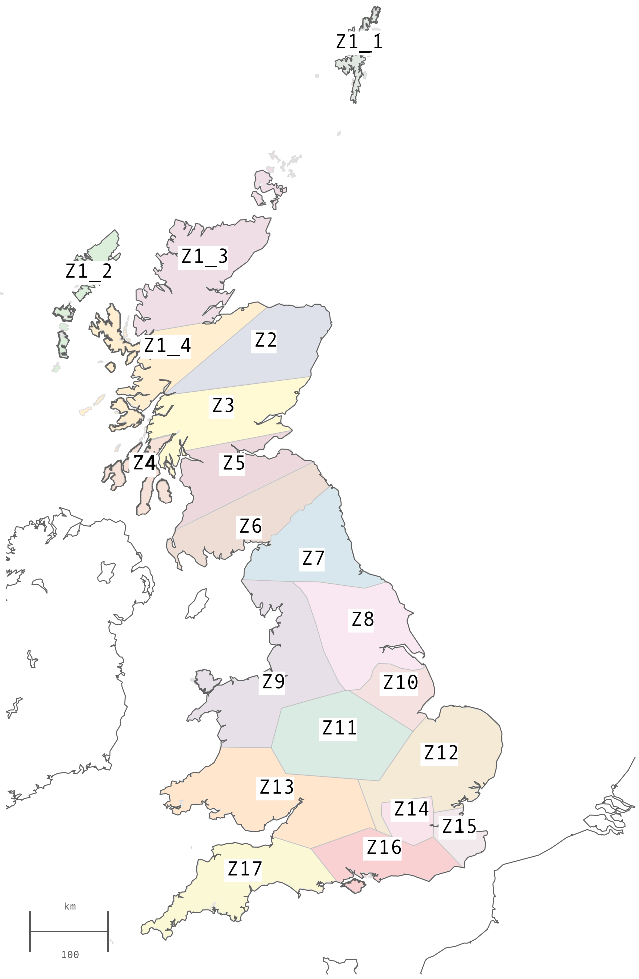

Fig. 1. Aggregation zones used, showing the model's aggregated spatial resolution (colors are used to visually differentiate neighboring zones). See the Supplementary material for more detail on how underlying data was aggregated to the model zones. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

uncertainties are discussed in the results section. Demand data for Great Britain are acquired from National Grid and disaggregated into the model zones. For the results reported here, the year 2012 is used for all time series (demand, wind and solar power). Life-cycle emissions for generation technologies are from IPCC [40], for the Great Britain transmission system from Harrison et al. [41] and Arvesen et al. [42]. In these data, the life-cycle emissions for renewable and nuclear technologies are much below 50 g CO_2e per kWh, but fossil fuels with CCS are above 100 g CO_2e per kWh. This is consistent with assessments of the CCS potential for the UK [43]. Natural gas in particular may have higher emissions from extraction than assumed so far [44], so assigning higher emissions to CCS technologies than to renewable ones appears justified. All cost and emissions data are tabulated in the Supplementary materials.

First, the model is validated for a 2012 system where all plant dimensions are fixed, i.e., capacity commissioning is exogenous, to verify that the model makes realistic aggregate dispatch decisions. Assumptions used for the 2012 model are described in the Supplementary material. The 2012 model computes a value for overall levelized cost of about 4 pence/kWh. In comparison, the average day-ahead price on the APX exchange in 2013 was about 5 pence/kWh [45]. The wholesale electricity price for extra large consumers was between 8 and 9 pence/kWh in 2013 [46], and according to Ofgem, the supply cost and profit margin is about 60% of this [47], again leading to about 5 pence/kWh. Given that distribution costs are (unlike transmission costs) not considered in the model, the slightly lower estimate of 4 pence/kWh can be considered as falling within the range of actual costs.

For the scenarios reported on in this paper, capacity commissioning is endogenous to the optimization model, unlike in the 2012 base case. However, it is still constrained by the high-level technology group fractions and the availability of individual technologies as specified by the scenario. Table 1 gives an overview of the scenario groups examined. The A group of scenarios consists of a series of individual model runs, where the constraint for the fraction of installed capacity of the three technology groups is varied between 0% and 100% in different combinations. This is repeated in the B group, but allowing up to 5% of demand to go unmet. As the optimization considers an full year of data, significant overcapacity is automatically built by the model in order to satisfy all combinations of power supply and demand in cases with high renewable shares. In addition, a constraint requiring 10% of the generation capacity to go unused while demand is at its peak adds an additional safety margin of reserve capacity.

The C group of scenarios takes one point from this parameter space (90% renewable, 10% fossil), and performs model runs across a range of grid-scale storage costs (spanning two orders of magnitude) to discover the importance of affordable grid-scale storage for each of the scenario groups. For each individual model run, an ex-post analysis computes system-wide levelized cost of electricity and emissions intensity. The system-wide monetary cost is composed of both the annualized construction and operational costs for all technologies in the system, including generation, transmission and storage, thus giving an estimate of a system's total cost. Diversity of supply is estimated via the Shannon index [48] as a measure of energy security by diversification. The import dependence of the system is assigned a score based on individual technologies being rated 0 (fully imported), 0.5 (imported fuel but domestic power plants), or 1 (fully domestic), with the overall indicator weighted by the contribution of each technology. All of these metrics are then aggregated to highlight differences between the individual model runs within a scenario group.

4. Results

Results for the system-wide levelized cost of electricity (LCOE) from the A group of scenarios are shown in Fig. 2. One thing is immediately apparent: for a large range of combinations between renewables, nuclear and fossils, the costs are essentially the same as they are for today's system. Only for the scenarios with renewables above 70% of installed capacity do costs start rising above 0.10 GBP/kWh, and only for 90% and 100% renewables do the costs go significantly beyond that figure. Table 2 shows the installed generation capacities for the case of 80% renewables, 20% fossils and no nuclear, for the scenario groups A1–A6. In addition, Figs. 3 and 4 show the installed capacity in the individual model regions, for two scenarios (expanded transmission and solar imports).

Looking at emissions, there are no surprises either: the higher the use of fossil fuels, the higher the system-wide emissions (Fig. 5). Fossil fuels coupled with CCS significantly reduce emissions from fossil-heavy cases. CCS-based systems with a heavy reliance on fossil fuels do retain similar emissions intensity to systems with relatively high renewables shares and non-CCS fossil contributions. This stems partially from the fact that open cycle gas turbine (peaking) plants are assumed not to have CCS fitted, as well as the emissions intensity for CCS-fitted plants, which remains above 100 g CO_2e/kWh.

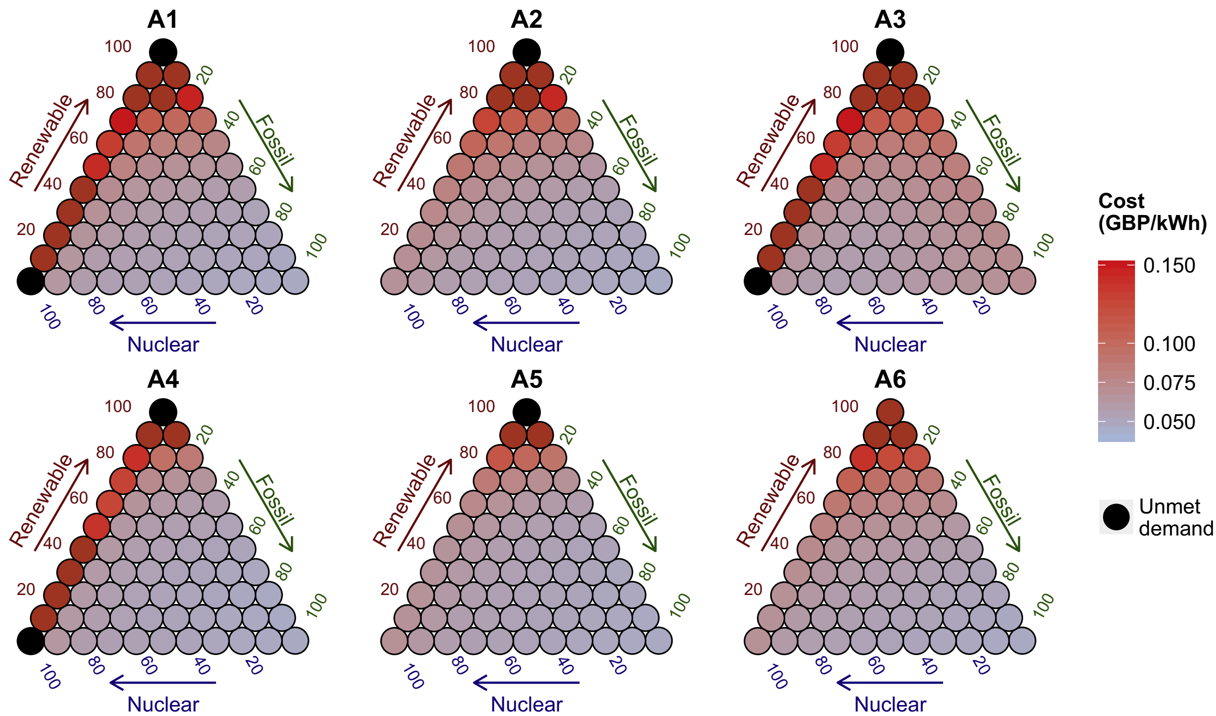

Fig. 2. System-wide levelized cost of electricity for scenarios A as ternary graphs. Costs above 0.15 GBP/kWh are shaded in dark red (●). Cases where the model setup makes it infeasible to meet all demand are highlighted in black. For the 100% renewables case, this happens because the currently available pumped storage capacity is insufficient to cover demand during some periods (e.g. with low wind). For the 100% nuclear case, this happens because no nuclear plants may exist in central London and the two zones immediately south of London, as well as the three northernmost Scottish zones, and the existing transmission limits are reached in some peak demand hours. Some scenarios with combinations of nuclear and renewables have some unmet demand, but always less than 0.05% of total demand. They are thus not marked as infeasible. Their high cost in scenarios A1, A3 and A4 is explained by the lack of either dispatchable generation, sufficient transmission, or storage in London and the South in those scenarios. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Table 2
Installed generation technology capacities (GW) for 80% renewables and no nuclear, for scenario groups A1-6 (all technologies deployed in the UK, with the exception of CSP for import, which is also accompanied by necessary transmission lines not shown in the table).

	A1	A2	A3	A4	A5	A6
Grid-scale batteries	–	–	–	–	–	12.51
CCGT	23.33	26.19	–	13.46	15.07	12.35
CCGT with CCS	–	–	29.71	–	–	–
Coal	6.94	–	–	–	–	8.89
Coal (ASC/FGD) with CCS	–	–	0.56	–	–	–
CSP solar import	–	–	–	–	20.58	–
HVDC import	5.00	5.00	5.00	5.00	5.00	5.00
Hydro	1.10	1.10	1.10	0.12	1.10	1.10
Nuclear	–	–	–	–	–	–
OCGT	14.38	18.52	14.38	10.75	12.25	11.78
Pumped storage	2.74	2.74	2.74	2.74	2.74	2.74
Large-scale PV	24.59	24.59	24.59	24.59	24.59	24.59
Rooftop PV	61.06	61.06	61.06	19.89	27.75	46.91
Tidal range	–	–	–	7.60	–	–
Tidal stream (deep)	–	–	–	15.01	–	–
Unmet power dummy supply	–	–	–	–	–	–
Offshore wind	7.89	8.13	7.89	–	–	2.95
Onshore wind	84.00	84.00	84.00	29.62	35.27	56.55

Fig. 6 shows the Shannon index for the different scenarios. A diversity index of 0 indicates perfect concentration, i.e. a single technology supplying all electricity. As the fossil fuel group contains two fuels (gas and coal), the Shannon index for highly nuclear-dependent scenarios is worse than for highly fossil fuel dependent ones. The highest (most diverse) Shannon index is in the region of about 60% renewables, 20% nuclear and 20% fossil, as this results in the most diverse generation mix. Scenarios with very high shares of renewables are relatively more diverse than ones with very high shares of the two other technologies.

Another aspect of energy security is the overall reliability of a system. The difficulty of achieving high reliability is determined as follows. The set of scenarios B has the exact same constraints as A, except that up to 5% of demand can go unmet at a very low cost (0.01 GBP/kWh). For each individual model run, the reduction in system-wide LCOE from A to B can be seen as an indicator of how easily system reliability can be maintained in that scenario. A large cost difference implies that allowing 5% of demand to go unmet makes it significantly easier to design a system that meets all constraints. In other words, the cost of the final 5% reliability may be high (reliability is difficult to achieve) or low (reliability is easy to achieve). Fig. 7 highlights those cases where this relaxation of constraints leads to system-wide a LCOE more than 25% and more than 50% lower than in scenarios A. Although the potential for demand response is not explicitly considered in the present work, this indicator could also be seen as a proxy for the usefulness of demand response or flexible demand in different scenarios, and demonstrates that scenarios with high shares of renewables would particularly benefit from such measures.

The import dependence of the various technology options is measured by the domesticity score: 0 for imported electricity, 0.5 for imported fuel to generate electricity, 1 for domestic production and fuel (see Fig. 8). By this measure, scenarios moving towards 100% renewables move towards a system-wide domesticity score of almost 1, whereas both nuclear and fossil-heavy scenarios move towards 0.5. The lowest scores of around 0.3 are for model runs combining renewables with desert solar import and fossils or nuclear. However even in the desert solar import scenario group, the 90% renewable cases achieve a score of almost 0.7.

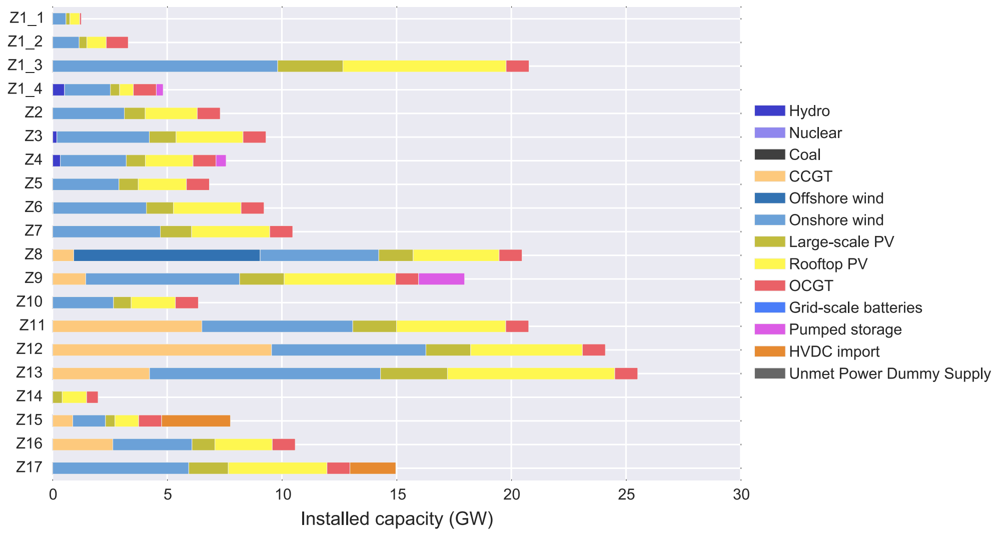

Fig. 3. Installed generation technology capacities (GW) for 80% renewables and no nuclear, for scenario A2 (new transmission).

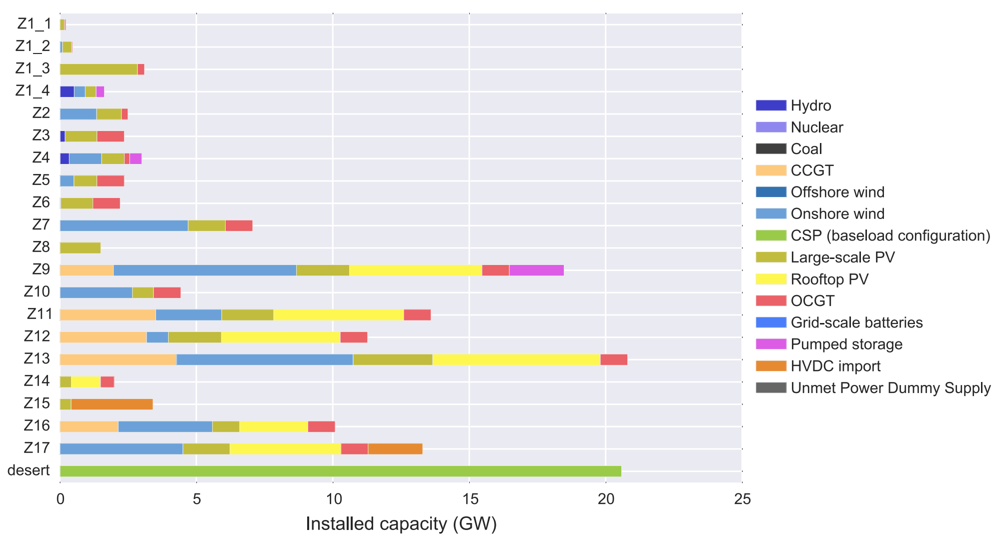

Fig. 4. Installed generation technology capacities (GW) for 80% renewables and no nuclear, for scenario A5 (solar imports).

Storage is considered a key element to enable higher renewables penetration. A generic grid-scale battery technology with a fixed cost of 42 GBP/kW charge/discharge capacity cost is used to examine its effect. As can be seen in Fig. 9, the availability of even expensive (above 350 GBP/kWh storage capacity) grid-scale storage significantly lowers the LCOE for scenario groups 1, 2 and 3. This cost decrease proceeds linearly until around 75 GBP/kWh, after which further cost reductions have a much stronger effect. This suggests that with grid-scale storage capacity at costs much below 75 GBP/kW, a combination of wind and solar with no other technologies moves within the realm of feasibility even without much interconnection outside the UK. Research into storage technologies is ongoing, although storage capacity cost estimates for technologies at the commercial or demonstration stage are in the upper range of the costs considered here [49]. Notably, scenario groups 4 and 5 see only a moderate cost reduction even with storage capacity costs below 75 GBP/kWh. This demonstrates the importance of either a baseload-capable technology (which is how we assume tidal power operates) or larger-scale geographic interconnection (of which the desert solar import can be seen as a proxy) in the absence of sufficiently cheap storage. Given the hourly resolution, these results cannot consider shorter-term balancing for which storage may be additionally relevant in scenarios with higher renewables shares.

5. Sensitivity analysis and possible improvements

Finally, there are many assumptions in the model considered here that may have considerable impact on the distribution of results. Three cost uncertainties shall be considered: the cost of gas, the cost of CCS, and the cost of solar PV. While the prediction of technology costs generally is fraught with difficulties, these three costs in particular have the potential to both fluctuate and are often seen as key costs for the economic viability of future energy systems. Fig. 10 shows final system-wide LCOE for the case of 90% renewables and 10% fossils, for default, low, and high cost scenarios. The low cost scenario assumed half the cost of the default, and the high cost scenario double the cost. The figure shows that, since most capacity is renewable, changes to the cost of gas or CCS have little or no effect, while changes to the cost of solar PV significantly affect the overall system LCOE. In contrast,

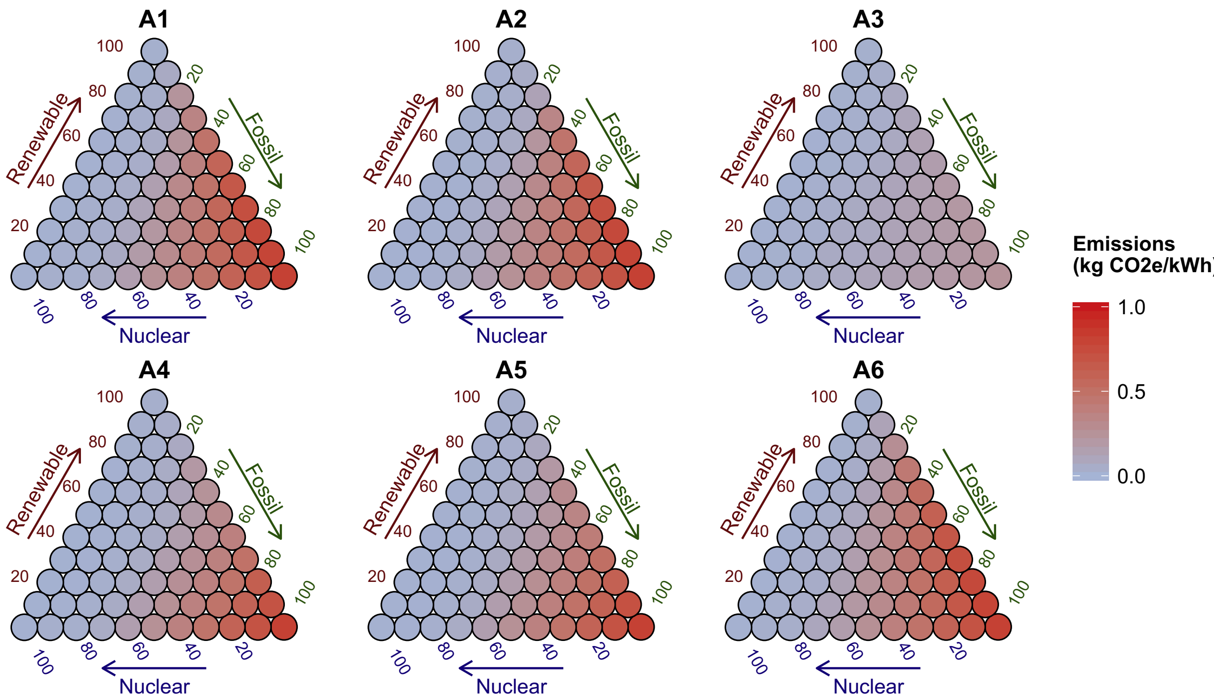

Fig. 5. System-wide emissions intensity from scenarios A as ternary graphs.

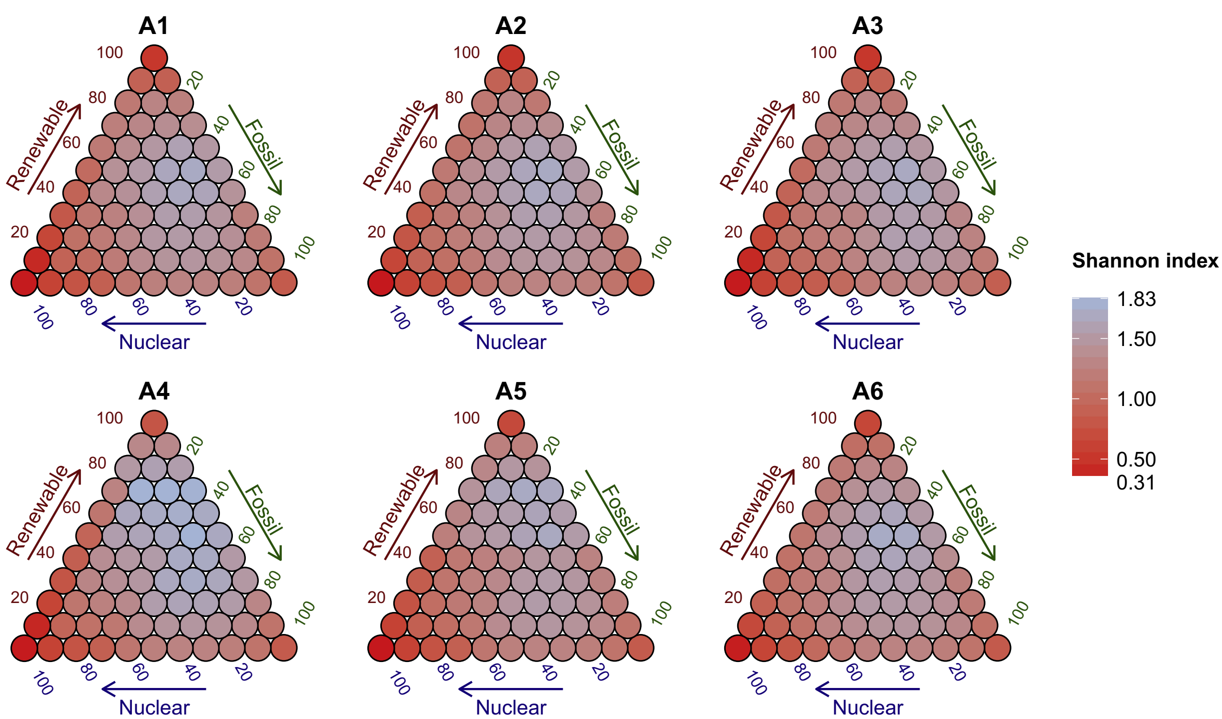

Fig. 6. System-wide diversity (Shannon index) from scenarios A as ternary graphs.

Fig. 11 shows the same scenarios for the case of 50% renewables and 50% fossils. Here, the effect of gas prices (in all scenario groups) and CCS prices (in the CCS scenario group 3) are apparent. The effect of CCS costs on the CCS deployment scenario is significant, but not so gas.

In addition, the degree of dependence on imported electricity (here modeled as desert solar, but this may be other renewable or non-renewable sources from European countries) may be determined more by political and social acceptability than by techno-economic considerations. Table 3 shows, for the case of 90% renewables and 10% fossils, the system-wide LCOE in the case of scenario A5 for a range of maximum deployment of imports (the base case is 30 GW). Even lesser amounts of solar imports result in substantial reductions of the overall LCOE, whereas (for the base model configuration and costs) the installed capacity does not exceed 20 GW even if the constraint is higher.

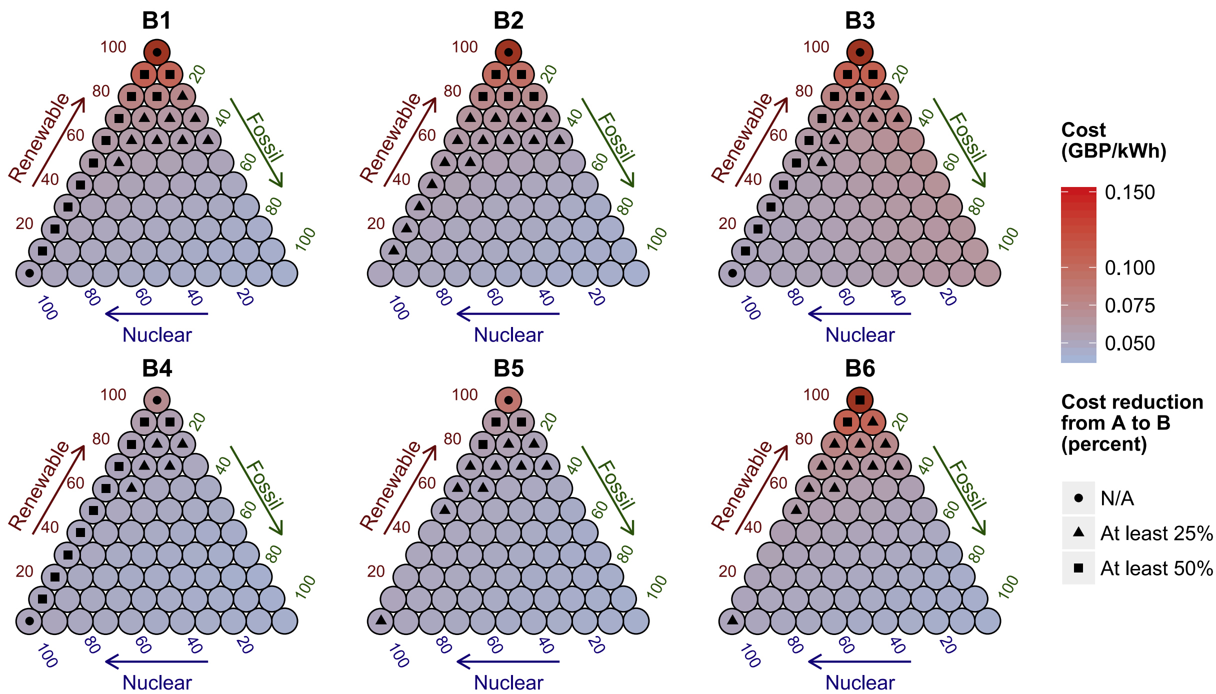

Fig. 7. System-wide levelized cost of electricity for scenarios B. Those runs where the LCOE in the B scenario is more than 25% or more than 50% lower than in the A scenario are marked. For the cases where the A scenario cannot meet all demand, a cost reduction was not calculated (marked N/A).

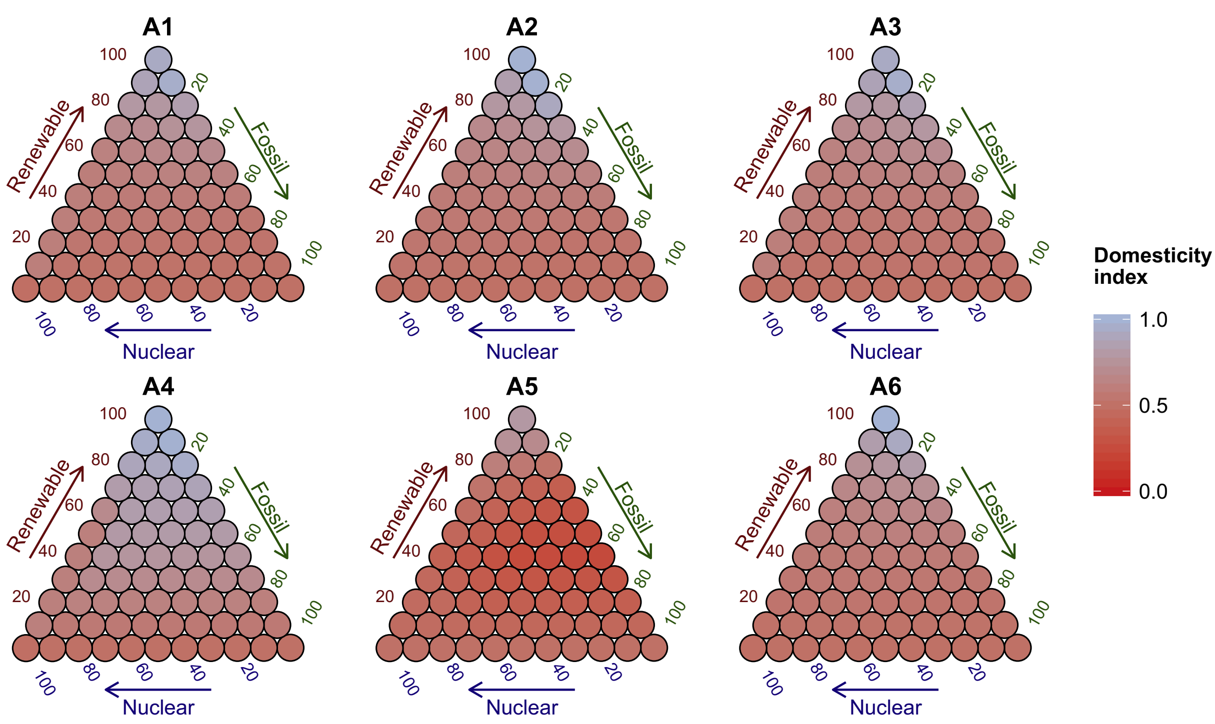

Fig. 8. Import dependence from scenarios A as ternary graphs (see text for explanation).

The current analysis has some limitations that could be improved in future work. First, only power is considered, yet it has been shown that integration (particularly of heat and power) can result in synergies and thus more stable or cost-effective systems [50]. Second, the current work was based on 2012 renewable resource data, but examining longer time series ideally spanning several decades will strengthen the insights, especially regarding the contributions of renewables [51]. Furthermore, the methods used to develop wind and solar resource potentials can be improved, in particular to capture extreme events more precisely. Third, the approach used to reduce the resolution of input data rather than choosing representative time slices means that, while it is able to represent the spatial and temporal correlation of PV, wind and demand, the method is computationally very intensive and needs a large computing cluster to run many scenarios within a reasonable time frame. More work on better selecting

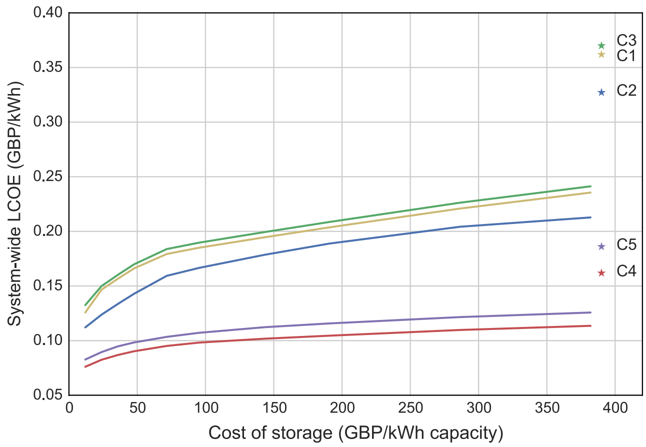

Fig. 9. System-wide LCOE for different costs of grid-scale storage, for scenarios C (with 90% renewables, 10% fossils, no nuclear). The points plotted as stars (★) are the cost from scenario group A for the respective scenario number, showing the LCOE without any grid-scale storage. C1: Wind and solar deployment with current grid, C2: C1 + Significant grid expansion, C3: C1 + CCS deployed, C4: C1 + Tidal stream and range deployed, C5: C1 + Large-scale solar imports.

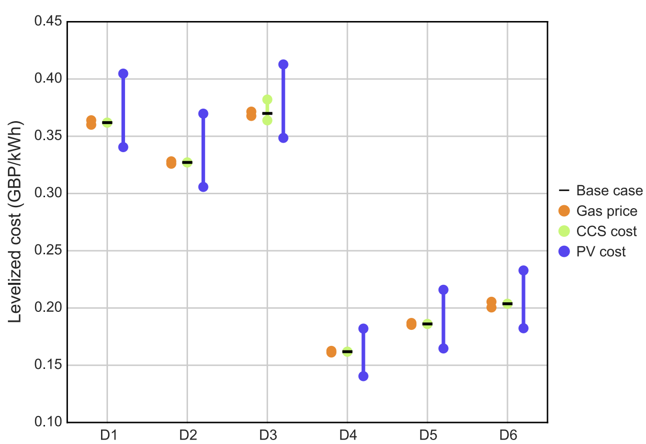

Fig. 10. LCOE (GBP/kWh) in the case of 90% renewables and 10% fossils under a range of cost sensitivities.

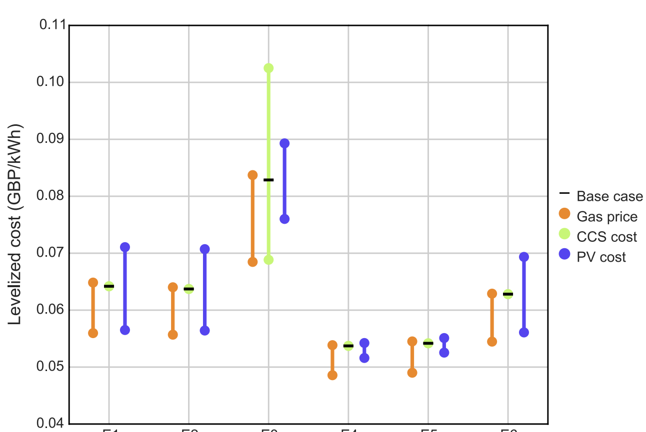

Fig. 11. LCOE (GBP/kWh) in the case of 50% renewables and 50% fossils under a range of cost sensitivities.

representative days (or longer periods of time), as also argued for example by Ludig et al. [52], will improve the computational tractability of the models used here while retaining the detail necessary to model a system heavily dependent on fluctuating renewables. Forth, and finally, the cost optimization method itself have been criticized for a variety of reasons, ranging from disagreements cost assumptions to ethical arguments for rejecting costs entirely as a metric [53]. However, cost optimizing models remain a powerful tool to structure the analysis of complex technical systems such as the energy sector. In the work presented here, instead of finding a global optimum, a large number of (individually optimal) scenarios are compared. The approach allows the formulation, solution, and analysis of a very large number of individual models differing in only a few key parameters, allowing new insight into the trade-offs between technologies within one consistent modeling framework. More work on improving the use of cost-optimizing models is still possible, however, as demonstrated by other recent work using an optimization model to generate maximally different scenarios within a certain distance to optimal solutions [54].

6. Discussion and conclusion

This work makes use of a novel combination of high-resolution renewable resource and electricity demand data with a national-scale energy systems model. It analyzes a wide range of scenarios by re-solving the same model many times with changed parameters in order to explore the decision space. The results show that fundamentally, a wide variety of systems are equally feasible. Feasibility here is measured by levelized cost, which within the framework of a specific optimization model can be seen as a measure of how easy or hard it is to construct a system that fulfills all the given requirements. Figs. 2–6 show how similar the levelized cost, emissions, and diversity of supply results are across the fuel mix space for a range of scenarios. There are important exceptions: very high shares of renewables deliver very low emissions but require at least some effort towards additional interconnections, substantial storage capabilities, or the development of new resources such as tidal range and stream power. The results therefore suggest that, using current technologies, renewable shares up to about 80% are possible without significant cost increases, but to go beyond that, improved technologies (either for dispatchable supply or for storage) and/or significantly increased interconnection and imports from beyond the UK are necessary.

The possibility for additional technological change and radical cost reductions for some technologies could change the landscape laid out here [55]. However, since the results show that even with the conservative cost assumptions used, achieving renewables shares above 80% is feasible from a cost perspective and from a technical perspective to the degree that hourly data can demonstrate this, an increased build of renewables should not be dismissed outright on either of these grounds. In any case, the weighting of different objectives – cost, energy security, emissions – will determine what mix of technologies appears more favorable. That weighting is not the subject of the analysis presented here. In addition, these trade-offs are fraught with issues that are ill captured by aggregate indicators such as system-wide costs or energy security indices. For example, despite the fact that electricity cannot easily be stored for longer periods, Lilliestam and Ellenbeck [56] have argued that Europe is not significantly vulnerable to a deliberate interruption of electricity exports. Yet the public may be particularly concerned with import dependence [57]. Other important issues, like electricity prices, or household energy poverty, are not addressed by the modeling approach used here. In order to make choices from the range of scenarios presented here, therefore, additional data on decision preferences, as well as other analyses connecting these high-level results to bottom-up effects, would be necessary.

Table 3
Results from desert solar import sensitivity analysis.

Max. desert solar import capacity (GW)	LCOE (GBP/kWh)	Deployed solar capacity (GW)
3	0.33	3.00
8	0.28	7.50
15	0.21	15.00
30	0.19	20.53

The results may suggest that no clear direction is needed for the energy sector, as a wide range of combinations appear similarly feasible. Despite this broad feasibility of very different strategies examined, a "no clear direction" energy policy is untenable for several reasons. First, it likely means that decisions about deep decarbonization are deferred to a later date, which is counterproductive from the perspective of climate change mitigation [58]. Second, frequent policy changes and many possible solutions create deep uncertainty for investors, for whom the most reasonable approach then is to wait and follow minimum requirements rather than to actively seek out financing opportunities for alternative technologies at a large scale. Finally, many of the technological options come with drawbacks or caveats, for example, the large-scale deployment of wind farms results in disagreements over its resulting effect on landscapes. Thus these options need early consultation and buy-in from a broad range of societal actors, a process that takes time and effort. A "no clear direction" policy does not send a strong message to investors, and later changes in focus may leave them with stranded assets. This is why instead, an "all of the above" policy approach is necessary: a policy built on clear framing of goals and conscious choice to support investment into a specified set of options, for a minimum duration of time. It is important to create a transparent framework so that whichever system is desired is actually built. Only clarity on goals can result in the participation and buy-in of government actors, market actors, and civil society actors, all of which are necessary for a successful energy system transformation.

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Appendix A. Supplementary material

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.apenergy.2015.04.102.

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