Large-scale electricity storage

POLICY BRIEFING

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Policy briefing

Politics and science frequently move on vastly different timescales. A policymaker seeking evidence on a new policy will often need the answer in weeks or months, while it takes years to design and undertake the research to rigorously address a new policy question. The value of an extended investigation into a topic cannot be understated, but when this is not possible good evidence is better than none.

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This briefing draws on the Royal Society's report on *Large-scale electricity storage*. The full report is available to view online at: **royalsociety.org/electricity-storage**

Large-scale electricity storage
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Executive summary

The UK Government has a stated commitment "to have all electricity by 2035 come from low carbon sources, subject to security of supply" and to reach net zero by 2050. As the energy system is decarbonised, electricity will play an increasing role in transport, industry and heating. Electricity will be generated by a range of sources including wind, solar, nuclear and gas with CCS, or imported using interconnectors. An increasing fraction will be provided by wind and solar, which already provide over 30% and are the cheapest form of low carbon electricity generation. They are, however, intermittent and will therefore have to be supported by storage and/or flexible supply.

This policy brief considers the role large-scale electricity storage will need to play in a GB electricity system supplied largely by wind and solar. The analysis of the amount and type of storage that will be needed allows for baseload nuclear power or gas with CCS. Ultimately, the optimum mix will depend on costs, security and sovereignty of supply and the level of carbon and methane emissions considered acceptable. Resilient planning assumptions will need to be made to reach net zero by 2050 cost effectively.

The need for storage and how it can best be provided depend on local factors, including the demand profile, the weather and climate, and the potential storage technologies and available sites. While this brief focusses on GB, the methodology and the conclusions on storage technologies are applicable elsewhere.

The potential for wind and solar generation in GB exceeds projected future electricity demand but it must be supported by large-scale storage or other forms of flexible supply when the sun doesn't shine and the wind doesn't blow. If surplus wind and solar supply is harvested and stored, energy security is improved. The cost of large-scale storage compares favourably with the cost of low-carbon alternatives.

Wind and solar supply can vary on timescales from seconds to decades. A study modelling solar and wind generation using 37 years of weather data found variations in wind supply on a multi-decadal timescale, as well as sporadic periods of days and weeks of very low generation potential. For this reason, some tens of TWhs of very long-duration storage will be needed. For comparison, the TWhs needed are 1000 times more than is currently provided by pumped hydro, and far more than could be provided cost-effectively by batteries. The need for such a large amount of energy storage is only apparent when weather patterns are analysed over several decades. Studies that look at a sample of individual years, rather than a sequence, seriously underestimate the need for storage, and conversely overestimate the need for other forms of supply.

Large-scale electricity storage systems are characterised by:

- the size and cost of the storage facility;
- the cost and rate of converting energy to the form in which it is stored;
- the cost and rate at which stored energy is converted back to electricity; and
- the conversion efficiencies and leakage.

A range of storage technologies is discussed here. Three were used to model the impact of storage on the cost of electricity: green hydrogen (which was found to be the leading option for long-term storage in GB), compressed air and Lithium-ion (Li-ion) batteries.

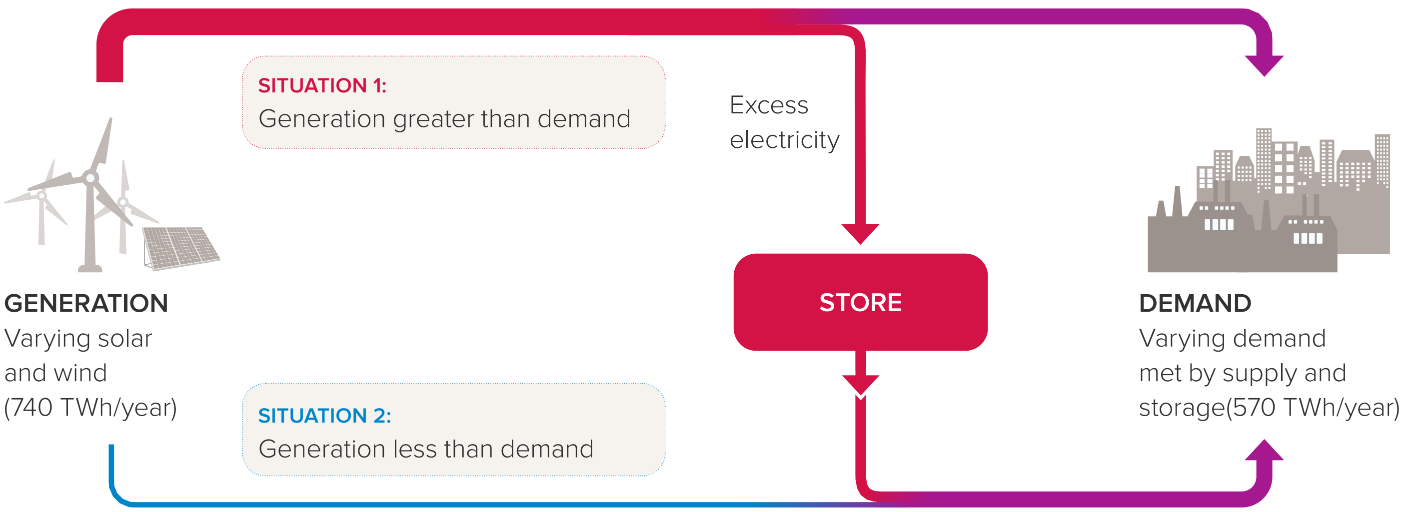
Hydrogen can be stored at scale in solution-mined salt caverns, for which GB has a much more than adequate potential, albeit not widely distributed. In addition to large-scale storage, some fast response storage is needed to regulate grid voltage and frequency. This function, which is costed assuming that it is provided by Li-ion batteries, takes little energy and has a negligible impact on other storage needs. Compressed air energy storage could not provide the essential large-scale long-term storage provided by hydrogen. However, adding compressed air would reduce the scale of the hydrogen storage that will be needed and would likely lower the overall cost.

The demand for electricity in Great Britain in 2050 is taken to be 570 TWh/year in this briefing, roughly twice current annual demand. Modelling finds that meeting this demand cost-effectively with wind and solar supply supported only by hydrogen storage (and some batteries) would require a supply of between 740 TWh/year and 800 TWh/year and correspondingly, a storage capacity (including contingency) ranging from around 123 TWh capable of delivering 85 TWh/year (with 740 TWh/year supply), to 76 TWh capable of delivering 76 TWh/year (with 800 TWh/year supply)[1]. The average cost of electricity varies very little over this range: the cost of wind and solar supply rises as its level increases, but this is offset by the decreasing size and cost of the storage that is needed. Figure 1 illustrates how an electricity store would operate.

FIGURE 1

Energy store operation.

Demand must always be balanced by generation and / or storage.



1 This is the thermal energy content of the stored energy expressed in terms of the Lower Heating Value.
Glossary available as part of the *Large-scale electricity storage report*, available at royalsociety.org/electricity-storage

With only wind and solar supply, supported by hydrogen storage and batteries for grid stabilisation, the average cost of electricity fed into the grid in 2050 ranges from £52 /MWh to £92 /MWh (in 2021 prices), depending on assumptions for the future cost of storage and of wind and solar power, and the discount rate used. The overall average cost is dominated by the cost of the wind and solar supply.

Combining compressed air with hydrogen storage is likely to lower the overall cost, although this is not assured. Li-ion batteries and / or some other form of storage that can respond very rapidly will be needed to provide the rapid response to deal with very short-term fluctuations in supply and demand.

Evaluating the need for hydrogen for large-scale electricity storage together with other uses for green hydrogen would almost certainly reveal systems benefits that would lower costs.

This briefing considers the effect of adding nuclear, and gas generation equipped with carbon capture and storage. However, the modelling used does not take account of continuing contributions from burning waste and biomass, hydropower and interconnectors, or the relative locations of supply, storage and demand, and their implications for the grid.

It is clear that in GB wind and solar supply varies by large amounts over time scales of decades. In an electricity system largely supplied from those sources, there will therefore be a need to store large amounts of energy (tens of TWh). The large-scale of the storage that will be needed in the net zero era must be taken into account when designing a decarbonised electricity system. While detailed predictions of what will be required will evolve as costs are better understood, the need for large-scale storage in a genuinely net zero system will remain.

Much of the required storage will have to be provided by hydrogen. Constructing the required infrastructure by the net zero target date of 2050 modelled in this report will be challenging. Action needs to start now and, by implication, any ambition to achieve a fully decarbonised grid by an earlier date will be even more challenging.

This briefing draws on the Royal Society's report on *Large-scale electricity storage* (hereinafter referred to as the report). The full report and references can be found on the Royal Society website.

Introduction

The report focuses on the need for large-scale electricity storage to maintain a stable power supply system in Great Britain when power is predominantly provided by wind and solar, and how and at what cost storage needs might best be met. This depends on local factors, including demand, weather and climate, and the availability of storage sites. The methodology that was used and the conclusions on storage technologies are however generally applicable.

Reducing greenhouse gas emissions to net zero will require major changes in generation and consumption. Fossil fuels will have to be replaced in providing industrial process heat, space heating and transport. This will require greater electrification, and hence a large increase in electricity supply. It is generally expected that, as the UK moves towards net zero, an increasing fraction will be provided by wind and solar generation, which are the cheapest forms of low-carbon generation. The potential for solar and wind generation capacity in the UK exceeds the country's future electricity needs.

1.1 GB electricity supply

1.1.1 Supply

Generation currently comes from sources which include gas, nuclear, solar and wind. A national transmission grid supplies electricity to a distribution network to homes and businesses. Supply must always meet demand to keep the system working. Demand varies by time of day, and the weather. Fossil fuel generation is currently used to balance wind and solar supply and demand. Box 1 shows the type and scale of energy stores the UK held in 2019 for all energy uses (electricity, transport, heating etc).

BOX 1

Energy Stored in the UK in 2019[2]

Fossil fuels on average stored:

- 35 TWh – coal (falling)
- 18 TWh – gas (9 average days' supply)
- 160 TWh – crude oil and petroleum products (not used to generate electricity)

Supported by:

- Pumped hydro – 30 GWh capacity
- Hot water tanks – 40 GWh
- Grid connected batteries – 1.8 GWh
- 320 Kt biomass at Drax power station → 560 GWh electricity

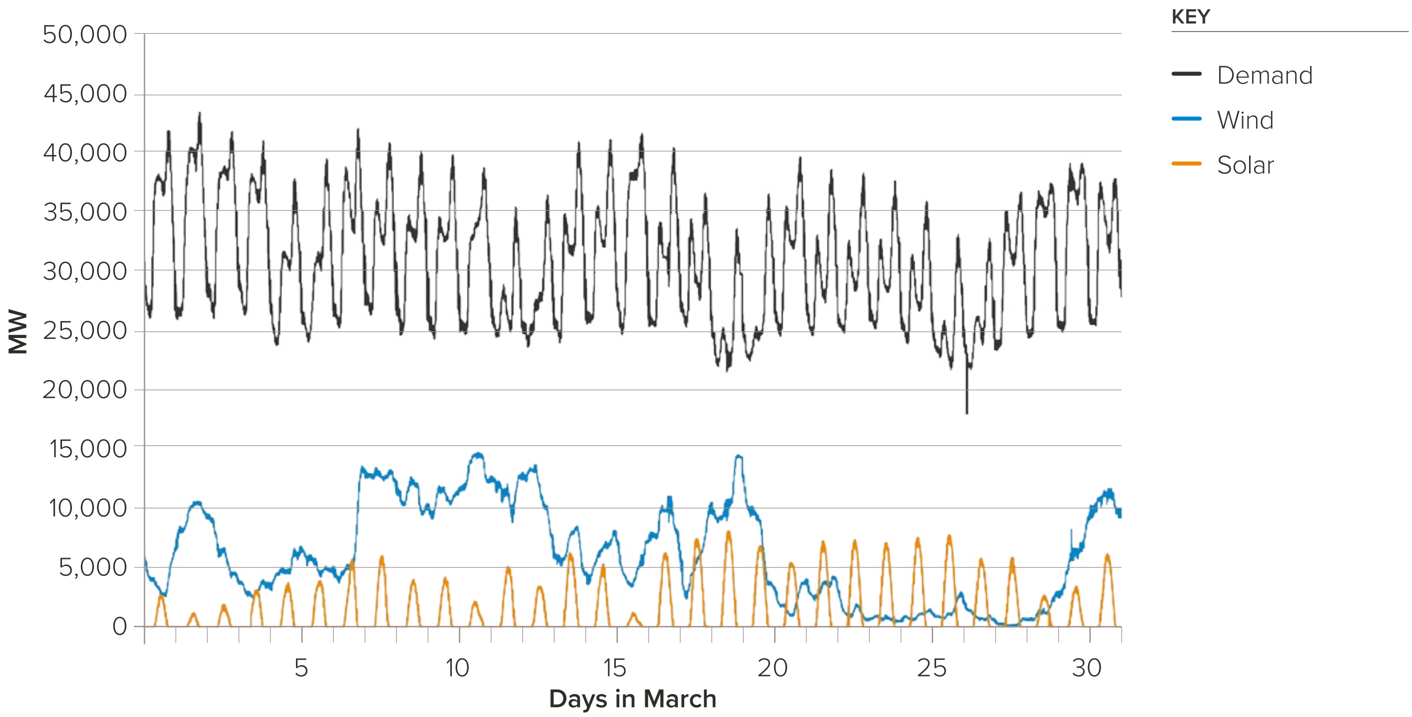
Wind and solar generation are highly intermittent and variable due to the weather, the diurnal cycle, and the seasons, and the variation is highly unpredictable (see Figure 2a). The more power that is supplied by wind and solar, the greater the probability of a disparity between supply and demand. Figure 2b shows periods of surplus generation and of unfulfilled demand that would occur in a month assuming four times the wind and twice current solar generation; March 2022 was modelled here. The deficits could destabilise the electricity grid, leading in the worst case to complete failure and blackouts. This can be overcome by putting in place energy storage, deploying flexible low carbon generation or importing electricity.

2 Figures for 2019 compiled from the Digest of UK Energy Statistics (DUKES), Energy Trends (UK gas) and the Renewable Energy Planning Database (GB only). The year 2019 was chosen to be representative of UK energy storage prior to COVID-19 and recent international energy market instabilities.

FIGURE 2

Variable UK demand and the variable output from solar and wind generation for March 2022.

A) Note that demand is lower at weekends and at night. Similarly, the day / night cycle is obvious in solar supply but note that the wind blows strongly on some days and weakly on others.



B) Theoretical times of surplus (supply > demand) and deficit (supply < demand) solar / wind supply if the March 2022 demand had only been met with four times as much wind and twice as much solar generation.

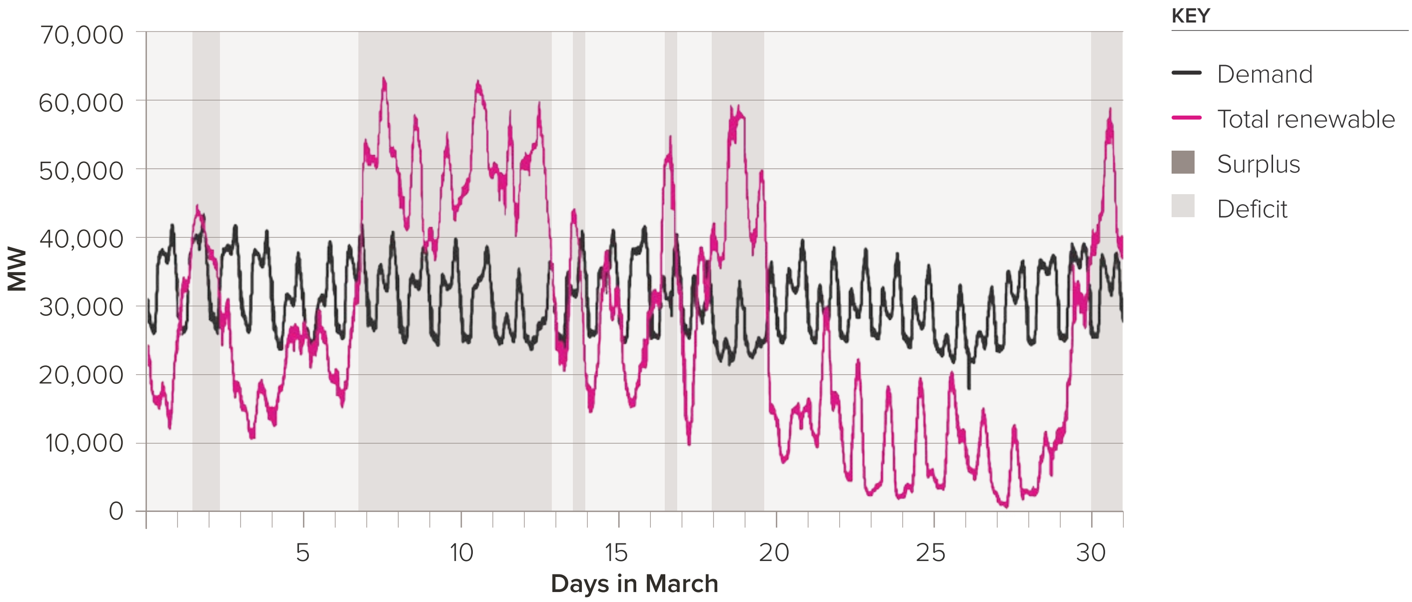
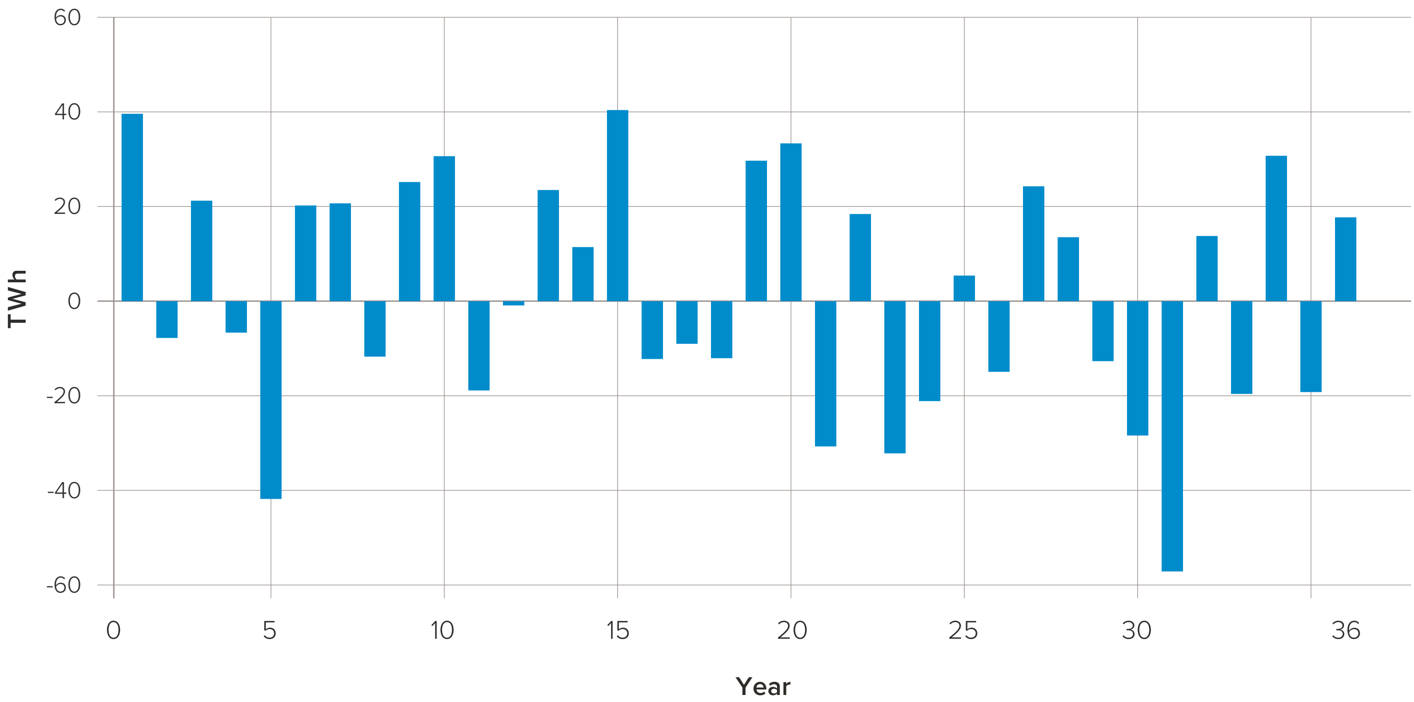


FIGURE 3

The difference between demand and wind plus solar supply.

Based on actual hour-by-hour weather data in the years 1980 – 2016, scaled to average 570 TWh/year (with 80% wind and 20% solar), and a model of GB demand of 570 TWh/year. Years April to March are used in order to include contiguous quarters 3 and 4 and not dilute the effects of severe winters.



The scale of the need for storage, or other forms of flexible supply, is set by long-term variations in wind supply. Figure 3 shows the annual deficits in the period 1980 – 2016 found with real weather and an hour-by-hour model of 2050 demand kindly provided by AFRY. In order to use storage to fill the deficits in years 29 to 31, it would be necessary to store energy for decades. Studies of shorter periods seriously underestimate the need for storage. Contingency is included in the modelling to allow for variations not seen in this period.

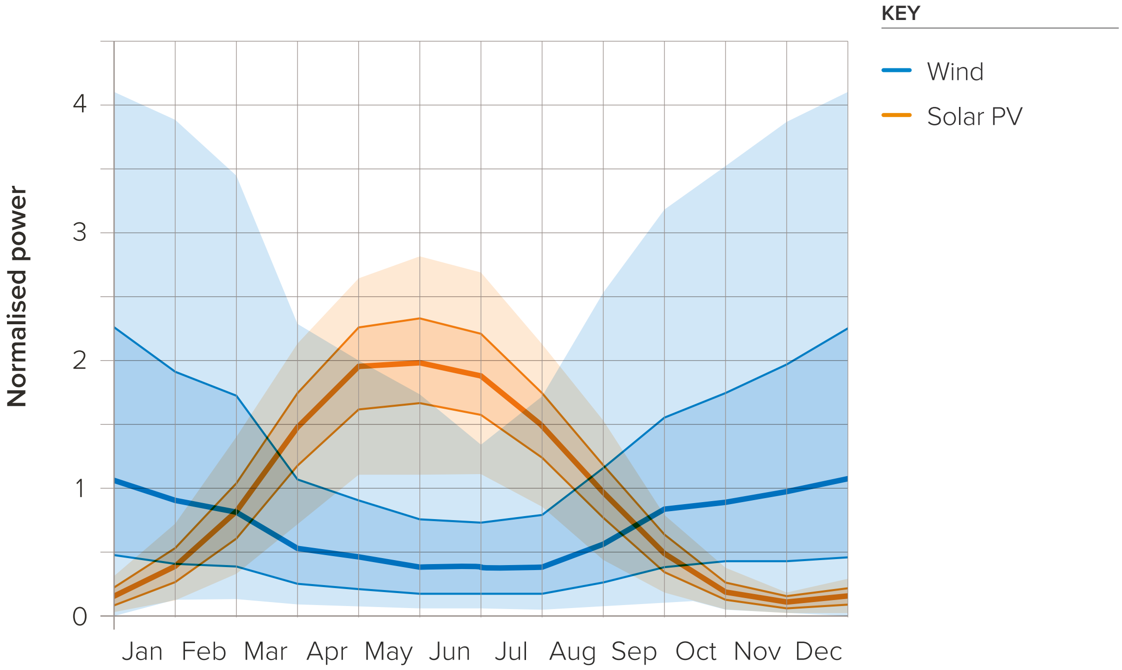
1.1.2 Weather, wind and sun, and temporal and spatial variation

The mean solar and wind power across a grid covering the landmass of GB is shown in Figure 4. The different profiles of solar and wind power are complementary and, as shown later, an appropriate mixture can, on average, roughly match the seasonal profile of demand. While the average wind power generation varies less than average solar power generation across the year, the year-to-year variability of wind, which dominates the mixture, is greater than solar variation in all months, and will dominate the design of GB's energy supply.

FIGURE 4

Distribution of daily mean wind and solar PV power output in each month in 1979 – 2013 scaled to their averages.

The lines and shading indicate the medians, the 25th and 75th percentiles and the 5th and 95th percentiles of the daily data.



Source: Met Office.

TABLE 1

Extreme weather events.

Stress events	Description	Frequency
Summer wind drought – frequent	One full day of very low wind speed in summer.	One or two per year
Summer wind drought – infrequent	Up to four weeks of very low wind speed in summer.	Once every 10 years
Winter wind drought	Up to a week of very low wind speed in winter.	Every few years

Infrequent but extreme weather can have a major impact on systems that rely heavily on wind and solar power. GB's electricity system will be affected by the three types of extreme weather events described in Table 1. These events were identified in a study based on historical data and modelling.

Winter wind droughts occur when wind speeds over the North Sea are low. These pose the biggest challenge to very high renewable systems because they coincide with cold air over many parts of central and Northern Europe, resulting in high energy demand.

As the distance between wind and solar farms increases, their outputs become less correlated. Connecting farms in distant locations can therefore reduce the short-term variability of supply. At a large scale, stronger electricity interconnectors across Europe would smooth weather-driven generation fluctuations in high wind power regions in Northern Europe and high solar power regions in Southern Europe, and transitory high and low wind patterns in Western and Eastern Europe. However, although temporally averaged correlations fall with distance, the weather in different parts of Europe is linked. Imports to GB are vulnerable to pan-European wind droughts and cold periods, water shortages, and political factors. It would therefore be wise to design a GB system that would cope when imports are not available. Contributions from interconnectors are therefore not included in the modelling in the report.

1.2 Characteristics of low-carbon sources of power

The only low-carbon sources that could meet a significant fraction of demand, other than wind and solar, are nuclear, gas with carbon capture and storage (CCS), and bioenergy with or without CCS (BECCS). Their characteristics are shown in Table 2. All are expensive or very expensive if operated flexibly to complement fluctuations in supply and variations in demand.

TABLE 2

Attributes of complementary sources of electricity.

Costs from BEIS (2020) are for plants commissioned in 2040, except for nuclear which is from BEIS (2016) for reactors commissioned in 2030.

Low carbon options	Cost of power – £/MWh	Flexibility	Environmental credentials	Comments
Nuclear	66 – 99 with 90% load factor (LF)	Expensive to run flexibly: best as baseload. Cost (63 + 17.5 / LF) = £78/MWh if LF = 90%	Good	Cost very sensitive to discount rate. Small Modular reactors could be cheaper.
Gas with Carbon Capture and Storage	79 – 85 with 92% LF assuming gas costs £21.8/MWh	Expensive to run flexibly: best as baseload. Cost (62 + 18.4 / LF) = £82/MWh if LF = 92%	Compromised by leaked methane and fugitive CO_2 emissions	
Bioenergy with CCS	182 – 211 for post combustion capture[f], with 90% LF	Best run as baseload as it is: i) expensive (if not supported by carbon credits); and ii) carbon negative	Negative emissions if biomass carefully sourced	Availability of biomass limits GB potential to some 50 TWh_e/year (without imports).
Hydropower	75 for large-scale hydro	Good	Good depending on site	Potential limited in GB. Delivered 5.5 TWh_e in 2021 (including 1.8 TWh_e from pumped hydro).
Biomass	90 – 105 dedicated biomass	Characteristics are different for plant mass (which contributed 27.1 TWh in 2021), and biodegradable waste, landfill gas, anaerobic digestion etc (which together contributed 8.79 TWh)		

Matching demand and direct wind and solar supply

Electricity demand is expected to increase in the future, by an amount that will depend on the degree of electrification of heat, transport, and industrial processing, increases in the use of air conditioning, improvements in efficiency, economic growth, changes in population and changes in behaviour.

Figure 5 shows the elements of the electricity network. Basic demand, modelled in this work, does not include transmission and distribution losses, in contrast to customer demand as defined by the National Grid. Both exclude the demand for electrolytic production of hydrogen, for storing electricity (which is considered to be part of supply) and for other purposes.

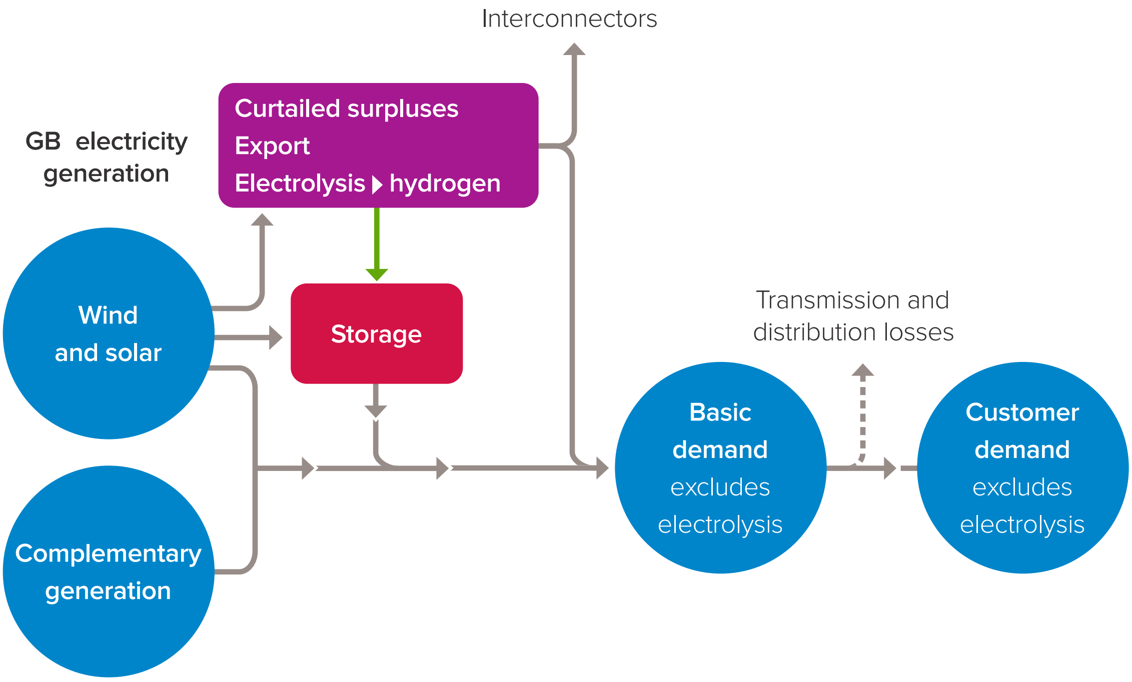
Co-production of hydrogen for other uses would almost certainly reduce the cost of using hydrogen to store electricity. All uses should be modelled together, but this is currently impossible as estimates of the demand for green hydrogen vary very widely.

Basic GB demand is assumed to be 570 TWh/year in 2050. This is the level in the AFRY hour-by-hour profile that was used in modelling storage which is based on the weather in 2018. It comprises a base contribution of 355 TWh with 96 TWh for heating, and 119 TWh for electric vehicle (EV) charging.

FIGURE 5

Elements of the electricity network

Storage includes all types (batteries, compressed air, liquid air etc) except off-grid storage. Off-grid generation is also not shown.



The future role of energy storage depends on the level and profile of demand, the variability of wind and solar supply, the potential complementary supply, and the scope for managing demand, which must be considered in the context of the whole electricity system. These factors are considered in turn here.

2.1 Inputs for modelling the need for storage

To quantify the need for large-scale energy storage, an hour-by-hour model of wind and solar supply was compared with an hour-by-hour model of future electricity demand. A model of 2050 demand kindly provided by AFRY management consultants was used. Supply was modelled using Renewables.ninja (R.N) simulations of power output from wind and solar power plants for 1980 – 2016, which was the largest and longest data set available when this work was carried out. These simulations are based on historical satellite weather data.

Two caveats apply to the use of weather data for 1980 – 2016:

1. A study by the Met Office found that this period does not provide a fully representative sample of weather events. There is approximately a 10% chance per decade of a winter month with wind speeds lower than in the period studied. This uncertainty is accommodated by adding a 20% contingency to the size of the hydrogen store.
2. Climate change will lead to changes in the weather. The scale of projected changes in wind speed and solar irradiance due to climate change differs between models and is highly uncertain. It is hoped that this uncertainty will be accommodated by the contingency included in the size of the hydrogen store. This hope is encouraged by modelling which finds that year-to-year variability of wind (and, to a lesser extent, solar), which is expected to continue at today's level, will have a bigger impact on electricity supply than climate change.

In the report it is assumed that on- and offshore wind outputs are mixed 30:70, and that wind and solar are mixed 80:20. An 80:20 mix maximises the solar and wind power that can be used to meet demand directly. The maximum is not very sensitive to the mix for values between 70:30 and 90:10, nor, it turns out, is the cost of electricity found by modelling. This is reassuring since the mix will be influenced by other factors, such as planning permissions and the appetite of investors.

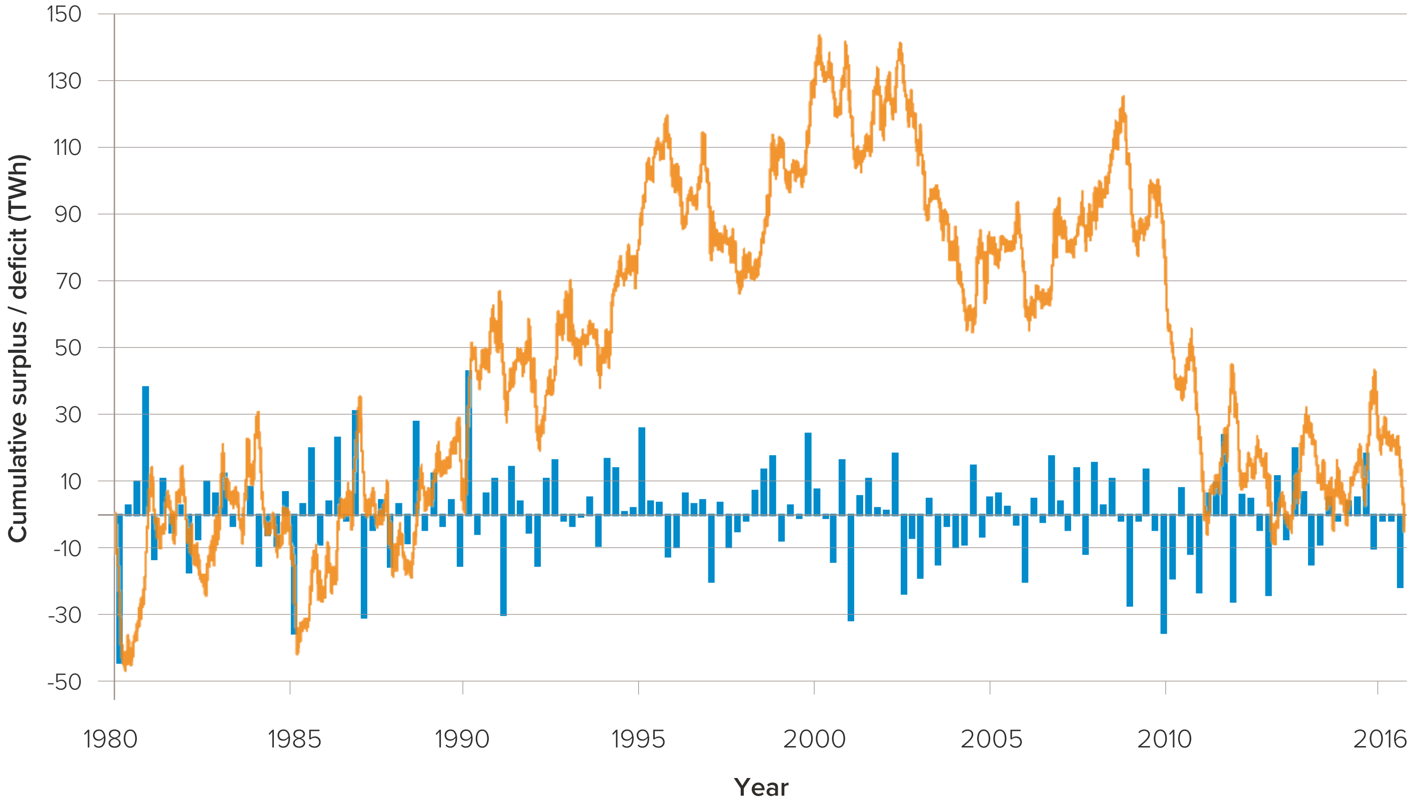
2.2 Surpluses and deficits

Figure 6 shows the cumulative difference between supply and demand in each quarter and over the 37 years studied. The large variation from year to year, which is strikingly manifested in the very large value reached by the cumulative total in the middle of the period, shows that studies of single years or even decades will generally give misleading results.

FIGURE 6

Cumulative differences between supply and demand 1980 to 2016.

Obtained by combining the AFRY and R.N models. with the AFRY model of hour-by-hour demand of 570 TWh/year and wind plus solar supply (mixed 80 / 20) scaled to average 570 TWh/year over 37 years.



KEY

- Quarterly cumulative total
- Cumulative total

Energy storage technology options

3.1 Key features of energy storage

The storage and supply of any material depends upon:

- the size of the storage facility;
- how quickly it can be filled;
- how quickly it can be discharged; and
- how much is lost in-to-out – due to inefficiencies and leakage.

Electricity stores are characterised by:

- the rate of energy conversion from electricity to the stored energy form;
- the size of the store;
- the rate of conversion back to electricity, which has to be sufficient to meet demand; and
- the overall efficiency from electricity to an alternative form of energy and back to electricity.

In storing energy as hydrogen, for example, the electrical energy is converted to chemical energy (hydrogen) by electrolysis, held in a cavern under pressure and then converted back to electricity using full cells, four-stroke engines, or possibly turbines. The electrolysers and fuel cells / four-stroke engines control the rates of filling and emptying, and their efficiencies (plus any leaks from the store, which are expected to be relatively small in the case of hydrogen storage) give the overall 'round-trip' efficiency.

3.2 Hydrogen

3.2.1 Properties of hydrogen

Hydrogen is a highly reactive gas at room temperature and is highly explosive in the presence of oxygen at a wide range of concentrations. Its use in GB is subject to stringent controls.

FIGURE 7

Bulk storage of hydrogen.

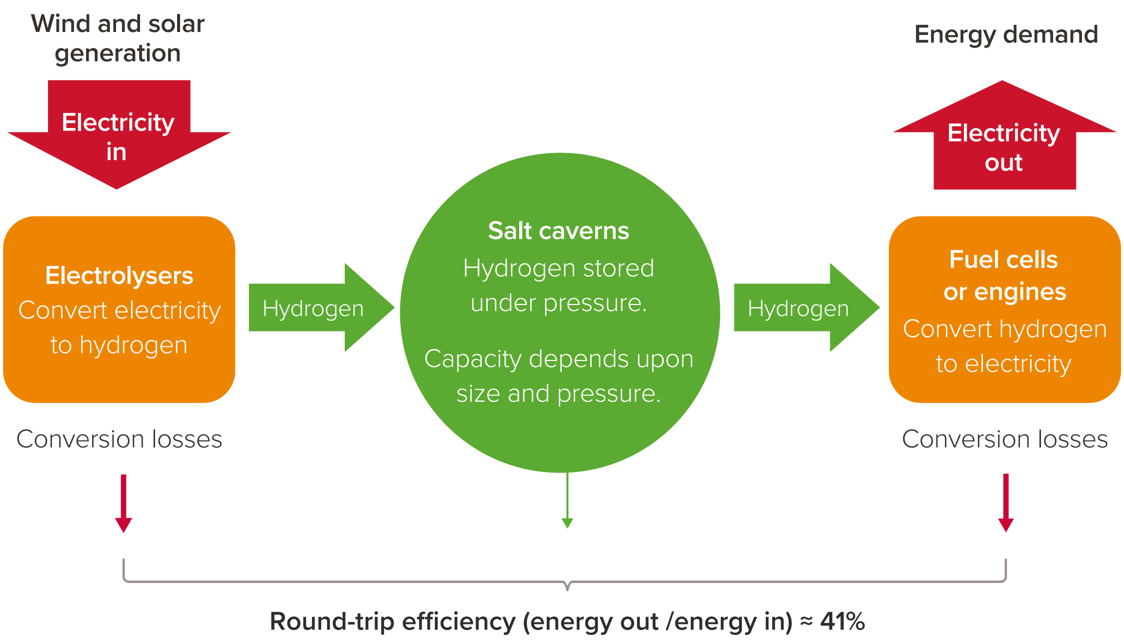


TABLE 3

The main hydrogen electrolyser technologies – strengths and weaknesses.

Electrolyser technology	Alkaline	Polymer Electrolyte Membrane	Solid Oxide
Technology stage	Commercially available for many years.	Commercially available but potential for improvement.	Not yet demonstrated at scale.
Flexibility to follow supply	Can follow.	Can follow very fast transients less than one second.	Ability depends on the design.
Efficiency today	43 – 70%	40 – 67%	61 – 81%
Estimated efficiency 2050	70 – 80%	67 – 74%	77 – 90%
Cost today $/kW	500 to 1400	700 to 1800	2000 to 5600
Estimated future cost 2050 $/kW	200 to 700	Less than 200 to 900	Less than 300 to 1000

Low-carbon hydrogen can be made by splitting hydrocarbons such as methane and capturing as much as possible of the resultant CO_2 ("blue" hydrogen) or through the electrolysis of water ("green" hydrogen). The physical properties of hydrogen makes it much harder to transport and store than petroleum or natural gas. It is generally stored either at high pressure (above 350 bar) or as a liquid at very low temperatures (-252°C). Liquefaction of hydrogen requires large amounts of energy input.

3.2.2 Hydrogen as an energy store

In order to store excess electricity, electrolysis is used to produce hydrogen, which is later converted to electricity using fuels cells, engines or turbines. There are three electrolyser technologies, each with their own advantages and disadvantages (see Table 3).

As the storage of hydrogen requires either extremely low temperatures or high pressures, bulk storage at the TWh scale is only likely to be practical at high pressure in large solution-mined salt caverns. These caverns are widely used, in GB and elsewhere, to store natural gas. Three large caverns have been used in Texas for many years to store hydrogen, and three smaller (70,000 m^3) hydrogen storage caverns have been in use in GB since 1972. The British Geological Survey has estimated the potential storage capacity in three regions: Cheshire, Wessex and East Yorkshire alone. As an example, there are more than 3000 potential cavern locations in East Yorkshire alone that could each store 122 GWh of hydrogen. This equates to about 366 TWh, approximately three times what GB will need to store electricity if only hydrogen storage is deployed and wind and solar are the only sources of supply.

3.3 Ammonia

Ammonia (NH_3) is a gas at room temperature, possessing a higher volumetric energy density than hydrogen. It is much more easily liquefied than hydrogen. Its predominant use is in fertiliser manufacture. It can be burnt in air in gas turbines and piston engines to release its energy or fed into fuel cells to produce electricity. In both cases the exhaust products are water and nitrogen.

Ammonia can be synthesised from hydrogen and nitrogen in the Haber-Bosch process. Low-carbon "green" ammonia can be made from green hydrogen. It is often stored as a liquid in tanks at around 10 bar or at atmospheric pressure in large, refrigerated tanks at -30 °C. Although a naturally occurring chemical, it is toxic at high concentrations. Bulk storage and transportation of ammonia is widely practised, though its use is highly regulated.

Making ammonia costs more, and uses more energy, than making hydrogen, from which it is synthesised. However, ammonia is cheaper to store than hydrogen.

3.4 Battery storage

3.4.1 Lithium-ion batteries

Li-ion batteries employ a conventional anode, cathode and electrolyte structure. They have taken over many battery applications and can operate through many charge-discharge cycles. Their costs have also fallen as their use has increased.

Li-ion batteries have created an electric vehicle revolution and larger-scale battery installations (20 to 190 MWh) are providing short term grid balancing services. Vehicle batteries are being increasingly used to provide power to the grid when the vehicle is not in use. Smaller Li-ion batteries of around 3 to 6 kWh are increasingly being installed in homes to enable solar energy to be stored locally.

Li-ion batteries have a high round trip efficiency. However, although their costs have fallen dramatically, they are very high compared to those of most other forms of storage. Further, there are concerns over the future availability of raw materials as EVs increase in number worldwide. Alternative chemistries, such as sodium-ion, which use cheaper and more abundant materials are being developed, but it may be hard for them to get a large foothold in the lithium-dominated market.

3.4.2 Flow batteries

Redox flow batteries (RFBs), which are widely considered to be one of the most realistic candidates for medium-scale stationary energy storage, are currently at a technology readiness level of 7 – 8. They differ from conventional batteries by using chemicals in two different oxidation states, dissolved in liquids that are pumped through a cell between electrodes on opposite sides of a membrane. The storage capacity, which depends on the size of the chemical tanks (and could be many GWh), is independent of the power that the RFB can deliver.

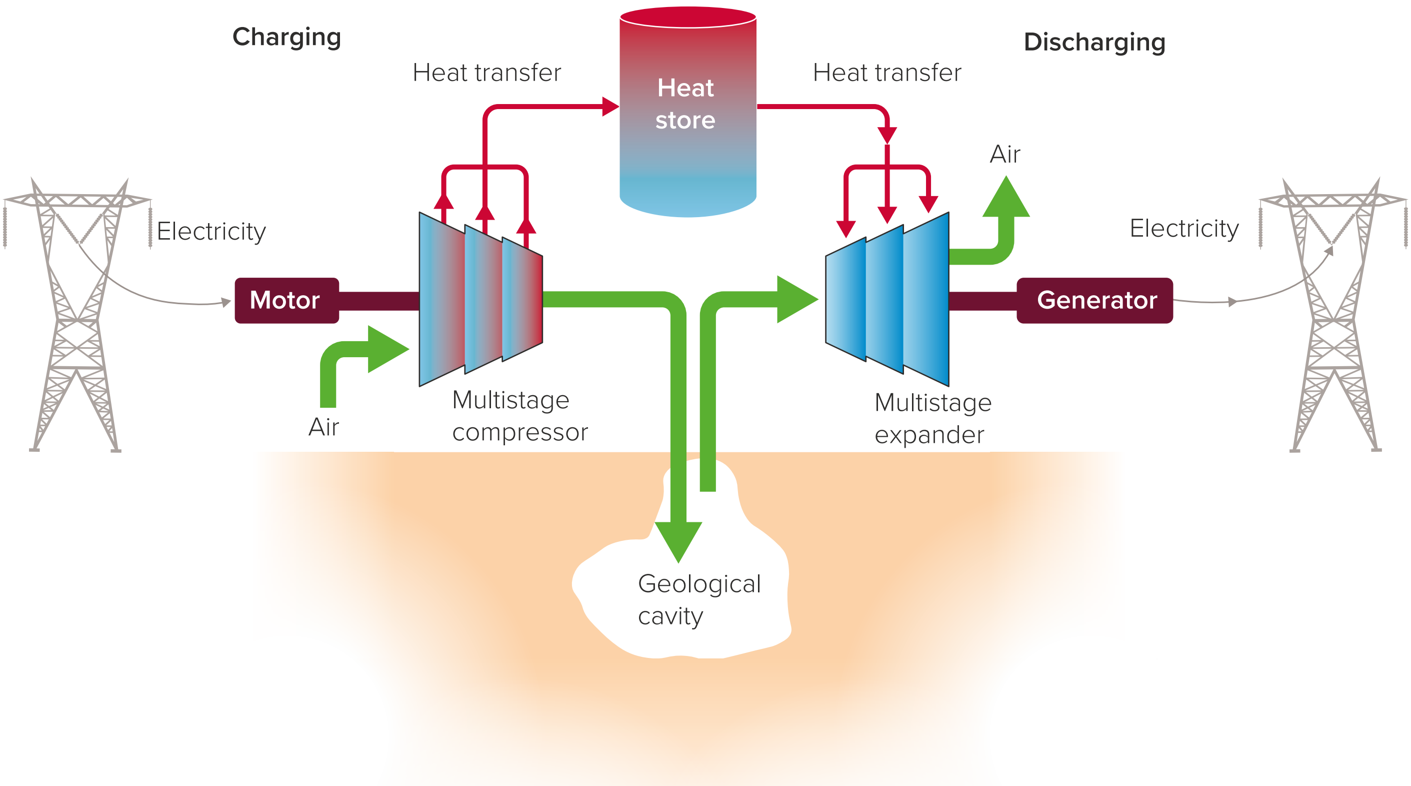
The deployment of RFB systems typically spans kWh to MWh applications, with discharge times of 3 – 5 hours (for example 10 MW, 40 MWh). Historically, applications targeted uninterrupted power supply and load shifting, but there is a growing appetite for large-scale energy storage which leverages the inherent scalability of the technology, with systems approaching 1 GWh in development. Self-discharge is minimal, so longer-term storage is feasible.

Vanadium, which is a key component in many flow batteries, is expensive, and its price is volatile. As flow batteries that use materials that are significantly cheaper than vanadium become available, they could play an important role in grid-scale storage.

FIGURE 8

Advanced compressed air energy storage.

The air is compressed and injected into a cavern and the heat produced during compression is stored. To generate power, the compressed air is heated using the stored heat and fed into an expander / generator set.



3.5 Nonchemical energy storage

There are several options for storing energy in the form of potential or thermal energy.

3.5.1 Advanced Compressed Air Energy Storage (ACAES)

Electricity can be used to compress air, which can be stored in underground caverns in large-scale systems. When expanded back to atmospheric pressure, with heat provided to prevent freezing, the air can drive a turbine and generate electricity. In a net zero system, the heat has to come from a carbon-free source (in the case of Compressed Air Energy Storage, CAES), or from storing and reusing the heat generated when the air is compressed (in the case of Advanced Compressed Air Energy Storage, ACAES) – see Figure 8.

The design and cost of ACAES systems depend upon the size of the cavern, how the heat is stored and the cost of the compressors and expanders. Three grid-connected ACAES plants are now in operation in China. One of which is a 10MWe/100MWhe plant, which has been in operation since September 2021, with air stored in a salt cavern and heat in supercritical water.

3.5.2 Carnot batteries

Carnot batteries store heat at high temperature for later delivery as electrical power provided by a turbine. Relatively small-scale 'pumped thermal energy storage' systems work by transferring heat between cold and hot gravel packed beds. Large-scale can be reached by storing electrically produced heat in rocks. It is possible to imagine a large number of such Carnot batteries providing over 1 TWh of storage in GB. It is expected that they would be one of the cheapest storage options in terms of cost per unit of energy stored. They would, however, be more expensive than hydrogen storage without being very much more efficient.

3.5.3 Liquid air energy storage

Liquid air energy storage (LAES) uses electricity to cool air until it liquefies, which is then stored in a tank. When needed, the liquid air is brought back to a gaseous state using heat from the atmosphere, waste heat, or heat stored during the original compression, and the expanding air turns a turbine which generates electricity. Round-trip efficiency could be up to 55%, depending upon thermal management.

3.5.4 Pumped hydroelectric storage

Electricity is generated when water held in a reservoir is allowed to flow downhill to a second reservoir through a turbine. The water is pumped uphill at times of lower energy demand.

The UK currently has 2.8 GW of pumped hydroelectric storage with a storage capacity of 26.7 GWh. This generated 1.8 TWh of electricity in 2019. A new 1.5 GW, 30 GWh pumped hydroelectric system is planned at Coire Glas in Scotland. The expansion of pumped storage in the UK is limited by geography and that implies that it will only have a marginal impact on GB's need for tens of TWh of large-scale storage to complement high levels of wind and solar.

3.6 Synthetic fuels for long-term energy storage

Energy can be stored in carbon-hydrogen bonds in synthetically produced organic molecules known as 'electro-fuels' (e-fuels) such as e-methane, e-kerosene and e-methanol. E-fuels can be regarded as carbon-containing hydrogen stores, just as ammonia is a nitrogen-based hydrogen store. Synthetic hydrocarbons typically provide the ease of transport and energy density of fossil hydrocarbons, and in some cases can be a drop-in replacement for diesel and petrol. Where they have been produced using CO_2 from direct air capture powered by clean energy, they can be considered to be net zero.

E-fuels can be made by combining green hydrogen with captured carbon dioxide, or with carbon mon- or di-oxide produced by gasification of biomass or waste. E-fuels are expected to play a role in transport – see the Royal Society policy briefing, *Sustainable synthetic carbon-based fuels for transport*[3]. They can be used to store electricity, but it is generally cheaper and more efficient to store the hydrogen used to make them.

3 Sustainable synthetic carbon-based fuels for transport, the Royal Society, 2018. See https://royalsociety.org/synthetic-fuels (accessed 15 May 2023).

Summary of storage technologies

A summary of the energy storage technologies discussed above is given in Table 4, showing the capacity, efficiency and technology readiness of each.

TABLE 4

Large-scale electricity storage technologies.

Technologies for large-scale energy storage. Capacity is defined here as the electrical energy delivered on full discharge.

Technology	Maximum unit capacity	Round-trip efficiency	Technology readiness level[4] and comments
Storage time: minutes to months – limited by need to recover investment			
Non-flow batteries	Largest installation today 3 GWh	Less than or equal to 90%	Lithium-ion – TRL 9; other chemistries at lower TRL.
Storage time: up to weeks, in some cases months			
Flow batteries	Single battery many GWh	70 – 80%	TRL 7 – 8
ACAES	Single cavern. Less than or equal to 10 GWh	Less than or equal to 70%	Compressors, expanders, storage caverns and thermal storage TRL 9. Complete systems 7 – 8.
Large Carnot battery	GWh	45%	TRL 7 with resistive heating.
Pumped thermal energy storage	Less than GWh	50%	TRL 4-6
Liquid air energy storage (LAES)	Less than GWh	Less than or equal to 55%	Systems in operation – TRL 9. Larger / more advanced systems – TRL 7.
Able to provide months or years of storage			
Synthetic fuels	Single large tank Approx 1 TWh	Less than or equal to 30%	TRL 6 – 7. Expected to play a role in transport but outclassed by ammonia and hydrogen for electricity storage.
Ammonia	Single large tank Approx 250 GWh	Less than or equal to 35%	Production and storage – TRL 9. Conversion of pure ammonia to power – TRL 5. More expensive than hydrogen, but deployment is more flexible geographically. May play a role as an imported fuel.
Green hydrogen	Single large cavern. Less than or equal to 100 GWh	Approx. 40%	At grid scale electrolysers – TRL 8, storage caverns – TRL 9; PEM cells -TRL 7 – 8; conversion to power by 4-stroke engines TRL 6 – 7. Potential storage sites limited to East Yorkshire, Cheshire and Wessex.

4 European Commission definitions: TRL 1 – Basic principles observed; TRL 2 – Technology concept formulated; TRL 3 – Experimental proof of concept; TRL 4 – Technology validated in lab; TRL 5 – Technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies); TRL 6 – Technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies); TRL 7 – System prototype demonstration in operational environment; TRL 8 – System complete and qualified; TRL 9 – Actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies).

Modelling and costing storage

There are many energy storage technologies as illustrated above. While some forms or combinations of storage technologies are cheaper, others provide a better return trip efficiency. This chapter explores the interplay of these factors. The case in which wind and solar provide all power, mixed 80:20, supported only by hydrogen storage, is described first, prior to a discussion of other options[5]. A discount rate of 5% or 10% was assumed.

5.1 Hydrogen storage only

The assumptions that are used in costing hydrogen storage stage are collected in Table 5.

There is a minimum level of wind and solar supply at which all demand can be met by wind, solar and hydrogen storage over the 37 years studied. At this minimum threshold level (which depends only on the round-trip storage efficiency), all surpluses must be stored, and the electrolyser power and the minimum store size are fixed. Above the threshold, it is not necessary to store all surpluses, and there is a choice (within limits) between a relatively small storage capacity charged rapidly by a powerful cohort of electrolysers and a larger capacity charged more slowly by a less powerful cohort.

TABLE 5

Assumptions used in modelling and costing hydrogen storage in 2050.

The storage costs are for the very large systems assumed in this report. Cost of Wind and Solar Energy before transmission to consumers or to store, for an 80 / 20 wind / solar mix: £30.2/MWh (IEA 2040 projection adapted for UK load factors), £35/MWh (BEIS low 2040 projection) or £45/MWh (BEIS high 2040 projection). Modelling uses the AFRY model of 570 TWh 2050 electricity demand and the Renewables.ninja model of 80% wind (30% / 70% on / off-shore) and 20% solar supply.

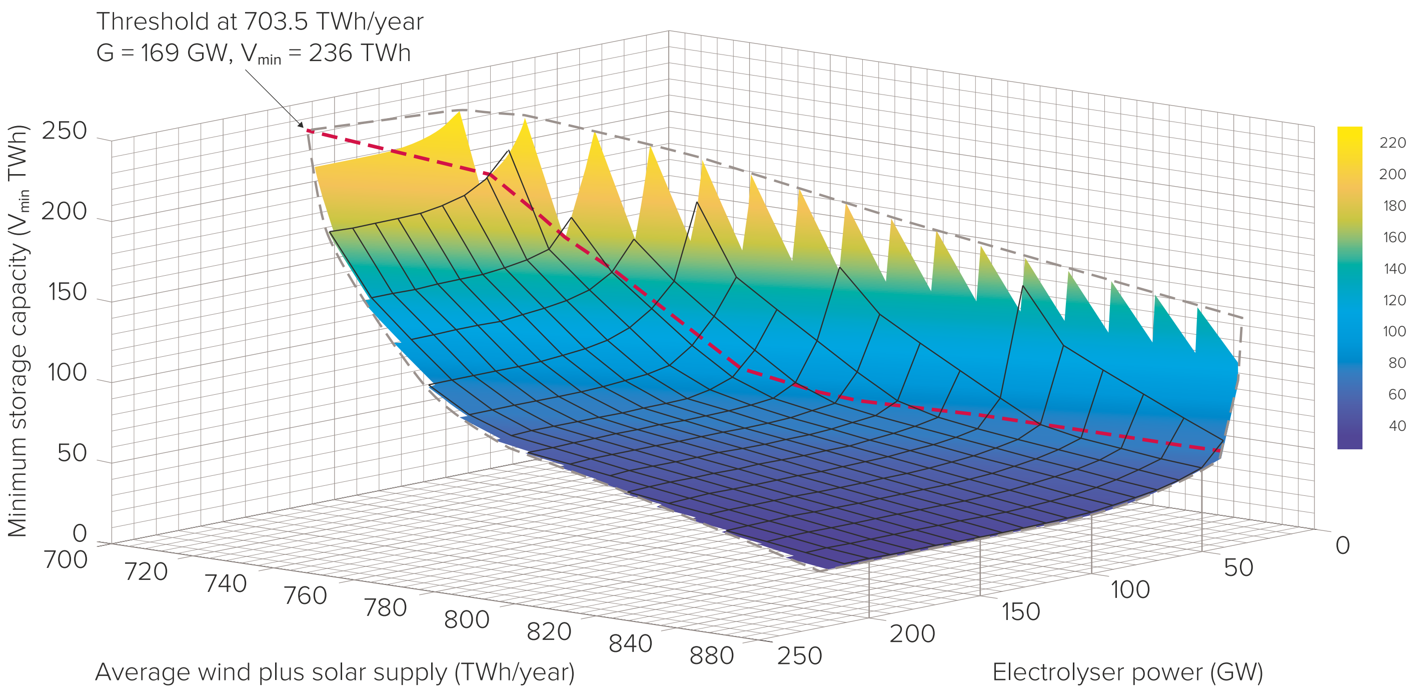
Assumptions for 2050	Input £/kWe	Storage £/MWh_e – delivered	Output £/kWe
Capex – Low / **base** / high	167 / **333** / 500	485 / **727** / 970	222 / **315** / 472
Opex per annum	1.5% of capex	1.5% of capex	1.5% of capex
Financial life	30 years	30 years	30 years
Efficiency	74%	Round-trip 41%	55%

5 Some small-scale storage that can respond rapidly, which could be provided by batteries, will also be needed to stabilise the grid.

FIGURE 9

Hydrogen storage capacity mapped against electrolyser power and average wind and solar generation.

The surface was constructed using the AFRY / Renewables.ninja models of demand / wind and solar supply, and assuming an efficiency of 74% for electrolysers and 55% for converting hydrogen to power. The colours show the values of V_{min} on the surface, according to the scale on the right. The dashed red line shows the values of electrolyser power for which, for given wind plus solar supply and the assumed ratio of the costs of electrolysers and storage, the average cost of electricity is a minimum with 20% contingency added to the volume, ie $V = 1.2 \times V_{min}$.



The range of electrolyser powers and the minimum storage capacities that can do the job are shown in Figure 9 for different levels of wind and solar supply. If the electrolysers' power was less than the value at the back edge of the surface in this figure, they would not be able to replenish the store fast enough to keep pace with depletion, and not all demand could be met. At the front edge of the surface, there is enough power to store all surpluses and there would be no point in installing more.

It is assumed that 20% contingency should be added to the store. For given costs of wind plus solar supply and storage (Table 5), the average cost of electricity is then calculated at points 20% above the surface in Figure 10 and the minimum is found. Before turning to the cost, it is interesting to consider the level of hydrogen in the store, which is shown in Figure 10 in the case of average wind and solar supply of 740 TWh/year (equal to 1.3 times the demand).

FIGURE 10

Level of stored hydrogen.

Assuming electricity demand of 570 TWh/year and that all electricity is provided by wind and solar generation that averages 740 TWh/year, supported by hydrogen storage, apart from a small amount needed to regulate voltage and frequency.

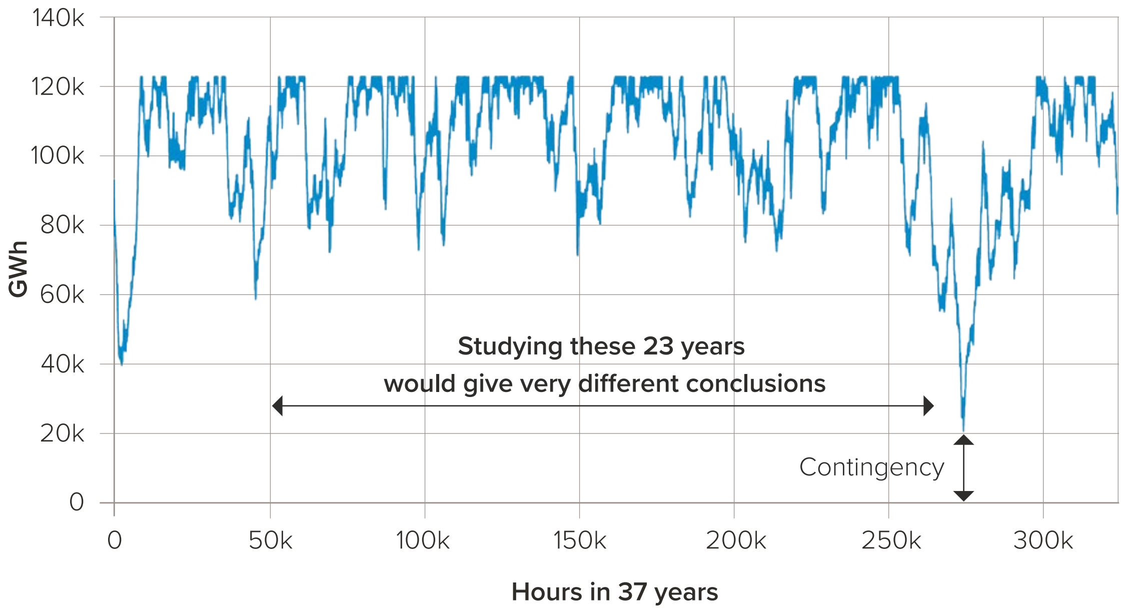


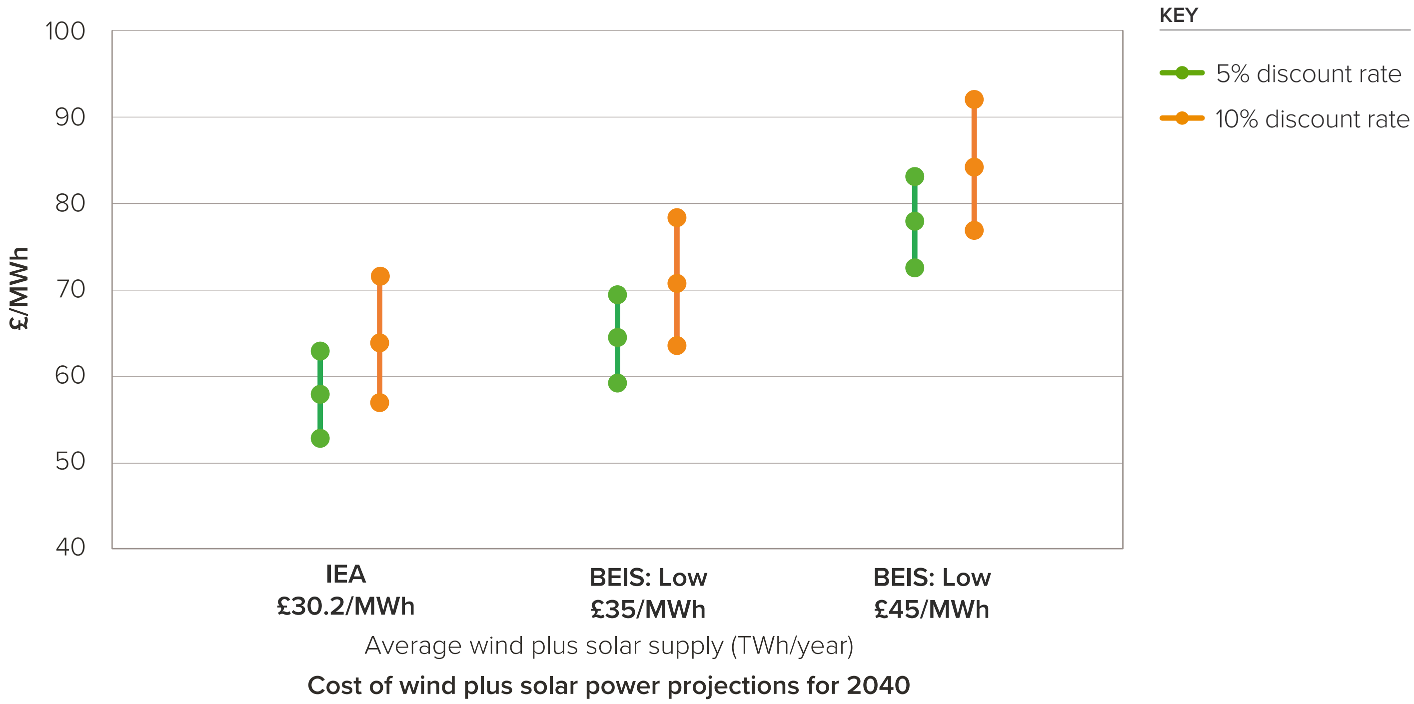
Figure 10 exhibits two striking features. First, a study of the 23 years 1984 – 2006 would have found a storage volume very much smaller than found by studying 1980 – 2016. Second, there is a very large call on storage in the period 2009 – 2011 which reflects persistently low wind speeds that led to large deficits (some of the energy that fills these deficits would have been in the store since 1980). These features lead to the conclusion that it would be prudent to add contingency against prolonged periods of very low supply and the possible greater clustering of 2009 to 2011-like years.

The average cost of electricity fed into the grid ranges from £52/MWh to £92/MWh, depending on the assumed costs of wind and solar and storage and the discount rate. The way in which the cost varies with these factors in shown in Figure 11.

FIGURE 11

Estimates of average cost of electricity provided to the grid, 2050.

Range of estimates of the average cost of electricity provided to the grid in 2050 assuming that large-scale storage is provided by hydrogen, and that wind plus solar generated electricity are the only sources of supply, for different costs of wind + solar power (mixed 80% / 20%) and discount rates. The dots indicate costs obtained with low, base and high estimates of hydrogen storage costs (in 2021 prices). 20% contingency is included in the store size. £4/MWh is included for the estimated cost transmitting power from wind and solar farms to stores and providing the batteries that are needed to regulate the frequency and voltage.



5.2 Hydrogen storage with baseload generation

The addition of constant nuclear baseload supply to a system in which all power is supplied by wind plus solar, supported by storage, will increase the average cost of electricity unless the cost of nuclear power is lower than the cost without nuclear. This will only happen if:

- the cost of nuclear is at the bottom of the projected range (£66 – 99/MWh – see Table 2); and/or
- the cost without nuclear is towards the top of the projected range (£52 – 92/MWh).

Baseload generation could also be provided by:

- Natural gas generation equipped with CCS. Used as baseload, gas + CCS would raise the average cost of electricity unless the future price of gas is lower than the 65p/therm assumed by BEIS when projecting 2040 costs, and hydrogen storage costs are high. Even then it could only have an appreciable impact on costs if added in amounts that would lead to unacceptable emissions of methane and carbon dioxide.

- Bioenergy with Carbon Capture and Storage (BECCS). Adding BECCS would lower the average cost of electricity if the carbon it saves attracts a credit of order £100/(tonne CO_2 saved) or more. Adding as much carbon-negative BECCS as possible would be doubly attractive if it lowers the average cost of electricity, but it could not provide GB with more than 50 TWh/year without imports of biomass.

5.3 Combining storage technologies – ACAES and hydrogen

Combining ACAES with hydrogen could lower the average cost of electricity. Since the future costs of the large compressors and expanders and associated heat exchangers needed in large-scale ACAES are poorly known, a range was assumed, as shown in Table 6. It is assumed in this briefing that compressed air is stored in the large caverns that were costed as hydrogen stores, and water pits are used to store the heat, for which costs are well established.

With the 68% round-trip efficiency that was found in modelling, combining ACAES with hydrogen system leads to a cost saving over hydrogen alone provided compressors and expanders to cost less than £500/kW.

Adding ACAES reduces the scale of hydrogen storage that is required, by (e.g.) 40% in a case that is described in the report. However, it will not necessarily reduce the number of storage caverns that are required since the volume of stored air that is needed to deliver a given amount of energy is some 20 times bigger for ACAES than for hydrogen. Although, in terms of deliverable energy, the capacity of ACAES at the cost minimum is much smaller than that of the hydrogen store, it delivers much more energy annually (fourteen times as much in the case described in the report) as it is cycled much more rapidly.

TABLE 6

Assumptions used in costing ACAES.

Assumptions for 2050	Input £/kWe	Storage £/MWh$_e$ – delivered	Output £/kWe
Capex	Up to £500/kW*	3911	Up to £500/kW*
Opex per annum	4% of capex	2% of capex	4% of capex
Financial life	30 years	30 years	30 years

* Full cost for powers of around 80MW. The cost/kW is thought to vary as (power rating)-0.4 for devices with similar characteristics.

5.4 Providing flexibility using gas with CCS

Using forecasts of supply and demand, it could be possible for natural gas-powered generation equipped with CCS to provide most of the flexibility needed to match variations in wind and solar supply and demand. Using gas generation equipped with CCS to provide all flexibility, instead of storage, would lead to unacceptable emissions of CO_2 and methane, and also to higher costs. However, using a combination of storage and gas plus CCS could lower costs significantly, without necessarily leading to unacceptable emissions. Whether it would lower costs depends on the costs of storage, wind and solar power, and gas plus CCS, the price of natural gas and the carbon price. It would not remove the need for large-scale long-term storage, although it would reduce the required scales of storage and wind plus solar supply. While it would provide diversity, it would expose GB's electricity costs to fluctuations in the price of gas, and increasing reliance on imports as GB's gas reserves decline.

5.4.1 Managing demand

The National Grid uses a demand flexibility system to flatten peaks in demand by paying heavy users to cut their demand at these times. Their 2022 net zero compatible 2050 scenarios assume demand side response flexibility of up to 37 GW, which looks achievable. However, demand management could not deal with longer periods of scarce wind and solar supply, which can last up to two weeks. Nor could it cope with the fact that the maximum energy deficit occurs over a much longer period because multiple scarce periods can follow each other closely.

5.4.2 Areas for further investigation

Considering the need for hydrogen for large-scale electricity storage along with other uses for green hydrogen would almost certainly provide systems benefits that would lower costs.

Further work is needed on the design and implementation of procedures for scheduling the use of a mixture of different types of store. More work is also needed on the long-term variability of wind and solar supply and the need for contingency.

The underlying assumptions on the cost of storage and of providing wind and solar power should be underpinned by detailed engineering estimates. Meanwhile, it should be stressed that the costs quoted above, which are in 2021 prices, are obviously sensitive to increases in commodity prices, and other forms of inflation.

The Grid, electricity markets and coordination

There will be major changes in the scale and nature of GB's electricity system as heating, transport and parts of industry are increasingly electrified, the roles of wind and solar energy grow, and storage is widely deployed. These changes have important implications for the electricity grid and are likely to require major changes in electricity markets.

6.1 The Grid

The transmission grid will have to be enlarged to connect new solar and wind farms and accommodate storage, and strengthened to deal with larger fluctuations, dominated by variations in supply, and higher peak loads. Ensuring that supply remains reliable and resilient will become increasingly important as the role of electricity grows. Reliability and resilience are currently mainly provided by dispatchable unabated gas generated by synchronised rotating machinery, whose mechanical inertia provides stability and helps maintain a constant voltage and frequency. Wind and solar plants use power electronics to provide AC power to the grid. If wind and solar supply is combined with energy stores that can be accessed quickly, problems arising from the absence of mechanical inertia can largely be overcome. There is, however, a need for engineering research to guide how the increasingly ubiquitous power electronic converters should be designed and used, and modelling is needed to understand their impact.

6.2 Market Issues

Investors in storage will be dependent on revenue streams over long asset lives. During this time prices, regulations and government policy will change in unpredictable ways. The investors will have to take a view on the future cost of buying energy, the selling price, the optimum timing of sales, and the behaviour of competitors. They will therefore be looking for some form of long-term contractual assurance. This could be provided by a regulated asset base approach, or government commitments. However, incentives to invest in storage based on output could lead to operators releasing energy whenever possible, leaving stores in profit but empty in a crisis when they are needed.

If paid only on the basis of short-run costs, the large-scale long-term storage that this briefing argues will be needed could never recover its capital costs since it will be idle much of the time. Capacity markets can be designed to address this problem (for storage, capacity could mean storage volume, and / or input or output capacity). Another possible remedy is a 'cap and floor' mechanism in which investors' income is partly determined by energy markets but their exposure to downside risks and potential upside gains is limited. This approach is currently used for GB's interconnectors and has been proposed for storage capacity. Finding effective pricing arrangements will become increasingly important as i) the complexities of managing low carbon systems grow, and ii) scheduling and dispatch decisions increasingly relate to complex operating regimes, such as those required with storage, rather than simple merit order ranking.

Existing markets and regulations are unlikely to deliver a portfolio of generation and storage that would lead cost-effectively to a net zero electricity system or ensure the operational coordination necessary to control costs. Possible alternatives – presented to provoke discussion – include:

- Centrally driven coordination of investment plans, which are quite common internationally (examples include France's EDF and Germany's *Energiewende*).
- Close cooperation between members of umbrella groups (such as 'power pools' in the US) which implicitly assume responsibility for reliability (which can raise competition policy questions).
- Reverse auctions of the obligation to provide 'firm', dispatchable, power (which would require cooperation between generators and providers of storage).
- The creation of a 'central buyer', responsible not only for procuring capacity, but also for buying power from generators and selling it to retail suppliers and large consumers. While not involving ownership of generation, storage or transmission, this model would be similar to public ownership in many ways, but without removing competition and requiring taxpayers to bear all risks.

Concluding remarks

In Great Britain an electricity system largely powered by wind and solar energy will need tens of TWh of large-scale long-term storage, which would best be provided by storing hydrogen in solution-mined salt caverns. A model in which all of GB's future electricity demand is met by wind, solar and hydrogen provides a benchmark for comparison with other cases. This would require wind and solar supply averaging around 760 TWh/year supported by some 100 TWh of hydrogen storage. In this model, the average cost of electricity would be in the range £52 – 92/MWh (in 2021 prices) depending on the cost of storage, the assumed discount rate and, most sensitively, the cost of wind and solar.

Combining ACAES (or other types of stores with relatively high round-trip efficiencies) with hydrogen storage could lower the average cost of electricity. Conventional batteries are not expected to provide large-scale storage, although they are likely to play a role in stabilising the grid.

Adding nuclear could lower the cost of electricity if its cost is at the lower end of current projections, and / or large-scale storage costs are at the top of the range found in this briefing.

The flexibility needed to complement levels of wind and solar could be provided by a combination of storage and gas + CCS. It could lower costs, depending very sensitively on the price of natural gas, and on a range of other costs. It would not remove the need for large-scale long-term storage, although it would reduce the required scales of storage and wind plus solar supply. Using gas + CCS would require accepting some emissions of CO_2 and methane.

Although it is unlikely that 'new science' will be able to make a major contribution before 2050, basic research is important for the long term – for example cheap direct synthesis of ammonia from air and water would be transformative. Meanwhile, there is huge scope for demonstrating and improving existing technologies, as well as combining them in new ways. For example, in wind-integrated storage, reversible electrolysers / fuel cells and reversible compressors / expanders will be needed. There are also specific R&D challenges, such as reducing or eliminating iridium in PEM electrolysers.

In the case of many large-scale storage technologies, demonstrators are needed to identify and solve engineering and integration issues[6] before they can be widely deployed.

Great Britain is blessed with the natural assets needed to construct a net zero electricity system powered largely by wind and solar supported by large-scale storage. Constructing the large number of hydrogen storage caverns that will be needed, and the necessary wind and solar capacity, will be challenging. However, Britain is well positioned to meet the challenge, and – guided by a road map – it could be done by 2050 provided a start is made in the very near future.

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6 BEIS announced further funding (of £32.8 million in total) for storage technologies that were initially at TRL 6/7 to take five of them through to first-of-a-kind full-system prototypes https://www.gov.uk/government/publications/longer-duration-energy-storage-demonstration-programme-successful-projects/longer-duration-energy-storage-demonstration-programme-stream-2-phase-2-details-of-successful-projects. This is a welcome development but does not meet the need for large-scale demonstrating/constructing systems at high TRL which could provide multi-TWh scale storage in 2050.

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