

Net-zero GB electricity: cost-optimal generation and storage mix

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IDLES Programme White Paper



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List of acronyms

BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department of Business, Energy and Industrial Strategy
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
CAPEX	Capital Expenditure (investment cost)
CCC	Climate Change Committee
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CfD	Contract for Difference
COP	Coefficient of Performance
DAC	Direct Air Capture
DER	Distributed Energy Resource
DSR	Demand-Side Response
ESC	Energy Systems Catapult
EV	Electric Vehicle
GHG	Greenhouse Gas
HHP	Hybrid Heat Pump
HP	Heat Pump
HVDC	High-Voltage Direct Current
IRENA	International Renewable Energy Agency
LCOE	Levelised Cost of Electricity
LDES	Long-Duration Energy Storage
LOLE	Loss of Load Expectation
OCGT	Open Cycle Gas Turbine
OPEX	Operating Expenditure (operating cost)
PHEV	Plug-in Hybrid Electric Vehicle
PV	Photovoltaic
RES	Renewable Energy Sources
SMR	Small Modular Reactor
SOC	State-of-Charge
V2G	Vehicle-to-Grid
WeSIM	Whole-electricity System Investment Model

Executive summary

It is anticipated by the Climate Change Committee (CCC)¹ that the UK's electricity sector will need to undergo a deep and wide-ranging transformation over the next 10 to 15 years to become net-zero carbon by 2035.

As the CCC lays out, a zero-carbon electricity sector is then used to decarbonise heat and road vehicle transport. The electricity sector therefore will need to expand supply to service the new sectors and manage increased variable renewable electricity generation. The analysis presented here addresses the transformation of the electricity supply systems towards this via a *Whole-electricity System Investment Model (WeSIM)* that balances long-term investment decisions against short-term operation decisions, across electricity generation, transmission, and distribution. The study explores cost-efficient portfolios of generation and storage technologies that could achieve a net-zero carbon emissions electricity system for Great Britain. It identifies the scale of investment needed in various technologies and how they combine to deliver zero-carbon electricity securely. It shows how system configuration and investment changes in light of cost variations of available technologies and the availability of flexibility.

In exploring the composition of a net-zero carbon electricity system for Great Britain for 2035, four key questions were set out on **the volume of offshore wind capacity, the volume of energy storage, the role of other zero-carbon generation beyond offshore wind, and the variation in the cost of electricity**. Multiple case studies, described in detail in the Main Report, were run in order to answer these questions. The questions were chosen in recognition of the view that offshore wind is set to become the backbone of the UK energy system² but that there will be key roles for energy storage and other supporting technologies in producing a cost-effective system. The answers to these questions are summarised in the next section and those answers have enabled a series of conclusions to be reached.

The capacity of offshore wind needed to achieve net-zero electricity for Great Britain in 2035 is at least twice the existing 2030 target. In the Central case of this study, 108 GW of offshore wind is required which is not only a tenfold increase on the current installed capacity of 10.4 GW but is also two and a half times the UK government's target for 2030. This finding is robust to changes in the Levelised Cost of Energy (LCOE) of offshore wind of $\pm£5/\text{MWh}$ on the Central case of $£35/\text{MWh}$.

Achieving net-zero carbon for the electricity sector by 2035 would require a significant increase in what is already a very ambitious target for offshore wind build out, implying both a higher build-rate prior to 2030 and a continuation through to 2035. **Opting to build 10 GW more nuclear power and 18.5 GW more solar generation than is optimal in the Central case would reduce the required build of offshore wind for 2035 by 24 GW but increases the total cost of the system by about 3.3%.** In doing so, 7 GW of battery storage is also displaced. This new capacity of offshore wind at 84 GW is still double the present 2030 target. Further steps to diversify the portfolio of zero-carbon generation may yet be needed to achieve net-zero by 2035 within build-rate constraints, at the penalty of increased system and unit electricity costs.

¹ <https://www.theccc.org.uk/2020/12/09/building-back-better-raising-the-uks-climate-ambitions-for-2035-will-put-net-zero-within-reach-and-change-the-uk-for-the-better/>

² <https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future>

A substantial increase in the volume of energy storage is needed to support a system dominated by wind and solar energy. Not only do batteries help demand-supply balance when wind and solar output varies but they also assist with security of supply, obviating some expansion of electricity grids and meeting the needs of heat-pumps during spells of especially cold weather. Nevertheless, the volume of battery storage that would need to be built is over 140 GW, which would be more than a hundredfold increase on the 1.1 GW of grid-connected batteries of today.

Direct Air Capture (DAC) of CO₂ could have a large impact on how electric heating is supported. With DAC available as a negative-emissions technology, hybrid heat pumps could use natural gas during the coldest days of the year, which would reduce battery energy storage capacity by 45 GW.

In view of its large and very good potential sites for offshore wind, **Great Britain could expand offshore wind capacity beyond that needed to supply its own demand** and export zero-carbon electricity to neighbouring countries. This could involve an additional build of 18 GW of offshore wind farms with little increase needed beyond existing interconnections. The cost of this expansion would be compensated by the revenues earned by exporting energy.

It was also found that **nuclear energy would need to halve in cost to warrant major new builds within a cost-optimal system.** At a cost of £45/MWh, approximately 50% of the strike price of the Contract for Difference (CfD) for Hinkley Point C, 13 GW of additional nuclear capacity would be included in the cost-optimal system.

Finally, **solar PV would need further and very significant decreases in cost to play a major role in the net-zero Great Britain system.** Costs need to fall 60% from the central estimate, from £50/MWh down to £20/MWh, before a major expansion of its use is justified purely on cost grounds.

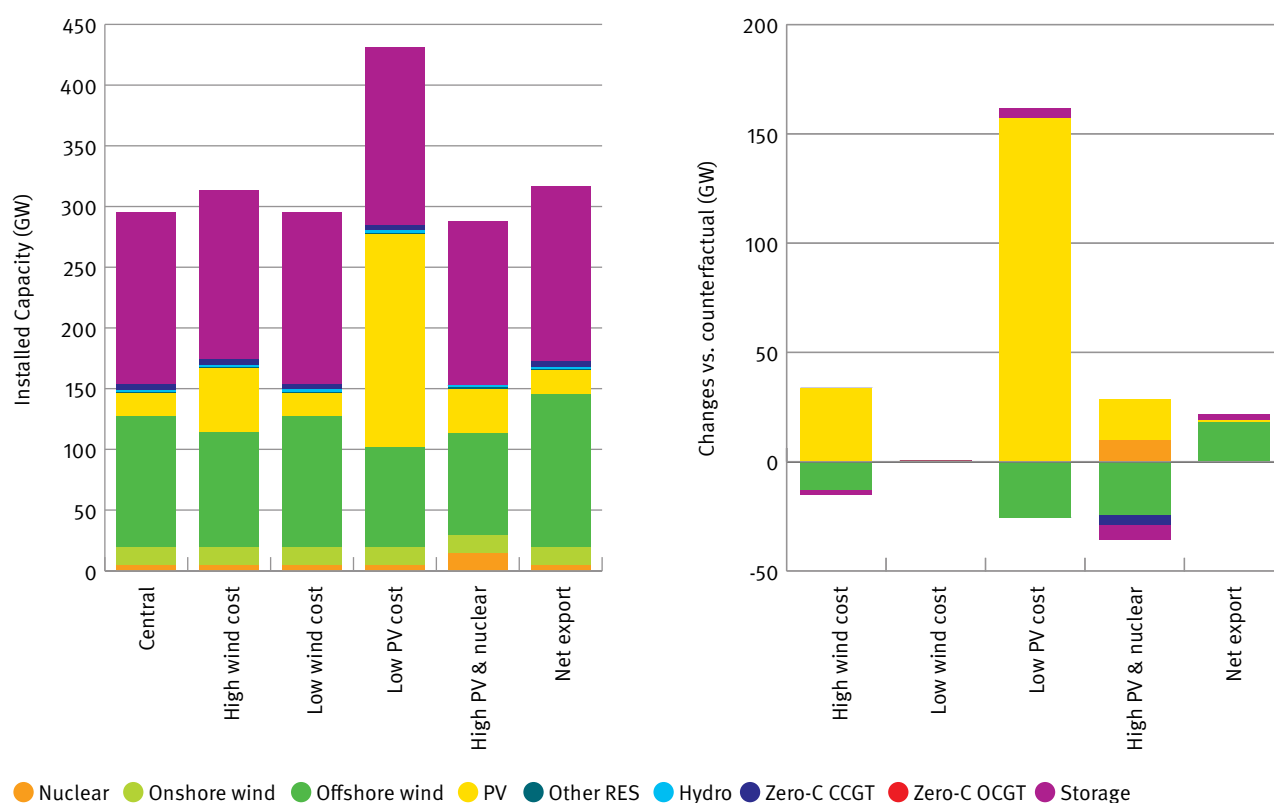
Summary of answers to the key questions

Four questions were devised by the IDLES team to draw out the key features of a 2035 net-zero electricity system and a summary of the answers is given here. The questions reflect the prominence of offshore wind in the UK Government's plan to accelerate the path to net-zero and the importance of flexibility in a system with a large fraction of variable renewable generation. A series of case studies were conducted to provide evidence to help answer the questions and in each case study, an investment optimiser was used to determine the configuration of electricity system required to achieve net-zero carbon emissions and a certain security of supply. A set of assumptions on the cost and performance of various technologies were made representing a Central case (Table 1) and variations to this Central case were then studied³. The role of system flexibility was explored in terms of Demand-Side Response (DSR), storage of various durations and international interconnections. Cost-points where a significant system reconfiguration would occur were identified and calculations made to assess how the overall system cost would change relative to the Central case, allowing conclusions to be drawn on what could most strongly influence the shape of the future system. Subtle changes to the unit cost of delivered electricity across a net-zero system also emerged as variations in technology costs and technical parameters were tested.

1. How much offshore wind capacity will GB need?

Offshore wind is widely seen as the best route to decarbonisation of the UK energy system and features prominently in the UK government's plans, with a specific commitment to an additional 30 GW of offshore wind capacity by 2030 on top of the 10 GW present today. How does this commitment compare with what is required for net-zero emissions and does it place the UK on the right trajectory?

Figure ES.1. GB system for net-zero with variations in cost of offshore wind and solar PV, in minimum levels of nuclear and solar PV and with option to export electricity: total capacities (left) and capacity difference vs. Central (right)



³ The datasets behind all of the charts in this White Paper are available for [download](#) in an Excel spreadsheet alongside the report.

In the Central case with the Levelised Cost of Electricity (LCOE) of offshore wind of £35/MWh, the model identifies that a cost-optimised net-zero electricity system would operate with offshore wind fulfilling over 75% of total annual electricity generation. The volume of offshore wind capacity identified, 108 GW, is ten times larger than the current fleet which was 10.4 GW at the end of 2020. Accompanying this is a very large deployment of battery energy storage capacity, 142 GW. Storage is discussed further in Question 2.

Two variations were tested: a high cost of wind power at £40/MWh and a low cost at £30/MWh. The left-hand side of Figure ES.1 shows the new cost-optimal generation and storage capacities and the right-hand side shows changes against the Central case. Installed capacity of offshore wind is reduced by only 13 GW in the high-cost case and very little extra is deployed in the low-cost case, suggesting that offshore wind is the most cost-efficient form of power generation even after accounting for these cost variations.

Changes elsewhere in the system, which could influence the choice of wind as the main route for decarbonisation in GB, were also examined. Considering PV at £50/MWh, the model does not add any additional PV beyond the minimum prescribed in Table 1, but at £20/MWh a very large volume of 175 GW (of relatively low load factor) is added and offshore wind is reduced by 26 GW. Even so, the cost-optimal volume of offshore wind, at 82 GW, is still eight times higher than that installed today.

Such a rapid expansion of offshore wind over the next 15 years raises challenges in seabed leasing, project development, turbine supply chain and construction. Recognising this challenging build-rate, it may be necessary to build more nuclear power and more solar generation to deliver net-zero carbon power, even without cost reductions in these items. To explore this, the imposed capacity of nuclear power was raised to 14.5 GW (compared to the 4.5 GW imposed from pre-existing plant in the Central case) and PV raised to 37 GW (rather than 18.5 GW) and the remaining system cost-optimised. 24 GW of offshore wind and 7 GW of battery storage was displaced but the system cost increased by about 3.3% of the Central case. This new capacity of offshore wind at 84 GW is still double the present 2030 target.

In the Central case, import/export neutrality over a year was imposed. If that constraint is lifted, the offshore wind capacity in GB can expand beyond that needed to supply GB demand and energy is then exported to mainland Europe, when economically efficient for both British and continental European systems. Electricity systems of continental Europe and Ireland were modelled in a simplified fashion with their own demand profiles and generation portfolios. With net export allowed, the model adds a further 18 GW of offshore wind, increasing the total GB offshore wind capacity to 126 GW. The increase in cost would be compensated by the revenues earned from selling exported electricity to the neighbouring markets. The breakeven average price required to cover the additional cost of supplying exported electricity is £33/MWh, calculated as the ratio of the additional system cost to the net volume of electricity exported.

2. How much energy storage will be needed in a net-zero system?

Storage is widely seen as an important partner to variable renewable generation and a source of the flexibility needed for system operation. What is the cost-optimal volume and how does it depend on the cost and technical characteristics of the storage type, and its alternatives?

The Central case uses 142 GW of energy storage, a very large volume compared to that which exists today⁴. It is needed to accommodate the large volume of offshore wind in terms of balancing the variations in renewable output, but it also avoids grid reinforcement and provides firm capacity during periods of peak demand, notably those associated with electrified heating.

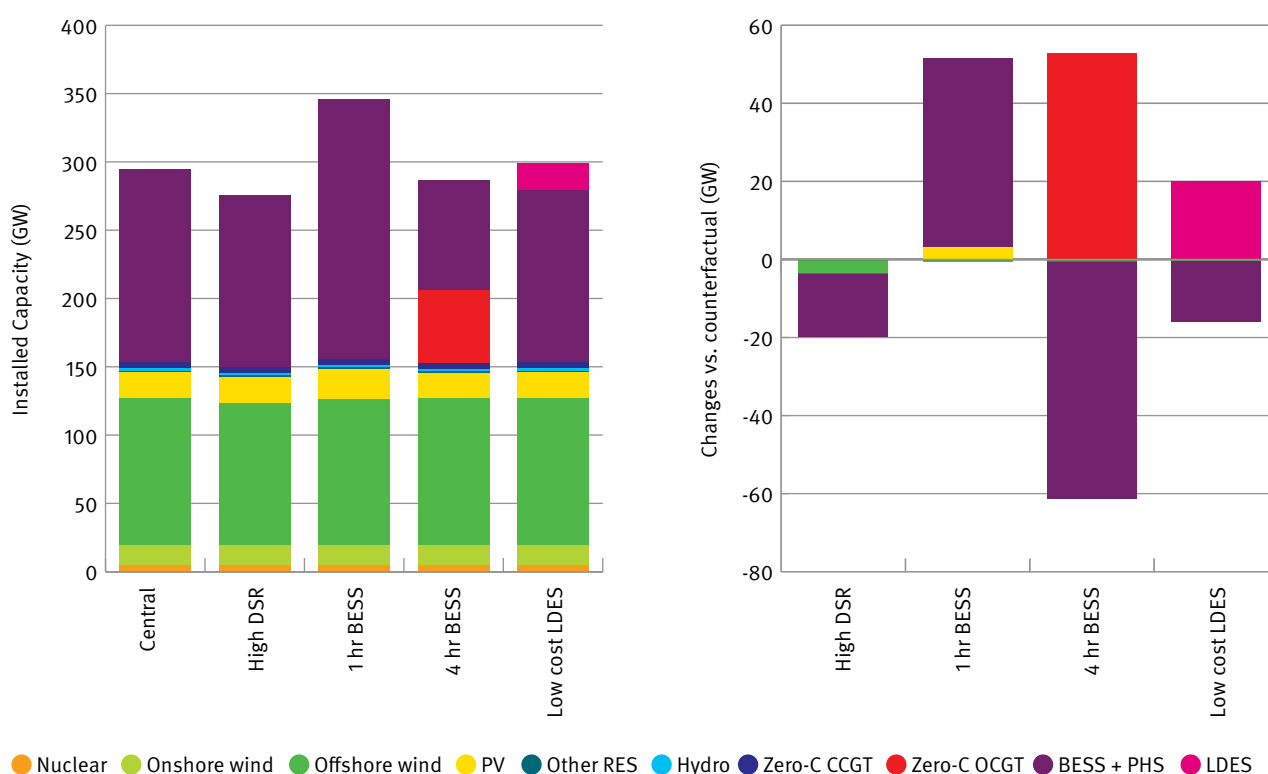
⁴ GB has 1.1 GW of operational battery storage units. There is also 15 GW of battery storage projects under construction or being planned. <https://www.energylive.news.com/2021/02/08/uk-battery-storage-pipeline-surpasses-16gw/>

It could be that at least some of the substantial capacity of Electric Vehicle (EV) batteries in the future system could be made available to provide Vehicle-to-Grid (V2G) services to reduce the requirement for dedicated battery storage capacity.⁵

Storage is not the only possible provider of supply and demand balancing in a future system. A widely-recognised source of flexibility is Demand-Side Response (DSR), present in industrial and commercial sectors, smart appliances, heat pumps and EVs. DSR was present in the Central case, at an uptake of 25%. When the DSR uptake is increased to 75% – the High DSR case shown in Figure ES.2 – a modest reduction in the storage capacity by 16.2 GW to 125.5 GW was found despite the large increase in DSR uptake.

The storage duration of a Battery Energy Storage System (BESS), *i.e.*, the length of time for which full power can be provided (which can also be expressed as the energy-to-power ratio), is an important technical characteristic. The BESS in the Central case had a storage duration of 2 hours, which is typical of current lithium-ion battery projects. Case studies were also carried out with shorter and longer BESS durations between 0.5 hour and 8 hours. The same cost per unit energy storage was used across the case studies (£187.5/kWh) on the assumption that the cost of batteries (energy-related) dominates over the cost of the grid interface (power-related). Figure ES.2 shows that when BESS durations are short, such as 1 hour, the model adds more battery storage capacity in terms of power than in the Central case but this is still less in terms of energy. This result indicates that the power capacity is more valuable to the system than the energy capacity. When BESS durations are long, it becomes expensive to provide power capacity, so an increase in deployment of fast-acting zero-carbon fuelled generation is seen instead (via Open Cycle Gas Turbine (OCGT) using hydrogen or other zero-carbon gas such as biogas).

Figure ES.2. GB system for net-zero with variations in parameters of energy storage: total capacities (left) and capacity difference vs. Central (right)



⁵ Earlier work (Vivid Economics and Imperial College London, 2019) estimated that EV batteries could displace up to 35 GW of battery storage.

Notwithstanding the results of the BESS study favouring short durations, technologies that specifically offer Long-Duration Energy Storage (LDES) were examined. At the right cost, these may be a good solution to the variation of renewable output over days and may substitute for interconnection or zero-carbon fuelled generation. In this case, storage with 120-hour duration and roundtrip efficiency of 60% was explored.⁶ With a cost assumption of £80/kWh (which is less than half the assumed cost of short-term battery storage at £187/kWh), no appreciable change in the installed capacities of technologies was seen. Figure ES.2 shows that even with extremely low cost of LDES of £4/kWh, only 20 GW is deployed, displacing 15.7 GW of battery storage.

3. What role is there for other zero-carbon and negative-carbon technologies?

Specifically, how is system configuration changed with variation in the cost of nuclear energy and zero-carbon fuelled generation (such as CCGT and OCGT using hydrogen or other zero-carbon gas such as biogas) as sources of firm generation capacity and in the cost of Direct Air Capture (DAC) as a means to offset residual emissions?

Figure ES.3 shows the results for a study of these options. Decreasing the cost of zero-carbon fuel by 33% compared to the central assumption is seen to have very little effect on the installed capacities of zero-carbon CCGT/OCGT and the associated investment costs. The changes that do occur are accompanied by small reductions in capacity of offshore wind and battery storage.

There has been much interest in the future of nuclear energy such as the importance of cost-reductions and the emergence of small modular reactor (SMR) format. At £45/MWh, which is approximately a 50% reduction in the unit electricity price compared to the £92.5/MWh (2012 prices) of the Hinkley Point C project, 13 GW of nuclear capacity is added. This displaces 26 GW of offshore wind, 9.6 GW of BESS, and 4.5 GW of zero-carbon OCGT (which was providing firm capacity but very little energy). Savings in total system cost result from this, which are discussed with Figure ES.4.

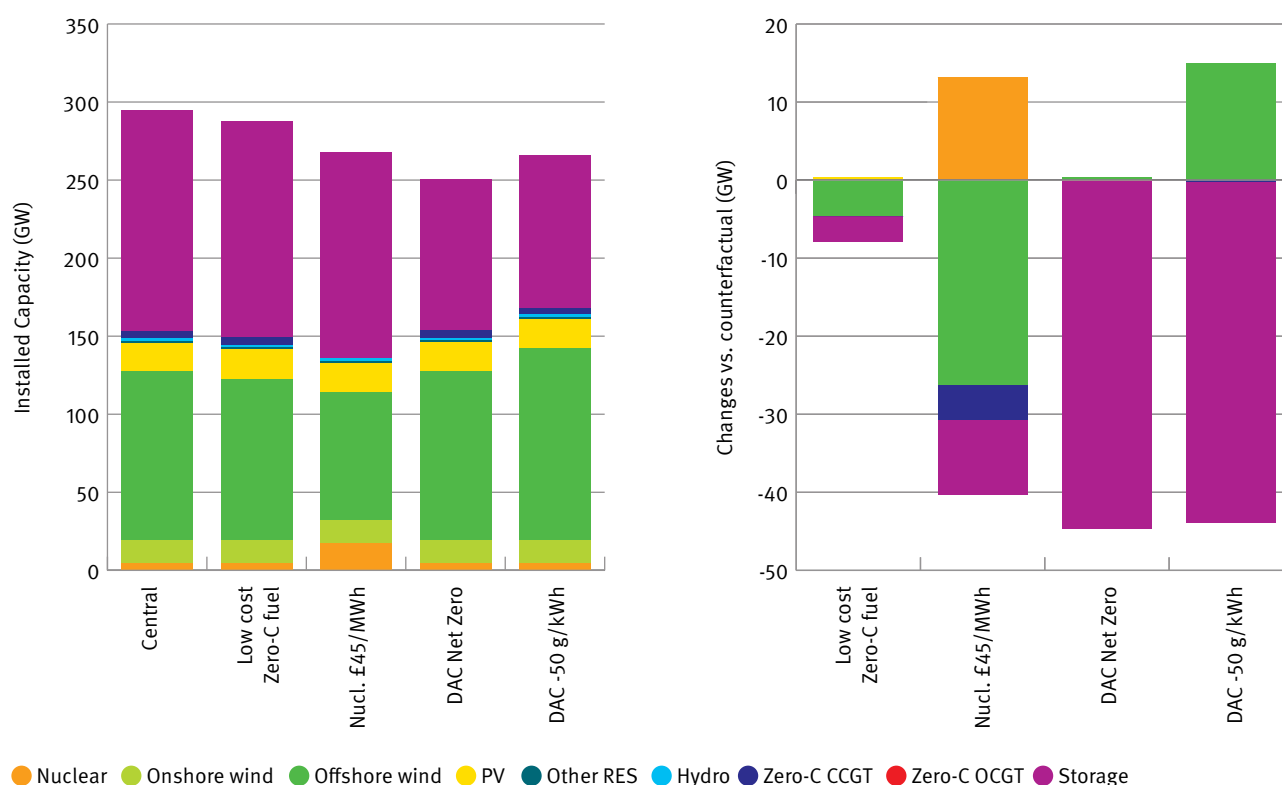
DAC is not a mature technology and there are no firm cost estimates available for deployment at scale and therefore the studies undertaken should be seen as exploratory. Cases were run with levelised fixed costs of CO₂ capture as follows: Low (£44.4/tCO₂); Medium (£88.8/tCO₂) and High (£133.2/tCO₂). On top of these costs, additional electrical energy demand arises. Results for the Low-cost case are shown in Figure ES.3.

The principal impact of DAC is a reduction in the battery storage capacity deployed. This can be traced to changes in the type and operation of heat pumps. Standard, electric-only, heat pumps make a large addition to peak electricity demand in winter evenings leading to network reinforcement and deployment of distributed storage. CO₂ removal with DAC enables hybrid heat pumps (HHPs) to use conventional gas during the coldest days of the year thereby avoiding the high cost of grid reinforcement and reducing battery storage by 44 GW. This reveals that about 30% of the very large storage capacity is there to support heat pumps at peak demand. The substantial role seen here for DAC rests on the cost assumption made for DAC and also on the path chosen for decarbonisation of building heating.

The analysis was extended from net-zero to net-negative with the electricity system required to achieve -50 gCO₂/kWh. An increase in DAC of 30 million tonnes of CO₂ per year was needed to achieve this, accompanied by 15 GW more offshore wind to supply the extra energy required.

⁶ LDES could be achieved in a number of ways, for example, via compressed air energy storage, liquid air energy storage or pumped thermal energy storage.

Figure ES.3. GB system for net-zero and net-negative with variations in cost and availability of nuclear, zero-carbon fuel generation and DAC: total capacities (left) and capacity difference vs. Central (right)



4. What range of system costs and unit costs of delivered electricity might be expected in a net-zero system?

The results of the modelling have been discussed in terms of the investment in capacity of various technologies to achieve a 2035 net-zero electricity system for Great Britain. Alongside this are changes to operating and investment costs in reinforcement of distribution grids and international interconnections. Taken together, these lead to subtle changes in the total cost of owning and operating the electricity system and therefore also in the unit cost of electricity across the system, as presented in Figure ES.4. These details are discussed in the Main Report but summarised here.

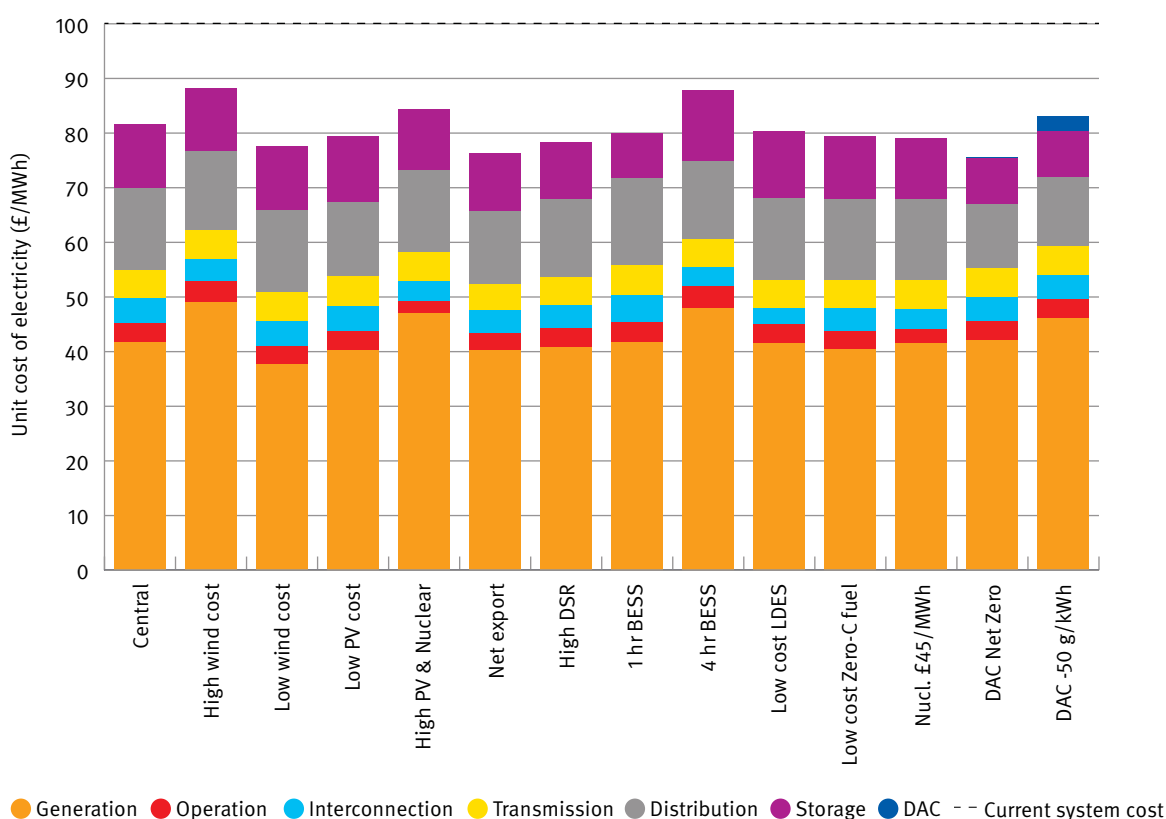
Cost figures in Figure ES.4 include all the investment cost of generation, storage and network assets as well as their operation, but not the metering, billing, tax and supplier margins that would also be expected to appear in a retail price. To aid comparison with today's cost of delivering electricity, the equivalent unit cost of the 2020 Great Britain power system has been estimated at 10.1 p/kWh⁷, although this value is subject to a number of uncertainties⁸.

⁷ This value is lower than the price of energy typically seen in electricity bills due to other cost components not considered in the modelling which are the environmental and social obligation costs, metering, billing, VAT and supplier margins.

⁸ It is not straightforward to assess the capital cost of existing generation assets due to a great variety of vintages, technologies, investors and financing models that have formed the system. Further, much of the data is commercially sensitive and not available in the public domain. Nevertheless, the cost of variable renewables has been estimated based on the CfD register, while conventional generation cost has been estimated based on 2016 BEIS cost estimate of electricity generation costs. Transmission and distribution network costs have been evaluated based on revenue allowances specified in RIIO-ED1 and RIIO-T1 price control periods.

All cases presented in Figure ES.4 represent a noticeable reduction in total system cost from today's levels. For the Central case, the average system cost of electricity is £81.6/MWh or 8.2 p/kWh. The decrease arises primarily from substantial reductions in the cost of renewable generation, in particular offshore wind which has an LCOE of £35/MWh in the Central case. A rise of £5/MWh to £40/MWh for the LCOE of offshore wind increases the unit cost of electricity to 8.8 p/kWh, whereas a reduction of £5/MWh leads to 7.8 p/kWh. Low PV cost reduces the average cost by about 0.2 p/kWh from the Central case and the opening up of export of electricity further reduces this to 7.6 p/kWh.⁹ Imposing higher than optimal capacity of nuclear and solar PV generation at Central case costs (to reduce build rates of offshore wind) results in a cost increase of 0.3 p/kWh. High DSR penetration brings about savings of about 0.3 p/kWh compared to the Central case. Shorter BESS duration and availability of low-cost LDES result in modest reductions in the unit cost, while longer BESS duration results in an increase in unit cost to 8.8 p/kWh. A decrease in the cost of zero-carbon fuel for thermal generation (used mostly for providing firm capacity but also some energy) reduces system unit cost to 7.9 p/kWh. Nuclear at an LCOE of £45/MWh also reduces unit system cost to 7.9 p/kWh and availability of low-cost DAC technology leads to a unit cost of 7.6 p/kWh.¹⁰ Pushing the emissions target to a net-negative case (-50 gCO₂/kWh) increases unit cost, but only slightly, to 8.3 p/kWh.

Figure ES.4. Variations in average cost of electricity in the GB system across various cases



⁹ In the Net export scenario, the total system cost is divided by the total GB generation rather than total demand.

¹⁰ In cases where DAC was assumed to be available the electricity demand of DAC operation itself was not included in the total system demand when calculating the average cost of electricity.

Summary of assumptions

Table 1. Table of key assumptions for the Central case

All case studies are constrained to net-zero carbon with a notional implementation date of 2035

Cost assumptions for the main generation and storage technologies			
Technology	Central Cost	Reliability of Assumption	Variants
Offshore wind	LCOE = £35/ MWh	High	High: £40/MWh Low: £30/MWh
Onshore wind	LCOE = £50/MWh (with a build limit of 30 GW)	Medium	
Solar PV	LCOE = £50/MWh	Medium	Low: £20/MWh
Nuclear	LCOE = £92.5/MWh	Medium	Medium: £60/MWh Low: £45/MWh
Zero-carbon thermal generation (Combined Cycle Gas Turbine and Open Cycle Gas Turbine) using hydrogen or zero-carbon gas	Cost of zero-carbon fuel was assumed at £38/MWh (£10.5/GJ), which resulted in an operating cost of £74/MWh for zero-carbon CCGT and £109/MWh for OCGT (at full output). It is assumed there is enough zero-carbon fuel to meet demand.	Low Medium	High: zero-carbon fuel cost is 33% higher (£51/MWh); Low: zero-carbon fuel cost is 33% lower (£25/MWh)
Energy storage	Short-term battery storage with 2-hour duration and 85% roundtrip efficiency, with the investment cost of £187.5/kWh. Long-Duration Energy Storage (LDES, 120-hour duration and roundtrip efficiency of 60%) was not available as a technology option in the Central case. The system was assumed to include 2.7 GW of existing pumped-hydro storage of 6-hour duration.	High Low High	0.5, 1, 4, 8-hour duration at same unit energy cost High: £500/kWh Medium: £80/kWh Low: £4/kWh
Direct Air Capture (DAC)	DAC was not available as a technology option in the Central case	Low	Low: £44.4/tCO ₂ Medium: £88.8/tCO ₂ High: £133.2/tCO ₂

Minimum capacity levels (or assumed pre-existing build)			
Technology	Central Cost	Reliability of Assumption	Variants
Offshore wind	18.6 GW (80% above 2020)	High	
Onshore wind	14.7 GW (10% above 2020)		
Solar PV	18.5 GW (40% above 2020)		High: 37 GW
Nuclear	4.5 GW (Hinkley Point C plus Sizewell B)		High: 14.5 GW (with LCOE = £75/MWh)
Hydro and other renewables	2.8 GW (2020 level)		

Electricity Demand		
Assumptions	Reliability of assumption	Variants
Number of electric vehicles = 37 million (close to the entire passenger vehicle fleet). Number of households with heat pumps = 15.2 million (comprising 9.5 million hybrid heat pumps and 5.7 million electric-only heat pumps). Heat demand is based on temperatures in a normal year, with three very cold days assumed in January to ensure the system has adequate capacity for extreme weather conditions. Other electricity demand (not including newly electrified heat and road transport) = 325 TWh annually. Uptake of Demand-Side Response (DSR) is at 25% of the potential volume which is taken to be: • Electric vehicles: flexibility in EV charging enables up to 80% of EV demand to be shifted away from a given hour to other times of the same day; • Heat pumps: heat storage enables 35% of HP demand to be shifted from a given hour to other times of day; • Smart appliances: smart operation of white appliances enables 100% of their energy demand to be shifted away from peak demand times; • Industrial and commercial demand: 10% of the demand of I&C customers participating in DSR schemes can be redistributed.	Medium	High DSR: 75% uptake

Other	
Assumptions	Reliability of assumption
Starting capacity for <i>interconnection</i> is 20 GW, of which 1 GW is between GB and Ireland and the rest between GB and continental Europe. The model can add more between GB and continental Europe if cost-efficient at the cost of £96/MW/km/yr.	High
GB electricity system is <i>energy-neutral</i> , i.e., the sum of its annual net electricity exports over the year is the same as the annual sum of all imports.	Medium
The <i>security standard</i> , expressed through Loss of Load Expectation (LOLE), is maintained at 3 hours per year. Security of the GB system is assumed to be provided by generation, storage and demand assets within GB borders only.	High

Net-zero GB electricity: cost-optimal generation and storage mix

Main Report

1. Introduction to main report

1.1. Challenges associated with decarbonisation of energy supply

Deep and wide-ranging transformation is expected in energy supply systems around the world over the next three decades to achieve the ambitious targets set for decarbonisation. The UK became the first major economy in the world to enshrine in law its commitment to bring its greenhouse gas (GHG) emissions to net-zero by 2050 following an announcement in June 2019 (BEIS, 2019b). The Sixth Carbon Budget set by the Climate Change Committee (CCC) sets a target of an almost 80% reduction in GHG emissions (from 1990 baseline) by 2035 and notes that until recently this was the target for 2050 (CCC, 2020). The Sixth Carbon Budget also sets out that electricity should be net-zero carbon emissions by 2035 and should, by that point, already be supporting large volumes of electric vehicle charging and electrified building heating.

The concerns over climate change and also air quality are widely shared, and many countries are driving toward 100% renewable energy supply by 2050 (IRENA, 2019).

To achieve net-zero, the UK will need to address many challenges, including:

- Decarbonisation of building heating and transport sectors (largely through electricity)
- Managing variability of renewable electricity generation through responding to increased balancing requirements, reduced inertia and increased uncertainty affecting security of supply
- Providing increased flexibility (energy storage, Demand-Side Response (DSR), interconnectors, sector coupling) to support cost-effective operation and investment
- Economic and other challenges related to expanding nuclear generation capacity
- Uncertainties around the performance and costs of new technologies such as Carbon Capture and Storage (CCS), Direct Air Capture (DAC), Bioenergy with CCS (BECCS) and hydrogen
- Treating net-zero carbon electricity as an intermediate point toward net-negative carbon electricity to achieve net-zero carbon more widely in the economy

Set against the challenges are opportunities such as:

- Rapid and continued decreases in the cost of wind and solar PV, with offshore wind especially relevant in the UK context
- Decreases in the cost of energy storage (batteries)
- Emerging technologies showing promise for a net-zero system such as long-term energy storage, small modular reactors (SMR), DAC and zero-carbon fuels such as biogas or green hydrogen, albeit that there are uncertainties around these.

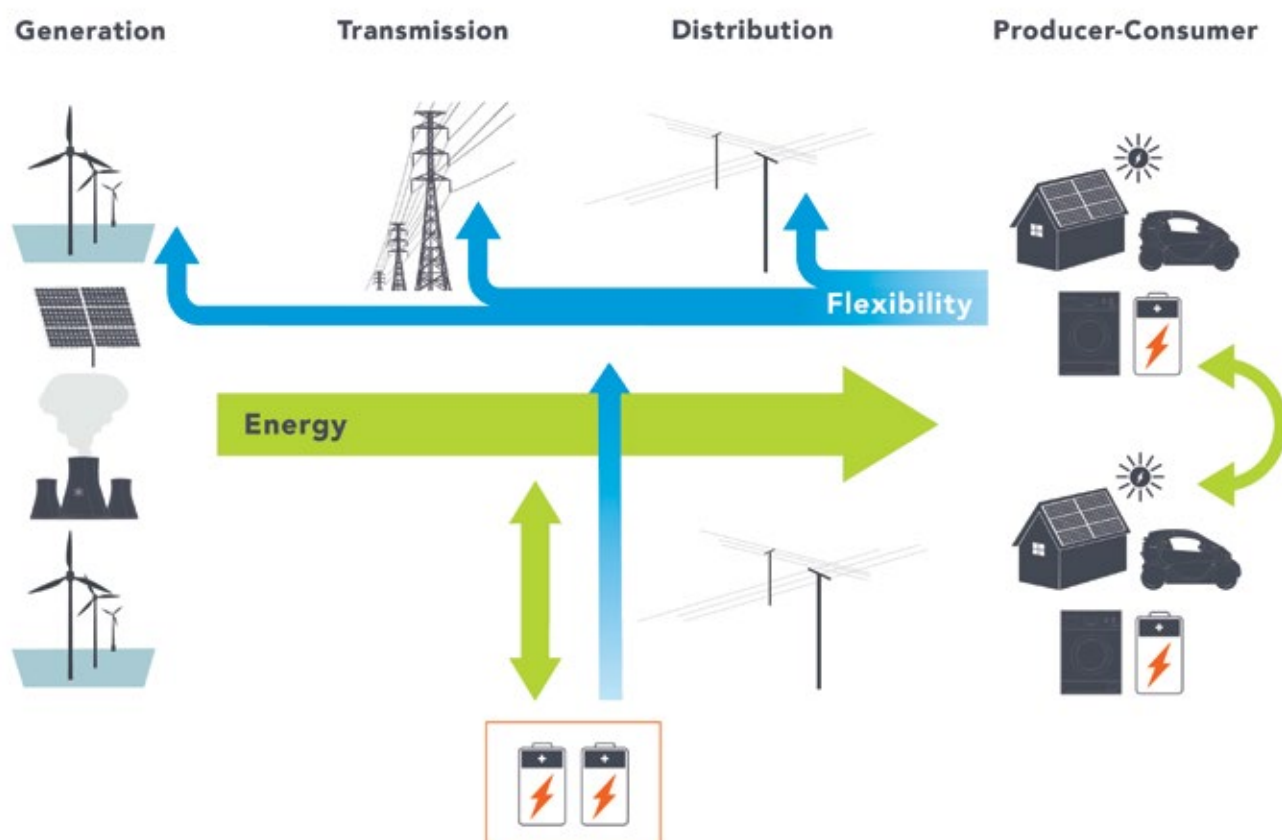
Note that the study will address decarbonisation of the electricity system in Great Britain (GB), recognising that the system in Northern Ireland is run separately from GB and together with the system in the Republic of Ireland. The policy framework for GB is set by the UK government, non-departmental public bodies such as the CCC, and the devolved governments of Scotland and Wales.

1.2. Role of flexibility in delivering cost-efficient low-carbon energy systems

According to data published by BEIS, the GB grid carbon intensity in 2019 was 177 gCO₂/kWh, which is less than half of the level of 500 gCO₂/kWh a decade ago¹¹. This has been achieved by a rapid expansion of renewable generation capacity such as onshore and offshore wind and solar PV, while at the same time substantially reducing the share of coal power generation to the level of just a few percent of total annual demand.

Large-scale low-carbon technologies such as offshore wind farms are expected to remain important in our energy systems and so too are national-scale transmission grids, but a shift is expected that sees the flexibility and resilience of the system being provided by distributed energy resources (DER) and end-consumers via DSR (Strbac *et al.*, 2019). As illustrated in Figure 1.1, distributed generation, smart appliances, EVs, and energy storage technologies will transform passive consumers into active prosumers who are then able to provide both energy and flexibility services to the local and national systems. The exploitation of the flexibility of local energy storage, distributed generation and DSR, has been shown to lead to cost savings at a system level (Strbac *et al.*, 2019). Part of the cost saving comes from a paradigm shift from providing resilience through redundancy in assets toward using intelligently coordinated DER and therefore further potential savings in system cost.

Figure 1.1. Illustration of energy flowing from grid to consumers while flexibility flows from prosumers to the grid



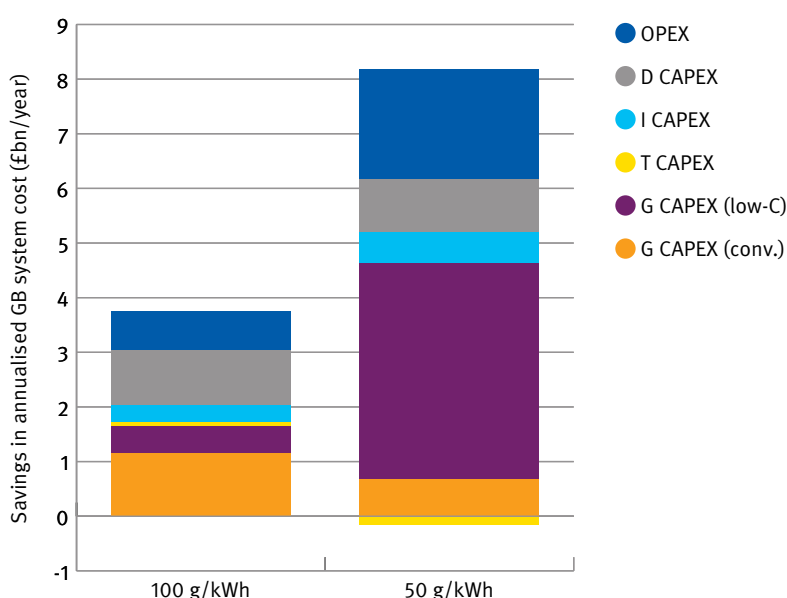
¹¹ This is based on preliminary 2019 statistics from BEIS on power system emissions and generation figures. 177 gCO₂/km is obtained as the ratio of total emissions from power generation of 57.4 million tonnes of CO₂ equivalent reported in (BEIS, 2019a), and total annual generation of 325 TWh reported in (BEIS, 2020a).

Our previous modelling has demonstrated that using decentralized flexibility across the entire GB electricity system can deliver cost savings between £3.8 and £8 billion/year at carbon intensity targets of 100 gCO₂/kWh or 50 gCO₂/kWh (Strbac *et al.*, 2015), which gives hope that flexibility continues to bring benefits to system cost as the emissions target is driven down to zero and subsequently turned negative.

The detail of how cost savings from flexibility are apportioned between operating and capital expenditure is shown in Figure 1.2 for the case of adding 10 GW of new energy storage capacity and achieving maximum DSR uptake. The benefits refer to the gross savings in annual system costs and therefore do not include the cost of deploying and operating new DSR and storage. In that 2015 study, the operation of DSR and the location of new energy storage were optimized to maximize system benefits.

Figure 1.2. Gross system cost savings, for two emissions intensity targets, enabled by providing flexibility (Strbac *et al.*, 2015)

Key: OPEX = Operating Expenses; D CAPEX = Distribution investment cost; I CAPEX = Interconnection investment cost; T CAPEX = Transmission investment cost; G CAPEX (low-C) = investment cost of low-carbon generation; G CAPEX (conv.) = investment cost of conventional generation



The key components of gross cost savings delivered by decentralized flexibility resources include:

- Lower operating expenses arising from avoided curtailment of renewable generation, enhanced operating efficiency of conventional generation, and more efficient delivery of balancing services.
- Reduced network reinforcement, including distribution capital expenditures (D CAPEX), interconnection (I CAPEX), and transmission (T CAPEX) enabled by the reduced peak demand and enhanced utilization of existing infrastructure.
- Reduction in the capacity of low-carbon generation (G CAPEX) which is required to meet a given system-level carbon target arising from improved utilisation of renewable generation that is deployed through demand shifting and storage.
- Reduced investment in conventional G CAPEX because of reduced system peak demand.

These results illustrate that flexibility becomes increasingly important as carbon emissions targets for the electricity sector are reduced. It might be expected that provision of flexibility becomes even more important in achieving net-zero carbon or net-negative carbon targets.

One of the topics this paper will explore will be the extent to which the availability of flexibility changes the mix of generation that should be adopted and the changes in costs that result from that. An important consideration in configuring a future electricity system for net-zero carbon will be to strike the right balance between national and local objectives, in other words, to ensure that distributed flexibility sources such as local energy storage and DSR can not only help in minimising the cost of the electricity grid in their local area but also are enabled to support integration of variable renewable resources at the national level.

1.3. Achieving net-zero and net-negative carbon emissions in future electricity systems with a high share of renewable energy

Wind and solar energy technologies have emerged as the most promising options to produce zero-carbon energy in most countries around the world due to their widespread availability and continued decreases in their cost. However, these are variable in that they depend on weather conditions and this is challenging when attempting to use them as the predominant source (NREL, 2012). The cost reductions in renewable sources, particularly wind and solar, have been substantial over the past decade (IRENA, 2020), to the extent that costs have become comparable to fossil fuel-fired power plants (for instance, IRENA reported the cost of \$43/MWh for wind and \$39/MWh for solar for projects starting in 2021). These cost reductions have been driven by improvements in technology and manufacturing processes, regional manufacturing and a competitive global market. In the UK, the Government's Contract for Difference (CfD) auction in September 2019 saw the price of offshore wind for 2023/24 delivery drop below £40/MWh, a 30% decrease from £57.50/MWh seen just two years earlier.

The UK Government's Ten Point Plan for a Green Industrial Revolution (HM Government, 2020) published in November 2020 sets out the UK's ambition to leverage the recovery from the COVID-19 pandemic to become a global leader in green technologies. The plan focuses on several key areas, including the accelerated development of offshore wind, with the stated objective of delivering 40 GW of offshore wind by 2030. Alongside this are promotion of low-carbon hydrogen and delivery of new and advanced nuclear power. Other focus areas of the plan include decarbonisation of road transport, shipping and aviation; greener buildings; CCS; protection of our natural environment and green finance.

National Grid's Future Energy Scenarios (National Grid ESO, 2020) for GB, published in July 2020, envisage that in order to achieve net-zero GHG emissions for the whole of the UK's economy, the power sector will need to reach net-negative emissions in the early 2030s, dropping to between -50 and -100 gCO₂/kWh by 2035. The thinking is that the electricity sector can offset the emissions from other sectors that are very difficult to fully decarbonise such as industry, agriculture, waste, aviation and shipping. To achieve negative emissions from electricity, it is envisaged that up to 10 GW of BECCS would be combined with about 200 GW of wind and solar capacity and up to 16 GW of nuclear power. Along similar lines, the CCC envisage in their Balanced Net Zero Pathway in the Sixth Carbon Budget that in 2050 around the same volume of renewables capacity will be needed, plus 10 GW of nuclear power and 20 GW of dispatchable low-carbon generation via BECCS and gas CCS.

There is a substantial body of literature exploring the technical feasibility and economic viability of 100% renewable pathways for decarbonising electricity generation, with a comprehensive overview provided in Hansen, Breyer and Lund (2019). There are, however, concerns over the feasibility of achieving a 100% renewable electricity system. Heard *et al.* state that most of the relevant studies do not meet the criteria of consistency with energy demand forecasts, reliability and resilience, transmission and distribution network requirements and the provision of essential ancillary services (Heard *et al.*, 2017). Brown *et al.* oppose those concerns by identifying existing low-cost solutions from available literature that make high-renewable systems technically feasible and economically viable (Brown *et al.*, 2018).

Bogdanov *et al.* make the case for a technically feasible and economically viable evolutionary change towards a 100% renewable electricity system globally by 2050 (Bogdanov *et al.*, 2019). The benefits of designing a 100% renewable electricity sector have been presented in (Child *et al.*, 2019) for a larger area (such as the whole of Europe) with stronger interconnection links rather than at a smaller-scale regional level. It has also been shown that transition towards a 100% renewable energy-based system by 2050 is feasible even for countries with severe climate conditions and an energy intensive industry, such as Kazakhstan (Bogdanov *et al.*, 2021), with the power sector becoming the backbone of the entire energy system through electrification and intensive sector coupling that delivers additional flexibility.

It is therefore clear that increasing the share of renewable sources to a high level as part of a net-zero or net-negative carbon system will require a new appraisal of where investment would best be made to deliver electricity in a cost-efficient manner and in particular, attention needs to be paid to expansion of sources of flexibility, such as energy storage and DSR (Strbac *et al.*, 2017). It has been shown that reaching a high penetration of renewables will require an order of magnitude increase in the volume of energy storage and DSR (Denholm and Margolis, 2016).

1.4. Purpose of the White Paper

This paper sets out quantitative evidence on how a net-zero carbon electricity system should be configured in terms of capacities of various generation types and energy storage. It does this by cost-optimising the capacities to achieve net-zero subject to hour-by-hour supply-demand balance, security (in terms of ability to meet peak demand with allowance for plant failures) and subject to realistic network capacity constraints. There is more than a single answer to this question and so a range of answers are contrasted that account for variations in cost of technologies, uptake of DSR, power-to-energy ratio of storage and extent of international interconnections.

The main focus of this White Paper is achieving net-zero emissions in 2035 but this will be compared to a net-negative case set at $-50 \text{ gCO}_2/\text{kWh}$, similar to the Future Energy Scenarios (National Grid ESO, 2020), which might support other sectors of the economy that are more difficult to decarbonise.

The four main questions this report addresses are:

1. How much offshore wind capacity will GB need? Offshore wind is widely seen as the best route to decarbonisation of the UK energy system and features prominently in the UK government's plans, with a specific commitment to an additional 30 GW of offshore wind capacity by 2030 on top of the 10 GW present today. How does this commitment compare with what is required for net-zero emissions and does it place the UK on the right trajectory?
2. How much energy storage will be needed in a net-zero system? Storage is widely seen as an important partner to variable renewable generation and a source of the flexibility needed for system operation. What is the cost-optimal volume and how does it depend on the cost and technical characteristics of the storage type, and its alternatives?
3. What role is there for other zero-carbon and negative-carbon technologies? How is system configuration changed with variation in the cost of nuclear, or emergence of biofuels and synthetic zero-carbon fuels, or deployment of Direct Air Capture of CO_2 ?
4. What range of system costs and unit cost of delivered electricity might be expected in a net-zero system? How does the cost of electricity vary with changes to the technology cost assumptions?

To answer these four questions, our whole-system modelling framework is used as described in Chapter 2.1, with a Central case and a series of variations, to find the cost-optimal system

for each. The results include data on the total built capacities of each generation and storage type (under cost optimality), their annual electrical energy outputs, the total system cost and the expected cost per unit of electricity, including network costs, in the net-zero system. Further information, such as examples of hourly or daily operating patterns, are provided where this aids understanding of the system configuration.

There are many uncertainties that could greatly affect the cost-optimal configuration of a net-zero carbon power system, so a large number of sensitivity studies have been carried out. Those that illustrate the main findings are in the main report of the paper with others described in the Appendix for completeness.

2. Modelling approach and assumptions

2.1. Whole-system modelling of low-carbon power systems

Capturing the interactions across different time scales and across different asset types is essential for the analysis of future low-carbon electricity systems that include flexible technologies such as energy storage and Demand Side Response (DSR). Clearly, the application of those technologies may improve not only the economics of real-time system operation, but also reduce the investment into generation and network capacity in the long run.

In order to capture these effects, and in particular trade-offs between different flexible technologies, it is critical that they are all modelled in a single integrated modelling framework. In order to meet this requirement, Imperial has developed the *Whole-electricity System Investment Model (WeSIM)*, a comprehensive system analysis model that is able to simultaneously balance long-term investment decisions against short-term operation decisions, across generation, transmission and distribution systems, in an integrated fashion.¹²

WeSIM determines optimal decisions for investing into generation, network and/or storage capacity (both in terms of volume and location), in order to satisfy the real-time supply-demand balance in an economically optimal way, while at the same time ensuring efficient levels of security of supply. An advantage of WeSIM over most traditional models is that it is able to simultaneously consider system operation decisions and capacity additions to the system, with the ability to quantify trade-offs of using alternative mitigation measures, such as DSR and storage, for real-time balancing and transmission and distribution network and/or generation reinforcement management. A prominent feature of the model is the ability to capture and quantify the necessary investments in distribution networks in order to meet demand growth and/or distributed generation uptake, based on the concept of statistically representative distribution networks.

Analysing future electricity energy at sufficient temporal and spatial granularity is essential for assessing the cost-effectiveness of alternative decarbonisation pathways. In this context, WeSIM-based modelling has clearly demonstrated that in order to quantify system operation and investment cost and the carbon performance, quantitative models need to simultaneously consider second-by-second supply-demand balancing issues as well as multi-year investment (e.g., reduced system inertia may trigger investment in flexible technologies). Furthermore, electricity system decarbonisation will also need to adequately consider the synergies and conflicts between local/district level and national (or trans-national) level infrastructure requirements, which is another key feature of WeSIM.

¹² A more detailed description of WeSIM modelling framework can be found in the Appendix of the report “Whole-system cost of variable renewables in future GB electricity system”, available at: http://energysuperstore.org/esrn/wp-content/uploads/2016/11/Whole-system-cost-of-variable-renewables-in-future-GB-electricity-system-Imperial_Nov2016.pdf

WeSIM carries out an integrated optimisation of electricity system investment and operation and considers two different time horizons: (i) short-term operation with a typical resolution of one hour or half an hour (while also taking into account frequency regulation and short-term reserve requirements), which is coupled with (ii) long-term investment, i.e., planning decisions with the time horizon of typically one year (the time horizons can be adjusted if needed). All annual investment decisions and 8,760 hourly operation decisions are determined simultaneously in order to achieve an overall optimality of the solution. Key features and constraints considered in WeSIM include: a) power balance, b) reserve and response requirements, c) generator operating limits, d) DSR capability; e) distribution network investment, f) carbon emission constraints, g) constraints on electricity imports and exports, and h) security constraints.¹³

The system cost that is optimised in WeSIM only includes the reinforcement cost of transmission and distribution networks, i.e., the cost of upgrading the current network capacity. In order to reflect both existing and additional network infrastructure in the total system cost results presented in this paper, the system cost identified by WeSIM was increased by £2.4bn/yr to account for the existing transmission network and by a further £5.5bn/yr for the existing distribution infrastructure.¹⁴ The investment cost of interconnection between GB and the neighbouring systems is attributed to the GB system. The total system cost presented here does not include the cost of enabling DSR through automation or additional metering. The unit cost of electricity is calculated for each case by dividing the total annual system cost with the total annual generation output from the GB system.¹⁵

2.2. Key assumptions

The context for the study is a net-zero emissions system in 2035, with an extension to net-negative emissions. The analysis considers a snapshot for a single future year in which total cost, comprising annualised investment cost and operation cost, is minimised. Pathway dependencies were also examined by setting volumes of pre-existing investments of, say, nuclear and solar PV, that have been locked-in by previous decisions or policies and placing upper limits on volumes of other technologies to recognise build-rate limits. To maintain the same level of system security as today, the security standard, expressed through Loss of Load Expectation (LOLE), was maintained at 3 hours per year.

2.2.1. Technologies available for deployment

The following generation and storage technologies are the main options available:

- **Offshore wind:** the central assumption is for a Levelised Cost of Electricity (LCOE) of £35/MWh, which represents a continuation of the current trend of decreasing cost of offshore wind generation. Two sensitivity cases were added at $\pm$ £5/MWh on the Central case: high-cost wind at £40/MWh and low-cost wind at £30/MWh. The narrowness of the range reflects the steady maturation of this technology and relatively high confidence in its cost progression.
- **Onshore wind:** an LCOE of £50/MWh is assumed which is higher than offshore wind because of a lower load factor. A build limit of 30 GW is imposed to recognise constraints such as limited areas for development and protracted planning approval.
- **Solar PV:** the assumed LCOE is £50/MWh to reflect relatively low PV load factors in GB (around 11% in the south of the country). Nevertheless, a sensitivity study is included at £20/MWh to assess substantial further technology LCOE reductions.¹⁶

¹³ Detailed formulation of WeSIM can be found in (Pudjianto *et al.*, 2014)

¹⁴ These figures were obtained from average annual revenue allowances for GB transmission and distribution network operators specified in RIIO-ED1 and RIIO-T1 price control periods.

¹⁵ Due to the assumed energy neutrality (Section 2.2.3) the total annual generation output in most cases was equal to total system demand. The only exception to this was the case with allowed net annual exports of electricity.

¹⁶ LCOEs of PV in the range £20–£30/MWh have been reported from solar farms in India, China and Mexico but these locations are at lower latitudes and with weather conditions giving more days per year of clear skies and thus they achieve higher load factors and lower LCOE for the same equipment cost.

- **Nuclear:** the central assumption is for an LCOE of £92.5/MWh which is the Contract for Difference (CfD) strike price awarded to the Hinkley Point C project. This is a conservative assumption and makes no allowance for reductions of cost beyond the first-of-a-kind cost for this reactor type. It is considered unlikely that costs above this would be entertained and so two variations below this down to half this cost were included in the analysis. Current GB nuclear plants are inflexible but here it is assumed that output can be modulated down to 60% of maximum power when needed which reflects the pressure to provide flexible operation of all assets.
- **Zero-carbon fuelled generation:** it was considered that Combined-Cycle Gas Turbines (CCGT) and Open-Cycle Gas Turbines (OCGT), currently designed for natural gas fuel, could in future use either hydrogen or zero-carbon gas (biogas). The investment cost for zero-carbon CCGT and OCGT was assumed to be the same as their current conventional counterparts. The cost of zero-carbon fuel was assumed to be £38/MWh, which resulted in an operating cost of £74/MWh for zero-carbon CCGT and £109/MWh for OCGT. Both costs are for operation at full output and are operating costs not LCOE¹⁷.
- **Energy storage:** the central assumption is for battery storage with 2-hour duration¹⁸ and 85% roundtrip efficiency at £187.5/kWh, equivalent to a cost per unit power of £375/kW at 2-hour duration¹⁹. Variations of duration were explored, as well as non-battery longer-duration storage of 120-hour duration at costs between £4 and £500/kWh. Pre-existing pumped-hydro storage of 2.7 GW is assumed.

Other generation technologies such as conventional gas CCGT and OCGT or gas CCS are available in the model framework but were not deployed because the emissions or residual emissions are inconsistent with the net-zero constraint, except for the cases where DAC is available as a technology option.

The standard portfolio of pre-existing capacity (the minimum capacity constraints for the optimiser) reflects the portions of today's generation portfolio that are expected to continue operating to 2035 and capacity additions that are already in development, such as Hinkley Point C nuclear power station, as follows:

- **Offshore wind:** 18.6 GW comprising 10.4 GW of capacity existing in 2020 and 8.2 GW of capacity under construction and with planning consent obtained by the beginning of 2020²⁰
- **Onshore wind:** 14.7 GW comprising 13.2 GW of capacity in 2020 plus modest expansion
- **Solar PV:** 18.5 GW comprising 13.0 GW of capacity in 2020 plus expected expansion
- **Nuclear:** 4.5 GW anticipated capacity from plant retirements and plants under construction²¹
- **Hydro and other RES:** 2.8 GW

Where other minimum capacities were used, this will be stated explicitly.

¹⁷ The LCOEs of zero-carbon gas generation technologies will be a function of operating cost but also their utilisation across a year, which is determined by the optimisation model and is therefore not known in advance. Nevertheless, for illustrative purposes, the LCOE of zero-carbon CCGT at 50% load factor works out as £91/MWh, while for OCGT generation, where a realistic load factors is around 10%, the resulting LCOE would be £177/MWh.

¹⁸ We have chosen 2-hour duration for battery storage as our central assumption given that most of the new battery development projects bidding into the GB Capacity Market are 2-hour batteries.

¹⁹ As a reference, Tesla's 100 MW battery in South Australia (Hornsedale Power Reserve) was built in 2017 for about £50m (A\$90m), i.e. at about £500/kW. According to Bloomberg New Energy Finance (BNEF) the cost of a battery pack dropped from \$214/kWh in 2017 to \$156/kWh in 2019, i.e., by 27% in just two years. BNEF's expectation is that this will further drop to \$100/kWh by 2023, representing more than 50% reduction from 2017. If the same reduction applied to a Tesla-like grid battery storage, its cost in 2023 would drop to less than £250/kW. Therefore, the numbers used in this study are plausible for 2035.

²⁰ RenewableUK's wind database, <https://www.renewableuk.com/page/UKWEDSearch>

²¹ This reflects the capacity of Hinkley Point C station (3.3 GW), expected to become operational before 2030, and the capacity of Sizewell B (1.2 GW), which is expected to still operate in 2035.

2.2.2. Demand evolution

In response to the ambition of carbon emissions reductions across many sectors by 2035, very high levels of electrification of heat and road transport is assumed across all case studies. It was assumed that most of the passenger vehicle fleet is electrified amounting to 37 million EVs. The number of households with heat pumps was assumed at 15.2 million. Both all-electric and hybrid gas-and-electric heat pumps are considered but the hybrid heat pumps using natural gas are only relevant to the case study with DAC available. A limit of 9.5 million hybrid heat pumps was applied. Demand for heating was based on temperatures across a typical year, with a period of three very cold days added in January to ensure the system has adequate capacity to meet demand in extreme weather conditions. The Coefficient of Performance (COP) of heat pumps (assuming most residential installations will be air-source HPs) was assumed to vary in line with variations in outdoor temperature.

Other electricity demand (not including newly electrified heat and road transport) was assumed to be 325 TWh per year. This gave a total electricity demand including electrified heat and road transport sectors of 456 TWh²².

By way of comparison, in the CCC's Balanced Net Zero Pathway demand is assumed at 460 TWh in 2035 and 610 TWh in 2050, figures which are inclusive of heat pumps and expansion of EV numbers. Heat pump deployment of 8 million in existing homes is included for 2035 and low-carbon heating is included for every home by 2050, including low-carbon district heat for 5.5 million existing homes, heat pumps for 21 million existing homes (including 5 million in a hybrid configuration, with some using hydrogen as a back-up) and direct electric heating for around 2 million existing homes. The number of EVs on the road assumed by the CCC is 28 million BEVs and 3 million PHEVs in 2035. By 2050, this will grow to 49 million BEVs, 0 PHEVs and 1 million low-carbon HGVs. The scenario assumes no sales of new petrol or diesel cars, vans or PHEVs from 2032.

Although there are many open questions around the regulatory and market arrangements for DSR and concerns over the extent of engagement with DSR, it was assumed that considerable DSR resource will materialise by 2035. Uptake of DSR was considered across all demand sectors that are potentially flexible including industrial and commercial (I&C) demand, smart appliances, heat pumps and EVs. The extent of DSR uptake was defined with respect to the maximum theoretical potential. That theoretical potential is taken to be:²³

- **Electric vehicles:** flexibility in EV charging enables up to 80% of EV demand to be shifted away from a given hour to other times of the same day;
- **Heat pumps:** heat storage enables 35% of HP demand to be shifted from a given hour to other times of day;
- **Smart appliances:** smart operation of white appliances (washing machines, dishwashers, tumble dryers) enables 100% of their energy demand to be shifted away from peak demand times;
- **Industrial and commercial demand:** 10% of the demand of I&C customers participating in DSR schemes can be redistributed.

²² Note that this demand does not include transmission and distribution network losses, which were added in the whole-system model at the level of 7% of net demand.

²³ An overview of the rationale and evidence behind these assumptions is provided in (Aunedi, Teng and Strbac, 2014).

The central assumption for 2035 is that 25% of the maximum potential for DSR will be available for use. For instance, for a full DSR penetration (corresponding to 100% uptake), up to 10% of I&C demand can be shifted away from peak hours within the same day, an assumption based on the authors' previous bottom-up modelling of demand flexibility (Aunedi, Teng and Strbac, 2014). At lower DSR uptake levels, this was scaled down accordingly, so that at 25% uptake, 2.5% of the baseline I&C demand was considered shiftable. A High-DSR case with 75% uptake is also explored.

The primary use of DSR is improving energy management but it can also be used to lower peak demand and thereby ease capacity adequacy requirements. DSR is also assumed to be able to provide frequency response to maintain grid frequency.

2.2.3. International interconnection

Interconnection between GB and continental Europe is available to be added at an annualised cost of £96/MW/km/yr (based on the cost of subsea HVDC links). Starting capacity for interconnection was 20 GW, of which 1 GW was between GB and Ireland and the rest between GB and continental Europe.

To address interconnection, electricity systems of continental Europe and Ireland were modelled in simplified fashion with their own demand profiles and generation portfolios. The model minimised the total cost of British and European power systems through investment in generation and storage assets with a carbon emissions target outside GB of 25 gCO₂/kWh.

The general assumption was that the GB electricity system is energy-neutral for electricity, i.e., although at any hour interconnections can be exporting or importing, electricity exports match imports over the course of a year. In one case study, this constraint was removed to allow net exports through further expansion of offshore wind energy capacity (Section 3.1).

Security of the GB system, an LOLE of 3 hours per year, was assumed to be provided by generation, storage and demand assets within GB borders only.

3. Key results for the net-zero GB system

The key results and findings from the whole-system modelling studies will now be presented. For each case study the results are presented collectively with three charts: (a) generation capacity mix together with storage, (b) annual generation output and (c) annualised system cost for GB²⁴. In each of the charts, the left-hand part shows the complete results for the case study and the right-hand part shows the differences with respect to the relevant counterfactual case, often the Central case summarised in Table 1.

This section comprises three subsections that directly address the first three questions set out in Section 1.4. The fourth question addresses variations in system cost and these variations are very closely related to the changes in installed capacity of various technologies and their annual energy production. Therefore, discussion of system cost and unit cost of electricity is integrated into each of the three subsections where key drivers for the observed cost changes can be described.

²⁴ The datasets behind all of the charts in this White Paper are available for [download](#) in an Excel spreadsheet alongside the report.

3.1. How much offshore wind capacity will GB need?

To answer the first question set out in Section 1.4, the Whole-electricity System Investment Model (WeSIM) was run for the Central case and for variations, as defined in Section 2.2, of the cost of offshore wind to high-cost at £40/MWh and low-cost at £30/MWh (i.e. $\pm$ £5/MWh on the Central case of £35/MWh), low-cost solar PV at £20/MWh (c.f. £50/MWh Central case), locking in higher capacities of nuclear (14.5 GW instead of 4.5 GW) and solar PV generation (37 GW instead of 18.5 GW) and relaxation of electrical energy neutrality for GB. This gives a total of six studies that combine to answer how much offshore wind capacity GB will need to achieve zero-carbon electricity and the results are shown in Figure 3.1.

3.1.1. Capacity mix

Figure 3.1(a) shows the cost-optimal capacity mix and it is clear that very substantial expansion of offshore wind capacity beyond the 2030 target of 40 GW is needed: expansion by a factor of roughly 2–2.5, to 85–108 GW. If net export of renewable energy is envisaged, an expansion by a factor of roughly 3 to 126 GW is indicated. In the Central case, onshore wind, solar PV and nuclear generation are not significantly expanded beyond their imposed minimum capacity because of favourable Levelised Cost of Electricity (LCOE) of offshore wind compared to other low- and zero-carbon generation (the cost assumptions were set out in Section 2.2.1). In the High Wind Cost case, there is some expansion of solar and in the Low PV Cost case, solar expands significantly to 175 GW. The net-zero constraint means that neither unabated gas nor gas CCS (with its imperfect capture) is selected for investment. Offshore wind is seen as becoming the dominant source of electricity in the net-zero GB system, as will be discussed further in relation to Figure 3.1(b).

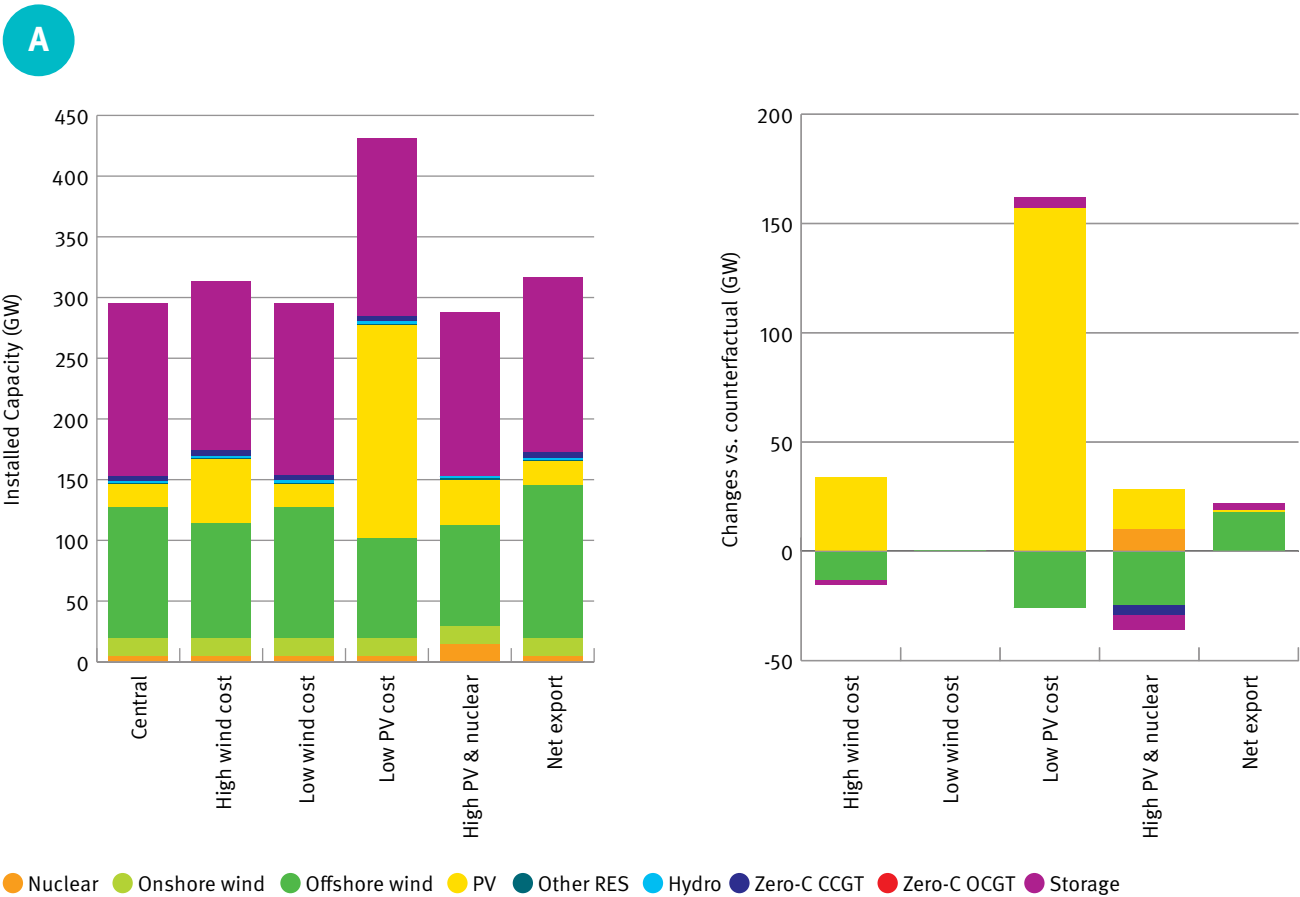
Another prominent feature of the cost-optimised net-zero system is a very large deployment of battery energy storage taking the capacity to 142 GW in the Central case. This represents an increase of more than one hundredfold from today's levels. The role of battery storage is discussed in more detail in Section 3.2, nevertheless it is clear that large volumes of battery storage are needed to balance the fluctuations in wind output (and to a smaller extent solar PV output).

The model selects 4.5 GW of zero-carbon CCGT capacity in Central case. This ensures the availability of zero-carbon electricity during periods of low wind output. The cost structure of zero-carbon CCGT (with moderate investment cost and relatively high operating cost) is favoured as a partner to wind over high capital cost options such as nuclear because it remains economical even at low load factor.

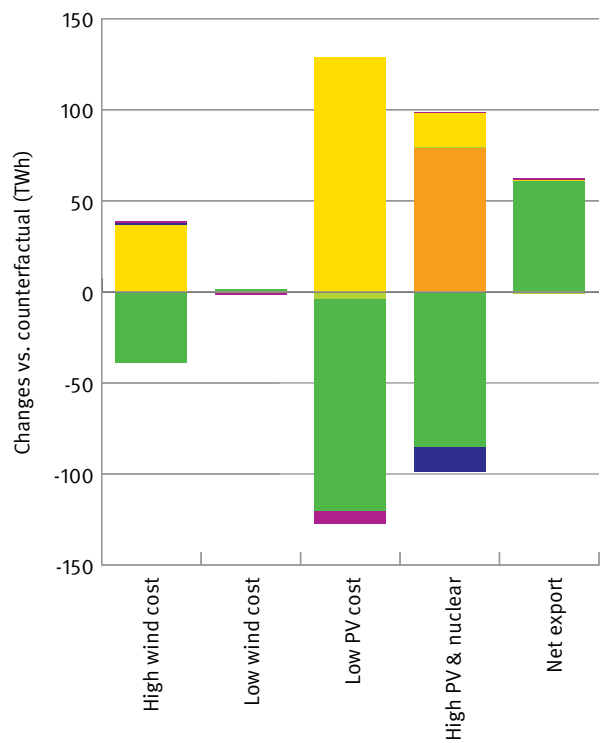
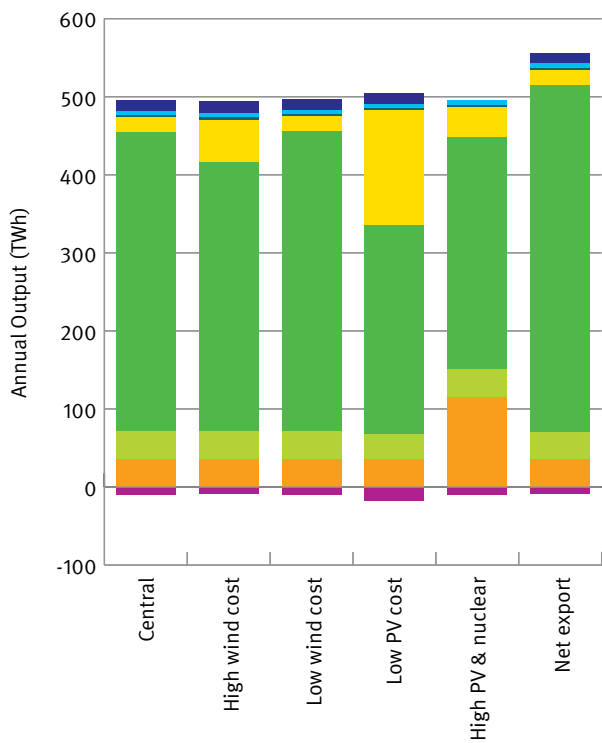
The expansion of offshore wind capacity in GB to reach net-zero carbon requires, alongside energy storage, a large increase in the capacity of interconnections with electricity systems in neighbouring countries. As of January 2021, there is 5 GW of interconnection capacity in operation, connecting the GB system with the power systems of France, Belgium, the Netherlands and Ireland. There is a further 4.8 GW of interconnection capacity in construction, with an additional 8.1 GW progressing through regulatory approvals.²⁵ The total of all interconnection projects that are operational, under construction or pending approval is about 18 GW. The model increases this substantially to 43 GW for a net-zero 2035 system.

²⁵ https://ec.europa.eu/energy/sites/ener/files/gb_implementation_plan-final.pdf

Figure 3.1. GB system for net-zero with variations in cost of offshore wind and solar PV, in minimum levels of nuclear and solar PV and with option to export electricity (a) total capacities (left) and capacity difference vs. counterfactual (right) (b) annual generation output, total and difference (c) system cost, total and difference

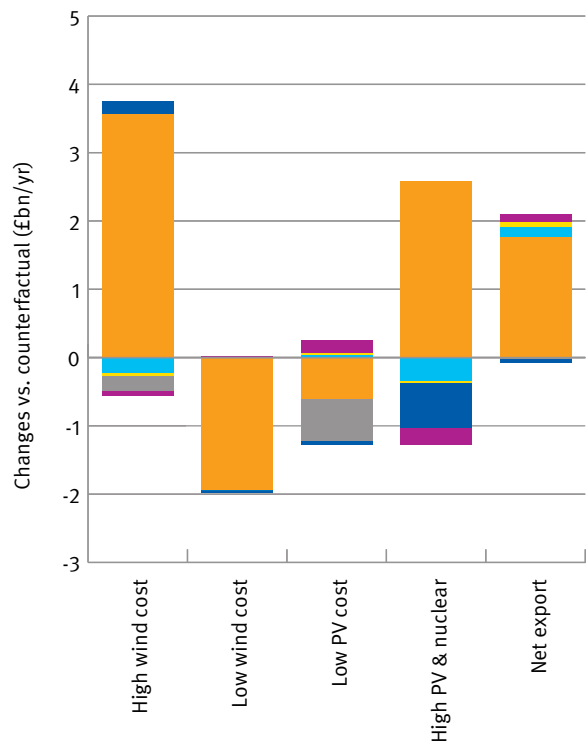
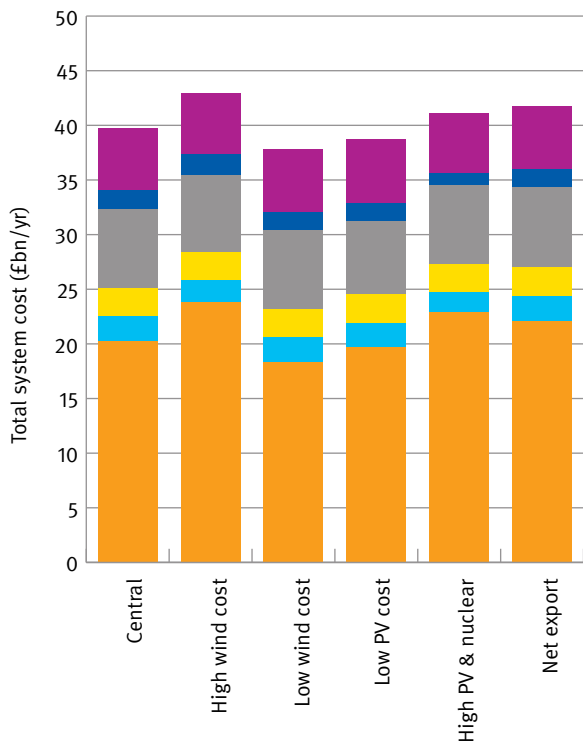


B



Nuclear Onshore wind Offshore wind PV Other RES Hydro Zero-C CCGT Zero-C OCGT Storage

C



Gen. CAPEX Interconn. CAPEX Transm. CAPEX Distr. CAPEX OPEX Storage CAPEX

The chart to the right-hand side of Figure 3.1(a) shows the changes in cost-optimal levels of generation capacity against the Central case. It is evident that the cost-efficient volume of offshore wind does not change much with plausible variations in its cost. In the High Wind Cost case (£40/MWh), there is 13 GW less wind capacity, replaced with about 34 GW of new solar PV generation (with much lower load factor). Negligible changes are seen in the Low Wind Cost case (£30/MWh), suggesting that offshore wind is already the most cost-efficient form of power generation.

If the LCOE of solar PV reduces to just £20/MWh (Low PV Cost case in Figure 3.1), it becomes more attractive and its capacity is increased to 176 GW, displacing 26 GW of offshore wind. This still leaves offshore wind at 82 GW: eight times the installed capacity today and twice the UK government's 2030 target. The volume of battery storage increases by 5 GW.

Choosing to build more nuclear power and more solar generation than is optimal in the Central case could also reduce the potentially challenging build-rate of offshore wind for 2035. With the imperative of achieving net-zero for the electricity sector by 2035, a system that uses less offshore wind, and is therefore sub-optimal on cost according to the results in the Central case may be necessary. Where higher than cost-optimal volumes of nuclear power (14.5 GW rather than 4.5 GW) and PV (37 GW rather than 18.5 GW) are imposed and the remaining system cost-optimised, 24 GW of offshore wind and 7 GW of battery storage is displaced. The new capacity of offshore wind at 84 GW is still double the present 2030 target.

The final case examines the potential to expand the offshore wind capacity in GB in order to export electricity to mainland Europe, where the opportunities for wind energy expansion are perhaps less advantageous to a developer. The cost-optimal solution suggests adding a further 18 GW of offshore wind, increasing the total GB offshore wind capacity to 126 GW. This is accompanied by a small increase of 3 GW in battery energy storage to manage the increased wind output variability, and perhaps surprisingly, an increase of only 3 GW of interconnector export capacity on top of the 43 GW in the energy-neutral Central case.

3.1.2. Electricity output

Figure 3.1(b) presents the annual energy output of each type of generation with changes in total annual generation from the Central case on the right-hand side. The share of variable renewables (wind and PV) in total production is around 88% in all cases, with nuclear contributing a further 7% and the remaining 5% provided by a mix of zero-carbon CCGT and other renewables such as the existing hydro. The annual capacity factor for zero-carbon CCGT is around 35%. Net contribution of energy storage in the chart appears as a negative energy which is the roundtrip energy loss in charging and discharging the storage.

Although not shown in the figure, the curtailment of available wind output across a year was found to be relatively low, at 3.6% in the Central and Low Wind Cost cases, and 1.5% for High Wind Cost case. Curtailment occurs when either the output of wind plus must-run generation (the minimum nuclear output and generation required for inertia or other technical purposes) exceeds demand or when network constraints prevent transmission of wind output to a demand centre.

In the case of Low PV Cost, a large volume of PV displaces some offshore wind capacity but together the two technologies produce a very similar amount of energy in this case compared to the Central case. Specifically, PV of double the capacity of offshore wind contributes a little over half as much energy. Because of the higher variability of solar PV output compared to wind generation, the utilisation of battery storage is higher in the Low PV Cost case compared to the Central case, which in turn increases the energy losses (negative energy output) of the storage.

It is also interesting to note that the level of PV output curtailment increases substantially, from 2% in the Central case to 18% in the Low PV Cost case. Such a high level of curtailment is

acceptable from an economic point of view given the very low LCOE of PV in this case. The opportunities to export excess PV generation are expected to be much more limited than for wind because of the similar PV output profiles in continental Europe.

With higher than optimal capacity of solar PV and nuclear, the additional generation output provided by these two technologies displaces about 100 TWh of combined offshore wind and zero-carbon thermal generation. In the net export case, the annual offshore wind output increases by 60 TWh, while the outputs of other technologies remain broadly the same. This exported energy is an addition of about 12% on top of the energy needed to meet the GB (gross) electricity demand of around 500 TWh.

3.1.3. Total system cost

The comparison of total system cost is provided in Figure 3.1(c), with totals provided on the left-hand side and differences from the Central case on the right-hand side. Total system cost is broken down into several categories representing the capital investment cost (CAPEX) of low-carbon generation, storage, interconnectors, transmission and distribution network plus the operating cost of generation (OPEX).

Total system cost in the Central case is dominated by the investment cost of low-carbon generation (an annualised value of about £20bn/yr), followed by a significant investment cost of energy storage (£5.7bn/yr), OPEX of zero-carbon fuelled generation (£1.7bn/yr) and CAPEX of interconnection (£2.2bn/yr) and distribution (£7.3bn/yr) infrastructures (of which £1.8bn/yr represents the reinforcement of distribution networks over current condition). Transmission network cost is about £2.6bn/yr, with transmission network reinforcement representing only a relatively minor component of this cost with £140m/yr. Total system cost in the Central case amounts to about £40bn/yr.²⁶

Higher cost of wind results in a total system cost that is £3.2bn per year higher than in the Central case, as the result of capacity of offshore wind being largely unchanged (because it remains the best choice) but being installed at higher cost. For the same reason, the Low Wind Cost case results in a system cost that is £2bn lower than in the Central case. Other cost components change very little with the variations in the cost of wind. In the Low PV Cost case, cheaper PV generation displaces offshore wind, which reduces the generation investment cost (£20/MWh solar replaces some £35/MWh offshore wind), while also decreasing the distribution network investment cost, resulting in a total system cost that is £1.0bn/yr lower.

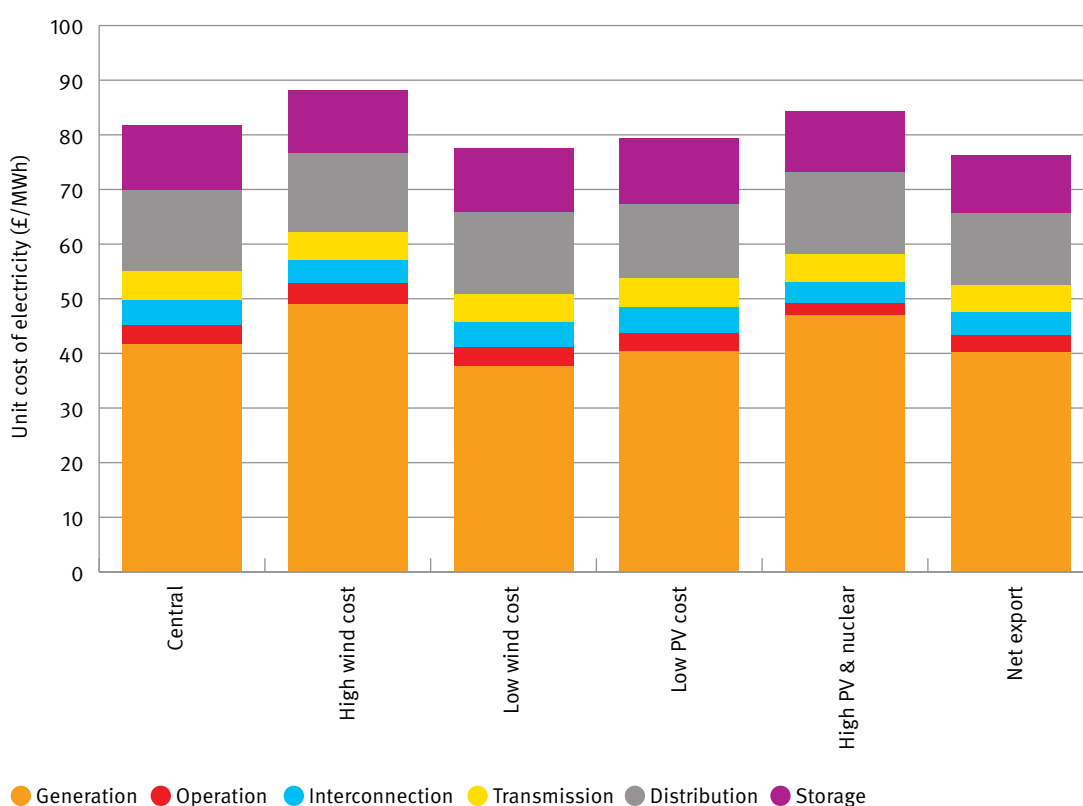
Investing in more nuclear power and more solar PV generation than is optimal in the Central case increases the total system cost by about £1.3bn/yr, or 3.3%. This increase is driven by higher than optimal investment in low-carbon generation capacity, while at the same time there is slightly reduced cost of operating zero-carbon gas generation and lower cost of interconnectors.

As expected, the option to become net exporter of electrical energy increases the total system cost compared to the Central case which enforced energy neutrality across a year. The majority of this £2bn/yr cost increase arises from the greater investment cost of offshore wind. The increase in cost would be recovered through the revenues earned from selling electrical energy to customers in neighbouring markets. The breakeven average energy price required to cover the additional cost of supplying the exported energy was found to be £33/MWh.

²⁶ It is interesting to compare the total system cost with the cost reported in the modelling supplement to Energy White Paper issued by BEIS (BEIS, 2020b), which was between £53bn and £62bn per year in near-zero carbon 2050 scenarios for Lower and Higher Demand, respectively, with hydrogen. System cost figures are expectedly higher due to higher electricity demand assumptions (575 TWh for Lower and 672 TWh for Higher Demand scenario). Nevertheless, at £92/MWh the average cost of electricity was comparable to the findings in this paper. Note also that the White Paper analysis assumed much lower levels of flexibility across DSR, storage and interconnection resources, and did not consider any CO₂ removals in the power sector.

Variations in the unit cost of electricity across the various cases are presented in Figure 3.2. For the Central case, the average system cost of electricity is £81.6/MWh. This includes all the cost of generation, storage and networks but not the metering, billing, tax and supplier margins that would also appear in a retail price. A rise of £5/MWh from the central assumption of LCOE of offshore wind of £35/MWh increases the unit cost of electricity to £88/MWh whereas a reduction of £5/MWh leads to £78/MWh. Low PV cost reduces the average cost by about £2/MWh from the Central case, while the option to export electricity further reduces this to £76/MWh.²⁷ Increasing the minimum capacities of nuclear and solar PV generation pushes the average cost upwards to more than £84/MWh.

Figure 3.2. Unit cost of electricity in the GB system for net-zero with variations in cost of offshore wind and solar PV, in minimum levels of nuclear and solar PV and with option to export electricity



3.2. How much energy storage will be needed in a net-zero system?

It was evident in the results discussed in Section 3.1 that very large volumes of battery energy storage are needed in a zero-carbon GB electricity system. Several detailed questions arise from this, such as how does the required volume of storage change if the energy-to-power ratio of the battery changes or the volume of available DSR changes. This study was exploratory so no limits were placed on the total volume of battery energy storage that could be deployed. One must recognise though that many of the presented outcomes will require an unprecedented scaling up of battery supply chains.

²⁷ Note that in the Net export scenario the total system cost is divided by the total GB generation rather than total demand.

The following cases are analysed in this section and compared to the results of the Central case:

- High DSR case with uptake²⁸ of 75% compared to 25% in Central case
- 1-hour BESS which is a shorter duration than the Central case (of 2 hours)
- 4-hour BESS which is a longer duration than the Central case
- Low-cost Long-Duration Energy Storage (LDES)

Further results from sensitivity studies on various parameters of energy storage can be found in the Appendix.

The central assumption on the duration of BESS was 2 hours, which is typical of recent grid-connected lithium-ion battery installations. A 2-hour BESS with a stored energy of 1 kWh would be able to deliver 0.5 kW for 2 hours. Another way to view this is that a 2-hour duration BESS has an energy-to-power ratio of 2. Although 2 hours is typical at present, various battery projects with lower and higher durations have been built. Two additional cases were therefore analysed where the battery storage duration parameter took the values of 1 h and 4 h (energy-to-power ratios of 1 and 4). It was considered that the major cost of a battery energy storage system is the battery itself, the volume of which is determined by the energy. The cost of the grid interface, which is related to the power, was considered to be a small fraction of the total and so all battery energy storage is costed at £187.5/kWh (as set out in Section 2.2.1). This has important implications if the battery storage is providing power capacity (such as to meet peak demand), in which case the cost of a unit power capacity (£/kW) is higher for the longer duration storage (since $\text{cost-per-unit-power} = \text{cost-per-unit-energy} \times \text{energy-to-power-ratio}$).

The final case in this section considers the role of LDES, defined here as being 120-hour duration. Cost and characteristics were based on alternatives to batteries, such as flow batteries and thermal-electric storage. The roundtrip efficiency was taken as 60%. Only the Low-cost case LDES at £4/kWh is presented here but other cost cases are included in the Appendix.

3.2.1. Capacity mix

The cost-optimal capacities of generation and storage are shown in Figure 3.3(a) for the Central case (with 2-hour duration storage and 25% DSR) and then the four variants described above.

Compared to the Central case, High DSR uptake reduces the need for battery storage by 16 GW which reflects the ability of DSR to reduce peak demand and therefore reduce the capacity needed to guarantee serving it. There is also a 3.5 GW reduction in offshore wind capacity.

Given the high Electric Vehicle (EV) penetration assumed in this analysis, it is conceivable that EV batteries could displace some of the necessary battery storage capacity by providing Vehicle-to-Grid (V2G) services to the future system i.e., by injecting energy into the grid at time of need. This option was not explicitly considered in the modelling here but an earlier study (Vivid Economics and Imperial College London, 2019) estimated that EV batteries at this level of EV penetration could displace about 35 GW of battery storage, although this estimate did not involve any explicit modelling of V2G operation within the power system nor considered vehicle journey patterns.²⁹

Turning to variation of BESS duration (or energy-to-power ratio), the cost-optimal battery capacities for 1, 2 and 4 h duration cases are 187, 139 and 78 GW (note that the capacity reported in the chart also includes 2.7 GW of pumped hydro storage). These power capacities translate

²⁸ The definition of DSR uptake appears in Section 2.2.2.

²⁹ Emerging work on whole-system benefits delivered by V2G-enabled EVs (Nissan, Imperial College London and E.ON Drive, 2021) indicates that these benefits could be very high, especially for fleet EVs with more predictable usage patterns.

to energy capacities of 187, 278 and 312 GWh. Neither energy nor power is constant across these cases, suggesting that the system need for storage is based on both its ability to provide energy capacity to balance variable renewables over periods of time but also its ability to provide power capacity to meet demand peaks.

For the shorter, 1-hour duration case, the model increases the power capacity compared to the Central case but does not double it so the energy capacity (and cost) is somewhat lower than the Central case. This suggests that in the Central case, some but not all of the energy capacity is needed to support the variable renewable energy resources and the remainder was needed for the firm power capacity it brought with it. For the longer, 4-hour duration case, the energy capacity increases slightly (about 12%) so the power capacity almost halves (falls by 43%). This is because these long duration batteries are an expensive way to provide power capacity and so the model opts instead to install an additional 53 GW of OCGT (with zero-carbon fuel) against the 60.9 GW reduction in power capacity of storage. This indicates that a substantial fraction of the value of the storage in the Central case arises from its firm power capacity and not from energy balancing.

The final case in Figure 3.3(a) shows the impact of including long-duration storage in addition to BESS and the existing Pumped-Hydro Storage (PHS). In this case, 20 GW of LDES is added and 16 GW of BESS is displaced. This is a relatively small change set against the 141 GW of BESS in the Central case despite the unit energy cost of LDES being set very low (£4/kWh against £187.5/kWh for BESS). Higher, and arguably more realistic, costs for LDES were examined, as described in the Appendix, but deployment volumes are very small.

3.2.2. Electricity output

The annual energy output of generation, plus the roundtrip energy losses of storage, are shown in Figure 3.3(b). In the High DSR case, there is less BESS and what is present is used less intensively, which in turn reduces the energy losses (losses are shown as a negative output so a reduction in losses is a positive change in the right-hand chart). Consequently, less output is needed from offshore wind.

In the shorter, 1-hour duration storage case, about 3 TWh annually of offshore wind output is replaced with PV output but this is a relatively minor change within the total energy output of approximately 500 TWh. At the higher, 4-hour duration, the storage power and utilisation reduce which is reflected in lower roundtrip losses. The displacement of some of the power capacity of storage by OCGT sees some energy output from the zero-carbon fuel sources, albeit at very low load factor, but also a reduced ability to absorb wind generation at times of high output and low demand which results in “spilling” some wind output and a reduction of 2.6 GWh in wind energy output.

The assumed roundtrip efficiency of LDES of 60%, compared to the 85% for BESS, results in higher losses from storage when LDES displaces BESS. It can also be observed that the output of offshore wind increases in the LDES case despite almost no change in installed capacity. This is because curtailment of wind is reduced by the presence of LDES from 3.6% in the Central case to 1.7% in the LDES case.

3.2.3. Total system cost

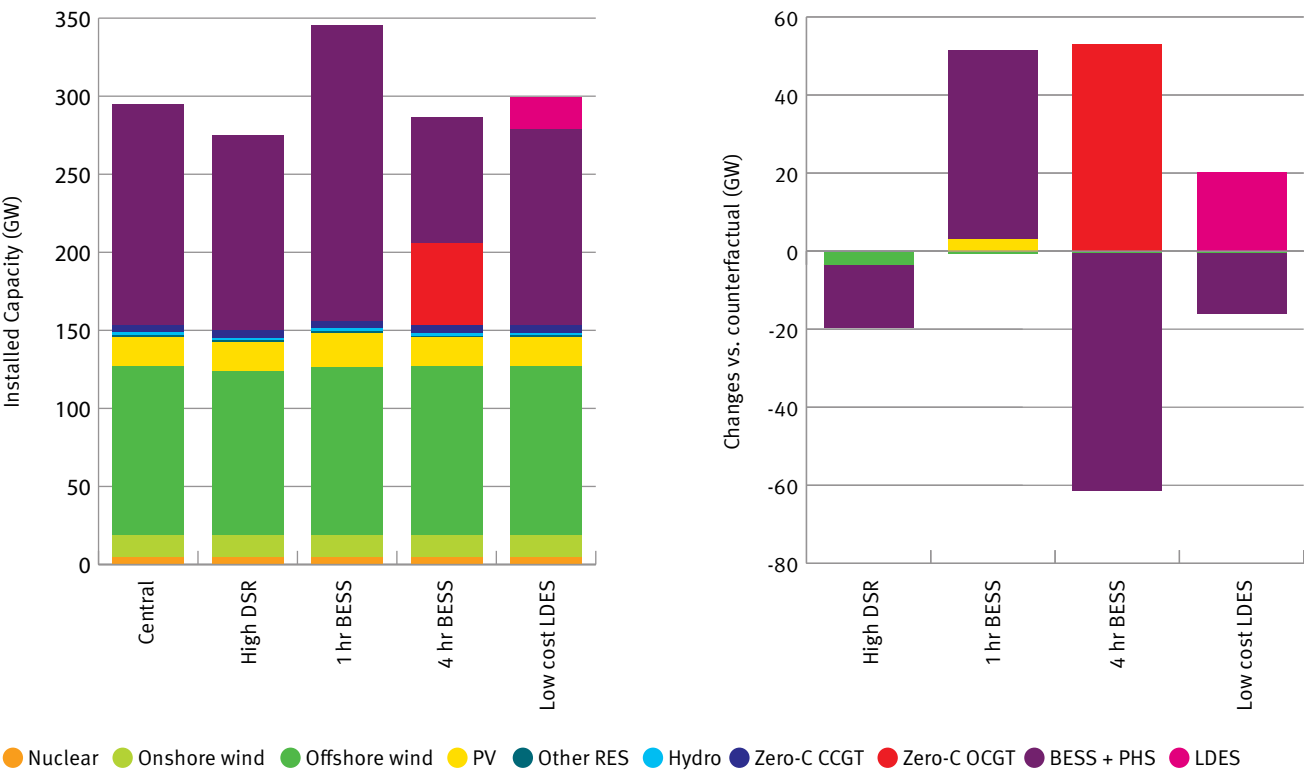
The impact of varying storage durations on the total system cost is presented in Figure 3.3(c). The cost reduction in the High DSR uptake case is £1.6bn/yr, which arises from CAPEX savings in battery storage, low-carbon generation, interconnection and distribution. However, as explained in Section 3.1.3, this cost saving does not take into account the additional cost of implementing the extra DSR uptake.

Reduction in battery storage duration to 1 hour reduces the total system cost by £0.8bn/yr, or 2.5%, compared to the Central case, while the 4-hour duration results in a £3.1bn/yr higher (9.7%) total system cost. In the short-duration case, the net cost saving is achieved through reduced storage investment cost, partially offset by costs of distribution network reinforcement and interconnector expansion. In the long-duration case, the system cost increases through higher investment in zero-carbon OCGT capacity that substitutes for firm capacity provided by BESS in the Central case. The cost of interconnection also reduces in the long-duration case, as the installed capacity drops by 12 GW compared to the Central case.

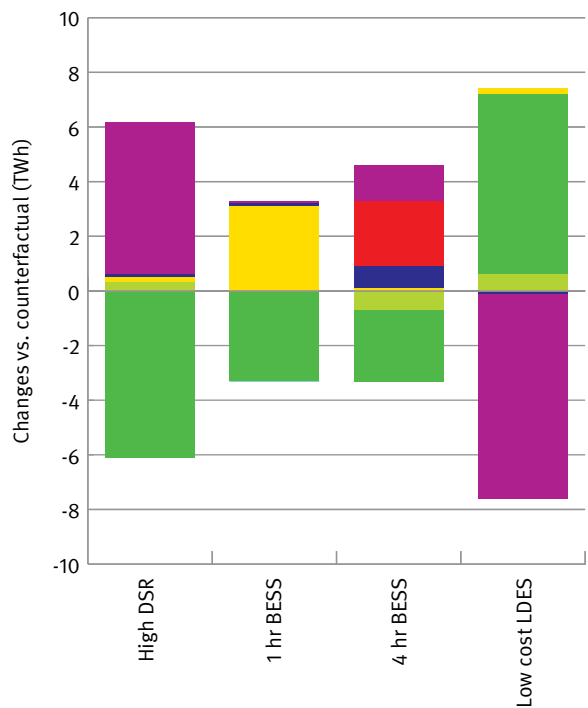
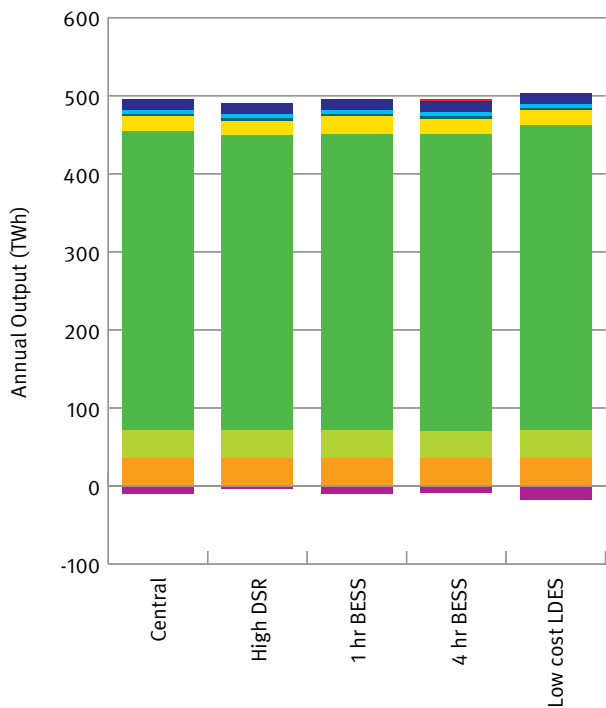
Availability of low-cost LDES reduces the overall system cost (note that in Figure 3.3(c) the storage CAPEX is separated into LDES and the sum of BESS and PHS). Net savings over the Central case are £0.6bn per year (1.9%), which is delivered mostly through avoided BESS investment cost, but also through reduced requirement for interconnection capacity. This suggests that LDES and interconnectors compete in providing multi-day flexibility to the system. Interconnector capacity reduces from 43 GW in the Central case to only 29 GW in the Low-cost LDES case.

Figure 3.3. GB system for net-zero with varying assumptions on DSR and energy storage: (a) total capacities, (b) annual generation output, (c) system cost

A

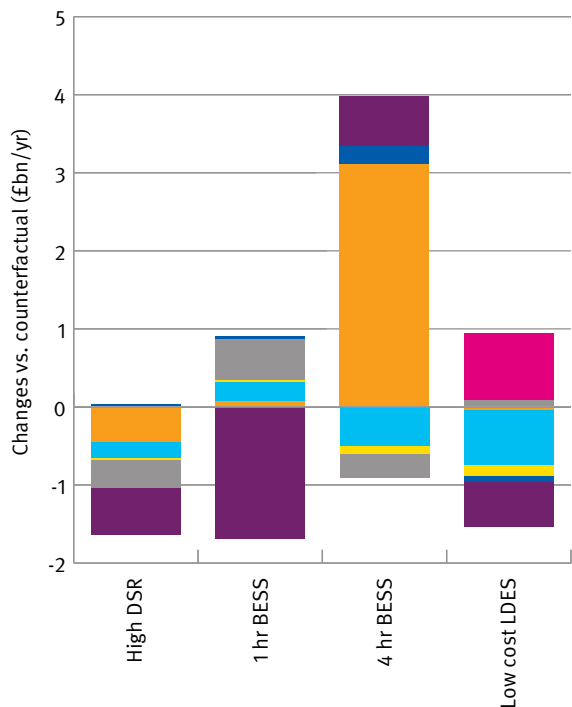
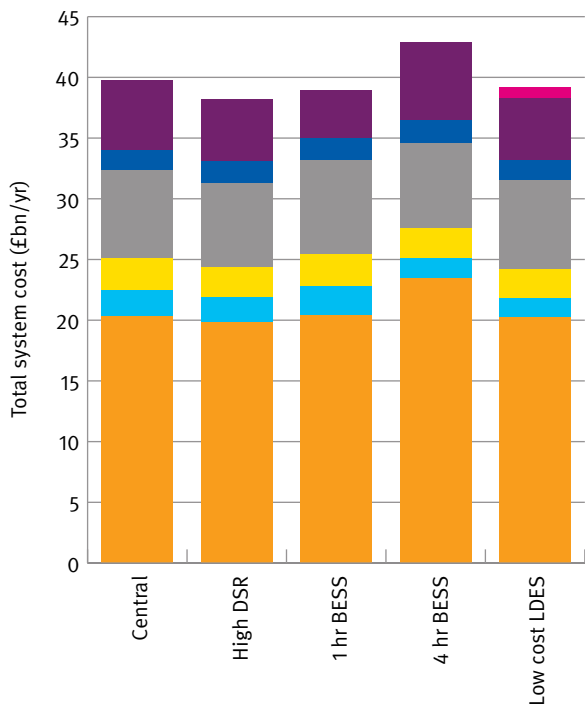


B



● Nuclear ● Onshore wind ● Offshore wind ● PV ● Other RES ● Hydro ● Zero-C CCGT ● Zero-C OCGT ● Storage

C

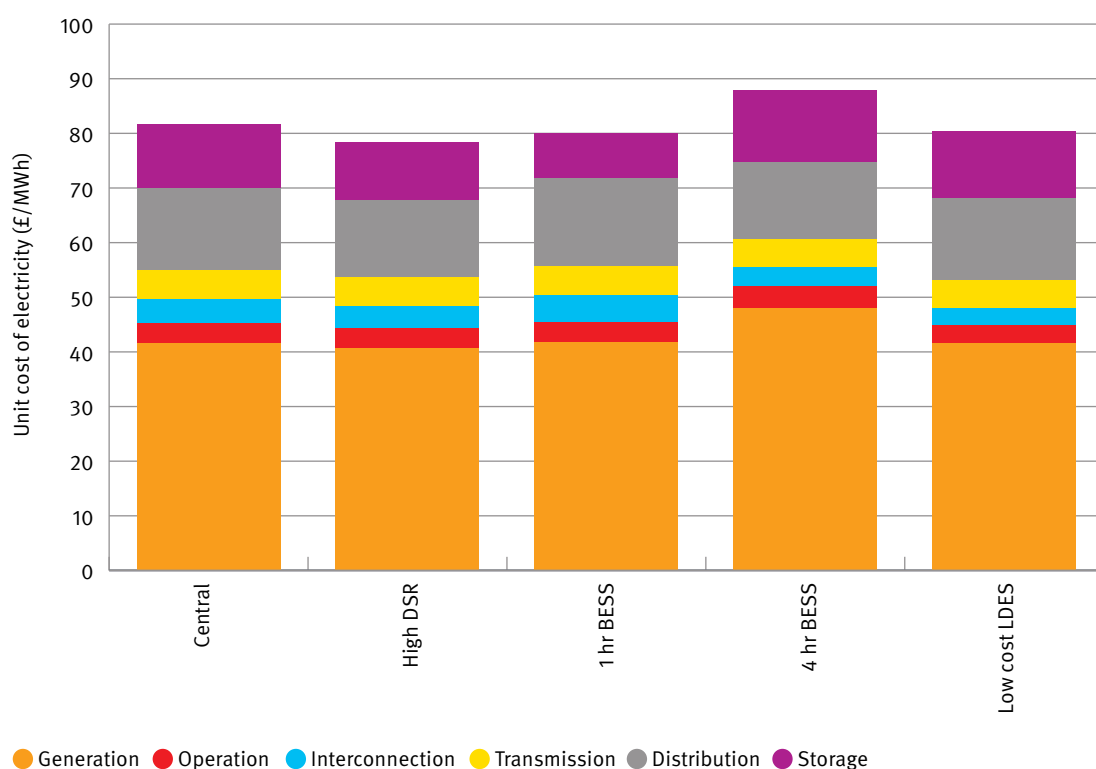


● Gen. CAPEX ● Interconn. CAPEX ● Transm. CAPEX ● Distr. CAPEX ● OPEX ● BESS + PHS ● LDES

Although the capacities of energy storage proposed by the optimiser appear very high when presented alongside generation capacity, when these are put into the context of their energy volume the capacity involved is actually rather modest. The energy that can be stored in batteries in the Central case represents only about 20% of the average daily electricity demand in the GB system. Note, however, that in the low-cost LDES case the volume of energy that can be stored increases significantly to about twice the level of daily average GB power demand.

Changes in unit cost of electricity across different DSR and energy storage cases are shown in Figure 3.4. Recall that these are system costs which include network costs (so encompass more than the wholesale price) but not taxes and supplier margin (so do not include all elements of a retail price). High DSR penetration brings about savings of about £3/MWh compared to the Central case. Shorter BESS duration and availability of low-cost LDES result in modest reductions in the unit cost of around £1/MWh, while longer BESS duration results in a unit cost increase to £88/MWh.

Figure 3.4. Unit cost of electricity in the GB system for net-zero with varying assumptions on DSR and energy storage



3.3. What role is there for other zero-carbon and negative-carbon technologies?

One of the recurring questions around cost-efficient decarbonisation of electricity systems is how much firm low-carbon generation should be added to the system to complement variable renewable energy. This firm capacity could include nuclear power or fuelled generation (also known as thermal generation) that uses biogas, green hydrogen or some other form of zero-carbon fuel. There are clear merits to using firm low-carbon generation, such as independence from weather conditions and better controllability including ability to provide technical services such as inertia and frequency response. The proportion of firm low-carbon generation in a net-zero system will to a large extent be driven by the cost of competing technologies, in the cost of wind and PV for the provision of energy and the cost of batteries for the provision of services. In all these cases, steep reductions in cost have occurred in recent years.

The first objective in this section is to explore how the variations in cost assumptions for firm low-carbon generation affect the composition of the cost-optimal generation mix. Two cases were examined:

- The cost of zero-carbon fuel for CCGT and OCGT is set 33% lower than the Central case cost of £38/MWh
- The LCOE of new nuclear is halved (approximately) to £45/MWh from the Central case³⁰

A second pair of cases were used to explore the potential of a carbon offsetting technology, Direct Air Capture (DAC), to assist in achieving, firstly, the net-zero carbon target and, secondly, a net-negative carbon target of up to -50 gCO₂/kWh. Net-negative emissions from electricity would offset emissions elsewhere in the economy³¹. DAC is not a mature technology and so there are no firm estimates of its cost for deployment at scale. It is understood there is potential for significant cost reduction from the current state of the art. Using the available literature, high, medium and low assumptions have been identified for the investment cost and energy consumption of DAC plants as set out in Table 1. Full results from these cases are discussed in the Appendix but only the results for the Low-cost case are presented here. This case will help identify the likely upper bound on volumes of DAC that might be deployed for a net-zero or net-negative carbon electricity system.

The Low-cost DAC case has a cost of £44.4/tCO₂ which is exclusive of the electrical energy consumed but inclusive of the annualised investment cost (rather like an LCOE). The electricity consumption of 1.83 MWh/tCO₂ was added as a further component of the total demand on the system. More details on cost assumptions and additional sensitivity studies are provided in the Appendix.

³⁰ The “fixed” 4.5 GW of nuclear is costed at the central LCOE assumption for nuclear of £92.5/MWh. Note that this assumption does not affect the cost differential between the low nuclear cost case and Central case.

³¹ CCC’s Sixth Carbon Budget envisages the deployment of 58 MtCO₂/yr of engineered (i.e. non-nature based) GHG removals by 2050 in its Balanced Net Zero Pathway. Of this volume, 19 MtCO₂/yr is expected to come from Bioenergy with Carbon Capture Storage (BECCS) in the power sector and 5 MtCO₂/yr from DAC.

3.3.1. Capacity mix

The results for capacities of generation and storage are presented in Figure 3.5(a). With the low cost of zero-carbon fuel, the optimal solution sees 5 GW of offshore wind and 3 GW of BESS displaced from the Central case. This did not require additional CCGT or OCGT capacity. Instead, the lower fuel costs meant that the existing capacity was used more for energy provision, on top of its role in providing firm capacity. With the cost of nuclear halved to £45/MWh, the model adds 13 GW more nuclear power, displacing 26 GW of offshore wind, 4.5 GW of zero-carbon CCGT and 10 GW BESS. This volume of nuclear plant addition is more than the 10 GW called for by the Energy Systems Catapult (Energy Systems Catapult, 2020) but the reduction of 10 GW in offshore wind still leaves a need to double capacity beyond the UK government target of 40 GW for 2030.

In the two DAC cases of net-zero and -50 gCO₂/kWh, the cost-optimal solution includes building 340 and 3,800 tCO₂/hr of DAC capacity respectively. The principal impact of DAC, perhaps not easily foreseen, is a very significant reduction of 44 GW, or 31%, in the BESS capacity deployed compared to the Central case. The only other change in capacity is an increase in offshore wind generation of 15 GW that supplies the additional electrical energy for running the DAC facilities in the net-negative case. In contrast, a very small increase in offshore wind of 0.3 GW was needed in the net-zero case.

The explanation for installation of DAC allowing for a reduction in the requirement for BESS is found in the operation of hybrid heat pumps (HHPs). The Central case is net-zero carbon without DAC and so the heat pumps used to decarbonise building heating cannot use gas in a hybrid mode and instead must be all-electric. Meeting heat demand during cold spells in winter adds significantly to the existing peak demand for electricity which is accommodated by adding BESS to ensure sufficient capacity. It is also necessary to reinforce the distribution grids to carry additional power at peak times. With DAC available, the model can use gas in HHPs during the coldest days of the year and offset the carbon with the DAC. This obviates some of the BESS and distribution grid reinforcement.

3.3.2. Electricity output

The annual electricity output, shown in Figure 3.5(b), shows that in the case of lower cost zero-carbon fuel, the output of zero-carbon CCGT generators increases from 14 to 19 TWh and some savings are made in roundtrip losses in BESS which together displaces 9 TWh of offshore wind output. With low-cost nuclear power available, the share of nuclear power in total electricity supply quadruples from around 7% in the Central case to 28% in the low-cost nuclear case, displacing the entire output of zero-carbon CCGT and 91 TWh of offshore wind generation.

The main effect of DAC on the annual electricity output is the higher output of offshore wind generation which is needed to supply the additional energy required to drive the DAC processes. In the net-zero case, the DAC energy requirement is around 5 TWh, while in the net-negative case, the extra demand is 55 TWh.

3.3.3. Total system cost

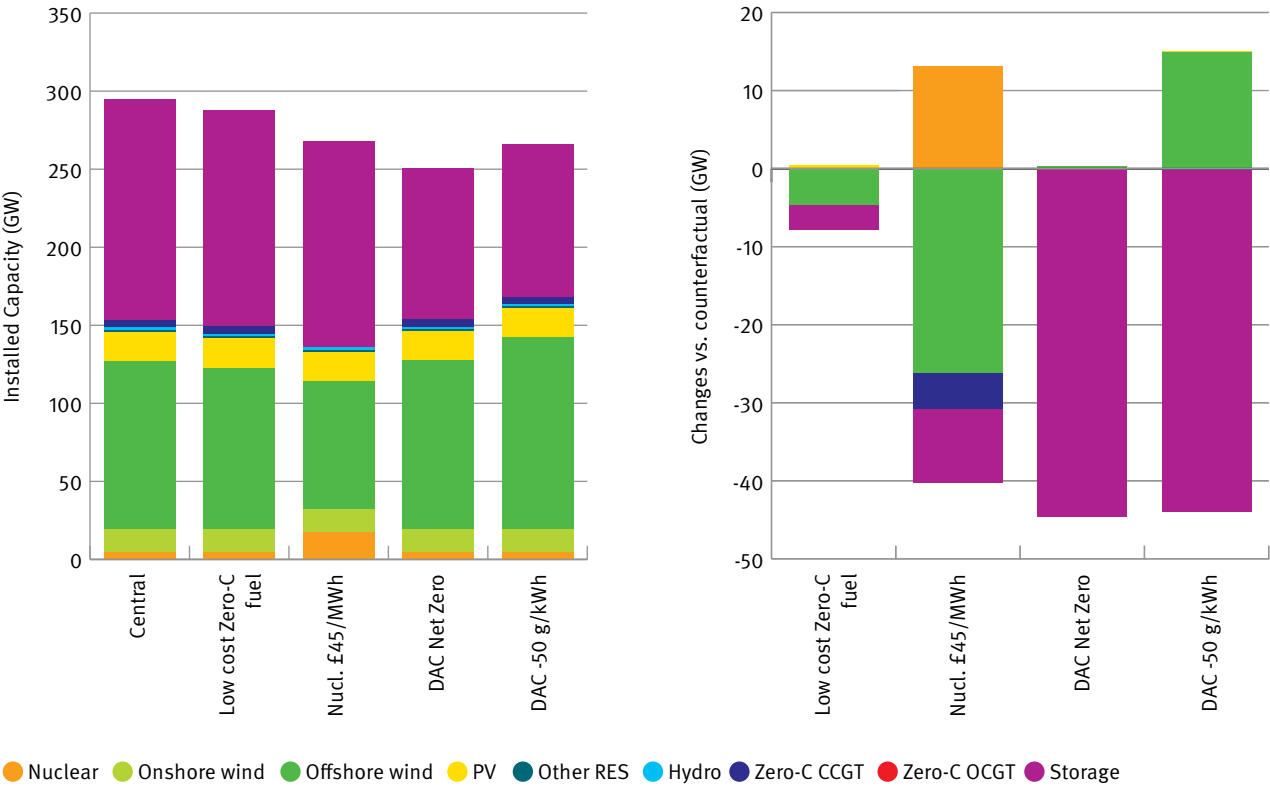
The implications for the total system cost are illustrated in Figure 3.5(c). With lower zero-carbon fuel cost, the system cost reduces by £1.1bn/yr, mostly through reduced CAPEX of offshore wind generation. A cost-optimal system configuration with an LCOE of nuclear of £45/MWh would deliver a total system cost saving of £1.3bn/yr, arising from reduced cost of investing into low-carbon generation, as well as noticeable savings in operating cost, storage investment cost and interconnection investment cost (required interconnection capacity in the £45/MWh case is 36 GW, which is lower than the 42 GW of interconnection in the Central case).

The DAC net-zero case delivers significant net cost savings of £3.2bn/yr, with only a moderate investment in DAC capacity of £120m/yr. The bulk of the cost savings arises from avoided distribution network reinforcement cost and reduced need to invest in battery storage capacity. Both of these sources of cost savings are still present in the net-negative DAC case, however given the additional investment in DAC facilities (about £1.3bn/yr for -50 gCO₂/kWh) and additional offshore wind capacity required to support DAC operation, the system cost increases by £0.4bn/yr.

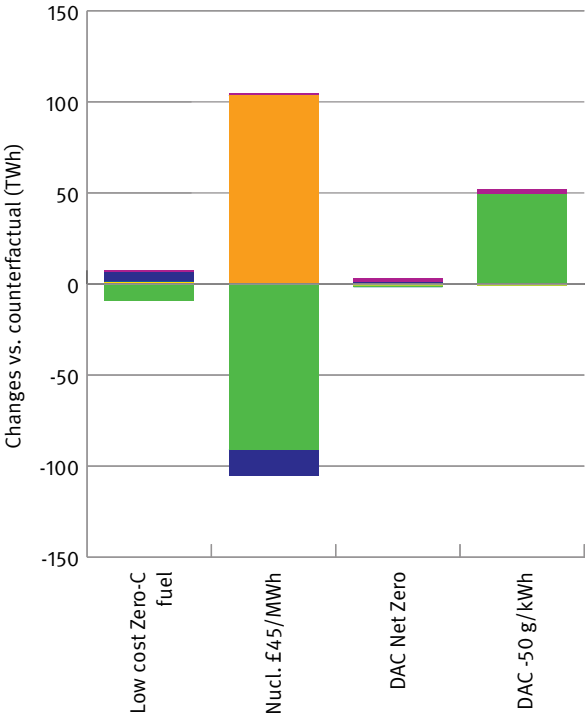
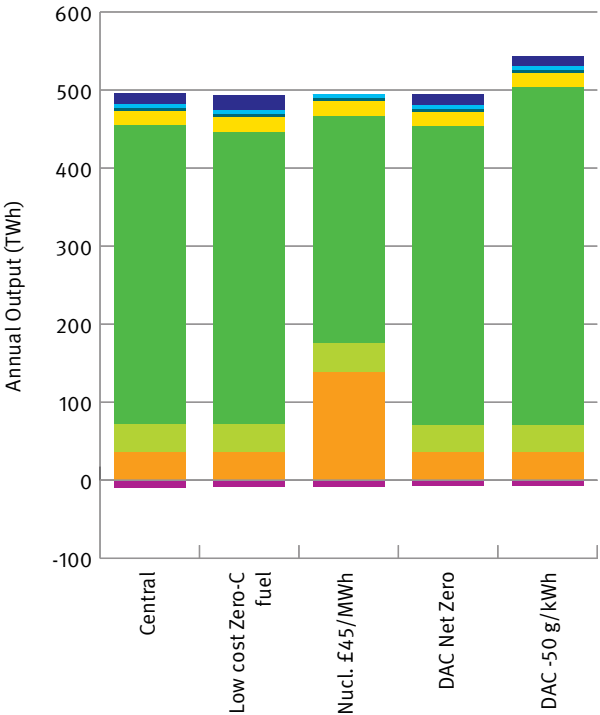
Finally, Figure 3.6 quantifies the variations in the unit cost of electricity for variations in the cost of nuclear and zero-carbon fuel and availability of DAC. A decrease of the cost of zero-carbon fuel for thermal generation reduces system unit cost by about £2/MWh, *i.e.*, to £79/MWh. Availability of nuclear power at an LCOE of £45/MWh reduces unit system cost to £79/MWh, while the availability of low-cost DAC technology with a net-zero target reduces the cost to around £76/MWh. With the net-negative system emissions target the additional cost of DAC capacity required to deliver negative emissions increases the unit cost to £83/MWh.

Figure 3.5. GB system for net-zero and net-negative carbon with variations in cost of nuclear and zero-carbon generation and availability of DAC: (a) total capacities, (b) annual generation output, (c) system cost

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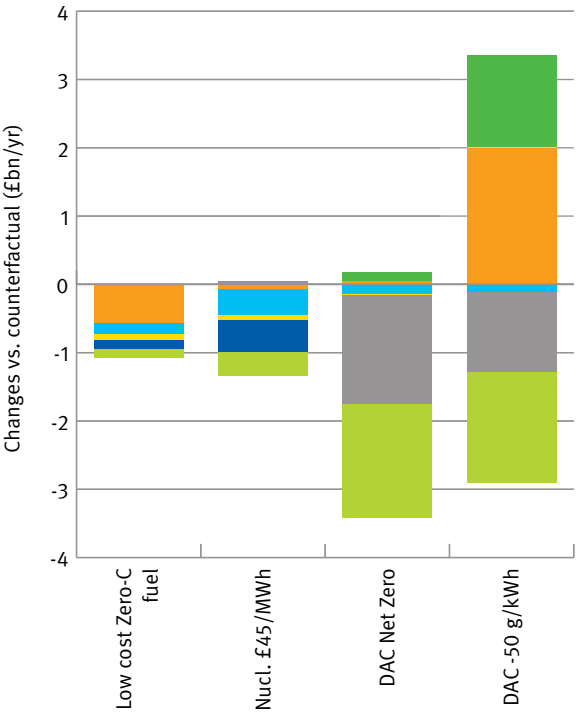
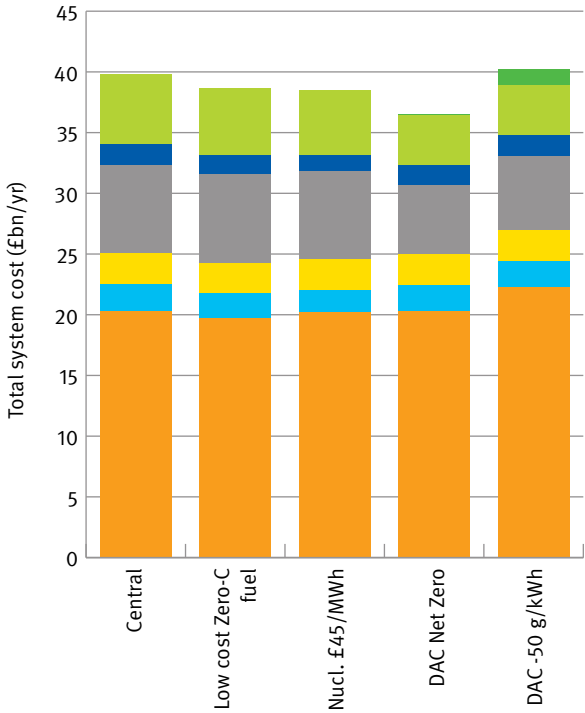


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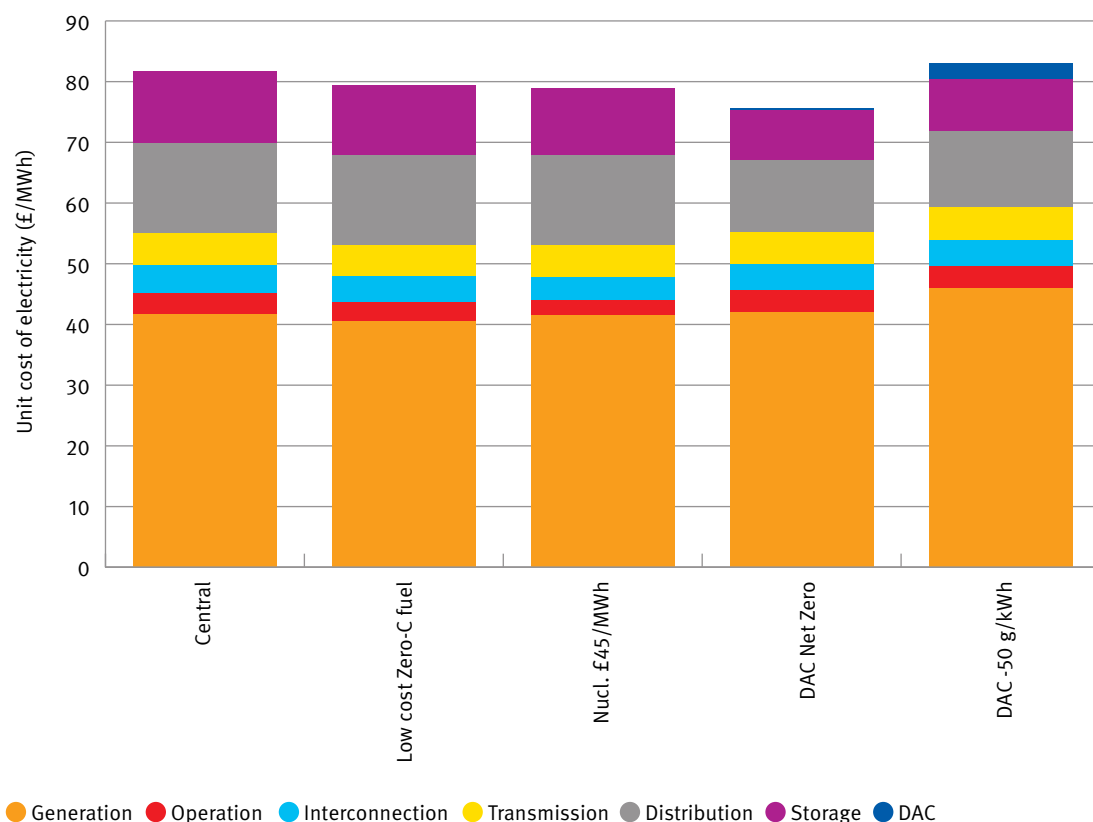
● Nuclear ● Onshore wind ● Offshore wind ● PV ● Other RES ● Hydro ● Zero-C CCGT ● Zero-C OCGT ● Storage

C



● Gen. CAPEX ● Interconn. CAPEX ● Transm. CAPEX ● Distr. CAPEX ● OPEX ● Storage CAPEX ● DAC CAPEX

Figure 3.6. Unit cost of electricity in the GB system for net-zero and net-negative carbon with variations in cost of nuclear and zero-carbon generation and availability of DAC



4. Conclusions

In exploring the composition of a net-zero carbon electricity system for Great Britain for 2035, four questions were set out on the volume of offshore wind capacity, the volume of energy storage, the role of other zero-carbon generation beyond offshore wind and the changes in system cost driven by variations in technology costs. In exploring these questions, and in particular exploring how sensitive the cost-optimal generation mix is to variations in cost and technical characteristics of each technology, the following conclusions have been reached.

1. The capacity of offshore wind needed to achieve net-zero electricity for GB in 2035 is at least twice the existing 2030 target.

108 GW of offshore wind is required in the Central case of this study of net-zero, which is not only a tenfold increase on the installed capacity of 10.4 GW in 2020 but is also two and a half times the UK government's target for 2030. The finding is consistent with the 95 GW of offshore wind suggested in the Balanced Net Zero Pathway of the Sixth Carbon Budget to 2050 (which also includes 30 GW of onshore wind and 85 GW of solar), and is robust to changes in the Levelised Cost of Electricity (LCOE) of offshore wind by $\pm£5/\text{MWh}$ on the Central case of $£35/\text{MWh}$. On this view, achieving net-zero carbon for the electricity sector by 2035 would require a significant increase in what is already a very ambitious target for offshore wind build out, implying both a higher build-rate prior to 2030 and a continuation through to 2035. Considering the barriers to this high build out rate, a case study that installed more nuclear and solar generation was also run.

2. Opting to build more nuclear power and more solar generation than is optimal in the Central case would reduce the required build-rate of offshore wind for 2035 and increases system cost by about 3.3%.

A rapid expansion of offshore wind over the next 15 years as set out in Conclusion 1 raises challenges in seabed leasing, project development, turbine supply chain and construction. With the imperative of achieving net-zero by 2035, a system that uses less offshore wind, and is therefore sub-optimal on cost according to the results in the Central case, may be necessary. Where higher than cost-optimal volumes of nuclear power (14.5 GW rather than 4.5 GW) and PV (37 GW rather than 18.5 GW) are imposed and the remaining system cost-optimised, 24 GW of offshore wind and 7 GW of battery storage is displaced but the system cost increases by £1.3bn/yr on top of the £39.8bn/year (3.3%) of the Central case. Unit electricity cost increases by £2.7/MWh on top of the £81.6/MWh for the Central case.

This new capacity of offshore wind at 84 GW is still double the present 2030 target. Further steps to diversify the portfolio of zero-carbon generation may yet be needed to achieve net-zero by 2035 within the build-rate constraints, at the penalty of increased system and unit electricity costs.

3. A substantial increase in the volume of energy storage is needed to support a system dominated by wind and solar energy.

The cost of energy storage to help balance supply and demand was factored into the conclusion that GB can achieve net-zero carbon electricity largely from expanding offshore wind capacity. Nonetheless, the volume of battery storage that would need to be built is over 100 GW and with a 2-hour duration able to supply 200 GWh of energy. Not only do the batteries help demand-supply balance when wind (and solar) output varies but they also assist with security of supply, obviating some expansion of electricity grids and meeting the needs of heat pumps during spells of especially cold weather. But 200 GWh (100 GW) of battery storage would be more than one hundredfold increase in the grid-connected batteries of today. A high uptake of Vehicle-to-Grid (V2G) technology provided by Electric Vehicle (EV) batteries in the future system could reduce the requirement for battery storage capacity by several tens of gigawatts; however, the majority of the requirement for new battery capacity will remain.

4. Direct Air Capture of CO₂ could have a large impact on how electric heating is supported.

Heat pumps are an important way to heat buildings using zero-carbon electricity but on the very coldest days of the year impose a large burden on the electricity system which, in the Central case, was met by a combination of grid reinforcement and battery energy storage. Adding Direct Air Capture (DAC) as a negative-emissions technology allowed hybrid heat pumps which could supplement heat output with some unabated natural gas on very cold days. This saved the need to build 45 GW of battery energy storage but, overall, the cost of running the whole system decreased very little.

A key feature of DAC as part of an energy system is to achieve negative emissions. With a target for electricity of -50 gCO₂/kWh, DAC of around 3,800 tCO₂/hr was needed with an additional electricity consumption of 55 TWh serviced by an extra 15 GW of offshore wind.

5. Great Britain could export 60 TWh of zero-carbon electrical energy.

Great Britain has large and very good potential sites for offshore wind and could build additional capacity of offshore wind farms of around 20 GW to sell energy to neighbouring countries. This would be expected to increase production by 60 TWh (or 12%) above national demand. The exports would need to realise a price of around £33–36/MWh to recover the cost of the extra wind farms plus some additional battery energy storage and a small increase in capacity of international interconnector cables

6. Nuclear energy would need to halve in cost to warrant major new build.

Taking the strike price of the Contract for Difference (CfD) for Hinkley Point C, £92.5/MWh (in 2012 prices), as a starting point, there is no case for building new nuclear plants. A cost reduction of approximately 50% to £45/MWh, causes 13 GW of additional nuclear capacity to be included. This is a little more than the 10 GW called for by the Energy Systems Catapult. However, that 13 GW of nuclear plant would need to be on-line in 15 years from now to contribute to meeting the Sixth Carbon Budget.

7. Solar PV would need further very significant decrease in cost to play a major role in the net-zero GB system.

Solar PV is a cost-competitive technology in many parts of the world but the latitude and weather conditions in GB count against it, and with a load factor of around 11%, even large capacities of solar PV produce relatively small energy contributions. For this reason, solar PV costs needed to fall 60% from the central estimate, £50/MWh down to £20/MWh, before a major expansion of its use is justified on cost grounds. With this in place, around 150 GW of additional solar farms could be built but this only removes 25 GW of offshore wind from the optimal generation mix because of the relatively poor load factor. Nevertheless, Conclusion 2 – that solar might be expanded to ease the build rate of offshore wind – still stands.

5. Appendix: Additional case studies

This Appendix presents a further set of sensitivity studies beyond those presented in the main report and covering:

- Higher and lower cost of offshore wind combined with High DSR uptake
- Lower PV cost with High DSR uptake and higher minimum PV capacity
- Variations in storage duration with High DSR uptake
- Large energy storage capacity on hourly operation of the power system
- Variations in characteristics of long-duration storage
- Alternative cost assumptions on battery storage and peaking generation capacity
- Possibility for net exports with High DSR uptake
- Variations in the cost and availability of firm low-carbon generation
- Cost variations for Direct Air Capture of CO₂

In this Appendix the term main case(s) is used to refer to the Central case, as featured in the studies throughout the report so far, and its High DSR variation. As in the main body of the report, the results are presented with charts consisting of three components: (a) generation capacity mix, (b) annual generation output and (c) annualised system cost for GB. In each of the three component charts, the left-hand part shows the total results for a given set of cases, while the right-hand part shows the differences in capacities, outputs and costs against the relevant counterfactual case.

At the end of this Appendix, a summary is provided of total system cost variations across all of the sensitivity studies presented in the report, shown as cost differentials from the main Central and High DSR cases.

5.1. Impact of higher and lower offshore wind cost combined with High DSR uptake

The cost-optimal generation portfolios, annual outputs and total system costs for the Central and High DSR net-zero cases with central, high and low cost assumptions for offshore wind are shown in Figure 5.1. Additional battery storage requirements reduce only a little to 125 GW in the High DSR case.

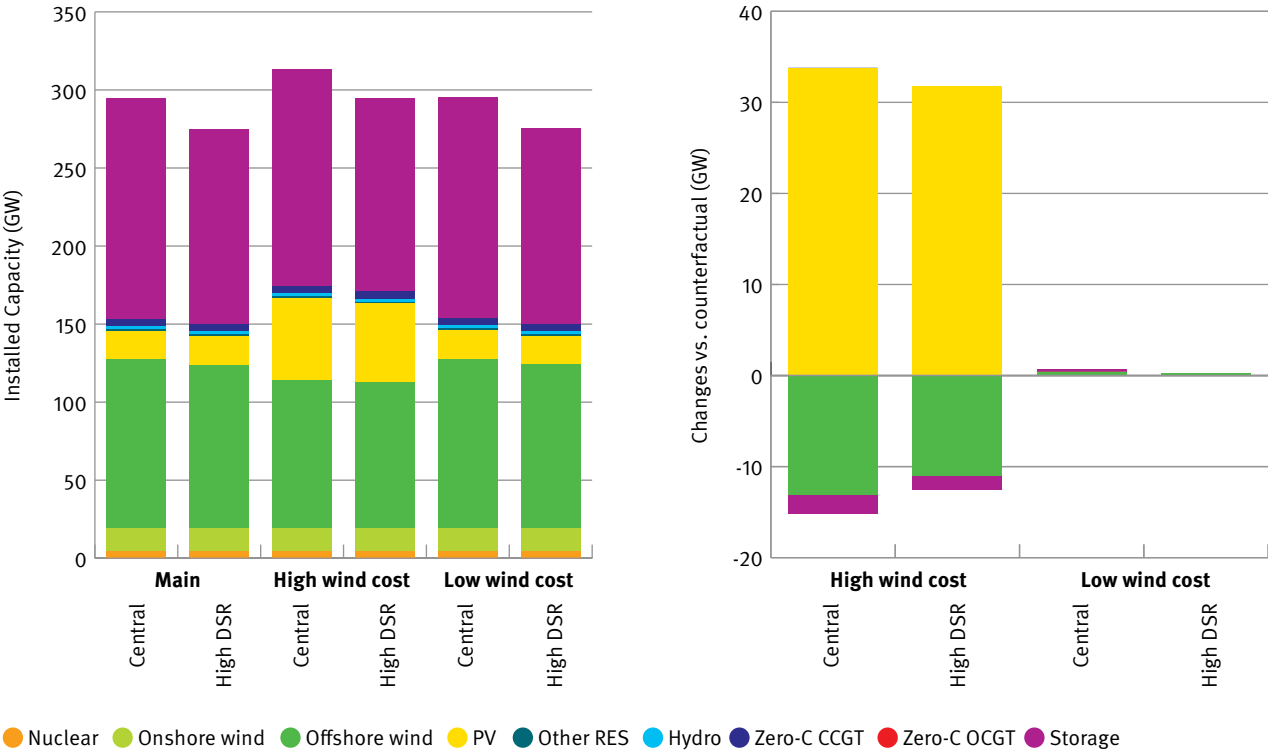
Curtailment of annually available wind output is relatively low, at 2.0–3.6% in the main and Low Wind cost cases, with lower curtailment levels expectedly observed in High DSR than in Central cases. With High Wind cost the curtailment levels drop to 0.8–1.5%.

The assumed annual utilisation factor (or load factor) of offshore wind generation in the majority of the studies presented in the White Paper was 42%. Recent developments in the offshore wind sector however suggest that much higher load factors can be expected for future offshore wind generators (for instance, BEIS quoted a load factor of 58.4% in its May 2019 CfD Allocation Round 3 document³²). To establish how material the load factor assumptions are to general findings on the 2035 net-zero carbon electricity system in GB, sensitivity studies were run that assumed a higher load factor for offshore wind of 58.4%, while maintaining the same level of LCOE. As expected, the main difference from the case based on default load factor assumptions is that a lower capacity of offshore wind is required to deliver broadly the same volume of annual output. Capacities of other technologies (nuclear, solar PV, zero-carbon CCGT and battery storage) change only marginally.

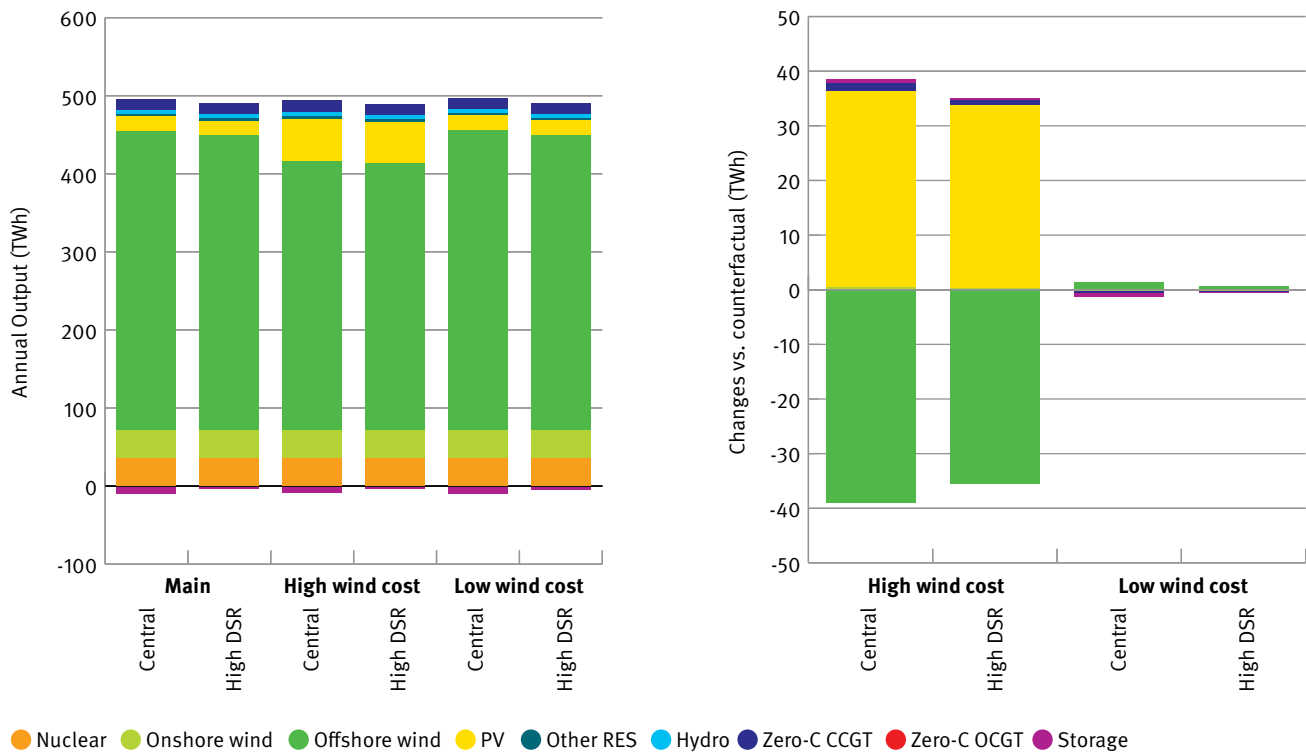
32 See Appendix 3 of BEIS' CfD Allocation Round 3 document (BEIS, 2019a).

Figure 5.1. GB system for net-zero with variations in cost of offshore wind (a) total capacities (left) and capacity difference vs. counterfactual (right) (b) annual generation output, total and difference (c) system cost, total and difference

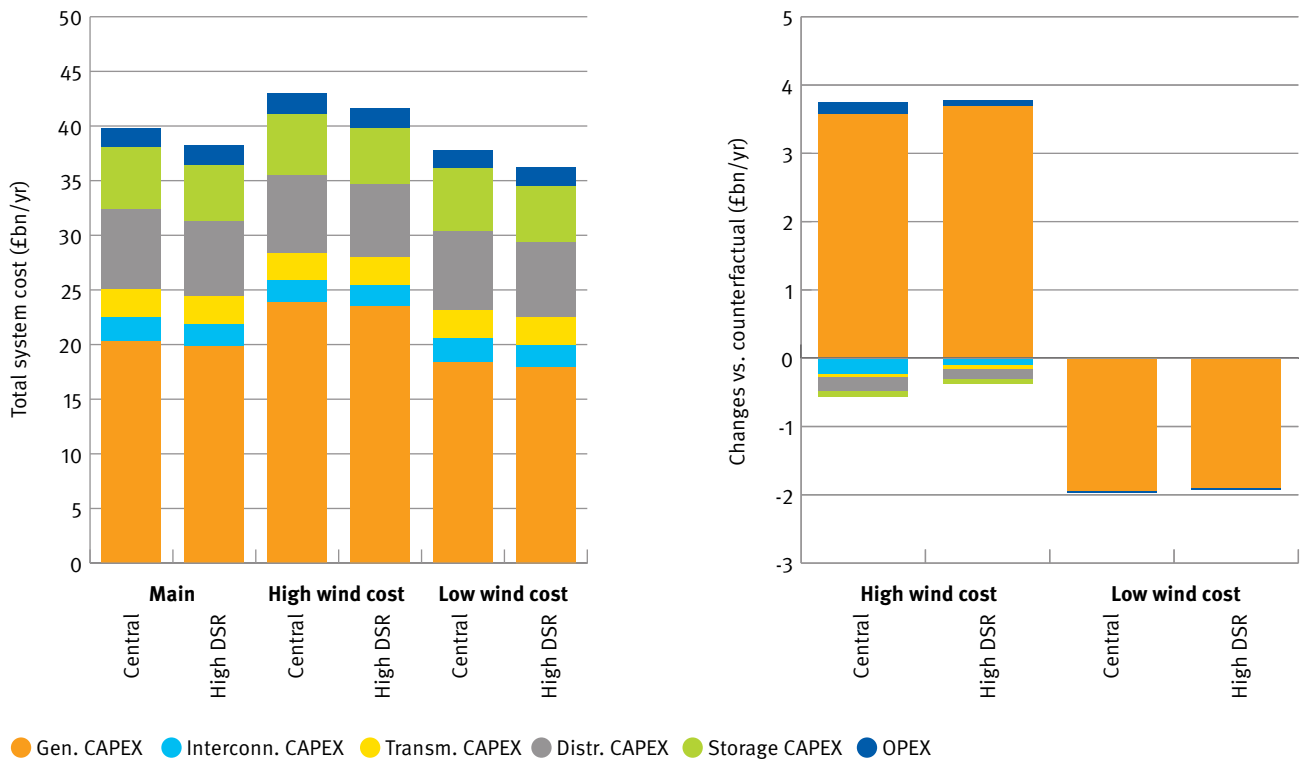
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The cost-optimal offshore wind capacity with higher load factor suggested by the model is 74–77 GW, which is about 30 GW lower than with default load factor assumptions. Nevertheless, the annual output of offshore wind, as well as the output of all other technologies, remains very similar to the default case, with any changes in output well below 1 TWh annually.

The other differences observed as the result of higher load factor assumption for offshore wind are the reduced level of wind output curtailment (from 2.0–3.6% in the main cases to 0.9–2.4% in high load factor cases) and reduced investment in interconnection capacity by about 9 GW. As a result, the total system cost with a higher load factor is £0.7bn/yr lower than in the main cases, mostly because of lower interconnection capacity cost. Other cost components change very little with variations in offshore wind load factor. Given that our main concern is how the variations in input assumptions change the total system cost in a net-zero carbon power system, it is concluded that any such differences from the Central case will be only marginally affected by potential variations in wind load factor.

5.2. Impact of lower PV cost with High DSR uptake and higher minimum PV capacity

This set of sensitivity studies explores the impact of two variations in input assumptions on the cost-efficient technology mix, while also combining them with High DSR uptake:

1. Solar PV becomes available at a substantially lower cost than in the main set of assumptions, i.e., at £20/MWh rather than at £50/MWh.
2. PV capacity in the mid-term (2025–2030) increases above the 2035 cost-optimal level. It was assumed that the minimum PV capacity on the system doubles from 18.5 to 37 GW.

The cost-optimal portfolios for these two PV case studies are shown in Figure 5.2(a) alongside the main Central and High DSR cases. If the LCOE of solar PV reduces to just £20/MWh, it becomes the most cost-efficient low-carbon generation technology in the GB system, with its capacity increasing to 176 GW in the Central and 198 GW in the High DSR case. As a consequence, the cost-optimal volume of offshore wind reduces by 26–34 GW compared to main cases, to the level of 70–82 GW (still many times higher than today's offshore wind capacity). The volume of battery storage in both Central and High DSR cases increases by 5–6 GW, while the peaking OCGT capacity reduces by a similar amount. In the higher PV minimum sensitivity (which assumed a higher starting PV capacity for optimisation but the same LCOE of £50/MWh as in the main cases), the model does not add any PV capacity above the minimum. Doubling the minimum PV capacity, however, results in 5 GW less of offshore wind generation.

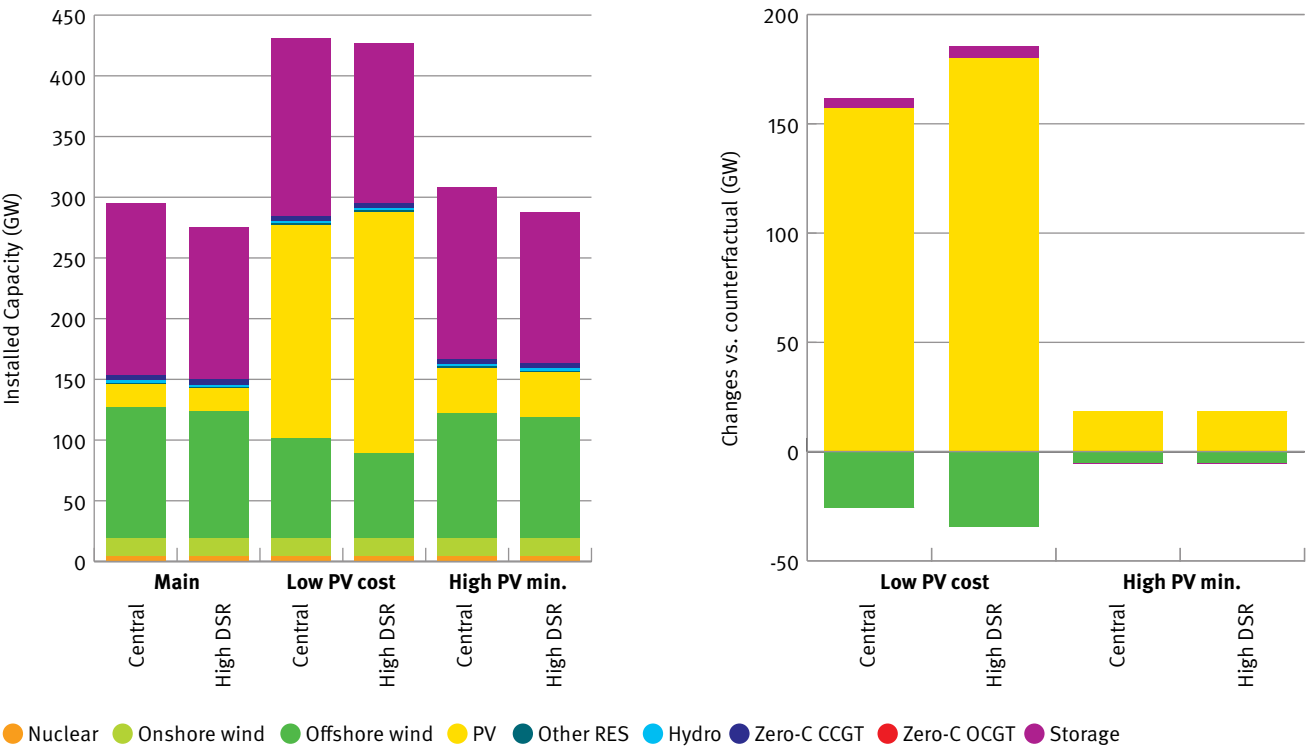
As for the impact of PV cost and capacity sensitivities on annual electricity output provided by various technologies, as presented in Figure 5.2(b), similar conclusions emerge as for generation capacity. PV capacity displaces offshore wind in the generation mix, although the total share of variable RES output remains very similar. Given the higher variability of solar PV output compared to wind generation, the utilisation of battery storage is higher with high PV capacity, which is reflected in a negative change in the net annual output of storage i.e., higher aggregate cycle losses.

It is also interesting to note that in the two case studies with radically higher PV capacities, the level of output curtailment increases substantially, from 1–2% in the main cases to 14–18% in Low PV cost cases. Such a high level of curtailment is acceptable from the economic point of view given the very low nominal LCOE of PV generation. Also, the opportunities to export excess PV generation are likely to be limited due to similar PV output profiles in continental Europe.

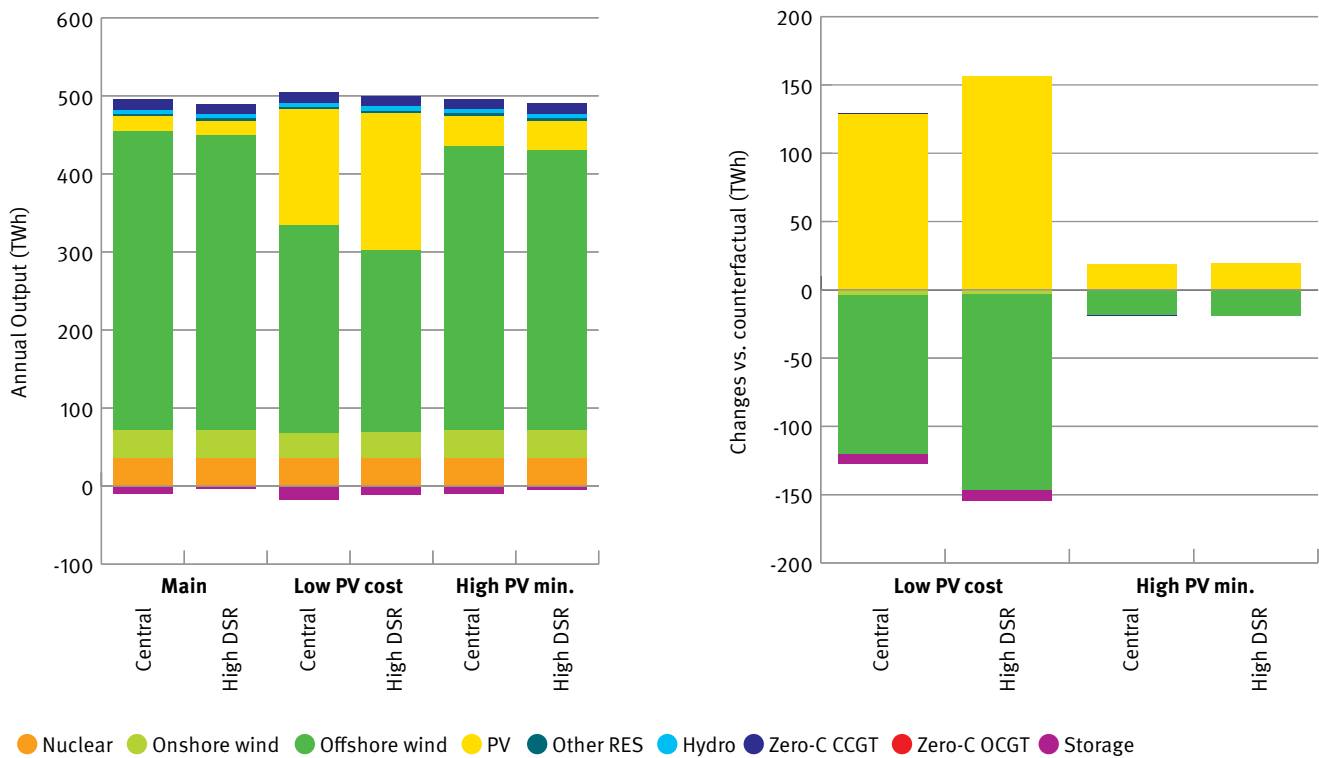
The implications of solar PV sensitivities for total system cost are quantified in Figure 5.2(c). Displacing offshore wind with cheaper solar PV generation reduces the generation investment cost component while also decreasing the distribution network investment cost, resulting in a total system cost that is £1.0bn/yr lower in the Central case, and £1.5bn/yr lower in the High DSR case. On the other hand, if solar PV is available at the originally assumed cost (£50/MWh) but is fixed at twice as high minimum capacity, the total system cost increases slightly, by £177–205m per year.

Figure 5.2. GB system for net-zero with lower cost of solar PV and higher minimum PV capacity: (a) total capacities, (b) annual generation output, (c) system cost

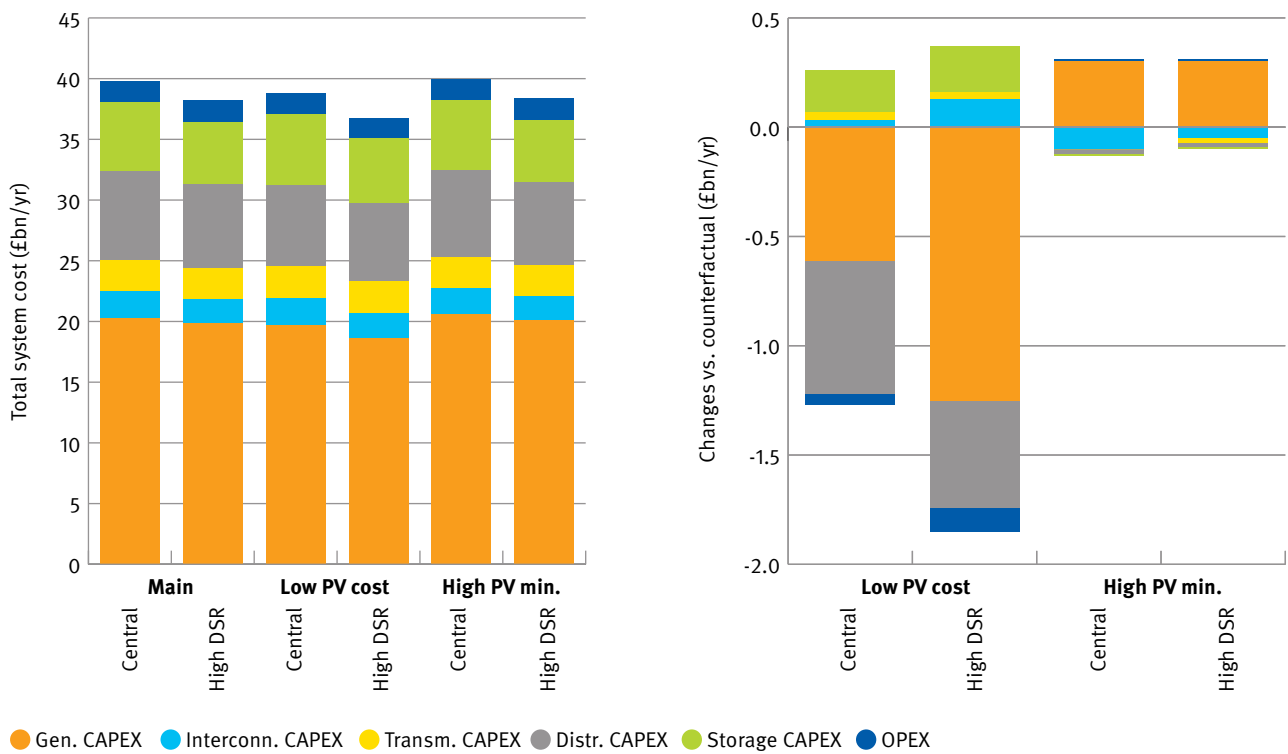
A



B



C



5.3. Sensitivity to storage duration with High DSR uptake

The baseline assumption on the duration of new battery energy storage was 2 hours, which represents a typical energy-to-power ratio for lithium-ion battery projects. A battery with an energy of 1 kWh would be able to deliver 0.5 kW for 2 hours and so the 2-hour duration maps to an energy-to-power ratio of 2. Although 2 hours is typical at present, various battery projects with lower and higher durations have been implemented. A series of sensitivity studies was therefore carried out where the BESS duration parameter (or energy-to-power ratio) took the following values: 0.5 h, 1 h, 4 h and 8 h. All four sensitivity studies were run for both Central and High DSR case.

It was decided to maintain the cost per kWh of BESS at the same value as in the main cases (£187.5/kWh, Section 2.2.1) on the assumption that the cost of batteries (energy-related) dominates over the cost of the interface (power-related). When looking at the energy storage alongside generation in terms of power capacity, the cost of a unit of power capacity (£/kW) of storage will be proportional to the duration given that the cost is determined by the energy.

Variations in the cost-optimal portfolio for the net-zero carbon system resulting from variations in storage duration are shown in Figure 5.3(a) alongside the results for main Central and High DSR cases that assumed 2-hour duration. The power capacity of BESS chosen by the optimiser varies significantly as the duration (energy-to-power) ratio is changed with longer duration batteries being included at lower power capacity. For the Central case, the power capacities of storage for 0.5, 1, 2, 4 and 8 h are 374, 187, 139, 78 and 39 GW (note that the capacity of storage reported in the chart also includes 2.7 GW of pumped hydro storage of 6-hour duration). It is evident that with lower durations of 0.5 and 1 hour, the model adds more BESS capacity in terms of power than in the main cases. For the short durations, the cost of batteries per unit power is lower under the assumption of fixed cost per unit energy. The result suggests that some of the storage requirements are driven by the energy capacity needed to store surplus RES output.

In contrast, when storage duration increases to 4 or 8 hours, the cost per unit power of battery power increases by a factor of 2 and 4 respectively, which gradually shifts the balance of firm capacity needed to meet the capacity adequacy margin in favour of zero-carbon OCGT generation. Also, considerably less battery storage capacity (broadly half) is added in High DSR than Central sensitivity studies. In all cases, there is very little change in the cost-optimal volume of offshore wind.

The impact of varying storage duration on annual generation output is shown in Figure 5.3(b). In Central low-duration cases, about 3 TWh annually of offshore wind output is replaced with PV output. At higher durations, the storage capacity reduces and so does its utilisation, which is reflected in lower cycle losses. At the same time, there is more output from zero-carbon OCGT generation (albeit at very low annual capacity factors), while the ability of the system to absorb wind generation reduces, which results in higher curtailment and lower wind output.

Implications of varying storage durations for the total system cost are presented in Figure 5.3(c). A common observation for all sensitivities is that the reduction in BESS duration reduces the total system cost by £0.8–0.9bn/yr, compared to the relevant counterfactual case, while increased duration results in a £2.9–3.1bn/yr higher total system cost for 4-hour storage, and £4.5–5.7bn/yr cost increase for 8-hour storage. In low-duration cases, the net cost saving is achieved through reduced storage investment cost, partially offset by increased cost of distribution network and interconnectors. In the high-duration cases, on the other hand, the system cost increases due to higher investment in zero-carbon OCGT capacity that is displacing firm capacity provided by BESS. The cost of interconnection capacity also reduces in the high-duration storage cases, given that the installed capacity drops by 10–12 GW in the Central case, and by 6–7 GW in the High DSR case.

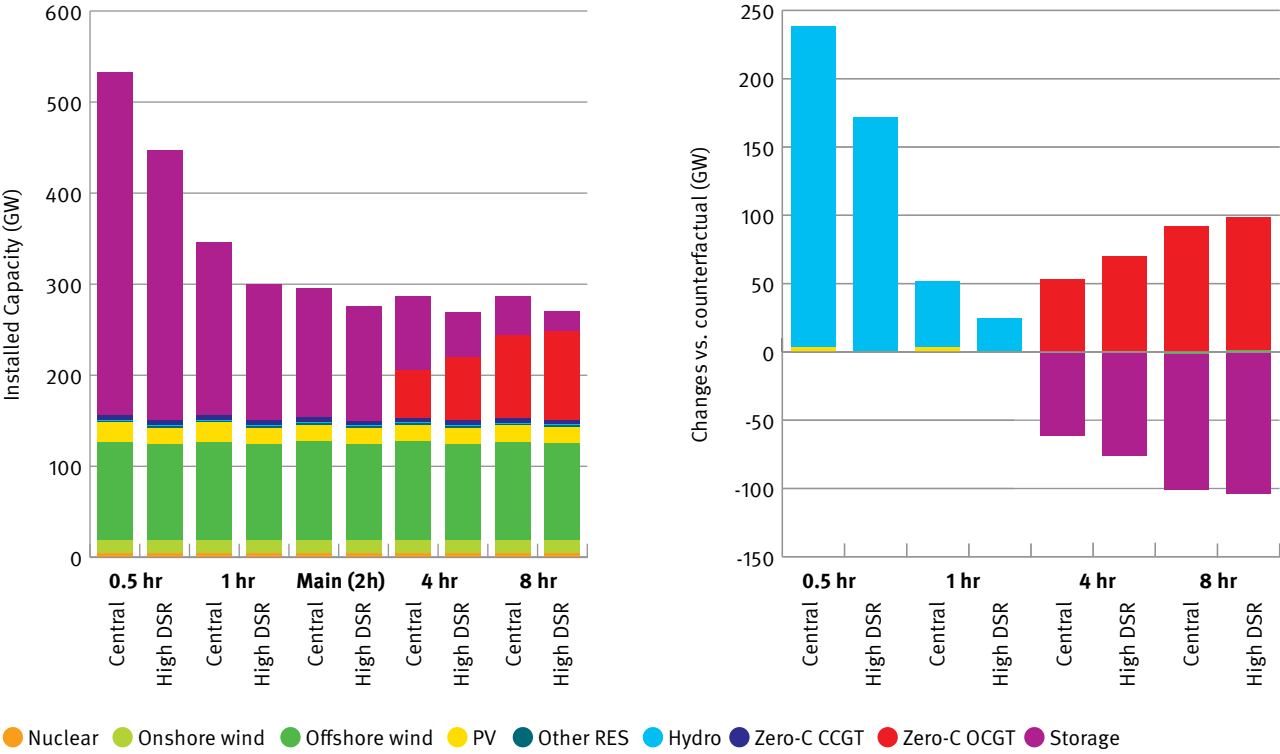
The installed energy capacities for various durations of BESS and pumped hydro storage (PHS) are shown alongside each other in Figure 5.4. For the Central case, the battery storage capacities are 187, 187, 278, 312 and 312 GWh. The variations in storage energy sizes are much lower than variations in power capacity, suggesting that the optimiser is finding value principally in the energy but the fact that more energy is selected at the longer durations (higher energy-to-power meaning lower power-to-energy) further suggests that enough power capacity must be available to deliver or absorb the energy at the required points in time. These conclusions are under the assumption that the cost of the battery storage is set by the energy alone and not the power.

For the High DSR case, the power capacity selected also decreases with increasing duration but more steeply, with the energy varying more. This suggests that there is less need for the power capacity of storage when partnered with DSR, but the energy is of more value. It appears that the 2-hour duration may represent a “sweet spot” for the High DSR case.

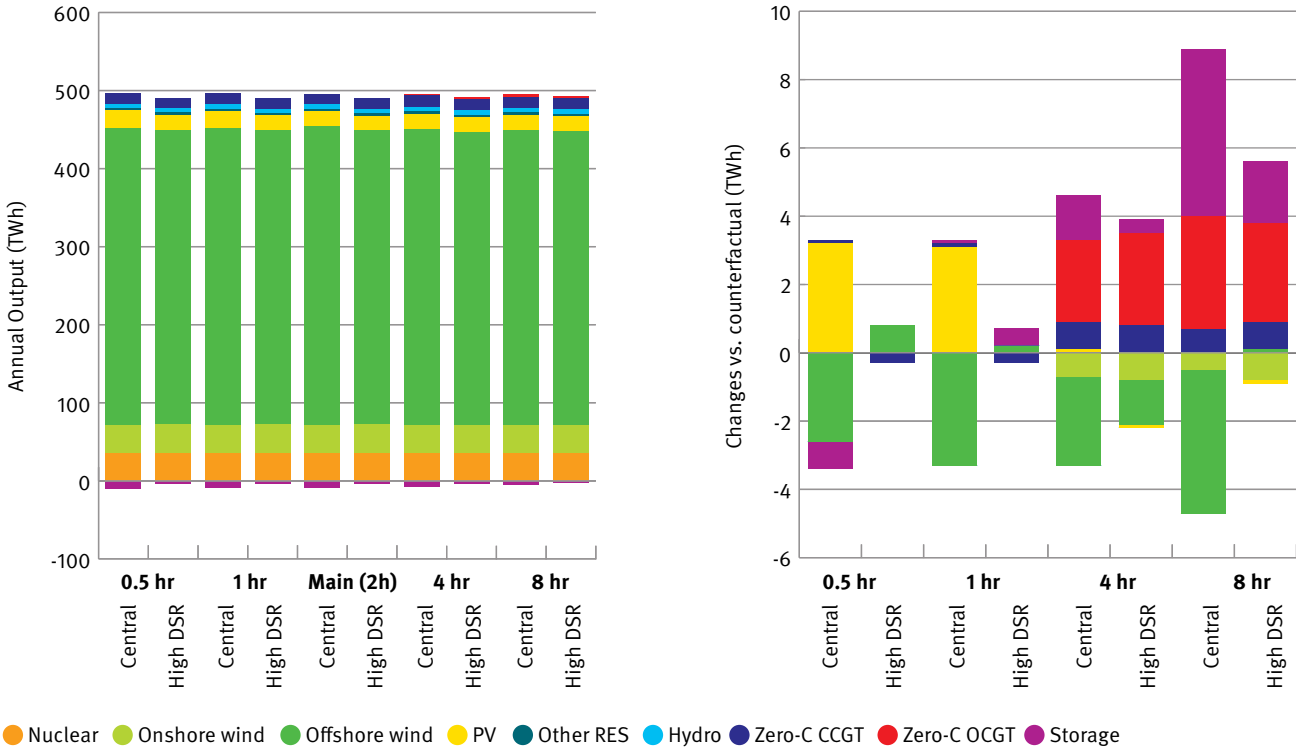
Finally, a major driver for the large capacity of storage was found to be the assumption that hybrid heat pumps (HHPs) can only use unabated natural gas as alternative to electricity. Therefore, in a net-zero system, heat pumps use only electricity, which results in high levels of peak demand during cold winter days. A further consequence of this situation is a high investment to reinforce local distribution networks. Some of the battery storage is installed to allow the system to cope with those increased peaks. On the other hand, it is possible that HHPs have access to zero-carbon gas so that they can switch from electricity to gas during the coldest days without violating the net-zero constraint. An additional set of sensitivity studies were run to establish the need for battery storage with this assumption, and the results suggest that in the Central Case, the cost-optimal volume of energy storage drops to 97 GW, and in the High DSR case to 84 GW, which represents a reduction of 45 GW and 41 GW compared to the main Central and High DSR cases, respectively.

Figure 5.3. GB system for net-zero with various durations of battery storage: (a) total capacities, (b) annual generation output, (c) system cost

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B



C

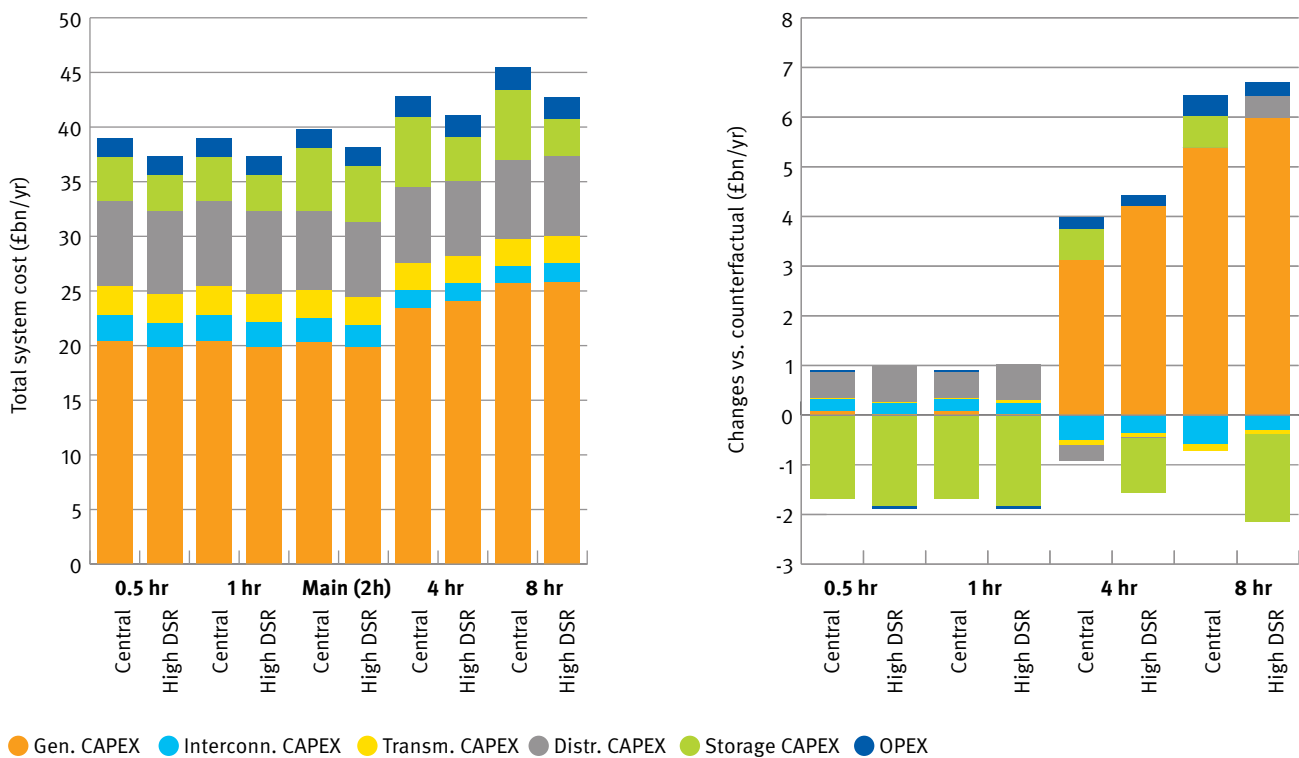
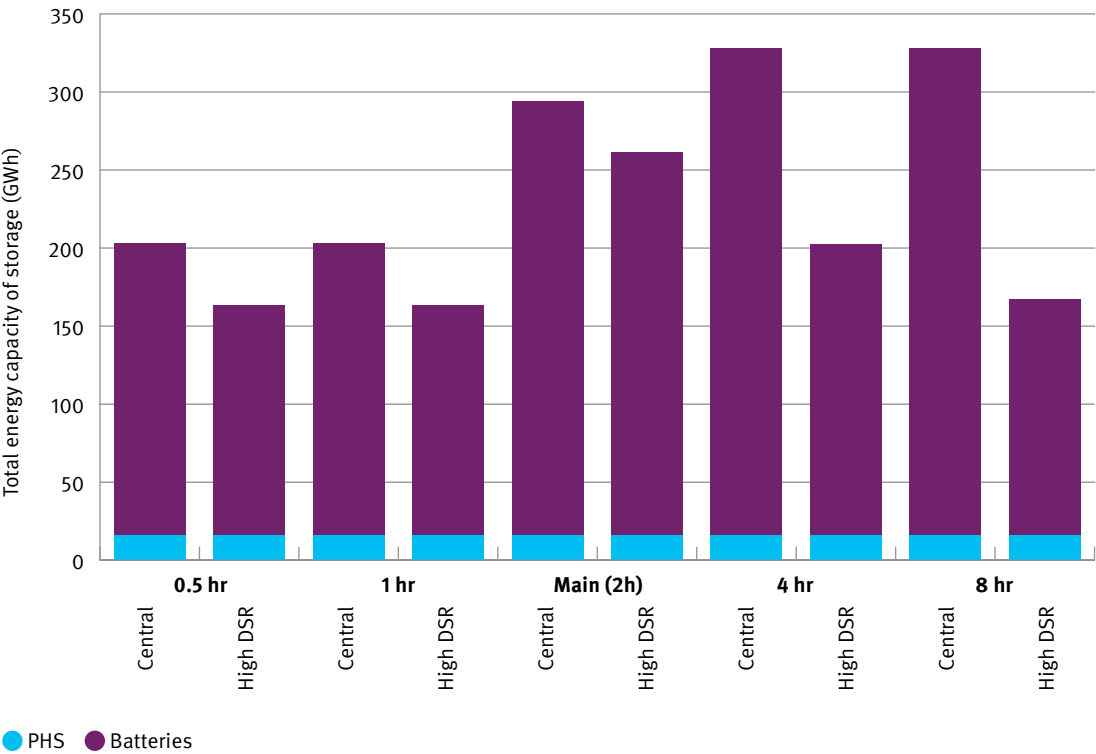


Figure 5.4. Optimal energy capacities for various durations of battery storage

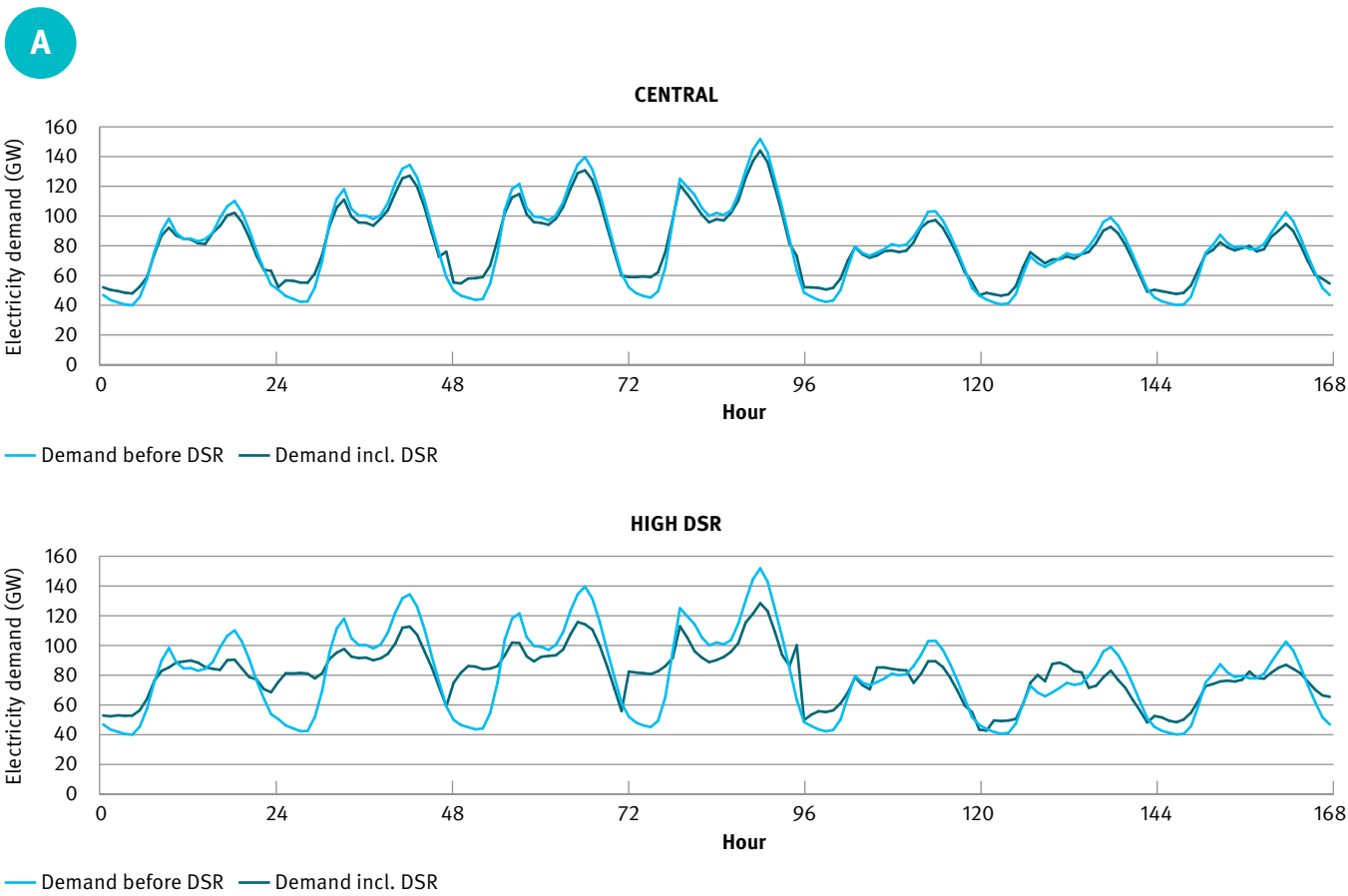


5.4. Hourly operation of power system with large energy storage capacity

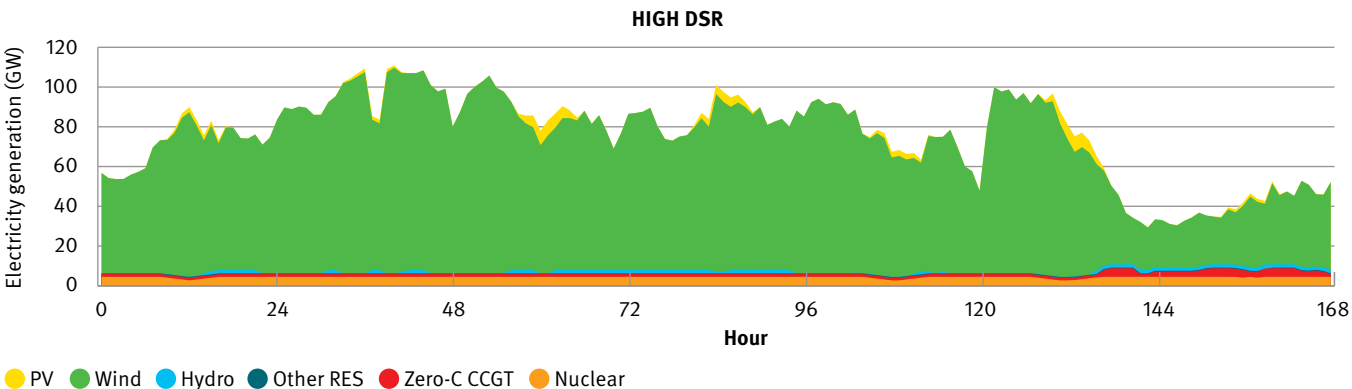
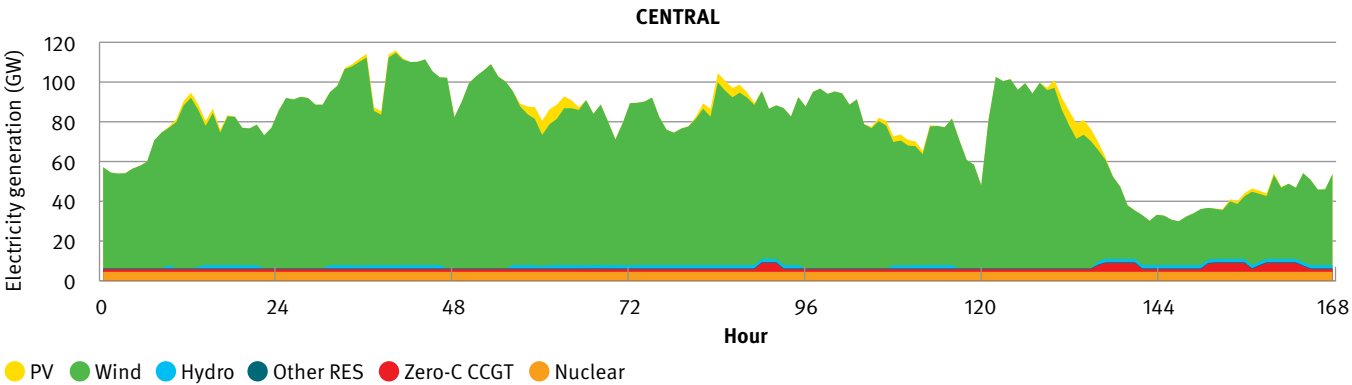
This section illustrates how energy storage contributes to the hourly operation of the net-zero carbon power system, by analysing hourly system operation across representative winter and summer weeks for the two main system cases (Central and High DSR).

Figure 5.5 presents the hourly system operation for Central and High DSR cases during a winter week. Three hourly charts included in the figure represent: a) aggregate national demand profiles, b) operation of all generation technologies, and c) net contributions of energy storage and interconnectors (positive values denote discharging i.e., electricity imports). Demand profiles depict the following two variables: 1) original demand without DSR actions; and 2) demand profile after DSR actions.

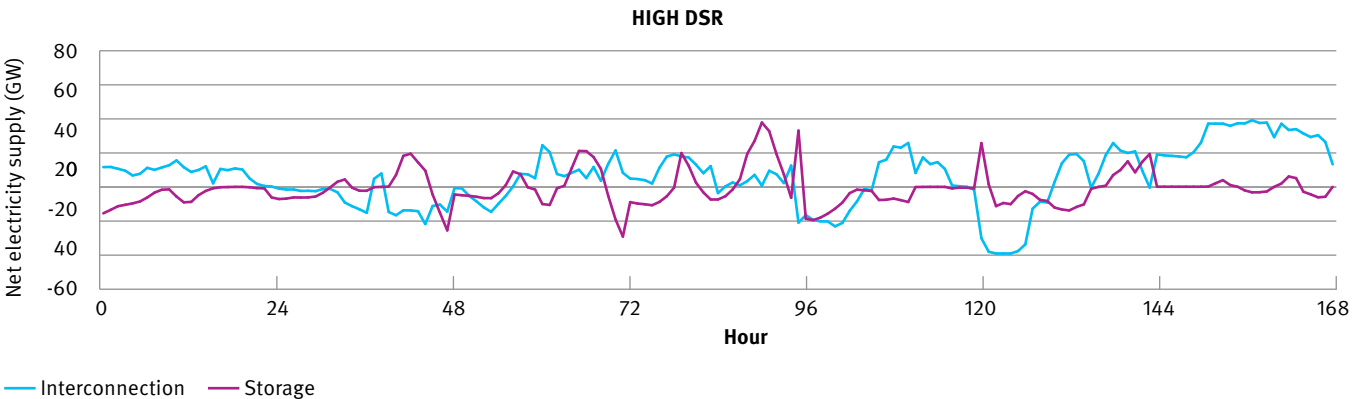
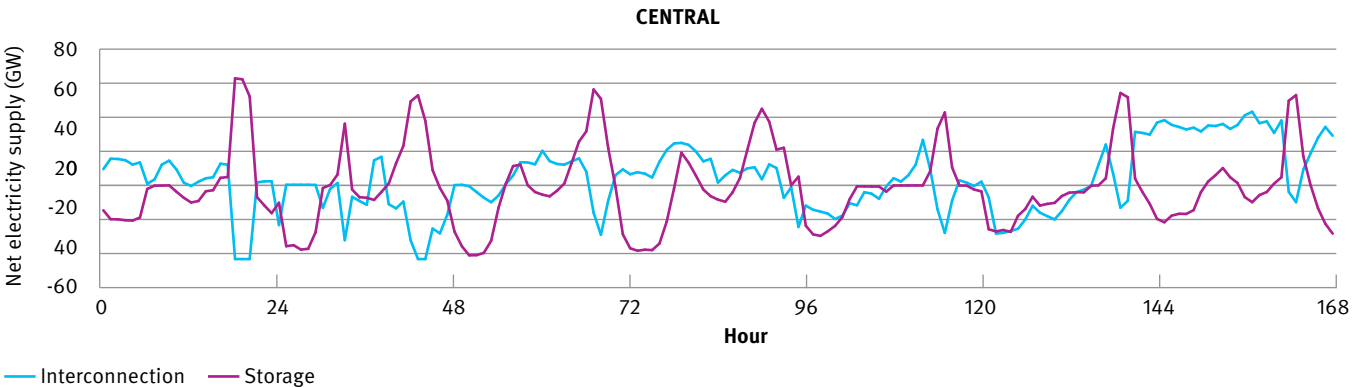
Figure 5.5. Hourly electricity system operation during a winter week in Central and High DSR cases



B



C

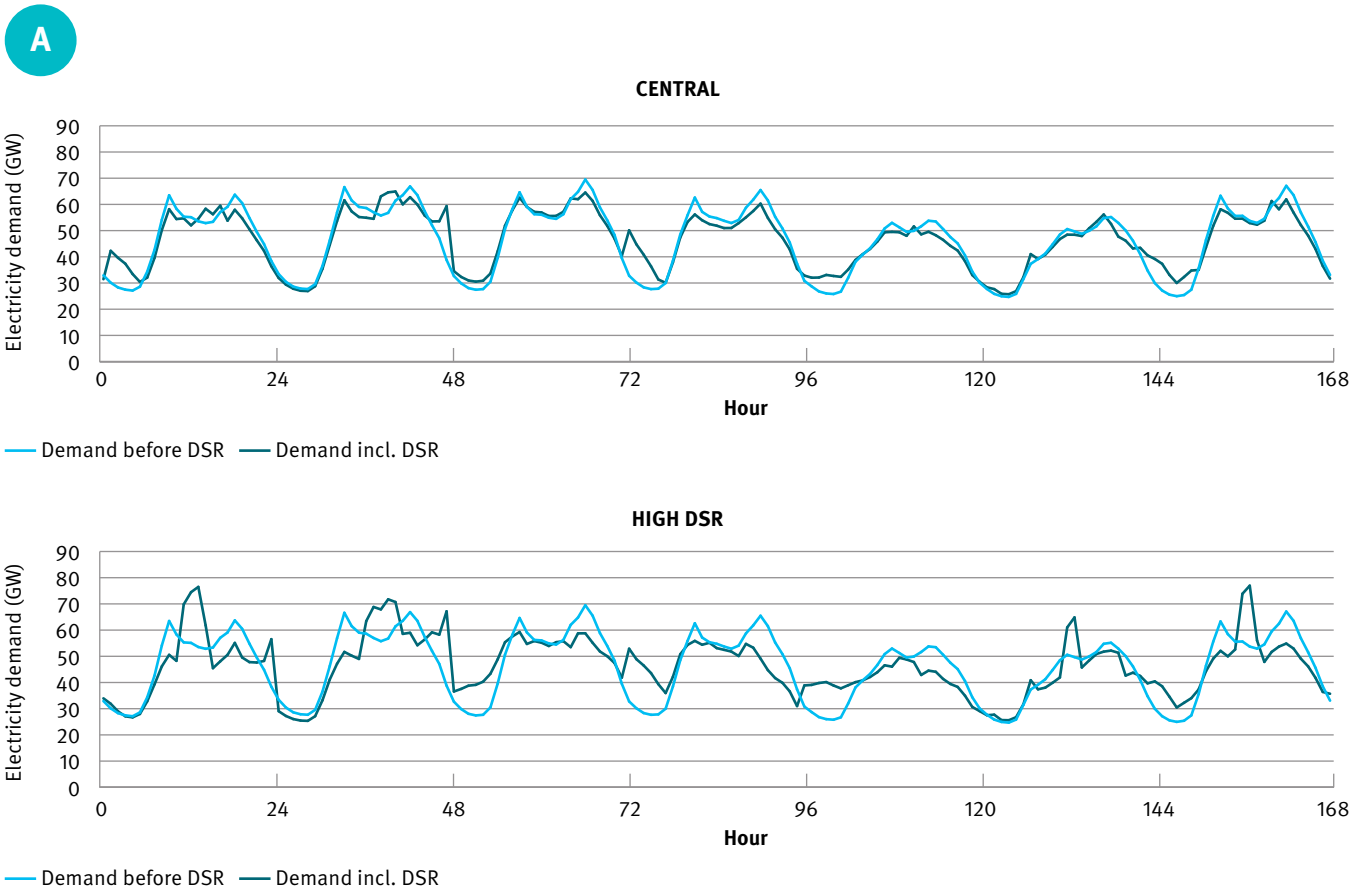


During the winter week, energy storage in the Central case mostly follows an operating pattern where it absorbs abundant wind output during night hours, when the demand is low, and then supplies demand peaks during the day. Peak demand reaches almost 150 GW as a consequence of high HP demand to supply heat during cold weather. Any excess storage output during peak demand periods is exported via interconnectors. During the last day of the week, however, the wind output drops significantly, which requires intensive use of interconnectors to import electricity.

In the High DSR case, the energy storage is used less because a large part of the fluctuations in demand and RES output is dealt with through higher DSR capability. Energy storage still supplies power during high winter peaks and absorbs energy during low-demand periods during the night, although at a much lower scale than for the Central case.

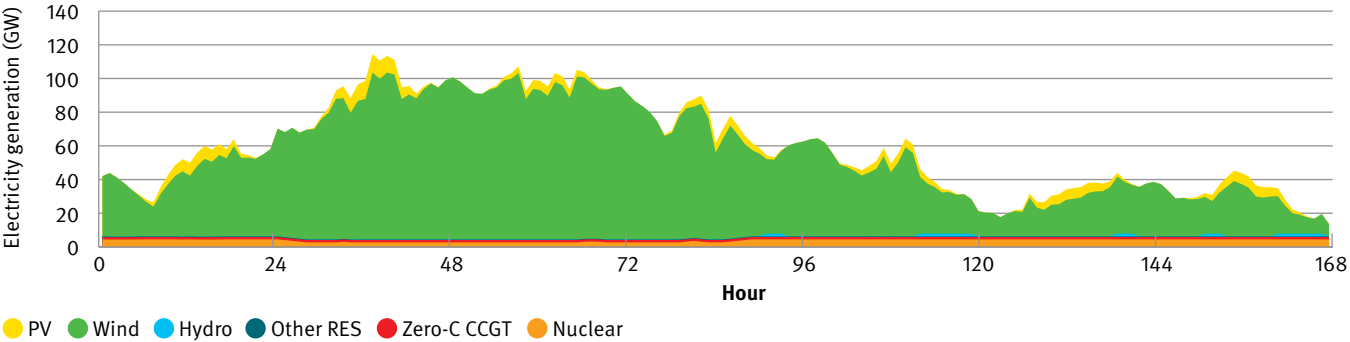
In summer (Figure 5.6), there are no large peaks to be supplied, therefore storage and interconnectors are mostly used to manage discrepancies between available RES output and demand. During the second, third and fourth day, this results in exporting large quantities of wind output, whereas towards the end of the week it becomes necessary to import electricity due to low wind output. There is slightly lower utilisation of energy storage in the High DSR case, although in both cases, the energy storage is used to absorb energy during low-demand and high-RES output periods, when excess RES output cannot be exported due to limits on interconnection capacity.

Figure 5.6. Hourly electricity system operation during a summer week in Central and High DSR cases

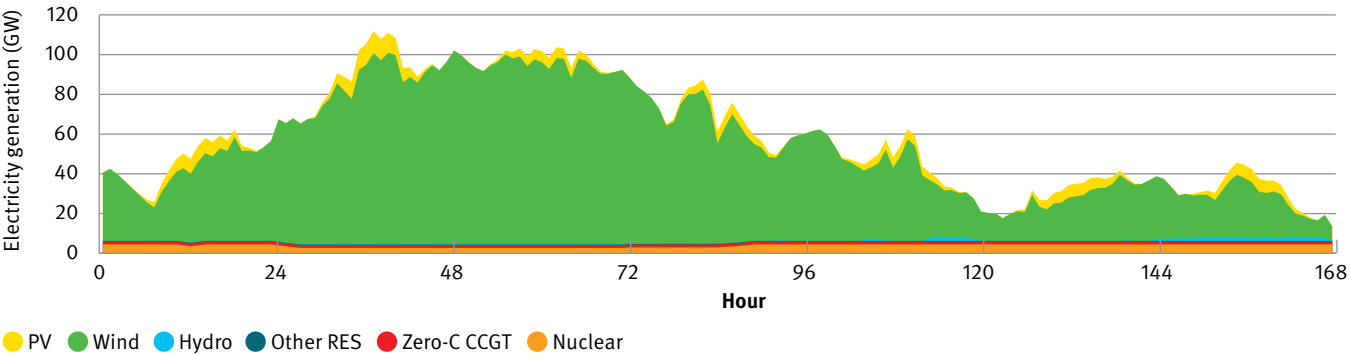


B

CENTRAL

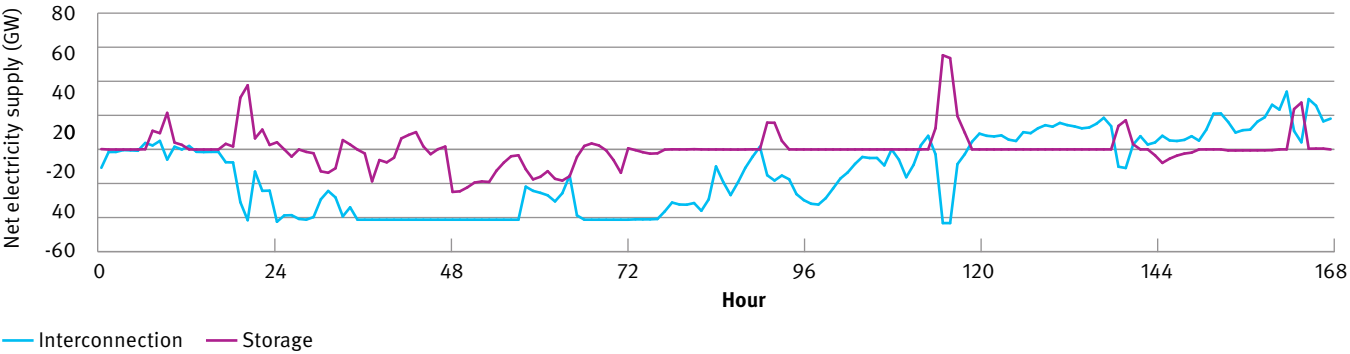


HIGH DSR

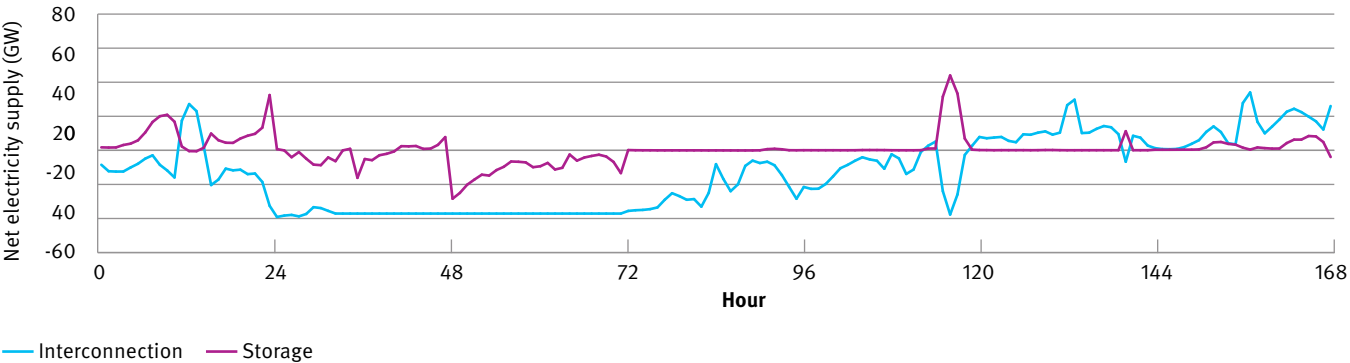


C

CENTRAL



HIGH DSR



5.5. Opportunities for deployment of long-duration storage

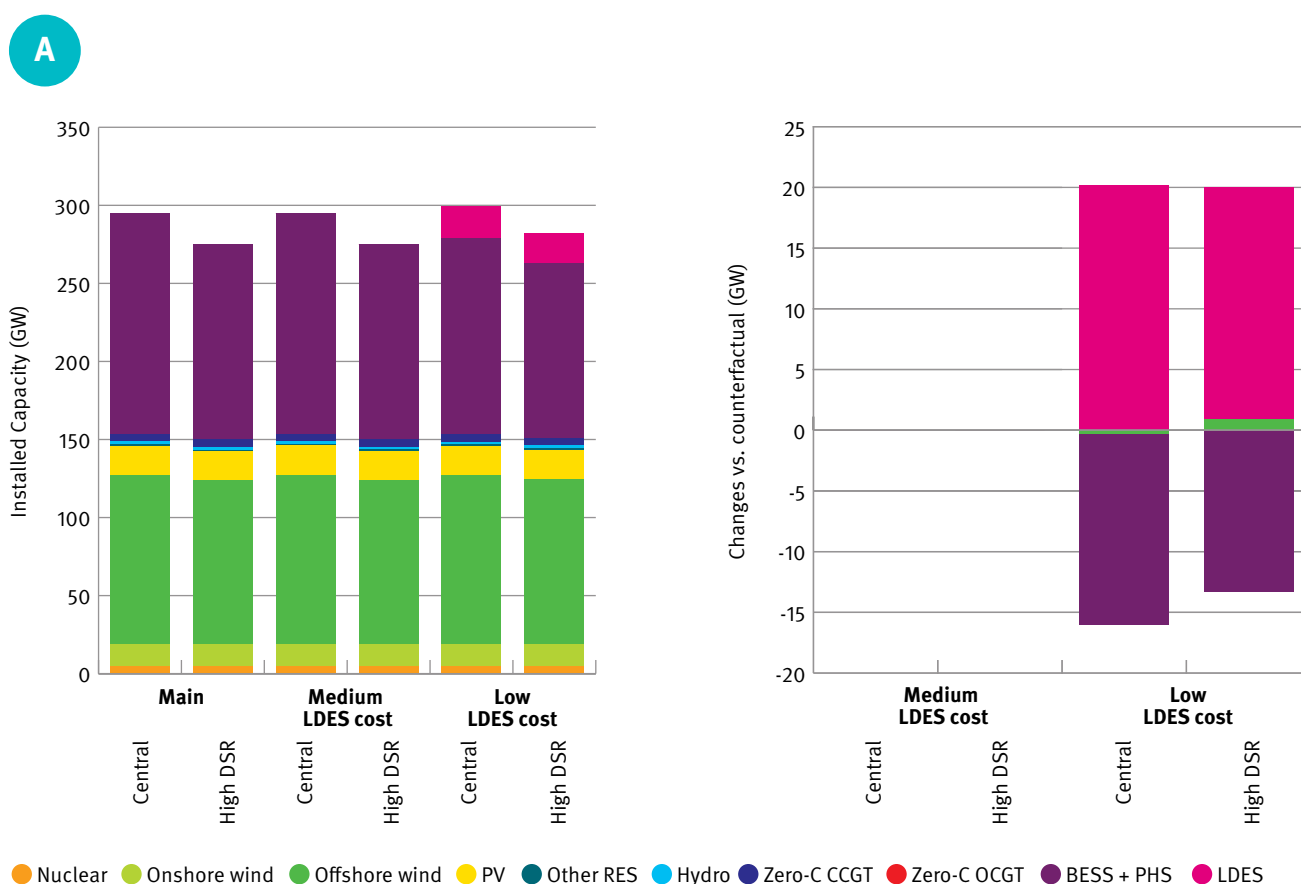
In a system dominated by variable renewables with output profiles fluctuating both daily and across seasons, it is of interest to consider the role of Long-Duration Energy Storage (LDES) in the system in addition to shorter-term storage in batteries. It is expected that the attractiveness of long-duration storage as an option will greatly depend on its relative cost. The attractiveness was therefore examined using three widely spread costs:

- High (£500/kWh)
- Medium (£80/kWh)
- Low (£4/kWh)

These example costs are based on our team's recent research into thermo-mechanical energy storage systems.³³ The assumed duration of long-duration storage was 120 hours and the roundtrip efficiency was 60%.

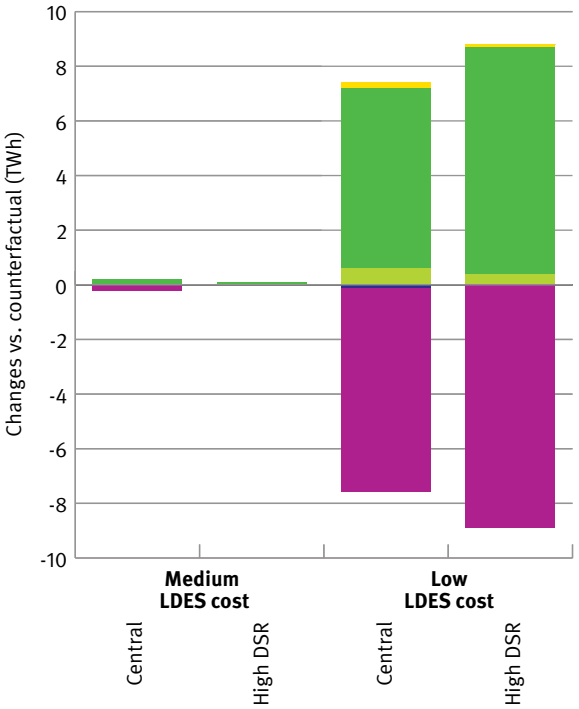
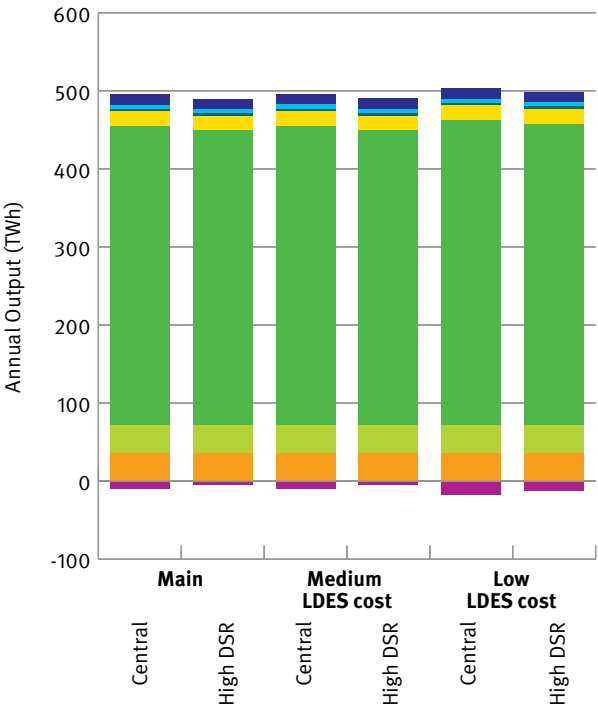
Figure 5.7(a) shows the impact of having long-duration storage available as an option in the net-zero carbon system, for various cost assumptions and the two main cases (Central and High DSR). Energy storage capacity in the figure is broken down into Battery Energy Storage Systems (BESS) and Pumped-Hydro Storage (PHS) as one category, and LDES as the other. It was found that in the High LDES Cost case there was no deployment at all of LDES, so this case has been omitted from the graphs. Even in Medium LDES Cost case, there is barely any effect on the cost-optimal portfolio. It is only when LDES becomes available at a very low cost of £4/kWh that the optimiser starts adding significant amounts of LDES capacity to the system. In this Low LDES Cost case, 19–20 GW is deployed and displaces about 13–16 GW of BESS.

Figure 5.7. GB system for net-zero with Long-Duration Energy Storage: (a) total capacities, (b) annual generation output, (c) system cost



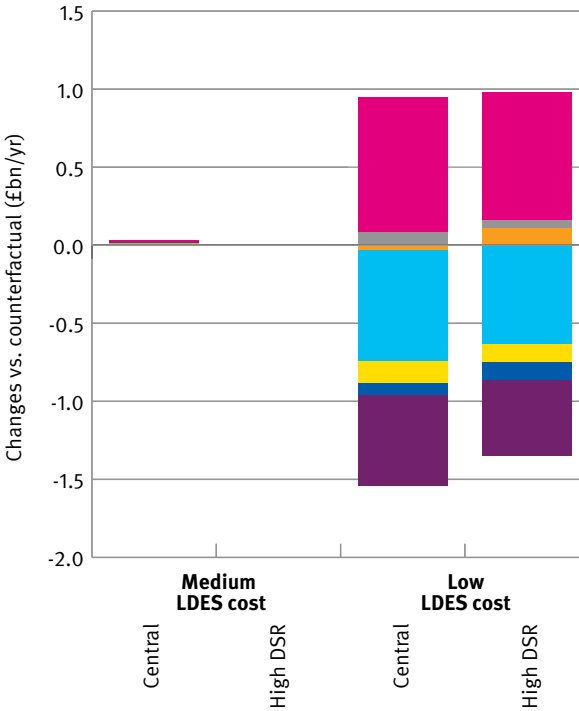
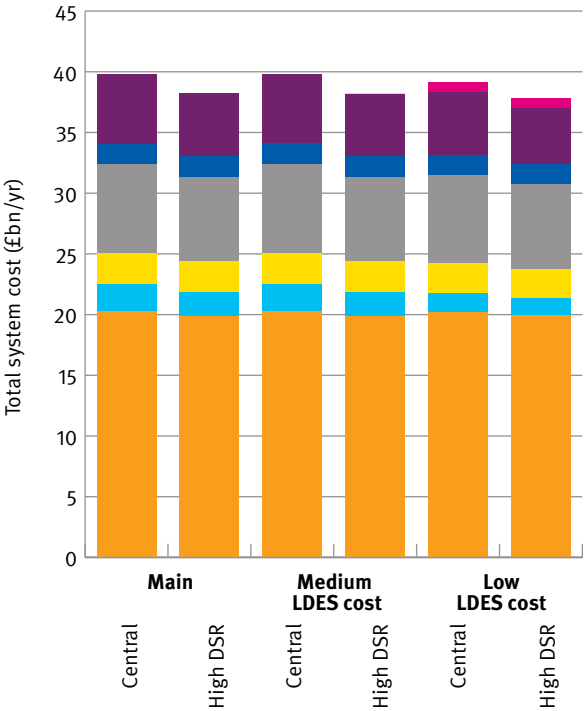
³³ This research is being carried out by other members of Imperial team within the IDLES Programme. The findings are expected to be published shortly.

B



● Nuclear ● Onshore wind ● Offshore wind ● PV ● Other RES ● Hydro ● Zero-C CCGT ● Zero-C OCGT ● Storage

C



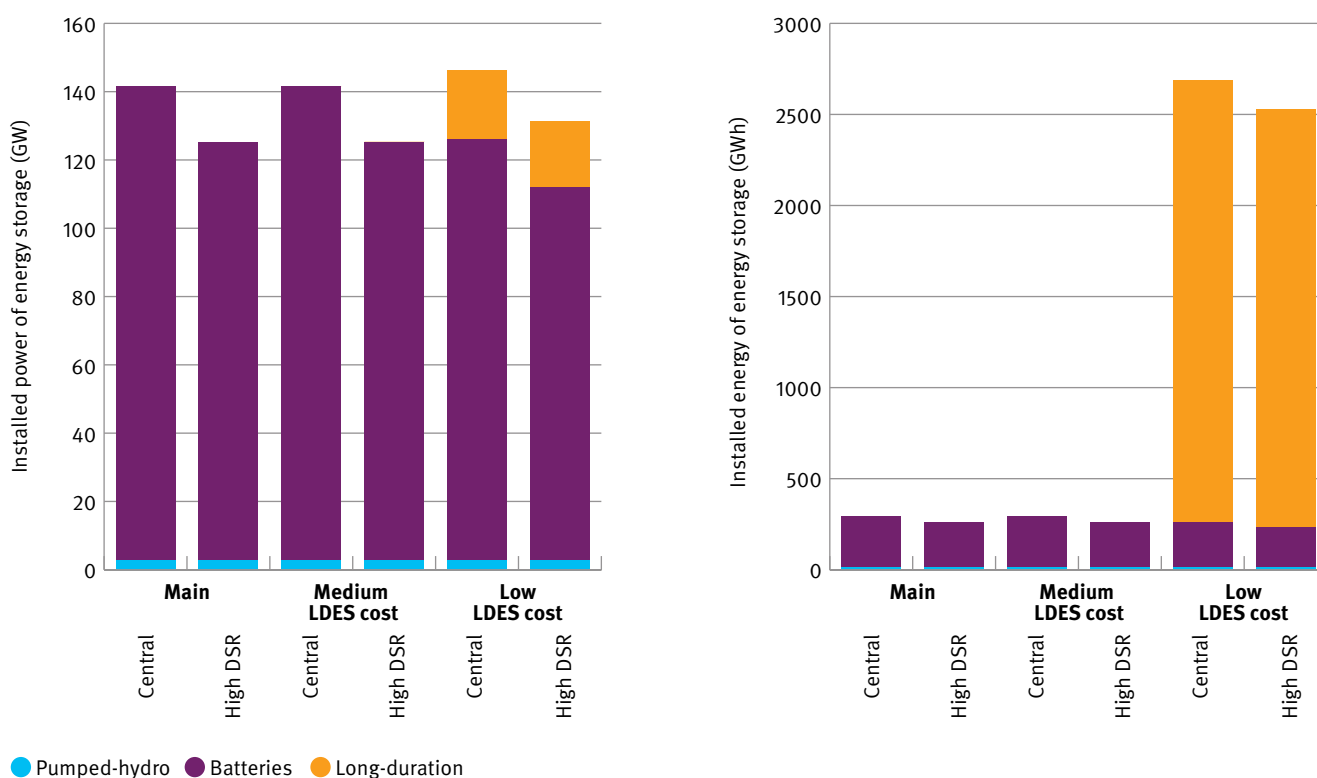
● Gen. CAPEX ● Interconn. CAPEX ● Transm. CAPEX ● Distr. CAPEX ● OPEX ● BESS + PHS ● LDES

The effect of LDES on annual electricity output of various technologies is illustrated in Figure 5.7(b). The roundtrip efficiency of LDES was assumed to be 60%, as opposed to 85% for BESS, so the net losses of storage are higher in cases with significant LDES capacity. It can also be observed that the output of offshore wind increases despite only marginal changes in its installed capacity. This is because curtailment of wind is reduced by the presence of LDES, specifically, the curtailment of offshore wind drops from 2.0–3.6% in the two main cases to just 0.6–1.7% in the low-cost LDES cases.

Availability of low-cost LDES also has the potential to reduce the overall system cost, as shown in Figure 5.7(c), where the energy storage cost component has been separated into LDES and the sum of BESS and PHS. Net savings in total system cost in Central and High DSR cases are £0.6bn and £0.4bn per year, respectively. Savings are delivered mostly through avoided BESS investment cost, but also through reduced requirement for interconnection capacity, suggesting that LDES and interconnectors compete in providing longer-term or seasonal flexibility to balance the system. While the model suggests a cost-efficient interconnection capacity of 39–43 GW in the two main cases, with LDES this reduces to only 26–29 GW.

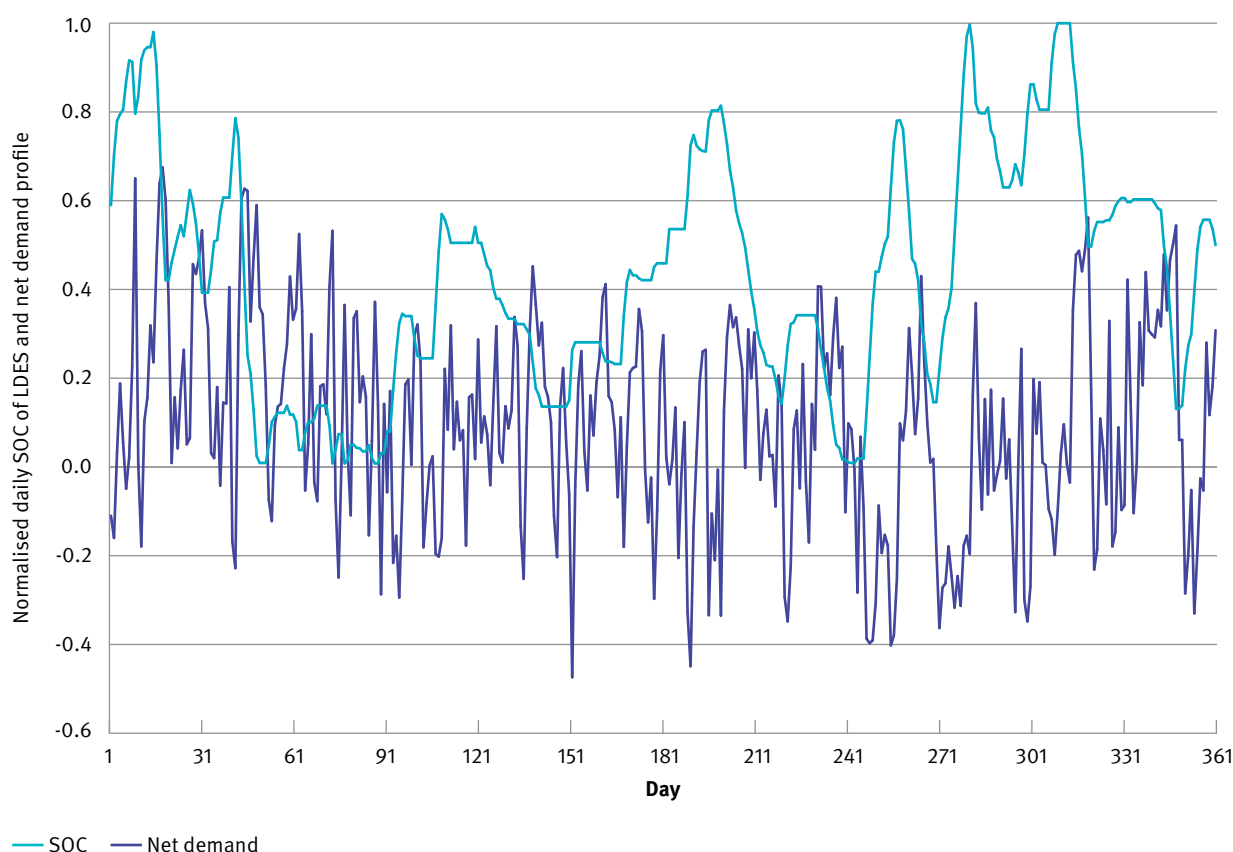
Note that the assumed duration capabilities for BESS and LDES (2 hours and 120 hours, respectively) mean that a unit of power capacity of LDES provides 60 times more energy capacity than a unit of BESS. Therefore, while the total power capacity of energy storage on the system remains broadly the same, the total energy capacity of storage in the system increases by an order of magnitude. This is further illustrated in Figure 5.8, which shows the total energy storage capacity in terms of both power and energy, split between PHS, BESS and LDES. While LDES represents a relatively small share of total power capacity on the system, when evaluated according to energy capacity LDES becomes the dominant technology, with about 10 times more energy storing capability than BESS.

Figure 5.8. Installed power (left) and energy (right) of different storage types



To illustrate how LDES is used over the course of the year, Figure 5.9 compares the normalised daily variations in State-of-Charge (SOC) of LDES in the Central case with low-cost LDES. Also shown is the normalised average daily levels of net electricity demand which is defined here as the total electricity demand minus the output of wind and PV, normalised by dividing average daily net demand by maximum hourly net demand (92.2 GW).

Figure 5.9. Normalised daily SOC of LDES and net demand profile over one year for Central case with low-cost LDES



In general terms, the operating pattern of LDES follows the principle that the SOC increases when net demand is negative (which is seen as a surplus of RES output) and decreases when net demand is positive. In this way, LDES supplies the demand during periods of low RES output and high demand. As might be expected, the SOC is held high in anticipation of high-demand periods in winter; however, its energy is also heavily utilised during periods of low RES output in August and September. The LDES is seen to help manage weekly and monthly fluctuations in RES generation.

Finally, several further model runs were carried out to establish how the deployment of LDES might change in a solar PV-dominated system such as the one analysed in Section 3.1, where the LCOE of PV generation was reduced to only £20/MWh. Solar PV generation varies seasonally much more than wind generation and its intra-day variations (between peak output at midday and zero output during the night) are even more pronounced. The results, taking the low-cost LDES case, showed that with a high solar PV capacity, exceeding 200 GW, the cost-optimal volume of LDES was only 15–16 GW compared to the 19–20 GW in the main cases with less PV and more wind. In contrast, the volume of short-term storage increased, suggesting that managing short-term fluctuations in PV output is a more significant need than managing the seasonal variations.

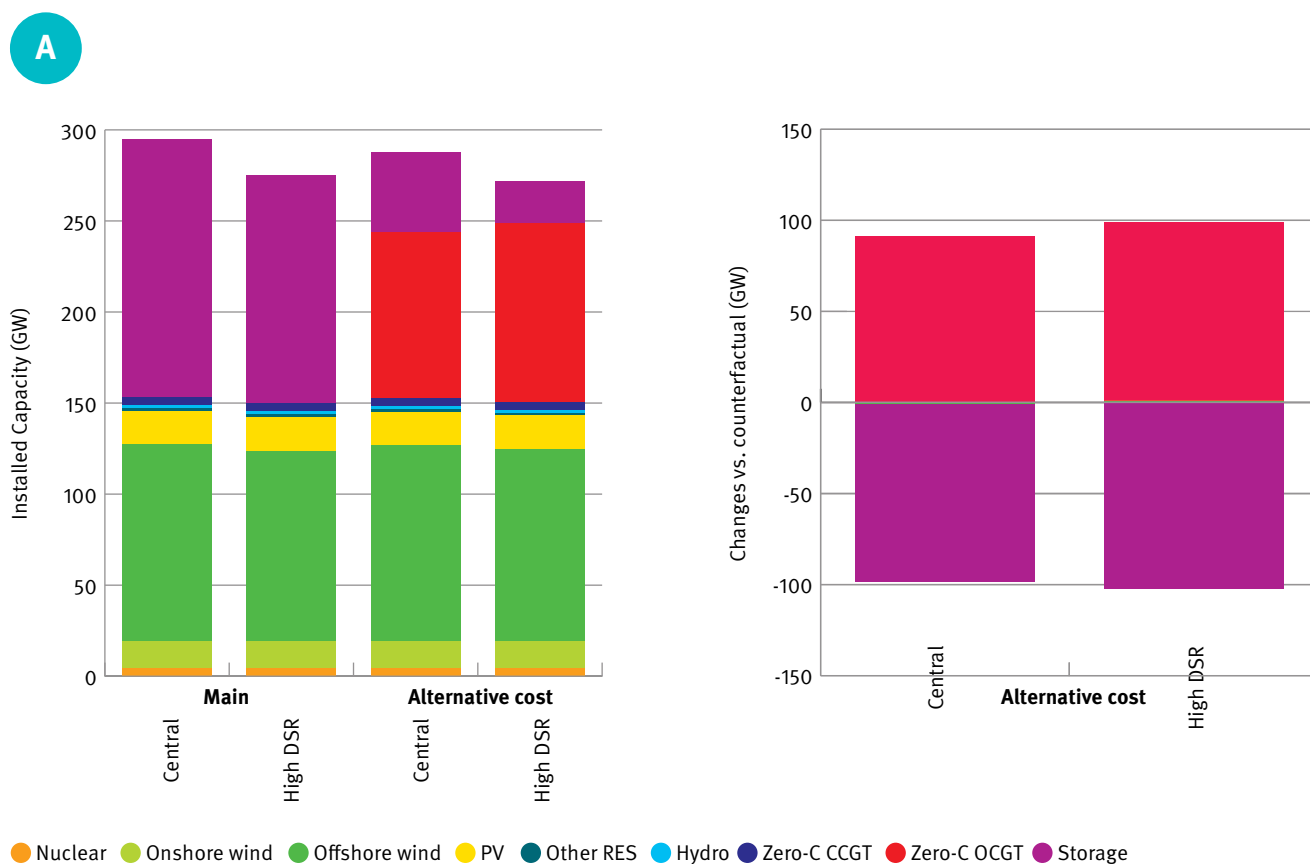
5.6. Sensitivity to cost assumptions on battery storage and peaking capacity

The results presented so far indicate that with the assumed investment cost of battery storage and zero-carbon OCGT capacity, battery storage is the more cost-effective option to meet the system capacity adequacy requirement. This is because the annualised fixed cost per kW of capacity, which includes mostly investment cost but also fixed O&M cost, infrastructure, insurance and connection cost, is £37.3/kW/yr for batteries, and £59.7/kW/yr for OCGT generation. As a result, the model suggests deploying large volumes of battery storage to deliver firm capacity on the system.

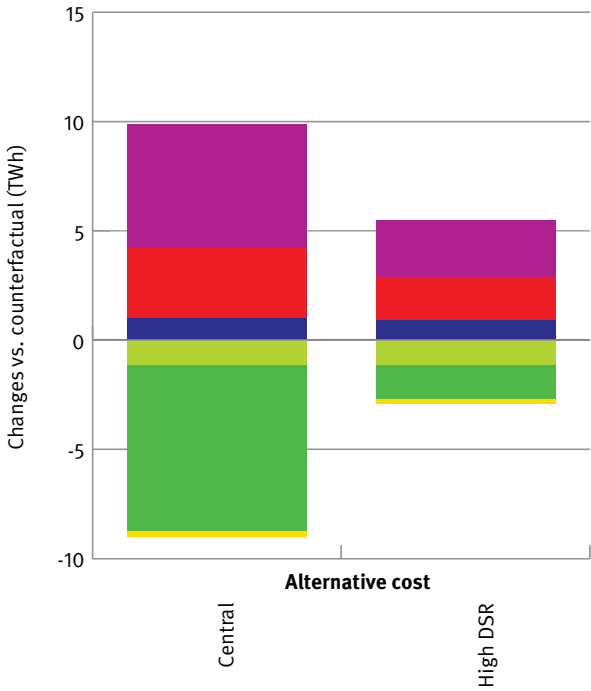
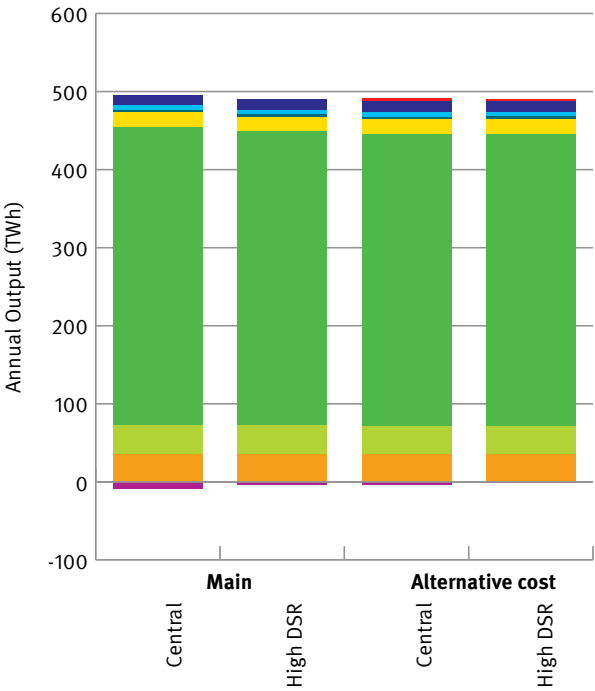
However, battery storage may not be cost-efficient in such high volumes if its installation cost does not drop below the cost of zero-carbon peaking (OCGT) capacity. Therefore, the next set of sensitivity studies determines the cost-optimal portfolio of generation and storage capacity if the cost evolution of battery storage and OCGT generation takes an opposite turn, with the resulting annualised cost of battery storage of £75/kW/yr (double the main case of £37.3/kW/yr), and the cost of OCGT of £37/kW/yr (a 40% reduction from £59.7/kW/yr).

As shown in Figure 5.10(a), the increase in battery cost coupled with decrease in OCGT cost results in OCGT becoming a preferred option for providing firm adequate capacity in the future system, with almost 100 GW added. At the same time, the capacity of battery storage reduces by about 100 GW, to 44 GW in the Central case, and 23 GW in the High DSR case, suggesting there is still value from having storage in the system, but not purely to provide firm capacity.

Figure 5.10. GB system for net-zero with increased battery storage cost combined with reduced zero-carbon OCGT cost:
(a) total capacities, (b) annual generation output, (c) system cost

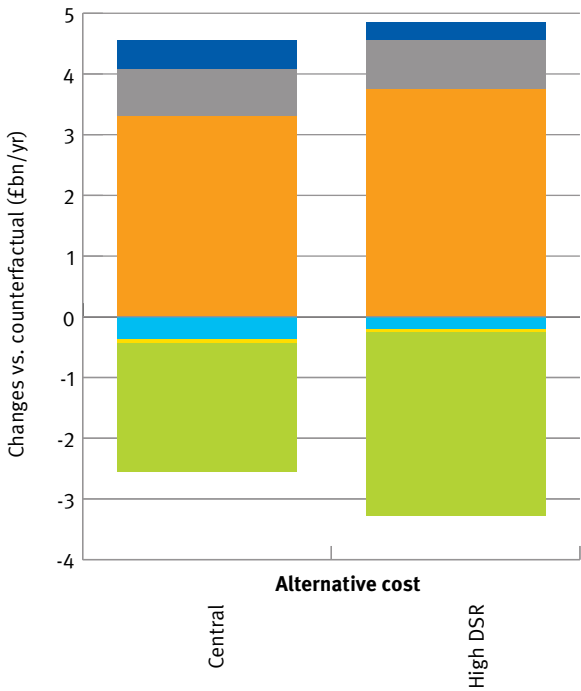
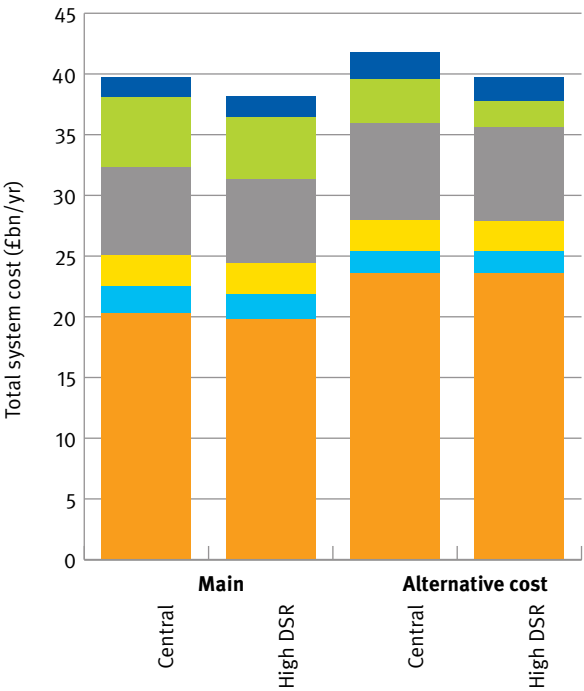


B



● Nuclear ● Onshore wind ● Offshore wind ● PV ● Other RES ● Hydro ● Zero-C CCGT ● Zero-C OCGT ● Storage

C



● Gen. CAPEX ● Interconn. CAPEX ● Transm. CAPEX ● Distr. CAPEX ● Storage CAPEX ● OPEX

The impact of alternative cost assumptions on the annual outputs of different technologies is presented in Figure 5.10(b). It is evident that with lower capacity of storage, its utilisation (as well as net demand) drops, resulting in a positive change in net annual output, while at the same time the increased output of zero-carbon CCGT and OCGT generation displaces the output of wind and PV, which get curtailed at the level of around 9 TWh annually in the Central case and 3 TWh in the High DSR case.

The cost implications of alternative cost assumptions, shown in Figure 5.10(c), are net positive for the total system cost, resulting in about £1.6–2.0bn/yr higher system cost. The increase is mostly due to the higher investment cost in low-carbon generation (i.e., the OCGT capacity), as well as increased distribution network cost (due to lower capacity of distributed battery storage) and OPEX, with some of this cost offset by reduced investment in battery storage. Investment in interconnection capacity also reduces, with about 7 GW less capacity than in main cases added in the Central case and 4 GW less in the High DSR case.

5.7. Sensitivities with net export and High DSR

All of the cases considered so far have assumed that the GB system will be energy neutral, i.e., that its electricity imports and exports over the course of the year will cancel each other and give no net export of energy. Given the high potential for offshore wind energy in GB waters, it may be attractive to expand the offshore wind capacity in GB beyond that needed to supply GB demand in order to export electricity to mainland Europe, where the opportunities for wind energy expansion are perhaps less advantageous to a developer. To understand the impact on the future GB system of this additional expansion, another set of sensitivity studies were run where the energy neutrality constraint was relaxed, so that the GB power system could act as net exporter of electricity, if economically efficient for both British and continental European systems.

The outputs of these studies are shown in Figure 5.11 in comparison to the main case with no net export. The cost-optimal solution for generation capacity in Figure 5.11(a) suggests adding further 18–22 GW of offshore wind to the already high capacity of over 100 GW in the energy-neutral cases, increasing the total GB offshore wind capacity to 127 GW. This is accompanied by 3–5 GW of additional battery energy storage to manage the increased level of wind output variability. Also, to enable higher flows of electricity towards mainland Europe, the volume of interconnection increases, although not substantially, from 39–43 GW in the energy-neutral cases to 44–46 GW in the net export cases.

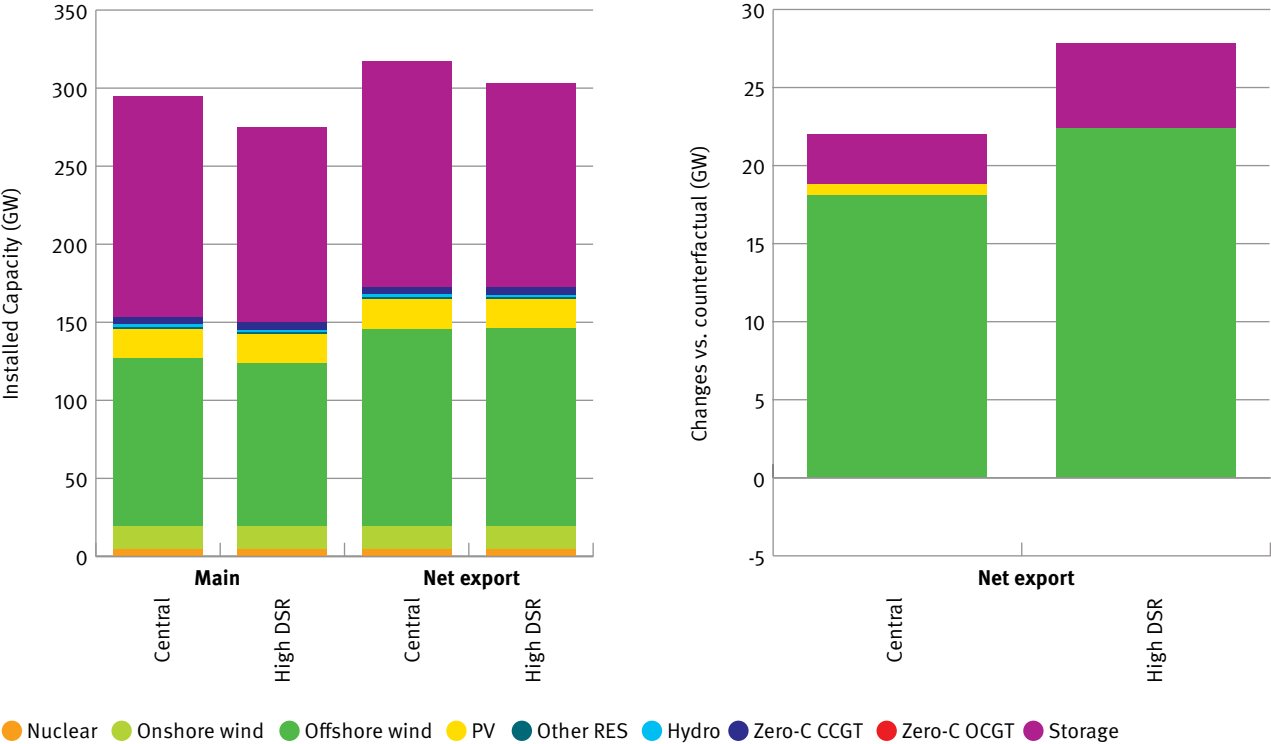
The impact of net electricity exports on annual generation output is depicted in Figure 5.11(b). Annual offshore wind output increases by 60–76 TWh to supply the net exports, while the outputs of other technologies remain broadly the same. This level of net exports represents 12–15% of annual GB electricity demand. The volume of net power exports (labelled Exp.) compared to the GB demand (labelled Domestic) is shown with grey bars in the background. The difference between generated and demanded energy in Figure 5.11 is the energy lost in the transmission and distribution networks.

The option to become net exporter will also have an effect on total system cost, as illustrated in Figure 5.11(c). As expected, the additional investments in offshore wind, battery storage and interconnection capacity result in a higher overall system cost, which is £2.0–2.7bn/yr greater than in the main energy-neutral cases. The majority of this cost increase is associated with higher investment in offshore wind generation.

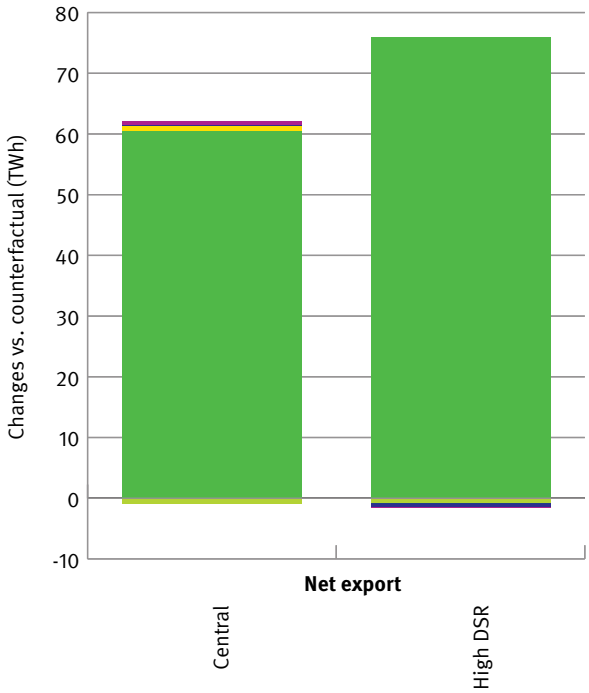
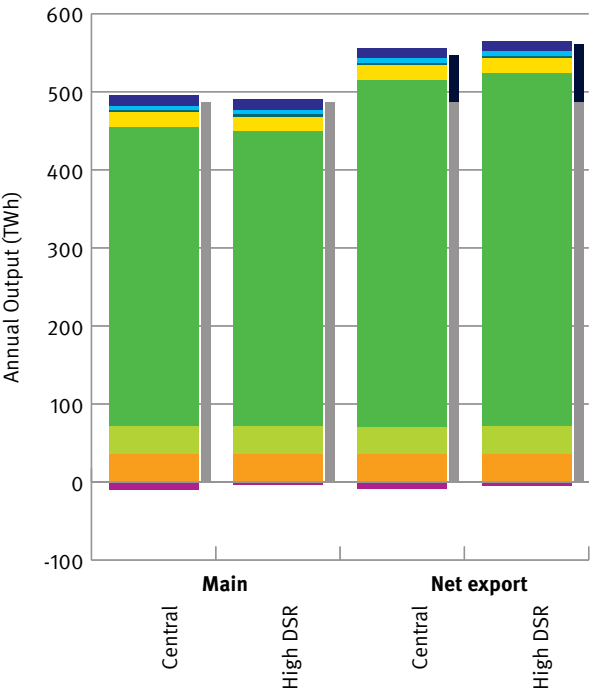
Obviously, the increase in cost would be compensated for by the revenues earned from selling exported electricity to the neighbouring markets. It is, however, difficult to determine what prices could be achieved for electricity exports in 2035 short of expanding the investment optimisation to continental-scale and including locational prices. Nevertheless, it is possible to calculate the breakeven average price required to cover the additional cost of supplying exported electricity as the ratio of the additional system cost to the volume of net electricity export. In the Central case, the breakeven price is £33.3/MWh and in the High DSR case, it increases to £36.5/MWh.

Figure 5.11. GB system for net-zero with net export allowed: (a) total capacities, (b) annual generation output, (c) system cost

A

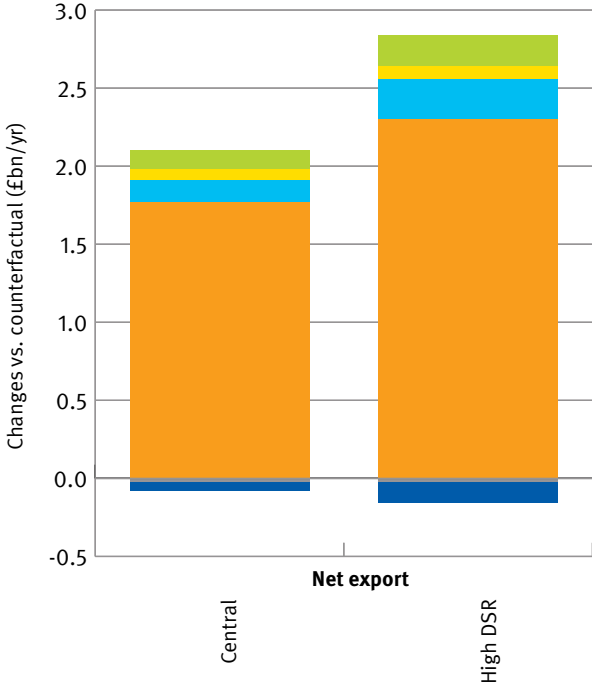
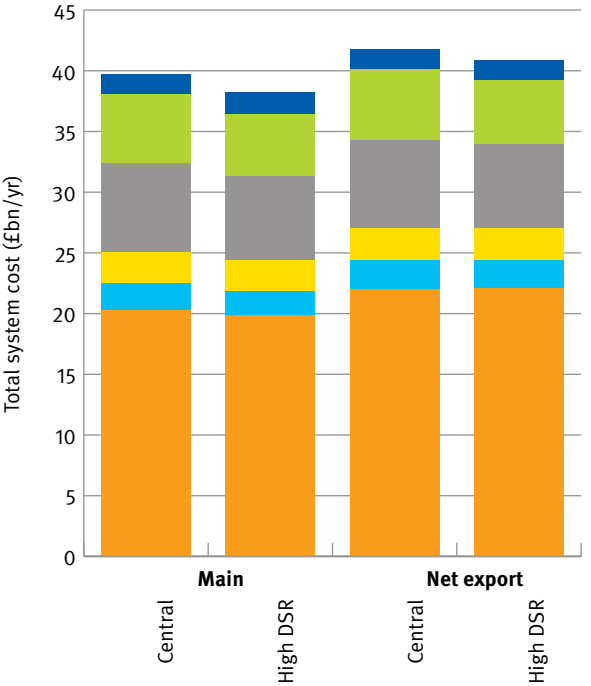


B



● Nuclear ● Onshore wind ● Offshore wind ● PV ● Other RES ● Hydro ● Zero-C CCGT ● Zero-C OCGT ● Storage ● Domestic ● Exp.

C



● Gen. CAPEX ● Interconn. CAPEX ● Transm. CAPEX ● Distr. CAPEX ● Storage CAPEX ● OPEX

5.8. Role of firm low-carbon generation

In a net-zero carbon system, firm low-carbon generation can complement variable RES. This includes technologies such as nuclear or zero-carbon fuel generation (i.e. thermal generation using biogas, hydrogen or some other form of zero-carbon fuel). Although there are clear merits to using firm low-carbon generation, such as better controllability, independence of weather events or technical factors such as provision of inertia and ancillary services, the right proportion of firm low-carbon generation in a net-zero system will, to a large extent, be driven by the cost of competing technologies, in particular wind and PV given their recent sharp reductions in cost.

This section explores how the cost assumptions on firm low-carbon generation affect the composition of the cost-optimal generation mix. A further objective is to assess the cost implications of locking in a higher minimum volume of nuclear generation. This is prompted by a recent Energy Systems Catapult study that suggested that the UK should commit to 10 GW of new nuclear beyond Hinkley Point C (provided, as they note, that its costs fall significantly) (Energy Systems Catapult, 2020). The sensitivities presented in this chapter are based on the following assumptions, imposed on both Central and High DSR cases:

- New nuclear power is available at LCOE of £60/MWh (£32.5/MWh lower than the assumption in the main cases)³⁴
- New nuclear power is available at LCOE of £45/MWh (approximately half of the default LCOE assumption)
- Fixed volume of nuclear power as a result of prior investments (from which the optimiser starts) is taken as 14.5 GW rather than 4.5 GW, with the LCOE of the added 10 GW of nuclear power at £75/MWh³⁵
- Fuel cost of zero-carbon fuel generation (CCGT and OCGT) is taken to be 33% higher or 33% lower than the central assumption

Variations in the cost-optimal generation mix identified by the model are presented in Figure 5.12(a). With the cost of nuclear reduced to £60/MWh, the model suggests adding further 4.5 GW of nuclear capacity, while removing about 6 GW of offshore wind generation and all of the 4.5 GW of zero-carbon CCGT. If nuclear becomes even cheaper, with an LCOE of £45/MWh, the model adds between 13 and 16.5 GW more nuclear power (where higher capacity corresponds to the High DSR case), displacing 26–33 GW of offshore wind and removing the 4.5 GW of zero-carbon CCGT. At the same time the cost-optimal capacity of battery storage is reduced by 10–11 GW, as there is less intermittent RES to be supported. In sensitivity studies where a fixed volume of 10 GW is added to the generation mix, the system is readjusted by removing 4.5 GW of zero-carbon CCGT, 19 GW of offshore wind and 7 GW of battery storage.

In the last two sensitivities, which had higher and lower assumptions for zero-carbon fuel cost, it can be observed that lower fuel cost results in a slightly lower (by 3–4 GW) capacity of both offshore wind and battery storage, whereas the higher fuel cost has very little effect on the capacity mix and results in 1.2–1.7 GW higher battery storage capacity.

³⁴ Note that in all nuclear sensitivities, the LCOE of 4.5 GW of nuclear plants included in the Central case was always £92.5/MWh.

³⁵ This additional capacity broadly corresponds to the numbers suggested in several recent system studies, while the cost reflects the price discussed at the time of negotiations around the potential construction of Wylfa station between the investors and the government.

When it comes to annual electricity output, shown in Figure 5.12(b), the main difference is that the share of nuclear power in total electricity supply increases from around 7% in the two main cases to 14% in the £60/MWh sensitivity for LCOE of nuclear, and to 28–34% in the £45/MWh sensitivity. With 10 GW of fixed additional nuclear generation, the share in supply increases to about 23%. In all cases, the increase in nuclear output is accompanied by reduced outputs of offshore wind and zero-carbon CCGT. In the case of lower zero-carbon fuel cost, the output of CCGT generators using the fuel increases by 35–50%, while in the case of higher fuel cost there is a negligible change in output.

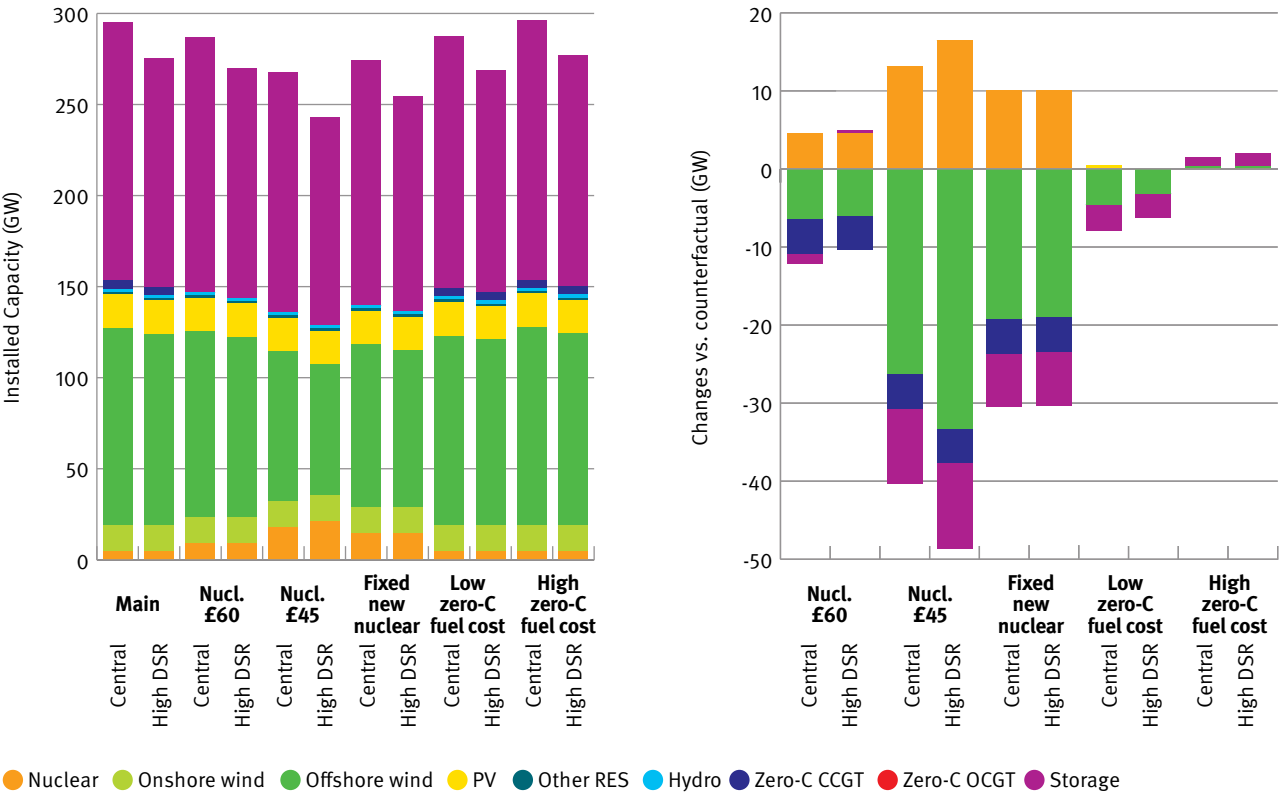
The implications of lower cost of nuclear for the total system cost are illustrated in Figure 5.12(c). A cost-optimal system configuration with an LCOE of nuclear of £60/MWh would deliver a total system cost saving of £0.5–0.6bn/yr, while a further reduction to £45/MWh would increase the savings to £1.1–1.3bn/yr. Savings mostly arise from reduced cost of investing into low-carbon generation, with noticeable savings in operating cost, storage investment cost and interconnection investment cost (required interconnection capacity in the £45/MWh case is 29–36 GW, which is lower than the 39–42 GW of interconnection in the main cases).

A fixed addition of 10 GW of nuclear capacity at the cost of £75/MWh results in a total system cost that is £1.1–1.2bn/yr higher than in the two main cases. This represents the opportunity cost of overinvesting in nuclear capacity and therefore not being able to take full advantage of cheaper offshore wind generation.

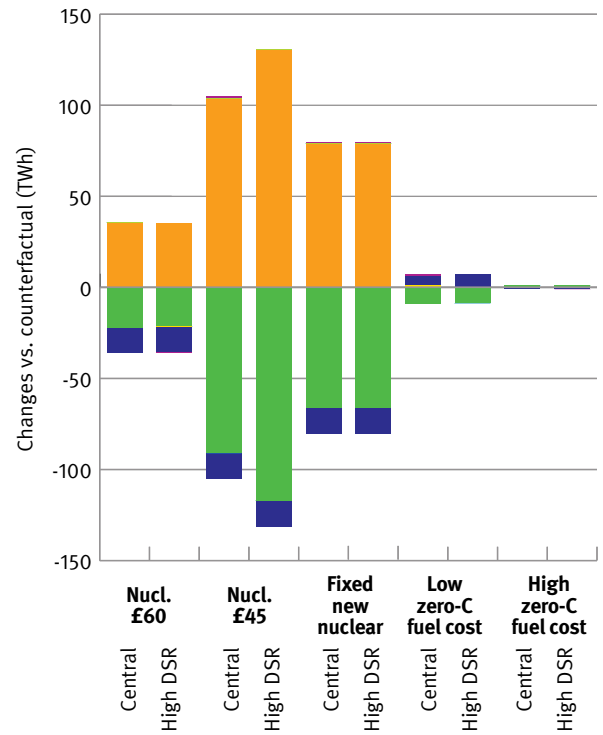
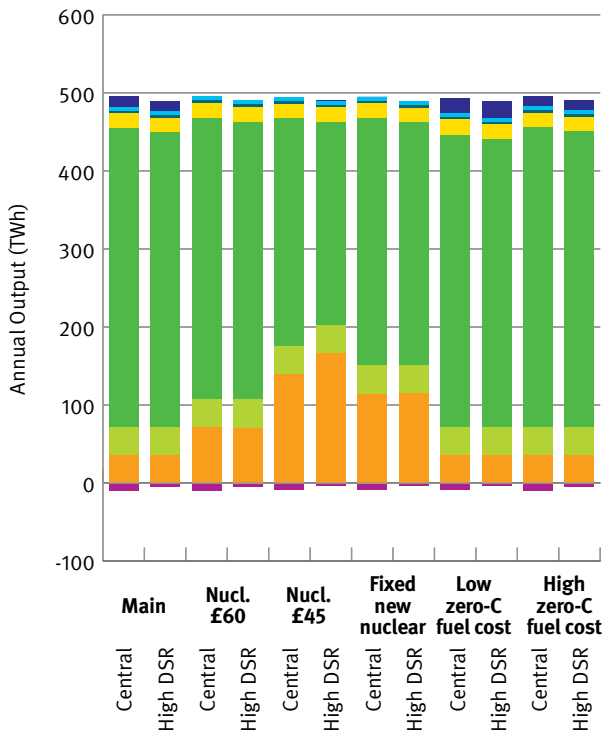
Finally, with lower zero-carbon fuel cost, the system cost reduces by £0.8–1.1bn/yr, while in case of an increase in the fuel cost, the system cost increases by £0.6bn/yr.

Figure 5.12. GB system for net-zero with variations in cost of nuclear and zero-carbon generation: (a) total capacities, (b) annual generation output, (c) system cost

A

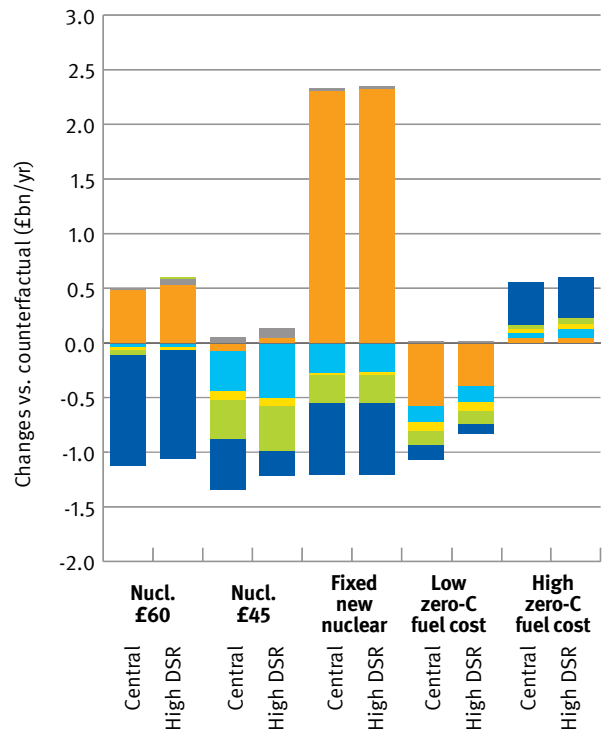
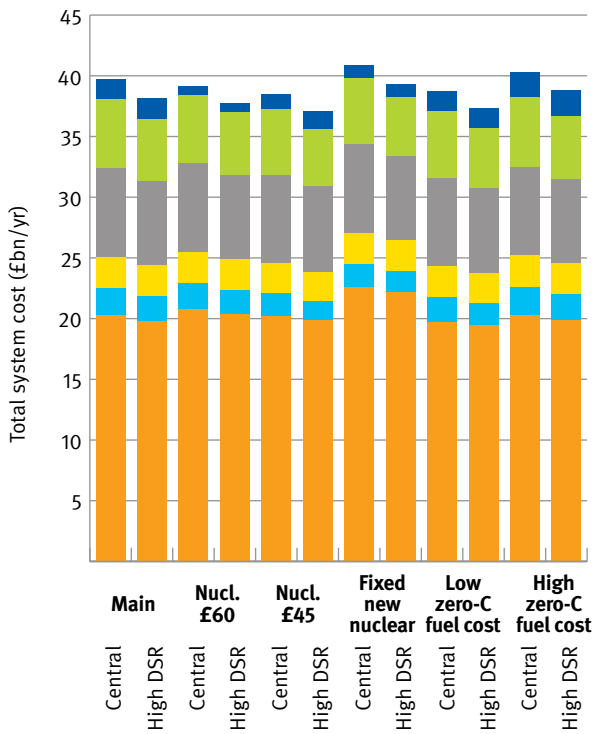


B



■ Nuclear
 ■ Onshore wind
 ■ Offshore wind
 ■ PV
 ■ Other RES
 ■ Hydro
 ■ Zero-C CCGT
 ■ Zero-C OCGT
 ■ Storage

C



■ Gen. CAPEX
 ■ Interconn. CAPEX
 ■ Transm. CAPEX
 ■ Distr. CAPEX
 ■ Storage CAPEX
 ■ OPEX

5.9. Direct Air Capture of CO₂ as a decarbonisation option

The final set of sensitivity studies explores the potential contribution of a carbon offsetting technology, Direct Air Capture (DAC), to achieving the net-zero carbon target and to go beyond that to a net-negative carbon target, perhaps to offset emissions elsewhere in the economy. Given that DAC is not a mature technology, there are no firm cost estimates available for deployment at scale, although it is understood there is potential for significant cost reduction from the current state of the art.

Recent literature has estimated the levelised cost of removing CO₂ from the atmosphere to be between \$94 and \$232/tCO₂ for a DAC facility that captures a million tonnes of CO₂ per year (Keith *et al.*, 2018). Other literature suggests an even lower cost of DAC, forecasting a drop to below \$60/tCO₂ in 2040 (Fasihi, Efimova and Breyer, 2019). This levelised cost consists of a fixed cost that is the sum of investment and O&M cost, and a variable cost that is associated with the energy required to capture a tonne of CO₂. This energy could be delivered by a mix of electricity and gas, but in the net-zero system it will be assumed that the energy required for running DAC will be provided entirely through electricity (Wohland, Witthaut and Schleussner, 2018). Estimates for energy requirements reported in the literature vary between 1.83 and 3.30 MWh/tCO₂.

Keith *et al.* suggest an annualised capacity cost of DAC of £716,000 per tCO₂/hr (which is the unit of plant capacity) per year. To allow for maintenance, the utilisation of DAC capacity over the year is taken as 90%. This results in a non-energy component of the levelised cost of CO₂ of around £91/tCO₂. Full levelised cost is obtained as the sum of the capacity component and the energy component, which in turn depends on the cost of energy required to capture a unit of CO₂. With this energy provided through electricity, its cost will vary on an hourly basis according to system conditions.

DAC was modelled as a separate technology in our whole-system model using three cost and energy consumption cases:

- **Medium cost:** annualised capacity cost of £700,000/(tCO₂/hr)/yr (cost reported by Keith *et al.* rounded to the nearest £100,000), and electricity consumption of 2.30 MWh/tCO₂
- **High cost:** annualised capacity cost of £1.05m/(tCO₂/hr)/yr (50% higher than Medium), and electricity consumption of 3.30 MWh/tCO₂
- **Low cost:** annualised capacity cost of £350,000/(tCO₂/hr)/yr (50% lower than Medium), and electricity consumption of 1.83 MWh/tCO₂

With the above cost assumptions, the levelised fixed (non-energy) cost components of CO₂ capture were £88.8/tCO₂, £133.2/tCO₂ and £44.4/tCO₂ for Medium, High and Low DAC Cost cases, respectively. As an illustration of the scale of energy costs of running DAC, an electricity cost of £40/MWh leads to costs of £92/tCO₂ (Medium), £132/tCO₂ (High) and £73/tCO₂ (Low) for the three cases. In reality the costs vary with the hourly cost of electricity.

The model was allowed to make investment decisions into DAC capacity if cost-efficient for the overall system, while the electricity required to run DAC in each hour was added to the total electricity demand. Therefore, the energy cost for operating DAC (and its variability) was included in the system implicitly rather than explicitly. It was further assumed that the utilisation of any DAC capacity added by the model is constrained to 90% of a year. Any DAC plants added by the model were assumed to connect to the transmission grid due to relatively large energy requirements (a typical 1 MtCO₂/year plant would require a power supply of 300 MW).

In addition to the three DAC cost cases, three further pairs of modelling runs were carried out based on the Low DAC Cost case in which the carbon targets for the overall system were set at $-10 \text{ gCO}_2/\text{kWh}$, $-25 \text{ gCO}_2/\text{kWh}$ and $-50 \text{ gCO}_2/\text{kWh}$. The purpose of these studies was to assess the necessary investment in DAC capacity if the system needs to go beyond the net-zero target and achieve net-negative emissions.

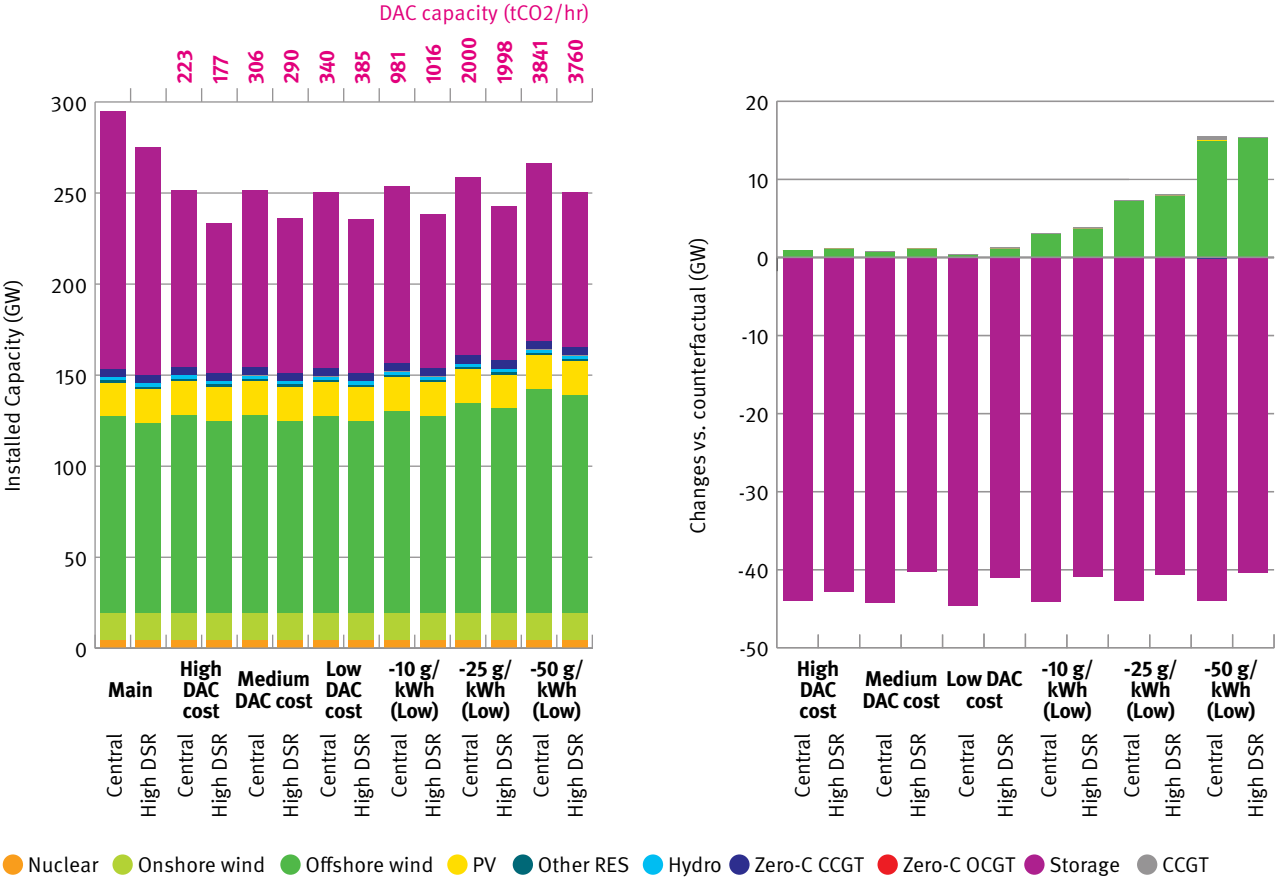
Figure 5.13(a) shows the generation mix, energy output and systems costs with DAC available as an investment option. The DAC capacity deployed is noted at the top of the chart rather than added as a generation capacity. The principal impact of DAC, perhaps not easily foreseen, is a reduction in the battery storage capacity deployed. This impact is consistent across different cases considered here at about 40 GW for the High DSR case and 45 GW for the Central case. The only other change in the capacity mix is an increase in offshore wind generation that is required to supply the additional electricity demand for running DAC facilities. Added offshore wind capacity across the three net-zero cases (i.e. with High, Medium and Low DAC cost) is up to 1 GW, which is relatively small at less than 1% of the capacity in the non-DAC cases. Nevertheless, the required volume of offshore wind increases more significantly in the net-negative carbon cases. The target of $-10 \text{ gCO}_2/\text{kWh}$ requires 3.0–3.7 GW additional low-carbon generation to supply the higher DAC capacity, which is broadly triple that needed for net-zero cases. The $-25 \text{ gCO}_2/\text{kWh}$ requires 7.2–7.9 GW of additional generation, double that of the lower target. At $-50 \text{ gCO}_2/\text{kWh}$ the additional offshore wind capacity further increases to around 15 GW.

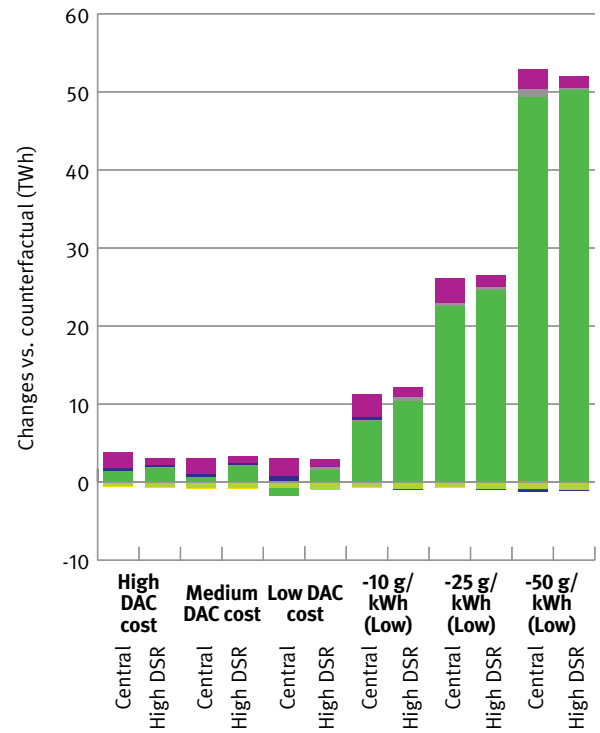
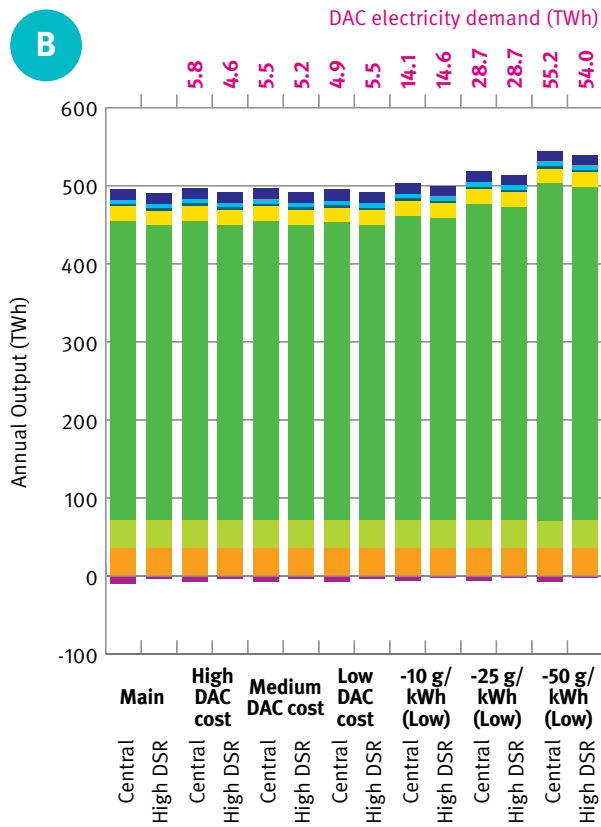
The way DAC impacts the annual electricity output is shown in Figure 5.13(b). The main effect of DAC is the reduced utilisation (and therefore lower cycle losses) of battery storage and higher output of offshore wind generation, both of which help to supply the additional energy required to drive the DAC processes. The additional electricity demand for annual DAC operation is included at the top of the chart in Figure 5.13(b). In the net-zero cases, the DAC energy requirement is around 5 TWh; in net-negative cases, $-10 \text{ gCO}_2/\text{kWh}$, $-25 \text{ gCO}_2/\text{kWh}$ and $-50 \text{ gCO}_2/\text{kWh}$, the energy demand for DAC operation increases to 14 TWh, 29 TWh and 55 TWh, respectively, which is met by adding more offshore wind generation.

Finally, the impact of DAC cases on total system cost is quantified in Figure 5.13(c). In all three net-zero cases, installing DAC delivers significant net cost savings of £2.1–3.2bn/yr, with only a moderate investment in DAC capacity of £120–230m/yr. The bulk of the cost savings arises from avoided distribution network reinforcement cost and reduced need to invest in battery storage capacity. Both of these sources of cost savings are still present in the two net carbon negative cases, however given that net-negative emissions require additional investment in DAC facilities (about £350m/yr, £700m/yr and £1.3bn/yr for $-10 \text{ gCO}_2/\text{kWh}$, $-25 \text{ gCO}_2/\text{kWh}$ and $-50 \text{ gCO}_2/\text{kWh}$ cases, respectively), the net cost savings reduce to £1.8–2.3bn/yr in the $-10 \text{ gCO}_2/\text{kWh}$ case and £0.9–1.3bn/yr in the $-25 \text{ gCO}_2/\text{kWh}$ case, while in the $-50 \text{ gCO}_2/\text{kWh}$ case, the total system cost increases by £0.4–0.8bn/yr.

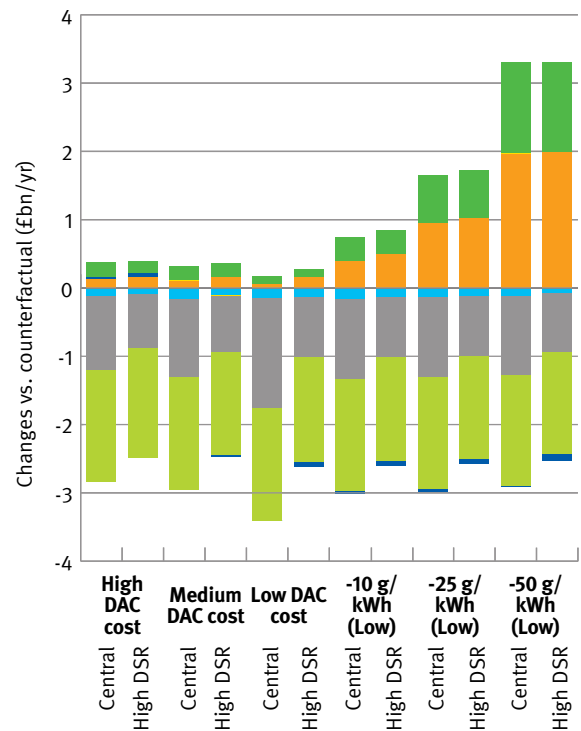
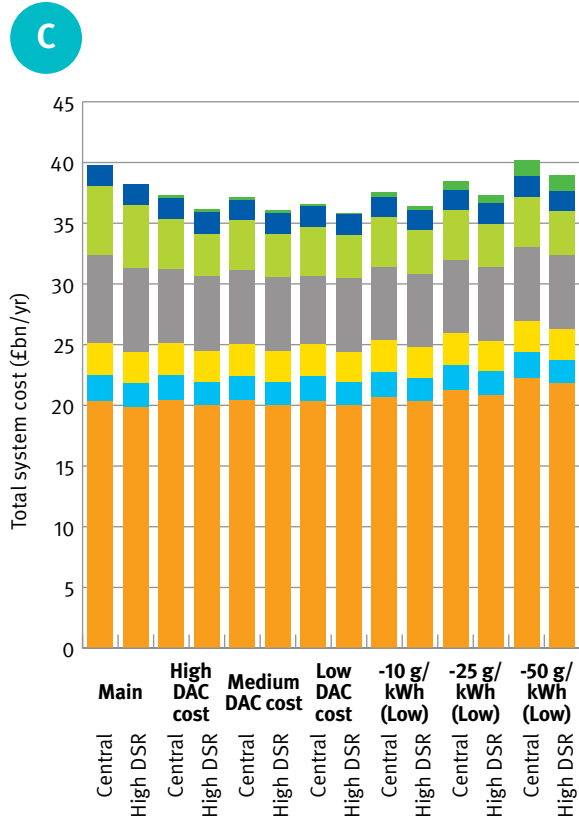
Figure 5.13. GB system for net-zero with variations in the cost of DAC and emissions target:
(a) total capacities, (b) annual generation output, (c) system cost

A





● Nuclear ● Onshore wind ● Offshore wind ● PV ● Other RES ● Hydro ● Zero-C CCGT ● Zero-C OCGT
● CCGT ● Storage



● Gen. CAPEX ● Interconn. CAPEX ● Transm. CAPEX ● Distr. CAPEX ● Storage CAPEX ● OPEX ● DAC CAPEX

The main driver for DAC reducing the requirement for battery storage in the system is related to the operation of HHPs. In the net-zero cases without DAC, HHPs are effectively prevented from using gas to supply peaks of the heat demand during cold winter spells, as that would violate the system-level net-zero carbon constraint. This means that the entire heat supplied by HHPs is provided by using electricity, causing very high levels of peak demand. In order to mitigate the resulting high reinforcement cost in distribution grids and high requirements for peaking capacity, the model installs a high volume of battery storage. When DAC becomes available as a carbon offset option, the model adds it to deliver carbon removals in the volume of 2–3 million tonnes of CO₂ per year, which in turn enables HHPs to use gas during the coldest days of the year and avoid the high cost of reinforcing the local grid and providing sufficient peaking capacity.

Annual carbon emissions and offsets are shown in Figure 5.14, where any emissions by HHPs in the net-zero cases are offset by carbon removals by DAC. In the net-negative cases, more DAC capacity is required to achieve the negative net emissions on top of offsetting around 2.5 mtCO₂ of annual HHP carbon emissions.

Figure 5.14. Annual carbon emissions for net-zero and net-negative cases with DAC

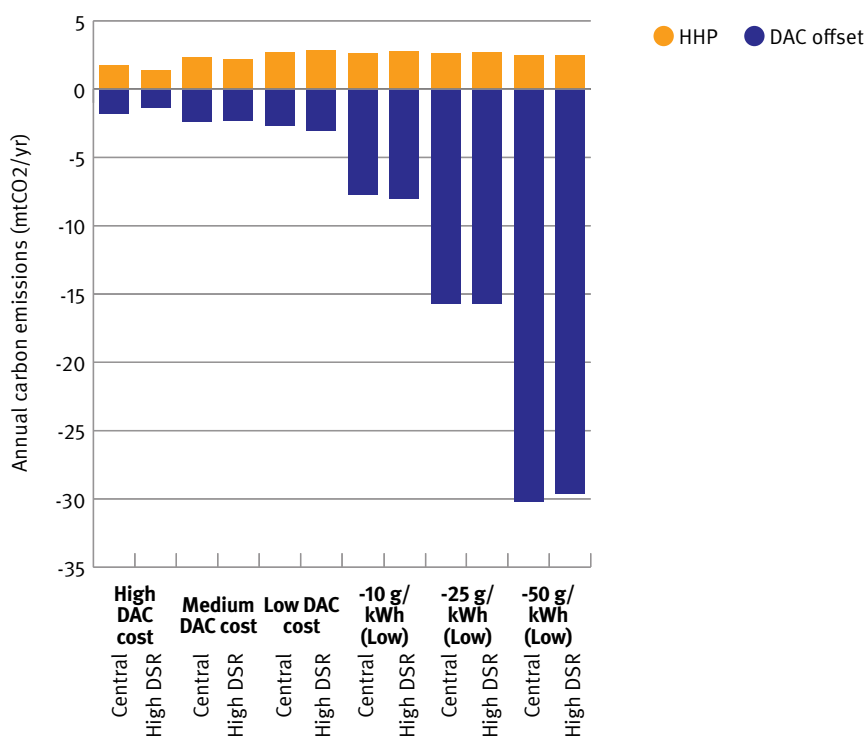


Table 5.1 summarises the optimisation results for the investment in DAC capacity and its utilisation. The installed capacity of DAC expectedly increases with lower cost, so that in the Central net-zero cases the capacity increases from 223 tCO₂/hr with High DAC cost to 340 tCO₂/hr with Low DAC cost. The corresponding annual carbon offsets are between 1.8 and 2.7 million tCO₂ per year. This increases significantly in net carbon negative cases, to around 1,000 tCO₂/hr with the target of -10 gCO₂/kWh, 2,000 tCO₂/hr for -25 gCO₂/kWh and 3,800 tCO₂/hr for -50 gCO₂/kWh. This is unsurprising given that DAC is the only technology assumed to be able to provide carbon offsets.³⁶ Total offsets in the -10 gCO₂/kWh case are around 8 mtCO₂/yr, while in the -25 gCO₂/kWh case this doubles to about 16 mtCO₂/yr and quadruples to around 30 mtCO₂/yr in the -50 gCO₂/kWh case.

Table 5.1. Cost-optimal capacities and outputs for DAC across cases

	High DAC cost		Medium DAC cost		Low DAC cost		-10 g/kWh (Low)		-25 g/kWh (Low)		-50 g/kWh (Low)	
	Central	High DSR	Central	High DSR	Central	High DSR	Central	High DSR	Central	High DSR	Central	High DSR
Capacity (tCO₂/hr)	223	177	306	290	340	385	981	1,016	2,000	1,998	3,841	3,760
Investment (£m/yr)	235	186	214	203	119	135	343	356	700	699	1,344	1,316
Output (mtCO₂/yr)	1.76	1.39	2.40	2.28	2.67	3.03	7.72	7.99	15.74	15.72	30.21	29.59
Utilisation	89.8%	89.8%	89.8%	89.8%	89.7%	89.8%	89.8%	89.8%	89.8%	89.8%	89.8%	89.9%
Demand (TWh)	5.8	4.6	5.5	5.2	4.9	5.5	14.1	14.6	28.7	28.7	55.2	54.0

It is also interesting to note that the utilisation of DAC capacity is always at the upper bound (90%). This suggests that the variation in the cost of electricity over the course of the year is not sufficient to justify running DAC plants at less than 90% utilisation given the relatively high investment cost. Although this has not been optimised in the model, it can be expected that any maintenance of DAC plants would occur during winter, when the marginal cost of electricity supply is likely to be higher. Conversely, the operation will be at full capacity throughout the warmer part of the year when the demand is lower and the output of PV generation is high.

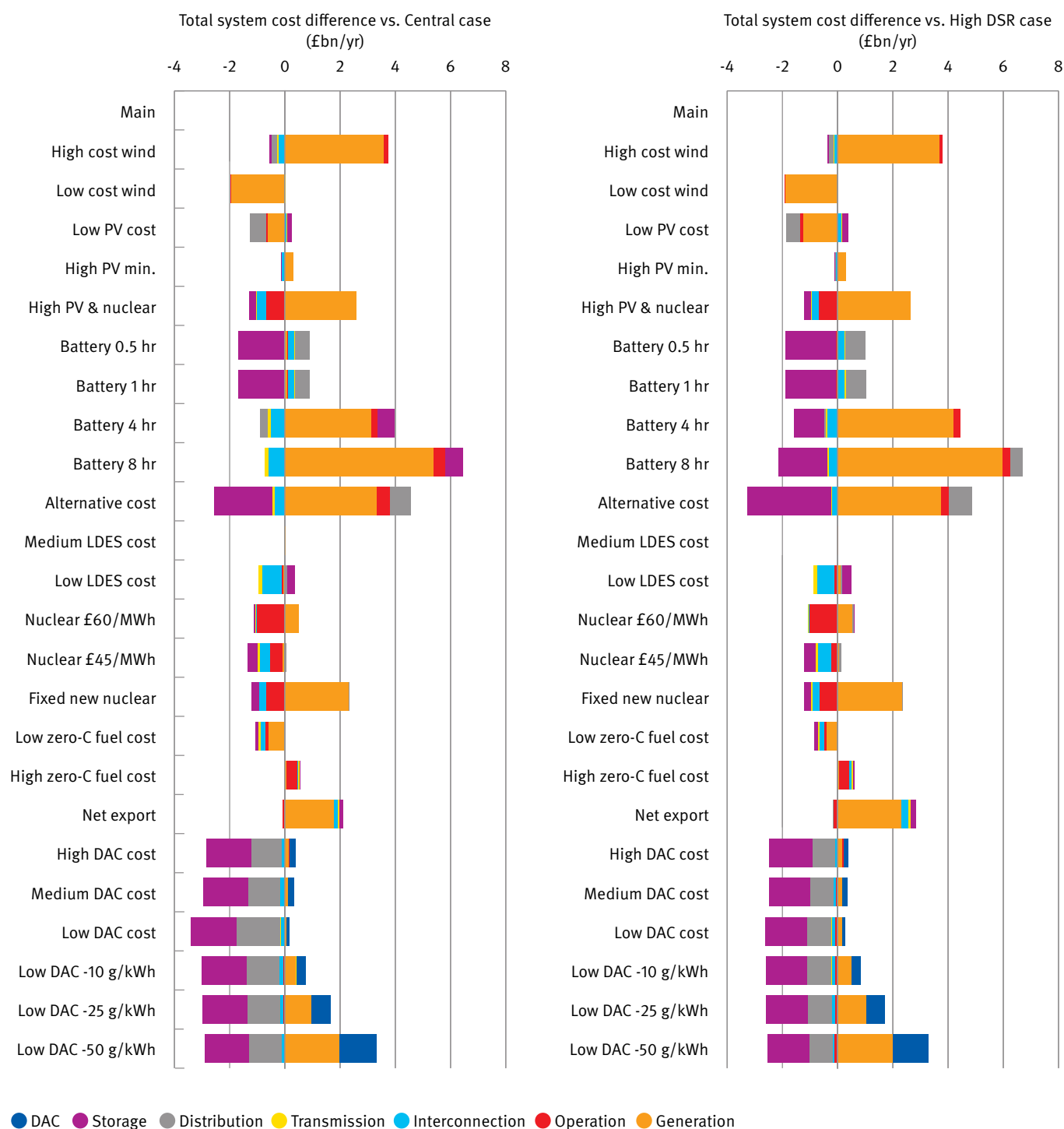
The analysis of DAC presented in this section was with the assumption that HHPs use electricity and unabated gas to supply heat. The effect of that assumption with a net-zero carbon objective was that HHP were, in effect, prevented from using gas unless carbon offsetting was available. Another batch of sensitivity studies (not presented here) was run to evaluate the need for DAC if HHP systems had access to zero-carbon gas (e.g. biogas or hydrogen) alongside electricity. This would allow the HHP to arbitrage between two zero-carbon energy vectors. In the net-zero cases, this form of HHP led to the optimiser choosing not to add any significant DAC capacity. In the net-negative carbon cases, however, the optimiser still deploys similar amounts of DAC as in the earlier cases in this section because the key driver to deploy DAC is to turn a largely net-zero electricity system negative.

³⁶ There are other technologies that could deliver net-negative carbon emissions such as Bioenergy with Carbon Capture and Storage (BECCS), however they were not included in the scope of this analysis. As a very rough estimate, reaching -50 gCO₂/kWh, i.e., offsetting carbon emissions of around 30 mtCO₂/yr using BECCS generation rather than DAC, would require building around 5.5 GW of BECCS capacity (assuming 90% utilisation of generation capacity and 90% carbon capture rate).

5.10. Summary of variations in total system cost across cases

The total system cost for each variation of technology cost or other assumptions has been compared to the base cases and summarised in Figure 5.15. Results are shown for the central and high-DSR version of the base case. Negative changes mean that the variation produced a lower total cost than the base case. The graphic illustrates how the cost difference is composed of differences in all of the component investment costs in: i) generation, ii) interconnection, iii) transmission, iv) distribution, v) storage, and vi) DAC capacity, plus the corresponding operating cost of electricity generation.

Figure 5.15. Variations in total annual GB system cost across different case studies from main Central (left) and High DSR (right) cases



The following main observations can be made from these results:

- Assuming a higher LCOE of offshore wind, up approximately 14% from £35/MWh to £40/MWh, results in a total system cost increase of £3.2–3.4bn/yr, which is approximately a 10% increase on the total base case cost of £32bn/yr. Since offshore wind made up 35% of the generation capacity in the main case (108 GW of 290 GW in Figure 3.1(a)), it is to be expected that an increase in the cost of this technology increases system cost unless the cost change is enough to cause significant substitution of another technology. The installed capacity of offshore wind reduced only a little with some substitution by higher-cost PV. The converse applies for reduction in the LCOE of offshore wind to £30/MWh, which leads to a reduction in system cost of about £2bn/yr. This is almost entirely a feed-through of a reduced capital cost with no significant changes in installed capacities of the various technologies.
- Assuming a very significantly reduced cost of solar PV generation to below that of offshore wind, down from £50/MWh to £20/MWh, decreases the total system cost but by only £1–1.5bn/yr. This is a smaller reduction in system cost than seen with the small reduction in offshore wind cost to £30/MWh, indicating that the cost of PV has a weak influence on the system cost in GB. Further evidence of weak influence on total system cost comes from the case where higher than optimal PV capacity (at the original cost assumption) was locked-in to the optimiser's starting assumptions. This was seen to increase the system cost by only £0.2bn/yr. On the other hand, if the suboptimal PV capacity is combined with 10 GW of new nuclear capacity locked in at the LCOE of £75/MWh, the total system cost increases by £1.3bn/yr or 3.3%.
- Increasing the power-to-energy ratio of battery energy storage (while holding the cost per unit energy constant but decreasing its duration) reduces system cost by £0.8–0.9bn/yr, indicating that high power capacity, short-term storage has system value and this was reflected in an increase in the deployed capacity of storage in terms of power capacity. Confirmation comes from the converse case, longer-duration storage (at the same energy cost and therefore lower power), which increased the system cost by £2.9–5.7bn/yr and was accompanied by an increased capacity of fast-acting zero-carbon fuelled generation (OCGT).
- Long-Duration Energy Storage (LDES) at the medium cost assumption (£80/kWh, which is less than half the cost of short-term battery storage at £187/kWh) had very little impact on the chosen capacities and therefore no impact on cost. A very low cost of LDES of £4/kWh caused it to substitute about 20 GW of battery storage but reduced system cost by only £0.4–0.6bn/yr.
- The assumption that nuclear power becomes available at a lower cost of £60/MWh (compared to the main case of £92.5/MWh), which might make it attractive compared to renewables, adds 4.5 GW of nuclear capacity and reduces the system cost by £0.5–0.6bn/yr. Further reduction in nuclear cost to £45/MWh added a further 6–11 GW of capacity and further reduced system cost by £1.1–1.3bn/yr. Assuming that prior investments had locked-in an additional 10 GW of nuclear capacity (the volume called for by ESC) and assuming its cost is £75/MWh results in a total system cost that is £1.1–1.2bn/yr higher than the main case.
- Increasing and decreasing by a third the cost assumption for zero-carbon fuel used by CCGT and OCGT had very little effect on the installed capacities and capital costs but has a direct feed through to operating cost, giving total system cost savings of £0.8–1.1bn/yr for the decrease and £0.6bn/yr of additional cost for the increase.
- Removing the constraint that Great Britain should not be a net exporter/importer of electrical energy over a year caused the investment optimiser to add about 20 GW more offshore wind, so that Great Britain becomes a net exporter of 60 TWh of electricity towards continental Europe for the Central case and 70 TWh for the High DSR case. Modest additions to interconnector and storage capacity were also needed, while total system cost increased by £2–2.7bn/yr. Dividing the system cost increase by the net exported volume of 60–70 TWh indicates a unit cost of £33–36/MWh, a cost which would be recovered through sales. Note that the cost of those exports is approximately the assumed LCOE of offshore wind, indicating that the accompanying other changes in CAPEX and OPEX had little impact.

- Adding Direct Air Capture (DAC) to the investment portfolio is seen to deliver savings of between about £2bn/yr and £3bn/yr for the assumed range of DAC investment costs. Its primary role is offsetting emissions from hybrid heat pumps (HHP) that use unabated gas and which otherwise could not form part of a zero-carbon system. The savings in system cost against the main case diminish to about £2bn/yr if a negative carbon intensity of $-10 \text{ gCO}_2/\text{kWh}$ is the target, and further to about £1bn/yr with a target of $-25 \text{ gCO}_2/\text{kWh}$. With a $-50 \text{ gCO}_2/\text{kWh}$ target, the system cost exceeds the cost of the main case by £0.4–0.8bn/yr. In an alternative case where HHPs have access to zero-carbon gas, the investment optimiser does not choose to deploy DAC for the zero-carbon cases and so there is no impact on electricity system cost. If the negative emissions target is then applied, DAC is deployed, adding to the total system cost.

These various technology cost assumptions, and accompanying changes in system configuration and system cost, change the average cost of supplying electricity. The average unit cost of electricity has been obtained by dividing the total annualised system cost by the total annual electricity production. Here, in contrast to the earlier results, an estimate of the cost of the pre-existing transmission and distribution networks has been added to costs of the network reinforcement. Note that the cost of implementing DSR flexibility has not been included because of the absence of firm cost estimates. (Our earlier work (Aunedi and Green, 2020) has shown that DSR remains a valuable system feature for wide ranges of implementation costs.)

The resulting average cost results for Central cases are shown in Figure 5.16, while those obtained in High DSR cases are shown in Figure 5.17.³⁷ The cost figures in the Central cases broadly vary around the level of £80/MWh, which is a moderate value even with today's standards, thanks to projected reductions in cost of variable RES generation and battery storage. Favourable variations in the costs of generation, storage and DAC technologies can reduce this to about £75/MWh, while less favourable outcomes could push the cost towards £90/MWh or even further in some cases. In contrast to today's electricity sector, a noticeable proportion of the electricity cost is driven by the cost of energy storage, which exceeds the transmission cost component and becomes comparable to the cost of distribution networks.

In the majority of High DSR cases, the electricity cost is about £2–3/MWh lower than in comparable Central cases. This reduction, enabled through increased DSR uptake, should be contrasted to the cost of enabling DSR, which for the reason of lack of reliable estimates was not considered in this analysis.

³⁷ Note that in the Export scenario, the total system cost is divided with the total GB generation rather than total demand. In the DAC scenarios, the electricity demand for DAC operation is not included in the total system demand when calculating the average cost of electricity.

Figure 5.16. Variations in average cost of electricity in the GB system across various Central cases

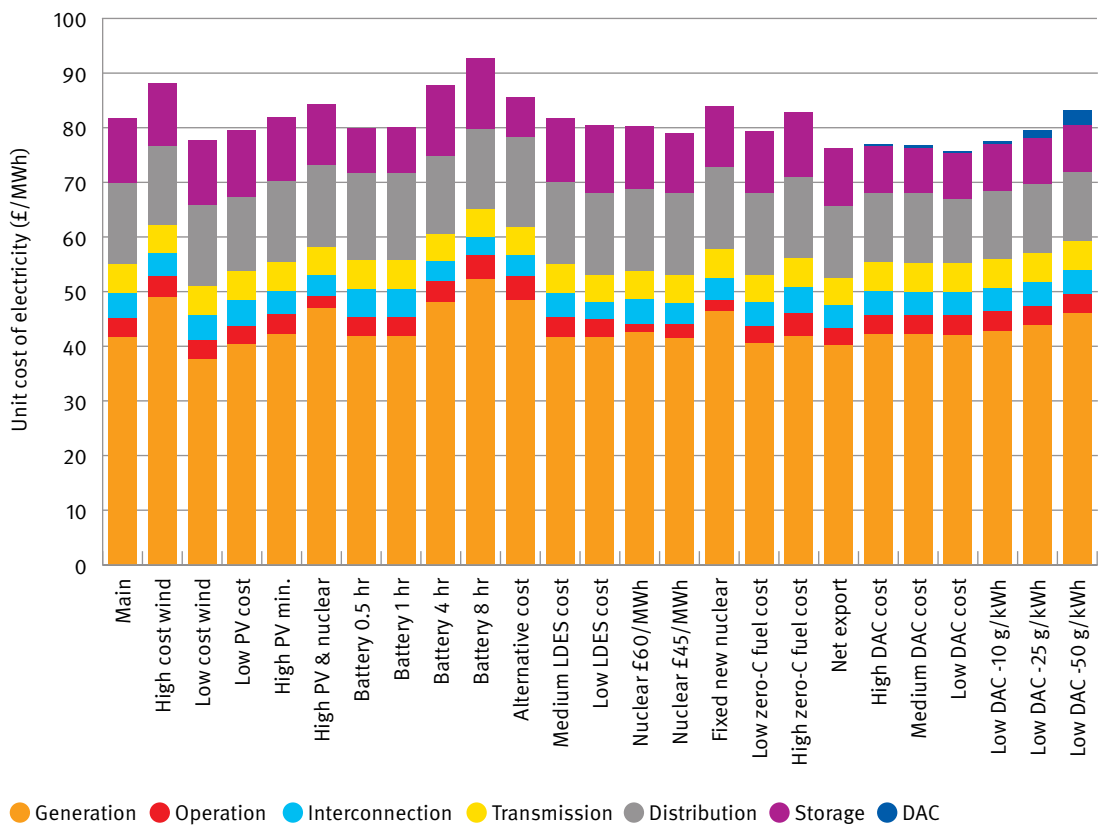
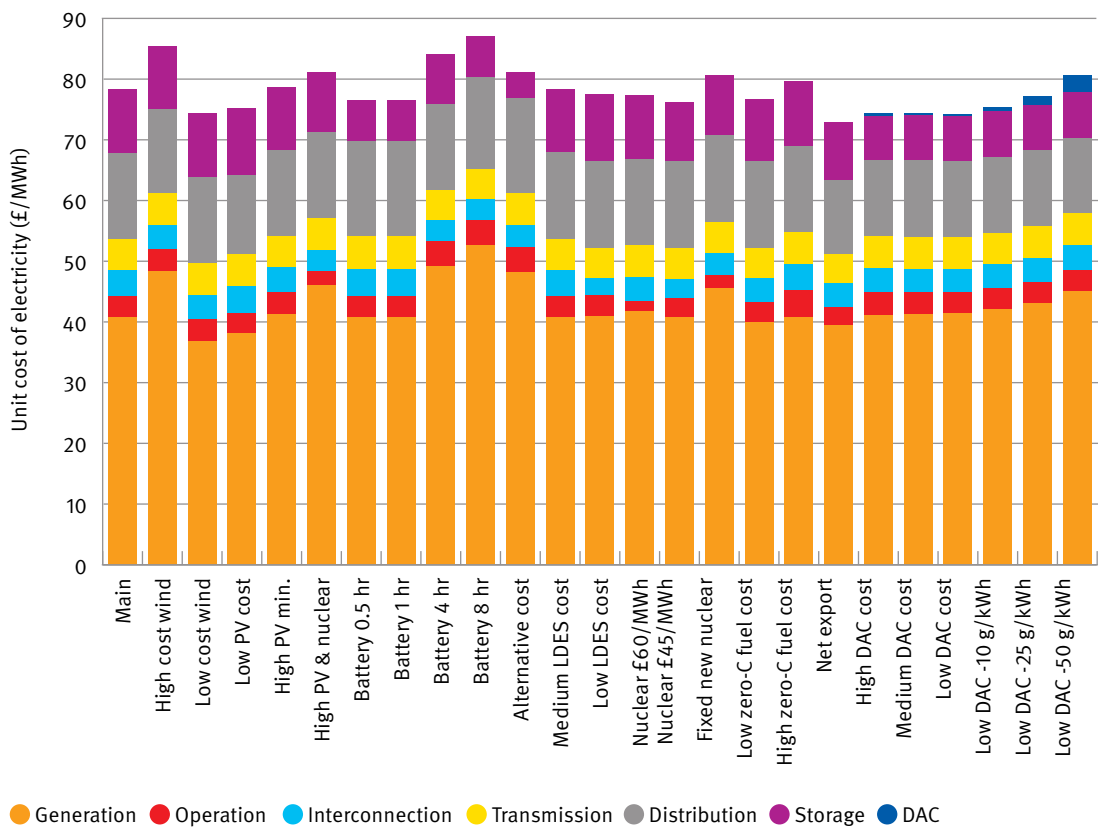


Figure 5.17. Variations in average cost of electricity in the GB system across various High DSR cases



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Data availability

The datasets behind all of the charts in this White Paper are available for [download](#) in an Excel spreadsheet alongside the report.

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