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Low carbon electricity systems for Great Britain in 2050: An energy-land-water perspective

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HIGHLIGHTS

- We assess how land and water constraints shape Great Britain's 2050 power system.
- We consider restrictions on nuclear/renewables siting and water for cooling.
- Combined these lead to an up to 25% more costly electricity system.
- Such constraints impact the system design both spatially and technologically.
- The cost optimal share of renewable generation is found to be at least 50%.

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ABSTRACT

The decarbonisation of the power sector is key to achieving the Paris Agreement goal of limiting global mean surface temperature rise to well below 2 °C. This will require rapid, national level transitions to low carbon electricity generation, such as variable renewables (VRE), nuclear and fossil fuels with carbon capture and storage, across the world. At the same time it is essential that future power systems are sustainable in the wider sense and thus respect social, environmental and technical limitations. Here we develop an energy-land-water nexus modelling framework and use it to perform a scenario analysis with the aim of understanding the planning and operational implications of these constraints on Great Britain's (GB) power system in 2050. We consider plausible scenarios for limits on installed nuclear capacity, siting restrictions that shape VRE deployment and water use for thermal power station cooling. We find that these factors combined can lead to up to a 25% increase in the system's levelised cost of electricity (LCOE). VRE siting restrictions can result in an up to 13% increase in system LCOE as the deployment of onshore wind is limited while nuclear capacity restrictions can drive an up to 17% greater LCOE. We also show that such real-world limitations can cause substantial changes in system design both in terms of the spatial pattern of where generators are located and the capacity mix of the system. Thus we demonstrate the large impact simultaneously considering a set of nexus factors can have on future GB power systems. Finally, given our plausible assumptions about key energy-land-water restrictions and emission limits effecting the GB power system in 2050, the cost optimal penetration of VREs is found to be at least 50%.

1. Introduction

Limiting global mean surface temperature rise to well below 2 °C above pre-industrial levels, the headline goal of the UNFCCC Paris Agreement, will require large scale changes to energy systems across the world, transitioning from carbon intensive today to 'net-zero' emissions before 2100 [1]. At the same time as achieving deep cuts in greenhouse gas (GHG) emissions, these national level energy system transitions must simultaneously address the other two pillars of the so-called energy trilemma by keeping overall costs as low as possible and enhancing and maintaining energy security. In this context, energy system optimisation models (ESOM), which capture a simplified representation of this complex problem, are often used to support and guide national and international policy making. These stylised models optimise the planning and operation of the energy system over a particular time horizon by minimising total costs under technology, emissions and policy constraints.

Long time horizon national whole energy system models such as the

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National Energy Modeling System [2] and UK TIMES (UKTM; [3]) are used to conduct scenario analyses which explore possible decarbonisation pathways to meet policy objectives and are particularly relevant given the bottom-up, Nationally Determined Contribution framing of The Paris Agreement. A common theme emerging from such scenarios (e.g. see Fais et al. [4]) is that the electricity sector will lead the decarbonisation charge, as it is already beginning to do, owing to its comparatively low marginal abate costs and that, in conjunction with the electrification of heat and transport, demand for electricity will grow in future, despite an overall increase in system efficiency. At present, key low carbon generation technologies that can support such a transition take three main forms: variable renewables (VRE) such as solar photovoltaics (PV) and wind, nuclear power and fossil generation with carbon capture and storage (CCS), which is considerably less proven at scale and thus has a more uncertain role going forward. It is this sector and these technology classes that will be the focus of this study.

While the aforementioned trilemma encapsulates three of the principle objectives of energy system transitions, these are by no means the only factors that guide the design of future low carbon energy infrastructure. With this in mind, for some time now a need has been identified to move beyond the trilemma to consider how the planning and operation of such systems will likely have implications for the wider coupled social, economic and environmental system in terms of a nexus of energy, land and water [5–7]. This natural resource viewpoint helps to add context to low carbon transitions and allows an assessment of their broader feasibility and impacts. For instance, future power systems could feature substantial amounts of fossil generation with CCS which rely on water for their cooling and have abstraction requirements significantly beyond that of their none CCS counter parts. If this extra abstraction is to be met by freshwater it must be considered simultaneously with increasing pressure from population growth and climate change [8]. Furthermore, solar and wind have seen substantial cost reductions globally in recent decades making them attractive options going forward, yet their scale, visibility, and infrastructure requirements mean that specific projects often face significant opposition due to a range of social, environmental and technical factors. For example, Höltinger et al. [9] found that Austria's physical onshore wind resource potential is reduced by over 95% when taking into account the multi-aspect criteria which can inhibit its deployment. Indeed, nuclear too can experience multifaceted issues around its siting for various, often quite different, reasons [10]. Therefore, all three of the key generation technology classes considered here have non-cost restrictions that will very likely shape their deployment in future and as a result could have a sizable impact on system costs and design.

To understand this complex problem, studies have taken various modelling approaches (for a full review of methods and tools see Dai et al. [11]). Some teams have brought together and integrated a number of models to form a nexus focused modelling framework with examples including the Climate, Land, Energy and Water Systems (CLEWS) framework [12,13] or the PRIMA model [14]. Other studies have integrated water directly into a sub-national [15], national [16] or regional [17] ESOM, thus forming a hard-link and allowing them to optimise the electricity system and its usage of water at the same time. On the land side, efforts have concentrated on bioenergy production and its interaction with the food system (e.g. [18,19]) while other papers have included siting limitations during the calculation of wind energy potentials [9,20,21] and both solar and wind in an ESOM [22]. From a UK perspective, studies investigating restrictions on water resources have typically taken pre-existing energy/electricity system scenarios and sought to estimate their footprints in terms of cooling [23–27]. Only very recently has cooling water availability been integrated into an ESOM and allowed to endogenously influence power system design Murrant et al. [28]. UK modelling studies addressing land-energy interactions have looked at bioenergy (e.g. [18,29]) and included constraints on the siting of wind turbines [30]. Work which has captured both resources (e.g. [25]) has focused on an analysis of pre-existing scenarios. None of these studies have simultaneously considered the implications of land and water availability, and its geographic detail, on the design of future low carbon electricity systems while at the same time modelling both key VREs, i.e. solar PV and wind, at a high spatiotemporal resolution.

Unlike conventional sources of generation, VREs possess significant spatiotemporal variability because of their dependence on weather. Studies have demonstrated the impact that low temporal [31] and spatial resolution [32] can have on results from ESOMs when modelling systems with significant renewable shares. To capture how important renewable sources such as solar and wind interact with the rest of the electricity system, e.g. dispatchable generation, electricity storage and the transmission network, studies have resorted to three key approaches. Firstly, efforts have been made to increase their temporal and spatial resolution (e.g. [32–34]). Secondly, separate system planning (capacity expansion) and detailed operational dispatch models have been integrated together, either in the form of a uni-directional (e.g. [35]) or bi-directional, iterative (e.g. [36]) link. Thirdly, recently a number of studies have used hybrid high spatial and temporal resolution ESOMs that simultaneously make investment and hourly operational decisions for a single "snapshot" year at a time (e.g. [22,37,38]). A key advantage of hybrid models is that both planning and dispatch decisions are made in the same high resolution whole electricity system framework. In addition, their spatiotemporal disaggregation allows them to simultaneously examine the system benefits of different contemporaneous weather conditions in different locations (spatial diversification) and different production profiles for different VRE technologies (technological diversification).

In this paper, and to the best of our knowledge for the first time, we simultaneously consider how constraints on both land-use and water for cooling impact the spatially detailed planning and high resolution operation of low carbon electricity systems consisting of the three key technology classes outlined above. We specifically focus on the cost and system design implications of restrictions on both resources at the same time. To do this we bring together two ESOMs, the high spatial and temporal resolution electricity system model (highRES) and the long time horizon ESOM UKTM, and a nexus tool, Foreseer,[1] and present a case study of potential future configurations of Great Britain's (GB) power system in 2050 taking into account land and water resource limitations. The system is further constrained by the UK's Climate Change Act which mandates an economy wide GHG emissions reduction of 80% relative to 1990 levels by 2050. We frame our land and water resource analysis in the context of the three technology classes outlined above and aim to represent some of the key restrictions that shape the deployment of each technology, i.e. water availability for power station cooling and limitations on the siting of VRE and nuclear. We use UKTM to provide 2050 electricity system boundaries to highRES, a nexus-aware hybrid power system model. A uni-directional soft-link of this kind ensures that the latter model designs scenarios that are consistent with the rest of the energy system, i.e. in terms of the demand met and emissions produced by the electricity system. The land and water constraints in the hybrid model are formulated by integrating methods and data from the nexus tool directly into it. Into this framework we feed a set of scenarios that are intended to span the plausible range of key restrictions that shape the deployment of the three technology classes we consider with the aim of quantifying the potential cost and system design impacts of these constraints.

This paper is structured as follows: in Section 2 we describe the models and methodology used here in more detail, Section 3 provides a thorough discussion of the results and Section 4 summaries the insights emerging from this study.

[1] https://www.foreseer.group.cam.ac.uk/.

2. Methodology

2.1. The models

2.1.1. highRES

highRES is a cost minimising, high spatial and temporal resolution model of Great Britain's (GB) electricity system written in the General Algebraic Modelling System (GAMS) language. It makes capacity investments (based on annualised costs) and operational decisions so that supply > = demand in every hour of the year (8760 time steps), in each of 20 zones that spatially represent Great Britain at least cost. The model optimises the system subject to technical (e.g. the zones are linked by a simplified representation of the high voltage transmission system), emissions, land and water constraints. In terms of low carbon generation it considers three VREs (solar PV – ground and roof mounted are considered one technology, on and offshore wind), nuclear and natural gas combined cycle turbines with CCS (NGCCS). To integrate renewables into the system we model natural gas open cycle turbines (NGOCGT) for fast and flexible response, electricity storage in the form of grid scale Sodium Sulphur batteries (NaS) and reinforcement of the transmission system. The model also incorporates 7.4 GW of interconnection to Europe/Ireland (based on existing and planned links currently under construction), with European electricity pricing taken from Capros [39], whose capacity is fixed in all model runs.

A core aim of highRES is a good representation of renewables and so we use 0.5° by 0.5° (30 km by 50 km) spatially gridded historical weather data (for 2006) to derive hourly time series of renewable capacity factors. Prior to execution the grid cells are aggregated to the zones and hourly zonal average time series for each VRE technology input into highRES. During optimisation the model simultaneously decides on the amount of VRE capacity to deploy in each zone, subject to land-use constraints which reflect the social, environmental and technical limitations on where renewables can be built, and whether to utilise or curtail its production. For non-VRE generation technologies, the model follows the same process with capacity deployment in each zone subject to water availability (NGCCS) and social, environmental and technical capacity limits (nuclear). Like other hybrid ESOMs, highRES is linear to maintain computational tractability and so does not capture typical Unit Commitment constraints like start-up costs. The model includes a simplified representation of system security by requiring a 10% installed capacity margin above annual peak demand with generation options de-rated by their availability (solar PV is not able to contribute to this margin as it is unavailable during peak demand in winter). It is solved by the commercial solver CPLEX. For further details see Zeyringer et al. [40].

2.1.2. UKTM

UKTM is a linear, technology-rich ESOM instantiated within the ETSAP-TIMES framework and describes the whole of the UK's energy system from imports and domestic production, fuel processing and secondary energy carrier supply to end-use technologies [4,41–43]. It minimises total energy system costs to meet exogenously set, but price elastic, demands subject to all specified user constraints (e.g. energy balances, GHG emissions, technology diffusion), in 5 year steps from 2010 (base year) to 2050. A key strength of UKTM is that it represents the whole energy system under a given decarbonisation objective, which means that trade-offs between mitigation efforts in one sector versus another can be explored. It is also solved using CPLEX. In addition to its academic use, UKTM is the main long-term energy system model used for policy analysis at the Committee on Climate Change[2] and the UK Government's Department of Business, Energy and Industrial Strategy[3] (BEIS).

2.1.3. Foreseer

Foreseer is an energy-land-water nexus tool which calculates emissions and other measures of stress in response to user-defined scenarios. The foundation of the tool is a group of linked physical models for these resources and the technologies that transform these resources into final services. Originally developed for California, a UK version has recently been created [25,29]. As detailed in the next section, we integrate the water abstraction methodology used in Foreseer directly into highRES.

2.2. Model linkage

A diagram depicting how the models used in this study are linked is shown in Fig. 1. To provide electricity system boundaries to highRES consistent with a decarbonised energy system we run UKTM constrained to meet the UK's legally binding 80% GHG reduction target by 2050. The latter model designs the optimal low carbon transition from 2010 to 2050 and in doing so determines the relative share of the emission reduction burden taken up by each sector. This gives us an annual electricity system CO_2 emissions budget and electricity demand for the UK in 2050 that is harmonised with the rest of the energy system. These are 2 $MtCO_2$ and 590 TWh which compare with 85 $MtCO_2$ and 357 TWh in 2015 [44].

We remove Northern Ireland's 2015 fractional share from both of these values given that UKTM models the entire UK whereas highRES only represents GB. The annual electricity demand from UKTM is then used to rescale metered hourly electricity demand for 2006 from the National Grid (GB's transmission system operator) to provide an estimate of hourly electricity demand in 2050. We note here that demand profile shape changes are not captured in this process. In addition highRES and UKTM input technology costs for 2050 are harmonised which include up-to-date renewable costs taken from BEIS.[4]

The water accounting methodology used by Foreseer, and discussed in Konadu et al. [25,29] (see also [24]) is integrated into highRES to form a new module. As part of this, NGCCS in highRES is given four possible cooling technologies (once through, evaporative, air and hybrid) that vary in terms of their water abstraction, plant efficiency penalties and costs (see Table 1 for an overview). We use cost and efficiency data from Murrant et al. [28] (hereafter M17b) and allow both fresh and saline water to be used in once through and evaporative cooling, with the latter water type resulting in a higher capital cost cooling system as described in M17b. The water module computes water abstractions per cooling technology in each zone based on updated abstraction coefficients from M17b. This allows investment and operational decisions in highRES to be constrained by water availability at the zonal level. We also leverage the wealth of land-use GIS datasets that are part of Foreseer to construct land availability scenarios which will be discussed in the next section.

As shown in the diagram, outputs from highRES include total system costs, the location and capacity of generation and VRE integration options and land/water use footprints.

2.3. Scenarios

The primary aim of our scenarios is that they span a large, plausible range for the key restrictions that shape the deployment of the three technology classes likely to feature prominently in GB's 2050 power system. With this in mind we now discuss the rationale behind these scenarios.

[2] https://www.theccc.org.uk/wp-content/uploads/2015/11/Committee-on-Climate-Change-Fifth-Carbon-Budget-Report.pdf.

[3] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/651916/BEIS_The_Clean_Growth_online_12.10.17.pdf.

[4] https://www.gov.uk/government/publications/beis-electricity-generation-costs-November-2016.

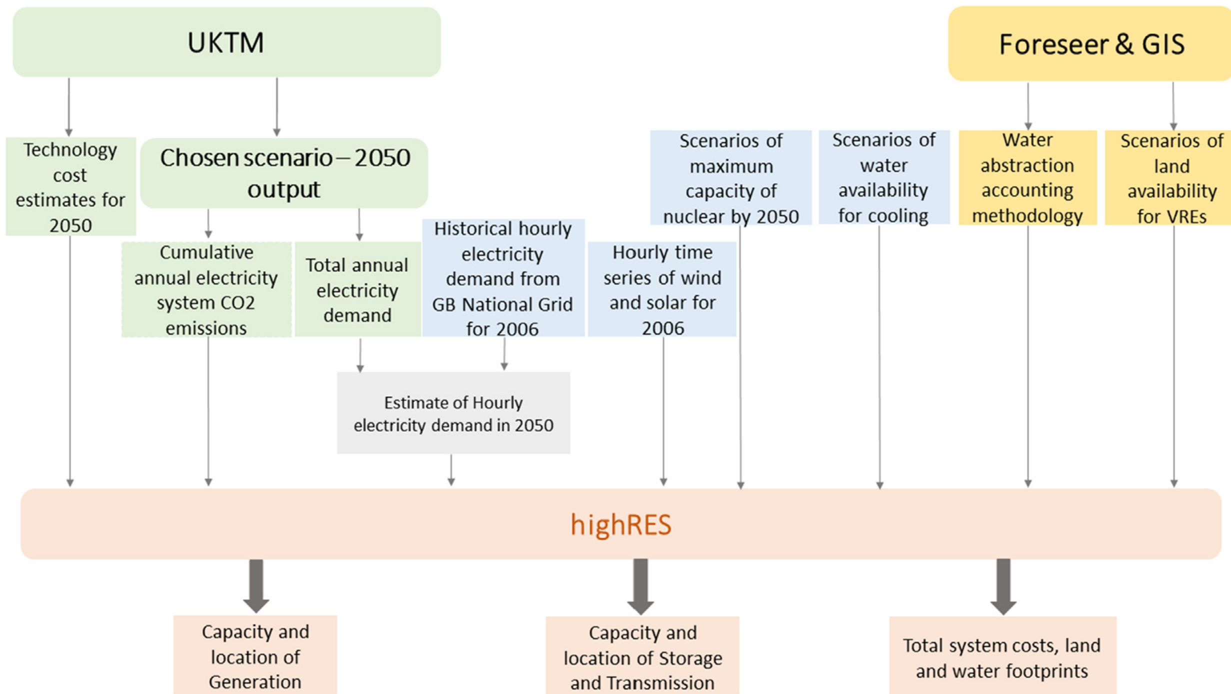

Fig. 1. Model linkage used in this work.

Table 1
The different cooling options considered in this study and their relative characteristics.

Cooling technology	Cooling method	Water abstraction	Capital & variable costs	Energy penalty
Once through (open loop)	Heat is removed by transfer to a running water source (be it fresh or saline)	Highest	Lowest	Lowest
Evaporate (closed loop)	Heat is removed by recirculating water and exposing it to the air via cooling ponds or towers	Intermediate	Intermediate	Intermediate
Air cooling	Heat is removed by air circulation using negligible water	Lowest	Highest	Highest
Hybrid cooling	Heat is removed by towers that can function with or without water	Between evaporate and air	Between evaporate and air	Between evaporate and air

2.3.1. Land for VRE deployment. As touched upon earlier, the availability of land for the deployment of VREs is set by multitude of criteria which here we group into social, environmental and technical issues and construct three levels of severity for each category (low, medium and high restrictions). For each limiting criteria we use GIS datasets to spatially represent and quantify their land-use implications. For instance, we restrict onshore wind from being built too close to settlements, which we classify as a social constraint and intend to capture some of the public acceptance issues around the siting of turbines (e.g. visibility and noise). To do this we use the high resolution CORINE[5] land cover GIS dataset and create an exclusion zone around urban areas which varies in size depending on the restriction level. Similarly, we limit the deployment of ground mounted solar PV on agricultural land based on its classification. The grading, which runs from 1 (highest quality) to 5 (lowest quality), assesses how suitable a parcel of land is for crop production. As such, to prevent highRES from building solar PV on the best crop land we exclude grade 1 in our low restriction scenario and increase this exclusion to grade 1, 2 and 3 for our high restriction, thereby giving a higher priority to crop production. As an example of a technical offshore wind restriction we allow turbines to be deployed up to a maximum depth of 100 m in the low, 80 m in the medium and 60 m in the high restriction scenario. These are just three examples of the extensive set of criteria we use to create our land availability scenarios, further details can be found in the Supplementary Information (SI) of this paper.

Next, for each technology separately, we merge all spatial constraints across all three categories (social, environmental and technical) at a particular restriction level and subtract this from a map of GB (or the UK Renewable Energy Zone for offshore wind) resulting in a map of where highRES can deploy each renewable. This map is then aggregated to the model's zones by summing up all the land area in each zone for each technology which is then converted to an installed capacity potential using an assumed footprint of 40, 3 and 5 MW/km^2 for solar PV, on and offshore wind respectively. For solar this is calculated using a weighted average of that for ground mounted (~33 MW/km^2 from [45]) and roof top (160 MW/km^2), with weights based on the amount of land area available for each option (assuming a medium scenario for ground mounted, the availability of roof space remains fixed across all scenarios). For wind, the land use footprints are based on the average footprint reported by Denholm et al. [46] for onshore and averaging the capacity density of the top five largest operational offshore farms in the UK as of 2017 (London Array, Gwynt y Môr, Greater Gabbard, Dudgeon and West of Duddon Sands), rounded down to be conservative, for offshore. Our wind footprints are very similar to those used by MacDonald et al. [22].

Finally, we note that when moving from one land restriction level to another, the installed capacity constraints for each VRE technology

[5] https://www.eea.europa.eu/data-and-maps/data/copernicus-land-monitoring-service-corine.

described above move together, i.e. a low land restriction means low for all VREs simultaneously. Also, we assume that the minimum installed capacity of each VRE in a zone is equal to its 2016, historical value, regardless of the capacity limit derived from our GIS analysis.

2.3.2. Water for cooling. Here we develop three water scenarios for power station cooling following a similar approach to that of M17b. For freshwater, we take data from the UK Environment Agency's Case for Change (hereafter C4C; Environment Agency [47,48]). We use their catchment level available resource data for Q95 flows, i.e. long-term average flows that are exceeded 95% of the time and are of most interest to water resource management [49], and aggregate this spatially to the highRES zones based on the assumption that the proportion of overlap between a catchment and a zone indicates the amount of water from that catchment available in that zone. The C4C provides available resource in Ml per day for 116 catchments covering England and Wales for a 2010 baseline and 60 scenarios for 2050. Available resource refers to the total amount of freshwater that may be abstracted in a catchment and is net of the so-called environmental flow indicator (EFI; the flow required to maintain good ecological status in a given water body – see Counsell et al. [49] for a good review).

Next we estimate the available resource for electricity cooling in each zone in 2050. To do this we use a database of GB power plants active in 2010, their location, cooling technology and water source (fresh, tidal or seawater) from Foreseer together with utilisation factors from DUKES (REF) and estimate freshwater abstractions in each zone in the baseline year. We have compared our national estimate of this figure with those from Fig. 5 of Murrant et al. [26] and find good agreement. We then use our zonal values to calculate the percentage share of available freshwater used for cooling in 2010 and make the assumption that this share (i.e. the ratio of the amount of water available for power station cooling to the total amount of abstractable water in a zone) remains the same in 2050. This allows us to estimate, using the 2050 projections from the C4C and these percentage shares, the available resource in each zone for cooling in 2050. We note that this assumption means that the proportions of water for cooling and for all other anthropogenic uses stays constant between 2010 and 2050. The 60 scenarios for 2050 from the C4C are derived from different combinations of future climate change, other anthropogenic demands and EFI criteria. We sort these 60 scenarios in terms of their cumulative national Q95 available resource and select minimum, median and maximum cases to represent our high, medium and low restriction freshwater scenarios respectively, thus spanning a large range of possible future resource availability.

For tidal and seawater (which hereafter we refer to both together simply as seawater), we take a different approach. Broadly speaking, a key finding emerging from many studies [24–26] is that if low carbon thermal generation is to feature heavily in the GB's future decarbonised power system, seawater must be increasingly utilised to mitigate pressure being placed on freshwater resources. However, as M17b discuss in detail, a variety of social, political, environmental and technical factors mean that coastal generation may well not be expanded. Therefore, we follow that study and aim to capture possible futures where tidal and seawater cooling is abundant (unconstrained availability in our low restriction water scenario) or unavailable (in our high restriction case) in England and Wales, with our medium scenario assuming continued availability at its 2010 level. For Scotland our high restriction scenario sets the zonal limit for water availability to the 2010 estimated tidal/seawater usage as the country no freshwater cooled assets in 2010 and there is a paucity of data on freshwater availability. The zonal availability of both fresh and seawater which is input into highRES is tabulated in the SI.

2.3.3. Nuclear. Site selection for nuclear power in the UK requires the consideration and balancing of a broad range of factors [10]. Some of these factors overlap with VREs, while others are unique to nuclear (e.g. radiological safety, waste management or extensive site decommissioning). The summation of these complex issues led the UK Government to ultimately limit the deployment of new nuclear in the UK to just 8 potential sites [50], all with a history of being used for nuclear generation and all on the coast. However, despite these tried and tested legacy sites being clearly endorsed by the UK Government some 7 years ago, to date construction has only begun at one location, Hinkley Point near Bristol. Even this project, led by Electricite de France (EDF), has come under criticism because of the subsidy scheme used to support it and serious cost and time over runs which have occurred at EDF's two other sites using the same reactor design (i.e. Flamanville in France and Olkiluoto in Finland). Thus, while the site selection hurdle has been passed, there is still significant uncertainty regarding the role of nuclear in the GB power system going forward.

Here, just as for our other scenario dimensions, we construct three nuclear scenarios that are intended to span a range of possible futures. As shown in Table 2 of the SI, our high restriction scenario assumes that construct of the 3.2 GW Hinkley Point C is completed by 2050 while all the currently active 9.5 GW of generation ceases operation in line with its expected closure date [51]. For our medium case we limit the nuclear deployment to the 8 potential sites and adopt station capacities from National Audit Office [51], which are spatially aggregated to the highRES zones. This leads to a maximum national installed capacity by 2050 of 18 GW. Finally, our low restriction scenario takes capacity limits for the build out of nuclear by 2050 from constraints in UKTM which were devised by BEIS and distributes this to the 8 potential sites by scaling up the National Audit Office [51] spatial capacity shares to give a total national capacity of 30.9 GW. This latter case represents our most positive outlook for nuclear in GB.

2.4. Scenario analysis

To understand the range of potential cost and system design impacts which result from the constraint scenarios outlined above on the GB power system in 2050 we run all combinations of these scenarios through our modelling framework. We do this for a cost optimal highRES case (hereafter referred to as OPTVRE), i.e. subject to the constraints placed on it the model designs a least cost power system for 2050. To examine the impact land restrictions have on the planning and operation of a highly renewable system, we also run highRES with an additional constraint requiring 80% of generation to be from VREs annually (hereafter referred to as 80VRE). Combined these two cases lead to 54 model runs (3 restriction dimensions each with 3 restriction levels leading to 27 runs per renewable share).

3. Results and discussion

3.1. Total system costs

First we look at the total system cost impact of the different restriction combinations on both our 2050 power system cases. In Fig. 2 we show the system levelised cost of electricity (LCOE) for the OPTVRE case. From this plot it is immediately apparent that moving from all low to all high restrictions results in a substantial change in LCOE, amounting to nearly a 25% increase in system costs (from 81 to 101 £/MWh). Therefore we see that spanning the full extent of our restriction space has sizable cost implications for the cost optimal power system. Diving a little deeper, it is also possible to identify which scenario dimension system LCOE is most sensitive to. Starting from all restrictions at low and moving one dimension at a time up to high (keeping the other two at low), we see that the nuclear dimension is most important, leading to an LCOE increase of 8%. Interestingly, when water and land are both at their highest setting and one again moves nuclear from low to high, we see a rise of 17%. Thus, there are greater cost implications for a given dimension when the constraints imposed by the other dimensions are more restrictive. Repeating this process for the other

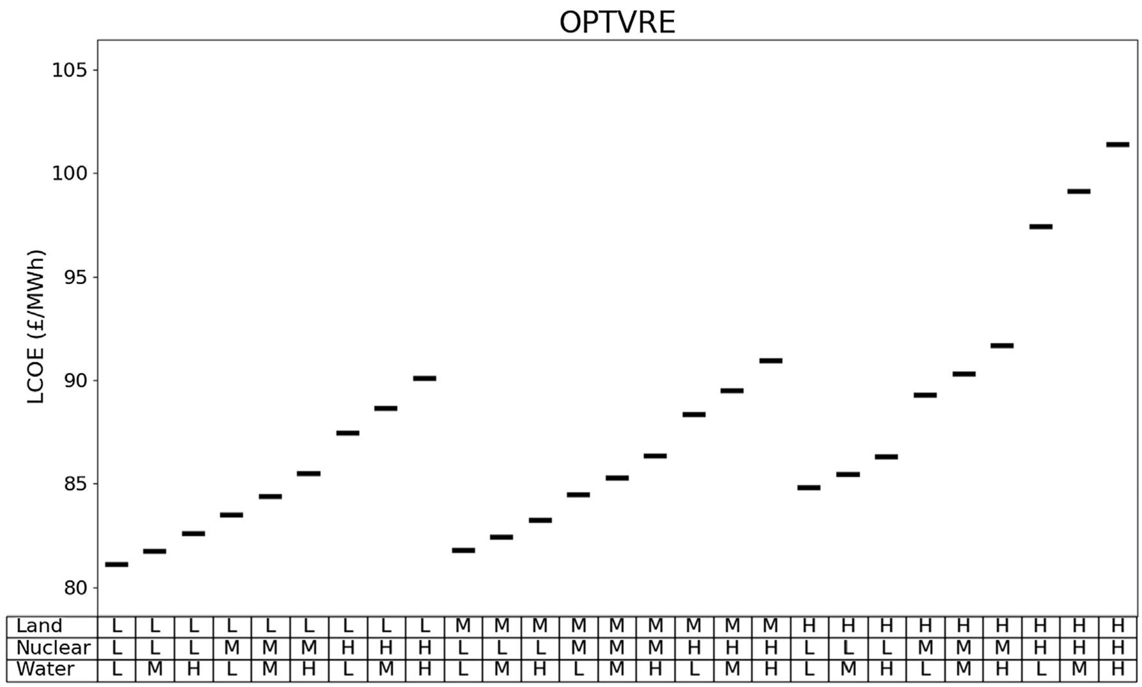

Fig. 2. System LCOE for all scenario combinations of our OPTVRE case in 2010 £/MWh. L = low, M = medium and H = high restriction.

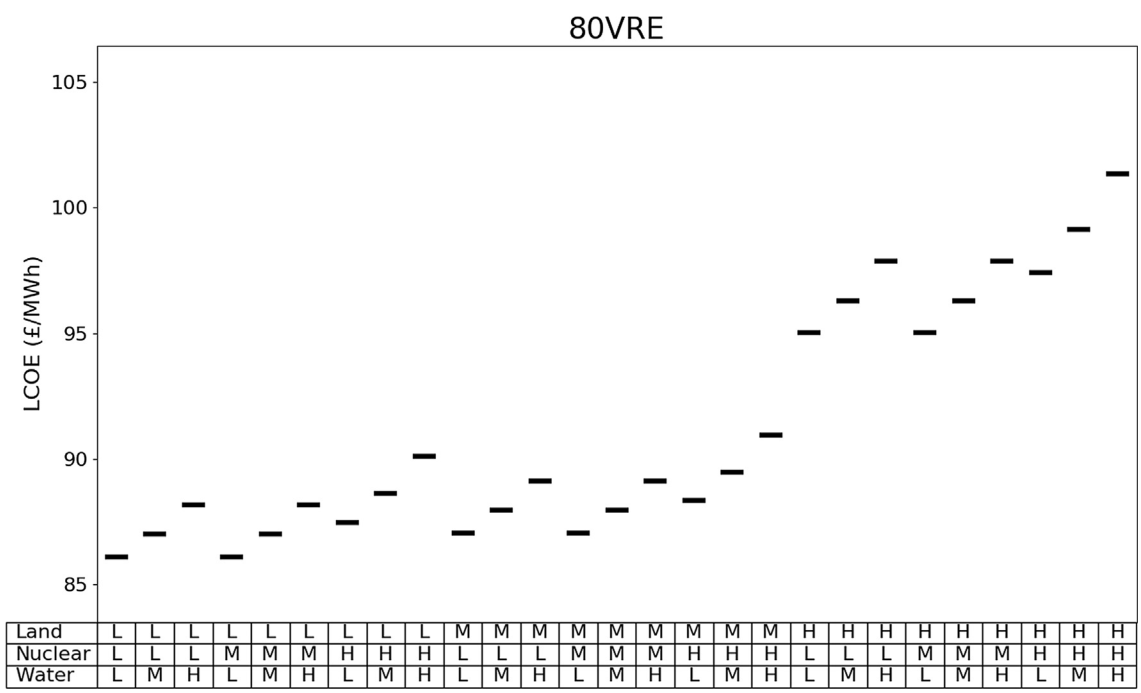

Fig. 3. System LCOE for all scenario combinations of our 80VRE case. Units and scenarios as in Fig. 2.

dimensions we find that land leads to a 5–13% LCOE increase while water results in a 2–4% rise. Such a comparatively small LCOE impact from changing water availability is perhaps surprising. However, as we will see in a later section, this is caused by the emission intensity of NGCCS (44–49 gCO_2/KWh, with once through cooling leading to lower emissions due to its relatively low parasitic load) being too high for its production to feature heavily in such a carbon constrained system.

Fig. 3 shows the equivalent LCOE plot for the 80VRE case. One important finding to note immediately is that the LCOE, and the system design, of the most restrictive scenario combination for both the OPTVRE and 80VRE cases are the same, i.e. OPTVRE also has 80% generation from VREs. That is, when the system is heavily constrained, i.e. nuclear capacity is maximally constrained and NGCCS is water and emissions limited, VREs become integral to the system. From Fig. 3 we see an 18% cost increase when moving from all low to all high restrictions (86–101 £/MWh) while land now becomes the most important dimension, leading to 10 (land low to high, nuclear and water at low) to 13% (land low to high, nuclear and water at high) LCOE increases. For both the OPTVRE and 80VRE cases, this occurs because as the land restriction progressively increases it limits access to the best sites, i.e. those with high capacity factors and a system beneficial timing of production, and the optimal mix of VRE technologies. Thus the model must deploy VREs to second best (or worse) areas which are comparatively more costly, i.e. have a higher site LCOE, and whose

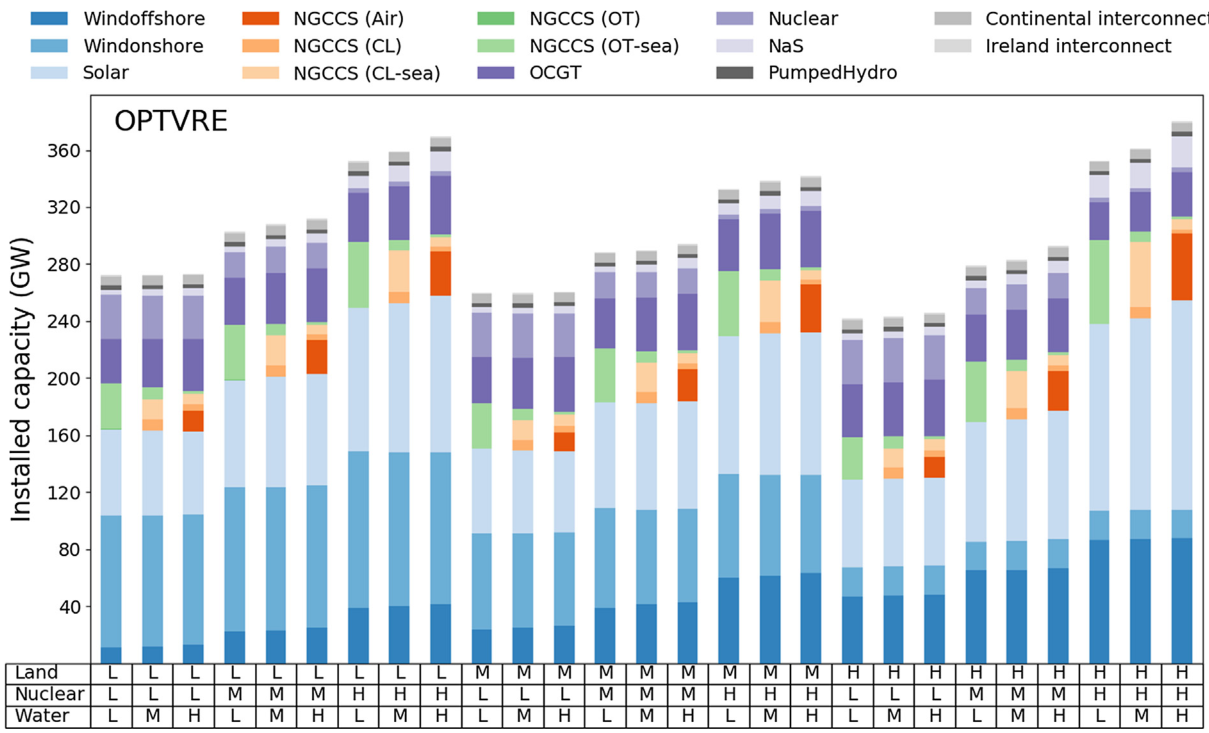

Fig. 4. Installed capacity in GW for all scenario combinations of our OPTVRE case.

production is not as optimally aligned with demand. As we will see in the next section, at the highest land constraint it is also heavily limited in the amount of onshore wind it can deploy, the cheapest form of generation by 2050 (and indeed BEIS estimate this will be the case by 2020[6]). As such, limits on the land available for VRE siting prevents the system from spatially and technologically diversifying in a cost optimal manner, two key avenues to assist in integrating renewables into the system.

This figure also shows that both nuclear and water restrictions are now of similar importance in cost terms, both resulting in 2–4% system LCOE increases.

3.2. Installed capacity

Now we move on to exploring the impact of our set of plausible future resource restrictions on installed capacity and in Fig. 4 show the capacity mix for all 27 runs of the OPTVRE case. Here we see that increases in the nuclear restriction consistently lead to total installed capacity growing as the model deploys more VREs, and to a lesser extent NGCCS, to compensate. We note that, because of its assumed cost effectiveness in the BEIS data used here, nuclear is always deployed up to its limit in all scenario combinations for this case. At the same time, greater restrictions on land availability result in much less onshore wind being built, with the model switching to offshore wind, solar and, once more to a smaller degree, NGCCS. Indeed, at the highest land constraint only ≈ 20 GW of onshore wind is installed, which would imply less than a doubling in capacity from the end of 2016. This reflects the fact that this technology often faces significant opposition at the local level and a challenging planning environment in GB today due to national policy changes in 2015. This plot also demonstrates the effect of limiting water availability for cooling which leads to a shift from once through (seawater), at the lowest level, through a mix of closed loop (fresh and sea) and once through (sea) finally to a system with predominately air cooled NGCCS at the highest restriction. Such a transition, from relatively cheap open loop to expensive air cooling, drives the cost increases seen previously when the water restriction changes and is caused by the model trying to efficiently utilise the available water resource.

Furthermore, Fig. 4 indicates that the increase in VRE deployment as nuclear is further constrained, and the shift in the mix of renewables, also leads to a sizable growth in the requirement for battery storage. Quantitatively, when land is at low and one moves nuclear/water from low to high, we see storage capacity increase from 3.7 to 14.3 GW, and a more substantial increase of 4.8 to 22 GW when repeating this exercise with land at high. This indicates that, when interconnection capacity and emissions are limited, storage becomes key to managing high VRE penetrations and even more so when the technologically and spatially optimal configuration of VREs is restricted by constraints on their siting. Indeed, if we isolate the impact on storage capacity from land restrictions alone, i.e. by moving the land constraint and keeping the other two fixed, we see that in a worst case greater limits on VRE siting can lead to more than a 50% (14.3–22 GW) increase in the requirement storage (nuclear/water at high, land low to high).

Fig. 5 presents the equivalent capacity mix plot for the 80VRE model runs. We note that all runs with nuclear at its highest restriction result in the same capacity mix as for OPTVRE. Predictably, given the 80% VRE generation constraint, renewables also feature more prominently in all the other solutions, i.e. those when nuclear is constrained at low and medium, and, as a result, these solutions have higher total installed capacities than those for OPTVRE. Another repercussion of this is that the capacity of storage deployed for a given scenario combination is higher (or the same when nuclear is at high). For instance, for two of the examples given previously, i.e. land/nuclear/water all at low and land at high, nuclear/water at low, installed battery capacities are 9.5 GW (cf 3.7 GW for OPTVRE) and 13.8 GW (cf 4.8 GW for OPTVRE) respectively. Thus, again we see a narrative that storage is important at high VRE penetrations and even more so when VRE deployment is spatially restricted.

[6] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf.

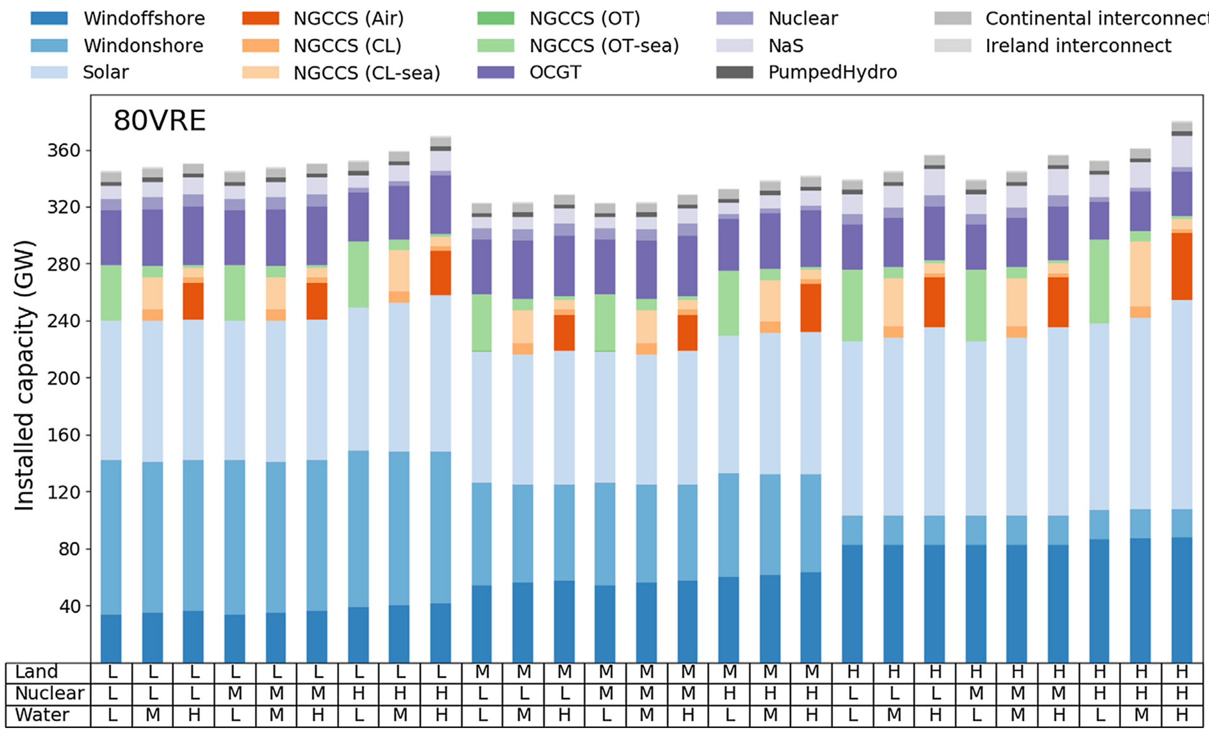

Fig. 5. Installed capacity in GW for all scenario combinations of our 80VRE case.

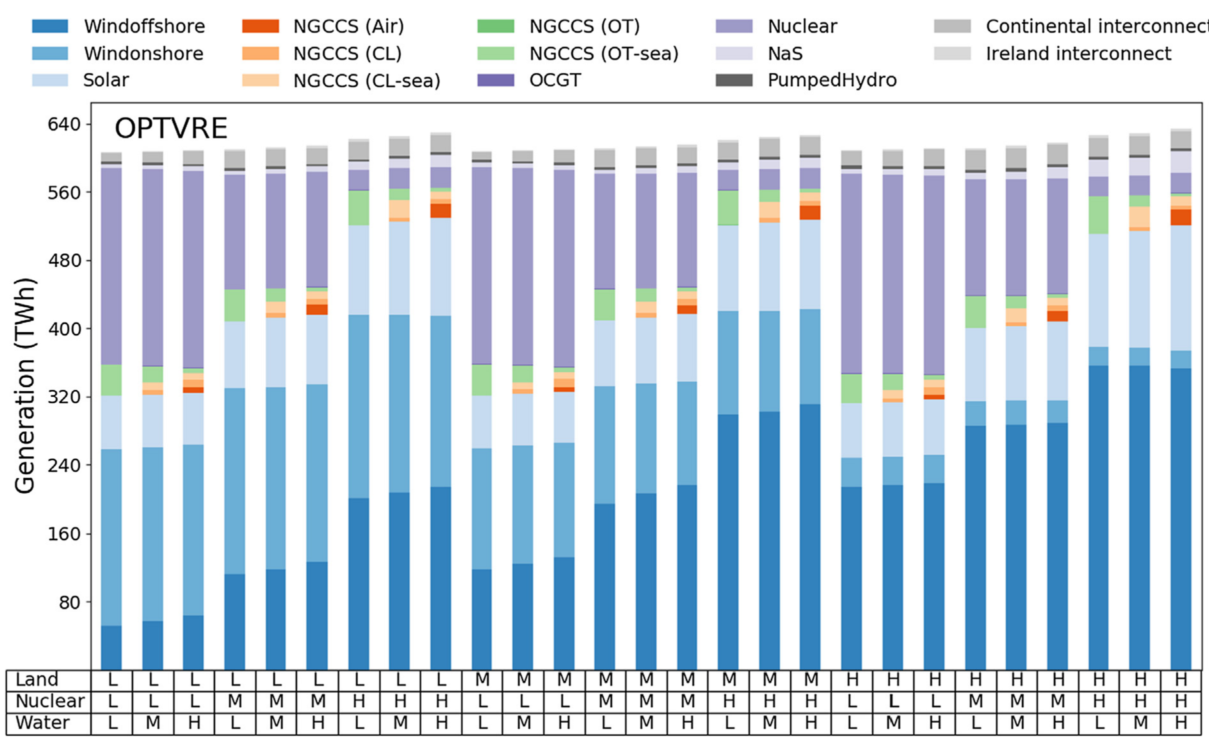

Fig. 6. Generation mix (in TWh) for all scenario combinations of our OPTVRE case.

3.3. Generation mix

Having illustrated the impact of our restriction dimensions on installed capacity we now turn to the utilisation of that capacity. In Fig. 6 we show the annual generation mix for the OPTVRE case and include that for 80VRE in the Supplementary Information for reference (Fig. 1 in that document). We note that the general stories for both are similar, with the exception that nuclear predictably features more strongly in the former and offshore wind, and to a lesser extent solar PV, in the latter at low and medium land restrictions.

A key insight from this figure is that, as commented on previously, NGCCS plays a secondary role to VREs and nuclear, despite 30–60 GW of capacity being installed (all cooling options aggregated) across the scenarios, with it producing between 5 and 7% of annual electricity demand. This leads to at best a 15% capacity utilisation, accounting for availability, and model output indicates that NGCCS is typically being

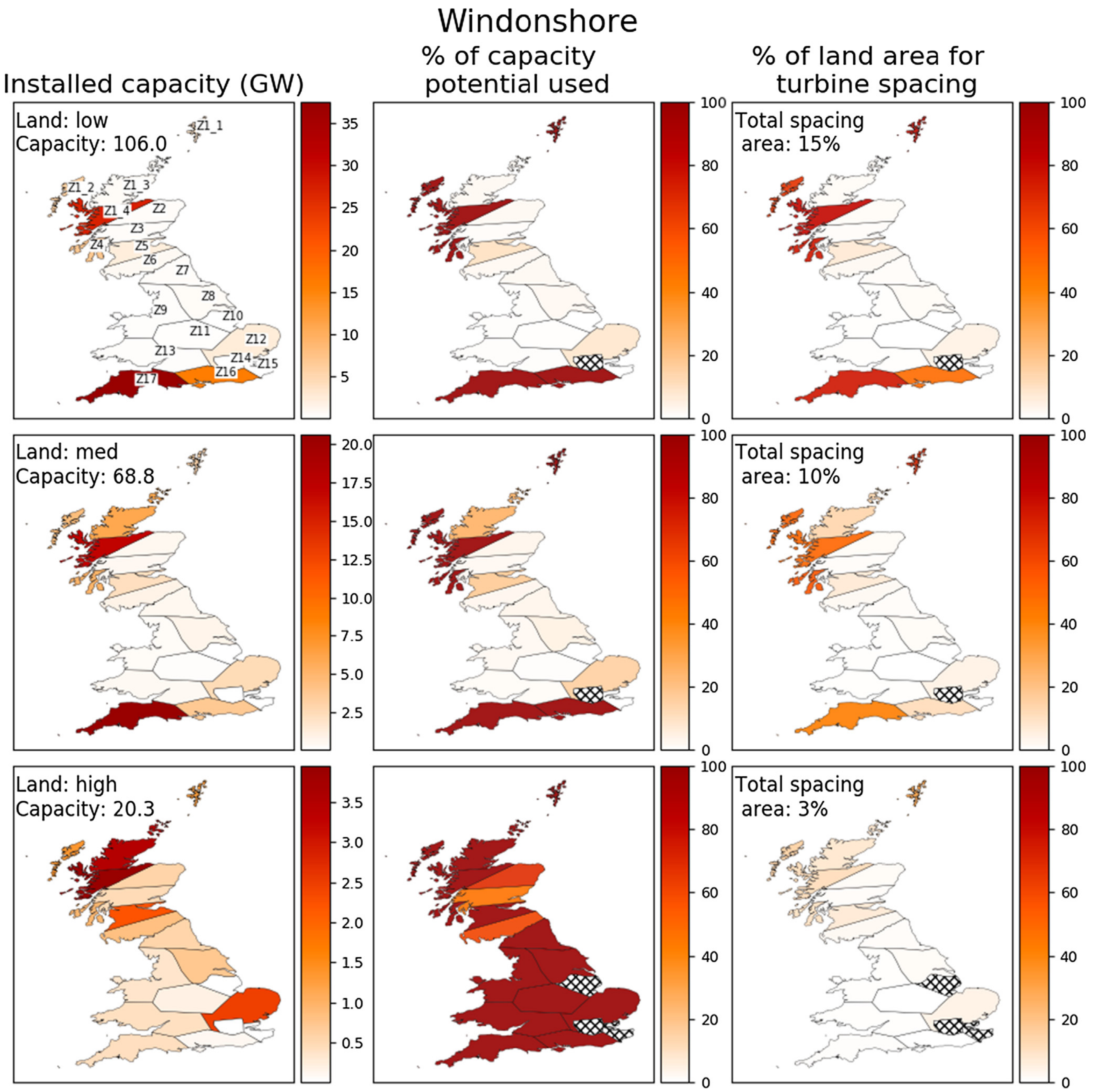

Fig. 7. Spatially explicit installed capacity of onshore wind (left column), the fraction of each zonal capacity limit used (middle column) and the fraction of each zone's area used for turbine spacing (right column) with land restrictions varying from low to high for our 80VRE case. Nuclear/water restrictions are set at medium in all cases. Hatch zones are those with no land available.

run in 11–15 h blocks depending on scenario, although occasionally as long as a week straight, to balance the system. Therefore, even with a 90% CO_2 capture rate, NGCCS is not able to run as base load in an emissions constrained 2050 system and more so serves to fill in for, sometimes extended, periods where VRE output is low and/or demand is high.

This figure also demonstrates a significant rise in offshore wind generation as onshore wind becomes highly limited with, simultaneously, generation from battery storage increasing from 4 to 25 TWh a year (up 600%) between the lowest and highest restriction combinations respectively. Once more this highlights the increasingly pivotal role for storage in a system whose VRE deployment is constrained which also has limited access to interconnection and no demand side measures.

3.4. VRE spatial deployment

In this section we look at how the spatial patterns of renewable deployment change as the land restriction is increased to reflect lower public acceptance, tighter environmental constraints and greater technical limits. We focus on onshore and offshore wind for the 80VRE case, with the OPTVRE case providing similar insights, and in Figs. 7 and show three columns of spatially explicit results. In both figures the left column shows installed capacity by zone for low, medium and high land restrictions, top to bottom respectively, all with water/nuclear set at medium. In addition, these panels show the total national installed capacity for reference. The central column presents three maps of the fraction of each zone's capacity potential used. The capacity potential is derived by taking the amount of land available in each zone from our

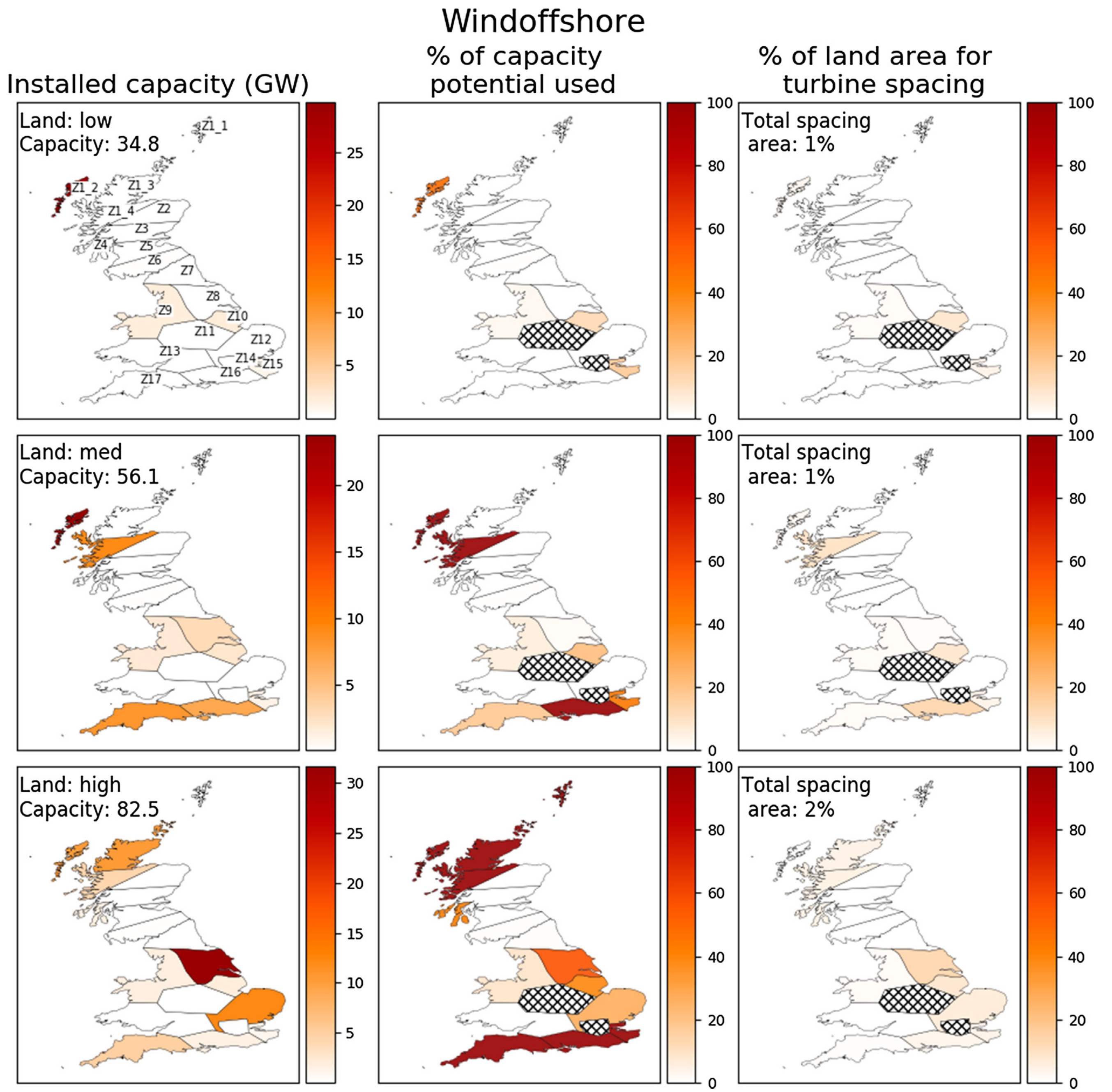

Fig. 8. Spatially explicit installed capacity of offshore wind (left column), the fraction of each zonal capacity limit used (middle column) and the fraction of the area of the UK's Renewable Energy Zone attributed to each zone's used for turbine spacing (right column) with land restrictions varying from low to high for our 80VRE case. Nuclear/water restrictions are set at medium in all cases. Hatch zones are those with no land available.

GIS analysis and multiplying it by the capacity footprint for each technology. The plotted fraction is then the installed capacity divided by this potential which, we note, changes based on the level of the land restriction, i.e. the denominator in each zone can change from top to bottom in this figure. Zones which are hatched have no capacity potential due to limited land availability. The right columns show the percentage of each zone's total land area required for each technology and the fraction of total GB land area used. For offshore these are the fraction of the UK Renewable Energy Zone (UKREZ) which has been attributed to each land zone occupied by turbines and the total amount of UKREZ area used. We note that this column is conservative as it is based on the spacing area and not the much smaller footprint area covered by turbine masts. That is, this area includes the large amount of land (or sea) required to adequately space turbines which could still be used for, for example, agriculture in the case of onshore wind.

Considering onshore wind first, from Fig. 7 it is immediately apparent, as we have seen previously, that a higher land restriction leads to substantially less onshore wind being installed nationally. From a spatial perspective, at a low/medium land restriction, the majority of capacity deployment is concentrated in 6 or 7 zones with these regions having large amounts of their technological potential occupied. Moving to a high land restriction results in essentially all of the capacity potential across GB now being utilised and deployment being spread across the country in less spatially optimal zones. At the same time the third column indicates that at low, and to a lesser extent medium, restrictions some zones have a large amount of their total land area (e.g. up to ≈80% at low) used for turbine spacing. Again, we reiterate that it is still possible for the land between turbines to be put to other uses in these zones. Both the total national land coverage and that at the zonal level drops dramatically at a high land constraint. Therefore we see that land availability restrictions have serious repercussions for the spatial pattern of deployment of onshore wind. We also highlight that this transition, from a large national installed capacity with a high concentration of turbines to less total capacity which is distributed across the entire country, is a key driver behind the greater system costs seen previously for medium/high land constraints. As touched upon previously, this is because increasingly stringent restrictions that limit/prevent access to the most cost effective sites lead to less spatially optimal deployment (timing of production), the utilisation of zones with higher site LCOEs (lower capacity factors) and more costly technologies being installed which together contribute to an increase in system LCOE.

As onshore wind is being heavily restricted, so offshore wind scales up to replace it as shown in Fig. 8. Similarly, its deployment is

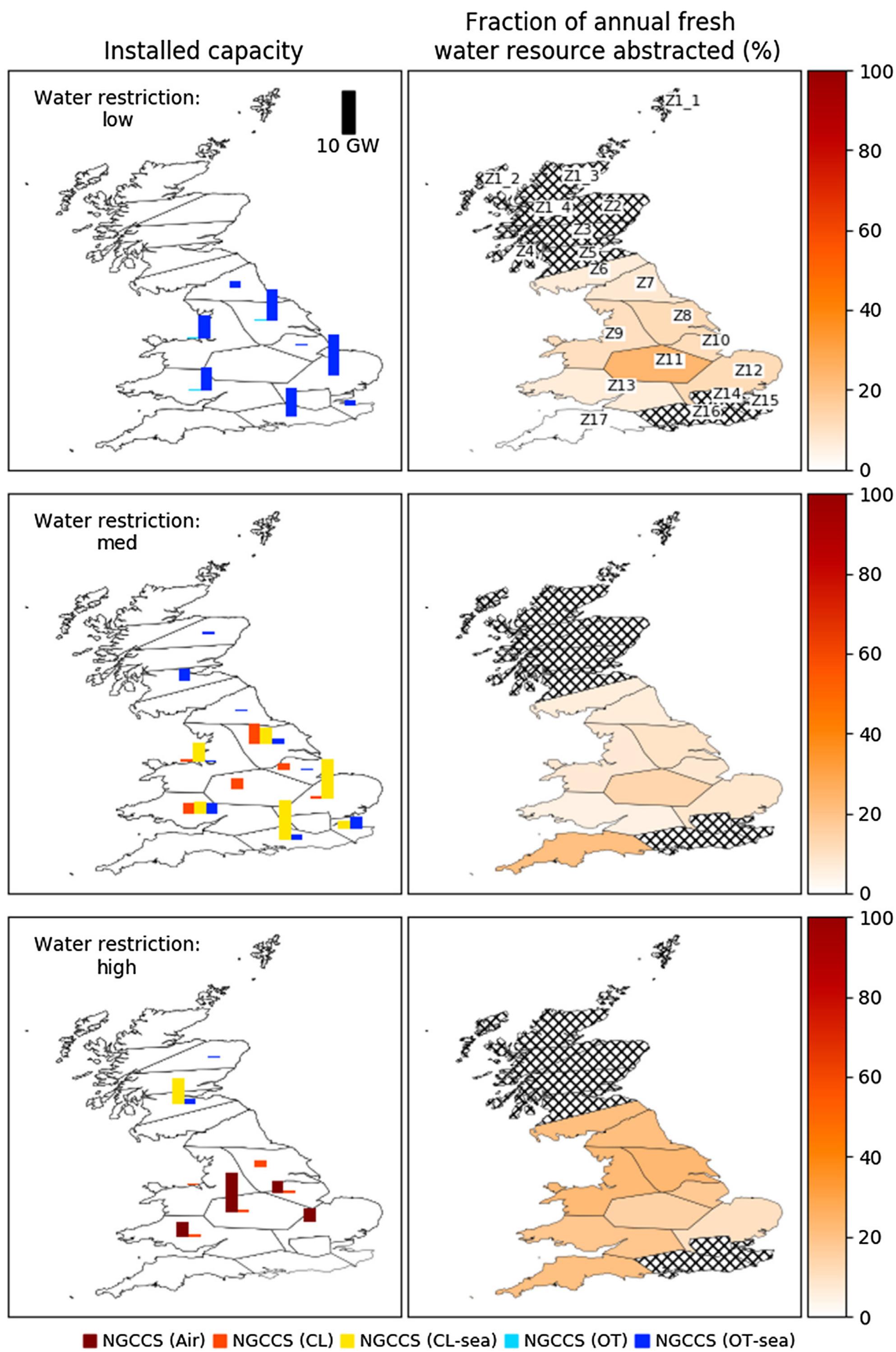

Fig. 9. The spatially explicit deployment patterns of NGCCS capacity by cooling type (left column) and the fraction of each zone's annual freshwater resource which is available for power station cooling utilised (right column) for the OPTVRE case. Water restrictions increase from top to bottom and nuclear/land constraints are set at medium in all panels. Hatch zones are those with no freshwater cooling in 2010.

concentrated in just a few zones at a high land availability (low restriction) but spreads to many more at low land availability (high restriction). In part this occurs to ensure greater spatial diversity as the electricity system becomes increasingly dependent on offshore generation (see Fig. 6) as the land constraint ramps up. The maximum coverage of the UKREZ area that is attributed to each onshore zone remains typically quite low at 14%, as does total national usage, indicating that the offshore wind deployment does not occupy large areas of the region in which the UK may deploy marine renewables. As for onshore wind, we see again that restrictions on the siting of VREs has sizable impacts on the total capacity installed and the optimal spatial deployment pattern for offshore wind.

3.5. Cooling technology and water use spatial patterns

In this final results section we look at the spatial implications of ramping up our water availability restrictions in terms of cooling technology choice and water usage. To that end, the left column of Fig. 9 shows the installed capacity by zone of NGCCS by cooling technology and the right column displays the percentage utilisation of each zone's freshwater resource on an annual level. Hatched zones have no freshwater availability for power station cooling, i.e. they had no plants using freshwater cooling in 2010, or, as is the case for London, we prevent capacity from being deployed there.

The installed capacity panels clearly highlight the shift, described above, from once through cooling using seawater at the lowest restriction, through a mix of once through/close loop sea with closed loop freshwater at medium to a system relying predominately on air cooling at our highest restriction. When seawater is abundantly available (low restriction), the model deploys all NGCCS capacity in England and Wales, closer to demand. At a high restriction, the seawater still available in Scotland is cost effectively utilised by switching to close loop cooling and limiting the amount of expensive air cooling built elsewhere across GB.

From the right column of Fig. 9 we see that, broadly speaking, the fraction of each zone's annual freshwater resource used for cooling rises as the water restriction increases. Interestingly, these plots also show that the most heavily abstracted zones have at most $\approx 40\%$ of their available resource utilised. This is not higher for two reasons. Firstly, as discussed previously, NGCCS is emission constrained and so is not used for base load leading to low utilisation and less than 100% cooling water usage over the year. Secondly, because we follow the UK Government's current planning guidance and limit nuclear deployed to legacy sites, all of which are on the coast, no freshwater is used to cool nuclear plants. Here we differ from M17b who do permit freshwater cooled nuclear and find greater system cost implications from their water constraints. It is highly likely that if we followed suit and relaxed this policy informed choice we too would find similar cost impacts. However, because of the array of complex issues around the siting of nuclear extends beyond its cooling requirements, we opted to stick with the 8 sites identified by DECC [50].

We note there are some limitations to our study which we wish to highlight. Firstly, we use a linear model that does not capture unit commitment constraints like start-up costs and has a simplified representation of the transmission system because we aim to strike a balance between computational expense and model complexity. As touched upon previously, such assumptions are not unusual in high spatial and temporal resolution hybrid ESOMs which aim to simultaneously make investment and dispatch decisions while remaining computationally tractable (see e.g. [22,37,38]). Secondly, as mentioned at various points throughout the work, we assume only limited growth in interconnection by 2050 (only those projects that have already started construction today). GB's interconnection to Europe may well grow beyond the 7.4 GW assumed here (see e.g. National Grid [52]) and, depending on the price of electricity from Europe, this could serve to limit the system cost impacts we have found. However, whether such an increased dependence on imported electricity would be socio-politically tenable given the importance of energy security within the UK's energy policy discourse [53] and Britain's looming departure from the European Union, is unclear. Thirdly, we do not model demand side measures. These options, which enhance system flexibility by, for instance, load shifting could potentially be used to increase system flexibility and reduce the cost impacts we observe if they experience significant uptake. However, as their large scale potential is uncertain due to non-cost barriers impeding their implementation [54,55], we do not include them here. Finally, we note that in this study we have constructed our restrictions based on data from a variety of sources in an attempt to capture a large, but plausible, range for the key constraints we consider. However, unlike such works as Höltinger et al. [9], we have not engaged with important stakeholders face to face and so do not have a fully empirical grounding to our resource restrictions. These caveats would be of value to investigate as the topic of future research.

4. Conclusions

ESOMs are now a common tool used to help support decision makers as they attempt to guide the high carbon energy systems around the world today to net-zero emission systems by 2100 while at the same time addressing the rest of the energy trilemma. However, as has been proposed for some time, such transitions will interact with the wider coupled social, economic and environmental system beyond this triumvirate of issues and so must respect key inter-linkages with these systems. With this in mind, so-called energy-land-water nexus thinking aims to design energy systems that are not just least cost and technically feasible but also grounded and shaped by additional, key real-world factors. In turn this adds a new layer of fidelity to the insights ESOMs provide to inform and support policy formation.

Here we have described a scenario analysis of the planning and operation of low carbon electricity systems for GB in 2050 from an energy-land-water perspective. To do this we have integrated two ESOMs and a nexus tool to form a modelling framework capable of simultaneously capturing land and water resource constraints while modelling VREs at high spatiotemporal resolution. Into this framework we fed plausible scenarios of key restrictions on land available for the siting of VREs, on fresh and seawater for power station cooling and the future installed capacity of nuclear power in GB. We then explored the system cost and design impacts of all combinations of these restrictions on two future power system cases, least cost and least cost but requiring at least 80% of electricity to be supplied by renewables annually. A summary of the key insights from this study is as follows:

- The combined cost implications of the land and water constraints analysed here are sizable, resulting in an up to 25% increase in system LCOE when moving from all low to all high restrictions. In cost terms, the two most important dimensions for the GB power system in 2050 are nuclear and land for VREs which can lead to increases in system LCOE of 17 and 13% respectively. We note that this would require various factors to conspire, such as no new nuclear beyond Hinkley Point C and an ongoing challenging situation for onshore wind. However, just one of these eventualities panning out results in an 8% higher LCOE (Hinkley C only, OPTVRE case with land/water at low) or a 10% higher LCOE (onshore wind limited to 20 GW, 80VRE case with nuclear/water at low) than a low restriction case. The latter point is particularly relevant given the current political hostility toward onshore wind in GB and indicates that if the deployment of this technology is limited, i.e. less than a doubling of capacity by 2050 relative to 2016, there will be repercussions for the cost of electricity. Additionally, regarding nuclear we stress that the potential cost overruns associated with building the first set of reactors for a generation in today's regulatory system with risk averse investors may diminish its relative importance going forward.

- Water constraints are seen to have a smaller impact on system costs, potentially leading to up to a 4% greater LCOE. We find that NGCCS plays a secondary role in 2050 (with utilisation of 8–15% depending on scenario), serving to help balance the system. As such, and assuming nuclear power does not use freshwater for cooling in future, we find that the system does not experience substantial freshwater stress in our scenarios.
- Land restrictions which capture important social, environmental and technical constraints on VRE deployment are found to significantly shape the spatial pattern of installed onshore and offshore wind capacity. Here, as land availability is increasingly limited, the least cost system shifts from large amounts of onshore wind concentrated in a few windy zones to small amounts spread across the country. This impacts system costs by restricting the mix of VRE technologies (technological diversity) and limiting access to zones with the lowest LCOE (highest capacity factors) and those with a system beneficial timing of production (spatially diversity).
- We show that storage plays an increasingly important role in integrating renewables into the system at higher VRE penetrations, as evidenced by the growth in its installed capacity when nuclear/water are further restricted (low to high). We find that, in the worst case, around 50% more storage must be installed to compensate for a less spatially and technologically diverse electricity system.
- Given reasonable assumptions about key energy-land-water restrictions and emission limits effecting the GB power system in 2050, we find that the cost optimal penetration of VREs is at least 50% (roughly 60% of total installed capacity), which agrees with Pfenninger and Keirstead [37]. Minimum VRE shares of this order may be considered a cost effective option for policy makers across the restrictions explored here, assuming limited access to demand side measures and a desire to maintain domestic energy security. However, the specific VRE technology mix does depend on their siting constraints going forward, with a consistent picture for solar PV but a switch from onshore to offshore wind if restrictions are high.

Going forward, in future work it will be essential to directly engage with the full range of stakeholders and learn from their input. Together it will be possible to derive empirically grounded limits, particularly for important technologies like onshore wind, and iterate with them to increasingly bridge the gap between the model world and the real world. The ultimate aim being to capture more of the real world's complexity and uncertainty and reflect how it shapes potential decarbonisation pathways, adding a crucial level of fidelity to the insights provided to policy makers.

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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.2018.06.127.

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