EPRG WORKING PAPER

UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

Designing cost-efficient, flexible, energy solutions for a decarbonized GB power system

EPRG Working Paper EPRG2418

Cambridge Working Paper in Economics CWPE2474

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Abstract
Decarbonised future power systems will rely on variable renewable energy (VRE). The variability and intermittence of VRE calls for cost-efficient flexibility providers, such as thermal generators, different energy storage technologies, interconnectors, and excess generation from VRE. This research decomposes the total system cost into cost of flexibility and energy, and constructs an agent-based structure for energy storage operators to price stored energy and a mechanism for all power sources to compete with each other. In the GB power system with the UK's projected VRE and energy storage capacity, the total system cost will be dominated by the cost of providing energy flexibility. Energy storage is more efficient both at reducing total system cost and carbon intensity than additional VRE, which can only reduce carbon intensity, and interconnectors, which can only reduce total system cost by exporting excess generation from VRE. Thermal generators will pay a transfer cost because of their frequent start-up and will still be cost-efficient for seasonal storage. Excess generation from additional VRE reduces carbon intensity but raises the total system cost. To reach the minimum carbon intensity and total system cost, we recommend that the GB power system introduce an additional 25 GW of storage capacity for its projected VRE capacity and introduce mechanical storage technologies which are cost-efficient for managing short-term variability as soon as possible.

Nomenclature

T	Total cost of system
F	Flexibility cost of system
E	Energy cost of system
C_i	Capital cost of i^{th} generator(generator for energy with flexibility)
C_j	Capital cost and O&M cost of j^{th} generator (generator for energy only)
d_{it}	Discharge amount of i^{th} storage pool at t^{th}period
S_i	Levelized storage cost to each MWh electricity of i^{th} storage pool
g_{it}	Generation amount of i^{th} generator at t^{th}period
M_{it}	Marginal generation cost of i^{th} generator at t^{th} period
C_{im}	The cost of introducing, maintaining and operating i^{th} generator and interconnector(Annual levelized capital cost plus fixed O&M cost)
C_{imt}	Variable O&M cost of i^{th} generator and interconnector at t^{th} period
O_{it}	VRE output of i^{th} generator at t^{th}period
i_{it}	Electricity amount transmitted through i^{th} interconnector at t^{th}period
I_{it}	Electricity price of i^{th} interconnector at t^{th}period
D_t	Real demand of t^{th}period
c	Carbon intensity of power system
c_i	operational intensity of i^{th}agent
e_i	body emission of i^{th}agent
O_{it}	Output of i^{th}agent at t^{th} period
a_{0i}	Storage cost levelized to each period for each MWh of electricity
δ	Usage factor of storage pool
N	The number of periods
b	Storage cost levelized to each cycle for each MWh of electricity
G_{wt}	Output of wind generator at t^{th} period
G_{st}	Output of solar generator at t^{th} period
v_i	Cut-in wind speed
v_t	Wind speed at t^{th}period
v_r	Wind speed for rated generation
v_o	Cut-off wind speed
α	Conversion factor from wind speed to power
G_r	Rated capacity of VRE generators
r_i	Cut-in downward solar radiation
r_o	Cut-off downward solar radiation
r_t	Downward solar radiation at t^{th} period
C_f	Fuel cost
C_v	Variable O&M cost
C_s	Possible start-up cost

η	Energy conversion efficiency
G_{il}	Generation capacity of i^{th} generator
u_i	Ramp-up limit of i^{th} generator
B_t	The available biomass fuel at t^{th} period
P_{it}	The available energy in i^{th} storage pool
p_i	The power capacity of i^{th} storage pool
I_{il}	The transmission limits of i^{th} interconnector
d	The newly produced biomass fuel at each period
F_w	The flexibility cost for electricity in wholesale market
D_w	The forecast demand in wholesale electricity market
F_b	The flexibility cost for electricity in balancing market
D_b	The difference between real demand and forecast demand
E_i	The energy capacity(size) of i^{th} storage agent

Introduction

The transformation of the current energy system from carbon-intensive to deeply decarbonised means variable renewable energy (VRE) will become the main supplier of energy. [1] However, because of its variability and intermittency, large-scale deployment of VREs inevitably leads to an energy flexibility demand [2]. Assessing this energy flexibility demand calls for a power system model (PSM) with precise VRE output variances and mechanisms evaluating energy flexibility providers, i.e. energy storage, low-carbon thermal generators, excess generation of VREs and transmission upgrades. [3]

The impact of large-scale VRE deployment on the power system can be resolved into the difference between supply and demand at each period in the PSM. [4][5]. To better depict the impact of VRE, details are added to increase the temporal [6], spatial [7], and technical [8] resolutions. Owing to limited computation power, compromises have to be made when using a dispatch model structure; for example, previous studies have selected sample time points in a day [9] or a sample day for a year [10] from the inter-annual hourly weather data. Different methods for changing the time resolution, including down sampling, heuristic selection of time steps, and clustering, led to substantially different results, particularly when modelling high shares of variable renewable generation. [11] In power system models using inter-annual hourly weather data, integrating different renewable technologies with technological diversity at different locations adds energy flexibility [12]. When meteorological variation, demand fluctuations, and forced outages (e.g. in models approximating Markov chain processes) are all taken into account, the energy flexibility gap at high renewable penetration still remains. [13] [12]

Current PSMs use a unit-commitment mechanism, which optimises the generation schedule based on the marginal generation cost and optimises the energy storage pool over a number of periods to maximise the arbitrage value of energy [14].

Using an alternative approach, Keles et al [15] developed an agent-based structure to explore the interactions amongst participants who attempt to maximise their profit in an imperfect electricity market. It was found that using thermal generation to provide energy flexibility with emission constraints will give a high electricity price owing to carbon pricing or the abatement cost of carbon, regardless of whether the model is optimising for maximum profit [16] or minimising cost [17]. Others have found that the effects of demand forecast error on generator behaviour [18] also lift the flexibility cost. By simulating suppliers' behaviour [19] it was shown that the cost of energy flexibility will only fall after a change in demand profile, namely consumer lifestyle. Agent-based models have also been used to study carbon and system benefits for energy storage operators where they can buy and sell electricity at a certain price. [20]

The feasibility of energy storage as an efficient and direct energy flexibility source for a power system has been studied[21]. By paying a periodic cost of moving energy from one time point to another, energy storage can be scheduled to give a global optimum. By testing different levels of energy storage, the energy storage capacity in a future power system can be optmised [22]. Specific energy storage technologies like thermal storage [23], pumped-hydro storage [24], compressed-air storage [25], hydrogen [26] and batteries [27] have been analysed within a power system model, but no single technology has been identified which out-performs all others. In reality, the solution will probably lie in some combination of different energy storage technologies. [28]

In addition to the energy flexibility gap, curtailment becomes another important feature when there is a high penetration of VRE in a power system. [29] Curtailment is defined as a reduction in the output of a generator from what it could otherwise produce given available resources, typically on an involuntary basis.[30] High penetrations of VRE will lead to periods when there is a significant amount of curtailment; for example, a case study in Ireland showed that the last MW of installed wind will have more than three times the hours curtailed than average [31], which makes pricing and utilising curtailment increasing important in future electricity market design.[32] Curtailment can be employed to provide energy flexibility[33], but requires energy to be wasted [34]. This approach only makes sense if energy flexibility is more expensive than energy itself, making oversupply cost-efficient. [35] Underestimating the output and lack of transmission availability [36] are also important causes of curtailment. In order to estimate the energy storage capacity for a future system, previous work has constrained the maximum curtailment of the VRE generation capacity. Generally, the permitted curtailment positively correlates with the cost efficient VRE capacity, and negatively correlates with required storage capacity. [37] [38]

This study attempts to quantify the value of energy flexibility and find a cost-efficient flexibility solution. Our analysis allows for the following key aspects that are important in understanding the value of different energy flexibility providers in a future power system with a high share of VRE: 1) a decomposition of the total system into the cost of providing energy and cost of providing flexibility2) a mechanism to permit competition among curtailment, thermal generation, interconnections and energy storage; 3) the spatial and temporal details of inter-annual weather variability affecting renewable outputs and flexibility demand; 4) a high technical resolution of different VRE generation, interconnections, thermal generation and energy storage technologies.

We build a single-period-optimised power system model with an agent-based structure, where energy flexibility providers (including curtailment, thermal generation, interconnections and different energy storage technologies) can compete with each other in the wholesale and balancing electricity market to mitigate the energy gap caused by VRE generators. We apply our modelling approach to Great Britain, a country with a national electricity price (implying transmission limits are not a concern in the market design), limited interconnection (7440MW in 2021) [39] and an ambitious decarbonisation target of its power system, where all of above flexibility solutions are under consideration. We build this power system model in one weather year so that we can easily compare the baseline scenario with reality.

Modelling the competition among flexibility providers

A traditional power system is dominated by thermal and thermal-like generators, namely generators that can provide flexible energy with a marginal generation cost consisting of the variable O&M cost and carbon cost. Typically, this includes gas and biomass fired generators and interconnectors. Nuclear generators are modelled as thermal generators but their flexibility is heavily constrained by their ramp rates. In such a system, the capacity of energy storage and VRE-like power sources, together with their capital and O&M cost, is decided before the system's operation. Because of their negligible variable O&M costs, VRE-like power sources and energy storage will be utilised as much as possible, and the marginal generation cost of the system will be that of the thermal generator at operating at the margin. To evaluate the optimal amount of energy storage and VRE capacity in a system, dispatch models are often used [40], which optimise the marginal cost in a given period. Optimal amounts of storage or VRE are then obtained by sweeping over a range of VRE and storage capacities. This methodology fails to reveal the competition between thermal generators and different energy storage technologies and is computationally expensive when analysing seasonal storage.

To optimise the co-existence of VRE generators, thermal-like generators and energy storage in a future power system, this research builds an agent-based structure in which energy storage operators compete against other flexibility providers, i.e. thermal-like generators and interconnectors. *Figure 1* shows the overall structure of the model, consisting of an ahead (wholesale) market interacting with a balancing market and various generation and storage agents. Each storage agent is characterised by nine parameters; energy capacity, charge/discharge rate, lifetime, life cycles, project cost including capital cost, fixed operation and maintenance cost, variable operating cost, utilisation factor, charge efficiency, discharge efficiency and self-discharge rate.

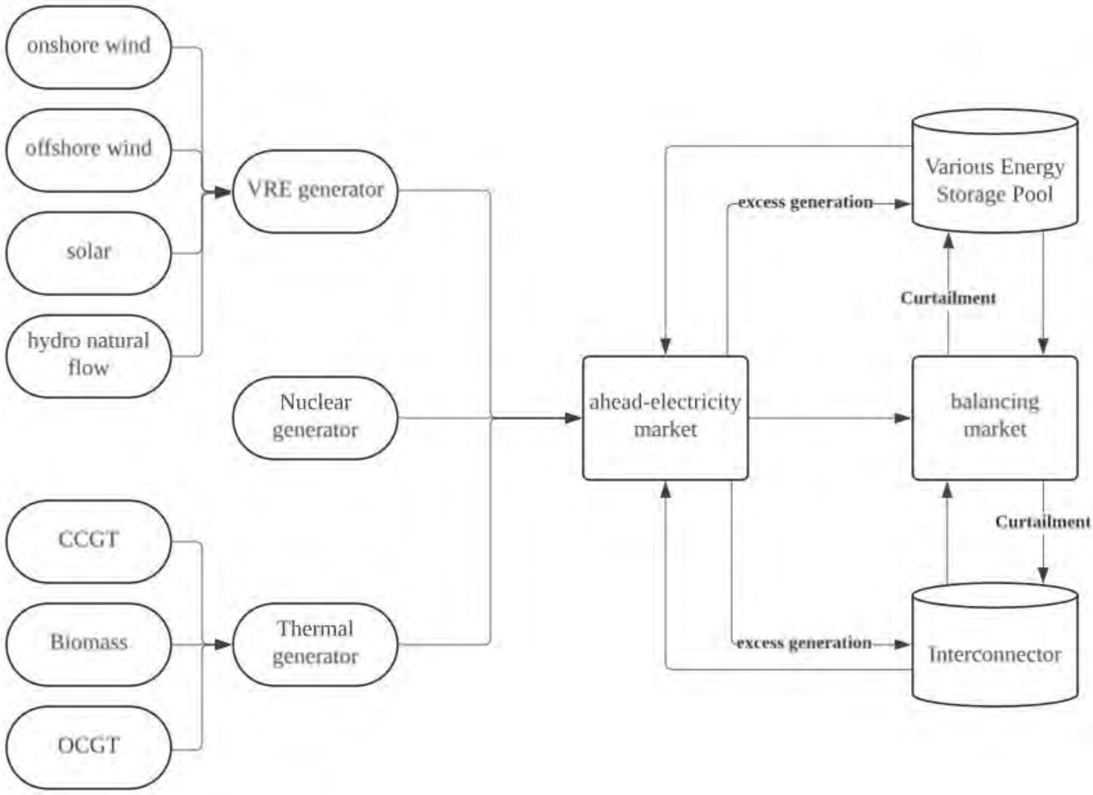


Figure 1: Structure of two-stage agent-based model

A centralised (pool) market clearing mechanism, which is proven to be cost-efficient when generators don't have market power [41], is employed here to model the competition among agents, who follow the bidding strategy of bidding with their marginal cost. The market is then cleared with the most cost-optimal generation schedule every half an hour, reaching the locally optimised generation schedule. To fully expose the issue of variability and intermittency of VRE, agents have no perfect foresight, which means that the optimum is only a single-period optimum. In the UK the pool market clearing mechanism was superseded by several iterations of market reform, the last of which, though being more complicated, should have eliminated market power [41], like an idealized pool mechanism. Unlike a traditional agent-based model where every agent learns from its previous experience, our model only allows the storage agents to have a learning capacity. The storage agents learn from the model results through an iteration of the model which determines the utilisation factor of their devices via a cost levelisation algorithm. In this approach, the agents don't attempt to maximise their profit but choose instead to bid their available capacity into the market with their marginal cost. At each period, the output of the model contains the electricity generated by each technology, the charge state or stock of each energy storage, and the total system and flexibility cost.

To compare the flexibility of thermal generators and energy storage fairly and reveal the physical cost when thermal generators transfer from energy provider to flexibility provider, a capacity market and other forms of long-term reserve are not considered. The no-reserve (no capacity market or any form of reserve) assumption reveals the naked flexibility of thermal generators. The thermal operators are not rewarded by the system operator for being on standby and being available to generate. Their only reward is bidding opportunities in the future if they warm themselves up. Thermal generators are constrained with a ramp-up rate limit and are subject to start up costs (shown in in Appendix 1). There are no additional costs associated with ramping thermal capacity once started. These assumptions make energy storage compete with thermal generators in an environment where their advantage of short-response time will be taken into account.

The two-stage design of the model allows the effects of demand forecast error on curtailment and energy flexibility demand to be examined. In the ahead electricity market (i.e. the wholesale market), the generators and energy storage operators will bid their available capacity with their marginal price into the market.The system operator will then clear the market to meet the day-ahead demand forecast from the electricity system operator (ESO) of GB National Grids [42], which is provided exogenously to the model. If the available capacity is insufficient to meet this demand, the balancing market will then attempt to meet the energy gap. The result of the ahead market becomes the initial generation schedule, whose difference between the real-time demand [43] decides the size of the balancing market. When the generation schedule exceeds the real-time demand, electricity sources in the schedule will bid their curtailment cost, which here is the difference between start-up cost and avoided opportunity cost of fuel. The curtailment market clears at the lowest curtailment cost. When there is a demand gap, either because of insufficient availability or demand forecast error, interconnectors and all the electricity sources with remaining availability will bid in to mitigate the demand gap. If there is still a demand gap at the end of the balancing market, the model will report a blackout.

Levelising storage cost into a periodic storage cost per MWh

In this section, we define a novel cost levelisation function based on technology parameters for energy storage technologies and embed it into energy storage agents. We also define the agent-based structure for competition among energy storage and thermal-like power sources The storage agents charge at zero cost using the excess generation and curtailment from VRE-like and nuclear generators (as this energy has zero value for the power system and will be abandoned if not used). The energy storage operator sets the cost of discharged electricity in order to the claim back their project costs, by pricing the stored energy using an algorithm to levelise the capital and operational cost of a storage project to each MWh of electricity in the storage operator's bid.

The capital and operational cost of each storage technology comes from an aggregation of example projects (1MW, 250MWh for hydrogen, 1MW, 4MWh for others) [44].

In our model, storage operators are divided into two categories, battery-like storage and pump-hydro like storage. Pumped-hydro-like storage is defined as storage in which the operational life is independent of the number of energy cycles which are delivered . In this case, all the capital and operational costs are levelized to a time cost, so that the cost for each MWh of electricity stored is, for the i^{th} generator,

$$S_i = \frac{a_i}{\delta_i} * N$$

where N is how many periods this particular MWh of electricity has been stored, a is the levelized time cost assuming full utilisation,

$$a_i = \frac{O\&M\ cost + capital\ cost}{E_i * lifetime(in\ periods)}$$

Here E_i refers to the energy capacity(size) of i^{th} storage agent. The lifetime is how many periods this storage agent can exist before its retirement. The utilisation factor of device i, δ_i, is defined as the ratio between the energy being stored (the stock) and the energy capacity of the device

$$\delta_i = \frac{\sum_{t=1}^{t=N_{max}} P_{it}}{N_{max} * E_i}$$

Where P_{it} is total amount of energy stored in the i^{th} agent at in time period t, and the sum runs over a suitable number of modelling periods (N_{max}). Thus, the model requires both tracking the history of each MWh of electricity stored and knowledge of the utilisation factor, which is not known by the agent and must be self-learned by the energy storage agent from its previous operation profile. Instead of learning from the past, the model is iterated with updated values for the utilisation factor, calculated from the usage profile over the entire modelling period until the utilisation factor converges.

Pumped-hydro-like storage is defined as storage in which the operational life is independent of the number of energy cycles which are delivered. Its capital cost is now levelized to a cycle cost (£ cycle^{-1}), leading to the cost associated with each MWh of energy stored for the i^{th} storage agent,

$$S_i = \frac{a_i}{\delta_i} N + b_i$$

where a_i is now

$$a_i = \frac{O\&M\ cost\ over\ lifetime}{E_i \times lifetime(in\ periods)}$$

For a battery, the life is limited by degradation caused by charging and discharging. A partial discharge does not cause as much degradation as a full discharge. The amount of cycle life used per discharge is assumed to be linear with the depth of discharge, i.e. the ratio of the energy discharged to the energy capacity. This means that

$$b_i = \frac{capital\ cost}{E_i * \ maximum\ cycles}$$

Where maximum cycles are the cycle life given by storage cost assumption documents released by BEIS in the forms of the number of full charges and discharges as technology can complete prior to end of life [44]. The demand profile of the GB power system [43] is used to decide whether a storage technology will use up its life cycles before the end of its lifetime(i.e. battery-like or pumped-hydro-like).

As there are usually two daily demand peaks in the GB power system, a storage technology is assumed to be pumped-hydro-like if it can loop two or more times a day over its lifetime (e.g. 70 years for a hydro plant[44]) without exceeding its cycle life (e.g. 10^6 cycles for a hydro plant [44]). In contrast, battery-like storage will use up its lifecycles before the end of its lifetime if it loops two times a day; for example a battery has lifetime of 15 years and can charge and discharge for 5000 cycles [44]. Therefore, pumped-hydro, compressed air, and thermal energy storage are counted as pumped-hydro-like storage. Li-Ion batteries and hydrogen (because of the membrane of PEM electrolysers) are counted as battery-like storage. Note that, because all the storage is newly installed capacity, the storage pool will be empty at the beginning of modelling.

Data used in the model to describe the storage agents has been taken from the storage cost assumption made by BEIS[44] (shown in Appendix 1). When the energy storage operators work with a full utilisation factor, the various thermo-mechanical energy storage devices (thermal, compressed-air, pumped-hydro) are cost effective for a storage intraday storage, while battery will be the optimal choice for storage length from 40 to 647 periods (20 hours to 323.5 hours) and hydrogen is optimal for longer storage terms.

Curtailment mechanism and spatial deployment of VREs

Curtailment from VREs has three sources: curtailment in re-dispatch by the system operator because of transmission limits, curtailment for all generators in the balancing market caused by demand forecast error, and excess generation of renewables because their output exceeds the demand. In this work, as the transmission capacity is assumed to be sufficient, the curtailment in re-dispatch is ignored. Here, the excess generation includes the excess generation of all inflexible generators, including nuclear, natural-flow hydro and VREs, which all have a near-zero marginal cost but are hard to dispatch.

Curtailment arises when the demand forecast for a dispatch period is too high and the excess of scheduled energy over the real demand needs to be moderated. In such cases the excess energy is first diverted to storage at zero marginal cost or sold through interconnectors (if overseas demand is available). Any residual excess needs to be curtailed at source and generators are invited to bid into a curtailment auction. In the curtailment auction, a thermal generators' start-up cost and avoided fuel cost compete against VREs zero marginal curtailment cost. The winning bidders are then paid to turn off.

To describe the variability and intermittency of VRE, this research employs the fifth-generation European Centre for Medium-Range Weather Forecasts (ECMWF) atmospheric reanalysis of the global climate (ERA5) for the UK and nearby seas (Hersbach H. 2023) to provide an hourly weather grid with a spatial resolution of 10km*10km. The 100m wind speed and downward solar radiation are used for wind and solar output calculations at each period, respectively. Figure 2 shows the geographic distribution of both operational and planned VRE installations in Great Britain. [45]

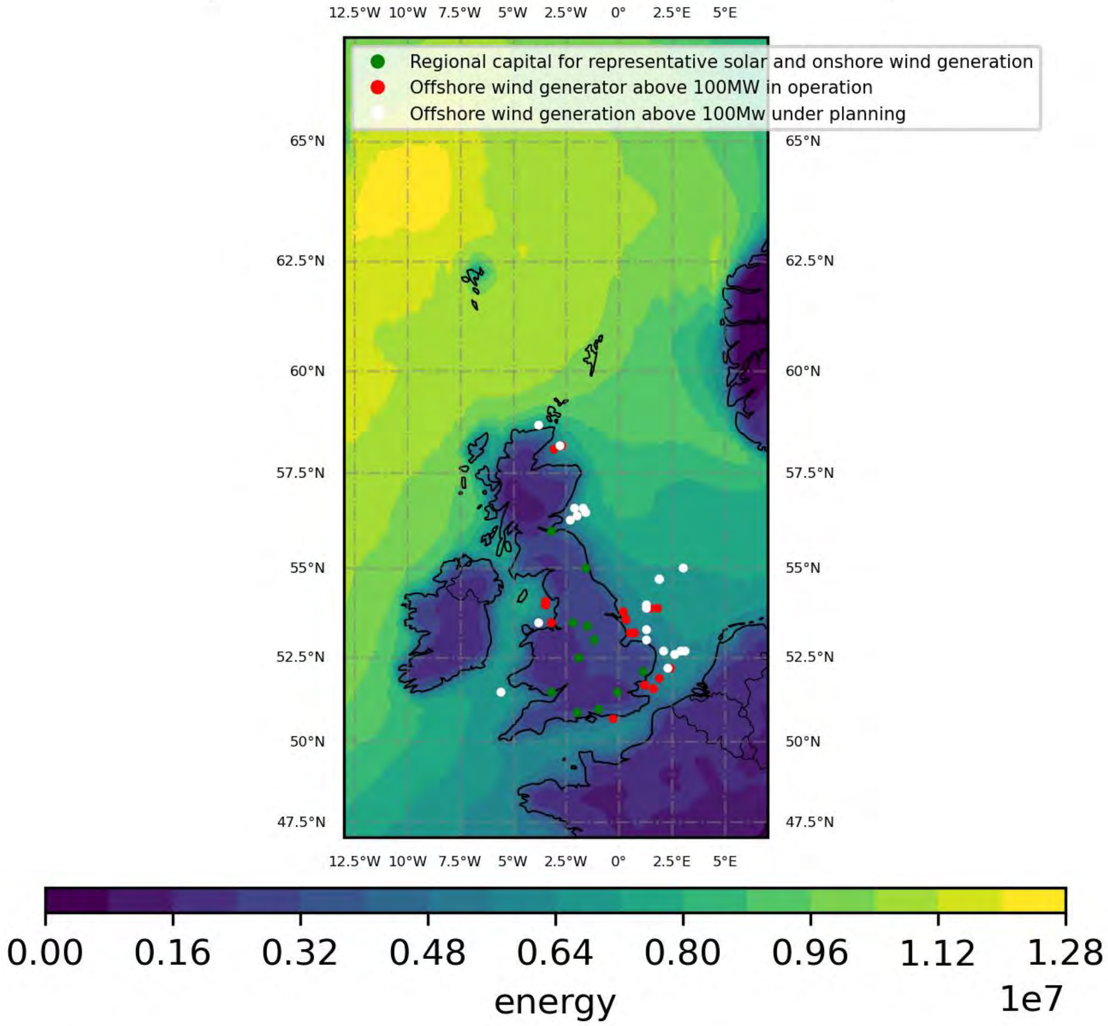


Figure 2: Wind potential map showing the yearly energy capacity for offshore wind generators in operation (red) and planned (white). Representative solar and onshore wind locations are also shown (green)

Onshore wind and solar capacity are aggregated at the regional level and located at representative locations (the primary city for each UK region, e.g. Nottingham, Ipswich, London, Newcastle, Manchester, Edinburgh, Portsmouth, Bournemouth, Cardiff, Birmingham, and Sheffield), as shown by the green points in figure 2. English regions are relatively compact and, therefore, have similar wind and solar profiles throughout.

The one exception to this is Scotland, whose size means that aggregating all the capacity at one location will lead to some error. However, it is shown in Appendix 3 that aggregating the Scottish onshore wind capacity results, at most, in a difference of 3.7% in the total VRE output and a 4.1% period by period root mean square error compared to Scottish onshore generation modelled site by site. The reduction in computational expense achieved by the aggregation is therefore deemed to justify the simplification. For offshore generation capacity, which has more geographic variability, generators above 100MW are considered individual entities at their precise locations; these generators account for 97.8% of the overall offshore wind capacity. The red points in figure 2 show the current offshore wind generators in operation, whilst the white points are planned. [45]

Other flexibility providers: Thermal generation and interconnectors

Apart from energy storage and excess generation from VREs, the energy flexibility providers include thermal generators (CCGT, OCGT, nuclear, and biomass) and interconnectors. Each thermal generator technology has an agent defined by operating emission, embodied emission, energy efficiency, fuel cost, carbon cost, fixed operational cost, variable operational cost, start-up cost and ramp-up rate. The biomass generator has an extra constraint of total available fuel based on GB annual biomass production (16 TWh[46]). Currently, the UK produces ~35 TWh [47] from biomass but this can result in carbon leakage as most of it imported. For capacity in operation, the embodied emission and capital cost are set to zero. In this research, gas prices of 20-50 GBP per MWh and carbon prices of 40-60 GBP per ton are tested for each scenario. The price of biomass energy is fixed at 20 GBP per MWh[46]

As a base case, future transmission availability through an interconnector is constrained by its historical 2022 transmission profile, scaled by the transmission capacity. When there is a demand in the balancing market, interconnectors bid their available capacity with the 2022 historical electricity price [48] and average carbon intensity (base scenario using today's reference from ESO [49], and future using their ambition) from their destination. When there is curtailment and excess generation, interconnectors can sell energy (after storage is filled) at the price in the destination if there is a demand on the opposite side. The income and expense (emission and cost) from selling and buying electricity through interconnectors are counted, along with the capital cost of new interconnectors, in the system cost. The embodied emissions from new interconnectors are included in the system's embodied emissions.

From a carbon and cost perspective, it only makes sense to buy or sell renewables via interconnectors since it will be cheaper to install thermal or energy storage capacity within the GB boundaries rather than outside, and incur the additional interconnector cost. As this model only extends to GB boundaries, modelling the excess VRE externally, and its correlation with GB demand is not in scope. Hence, to test the effect of interconnector availability, both the worst case (no interconnector availability) and best case (generous neighbours willing to supply the full interconnector capacity at all times) are used to provide upper and lower limits for the likely future impact of interconnectors.

Cost of the future power system

The cost of a power system can be divided into two parts: 1) the fixed cost of installing capacity for the power system, *i.e.* the capital cost and fixed O&M cost of various power sources; 2) the variable cost of operating the power system, *i.e.* the marginal generation cost of each power source. In our model the power systems consist of three kinds of power sources: thermal-like power sources, VRE-like generators and energy storage facilities. Decarbonisation of a power system is the process of phasing out thermal generators. VRE power sources and energy storage facilities operate with negligible marginal cost compared to the capital cost and fixed O&M cost needed to introduce them into and maintain them in the power system. In contrast, the cost of a thermal-like power source is dominated by the marginal generation cost. From the perspective of the demand side, the cost of providing energy can be divided into (1) the cost of generating electricity (i.e. energy) and (2) the cost of bringing electricity to a certain period (i.e. flexibility).

In conventional power systems, the majority of the cost of energy, which is generated with flexibility, is priced by the marginal generation cost of thermal-like power sources. Changing from a power system dominated by thermal-like generators to a future power system consisting of all three kinds of power sources will only happen when energy (VRE) is no more expensive than energy with flexibility (i.e. thermal-like generators). Energy with flexibility (thermal) will be replaced by energy (VRE) plus flexibility (storage) when energy plus flexibility is more cost-efficient than energy with flexibility. In a fully decarbonised power system, when thermal-like generators are phased out, the energy and energy flexibility will be priced separately. The flexibility will be priced by the storage cost and excess generation from VRE (i.e., more VRE capacity than necessary to meet the periodic total energy demand), while the energy will be priced by the cost of VRE-like power sources. Optimisation when designing a power system is then a question of deciding how much storage and VRE to introduce.

To better evaluate the flexibility solutions of a future power system, this paper uses the total power system cost *T*. Using total system cost better reflects the usefulness of a flexibility solution, in contrast to the electricity price, which is set by the marginal generation cost and the last bit of flexibility price. The total cost, T, for a power system, and the cost per MWh of electricity delivered in the t^{th} period, with i power sources, is calculated as follows:

$$T = \frac{\sum C_i + \sum_{t=1}^{t=T}[\sum(d_{it} \times S_i) + \sum(g_{it} \times M_{it}) + \sum C_{imt} + \sum(I_{it} \times i_{it})]}{\sum_{t=1}^{T} D_t}$$

$$T_t = \frac{\sum C_i}{17520 * D_t} + \frac{\sum(d_{it} \times S_i) + \sum(g_{it} \times M_{it}) + \sum C_{imt} + \sum(I_{it} \times i_{it})]}{D_t}$$

Here, C_i is the cost of introducing, maintaining and operating i^{th} generator, namely its annually levelized capital cost plus fixed O&M cost. d_{it} is the electricity discharged from the i^{th} storage agent at t^{th} period and S_i is the function translating the overall cost of a storage project to a cost for each MWh of electricity, depending on how long it has been stored. g_{it} is the amount of electricity produced by the i^{th} generator in the t^{th} period, and M_{it} is its marginal generation cost. i_{it} is the imported electricity through the i^{th} interconnector at the t^{th} period, which can be negative when the system operator is selling electricity to its neighbor and I_{it} is its price at the destination. C_{imt} is the variable operational and maintenance cost of each generator in operation in the system at t^{th} period. 17520 is the number of total modelling periods, i.e. half hour resolution for one year. Generation is constrained by the fact that the total electricity delivered in the t^{th} period, will always be equal to or less than (implying a blackout) the real demand, D_t i.e.

$$D_t \geq \sum(d_{it} + g_{it} + i_{it})$$

To further distinguish the cost of providing energy and flexibility, we separate the total system cost into a flexibility cost, *F*, and an energy cost, *E*, so that

$$T = F + E$$

The energy cost is taken to be the cost of VRE which is providing energy but not flexibility to the system, i.e. VRE-like generators not using excess generation to provide flexibility. In this research, they are set as the operational (Scenario A) and projected (Scenarios B,C,D) VRE capacity of GB power system. (BEIS 2024) The energy cost is then the sum of the capital and fixed O&M cost of these j generators of energy,

$$E = \sum C_j$$

The flexibility cost F_t at t^{th} period and the general flexibility cost *F* is then:

$$F_t = T_t - E_t = \frac{\sum C_i - \sum C_j}{N * D_t} + \frac{\sum(d_{it} \times S_i) + \sum(g_{it} \times M_{it}) + \sum C_{imt} + \sum(I_{it} \times i_{it})]}{D_t}$$

$$F = \frac{\sum C_i - \sum C_j + \sum_{t=1}^{t=T}[\sum(d_{it} \times S_i) + \sum(g_{it} \times M_{it}) + \sum C_{imt} + \sum(I_{it} \times i_{it})]}{\sum_{t=1}^{T} D_t}$$

The flexibility cost *F* reflects the cost of electricity flexibility levelised to each MWh of electricity in developing and operating a power system. *F* can be used to evaluate how cost-efficient a flexibility solution is for a future power system with *i* generators providing energy with flexibility and *j* generators providing energy only. In a perfect market, the total system cost should be the money consumers pay on their energy bill, while the flexibility cost will be the component that pays for flexibility alone.

Carbon intensity is another important index for a future power system. This model takes the embodied emission of energy storage facilities into account and the carbon intensity is calculated as,

$$c = \frac{e_i + \sum_{t=1}^{t=T} \sum(g_{it} \times c_i)}{\sum_{t=1}^{T} D_t}$$

c_i is the carbon intensity of each MWh of electricity from i^{th} thermal generator. e_i is the embodied emission of i^{th} agent levelised from its lifetime to the modelling period.

To study energy storage's impact on decarbonisation it is important to include the embodied emission of energy storage facilities (as included here). To be compatible with the current carbon intensity reported by the UK's National Grid we not include the embodied carbon for thermal and VRE installations. In this research, the marginal cost of each thermal generator consists of its carbon cost, fuel cost, fixed operational cost and variable operational cost, using the data from Calliope UK. [50]. The capital cost and embodied emission used here are all levelized to a yearly cost and emission. The carbon intensity for thermal generators is taken from the carbon intensity dashboard of the UK National Grid. [49]

Scenarios

This research builds two scenarios for the power system of Great Britain, one based on 2022 (scenario A) and one on the future, namely with all planned VRE capacity [51] [52]. For the future scenario, three energy storage levels are tested: (B) the current storage capacity, (C) the planned storage capacity, and (D) our recommended storage capacity (with 25 GW, 1330GWh storage). A summary of the capacities and assumed costs for each scenario is shown in Table 1.

Table 1: Current and future power capacities and key parameters for the model of the GB power system(capacities of energy storage technologies given in forms of (power capacity, energy capacity) [51] [52]

Parameter	(A) 2022	(B) Future with current level storage	(C) Future with planned storage	(D) Future with 25 GW storage
Generators				
CCGT (MW)	28000	28000		
OCGT (MW)	4146	4146		
Biomass (MW)	4163	4762		
Nuclear (MW)	5883	9143		
Interconnection (MW)	8400	14500		
Solar (MW)	8687	31351		
Onshore (MW)	12692	55352		
Offshore (MW)	9860	36782		
Storage				
Pumped-hydro storage (MW)	3233, 12932	3233,12932	4337,17348	5000,20000
Compressed air storage (MW)	0	0	0	5000,20000
Thermal(molten salt)storage (MW)	0	0	0	5000,20000
Li-Ion battery (MW)	1614, 6456	1614,6456	18211, 72844	5000,20000
Hydrogen (MW)	0	0	468, 117000	5000,1250000
Costs				
Gas price (£ per MWh)	20-50			
Carbon cost (£ per ton CO_2)	40-60			

Results

Figure 3 shows the generation share of each technology of the GB power system in scenario B. The nuclear generator was forced to run at the full load at the beginning of the model. CCGT (dark brown) is employed almost continuously to meet long-term variability, whilst biomass largely consumes all the available fuel. Pumped hydro utilization is intermittent and is employed to meet the short-term variability. The onshore and offshore wind represents the majority of VRE generation.

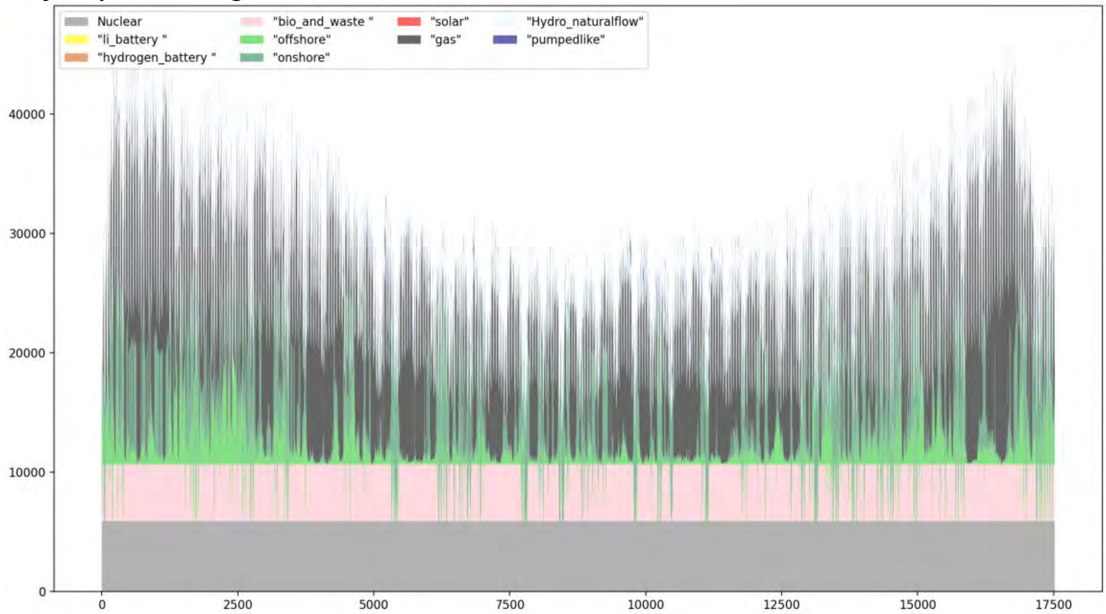


Figure 3: Generation share of scenario B under high gas and carbon price. Only electricity used to meet the demand is shown. Electricity charged to energy storage and sold through interconnectors are not included.

Table 2 shows a summary of the results. In all the future scenarios the VRE output represents a very large fraction of the total demand. Under these circumstances, the flexibility cost dominates the total system cost, no matter what flexibility solution is employed. This highlights the importance of cost-efficient flexibility providers and other flexibility measures, like demand-side controls.

Table 2: Output of the model over one year. "high" = high gas and carbon price; "low" = low gas and carbon price.

		(A) 2022	(B) Future with current amount of storage	(C) Future with planned storage	(D) Future with additional2 5GW storage
Thermal Generation (TWh)	low	117.0	54.9	53.6	52.9
	high	117.1	58.2	55.1	54.3
Curtailment(TWh)	low	0.12	2.0	1.9	0.96
	high	0.07	1.8	1.8	0.92
Excess Generation (excluding nuclear) (TWh)	low	0.45	112.1	111.3	109.2
	high	0.42	112.0	109.3	107.6
Thermal start-up cost (million GBP)	low	3.87	114.9	110.2	98.2
	high	9.24	149.9	130.3	136.9
Renewable Output (excluding nuclear) (TWh)	/	47.6	211.8		
Annual Demand (TWh)	/	232.9			
Energy cost (GBP/MWh)	/	3.35	12.68		
Flexibility cost	low	30.34	47.62	47.76	35.33

(GBP/MWh)	high	56.55	59.68	55.89	44.00
Total Electricity Cost (GBP/MWh)	low	30.89	60.30	60.4	48.01
	high	55.78	72.36	68.57	56.68
Carbon intensity (g/KWh)	low	199.4	93.6	93.5	89.1
	high	154.5	67.7	65.9	61.1

In the future scenarios (Scenarios B,C,D), a great deal more VRE has been installed. The amount of thermal generation called-on annually falls to around half that of 2022 levels. In these scenarios, thermal generation is used primarily to provide long-term flexibility (typically energy gaps longer than one week).

Thermal generators have the highest marginal generation cost, yet there is still considerable thermal generation in all future scenarios because of the need to mitigate long-term flexibility gap. (meeting ~25% of demand). In scenario B, there is insufficient installed energy storage, while in scenarios C and D, energy storage is at a similar scale to gas generation capacity and competes with it. In scenarios B, C and D, where VRE output + nuclear generation exceeds the total annual demand, thermal generation remains competitive, even when, for example, 18 GW of additional storage (17 GW Li-ion + 1 GW Pumped hydro) is added to scenario B to give C. Thermal generators in scenarios C-D, are more cost effective than interconnectors and energy storage when mitigating VRE's long-term variability and the seasonal storage demand.

Our cost calculation method means that the levelized storage cost of each MWh of electricity rises when it is stored for longer. This means long-term storage demand, which comes from long-term variability of VRE and seasonal differences between the demand and VRE supply profile, is more cost-efficiently mitigated by thermal generation. The exception being some extreme cases when energy storage need to store from a distant time but themal generators also have to start-up frequently.

Installing more VRE capacity to decarbonise the power system increases both the total system and the flexibility cost (Table 2). Additional VRE lifts the amount of curtailment and excess generation. When energy providers change from thermal generators to VRE, most curtailment comes from VRE, which raises the level of curtailment in Scenario B, C and D because in Scenario A, turning down thermal generatior isn't counted as curtailed energy. In Scenario D, the curtailment falls because curtailment for energy storage isn't really curtailed but sent back to storage with no loss.

The excess generation rises hugely to nearly the same scale of electricity delivered from VRE (half of total VRE output) even though the overall generation from VRE (nuclear exempted) is still lower than the annual demand. This highlights the potential of employing energy storage or flexible load to digest excess generation and curtailment. Note that here thermal generation reduction doesn't strictly equal the sum of avoided curtailment and excess generation because excess generation from nuclear also charges energy storage.

The rise in total system cost comes from the cost of frequent start-up of thermal generators (in flexibility cost) and the capital and fixed O&M cost of VRE (in energy cost). When thermal generators switch to being flexibility providers, they have to respond to VRE's variability and intermittency. In reality, these frequent start-ups could be avoided by keeping the thermal generators on standby, but this incurs warm up costs and additional emission.

The introduction of energy storage (especially pumped-hydro-like) will help avoid cost from frequent start-up. This is most obviously seen in the 25GW storage scenario (D), which has significant pumped-hydro like storage (compressed-air, pumped-hydro and thermal storage) that is cost effective for frequent looping and short-term storage. In contrast, the GB planning scenario (C) has mostly battery storage, whose cost-efficient storage period is between pumped-hydro like and hydrogen storage. Having more energy storage that can loop frequently in (D), mitigates the short-term variability and intermittency of VRE, and reduces the flexibility cost of the system. Increasing storage capacity also lessens the sensitivity of total system cost and carbon intensity to gas and carbon prices, as thermal generation makes up a smaller share of flexibility. The low energy cost in the 2022 scenario (A) arises from the small VRE capacity, with thermal generators serving as both flexibility and energy providers, and their cost allocated to the flexibility cost.

The yearly average carbon intensity of 2022 GB power system was 180 g/kWh[49], while in this model, the carbon intensity of 2022 scenario (A) is 154.53 to 199.35 g/kWh depending on gas and carbon price assumption. The discrepancy arises from: 1) the absence of transmission limits in the model; 2) at the lower end, the low carbon and gas price cases have average gas and carbon prices lower than in 2022, leading to less gas generation. In all future scenarios (B-D), the most significant decarbonisation of the GB power system comes from VRE's replacement of thermal generators as energy providers. Energy storage's replacement of thermal generators as flexibility providers also decarbonises the system. Going from scenario B to C (adding 18 GW more storage, mostly Li-Ion capacity) will reduce the GB power system carbon intensity by 2g/kWh. Another 1 g/kWh carbon abatement can be achieved moving from scenario C to D, which replaces Li-Ion battery capacity with more cost-efficient energy storage. For the "stubborn" thermal generation mitigating the long-term variability and seasonal storage demand, a high gas and carbon price will help decarbonise it significantly by making biomass more cost efficient than CCGT and OCGT. In our recommended scenario (scenario D) the cost per MWh of electricity delivered by the future of the future GB power system will be similar to 2022 under the high gas and carbon price assumption but will be higher than the low gas and carbon price assumption.

Competitiveness among various flexibility solutions

Here, the effectiveness of different flexibility providers including energy storage, interconnectors, thermal generators and curtailment from VRE generation, in mitigating flexibility gaps is examined, along with their marginal contribution to future system costs. To test a flexibility provider's effectiveness in mitigating blackouts, we base our test on the future GB scenario with no storage (i.e. B with all storage removed) but with all nuclear initially turned off (referred to below as scenario B'). Nuclear capacity, with its high start-up cost, is the least preferred flexibility provider, so it will only turn on when there is a large flexibility gap and a blackout is about to occur. In such a system, 1-5 blackouts happen in the year despite there still being significant thermal capacity. With no reserve mechanism to give thermal generation incentive to warm up, it turns off when VRE output is sufficient but then is constrained by ramp-up rate when restarting. In the next period, a blackout happens if the intermittent VRE output falls below the capacity of thermal generators to meet the demand. This reveals that flexibility from VRE excess generation may not be able to offset the flexibility consumed by the turn off of thermal generation. However, once thermal generation has been fully transitioned to a flexibility providier, adding more VRE does increase the flexibility.

In reality, the GB system has more flexibility than the model, owing to the no-storage and no-capacity-market assumption and lack of capacity market in the model. The no-capacity-market assumption allows the model to reveal the additional cost when thermal generators change from energy to flexibility providers under the assumption that a proper capacity market will perfectly price the start-up cost, and fairly compare them as flexibility providers to energy storage (who don't have warm-up costs and emissions). At the same time, turning off nuclear impairs system flexibility because it provides a stable supply and frees other thermal capacity to serve as a flexibility provider.

Figure 4 gives the first 1200 periods of the future Scenario B' (Scenario B with no energy storage capacity and all nuclear turned off), covering the first 25 days in January, with both a high gas and a high carbon price. Five blackouts occur at periods 266, 326, 806, 854,1178. Figure 5 and Figure 6 add 5GW of OCGT and interconnection capacity, respectively. Figure 7 adds 1 GW of each storage technology (5 GW in total).

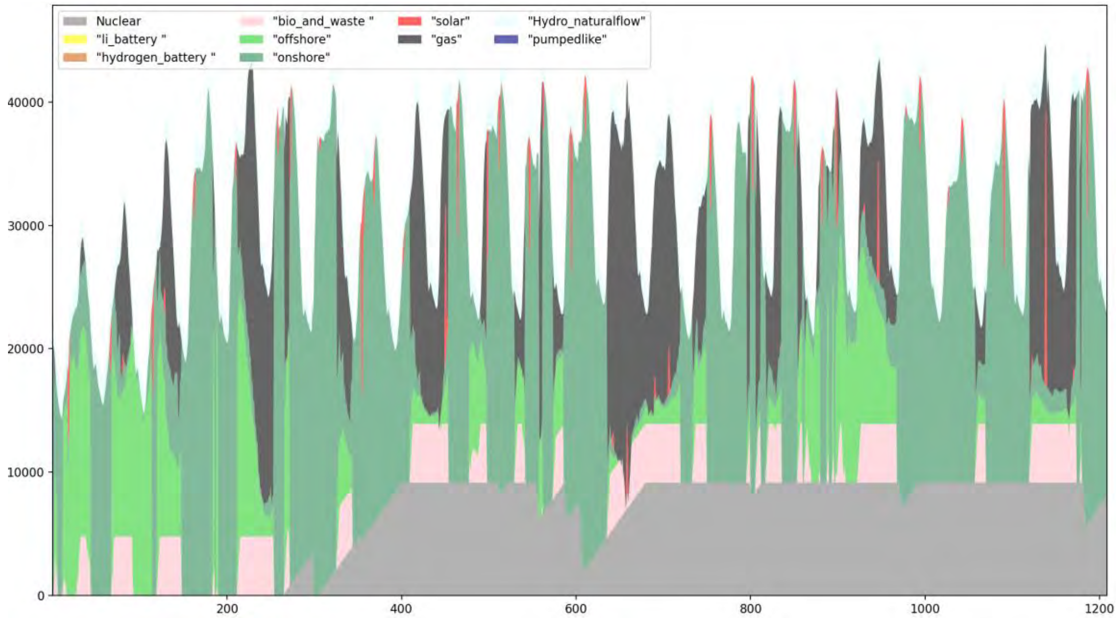


Figure 4: Profile of electricity delivered to meet the real-time demand for scenario B′ for periods 0 (Jan 1st 00:00) to 1200, assuming high gas and carbon prices.

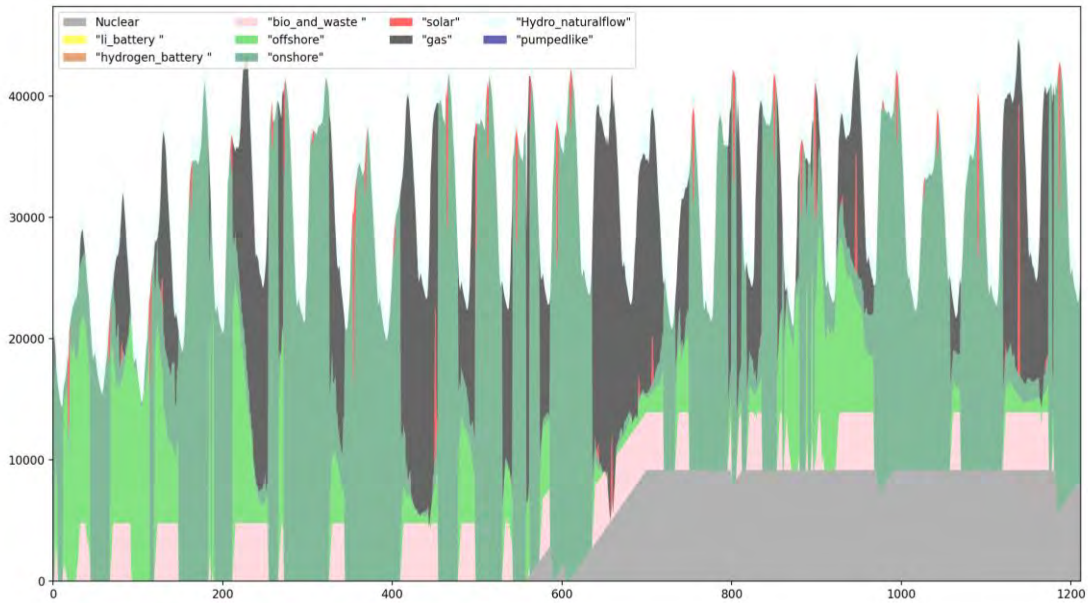


Figure 5: Profile of electricity delivered to meet the real-time demand for scenario B′ with 5GW of extra OCGT for periods 0 (Jan 1st 00:00) to 1200, assuming high gas and carbon prices.

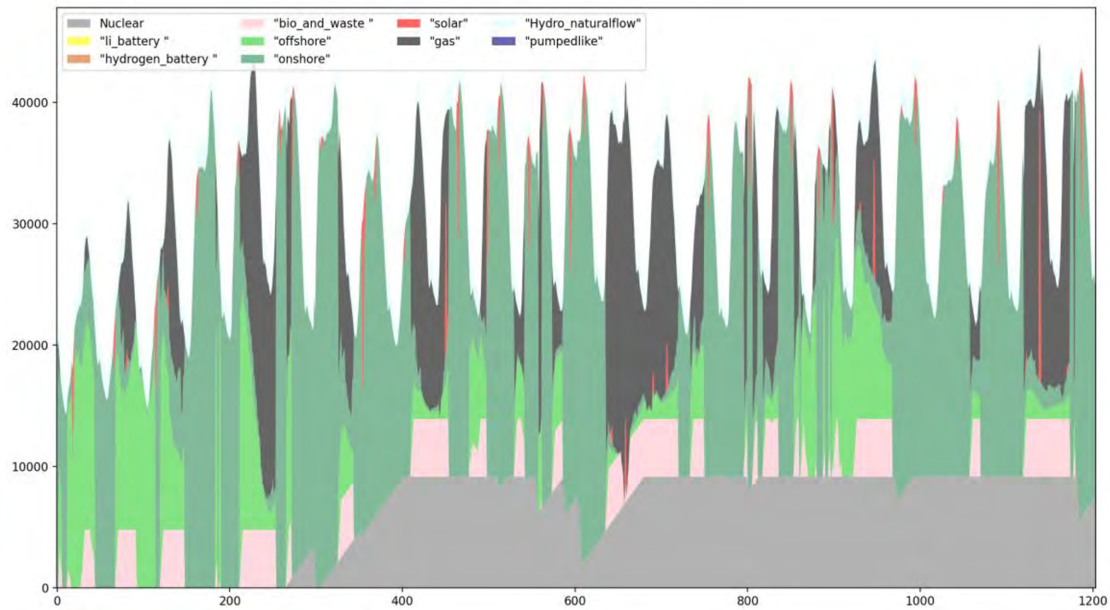


Figure 6: Profile of electricity delivered to meet the real-time demand for scenario B′ with 5 GW of addition interconnection for periods 0 (Jan 1st 00:00) to 1200, assuming high gas and carbon prices.

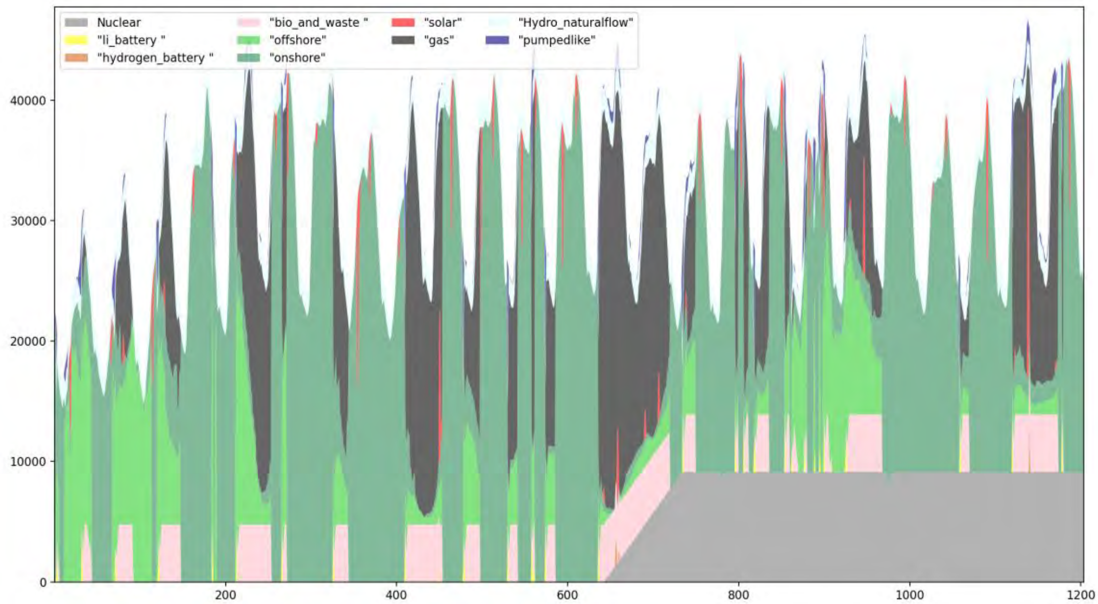
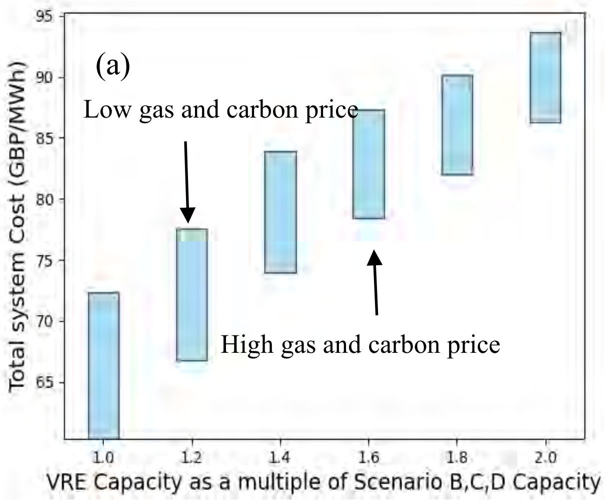


Figure 7: Profile of electricity delivered to meet the real-time demand for scenario B′ with 5 GW of additional storage for periods 0 (Jan 1st 00:00) to 1200, assuming high gas and carbon prices.

At the beginning of these cases, nuclear was turned off and doesn't start up because of its high start-up cost and only starts when it is more economic than using another competing flexibility provider. Thus, when nuclear starts is a proxy for the effectiveness of a flexibility provider. In figures 5-7 nuclear starts earliest in the case with added interconnection (Figure 6). Nuclear starts earlier in the "added OCGT" scenario (Figure 5) than the "added energy storage" scenario (Figure 7), suggesting that energy storage brings more efficient flexibility than thermal generators, or interconnections. The "added energy storage" case (Figure 7*)* is the only future scenario with additional flexibility that avoids blackouts. Between OCGT and energy storage, nuclear starts earlier in OCGT scenario, suggesting that energy storage brings more efficient flexibility than thermal generators. The OCGT generation capacity has the same extent of flexibility as energy storage (i.e. it can ramp up fully within one period) but is more expensive. Additional storage turns to be the best flexibility provider when there is flexibility gap.

A system without a flexibility gap (blackouts) should choose additional capacity to lower its total system cost and carbon intensity. To reveal the impact of additional VRE, which provides energy (and limited flexibility via excess generation), we test the impact of increasing the VRE capacity for the future scenario with 2022 storage capacity (B). Figure 8 shows (a) the carbon intensity and (b) the total system cost when increasing the VRE capacity (up to 2 times the base scenario).



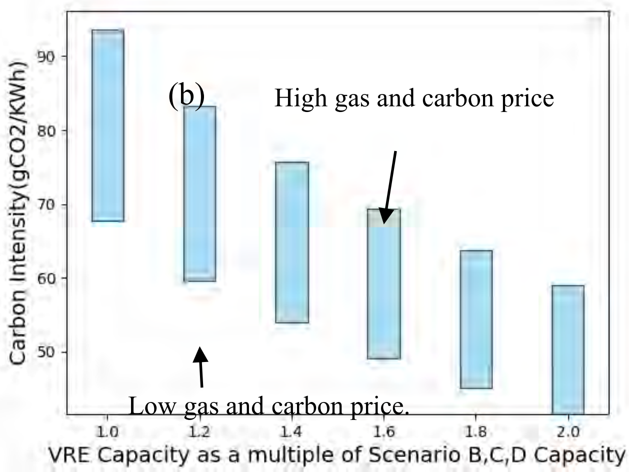


Figure 8: Carbon intensity (a) and total system cost (b) at different multiples of VRE capacity for the future scenario with 2022 storage capacity (B). The range shown corresponds to high and low gas price

In figure 8(a), moving vertically up a bar (from low gas and carbon price to high gas and carbon price) causes biomass generation to replace gas. Increasing VRE generation capacity reduces emissions, but the total system cost rises because the cost to the system of adding VRE capacity is higher than the saved fuel cost. The increased cost arises from the capital cost of building VRE and the cost of more frequent start-up and shut-down of thermal generators. The capital cost of the VRE only accounts for an increase of £ 2.5 MWh^{-1} of total system cost for each each 20% increase in capacity in capacity (e.g. going from 1 to 1.2 times the capacity). The additional start-up cost of thermal generation when VRE is increased exceeds the fuel cost avoided, bringing additional total system cost similar to the levelized capital cost of the VRE.

At around 1.4 times as much VRE as currently planned for the GB power system, all of the thermal generation capacity has transitioned to being a flexibility rather than an energy provider. Before this point, there is a cost associated with transferring the thermal generators from energy providers to flexibility providers (referred to here as the transfer cost), namely the additional start-up costs related to increasing the VRE generation capacity. For more than

1.4 times the VRE capacity, there is no longer a transfer cost from the changing role of thermal generators; the cost to the system of installing additional VRE increases more slowly as no additional start-up costs for the thermal generation capacity are added. Total system cost still rises because excess energy from additional VRE without storage is not a cost efficient flexibility provider under Scenario B. This is also explains why the rate at which avoided emissions falls decreases when VRE is more than 1.4 times the planned capacity; thermal generation stops being replaced as an energy provider.

Figure 9 shows how cost and carbon intensity change as more interconnector capacity is added to the system under high gas and carbon price (blue) and low gas and carbon price (red) using a base case (× on the figures) of scenario B. In the base case, an interconnector is constrained both by its transmission limit and historical transmission profile. Increasing the capacity of interconnectors will reduce total system cost. The fall of total system cost (Figure 9b) can be attributed to the export of more excess generation. The carbon intensity (Figure 9a) doesn't change because the GB power system is similarly decarbonised to its neighbours.

The upper and lower limits of the bars in Figure 9 show the sensitivity to the availability of interconnector capacity. In the best case (lower limit), the interconnectors are only constrained by their transmission limits in either direction, and the destination can digest any energy transmitted. In the worst case (upper limit), the interconnectors are turned off.

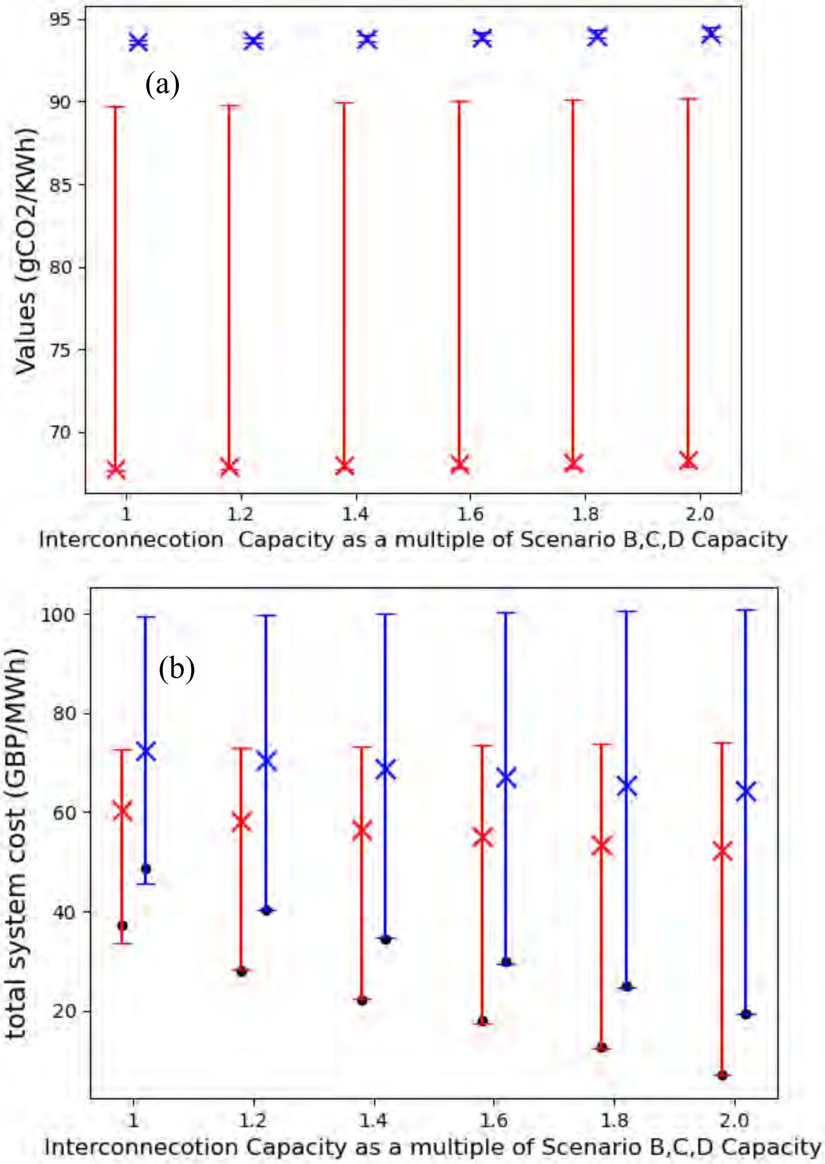


Figure 9: (a) Carbon intensity and (b) total system cost when interconnector capacity is scaled up in increments of 20% of the base case capacity for scenario B. × = base case where an interconnector is constrained by the scaled historical profile. Upper(worst) and lower (best) limits show the impact of the as-

sumption used for interconnector availability at the low (red) and high (blue) gas and carbon prices.• = "hungry" assumption

Turning off the interconnectors gives very similar carbon intensity to the case where interconnectors are not turned off, except for the case of high gas and carbon price, as shown by the top of the blue bars in Figure 9a. The flexibility (electricity used to mitigate the flexibility gap) from interconnectors, will only be more competitive than thermal generation with high gas and carbon prices. The rise of carbon intensity here happens because the electricity from GB's neighbours has a lower carbon intensity compared to carbon-intense thermal generation in GB.

The top of both the red (low gas and carbon price) and blue (high gas and carbon price) bars in Figure 9b show that turning off interconnectors will significantly increase the system cost. In contrast, the best case of a fully available interconnector (bottom of red and blue bars) significantly lowers the total system cost. The majority of the reduction comes from selling excess generation through interconnectors. This is highlighted by the hungry assumption (• in Figure 9b) representing the total system cost when interconnectors cannot import but their export is limited only by capacity, so their only contribution is income from selling excess generation.

The tests of additional interconnector and VRE highlight that the cost of a future power system will come mainly from providing energy flexibility. Adding VRE reduces the system carbon intensity but will consume the system's flexibility by reducing the ability to respond to demand peaks if the thermal generators are not warmed-up and raising the transfer cost of thermal generators. As there is a cost reduction by selling excess generation, it is reasonable to believe other system operators will also prefer to optimise their cost by selling excess generation instead of selling flexibility through interconnectors. Using interconnectors to provide flexibility relies on excess generation being available from neighbouring power systems at the right time. This argument also works for GB, so the income from selling excess generation through interconnectors may be overestimated. Importing flexibility from thermal generators or energy storage will not be more cost-efficient than employing them inside the GB power system as the capital cost and operational cost will be similar. Generally speaking, the planned interconnectors don't negatively impact the total system cost of GB power system, i.e. income from exported electricity exceeds the levellised capital cost. Note that we ignore the benefits of carbon reduction in GB's neighbours by selling them VRE generation, which may have been priced in their electricity price but may further reduce the carbon intensity of GB power system.

Compared to energy storage, VRE (introduced as flexibility provider) and interconnections are weak flexibility providers. VRE is not cost-efficient, and an interconnector will only reduce total system cost by selling excess generation instead of providing cheap flexibility. As highlighted in table 2, energy storage will be the most preferred flexibility provider for the future GB power system, reducing both the system carbon intensity and total system cost.

Storage solutions for future GB power system

The current planned capacities of energy storage and VRE won't remove thermal generation (Table 2), as thermal generators will still be cost-efficient when mitigating long-term VRE variability. Changing the storage portfolio to include more H_2, the most cost-efficient storage technology for longer-term storage, might be beneficial. Figure 10 examines the impact of changing the share of hydrogen in the storage portfolio, for 5 to 35 GW storage added to the future scenario (B)

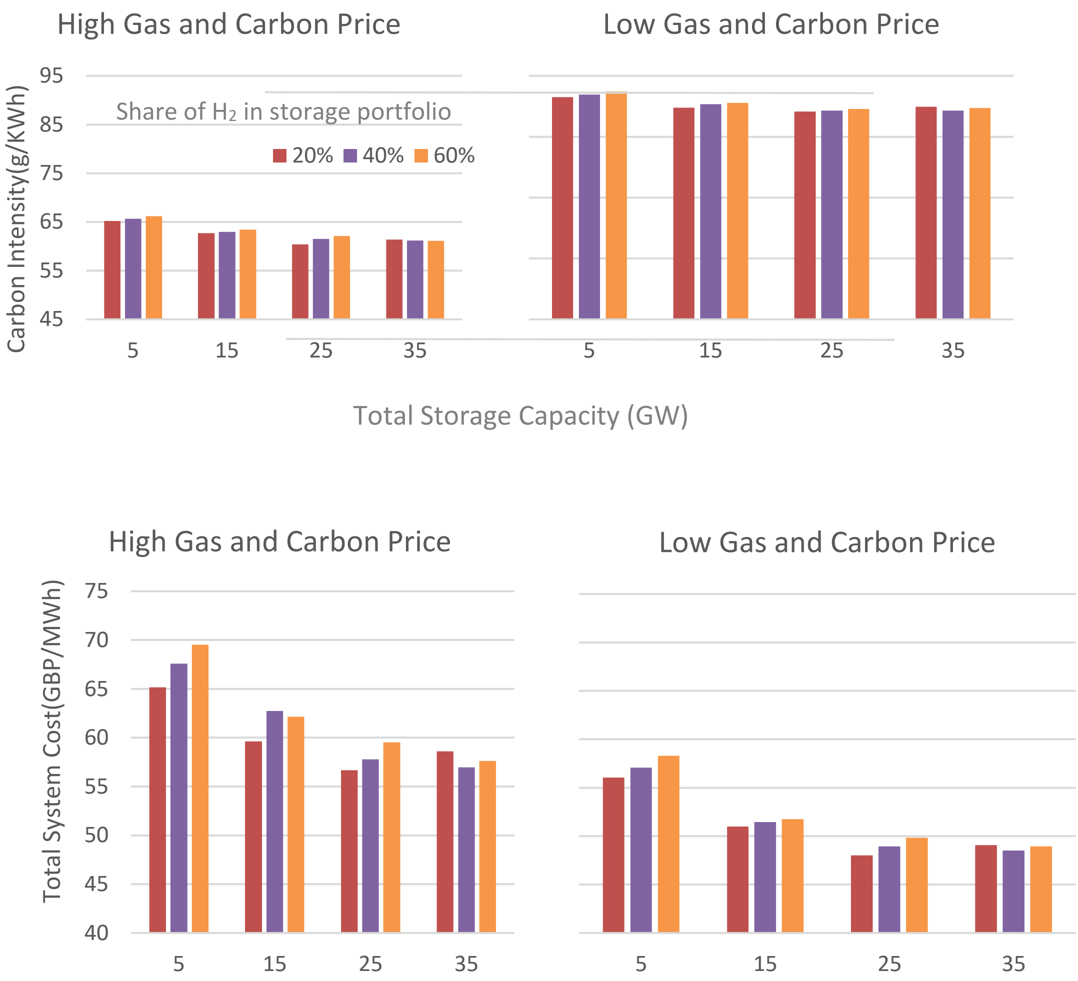


Figure 10: The carbon intensity and total system cost of future GB with different storage capacities and shares of H_2 storage, at high gas and carbon prices and low gas and carbon price

Increasing the share of hydrogen storage does not reduce the total system cost or the carbon intensity when it replaces short-term storage capacity. The benefit of seasonal storage is traded off with the reduced capacity suitable for short-term storage. After the flexibility demand suitable for short-term storage is all mitigated (i.e. more than the 25 GW recommended storage capacity), adding long-term (H_2) storage will reduce the system cost and carbon intensity by replacing thermal generation in responding to intermittent flexibility gaps in seasons where overall demand is high and overall VRE generation is low. Of all the cases, the case with 25 GW of energy storage capacity with low hydrogen share designed by us helps the GB power system reach its optimal system carbon intensity and total system cost, both under high and low gas and carbon price assumptions.

A higher gas and carbon price increases the competitiveness of energy storage by raising thermal generation costs. This causes a transfer from thermal generation to energy storage, represented by the significant reduction in total system cost and carbon intensity

Once large-scale energy storage capacity has been installed (i.e. >15 GW), the effect of high gas and carbon prices on energy storage's competitiveness becomes less significant. The final bit of thermal generation is difficult to phase out, despite the high gas and carbon prices, because the stored energy needed to replace it comes from the distant past and is therefore very expensive.

These results imply that when phasing out thermal (i.e. gas) generation in a power system, it is more cost-efficient to first replace it with quick-responding, short-term storage, before introducing long-term storage to completely phase it out. For the future GB power system, where planned VRE is cost-efficient as an energy provider and planned energy storage is insufficient for short-term storage demand (scenario C), short-term storage (e.g. pumped hydro) should be built first, and long-term storage (daily or seasonal) should be introduced after all short-term storage demands have been met. Based on this, we use low hydrogen share in our recommended storage composition.

Figure 11 shows the change in total system cost and the carbon intensity of the future GB power system (Scenario B) with different storage capacities using our "recommended" storage technology composition consisting of pumped-hydro, compressed-air, thermal, Li-Ion battery and hydrogen. Once energy storage is introduced (5GW), the flexibility cost and carbon intensity fall significantly compared to the future GB power system with the current level of storage. The total system cost and carbon intensity continue to fall with increasing additional storage capacity until 25 GW when further increases lead to a rise in total system cost.

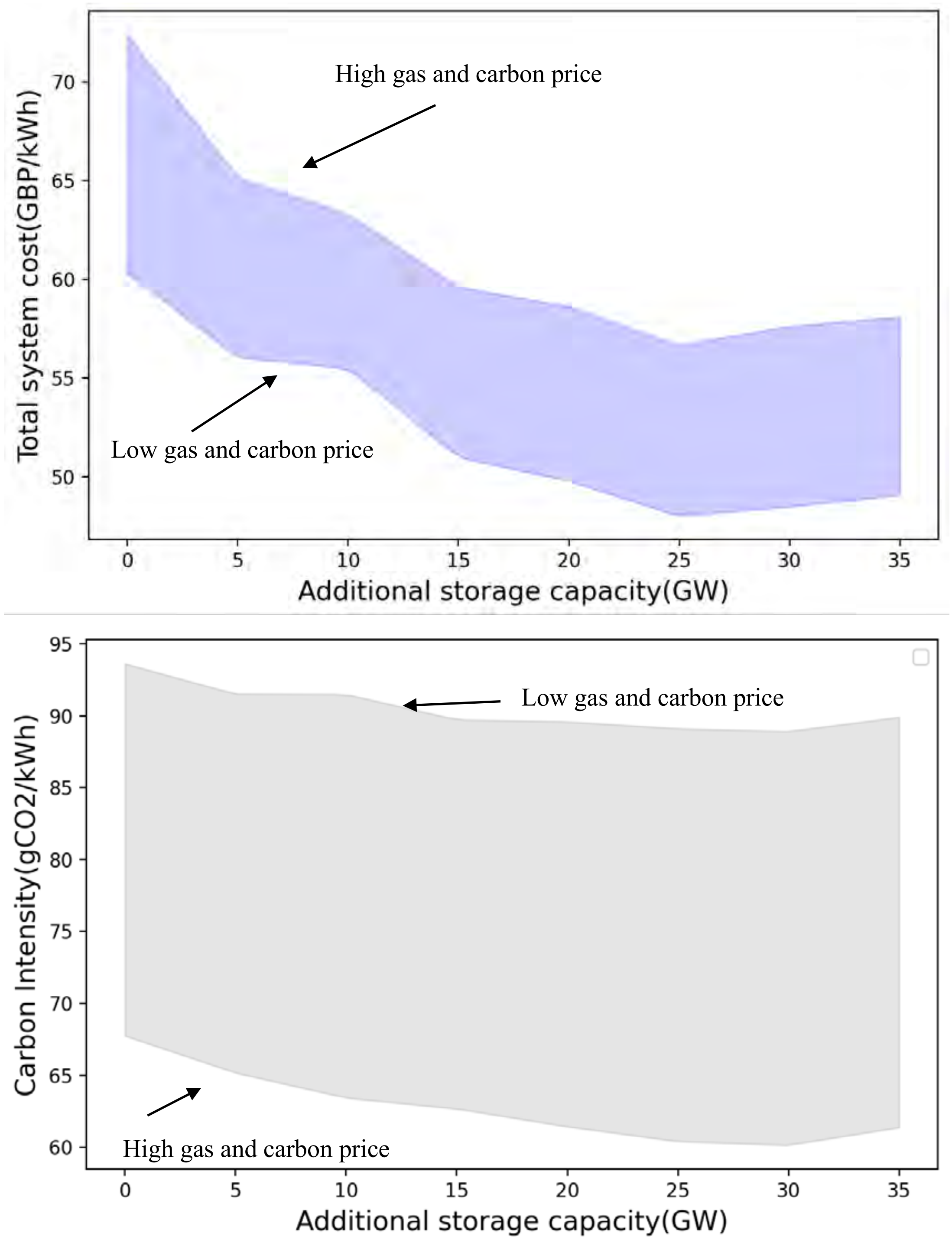


Figure 11: Total system cost (purple) and carbon intensity (grey) of future GB power system with increas-

ing storage additional to the future scenario (B)

When 25 GW additional energy storage capacity is introduced into the future GB power system, the carbon intensity under a high gas and carbon price (which is highly possible in 2030) is 60.4 g/kWh, higher than the 50g/kWh UK ambition [53].

Keeping the same level of thermal generation (CCGT and OCGT) as 2022 as a reserve of energy flexibility will lead to the carbon target not being met, as thermal generation is still a cost-efficient flexibility provider, especially when its capital cost and fixed O&M cost is not included in unit-commitment competition. Thus, additional policy levers or a higher carbon price than assumed here (60 £/ton) may be required to force the phase-out of gas at the power system planning stage. Adding more VRE can also help the GB power system reach its carbon ambition (Figure 8a) but leads to a rise in total system cost.

Conclusions

This research builds a power system model to analyse the flexibility demand of the GB power system based on 2022's weather and demand data, both for 2022 and the future (based on planned capacity). Thermal generators, interconnectors, excess generation from VREs and energy storage compete against each other in a unit-commitment mechanism. Each energy storage operator levelises their cost to a periodic cost of each MWh of stored electricity to allow them to compete against each other and provide flexibility.

The total system cost of the future GB power system will be dominated by the cost of providing energy flexibility (i.e. flexibility cost).

Under the 2022 patterns of weather and demand, an optimal national storage capacity of 1330GWh/25GW has been calculated. Under this scenario, the wholesale price for electricity will be close to that of the 2022 scenario with a high gas and carbon price (50 £/MWh for gas, 60 £/ton CO_2). The transition of thermal generators (CCGT, OCGT and biomass) from energy providers to flexibility providers will lead to frequent start-ups, which leads to start-up or warm-up costs (named transfer cost here), increasing the total system cost and making thermal generation as a flexibility provider more expensive than today as an energy provider. The large deployment of VRE may cause a significant flexibility gap (causing blackouts) as the ramp-up rate and start-up time of traditional thermal generators can't respond to the variability and intermittency of VRE. To mitigate this, flexibility solutions (energy storage proved to be the most efficient one) are needed. Interconnectors cannot bring significant flexibility to the GB system as the flexibility from GB's neighbours is less competitive than local flexibility providers. However, interconnectors can digest excess generation from VRE with the exported electricity, reducing the total system cost. GB may become an electricity exporter instead of an importer. Adding VRE capacity to the future GB power system will avoid carbon emissions but will increase the total system cost. As VRE replaces thermal generation, the saved fuel costs cannot offset the VRE capital cost and the increased start-up costs of thermal generators' (who transition to flexibility rather than energy providers). Among flexibility providers, energy storage is the most cost-efficient choice for reducing carbon intensity in the future GB power system with the planned VRE capacity expansion. Energy storage technologies that are cost-efficient for short-term storage demand should be introduced to the power system first to bring the most significant cost reduction. In responding to seasonal storage demand, thermal generation is more competitive than hydrogen storage except when thermal generators need to start up frequently. The high cost of seasonal storage makes thermal generation in the future GB power system difficult to phase out.

For the future GB power system, 25 GW of energy storage gives the lowest total system cost. By testing different storage compositions, equal shares of pumped-hydro, thermal, compressed-air, Li-Ion battery and green hydrogen are suggested to be the optimum and storage suitable for short-term storage should be introduced first. Considering the development and complexity of energy storage technologies, further work is needed to optimise the optimal storage composition.

This research highlights the importance to consider all flexibility providers together when designing a future power system or making policies. A key lesson from this research to a system operator or policymaker is that the energy flexibility problem is serious, and it is important to build mechanisms to dispatch different flexibility providers, particularly when there is competition among energy storage, interconnectors, thermal generators and excess generation from VREs. The optimisation of power system should include demand-side control methods and power to gas technology to utilise excess generation outside the boundary of the power system; even in our recommended energy storage case, the amount of energy stored is trivial compared with the total excess generation.
We alsot find that to reach the UK's emission ambition of power system (50g CO_2 /KWh), a high carbon price, more VRE capacity or retirement of gas-fired power plants is required. In this process phasing out OCGT and CCGT may also reduce the system cost lower than suggested here, as power plants are dispatched based on their marginal cost, not their total costs, which here are added to the cost calculation, regardless of how much they are run.

Appendix 1: Parameters of generators, interconnectors and storage

Technical parameters employed for generators, interconnectors and storage operators is based on previous power system model [50] and technical documents from IENRA[54]. The curtailment cost of thermal generators is calculated as the difference between start-up cost and the avoided fuel cost, using equation:

$$curtailment\ cost = startup\ cost - \frac{fuel\ cost}{conversion\ efficiency}$$

The technical and carbon intensity parameters of thermal generators are given in Table 1.
Table2：The technical and carbon intensity parameters of thermal generators(Staffell, 2017)

	Fixed O&M cost (GBP per MW)	Variable O&M cost (GBP per MWh)	Conversion efficiency	Ramping rate limit (per period)	Start-up Cost(GBP per MW)	Available energy (MWh)	Added energy (MWh per period)	Carbon Intensity(ton per MWh)
CCGT	231.82	0.1	51%	50%	50	/	/	0.394
OCGT	99.00	0.1	41%	100%	30	/	/	0.651
Biomass	350.00	0.2	25%	25%	83	16000000	913	0.120

The carbon intensity data of generators comes from the carbon intensity methodology employed by electricity system operator(ESO) of National Grids of UK. [49] The yearly levelized capital cost and fixed operational cost of VRE generators(for newly installed capacity), and interconnectors, and the body emission of VRE generators[55], interconnectors and storage operators come from literature review in forms of a range. The body emission and yearly levelized capital cost(including fixed O&M cost) of VRE generators, interconnectors, and storage operators are given in Table 2.
Table3：Capital cost and body emission of VRE and interconnectors

	Yearly capital cost+Fixed O&M cost(GBP per MW)	Yearly Body Emission(ton/MW) (UK Department for Business Energy and Industrial Strategy, 2020)
Onshore wind	40000	10
Offshore wind	80000	11
solar	24000	16
Interconnectors	20000	8

The detailed energy storage projects is based on the example energy storage projects given by BEIS[44]. The lifetime of onshore, offshore and solar is assumed to be 25 here. Because the capital cost of interconnectors depends highly on its destination and technology, here the cost is assumed to be the cost of building one MW more interconnectors using the current interconnection constitute. Considering hydrogen's emission comes from both hydrogen storage and hydrogen electrolysis, here its emission will be given in MWh for hydrogen storage and in MW for electrolysis and power generation, separately. The parameters of storage are given below:

Table4：Cost, energy efficiency, body emission, self-discharge rate, ratio of power to energy capacity, lifecycles and lifetime of storage

	Pumped-hydro	Compressed-Air	Thermal	Li-Ion	Hydrogen
Efficiency(round trip	75.0%	65.0%	65.0%	85%	32%
Self-discharge time(i.e. time elapsed before capacity is reduced to less than 80% by self-discharge) (hours)	87600	9600	480	1560	2500
Ratio of power capacity to energy capacity*	1：4	1：4	1：4	1：4	1：250
CAPEX(GBW/KW)	985.4	759.2	687.8	676.3	723.6
OPEX(GBP/KW/Year)	13.4	9.5	20.6	6.6	19.7
Life cycles	1000000	50000	50000	5000	1000
Lifetime(Years)	30	25	20	15	10
Body emission	0.5(ton per MWh,0.2-0.8)[56]	2.8 (ton per MWh，2.5-3)[57]	0.2(ton per MWh, 0.1-0.3)[58]	0.3(ton per MWh, 0.2-0.5)[59]	0.0006(ton per MWh, 0.0003-0.001)[60] 7.3(ton per MW,5-10)[61]

Appendix 2: Model Formula description

This model translates weather data of example year(2022)[62] at corresponding latitude and longitude to VRE generation output limit using a generator function. For each VRE generators, its capacity is modelled by aggregating examples generation units in forms of a piecewise generation function bounded by three key parameters, namely cut-in speed, rated speed and cut-off speed for wind turbine, and cut-in radiation, rated radiation and cut-off radiation for solar panels, shown as follows:

$$G_{wt} = \begin{Bmatrix} 0, \quad v_t < v_i \\ \alpha v_t, v_i < v_t < v_r \\ G_r, v_r < v_t < v_o \\ 0, v_o < v_t \end{Bmatrix}$$

$$G_{st} = \begin{Bmatrix} 0, \quad r_t < r_i \\ G_r, r_i < r_t < r_o \\ 0, r_o < r_t \end{Bmatrix}$$

Here G_{wt} represents the corresponding wind turbine's generation limit at t^{th} period, and G_{st} represents the corresponding solar turbine's generation limit. v_i, v_r and v_o are the cut-in wind speed, rated wind speed and cut-off wind speed respectively. r_i, r_r and r_o are the cut-in downward solar radiatio and cut-off downward solar radiation respectively. The VRE generator agents have perfect foresight of their future generation limit and will bid into the centralised market with 0 marginal generation cost.

Apart from VRE generators, power source in this model includes thermal generators (biomass and nuclear have special constraints), energy storage facilities and interconnectors. The marginal cost of thermal generators is calculated by

$$M = \frac{C_f}{\eta} + C_v + C_s$$

Here C_f is the fuel cost, η is the energy conversion efficiency, C_v is the variable O&M cost, and C_s is the possible start-up cost when a thermal generator starts up.

Each period at the centralised electricity market, VRE generator agents, thermal generator agents (biomass are modelled as thermal with special constraints), and storage agents will bid into a centralised clearing marketing by solving a unit-commitment problem, which is expressed as follows:

$$\min\,(F)$$

subject to

$$D_t = \sum (g_{it} + d_{it} + i_{it} + O_{it})$$
$$O_{it} \leq O_{il}$$
$$g_{it} \leq G_{il}$$
$$G_{it} \leq (1 + u_i) g_{it-1}$$
$$g_{jt} \leq B_t$$
$$d_{it} \leq P_{it}$$
$$d_{it} \leq p_i$$
$$|i_{it}| \leq |I_{il}|$$

Here O_{it} is the VRE output of i^{th} generator at t^{th}period. O_{il} is the generation limits of i^{th} VRE depending on the weather data. G_{il} is the capacity limit of i^{th} generator. u_i is the ramp-up limit of i^{th} generator. P_{it} is the storage pool stock of i^{th} storage pool at t^{th} period. p_i is the power limit of i^{th} storage pool. I_{il} is the interconnection limit from historical interconnection profile. B_{jt} is the stock of available biomass of j^{th} biomass generator, defined as:

$$B_t = B_{t-1} + d$$

d is the biomass production capacity of each period. The flexibility cost of a certain period is calculated as follows:

$$F = \frac{F_w * D_w + F_b * D_b}{D_r}$$

Here F is the periodic flexibility cost, F_w, F_b are the flexibility cost calculated at wholesale market stage and balancing market stage. D_w, D_b are the forecast demand at wholesale electricity market and the difference between real demand and forecast demand. D_r is the real demand of a period.

Appendix 3: Sensitivity test of VRE spatial resolution in GB power system,

To distinguish the worries that the use of a representative point at Edinburgh in Scenario B,C,and D may lead to the deviance of VRE output and variability, the VRE output under different spatial resolutions in Scotland is given here. In Scotland, onshore generation capacity is located where substation and transmission lines are available, mainly around Edinburgh, Aberdeen and Inverness. Four distribution methods of onshore generation capacity in Scotland are employed: a representative point at Inverness, a representative point at Edingburgh, a representative point at Aberdeen and distributed corresponding to the exact planned location of generators. Figure 8 shows the generation profile of these four methods.

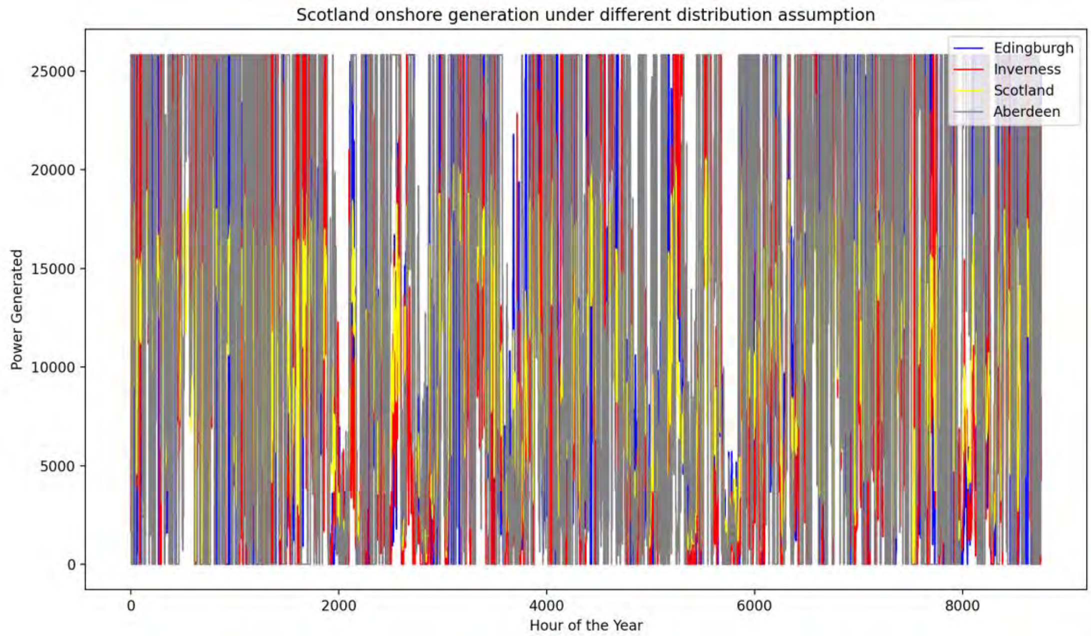


Figure 12: onshore generation profile under planned, and representative points at Edingburgh, Inverness, Aberdeen.

Using representative points for Scotland onshore generation leads to variance, however, using the highest resolution of onshore generation add unnecessary computational cost. The annual onshore generation under planning, Edinburgh, Inverness, and Aberdeen are 111.6 TWh, 115.7 TWh(3.7% higher), 105.1TWh (5.8% lower), and 117.2 TWh(5.0% higher). Figure 9 gives the deviation between the planned generation and three representative points, using

$$Difference_i = x_{pi} - x_{Ei,Ii,or\ Ai}$$

Here x_{pi} represents the output of planned onshore generation at i^{th}period, and $x_{E,I,or\ A}$ represent output of Edingburgh, Inverness and Aberdeen, respectively.

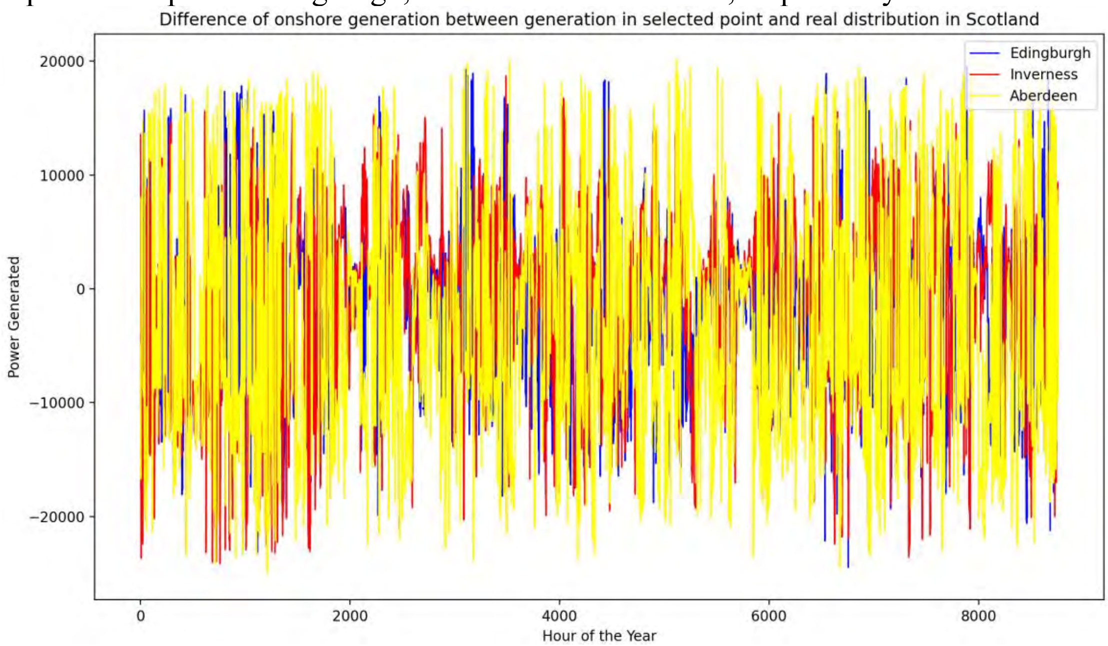


Figure 13: The deviation between planned and representative points at Edingburgh, Inverness, Aberdeen.

To quantify this difference, the standard deviation is calculated as

$$Deviation = \frac{\sum_1^{8760} \sqrt{Difference^2}}{8760}$$

The deviation between planned generation and Edinburgh, Inverness and Aberdeen are 614.6, 628.1, 896.0 (MW), while the total onshore generation capacity in Scotland under planning is

49360MW in scenario B,C and D. Note that this variance should be compared to wind capacity with full load factor(14917MW), instead of 49360MW directly.

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Financial Support	<funder, grant>

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