Large-scale electricity storage

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Executive summary

The UK Government has a stated ambition to decarbonise the electricity system by 2035 and is committed to reaching net zero by 2050. As Great Britain's electricity supply is decarbonised, an increasing fraction will be provided by wind and solar energy because they are the cheapest form of low-carbon generation. Wind and solar supply vary on time scales ranging from seconds to decades. However high the average level of supply might be, there will be times when wind and solar generation is close to zero and periods when there is enough to meet part of but not all demand, as well as times when it exceeds demand.

To ensure that demand is always met, the volatile wind and solar generated electricity that is fed directly into the grid must be complemented by other flexible low-carbon sources, and / or using excess wind and solar energy that has been stored. The excess could be stored in a variety of ways, for example electrochemically in batteries, gravitationally by pumping water into dams, mechanically by compressing air, chemically by making hydrogen, or as heat.

This report considers the use of large-scale electricity storage when power is supplied predominantly by wind and solar. It draws on studies from around the world but is focussed on the need for large-scale electrical energy storage in Great Britain[a] (GB) and how, and at what cost, storage needs might best be met.

Major conclusions

- In 2050 Great Britain's demand for electricity could be met by wind and solar energy supported by large-scale storage.
- The cost of complementing direct wind and solar supply with storage compares very favourably with the cost of low-carbon alternatives. Further, storage has the potential to provide greater energy security.
- Wind supply can vary over time scales of decades and tens of TWhs of very long-duration storage will be needed. The scale is over 1000 times that currently provided by pumped hydro in the UK, and far more than could conceivably be provided by conventional batteries.
- Meeting the need for long-duration storage will require very low cost per unit energy stored. In GB, the leading candidate is storage of hydrogen in solution-mined salt caverns, for which GB has a more than adequate potential, albeit not widely distributed. The fall-back option, which would be significantly more expensive, is ammonia.
- The demand for electricity in GB in 2050 is assumed to be 570 TWh/year in most of this report. In principle it could all be met by wind and solar supply supported by hydrogen, and some small-scale storage that can respond rapidly, which is needed to ensure the stability of the transmission grid. With the report's central assumptions, this would require a hydrogen storage capacity ranging from around 60 to 100 TWh[b] (depending on the level of wind and solar supply). The average cost of electricity that is available to meet demand varies very little over this range as the rising cost of wind and solar supply is offset by the decreasing cost of the storage that is needed.

a Northern Ireland is excluded from the study as its electricity grid is integrated with that of the Republic of Ireland.

b This is the thermal energy content of the stored energy expressed in terms of the Lower Heating Value – see the Glossary.

- Although some hydrogen (or ammonia) storage will be needed, it is quite likely that a portfolio of different types of storage would lower the average cost of electricity.
- Including steady nuclear ('baseload') supply would increase costs, unless the cost of nuclear is near or below the bottom of the range of projections made by the Department for Business, Energy and Industrial Strategy (BEIS) and / or the costs of storage are near the top of the range of estimates in this report. The addition of bioenergy with carbon capture and storage generation (BECCS) would lower the cost if it attracts a carbon credit of order £100 / (tonne CO_2 saved) or more, but it could not provide GB with more than 50 TWh/year without imports of biomass.
- Using natural gas generation equipped with carbon capture and storage (CCS) to provide flexibility, instead of storage, would lead to unacceptable emissions of CO_2 and methane, and also to higher costs. Used as baseload, it would only lower costs appreciably if added in amounts that would lead to unacceptable emissions; the future price of natural gas is lower than expected; and storage costs are high.
- Using a combination of storage and gas plus CCS to provide the flexibility required to match wind and solar supply 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 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.

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. The models were based on real weather data in the 37 years 1980 to 2016 and an assumed demand of 570 TWh/year. Thirty-seven years is not enough to provide a full sample of rare weather events which can seriously affect the supply of wind-generated electricity. Contingency is added to allow for this, and for the possible effects of climate change. Studies based on less than several decades of weather data are liable to very seriously underestimate the need for storage, and overestimate the need for other sources of flexible supply. These under/overestimates are especially large in studies that look only at individual years rather than sequences of years or examine selected periods of high stress.

Storage technologies

The contents of stores with large capital costs per unit of energy stored have to be cycled frequently in order to recover the investment. The storage technologies considered in this report can be grouped into three categories according to the typical time in which their contents must be cycled:

1. Minutes to hours: conventional (non-flow) batteries;
2. Days to weeks: flow batteries, advanced compressed air energy storage, Carnot batteries, pumped thermal storage, pumped hydro, liquid air energy storage; or
3. Months or years: synthetic fuels, ammonia, hydrogen.

Stores in category one are generally more efficient than those in two, which are more efficient than those in three. Higher efficiency can compensate for higher costs depending on how the stores are used.

Average cost of electricity with all large-scale storage provided by hydrogen

A case in which all demand is met by wind and solar energy supported by hydrogen storage, plus 15 GW of batteries (used to stabilise the grid), was analysed and used as a benchmark against which the other options were assessed. The average cost of electricity fed into the grid, was calculated with a range of assumptions for the 2050 cost of storage and of solar and wind generated electricity. In 2021 prices it ranges from:

- £52/MWh – with the low assumptions for the costs of storage and wind plus solar power (£30/MWh) and a 5% discount rate; to
- £92/MWh – with the high assumptions for the costs of storage and wind plus solar power (£45/MWh) and a 10% discount rate.

The overall average cost is dominated by the cost of the wind and solar supply. The average cost of electricity would be at least £5/MWh higher if all storage were provided only by ammonia. It appears very unlikely that any other form of storage could meet all needs on its own.

For comparison: in 2010 – 2020, the wholesale price of electricity hovered around £46/MWh, but it was more than £200/MWh during most of 2022.

Addition of other types of store

Advanced compressed air energy storage (ACAES) was studied in detail as an exemplar of stores in the second category identified above. A combination of ACAES with hydrogen storage provides the benefits of the greater efficiency of the former and the lower storage cost of the latter. The costs and efficiencies of large ACAES systems are poorly known. However, for a wide range of assumptions, it was found that combining ACAES with hydrogen would be likely to lower the cost relative to that found with hydrogen alone (by up to 5%, or possibly more), although this is not assured. When they are optimally combined, the capacity of ACAES is much smaller than that of the hydrogen store, but ACAES delivers more energy because it is cycled more frequently.

Adding other types of store to hydrogen and ACAES could lower the cost further.

Market and governance issues

The cost of electricity provided by storage will be many times the cost of wind and solar supply that is fed directly into the grid. Building the storage needed to provide this expensive but essential electricity will take large financial investments and time. While price differentials in wholesale and balancing markets may incentivise the construction of significant amounts of short-term storage, new mechanisms, including forms of guarantees, will be needed to make investment in large-scale, long-duration storage attractive. To contain storage costs, generators and owners of storage will have to cooperate to an unprecedented degree in scheduling charging and dispatch of energy from different types of store. Ensuring this cooperation is likely to require radical reforms.

Caveats and avenues for further work

This report is focussed on the large-scale storage that will be needed in 2050 in GB. While the possible roles of nuclear and of gas plus CCS are considered, the modelling 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.

The design and implementation of procedures for scheduling the use of a mixture of different types of store together with other flexible supply need to be studied further. More work is also needed on the long-term variability of wind and solar supply and the need for contingency. The need for hydrogen for large-scale electricity storage should be studied together with other uses for green hydrogen. This would almost certainly reveal systems benefits that would lower costs.

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 cost estimates in the report, which are in 2021 prices, are obviously sensitive to increases in commodity prices and other forms of inflation, and depend critically on estimates of the future cost of wind and solar power.

Constructing the large number of hydrogen storage caverns that this report finds will be needed to complement high levels of wind and solar supply by 2050 will be challenging but appears possible.

GB will need large-scale energy storage to complement high levels of wind and solar power. No low-carbon sources can do so at a comparable cost. Construction of the large-scale hydrogen storage that will be needed should begin now.

More details and background information are provided in supplementary information available at **royalsociety.org/electricity-storage**. This includes a description of unpublished work conducted in support of this report. For example, information relevant to section 3.2 is reported in, and referenced as SI 3.2. The contents of the supplementary information can be found in Annex B.

Exchange rates

Cost estimates in the report are first quoted in \$s or €s when that was the currency used in the original source, and then converted at £1.00 = \$1.35 = €1.18

Introduction

1.1 Scope of this report

This report draws on studies from round the world but is focussed on the need for large-scale electrical energy storage in Great Britain (ie the UK excluding Northern Ireland, where electricity provision is part of a separate Irish market), and how, and at what cost, it might best be met. The need for storage and how it can be met depend on local factors, including the weather and climate, and potential storage sites. The methodology needed to study storage, and conclusions on storage technologies are, however, generally applicable.

1.2 Supply and demand in a net zero context

1.2.1 Net zero emissions, electrification, and wind and solar energy

Reducing greenhouse gas emissions to net zero by 2050 will require major changes in energy production 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[1]. There is potentially much more than enough for them to meet the country's future electricity needs[2].

1.2.2 The need for flexible supply

The availability of wind and solar power varies on time scales ranging from seconds to decades, depending on the weather, see figures 1 and 2 (and SI 1.2). Demand is also variable, and mismatches between supply and demand occur on time scales ranging from milliseconds to years (see figure 1B) as a result of long-term variations in wind speeds, caused by the North Atlantic Oscillation (NAO).

As there are times when the sun is not shining and the wind is not blowing, wind and solar supply cannot meet demand directly on their own, however much generating capacity is installed. They therefore have to be supplemented by:

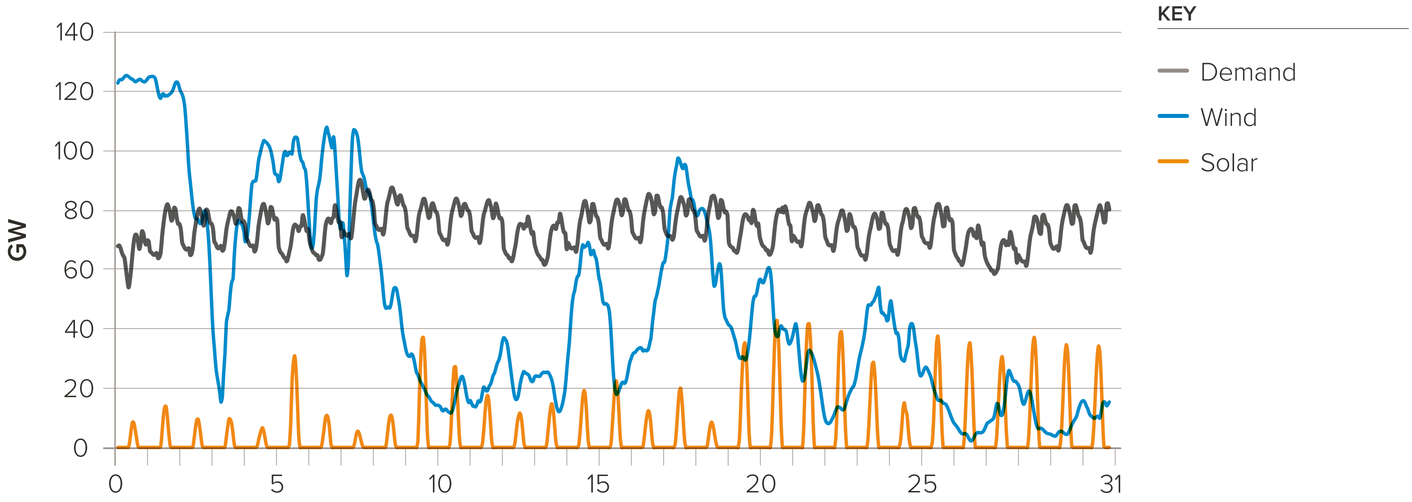
- large-scale flexible low-carbon generation; and / or
- importing electricity when needed; and / or
- generating electricity from the surplus wind and solar energy that has been stored.

FIGURE 1

Modelled profiles of wind and solar generation and electricity demand.

Profiles of i) wind and solar electricity generation, based on actual weather data in a typical year (1992) scaled to 570 TWh/year averaged over 37 years (with, for reasons explained in Chapter 2, 80% from wind and 20% from solar) and ii) a model (described in Chapter 2) of possible GB demand of 570 TWh/year in 2050. Flexible supply from other sources and / or imports and / or stored surpluses are required to fill the gap between demand and wind + solar supply.

A) January



B) July

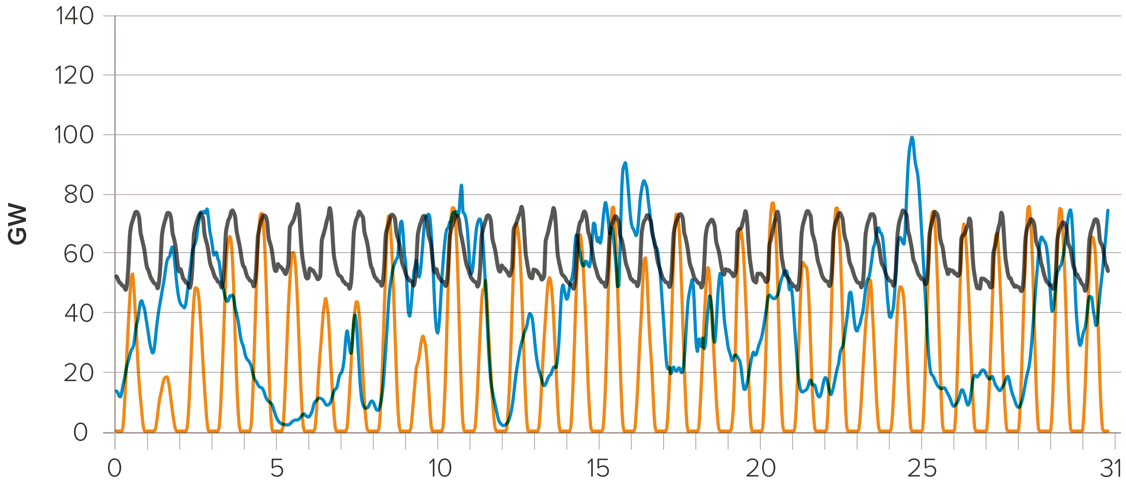
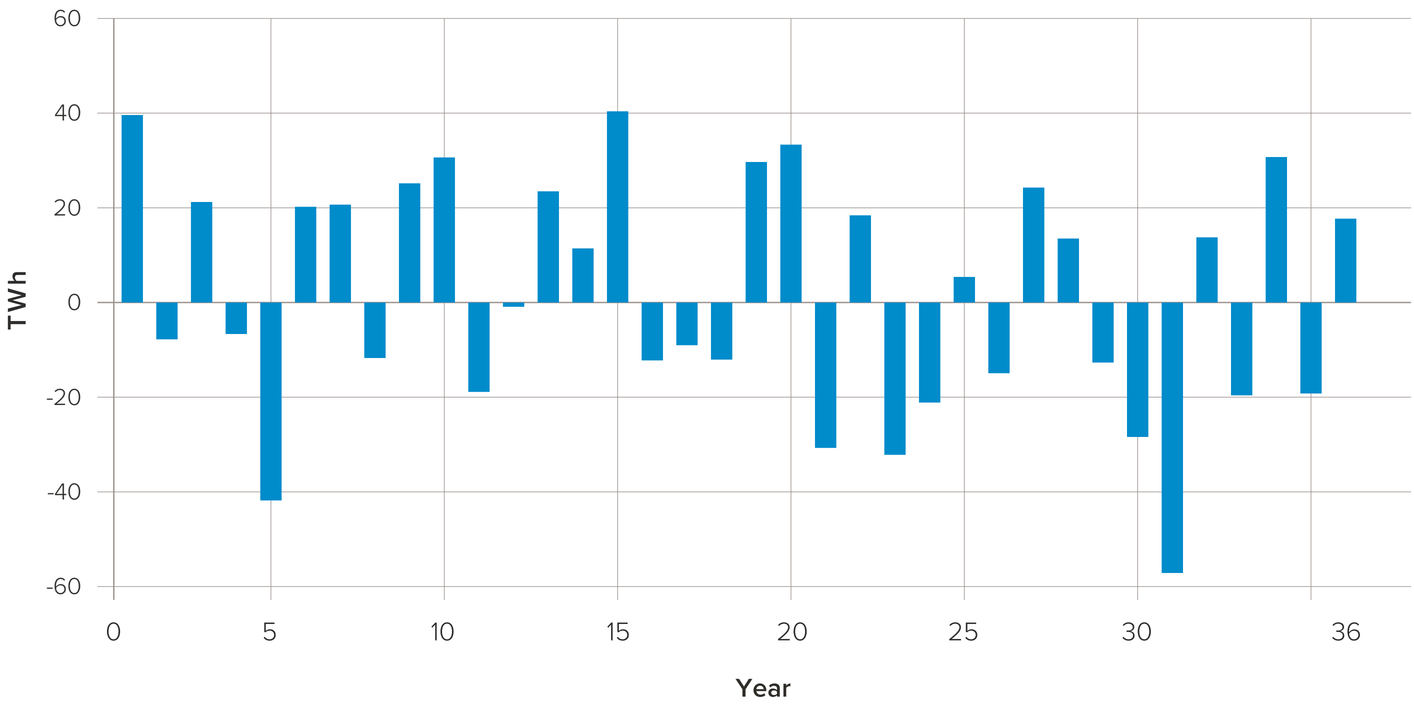


FIGURE 2

Modelled annual difference between wind plus solar supply and electricity demand.

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 over 37 years (with 80% wind and 20% solar), and the model of GB demand of 570 TWh/year used in figure 1. Years April to March are used in order to include contiguous quarters 3 and 4 and not dilute the effects of severe winters.



1.3 Storage

1.3.1 Energy storage today and the scale of future needs

Storage is needed in all energy systems to buffer mismatches between supply and demand. The average amount of energy stored in the UK in 2019 is shown in Box 1 (see SI 1.3). By far the largest amount was stored in fossil fuels, which are being phased out.

The scale of future energy storage needed in systems with high levels of wind and solar supply can be inferred from figure 2. It shows that, with only wind and solar generation, balancing supply and demand over 37 years (with 100% efficient storage) would require storing tens of TWhs for over several decades in order to fill the deficits in years 29 – 31 of the period studied. At the levels of additional supply needed to compensate for storage inefficiencies, it remains true that there is a need to store tens of TWhs for many years (see figure 13 and SI 1.3). The scale of the need and the time over which energy has to be stored involves a trade-off between the size of the store, the rate at which it is filled and the level of wind and solar supply.

BOX 1

Energy Stored in the UK in 2019[c]

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

To model this need it is necessary to compare models of wind and solar supply with models of demand, hour-by-hour, over as long a period as possible, and identify the mismatches in supply and demand. The future level and hourly profile of electricity demand are very uncertain, the biggest uncertainty being in the degree to which space heating will be electrified. The main conclusions of this report are based on a model of 2050 demand kindly provided by AFRY consulting[d] and variations thereon with higher and lower levels of demand, and the renewables.ninja model of wind and solar supply that is based on 37 years of real weather data (1980 to 2016).

1.3.2 Storage technologies

Great Britain's expected need of many tens of TWh of electricity storage could not all be provided by the stores shown in Box 1: the cost of tens of TWh of batteries would be prohibitive and the potential for pumped hydro is much too small.

There is a trade-off between the capital cost of energy storage systems and their efficiencies. They broadly fall into three classes that:

1. have high costs, and have to be cycled every few hours to recover the investment, but have high efficiency;
2. have low costs and can store large amounts of energy for years, but have low efficiencies; or
3. have intermediate characteristics.

In costing storage in this report, special attention is paid to one technology in each category: lithium-ion batteries, which are the obvious choice in the first; hydrogen storage, which emerges as the leading candidate in the second; and advanced compressed air energy storage (ACAES), which is chosen as an exemplar of many technologies in the last class. That final class also includes flow batteries, Carnot batteries and Liquid Air Energy Storage (LAES).

Some storage is required that can respond very rapidly in order to regulate the voltage and frequency and maintain the stability of the grid when there are sudden changes in supply or demand. Providing these 'rapid response grid services' takes relatively little energy. It therefore has almost no impact on the need for large-scale storage, and how it is provided is outside the scope of this report. It can, however, be expensive and an estimate of what it might cost is included, assuming that it is provided by lithium-ion batteries.

c Energy Stored in the UK in 2019; data from Digest of UK Energy Statistics (DUKES), Energy Trends (UK gas) and the Renewable Energy Planning Database (GB only data).

d Based on results of simulations using the BID3 power market model. See https://afry.com/en/service/bid3-power-market-modelling (accessed 15 May 2023).

1.3.3 Features of storage

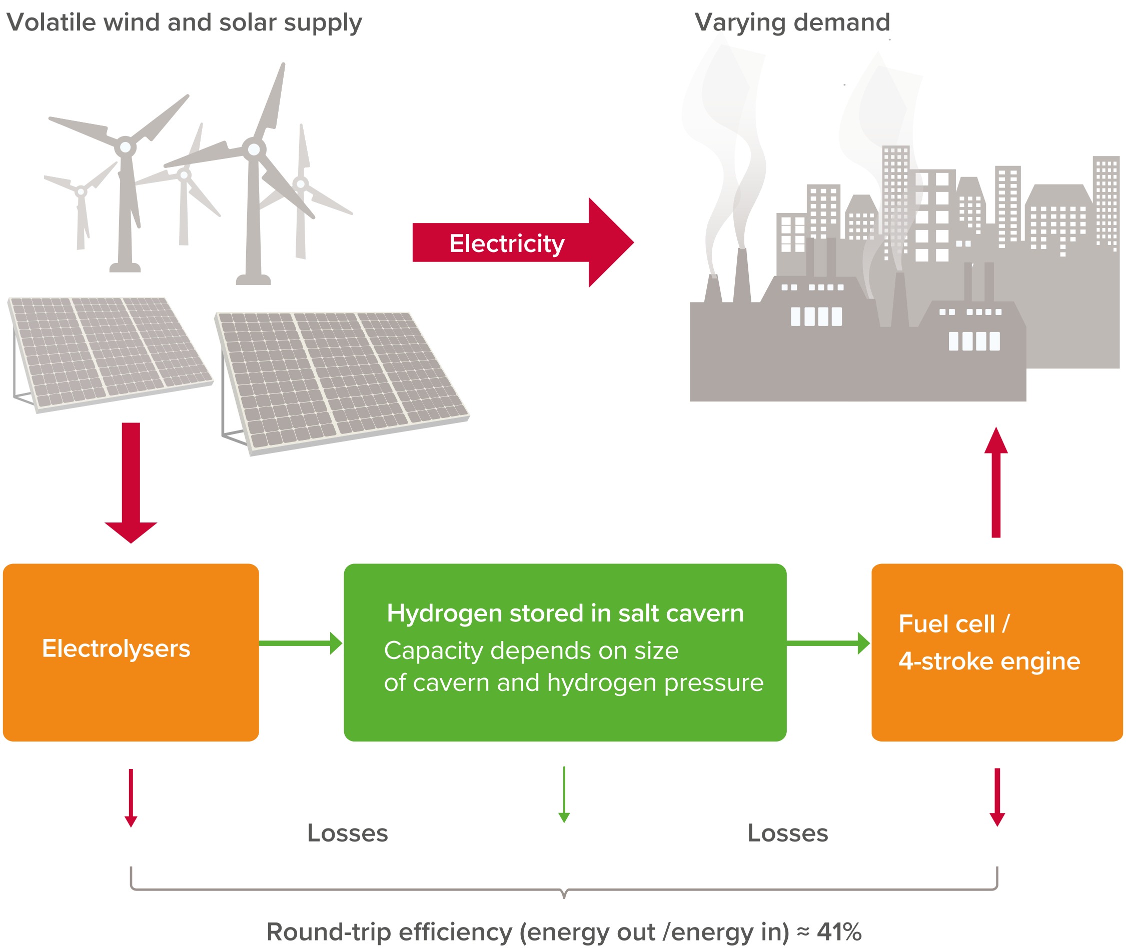
Hydrogen storage, which this report finds will be needed in GB, is used here to illustrate three general features of storage (see figure 3):

- The electricity provided by storage is generally much less than the input because of losses. With the overall (round trip) efficiency of 41% assumed for hydrogen, the surplus wind and solar energy that is stored must be at least factor of 1/0.41= 2.4 larger than the deficits that the stored hydrogen is required to fill. Wind and solar supply must therefore be greater than demand if no other sources of supply are available: with the modelling used here, a demand of 570 TWh/year can only be met with hydrogen storage alone if wind and solar supply is greater than 703.5 TWh/year.
- The amounts of hydrogen added to and withdrawn from the store must be equal when averaged over a long period. However, a given output can, within limits, be provided by a relatively small storage capacity charged rapidly with many electrolysers, or by a large storage capacity charged slowly by fewer electrolysers. The cost depends on the relative costs and sizes of the electrolyser and of the store. A system with the smallest possible store, which would have to be charged by electrolysers with enough power to store the largest deficits, would generally not be the cheapest.
- The total amount of demand that a store meets depends on how often it is filled and emptied. For example, in one case in which both hydrogen storage and ACAES are deployed, it is found that hydrogen stores and ACAES must be capable of delivering 37 TWh_e/cycle and 2.4 TWh_e/cycle respectively. However, hydrogen delivers 36 TWh_e/year, while the much smaller ACAES stores delivers 55 TWh_e/year, because ACAES is cycled much more frequently. This might suggest that hydrogen storage is not needed. However, this report finds that because of its higher cost per unit of energy stored, and the need – implicit in figure 1B – to store energy for long periods, using ACAES alone would be more expensive than using hydrogen storage alone. A combination of the two, which would benefit from the efficiency of the former and the low storage cost of the latter, would quite likely be cheaper than either alone.

FIGURE 3

Schematic of the use of hydrogen to store electricity.

The fuel cells and / or 4-stroke engines that convert hydrogen to electricity must be sized to be able to meet all demand when the wind is not blowing and the sun not shining. Within limits, demand can be met with a relatively small total storage capacity charged by very powerful electrolysers (which convert electricity to hydrogen), or a larger capacity charged by less powerful electrolysers.



1.4 Cost considerations

In this report, the average cost of the electricity that will have to be provided to the grid to meet 2050 demand is studied because i) AFRY's model of demand is for electricity entering the grid, and ii) it is relatively insensitive to changes in transmission costs, which only affect the cost of transmitting energy from wind and solar farms to stores.

1.4.1 Average cost of electricity

The more electricity that is provided directly to the grid by wind and solar, the less has to be provided by other sources (including storage). However, these other sources must still (collectively) be able to meet the full demand for power when the wind is not blowing and the sun not shining. With high levels of wind and solar, the flexible sources that complement them (including storage) will therefore spend a lot of time idle or operating well below full capacity. The power they do provide will therefore be expensive. It is, however, the average cost of electricity that matters, most of which will be provided directly by low-cost wind and solar whose contributions dilute the high cost of electricity provided by storage.

1.4.2 Costs and size

The costs of stores, and of devices that convert electrical energy to the form in which it is stored and reconvert it to electricity, depend strongly on their size. For example, the cost per unit storage capacity of solution-mined salt caverns that are used to store hydrogen varies approximately[3] as (the capacity)$^{-0.5}$, while the costs per kW of compressors and expanders (which are used in ACAES) varies approximately[4] as (the power rating)$^{-0.4}$. It is therefore important to specify the size of the system for which they are applicable when making or comparing cost estimates.

1.4.3 Operation and maintenance

The cost of using systems that operate with low load factors (which makes variable costs relatively unimportant), such as long-term storage, is very sensitive to fixed operation and maintenance (O&M) costs. For example, if the capital cost is discounted at 5% over 30 years, a fixed annual O&M cost of 2% of capex would contribute 24% of the total annualised cost; an annual O&M cost of 4% would contribute 38%. Estimates of fixed O&M costs are made case-by-case in this report, but they are necessarily imprecise without long operational experience.

Electricity demand and supply in the net zero era

2.1 Introduction

The future role of energy storage depends on the level and profile of demand, the variability of wind and solar supply, potential complementary supply and the scope for managing demand, which must be considered in the context of the whole electricity system (see figure 4). These factors are considered in turn in this chapter.

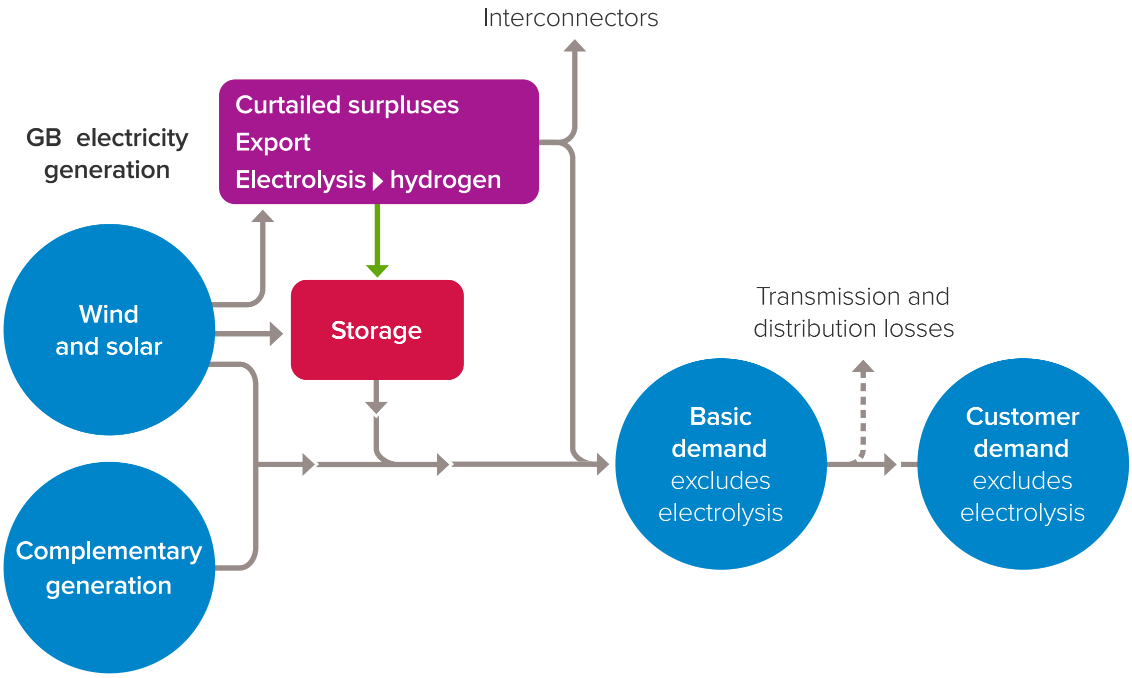
The first step in modelling systems with high levels of variable renewable generation is to understand how much of the quantity labelled 'Basic demand' in figure 4 can be met directly by wind and solar supply. Demand (basic or customer) that cannot be met directly and must be provided by complementary sources and / or storage, is known as Residual Demand (see Box 2): it is found by comparing wind and solar supply with (basic or customer) demand.

Customer demand (as defined by the National Grid)[5] excludes the demand for electrolytic production of hydrogen, both for storing electricity (which is considered to be part of supply) and for other purposes. Co-production of hydrogen for other purposes 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.

FIGURE 4

Elements of the electricity system.

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



BOX 2

Residual demand and residual energy

Residual demand is defined as Demand – (Demand met directly by wind + solar). It plays a key role in studying systems with high levels of wind and solar generation.

When wind and solar supply exceed demand, the term Residual Energy or Residual Power is used, which is equal to Wind + Solar Supply - Demand

2.2 Future electricity demand in Great Britain

Basic electricity demand was 317 TWh in 2021. It is expected to increase in the future, by an amount that will depend on: the extent to which the provision of heat, transport, and industrial processing are electrified; increases in the use of air conditioning; improvements in efficiency, economic growth, changes in population and changes in behaviour. Projections for 2050 range from 518 TWh in one of the National Grid's net zero compliant Future Energy Scenarios (FES)[5] to 672 TWh in BEIS'[6] high demand model. The higher projections assume high levels of electrification of space heating. The lower FES projections assume very big improvements in efficiency, and / or changes in behaviour.

In most of the modelling of storage in this report, basic GB demand will be assumed to be 570 TWh/year in 2050, although some results will also be reported based on simple models of demands of 440 TWh/year and 700 TWh/year. 570 TWh/year is the level in AFRY's hour-by-hour profile[e] (which is based on the weather in 2018) that was shown in figure 1A for January and July. It comprises base contribution 355 TWh, heating 96 TWh, and EV charging 119 TWh. Profiles of demand in the period 2012 – 2017 are shown in SI 2.2.

2.3 Weather, wind and sun

2.3.1 Temporal and spatial variation

Mean solar and wind power across a grid covering the landmass of GB is shown in figure 5[7] (the data are scaled to their multi-year averages, so this plot provides no information on the relative potentials of wind and solar power). 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. The variability of wind, which dominates the mixture, is higher than solar variation in all months, and will dominate the design of GB's energy supply. More information on the availability and behaviour of wind is provided in SI 2.3.

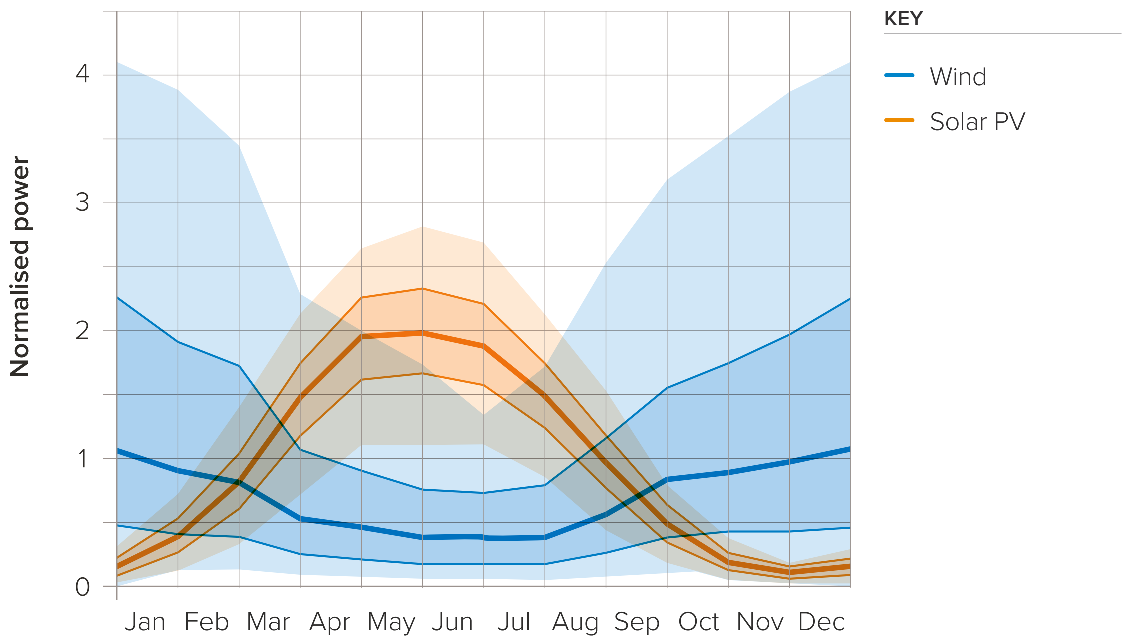
Infrequent but extreme weather can have a major impact on systems that rely heavily on wind and solar power. GB's electricity system will be affected by the three types of extreme weather events described in table 1 which were identified in a study based on historical data and modelling[8]. This study found "that climate change, rather than climate variability will have the greatest impact on temperature driven demand in the future … but climate variability is shown to have a greater impact on wind speed and solar irradiance".

e Kindly provided by AFRY Management Consulting, based on results of simulations using the BID3 power market model see https://afry.com/en/service/bid3-power-market-modelling (accessed 15 May 2023).

FIGURE 5

Distribution of mean wind and solar generation 1979 to 2013.

Distribution of daily-mean wind and solar generation in each month in 1979 to 2013 scaled to their all-year averages. The lines and shading indicate the medians, 25th and 75th percentiles, and 5th and 95th percentiles of the daily data.



Source: Met Office.

TABLE 1

Weather stress 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

Winter wind droughts, which occur when wind speeds over the North Sea are low, pose the biggest challenge to very high renewable systems[9] 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 (see SI 2.3). Connecting farms in different locations therefore reduces 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 (potentially) 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 this report.

2.3.2 Modelling wind and solar generation

Renewables.ninja[10, 11] (RN) provide simulations of (hypothetical) hourly power output from wind and solar power plants located anywhere in the world based on historical satellite weather data. In this report, their simulations of UK solar and on and offshore wind generation are used for 1980–2016, which was the largest and longest data set available when the work was done.

The year-to-year variability of wind (and to a lesser extent solar) power is expected to continue at today's level into the future, and to have a bigger impact on electricity supply than climate change[12] (some of the effects of climate change are discussed in SI 2.3). The scale of projected changes in wind speed and solar irradiance due to climate change differs between models and is highly uncertain[12]. This uncertainty can currently only be dealt with by including contingency when using models of future wind and solar supply.

Greater uncertainty is caused by the fact that the 37-year period (1980–2016) does not provide a fully representative sample of weather events. A study by the Met Office[13] found that 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 contingency to the size of the hydrogen store: other possible measures are discussed in section 8.7. A better understanding of the persistence and characteristics of periods of low wind speeds is required. This could be obtained by studying the period 1960 – 1980, when a negative phase of the NAO led to lower wind speeds than in 1980 – 2016, if / when weather data from that period are converted into wind and solar output.

2.4 Matching demand and direct wind and solar supply

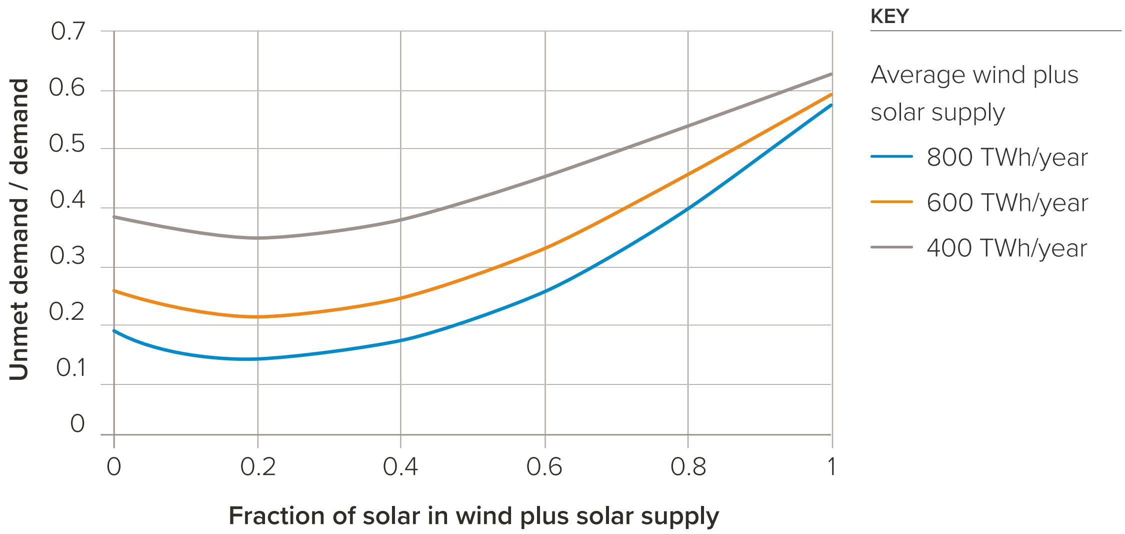
2.4.1 The optimal wind / solar mix

Wind and solar supply vary in different ways between winter and summer, as shown in figure 5. They can therefore be mixed in a way that minimises the supply that has to be curtailed, stored, or used for other purposes when it exceeds demand. With the 70 / 30 offshore / onshore mix assumed for 2050 in this report (see SI 2.4), and total wind plus solar supply fixed, the solar / wind mixture can be chosen to minimise the amount that cannot be used to meet demand directly by comparing 37 years of RN wind and solar data with AFRY's hourly model of 2050 demand repeated 37 times. As shown in figure 6, the minimum is at around a solar / wind mix of 20 / 80.

FIGURE 6

Fraction of demand not met directly by wind plus solar.

Demand that cannot be met directly by wind plus solar supply as a function of the wind / solar mix, for 570 TWh/year demand and different levels of wind plus solar supply, with no baseload supply.



The addition of constant baseload supply leads to a somewhat bigger winter / summer difference: matching it requires more wind / less solar.

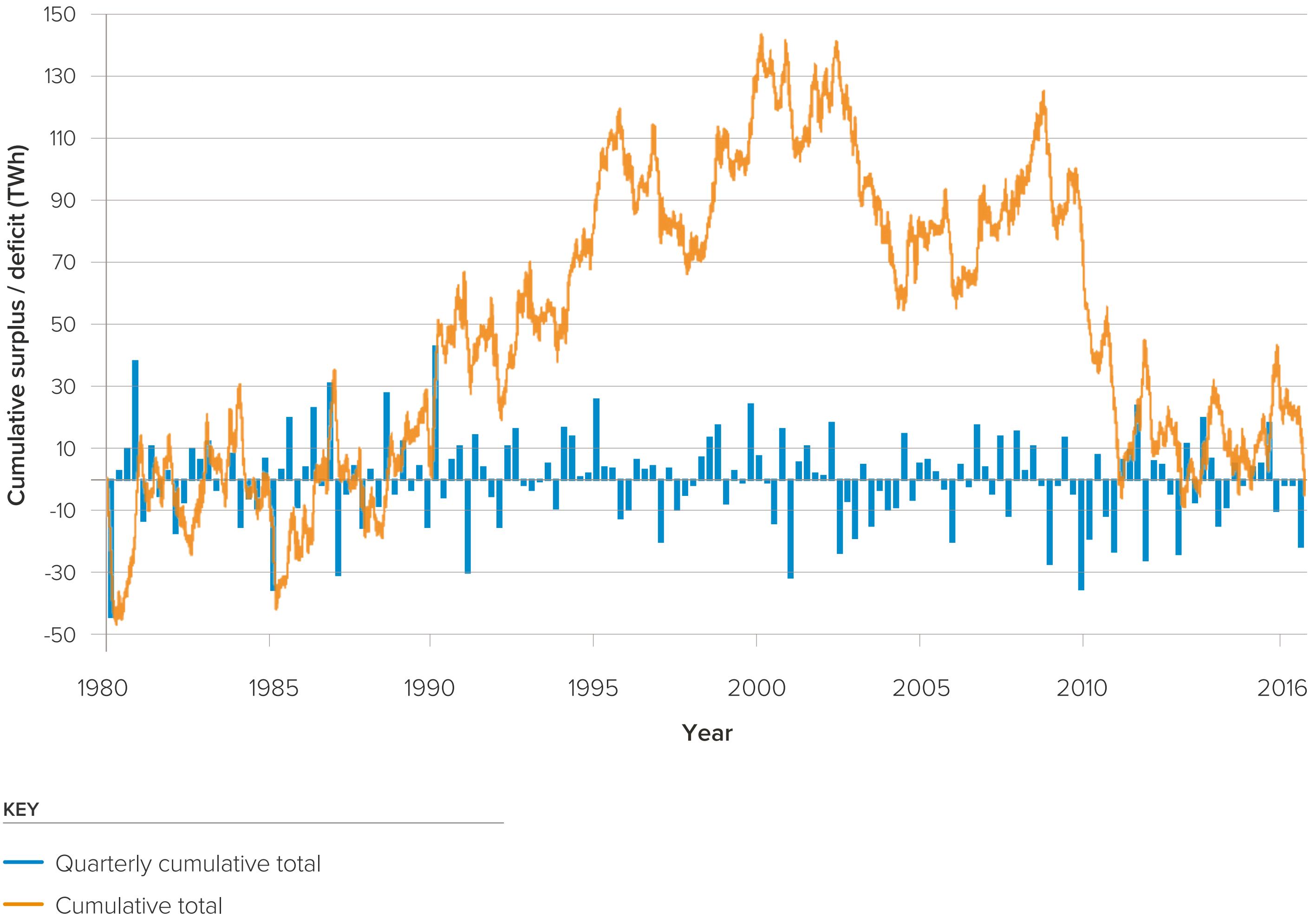
The solar / wind mix that maximises the direct use of renewables is not necessarily that which minimises the overall cost, which depends on the relative cost of solar and wind and the costs and characteristics of the complementary supply. However, the cost varies very little for solar contributions in the range of 10% to 30% (see section 8.3).

Comparison of 37 years of RN's model of supply with AFRY's model of 2050 demand repeated 37 times takes account of correlations between supply and demand to the extent that demand is lower in the summer than in the winter in the AFRY model, and lower at night when the sun is not shining. However, it does not take account of correlations that occur during winter anticyclones when it is cold and wind speeds are low. Modelling (see SI 2.3 and SI 2 Annex 1) finds that it is probably safe to neglect these correlations for quantities that depend on very long-term behaviour, such as the choice of the wind / solar mix and the need for storage on a decadal time scale, although it will lead to underestimates of the need for storage on shorter time scales. The substantial contingency that is included in the size of the long-term hydrogen store, provides protection against underestimates of the need for storage since hydrogen storage will be available on all except very short timescales.

FIGURE 7

Cumulative differences between supply and demand 1980 to 2016.

Cumulative differences between supply and demand, in each quarter and over 37 years, 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.



2.4.2 Surpluses and deficits

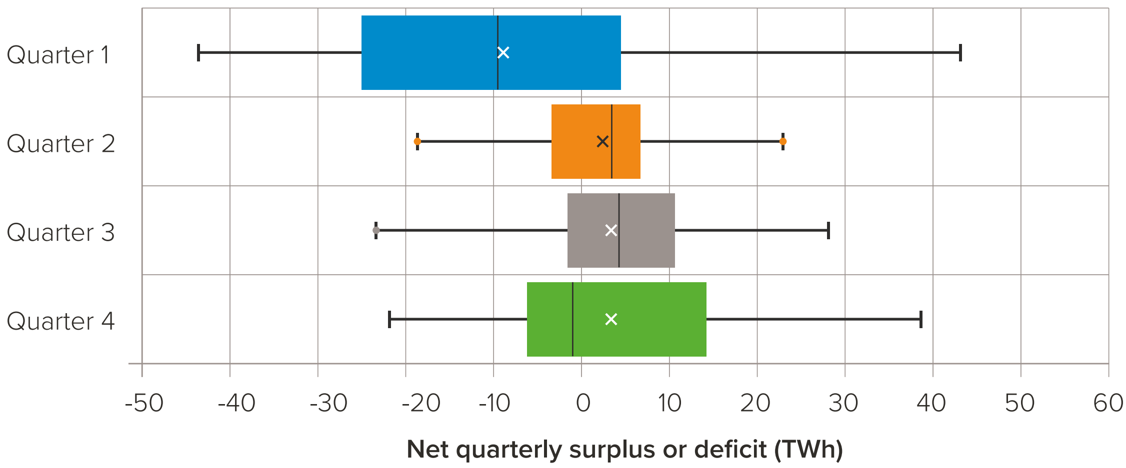
Figure 7 shows the cumulative difference between supply and demand, in each quarter and over 37 years, obtained by combining the AFRY and RN models, with renewable supply scaled to be equal to demand over the whole period. The large variation from year to year, which is strikingly manifested in the very 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. If displaced upwards by 50 TWh, the cumulative total would represent the amount of energy in a hypothetical 100% efficient store that initially contained 50 TWh, which could be used to exactly balance supply and demand over 37 years. Such a store would have to be able to accommodate 192 TWh (the difference between the maximum and minimum of the cumulative total) and be charged by a system capable of storing all residual power, which ranges up to 123 GW in this case. In the realistic case of much lower efficiencies, a much higher level of wind and solar supply would be needed to meet demand (assuming there are no other sources of supply). However, while the volume of storage and the power needed to fill the store are still dauntingly large at the minimum ('threshold') level of wind and solar at which demand can be met, they decrease very rapidly as the level increases above the threshold, as discussed in the next chapter and shown in figure 12.

The variation and 37-year averages of the quarterly deficits and surpluses seen in figure 7 are shown in figure 8. The differences between the mean values in different quarters are small compared to the variations between years, and to the average of the absolute values of annual / quarterly residual energy, of 123 / 30.8 TWh. With a wind-solar mix around 80 / 20, residual energy, and the need for storage, are dominated by volatility on all timescales, not by seasonal differences. This remains approximately true for solar contributions in the range 10 – 30%, although (see SI 2.4) with 30% solar there is a noticeable (although small compared to volatility) surplus in the summer, while with 10% solar there is a small surplus in the winter.

FIGURE 8

Net quarterly surpluses and deficits averaged over 37 years.

X is the mean, the central vertical line shows the median, the horizontal line extent shows the range of the data, and the coloured boxes show the interquartile range (the middle 50% of the data).



2.5 Residual demand, energy and power

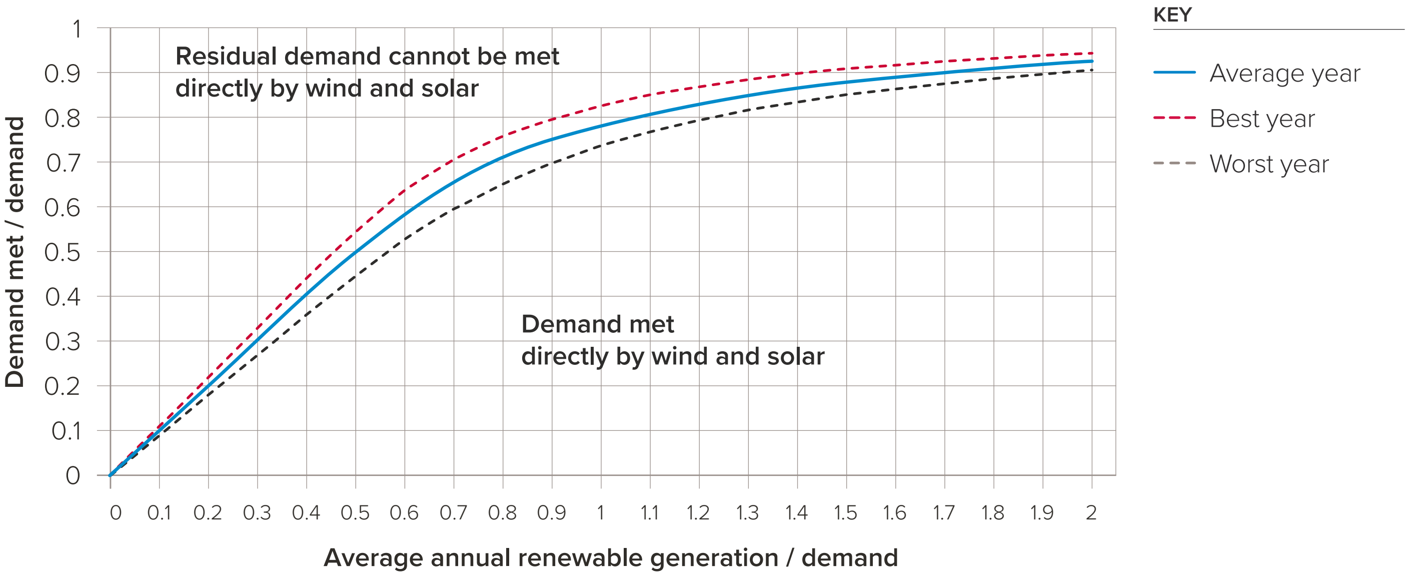
2.5.1 Residual demand and energy

The fraction of demand that (according to the AFRY / RN model) can be provided by wind and solar energy directly in an average year, is shown in figure 9a as a function of the average level of wind and solar generation divided by annual demand (expressed in this way, residual demand varies very little across a wide range of models – see SI 2.5). The surplus, which is implicit in figure 9a, is shown explicitly in figure 9b; it can be stored and used to meet all or part of residual demand, curtailed, or used for other purposes, as discussed in section 8.6.

These plots show that for renewable supply up to 50% of demand, almost all of the renewable supply could in principle be used in an average year. In practice, however, this could only happen if all other sources of supply were instantly turned down whenever their contributions plus those of renewables exceeded demand. Figure 10 shows the situation if some of the demand is met by inflexibly operated ‘baseload’ supply.

FIGURE 9

A) Fraction of demand that can be met directly by wind and solar in an average year.



B) Percentage of wind and solar generation that cannot be used to meet demand directly, and is therefore available to be stored or used in other ways.

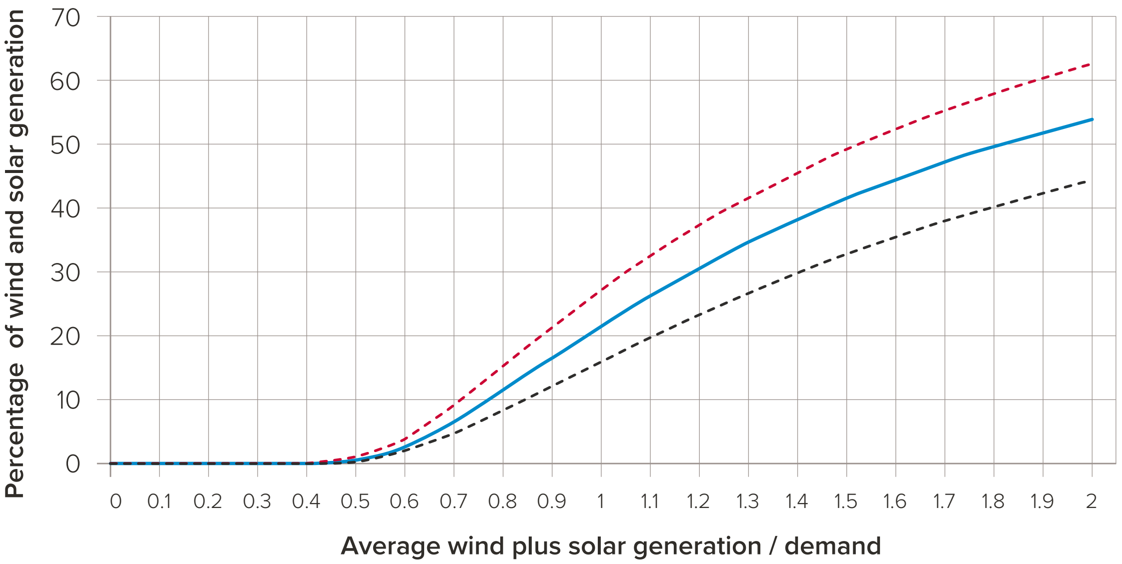
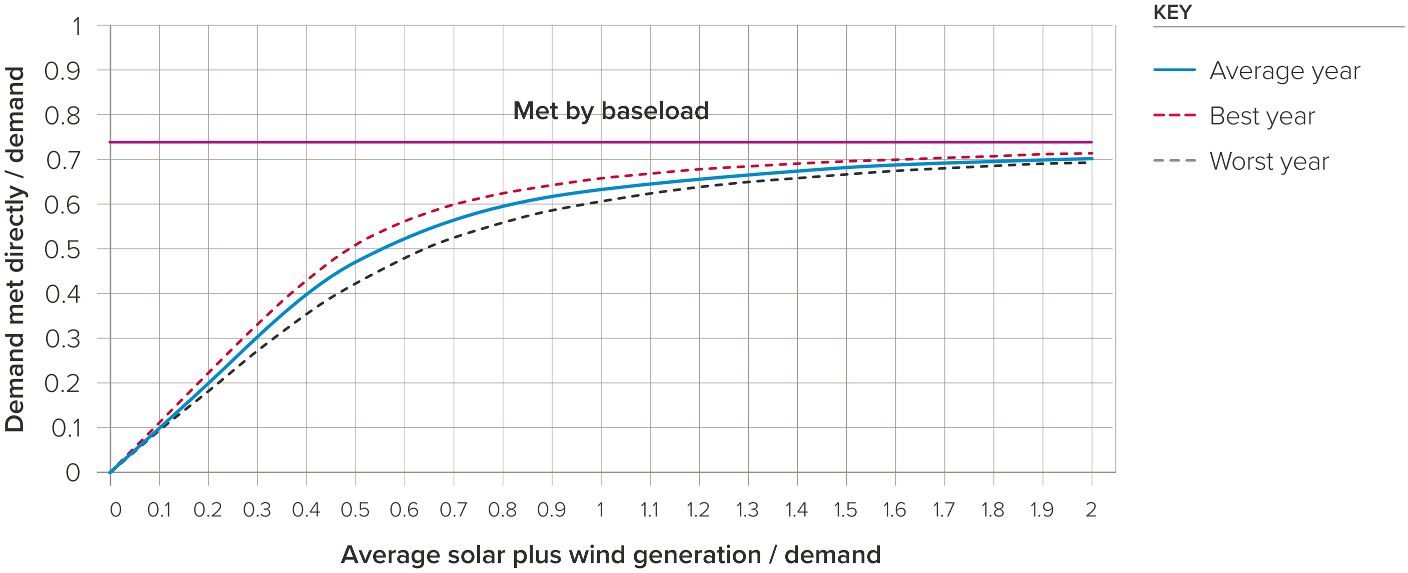


FIGURE 10

A) As in Figure 9 in the case that a constant baseload supply generates 150 TWh/year.



B) The surplus electricity after demand is met by baseload generation and wind and solar.

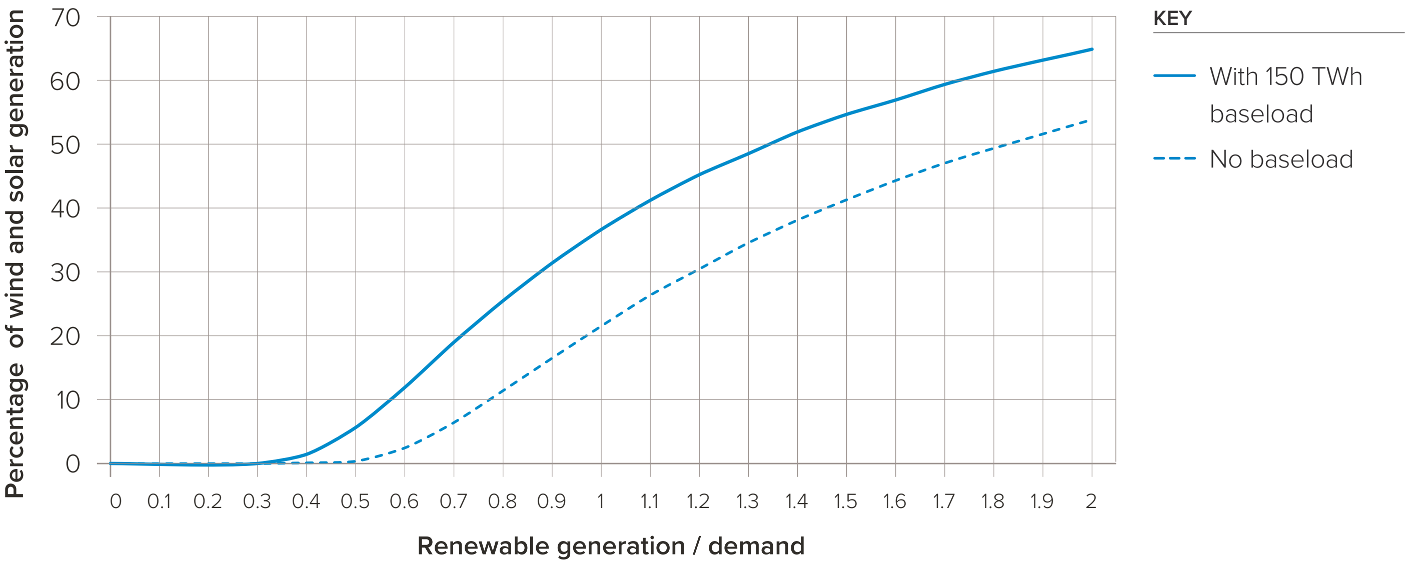
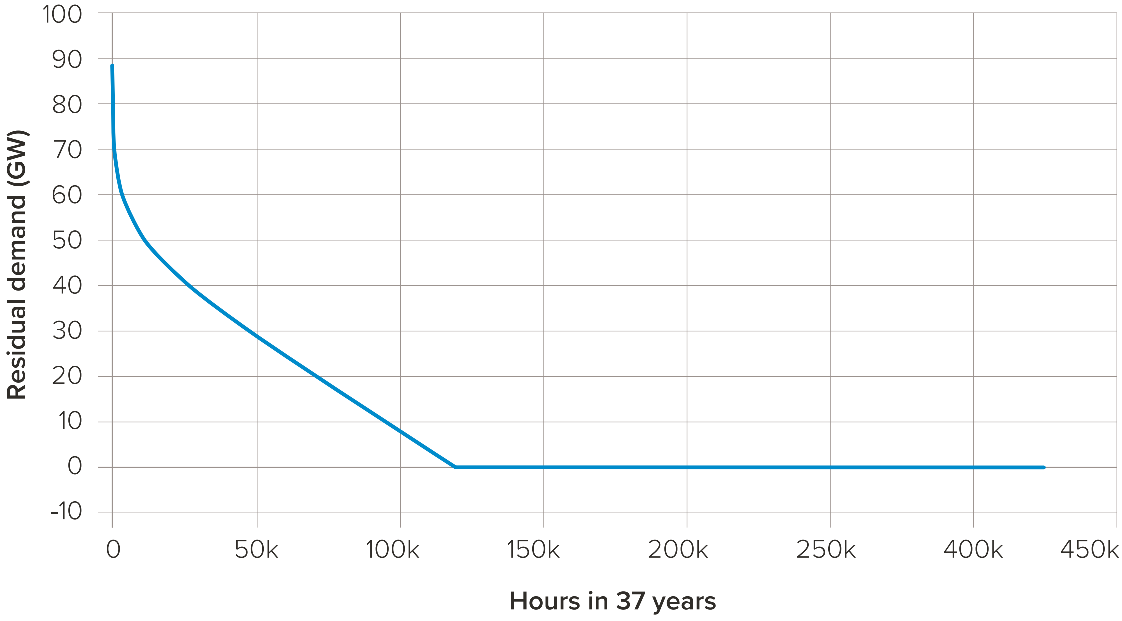


FIGURE 11

Spectrum of residual demand for 741 TWh/year average wind plus solar generation.

Spectrum of residual demand over 37 years with an average of 741 TWh/year wind plus solar supply and the AFRY model for 570 TWh/year demand used in every year. The inclusion of detailed correlations between the weather and demand would increase and broaden the peak.



2.5.2 Residual power

Figures 9 and 10 show that with high levels of wind and solar, residual demand for energy is relatively small. However, residual demand for power can reach very high levels, as seen in figure 11, which also shows that with supply = 1.3 x demand = 741 TWh/year there is a surplus 63% of the time in an average year. Whatever meets this demand (storage or other sources) will be operating most of the time well below the peak power that it was built to provide: the electricity it provides will therefore inevitably be expensive.

Maximum demand is 98.4 GW in the AFRY model, while the minimum in supply is 0.4 GW in the 37 years studied (the spectrum of demand and supply in these models is reported in SI 2.5). It happens that these values never coincide, and the model finds a maximum residual demand for power of 88.2 GW. However, correlations between the weather and demand, which will increase residual demand, and broaden the peak in figure 11, cannot be ignored in this case because the 37 years studied do not cover all possibilities. It would therefore be unwise to assume that such a coincidence can never happen, and storage plus complementary generation should be designed to meet maximum demand. The costing of storage in this report allows (prudently) for maximum residual power of 100 GW when using AFRY's model of 570 TWh/year 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) if £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)		

2.6 Generating costs

The desirable level of wind and solar generation, and the need for storage, will be determined by their costs, and by the availability, characteristics (especially cost and flexibility), and environmental credentials of generation by other low-carbon sources. In estimating the average cost of electricity in 2050, three values will be used for the weighted (80% wind – 70 / 30 offshore / onshore + 20% solar) average cost of wind plus solar power:

- £30.2/MWh, a value derived from the IEA's 2020 projection[14] of costs in Europe in 2040 using the capacity factors assumed by BEIS for the UK in 2040;
- £35/MWh, just above BEIS's low projection[1] for 2040 (of £34.9/MWh); and
- £45/MWh, just above BEIS's high projection[1] (of £39.6/MWh) for 2040.

SI 2.6 includes a detailed analysis of the other forms of low-carbon electricity generation. Table 2 summarises the key features of the main low-carbon options for GB. Only nuclear, gas with CCS, and Bioenergy, with or without CCS (BECCS) are capable of meeting a significant fraction of demand. All are expensive or very expensive if operated flexibly to complement fluctuations in supply and variations in demand.

f A report for BEIS projected £138/MWh with chemical looping, but BEIS 'has greatest confidence' in post-combustion capture

2.7 Demand management

The term demand management is used to describe both reducing demand and shifting it in time. Models such as AFRY's and the National Grid's scenarios build in assumptions about overall reductions in demand and improvements in energy efficiency, which will not be considered here. In order to evaluate the need for storage, it is important to understand the scope for emergency time shifting leading to temporary reductions, which could provide some contingency for dealing with rare weather events.

The National Grid's Demand Flexibility Service provides incentives that encourage shifting demand during peak winter days, while its net zero compatible 2050 scenarios[5] assume demand-side response flexibility of 24, 34 and 37 GW. This looks achievable (see SI 2.7) and would help flatten the evening peak in demand, and deal with short term mismatches between supply and demand. However, it 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, as shown by a study of wind and solar supply in Germany[15] the maximum energy deficit occurs over a much longer period because multiple scarce periods can follow each other closely (as discussed in SI 2.7 and seen on a yearly scale in figure 2).

Prolonged periods of low wind, which can occasionally last a few years, risk emptying energy stores if they are not provided with enough contingency. If these periods could be forecast in advance, the risk could be reduced by taking some of the measures described by the IEA[16, 17] in an analysis of responses to prolonged shortfalls in electricity supplies, which have occurred occasionally in many countries.

The IEA found that large savings can be made, especially when problems are foreseen well in advance. Examples include a 14% reduction over 9 months in California in 2002, and savings of 15% in Japan in the summer following the Fukushima disaster (more examples are given in SI 2.7). Successful strategies that have dealt with such shortfalls include: raising prices; campaigns to change behaviour, which urged measures such adjusting schedules for the use of electricity-intensive equipment; and rationing, which can be supplemented by trading of entitlements.

Modelling the need for storage

3.1 Introduction

Many estimates have been made of the need for storage (see SI 3.1). They are not always easy to compare as different assumptions were made, for example on the acceptable level of CO_2 emissions and what sources of supply are available, while the need for storage depends on the climate and weather. Further, while the amount of energy that has to be supplied by storage depends only on the scale and temporal profiles of supply and demand, the storage capacity required to provide this energy depends on the efficiency of whatever stores are deployed and the rates at which they can be charged and discharged.

3.1.1 Timescales

The characteristic periods on which residual demand fluctuates are:

- Daily – driven by day / night variations in demand and solar supply.
- Weekly – driven by week / weekend differences in demand.
- From days to weeks to a few months – driven by random weather variations and frontal weather systems that affect wind and (via cloud cover) solar supply.
- Seasonally – driven by demand, wind supply being higher in winter, and solar supply being higher in summer. With the 20 / 80 solar / wind mix used in this study of GB, the large seasonal variations that are seen in most years average out over many years: the underlying problem is variability not seasonality (as shown in figure 10).
- Multi-year – driven by long-term changes in wind, linked to changes in the magnitude and frequency of the NAO in atmospheric pressure.

There are also very short-term fluctuations in residual demand due to sudden changes in supply (created by system trips for example) and demand (including making the proverbial half-time cup of tea during major football matches). However, as discussed in section 1.3, the storage that is needed to deal with these fluctuations is small-scale and is outside scope of this report[g]. Apart from this need, and the need for stores with low capital costs to provide long-term storage, it is not possible to choose storage technologies by matching the time scales needed to recover costs with the characteristic times on which residual demand fluctuates.

3.2 Modelling and costing with a single type of store

3.2.1 The interplay of charging rates, storage capacities and the level of wind and solar supply

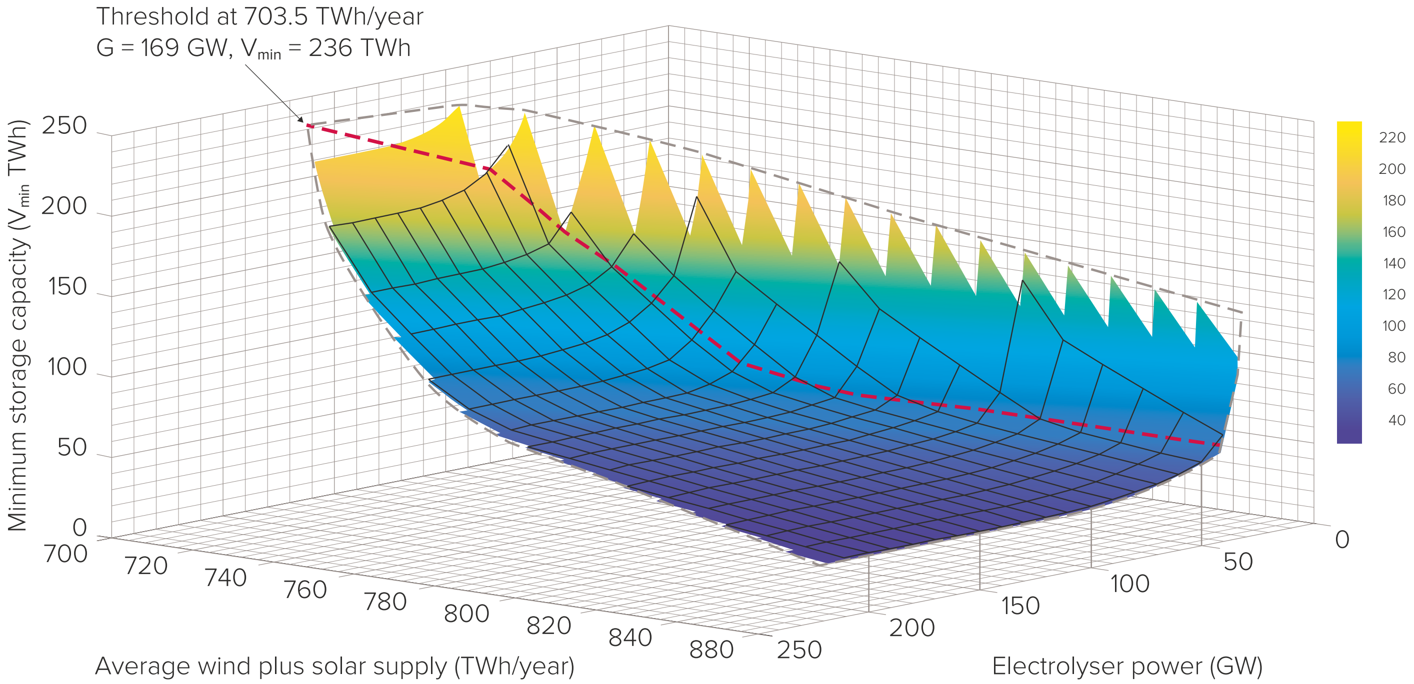
At the threshold, the minimum level at which wind and solar supply and storage can meet demand, all surpluses have to be stored. Above threshold, it is not necessary to store all surpluses, and there is a choice (within limits) between a relatively small storage capacity charged rapidly by a powerful cohort of electrolysers and a larger capacity charged more slowly by a less powerful cohort. The allowed domain is shown in figure 12 in the case that all GB's large-scale storage needs are met by hydrogen, and wind and solar are the only sources of supply. If the electrolysers' power was less than the value at the back edge of the surface in the figure, they would not be able to replenish the store fast enough to keep pace with depletion, and demand could not 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 (see SI 3.2 for further discussion).

g Very short-term needs cannot be seen or analysed using the models of demand and the weather used in this report which have a time resolution of one hour.

FIGURE 12

Level of wind and solar generation and hydrogen storage parameters for which all demand can be met.

Hydrogen storage can meet demand provided the storage capacity (V) is above the surface shown here as a function of the electrolyser power (G) and the level of 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, $V = 1.2 \times V_{min}$



3.2.2 Costs

The way in which the electrolyser power, the size of the store and the level of wind and solar supply and the corresponding average cost of electricity are found will be illustrated using the 2050 cost estimates in table 5, using a 5% discount rate, assuming that an 80 / 20 mixture of wind and solar power will cost £35/MWh and that 20% contingency should be added to the capacity of the hydrogen store. There are two steps (which can be combined):

Step 1

For a fixed average level of wind and solar generation, taken for purposes of illustration to be 1.3 x demand = 741 TWh/year, calculate the cost of electricity as a function of the electrolyser power (G) and storage volume $V = (1 + 0.2) \times V_{min}$, where 0.2 is the 20% contingency (V_{min} and G are dependent and must lie on the surface in figure 12). With the base costs for G and V, the values that minimise the cost of electricity are G = 89.4 GW, V = 123.1 TWh. The varying level of hydrogen in the store obtained with these values is shown in figure 13 over the 37 years studied.

FIGURE 13

Level of stored hydrogen in a 123 TWh_{LHV} hydrogen store filled by 89 GW of electrolysers.

Level of stored hydrogen assuming average of wind plus solar generation of 741 TWh/year, electricity demand of 570 TWh/year and that all electricity is provided by wind and solar supported by hydrogen storage, apart from a small amount needed to regulate voltage and frequency. It is not possible to see hourly increases and decreases with this resolution, which leads to the false impression that the store is frequently full for sustained periods.

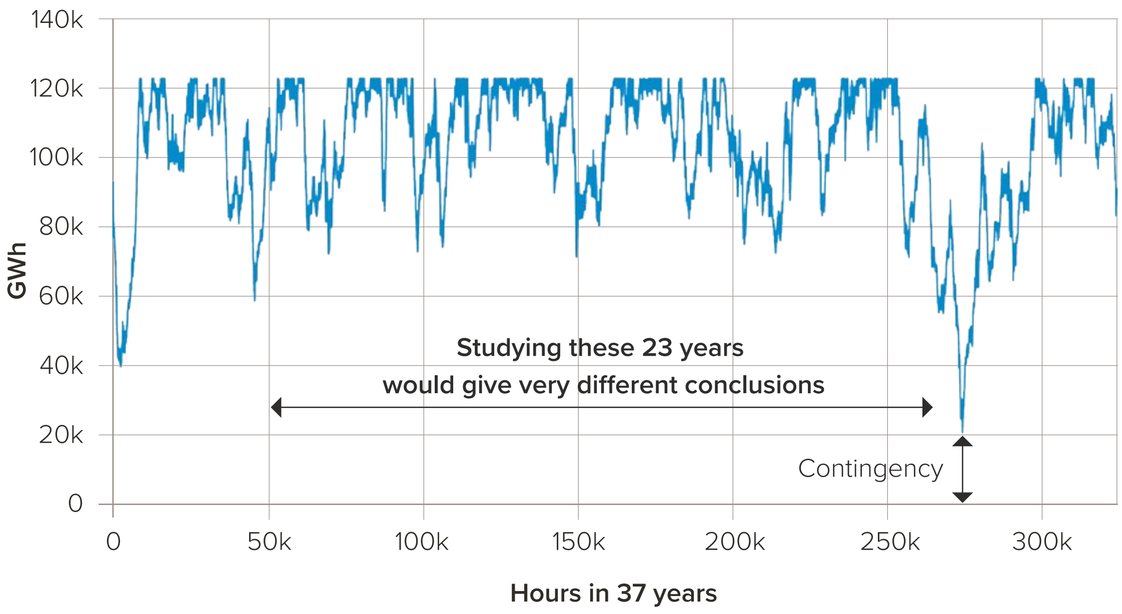


Figure 13 exhibits two striking features. First, a study of the 23 years 1984 – 2006 would have found a storage volume very much smaller than found by studying 1980 – 2016. Second, there is a very large call on storage in the period 2009 – 2011 which reflects persistently low wind speeds that lead to the large deficits seen in figure 2 (some of the energy that fills these deficits would have been in the store since 1980). These features reinforce 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.

Step 2

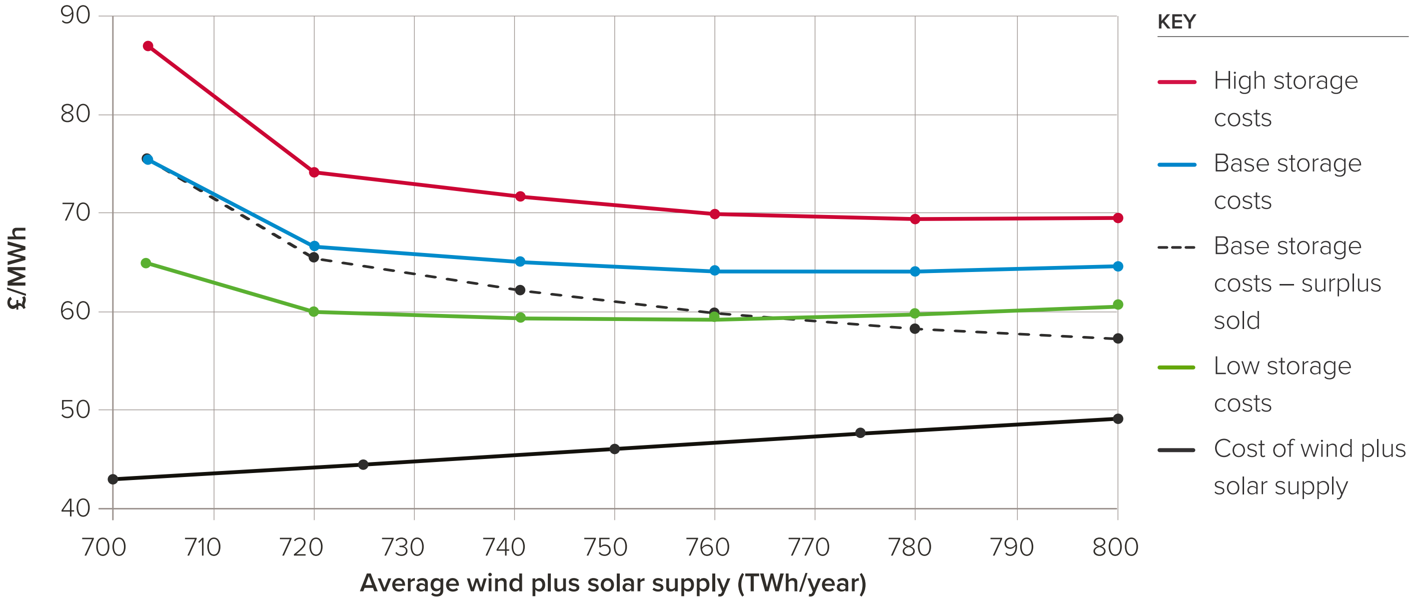
Find the level of wind and solar supply that minimises the average cost of electricity by allowing it to vary, as shown in figure 14. At the threshold level, the minimum storage volume and the required electrolyser power are both very large, as seen in figure 12, but their sizes and costs fall rapidly as the level increases. Meanwhile, the cost of the wind and solar supply increases, leading to a very broad minimum in the average cost of electricity at around 8% above the threshold, where wind and solar supply = 1.33 x demand, which is analysed further in section 8.3.1.

FIGURE 14

Average cost of electricity provided to the grid.

Wind plus solar @ £35/MWh. Discount rate 5%.

Average cost of electricity provided to the grid with different assumptions about costs. Here low / base / high refer to the assumed costs of electrolysers, storage and generating power from hydrogen. The significance of the dashed line is explained in Section 3.2.3.



3.2.3 Residual surpluses

Except at the threshold for storage to work over the whole 37-year period, a residual surplus of wind and solar energy inevitably remains after the assumed demand has been met. If additional demands (beyond those assumed in the AFRY model) that could make use of the residual surplus are found, it could have a significant effect on costs. If the entire surpluses were valued at cost (£35/MWh), which would represent a presumably unrealistic upper bound, it would reduce the average cost of electricity to the values shown by the dashed line in figure 14. Possible uses of the surplus are discussed in Chapter 8. The alternative to using the surpluses is to curtail or 'spill' part or all of them.

3.3 Modelling and costing with several types of store

Grid operators will have to decide how to assign surpluses to different types of store, and which stores to discharge to fill deficits. An assumption about how this will be done has to be made in order to model storage and estimate the average cost of electricity. Given the costs of all its elements, a system that would have delivered electricity at the least cost over a given historical period can be designed with hindsight. Such hindcasting can provide useful insights, but a system that worked at the lowest cost in the past would not necessarily do so (or even work) in the future given the vagaries of the weather.

To illustrate the scheduling procedure used in this report, which does not require foresight, consider combining ACAES with hydrogen storage. The addition of ACAES decreases the need for hydrogen storage. Adding ACAES will only be worthwhile if the consequent reduction in costs is greater than the cost of the ACAES system. This is most likely to happen if ACAES is normally[h] given priority in storing surpluses, and in discharging electricity to fill deficits. This is because the more energy that is stored in and delivered by ACAES, i) the smaller the size and cost of the hydrogen system, which must handle the remainder, and ii) the lower the amount and cost of the wind and solar energy that is required since ACAES is more efficient.

More work is needed on procedures for scheduling storing and dispatching electricity, and on combining storage with other sources of flexible supply. It would be interesting to study scheduling procedures that use seasonal, as well as weather, forecasts. It is generally not possible to predict day-to-day changes in the weather in much detail beyond a week ahead, but the reliability of long-range broad-brush forecasts is improving[18]. Key aspects of European and North American winter climates can be predicted months ahead with reasonable reliability[19]. This makes it possible to make probabilistic forecasts of near-surface wind speed and air temperature and therefore predict energy supply and demand[20].

Implementing any scheduling procedure designed to lead to low costs would require close cooperation between the electricity generators and the operators of storage. This raises challenges for the governance and design of the electricity market, which are discussed in Chapter 9.

h If, using forecasts of supply and demand, it is found that always giving priority to ACAES would result in it becoming more than ~ 90% full in the next 12 hours, priority in charging is switched to hydrogen. Conversely, if it would become less than ~ 10% full, priority in discharging is switched to hydrogen. (The precise level at which the switch is made depends on the assumed efficiency of ACAES: for details see SI 3.3). The introduction of this refinement changes the demands on each store to absorb and provide power and reduces the average cost of electricity by ~ 2% relative to the value that is found if ACAES is always given priority.

Green hydrogen and ammonia as storage media

4.1 Introduction

Hydrogen and ammonia can be used to store electrical energy in the sequence:

electricity → hydrogen or ammonia → transport / store → electricity.

Hydrogen has a higher gravimetric energy density (kWh/kg), but a much lower volumetric energy density (kWh/litre) than ammonia, methane or petroleum (see figure 15), unless it is compressed to several hundred times atmospheric pressure, liquified at -253°C, or stored as a component of a chemical compound (such as methanol CH_3OH, or ammonia NH_3) from which it can be readily be separated. Ammonia is more expensive to produce than hydrogen, but it becomes liquid at just -33°C at atmospheric pressure. It is therefore cheaper to transport and to store than hydrogen. For uses where either hydrogen or ammonia would serve, the former being cheaper will usually be preferred if the point of use is close in time and space to the point of production and large-scale storage and transport are not needed.

4.2 Hydrogen and ammonia production

4.2.1 Hydrogen

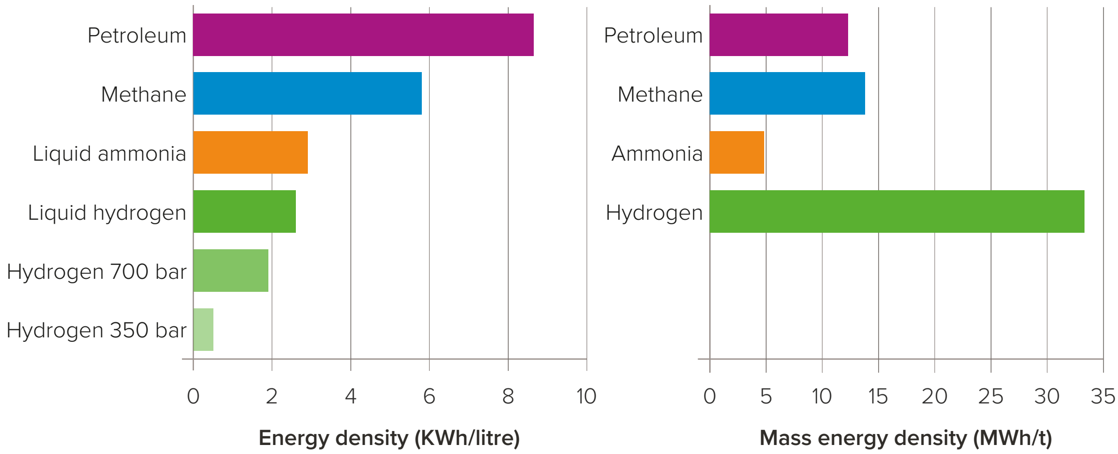
Worldwide, dedicated hydrogen production currently amounts to some 69 Mt p.a. mainly by steam methane reforming, with a thermal energy content of approximately 2,300 TWh_{LHV} (equivalent to the energy content of around 9% of annual global electricity supply)[21]. In addition, 48 Mt p.a. is produced as a by-product from the catalytic reforming in oil refineries and the production of chlorine and olefins. A small amount (around 2%) is produced electrolytically as a by-product of chlorine and caustic-soda production. Dedicated electrolysis provided less than 0.1% in 2019, but since then electrolyser capacity has grown, from 242 MW to 1398 MW in 2022, with 5,517 MW anticipated in 2023[21, 22].

The production process of interest in this report is electrolysis of water, powered by 'green' carbon-free renewable energy to make low-carbon 'green' hydrogen, which can be used directly as an energy store, or to make 'green' ammonia.

In electrolysis, a direct electric current is used to split water into hydrogen and oxygen, on the cathode and anode sides of an electrochemical cell, which are separated by an ion-conducting electrolyte. Electrolysers, which consist of a number of cells built into stacks, can range from domestic appliance size to industrial production facilities. The output scales with the surface area of their anodes and cathodes.

FIGURE 15

Energy densities of energy carriers[i].



The characteristics of three types of water electrolysers[j] are summarised in table 3. The projections of costs and performance span wide ranges as they depend on the size of the module and the scale of production, as discussed in SI 4.2. For example, although IRENA's summary table quotes a 2050 cost of < $200/kW for alkaline and polymer electrolyte membrane electrolysers their text gives $307/kW and $130/kW for cumulative production of 1 TW and 5 TW respectively.

In modelling storage in this report, the following 2050 electrolyser parameters are assumed: cost (including rectifier, balance of plant, installation and a share of site costs) $450 + / -50%/kW$_e$; efficiency 74% (the conclusions are not very sensitive to the efficiency); operating lifetime 30 years[k]; annual O&M cost of 1.5% of the capital cost; output hydrogen pressure of 30 bar (the higher the pressure, the less compression is needed prior to storage).

i Here and throughout this report the energy density/thermal energy content (or 'equivalent calorific value') of hydrogen is quoted in terms of its lower heating value (LHV). The higher heating value (HHV) is also often used. In the case of hydrogen, the HHV is 18% larger than the LHV (see glossary for definitions).

j Anion Exchanged Membrane Electrolysers, which are discussed in SI 4.2, are considered to be a promising fourth option, but they are less mature than the other three and limited information is available about their long-term operation, reliability and robustness.

k With the load factor of around 30% found in the high hydrogen storage scenario discussed in Chapter 3, a lifetime of 30 years corresponds to some 80,000 operating hours. The deterioration of electrolyser performance with use is ignored in costing storage in this report as it only has a small effect on their net present value because the fade rate is small and later years, when fade is significant (perhaps 30% at the end of life), are discounted.

TABLE 3

Properties of different types of electrolysers.

	Alkaline		Polymer Electrolyte Membrane		Solid Oxide	
Availability	Commercially available for many years		Commercially available but potential for improvement		Not yet demonstrated at scale	
Electrolyte / membrane	Sodium, or potassium hydroxide		Aqueous electrolyte polymeric membrane		Oxygen ion conducting ceramic, typically zirconia (ZrO_2) based	
Load following	Can follow		Can follow very fast transients < 1 sec		Ability depends on the design	
	IRENA[23]	**IEA**[21]	**IRENA**[23]	**IEA**[21]	**IRENA**[23]	**IEA**[21]
Efficiency today*	43 – 67%	63 – 70%	40 – 67%	55 – 60%	61 – 74%	74 – 81%
2050 (IRENA) / Future (IEA)	> 74%	70 – 80%	> 74%	67 –74%	> 83%	77 – 90%
Cost today $/kW**	500 – 1000	500 – 1400	700 – 1400	1100 – 1800	> 2000	2800 – 5600
2050 / Future	< 200	200 –700	< 200	200 –900	< 300	500 – 1000
Lifetime today 1000 operating hours	60	60 – 90	50 – 80	30 – 90	< 20	10 – 30
2050 / Future	100	100 –150	100 –120	100 –150	80	75 – 100
Output pressure (bar) today	< 30	1 – 30	< 70	30 – 80	< 10	1
2050 / Future	> 70	–	> 70	–	> 20	–

* LHV of produced hydrogen / electrical energy input – based on AC power input.

**Full system costs. Ranges depend on scale of manufacturing and size of module – see text. In their simulations, IEA assume a future cost of $450/kW and an efficiency of 74%.

Turning to the different types, which are discussed in more detail in SI 4.2:

Alkaline electrolysers may take up to 30 minutes to start from cold, but can be kept warm when not working, and can load follow when working, subject to some constraints on ramping rates. When storing volatile wind and solar power, electrolysers are likely to be switched on and off some 200 times / year. This could possibly reduce the lifetime of alkaline electrolysers, although recent measurements[24] support the expectation (see SI 4.2) that this will not be a serious issue.

Polymer Electrolyte Membrane (PEM) electrolysers use both platinum and iridium as catalysts. The availability of platinum is unlikely to limit deployment (as discussed below in relation to fuel cells), but the availability of Iridium will constrain rapid large-scale global roll out of PEM electrolysers. Reduction / elimination of Iridium should be a high priority for future R&D.

Solid Oxide (SO) electrolysers have not yet been demonstrated at scale, so their future costs are uncertain. They are fed by steam (which could be provided electrically or by waste heat) which leads to a somewhat higher efficiency than for low temperature alkaline electrolysers especially if waste heat is used. They have the major advantage that they can, in principle, be operated reversibly – as electrolysers when there is surplus wind and solar power, and as fuel cells when there is a deficit. This could provide a cost advantage for storage that would probably more than offset the fact that they produce hydrogen at ambient pressure.

The optimal way to source electrolytic hydrogen at scale may be from a mixture of facilities that use different technologies, for example using alkaline electrolysers when steady or slowly changing power is available and PEM electrolysers (which currently have higher unit capital costs) to provide additional flexibility and faster response to transients in the power supply.

With the electrolyser cost and efficiency used in this report (summarised above), the cost of green hydrogen (without the cost of the input power which dominates the total cost) would be \$(5.97/load factor) / MWh_{LHV} with a 5% discount rate, and \$(8.40/load factor) / MWh_{LHV} with 10%. The cost / tonne is given by multiplying by 33.3.

4.2.2 Ammonia

Ammonia is today produced by the Haber-Bosch (HB) process, in which hydrogen and nitrogen are combined at high temperature and pressure in the presence of a metal catalyst.

It is possible to synthesise ammonia directly from air and water using a catalytic electrochemical process. The rates observed in the laboratory are currently very low, and there are many challenges to be overcome before direct synthesis could be commercialised. Direct synthesis is the subject of R&D worldwide: success would be a game changer.

The HB process currently requires continuous running in order to maintain efficiency and avoid degradation of the catalyst or the process equipment. When input energy or hydrogen supply is variable, buffering by electricity, and / or more likely by hydrogen and nitrogen storage, would be required to ensure constant running. This will increase costs compared to using a plant with a constant power supply.

Natural gas-based ammonia is today almost all made in integrated plants that include a methane reformer (to produce hydrogen), an air-blown secondary reformer which introduces nitrogen, and an HB synthesis loop to produce ammonia. For green ammonia, the reformers would not be necessary, but nitrogen would have to be supplied from an air separation unit (ASU). Analysis of the costs of existing ammonia plants, and cost estimates found in the literature and provided by industry sources, which are described in SI 4.2, leads to the conclusion that the full cost of an ASU and an HB is around \$900 per tonne of ammonia per year on a US Gulf Coast basis. For comparison, the IEA gives a capital cost today of \$945 per tonne ammonia per year, and projects \$760 per tonne ammonia per year for the long-term cost. In recognition that costs may evolve over time (although the technology is mature), \$760 per tonne ammonia per year is assumed here for green ammonia production in 2050, excluding the cost of the associated electrolysers.

With this assumption, the estimated cost of hydrogen above, annual O&M of 4% of capex, a financial project lifetime of 30 years, the cost of making ammonia, excluding the cost of input power, would be:

- \$(32.6 for hydrogen production + 79.8 for ammonia synthesis) / (load factor) per tonne of ammonia per year, with a 5% discount rate; or
- \$(49.4 for hydrogen production + 111.0 for ammonia synthesis) / (load factor) per tonne of ammonia per year, with a 10% discount rate.

This assumes that hydrogen production and ammonia synthesis are concurrent (if not, hydrogen storage would add to the cost).

The overall efficiency [MWh_{LHV} ammonia produced) / (MWh input energy)] is: $((1.14 / (\text{electrolyser efficiency})) + 0.07)^{-1} = 62\%$ for an electrolyser efficiency of 74%.

4.3 Transport

In costing the use of stored hydrogen, it is assumed in this report that electrolysers, stores and whatever is used to generate electricity from hydrogen, are co-located. If not, it would be necessary to transport hydrogen to / from the stores in pipelines as using trains or tankers would be much more expensive (see SI 4.3 for a comparison of the options). The size and cost of the pipes that would be required depends on the maximum flow rate, which has to be calculated case-by-case (for which purpose the unit costs and flow rates used by IEA were assumed in this report). If GB were powered entirely by wind and solar energy supported by hydrogen storage, and electrolysers and generators were 100 miles from the store, transporting hydrogen would add some £22/MWh_e to the cost of the 15% of electricity that is provided by hydrogen storage, and £3.3/MWh_e to the average cost of electricity, unless it were possible to use refurbished natural gas pipelines.

4.4 Storage

4.4.1 Hydrogen

On the TWh scale, the cost of storing hydrogen in solution-mined salt caverns[l] is an order of magnitude less than the cost of storage in high pressure tanks or as a liquid[25]. GB currently has an underground cavern storage capacity for some 25 GWh of hydrogen and over 20 TWh of natural gas, which (if / when natural gas is phased out) could house some 7 TWh of hydrogen (much less than will be needed). Salt caverns, which are widely used to store natural gas, are 'recognised for being very gas tight and therefore well suited for hydrogen storage'[26]. Three salt caverns are used for hydrogen storage in Texas (they have volumes of 580,000 m^3, 566,000 m^3 and 906,000 m^3, and have been in operation since 1983, 2007 and 2017 respectively[m]). A cluster of three 70,000 m^3 caverns (which have been in operation since 1972) are used to store hydrogen on Teesside.

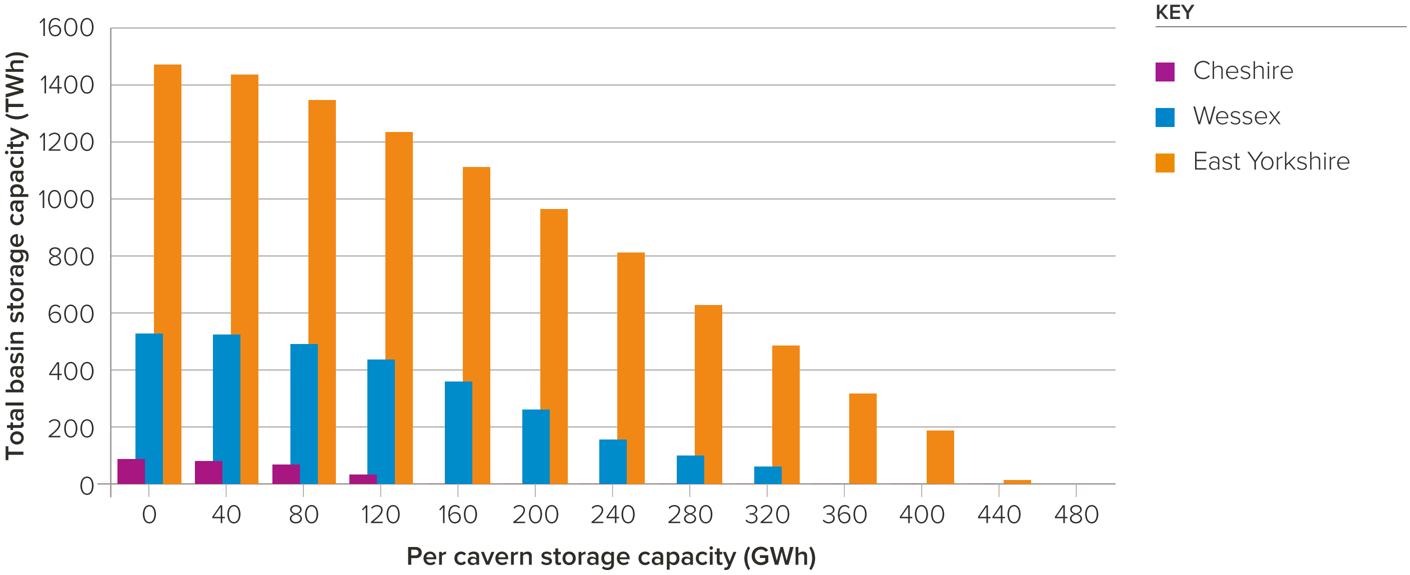
l There is a potential for storing hydrogen in undersea aquifers, relatively close to shore. On-going research is exploring this possibility. Losses of hydrogen could be an issue.

m The storage capacities, which depend on the pressure range, which depends on the depth, are 69, 194 and 232 GWh_{LHV}. The cluster of caverns on Teesside can accommodate 26 GWh_{LHV}.

FIGURE 16

Basin-wide storage capacities.

Basin-wide energy storage potential in the three study regions, after excluding areas occupied by towns, roads, railways, mine workings, waterways, rivers, canals, protected areas, geological faults, formation boundaries and areas of wet rockhead. For each value on the horizontal axis, the height of the bar is the total amount of energy storage available in the basin in caverns of that capacity or greater.



This report uses the H21 NE consortium's estimate of the cost of storing hydrogen in clusters of 10 300,000 m^3 solution-mined caverns in East Yorkshire[26]. Each cavern would house 122 GWh_{LHV} of useable hydrogen. The British Geological Survey has estimated the potential storage capacity as a function of the capacity in three regions[27] (see figure 16). Altogether there are more than 3000 potential cavern locations in East Yorkshire that could each store 122 GWh in the conditions assumed by H21 NE[26]. The distribution would allow them to be grouped in clusters of 10 caverns, which could all be within 15 miles of the sea thereby limiting the cost of brine disposal[n]. The potential capacity in East Yorkshire alone is far more than required to provide the ~ 100 TWh_{LHV} of hydrogen storage that would be needed to support GB's electricity system in the case of hydrogen storage only.

The cost of storing hydrogen in solution-mined salt caverns (described in figure 17), depends on many factors including:

- The geology, the depth and the distance from sites where brine can be disposed.
- The size and pressure. For example a study by the Argonne National Laboratory for the US Department of Energy[3] found that the cost of storing between 50 and 3000 tonnes of useable hydrogen at 150 bar varies approximately as $(mass)^{-0.52}$.
- The over ground equipment, management costs and contingency that are included.

n J Williams, British Geological Survey, private communication.

FIGURE 17

Solution-mining a salt cavern.

Note split vertical scale: the top of the 300,000 m^3 caverns costed by H21 NE are at a depth of 1700m. They have a height of 100m , and an average radius of 31m.

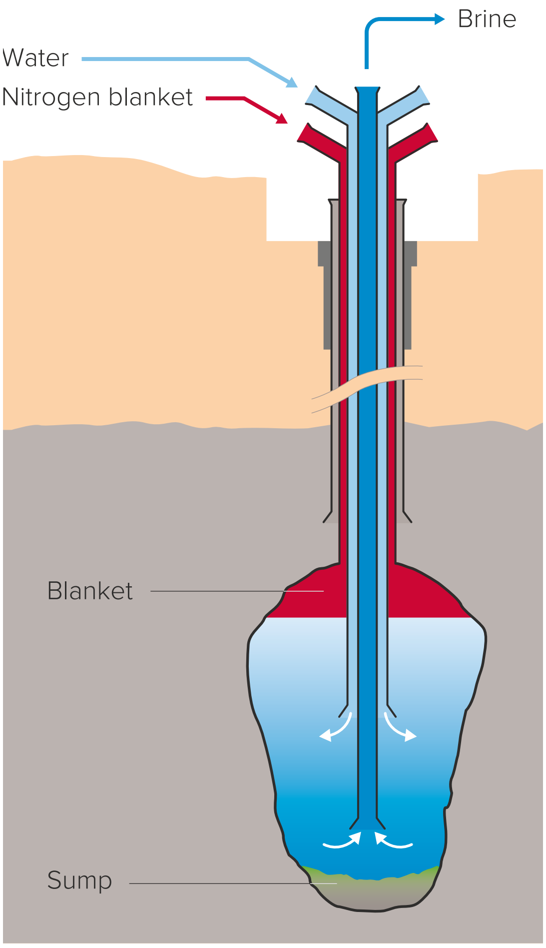


image: © DEEP.KBB GmbH.

H21 NE[26] based their estimates of subsurface costs on experience from an operational gas storage plant at Aldbrough and used quotations from suppliers to estimate the cost of critical equipment (compressors, coolers etc). The estimates include site preparation and services, management costs, brine disposal, and other costs, such as insurance, as well as some contingency. Their estimates are consistent with those made by the Argonne National Laboratory, although lower than some others in the literature, as discussed in detail in SI 4.4.

A range of one to two times the H21 NE[26] estimate, of £325M for a cluster of 10 caverns which would together house 1.22 TWh_{LHV} of useable hydrogen, will be assumed here.[o] The middle of this range is taken as the base case, reflecting uncertainties in costing underground work and the limited experience of building underground hydrogen storage facilities. The cost could be lower if constructing caverns substantially larger than 300,000 m^3 is practicable, compressor costs reduce, and electrolyser output pressures go up. It would, however, be rash to assume that the cost of storing hydrogen in 2050 will be lower than that estimated by H21 NE[26].

The H21 NE study assumes O&M costs of 4%/year of capex. This is for a system that is cycled regularly, whereas the modelling of storage described in chapter 3 suggests a very low throughput / volume, and 1.5% of total storage capex is assumed here. A financial lifetime of 30 years is assumed.

o The compressor power in the H21 NE[26] design is sufficient to handle hydrogen produced at the lower pressure and higher temperature assumed in this report, as it is provided at the lower rate needed for hydrogen storage.

A cluster of ten caverns of the size considered here could be built in five years, according to a well informed industry source, provided the caverns are solution-mined in parallel. If sufficient fresh water is not available, sea water could be used. If all the storage needed to complement high levels of wind and solar is provided by hydrogen, some 85 clusters of 10 caverns each will be required (without contingency, which would be added at the end). Building this many clusters by 2050 would be challenging, but the technical capabilities needed to execute such projects already exist in the UK. However, the UK's onshore natural gas storage could be converted to provide 7 TWh of hydrogen storage, while when – as proposed[28] – the offshore Rough storage facility is converted, it would provide another 10 TWh. Together these existing facilities would provide the same capacity as 14 of the clusters considered here.

4.4.2 Ammonia

At a large scale, the cheapest way to store ammonia is as a liquid, at -33°C and ambient pressure. The world's largest tanks can store 50,000 tonnes. Little public information is available about the cost of such tanks, but according to a source in the industry (private communication), costs for a 50,000-tonne tank and compressor in Europe would start at around €60M. Similar estimates can be found in the academic literature[29] and a cost of €60M will be used in this report. With the exchange rate used in this report, this corresponds to £197/MWh$_{LHV}$, which is 74% of H21 NE's[26] estimate of the cost of a hydrogen storage facility. In costing ammonia storage, it will be assumed that such tanks have a lifetime of 30 years, and that annual O&M would be 1.5% of their capital value.

4.5 Electricity generation

4.5.1 Hydrogen

Hydrogen can be used to generate power using fuel cells, internal combustion engines, or turbines. Although it is expected that hydrogen burning turbines will be available by the end of this decade, they will not be discussed here as it appears (see SI 4.5) that using fuel cells or 4-stroke engines would be cheaper.

Some savings could possibly be made by converting part of the existing fleet of ~ 30 GW of Combined Cycle Gas Turbines to burn hydrogen. However, hydrogen firing presents technical issues, and retrofitting of GTs to burn 100% hydrogen has not yet been demonstrated at scale. The cost of transporting hydrogen to CCGTs that are not close to where it is stored would reduce or remove potential savings.

Fuel cells

Fuel cells can be used to generate electricity, and also to provide industrial heat and combined heat and power. The options, none of which are currently deployed for grid scale hydrogen powered electricity generation, are:

Proton Electrolyte Membrane (PEM) fuel cells

These have high efficiency (today typically 55% for power application) and are increasingly used to power cars, buses, forklifts, etc, as well as to provide backup power for the grid[p, 30, 31]. Many studies have been made of the cost of fuel cells manufactured at large-scale for use in vehicles: a review for the US Department of Energy[32], for example, found that the cost of 237 kW stacks, produced at a scale of 20 GW/year, could fall to \$86/kW$_e$.

p They contain a catalyst consisting of platinum nanoparticles. It is expected that supply of platinum will be able to meet demand for fuel cells for power generation, and for powering vehicles, which is expected to be much larger, although 'there could be significant supply risks due to resource location' and 'reducing platinum loading…, increasing recycling rates, and improving the reliability of the platinum supply chain are appropriate measures to address the risks' (Hao H *et al.* 2019 Securing Platinum-Group Metals for Transport Low-Carbon Transition. One Earth 1, 117–125. doi:10.1016/j.oneear.2019.08.012).

Hydrogen powered cells designed for use in power generation will be more expensive as they will not be manufactured at such a large scale, balance of plant costs have to be added, and they will have to satisfy different demands (on operating point / power rating, power electronics, and stack material loading).

On the basis of a review of cost estimates in the literature (see SI 4.5), a base value of $425/kW$_e$ is assumed in this report (this is the central value found by Hunter et al, who give a range of 340 to 528/kW$_{e1}$[11]) for the full / installed capital cost of whatever technology is used to generate electricity from hydrogen in 2050, assuming large systems deployed at scale. A bottom of range cost of $300/kW$_e$ is assumed, based on the possible future cost of other types of fuel cells, the much lower costs found for PEM cells designed for use in vehicles, and estimates (below) of the possible cost of using 4-stroke engines. The top of the range is taken to be $425/kW$_e$ + 50% ($638/kW$_e$).

A financial lifetime of 30 years is assumed (typical projections in the literature are of operating lifetimes of 80,000 hours, corresponding to a much longer calendar lifetime given that the load factor on power generation is only 10% in the all-hydrogen storage scenario[q]), an efficiency of 55%. An operation and maintenance cost of 1.5% / year of the capital cost is assumed, which is the value given by the IEA for electrolysers, which are similar devices (O&M would be higher for 4-stroke engines).

Solid oxide fuel cells (SOFCs)

These are currently best suited for stationary applications, and can use a variety of fuels (methane, hydrogen and ammonia[33]). SOFCs powered by natural gas are around 60% efficient, although this could be increased to 85% or more by using waste heat. Little information is available on which to base cost projections, but SOFCs that operate at or below 700°C could become competitive with, or cheaper than, PEM cells in the future as manufacturing scales up and the technology matures. As discussed above, SOFCs can be reversed and operated as electrolysers. PEM electrolysers and fuel cells currently use different catalysts and cannot be operated reversibly.

High temperature proton conducting ceramic fuel cells[34, 35]

These, like phosphoric acid fuel cells, use catalysts based on materials that are widely available, but are at an early stage of development. Proponents believe that by 2050 they could be cheaper and more efficient than lower temperature PEM cells.

Internal combustion engines

Four-stroke internal combustion engines are widely used as standby generators, and – at larger scales – arrays of engines are becomingly increasingly competitive with gas turbines. For example, Wärtsilä have delivered a 600 MW peak power project in Jordan based on 38 multi-fuel engines[36]. The nine-engines in the 76 MW gas burning plant in Kansas cost approximately £30M ($395/kW$_e$) 'including appurtenances'[37].

q The deterioration of fuel cell performance with use is ignored in costing storage in this report. It only has a small effect on their net present value because the fade rate is small (very small with the load factor of 10% found in the all-hydrogen storage case) and later years when fade could become significant are discounted.

Pure hydrogen engines, which would be spark-ignition rather than compression ignition (unless a pilot fuel were included)[38], are coming into the marketplace today[39] and are already available from INNIO. They are being developed by JCB[40], Mercedes [41], Toyota[42], Wärtsilä[43] and other companies. Much of the development began by considering modifications of petrol engines, but some manufacturers are focussing on the ultra-lean burn conditions that are allowed by hydrogen's flammability, but are not accessible for petrol or diesel engines, with low temperature (which as a side-benefit mitigates NO_X formation). It seems that large engines designed to operate in this regime could be (at least) as efficient as PEM cells and not cost much more than petrol and gas engines. Although such engines are only at the prototype stage, it seems possible that large, mass-produced hydrogen burning motor-generator sets could fall below the $350/kW$_e$ cost of the engines in the Kansas plant. If so, 4-stroke hydrogen-burning engines could be cost competitive with fuel cells not only in the short, but in the long term. A graph of the efficiency of electric vehicles published by McKinsey[44] contains 'illustrative' lines which show hydrogen engines being more efficient than diesel engines for all output and more efficient that fuel cells above about 60% of the maximum output.

4.5.2 Ammonia

Ammonia can be converted back to hydrogen through a catalytic process, which consumes at least 13% of the energy content of the produced hydrogen. This hydrogen could be used in combustion but would need preconditioning for use in some types of fuel cells. Ammonia can also be used directly to generate electricity using:

Fuel cells

Ammonia can be used as a fuel in solid oxide fuel cells, but the heat required to crack ammonia would reduce the efficiency by at least 13% compared to using hydrogen directly, and ammonia SOFCs are still far from developed to enable quick response to large power loads. Research is underway on PEM fuel cells that use ammonia directly, but they are not likely to be commercialised within this decade. Alkaline Fuel Cells, which unlike PEMs are not poisoned by ammonia are being developed in the UK[45]. One study[46] described a device that uses a ceramic membrane to crack ammonia to pure hydrogen at 250°C, raising the possibility of constructing a combined cracker and proton conducting ceramic ammonia fuel cell.

Internal combustion engines

Ammonia combustion has been actively researched since the 1930s. MAN, Wärtsilä, and other ship engine manufacturers have identified the potential of ammonia as a zero-carbon fuel and are engaged in testing programs for the implementation of two and four stroke engines in the marine sector. MAN expect to be marketing two stroke engines with 50% efficiency in 2024[47].

Ammonia is a suitable fuel for gas engines to generate power in stationary applications, most likely using arrays of 4-stroke engines of 20 – 30 MW each[48]. The performance and reliability of ammonia gas turbines have been assessed numerically, experimentally, and under industrial conditions[49, 50]. Tokyo Gas, who led a Japan-Australia innovation project, have created a roadmap to produce the first 100 MW ammonia gas turbine by 2030.

In costing the use of ammonia in energy storage, it will be assumed (possibly optimistically) that in 2050 it will be possible generate electricity from ammonia at the cost, and with the same efficiency, assumed for hydrogen above.

4.6 Safety

Hydrogen and ammonia are produced in mature industrial processes at a very large scale, stored in a variety of forms, and transported over long distances. Safety issues, and potential hazards and the measures that can mitigate them, are discussed in SI 4.6. The use of hydrogen and ammonia in GB is subject to stringent controls, and concerns about safety are not expected to prevent the use of hydrogen and ammonia for energy storage on the scale envisaged in this report.

4.7 Climate impact

Hydrogen is a greenhouse gas, though ammonia is not. Analysis based on recent estimates of hydrogen's global warming potential[51] and of hydrogen leakage[52], finds that continued use of hydrogen storage at the maximum level envisaged here would lead to a temperature rise which would stabilise below 0.00013°C after 300 years (or 0.00047°C without measures to limit venting hydrogen during electrolysis, which 'would be relatively easy to incorporate[52]), with 99% confidence on leakage rates but ignoring uncertainties in the global warming potential and the climate science (see SI 4.7). The conclusion is that the use of large-scale hydrogen storage in GB will not have a significant climate impact, but tight control of leakage will be important if hydrogen use rises to large levels globally.

Non-chemical and thermal energy storage

There are many ways to store energy as heat or as mechanical potential, which can be used alone or in combination with chemical energy storage. Stored heat can be used to generate electricity and / or heat. Although this report is focussed on electricity storage, both are discussed as the latter is potentially very important and could reduce the need for the former.

5.1 Advanced compressed air energy storage (ACAES)

5.1.1 Introduction

Energy can be used to compress air, which would be stored in underground caverns in large-scale systems. When expanded 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 must come from a carbon-free source, or from storing and reusing the heat generated when the air is compressed[r]. The latter possibility, known as Advanced CAES or ACAES, is discussed here (see figure 18).

Three grid-connected ACAES plants are now in operation in China[s]. The first is a $10MW_e/100MWh_e$ plant, which has been in operation since September 2021, with air stored in a salt cavern and heat in supercritical water[53]. The second is a 50 MW_e/300 MWh_e plant, which has been in operation since May 2022, with air storage in a salt cavern, and heat stored in thermal oil[54, 55]. The third is a 100 MW_e/400 MWh_e plant, which started operation in September 2022, with air storage in an artificial mined rock cavern and heat stored in supercritical water[56, 57].

In these plants, and in the operating plants that burn gas to provide heat, the pressure of the stored air falls as it is released during the expansion phase. A 10 MWh demonstrator of an interesting and potentially more efficient alternative, in which hydrostatic compensation maintains the stored air at constant pressure, came into operation in 2019 in Ontario[58, 59]. Such 'isobaric ACAES' systems will not be considered further here since they have not yet been deployed at scale and installing them in caverns at the depth needed to provide a large storage capacity, which has not been demonstrated, could be challenging.

5.1.2 Underground ACAES storage capacity in Great Britain

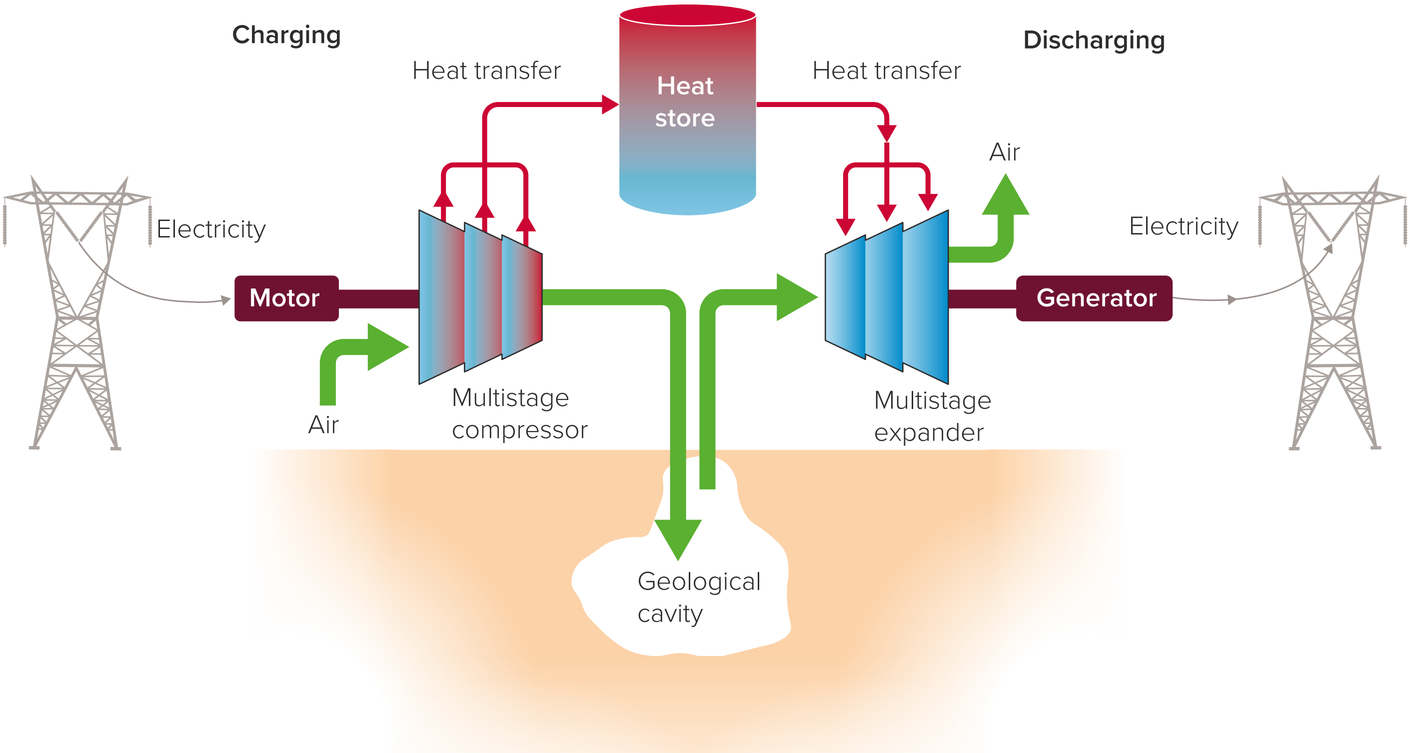
A British Geological Survey led study[60] found that 'Solution-mined salt caverns (which permit high injection / withdrawal rates required for rapid cycle storage) are the likely first choice for CAES in the UK... at least in the short term'. There are other options, but 'serious doubts exist over the likely development of porous rock CAES, with no plants having operated commercially... Aquifer storage for the UK ... would be remote offshore, thereby increasing costs... Depleted [gas] field storages appear even more unlikely with a potential hazard posed by residual hydrocarbons..." (the options are discussed further in SI 5.2).

r Two large-scale compressed air energy storage (CAES) plants are currently operational (in Huntorf, Germany and MacIntosh, USA) that burn gas to heat the air on expansion. More information about these plants and plans to build more isobaric systems are given in SI 5.2.

s This summary includes information kindly provided by Chinese colleagues via Professor Yulong Ding (University of Birmingham).

FIGURE 18

Schematic of advanced compressed air energy storage.



In modelling and costing large-scale ACAES it is assumed in this report that the compressed air will be stored in the 300,000 m^3 solution-mined salt caverns that were studied and costed as hydrogen stores by the H21 NE[26] consortium (see Chapter 4), and that the caverns will be at a depth of 1000 to 1700 m, at which the allowed pressure range is big enough to enable large-scale storage. On the basis of the modelling below, and BGS's estimates of the potential number of such caverns quoted in Chapter 4, up to 20 TWh$_e$ ACEAS storage capacity could in principle be provided in East Yorkshire, with perhaps as much again in Cheshire and Wessex. In practice, 20 TWh$_e$ (which would require some 3000 caverns) should be regarded as a strong upper bound on the onshore capacity. It is worth noting that in the modelling used in this report, the volume required to deliver a given amount of electricity is some 20 times larger for ACAES than for a hydrogen store.

5.1.3 ACAES design

The design and cost of ACAES systems depend on:

1. The size of the cavern and its depth which determine the possible pressure range. Modelling of 300,000 m^3 caverns in a depth range of 1000–1700 m finds (see SI 5.2) that they could typically store 10 GWh$_e$ with the support of 7.5 GWh of thermal storage (most of the energy of compression is stored as heat: the compressed air mainly stores 'exergy' – the ability to do work), and deliver 6.8 GWh of electricity, corresponding to a 68% round-trip efficiency. Higher efficiencies are possible in principle but require demonstration. The 10 GWh$_e$ needed to compress the air generates some 9.7 GWh of thermal energy, of which only 7.5 GWh is needed to support electricity storage: using the excess for other purposes, such as district heating, would improve utilisation of the input energy and generate revenue which could be offset against the cost of using ACAES to store electricity.

2. How the heat is stored. In the modelling in this report, it is assumed that compression is carried out in many, typically six, stages. This allows delivery of the thermal energy at a low enough temperature for the heat to be stored in water, rather than in molten salts, as assumed in most studies, which would be much more expensive. With a water operating temperature range of 35°C to 90°C, 117,000 m^3 of water would be needed to store 7.5 GWh of heat.

5.1.4 Readiness and cost of ACAES

No ACAES systems of the very large scale envisaged in this report have been built[t], but there is wide experience of making solution-mined salt caverns and of thermal storage. Air compressors and expanders are widely used for a variety of purposes. The cost is comprised of:

1. **Cavern cost**
   The costs used here are based on H21 NE's[26] estimates of the cost of constructing clusters of 10 300,000 m^3 caverns which share facilities. Removing the cost of the hydrogen surface facilities, after attributing management and miscellaneous costs *pro rata* to them and to the cost of the cavern, leaves a cost of £125.4M for constructing a cluster of 10 caverns. As in costing hydrogen storage, a 'base' value of 1.5 x £125.4M will be used, to reflect uncertainties in underground costings and the lack of data on actual costs.

2. **Thermal storage cost**
   On the basis of the full cost of an operational 200,000 m^3 water-pit store in Denmark[61], and the costs of other projects, full costs are estimated to be €30/m3 for volumes > 100,000 m^3. With a cluster of 10 caverns, 10 x 140,000 m^3 of water would be needed according to the figures above, which would presumably be provided by fewer than 10 pits, but more than one to provide flexibility. Given that costs fall with size, it would seem safe to assume a total cost of £50/m^3 including a share of management costs, site services and purchase of the site. With each cavern storing 10 GWh_e, the sum of the cavern and thermal storage costs corresponds to £2.6/(kWh stored). This is very much lower than other estimates used in other studies of CAES because of the assumption made here that very large solution-mined caverns and water pit thermal storage would be used.

3. **Compressors and expanders**
   The modelling described in Chapter 8 finds a need for multi-stage compressors and expanders with a power rating of around 70 MW if there is one compressor and expander per cavern. A rating of 233 MW would be needed if, for example, three were provided for each cluster of 10 caverns. Such compressors and expanders are today custom made.

t Although Siemens has produced a video and a flyer (https://www.siemens-energy.com/global/en/offerings/storage-solutions/thermo-mechanical-energy-storage/caes.html) that show a 6 GWh_e system in which compressed air is stored in a salt cavern.

It is not clear what compressors and expanders tailored to the needs of ACAES will cost in the future when manufactured at the scale that will be needed if ACAES is widely deployed. There are estimates in the literature, but it is often not clear what they include, or the power rating that was assumed, although the cost per kW (at least over some range for similar devices) varies as (power rating)$^{-0.6}$. In the absence of more precise information, a range of costs was studied of up to £500/kW for the full installed cost (including site purchase and preparation etc) of compressors and of expanders and associated heat exchangers. Information obtained from two leading manufacturers suggests that the cost could be well below £500/kW, but this is not assured[u].

Substantial savings could in principle be made by replacing each pair of compressors and expanders with single reversible compressor / expanders if high efficiencies can be obtained in both roles.

In costing electricity provided by ACAES, a financial lifetime of 30 years will be assumed. The cavern and water pit are expected to last much longer and will need very little maintenance. Compressors and expanders are also expected to last at least 30 years, assuming regular maintenance. O&M costs of 1% / year and 4% / year of their capital costs were assumed.

5.2 Thermal and pumped thermal energy storage

Thermal energy can be stored at low cost[v]. High grade heat (> 100°C) can be stored in molten salts, solids, thermal oils, liquid metals or as steam. At lower temperatures, water or other liquids or solids can be used. Potentially important systems include:

Water pit storage

Water pit storage is already deployed to provide district heating in Austria, Denmark and Germany. With a temperature range of 70°C, water can store 82 kWh/m^3 of thermal energy. Losses are below 0.1%/day in large systems, which can achieve (heat out) / (heat in) efficiencies of over 90% for heat stored in late summer and delivered in winter. As discussed above in the context of ACAES, where costs are quoted, the world's largest system has a volume of 200,000 m^3.

Molten salts

Molten salts store heat in the range 300–580°C. They are used at concentrated solar power plants and could be used in conjunction with nuclear power plants to buffer the output and render nuclear flexible. Plant sizes are typically 50 MW$_e$ upwards (a 1.2 GWh$_e$ store was installed at the now defunct Crescent Dunes Concentrating Solar Power plant), losses are < 0.1%/day, costs are in the range £(24–59)/kWh$_e$ and the density of stored energy is 53.6 kWh$_e$/m^3 assuming a temperature range of 200°C.

u A range up to £500/kW is compatible with estimates in the ACAES literature, e.g. MIT assume 2050 costs of \$(344–452)/kW for compressors and \$(469–627)/kW for expanders, albeit for power ratings that are not stated (but are presumably less than those found for the very large systems considered here). Other estimates are discussed in SI 5.2.

v Storage as latent heat – the thermal energy required to change the phase of a material (solid-liquid, solid-gas, liquid-gas) – is not suited to providing large-scale electricity storage, but may play other roles, e.g. in heating and cooling buildings.

Carnot batteries with resistive electrical heating

These store heat (provided by a resistive heater) at high temperature, for later delivery as electrical power provided by a turbine. A range of different configurations, storage, and charge / discharge cycles are being considered. EnergyNest[62] use concrete modules with embedded stainless steel heat transfer pipes to provide a scalable energy storage solution up to multi-GWh capacity. The materials costs are down to $25/kWh$_{th}$ depending on system scale / location and operating temperatures. Siemens Gamesa built a 30 MW high-temperature (> 600°C) thermal store that used 1000 tonnes of volcanic rocks to store 130 MWh[63, 64, 65] thermal energy, with claimed electrical – electrical round-trip efficiency of up to 45%, but they have currently abandoned plans to follow this up with a commercial plant.

Two hundred systems that could deliver over 5 GWh$_e$ and 100 MW would be needed to store 1 TWh, each of which would have to have a volume of around 37 m^3 assuming a rock density of 1 t/m3 (typical of pumice). It is therefore possible to imagine such Carnot batteries providing over 1 TWh of storage in GB. No detailed cost estimates are available. In terms of cost per unit of energy stored, they are expected to be one of the cheapest storage options, but they will be more expensive than hydrogen storage without being much more efficient (see SI 5.3).

Pumped thermal energy storage (PTES)

PTES systems are Carnot batteries that use heat pumps to transfer thermal energy between two thermocline gravel packed beds. The stored heat is used later to generate electricity using a turbine. PTES is at Technology Readiness Level (TRL) 4 – 6. The round trip efficiency is expected to be over 50%. One study[66] found a thermal energy density of 70 – 430 kWh/m^3 and a capital cost of €50 – 180/kWh. It will not be possible to make accurate estimates until working systems are in operation.

5.3 Thermochemical heat storage

Thermochemical heat storage involves a reversible reaction, in which:
chemical X + heat ↔ chemical Y + Z.
If Y and Z are stored separately, long periods of energy storage with low energy losses are possible (see SI 5.3). A number of reactions have been considered[67, 68], including: $CaCO_3 \leftrightarrow CaO + CO_2$, $Ca(OH)_2 \leftrightarrow CaO + H_2O$) and $MgSO_4\ 7H_2O \leftrightarrow MgSO_4 + 7H_2O$.
While the density of the energy stored (1.8, 1.4 and 1.6 MJ respectively) is small compared to the energy density of coal (which ranges from 18 MJ / kg for lignite to 33 MJ / kg for anthracite), multiple charge / discharge cycles are possible because the reactions are reversible.

Thermochemical storage could be used at small scale, for example to provide space heating[69], or at large scale, for example for storing industrial waste heat or in concentrating solar power systems. It is at an early stage of development (TRL 1–4), with technologies validated in lab conditions, at small scale generally for small numbers of cycles. Further research is required to develop materials, reactors and systems for different applications.

5.4 Liquid air energy storage (LAES)

Liquid air energy storage (LAES) uses electricity to cool air until it liquefies. The liquified air is stored in tanks. Energy is released when the liquid is brought back to a gaseous state and the expanding gas drives a turbine, which in turn generates electricity[70]. Liquid air can be brought back to a gaseous state by exposure to ambient air, or with heat stored when the air is liquefied or waste heat from an industrial process.

LAES systems use off-the-shelf components with long lifetimes, resulting in low technology risk. LAES is at TRL 7–9. The 15 MWh, 5 MW Highview Power LAES plant is the largest operational demonstrator. Highview are building a 50 MW/300 MWh system which will be completed in early 2025[71].

LAES is not suitable for small-scale distributed applications because the efficiency is low at small scale. The minimum size for commercial applications is likely to be 10 MW / 40 MWh. If the released 'cold' from the discharge process can be effectively recovered, the round-trip efficiency could be up to 55% (if not, it would be 35% or less). The power cost could be up to £2500/kW, falling to perhaps £850/kW as the technology matures. Estimated total storage costs (liquid air, hot and cold stores) are in the range £200 – 500/kWh.

5.5 Gravitational storage

5.5.1 Pumped hydroelectric storage

Pumped hydro stores electrical energy as gravitational energy by pumping water from a lower to a higher reservoir. The energy is converted back to electricity by allowing the water to flow back through a water driven turbine. The UK's hydropower generating capacity is currently 4.7 GW, including 2.8 GW of pumped hydro[72] with a storage capacity of 26.7 GWh[73]. Primary hydropower delivered 5.9 TWh in 2019, while pumped hydro generated 1.8 TWh, down from a maximum of 4.1 TWh in 2008[74].

The expansion of the UK's pumped storage capacity is restricted to areas with suitable terrain, predominantly in Wales, Scotland and parts of Northern England. Planned and proposed projects include a 1.5 GW, 30 GWh pumped hydroelectric system at Coire Glas[75]. Connections between all suitable pairs of existing reservoirs within 20 km would in principle provide a storage capacity of 0.5 TWh[76], although nothing on this scale is foreseen, let alone the theoretical potential of 5.3 TWh that would be provided by building new reservoirs within 20 km of existing ones.

While additional pumped hydro storage capacity will be helpful, it is clear that it would 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.

5.5.2 Other gravitational storage

A number of companies are considering storing energy by lifting weights and later, releasing the stored energy by dropping the weight and powering an electric generator. Ideas include: lifting weights in underground shafts[77]; using cranes[78], hauling wagons loaded with ballast up inclined rail tracks[79]; and using hydraulic pressure to lift large rock pistons in deep shafts[80] or underground caverns[81]. Such devices could release energy very quickly (providing grid services), or more slowly providing peak shaving. The proponents expect high round trip efficiency and claim that their schemes will be cheaper than using lithium-ion batteries, although there do not appear to be any detailed cost estimates in the published literature. Most would store MWh rather than GWh (dropping an 11m sided cube of granite through 100 m would release 1 MWh). Cycled frequently they could deliver significant amounts of energy if built in large numbers, but not enough to have more than a marginal impact on GB's need for tens of TWh of large-scale storage to complement high levels of wind and solar.

5.6 Storage to provide heat

Stored heat can reduce demand for electrical heating and play a potentially important role in shifting electricity demand away from peak hours. It can be distributed through heat networks, which currently provide only 2% of the UK's heat[w], although in some European countries, such as Denmark, local heat networks meet over 50% of space and water heat demand. Large-scale heat stores, charged with solar energy in summer and providing heat through local district heat networks in winter, are widely deployed in Germany, Denmark and Austria. In the absence of a clear idea of whether district and local heat storage are likely to expand to the TWh scale in GB, this possibility is not included in the modelling described in this report. However, given their potential, heat storage and heat networks[x] deserve much more attention.

At a local level, the 40 GWh that is stored in hot water tanks in the UK[y] could be managed to avoid them being charged during peak hours, which would have a significant impact on peak energy demand. A novel possibility, which is worth developing, would be to store heat provided in summer by heat pumps, or integrated solar thermal systems, thermochemically and use it to meet or reduce peak winter demand. The use of heat from nuclear generation is covered in separate work from the Royal Society[82].

w 6.5 TWh is supplied to the domestic sector and 5.5 TWh to non-domestic loads. Of the UK's 17,000 existing networks, 11,500 are communal networks that supply different customers in a single building, while there are 5,500 district networks that supply two or more buildings (often on a single site, eg a school, hospital or factory) see https://www.theade.co.uk/resources/publications/market-report-heat-networks-in-the-uk (accessed 15 May 2023).

x A recent UK Government Consultation refers to 'a significant potential for the number and scale of heat networks to increase dramatically' and reports an 'estimate that up to £16 billion of capital investment could be needed for heat networks to deliver their [undefined] full contribution to net-zero'. See, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/878072/heat-networks-building-market-framework-condoc.pdf. (accessed 15 May 2023). The December 2020 Energy White Paper expresses enthusiasm for heat networks, but only reported a commitment to "£122 million of funding towards a new Heat Network Transformation Programm"'.

y Using technologies such as those provided by https://www.mixergy.co.uk/mixergy-tank (accessed 15 May 2023).

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[83, 84, 85, 86], or 'liquid organic hydrogen carriers' (LOHCs)[87, 88], as well as in fossil fuels. 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, thus leveraging generations of innovation in combustion. See SI 6 for a detailed, analysis of synthetic fuels and energy storage.

6.1 Electro-fuels

E-fuels can be made by combining green hydrogen with captured carbon dioxide (as shown in figure 19), 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*[89]. They can be used to store electricity, but it is generally cheaper and more efficient to store the hydrogen used to make them.

6.2 Liquid organic hydrogen carriers (LOHCs)

Energy can be stored by attaching hydrogen chemically to certain organic liquids, and later detaching the hydrogen. Methylcyclohexane is an example that has attracted commercial interest: it consists of three hydrogen molecules attached to toluene, which could be re-cycled following dehydrogenation. LOHCs have particular promise where combined heat and power is required, especially at the building or district level.

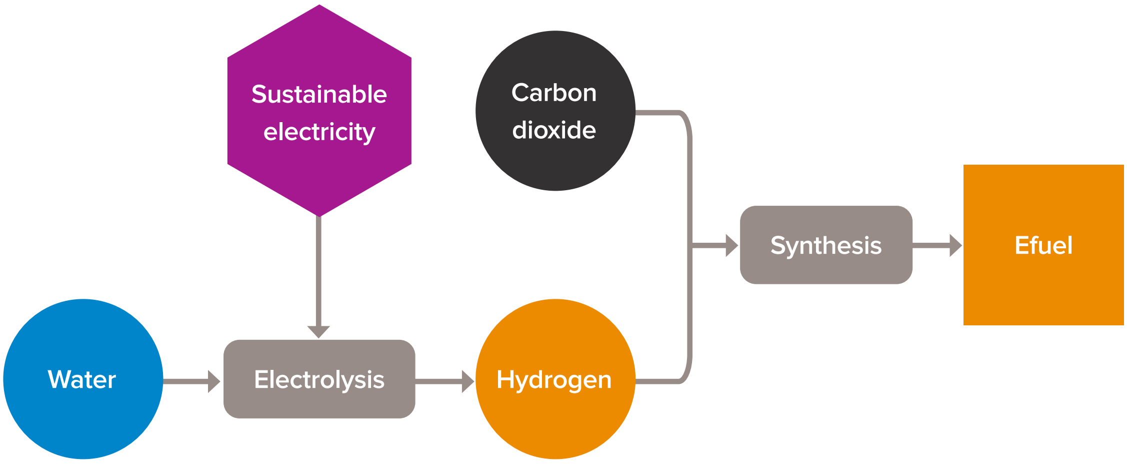
A comparative analysis of the round-trip efficiencies and costs of using different liquids to store electricity, and other factors that affect the choice of energy storage vector, is provided in SI 6. The conclusions are that:

- If cavern storage is not available for hydrogen, then ammonia and LOHCs appear to be lower cost solutions than gaseous or liquid hydrogen storage.
- Where salt caverns are available for hydrogen storage in locations with access to markets at reasonable transmission costs, then adding a synthesis plant to make hydrocarbons or ammonia, or liquid organic hydrogen carriers, appears to reduce efficiency and increase costs overall.
- LOHCs could play a role in distributed combined heat and power systems.

Given that the potential hydrogen storage capacity in GB is very large, and that its focus is on large-scale electricity storage, e-fuels and LOHCs are not considered further in this report.

FIGURE 19

Production of e-fuels using electrolysis.



Source: Sustainable synthetic carbon based fuels for transport report, the Royal Society.

Electrochemical and novel chemical storage

7.1 Electrochemical storage

7.1.1 Grid-connected lithium batteries

Lithium-ion batteries are driving the consumer electronics revolution and the market for electric vehicles (EVs). Increasingly, lithium-ion batteries are being used to support the National Grid configured into large-scale modules to provide grid services, such as maintaining grid stability and peak shifting. Off-grid batteries are allowing energy provided by solar panels in the day to be stored and used later.

Global lithium resources should be able to meet expected demand as the market expands, although supply chains may become strained. Investment in recycling and second-life strategies is required to support sustainable growth[90]. The availability of cobalt, a component of most lithium-ion batteries, could be a more serious constraint: there are concerns about its sources, although cobalt content has fallen and further reductions are expected, and lithium-iron phosphate (LFP) batteries are cobalt-free.

Lithium-ion based energy storage facilities have suffered catastrophic failures resulting in fires[91, 92, 93]. The problem is potentially most serious for very large systems, but the components of stationary batteries do not need to be packed closely and it should be possible to design safe systems, which incorporate flame retardants and other safety measures[94]. Some types of lithium-ion batteries (eg LFP) are safer and more thermally stable than others.

There are various types of lithium-ion batteries[95]: Nickel Manganese Cobalt (NMC) and Nickel Cobalt Aluminium (NCA) batteries, which are used in vehicles because of their relatively high (for batteries) energy densities, can also be used in storage that supports the electricity grid. NCA batteries are used in Tesla cars and in the grid-connected Tesla battery in Southern Australia. Lithium-ion phosphate (LFP) batteries also use relatively cheap materials but have lower energy density than NMC chemistries. Energy density is less critical in stationary applications, making LFP a potentially significant stationary storage technology by 2030.

Among the emerging alternatives, sodium-ion batteries use abundant materials and could in principle be cheaper, but initially high costs at low levels of production may be a barrier to achieving manufacture at scale.

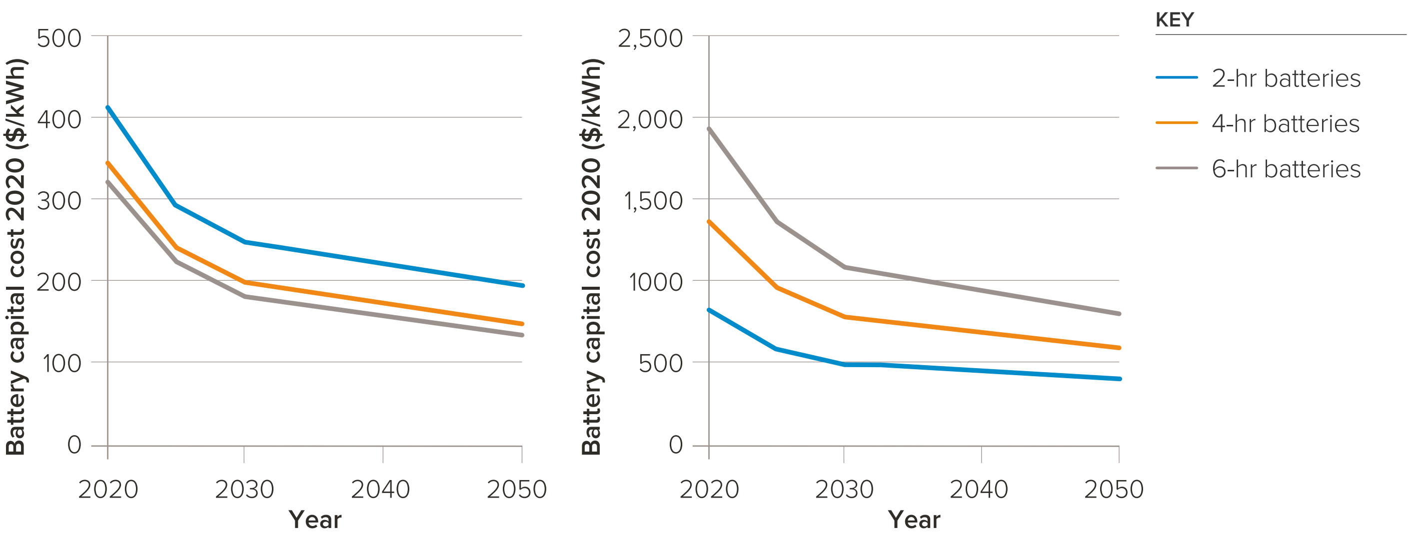
Costs

The core elements of a grid connected battery are the battery itself and the inverter (which converts AC to / from DC and determines the power rating). A meta-analysis of projections of future costs (see figure 20), which depend both on the capacity and the minimum discharge times (or equivalently energy capacity / power rating), made by the US National Renewable Energy Laboratory, shows costs falling rapidly[96]. However, these cost estimates are without mark up. Prices currently quoted by Tesla for 1000 units of 2 and 4 hour 3.9 MWh ‘megapack’ batteries are respectively 43% and 31% higher than NREL’s mid projection for 2022.

FIGURE 20

Results of a meta-analysis of projected capital costs of fully installed 2-, 4- and 6-hour batteries.

The cost is defined here in terms of the useable capacity per unit of delivered energy, which is equal to the nameplate capacity [as normally defined] x (the depth of discharge) / (discharge efficiency) and does not include mark-up.



Source: US National Renewable Energy Laboratory.

To calculate what it costs to store electricity in batteries, it is necessary to know not only the capital cost, but also:

1. **The round-trip efficiency**
The literature contains a range of estimates of efficiencies[97, 98, 99] which vary over a battery's lifetime, and depend on the duty cycle. The estimates of the cost of using batteries in this report are rather insensitive to the efficiency, for which a constant (2050) AC to AC value of 90%, near the top of the range, is possibly optimistically assumed.

2. **Lifetime**
Battery chemistry changes with use and the capacity 'fades' as batteries are cycled[100]. High-energy density lithium-ion automotive batteries are today typically expected to achieve around 1000 cycles before 20% of rated capacity is lost, which is generally used as an end-of-life criteria for their use in electric vehicles. However, recent research indicates that a 'million-mile' battery, corresponding to 4000 – 5000 cycles, could be possible, although this is not yet a commercial reality[101]. In large-scale stationary storage, degradation will occur more slowly as temperature and charge and discharge rates can be better controlled, and the fact that density is not a major constraint will allow the use of LFP or LTO (Lithium-Titanium-Oxide) batteries. In figure 21 it is assumed that in 2050 batteries used for stationary storage will be used for 5,328 cycles[102], after which their capacity will have dropped to 70% of the name plate value (this is double the number of cycles found in tests of an NMC battery: the performance of LFP batteries could be better), or until 25 years have elapsed (which ever happens sooner). Little seems to be known about fade as a function of time, rather than the number of cycles: costs with the lifetime limited 4000 cycles or 15 years are reported in SI 7.1.

3. **Operation and maintenance (O&M) costs**
It is generally agreed that variable O&M will be negligibly small. Estimates of fixed annual O&M vary, ranging up to the 2.5% of capex advocated by NREL[103] who include provisions for periodic injections of capital intended to 'counteract degradation'[104]. Tesla quote slightly over 0.2% for annual maintenance, to which operational costs should be added[105].

Combining these factors leads to the costs of delivering electricity from a battery (without the cost of the input electricity) shown in figure 21 in the conditions described in the caption. With NREL's high and low 2050 projections of capex, the costs in this figure should be multiplied by factors of 1.66 and 0.58 respectively. The cost of operating expensive or cheap batteries would not be expected to be very different. With high values of capex, it would therefore be natural to choose a relatively low value of Fixed O&M as a percentage of capex, and vice-versa.

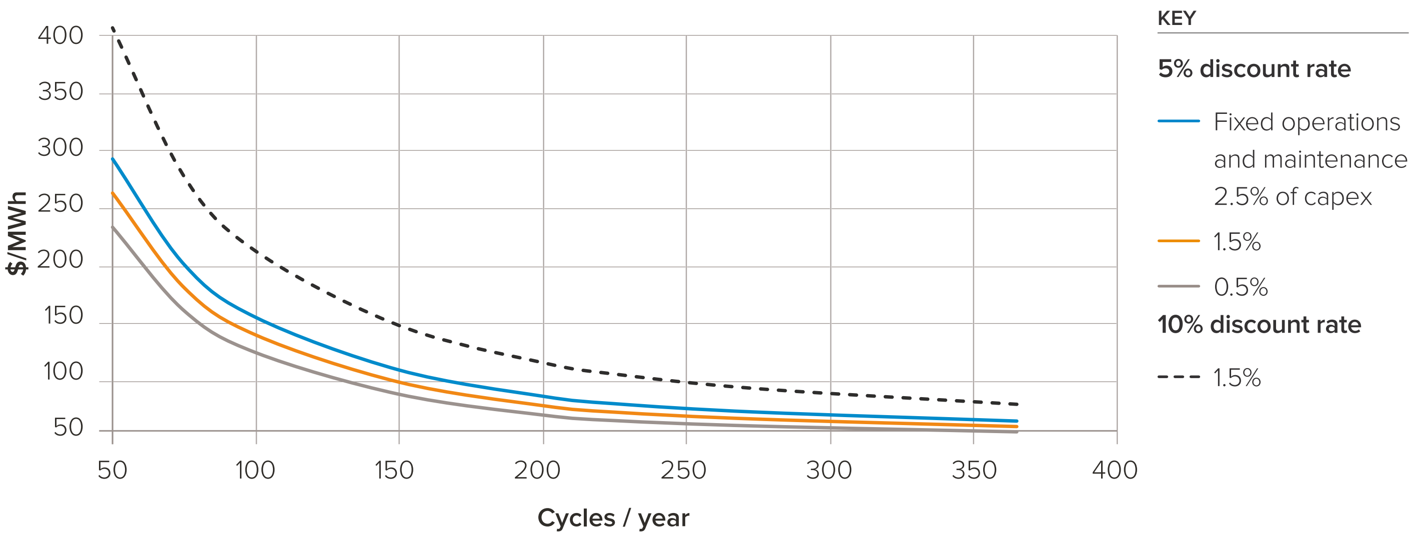
7.1.2 Vehicle to grid storage

There are currently 33 million cars in the UK. If all were electric, and had fully charged 70 kWh batteries, they would provide a combined storage capacity of around 2 TWh. If 10% of those vehicles were accessible to the operator of the electricity grid at any time, they could in principle provide the grid with 200 GW for up to an hour. The National Grid in its FES 2022[5], less optimistically proposes three net zero compatible 2050 scenarios which include vehicle to grid (V2G) capacities of 16, 34 and 39 GW. This would still be a very significant contribution. It is worth noting, as National Grid does, that 'less will be available during winter peak 5 – 6 pm due to vehicle usage'. Some work has been done to test the appetite for allowing the grid operators to access vehicle batteries. A trial[106] found that customers offered 30p/kWh to provide power to the grid on average earned £360/year. The use of a fleet of electric buses to support for grid is being trialled[107].

FIGURE 21

Cost of electricity delivered by a 4-hour battery.

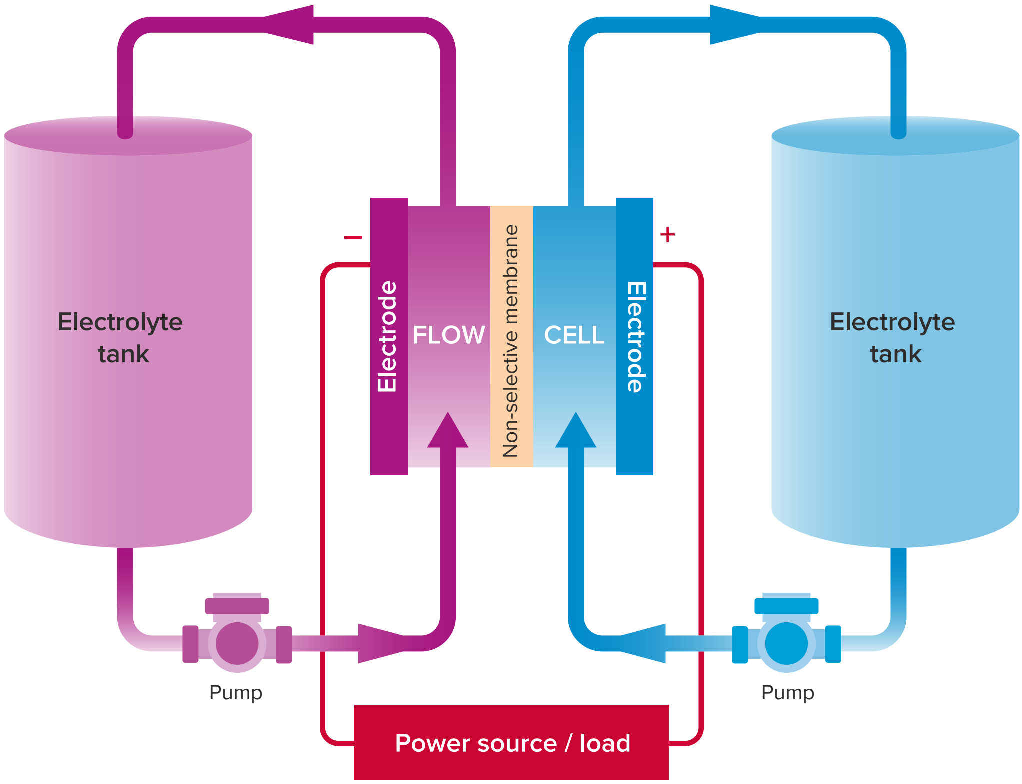
The cost, which does not include the cost of the input electricity, is shown as a function of the number of cycles/year [which is equal to the (annual amount delivered)/(day 1 useable capacity x discharge efficiency)], assuming i) NREL's mid capital cost projection of $149/(useable kWh) in 2050 (without mark-up), ii) a lifetime of the smaller of 5,328 cycles (during which capacity is assumed to fade by 30% x (number of cycles)/5328) and 25 years, iii) various values of Fixed Operating Costs and iv) two values of the discount rate.



EV batteries are likely to still have useful storage capacities when the vehicles themselves have reached the end of their lives. There is therefore a compelling case for considering using 'second life' EV batteries for the less demanding provision of stationary energy storage. A generation of second-hand batteries from 30 million cars would provide around 1.7 TWh. EV batteries should be designed with an eye to re-use and / or recycling the materials to make new batteries.

FIGURE 22

Elements of a flow battery.



7.1.3 Flow batteries

Redox flow batteries (RFBs) are candidates for medium-scale stationary energy storage and are currently at a TRL of 7–8. Single units could have capacities of many GWh.

'Redox' is shorthand for oxidation-reduction reactions in which electrons are transferred between two species. Chemical energy is provided by chemicals in different states of ionization, dissolved in liquids that are pumped through a cell between electrodes on opposite sides of a membrane, as described in SI 7.1 and illustrated in figure 22.

The capacity of the battery, which is determined by the volume of the electrolyte tank, is independent of its power, which is determined by the active area of the electrodes / cell and the rate of reaction. Consequently, RFBs offer highly flexible and scalable storage. A range of RFB chemistries are in development, of which the all-vanadium design is the most commercially mature.

The capital cost of RFBs is largely dictated by the cost of the membrane and electrolyte, as well as the balance of plant which must handle highly corrosive reactants. For larger scale energy storage, the electrolyte costs become the most important factor, due to the increasing amounts of electrolyte needed. This is reflected in the cost breakdowns for the energy and power rated components of flow batteries reported in a PPNL report[97], which projects costs of $573/kWh and $306/kW respectively in 2025 (corresponding to a total cost of $650/kWh and $2598/kW for a 4-hour battery). The cost per kWh is significantly higher than that found for lithium-ion batteries.

The high cost and price volatility of vanadium has affected the prospects of very large (TWh) scale applications of V-RFBs and has highlighted potential benefits of alternative lower-cost redox couples. For example, the use of a much lower cost (and abundant) manganese redox couple paired with a hydrogen store is being pioneered by UK company RFC Power[108], while both RFC Power and Form Energy in the US are seeking to develop very low-cost systems based around the use of sulphur species in alkaline electrolytes as a redox couple.

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[109]. RFBs can typically respond rapidly. Self-discharge is minimal so longer-term storage is feasible, with capacity scaling with the size of the electrolyte reservoir.

If flow batteries using materials that are significantly cheaper than vanadium become available, they could play an important role in grid-scale storage.

7.2 Novel chemical storage

Chemical energy can be stored by 'reducing' iron oxide to iron and later oxidising it in the reactions:

iron + water ➜ iron-oxide + hydrogen, or
iron + air (oxygen) ➜ iron oxide + heat

The heat produced could be used to drive a turbine. This suggests that a 'strategic reserve' of iron could play a role as an emergency source of hydrogen or electricity, to be used during once-in-a-decade wind droughts if hydrogen used to store electricity that is normally produced by electrolysis runs out. However, the scale of investment in the infrastructure needed to occasionally but rapidly convert iron to hydrogen rules out this possibility in current conditions (see SI 7.2). Reduction / oxidisation of other elements such as silicon or boron could, however, play a role as portable local sources of hydrogen, for example in powering ships or fuelling vehicles.

Powering Great Britain with wind plus solar energy and storage

8.1 Technology choices

Some key attributes of potentially large-scale storage technologies are summarised in table 4, where they are separated into the three categories introduced in section 1.3.2 and discussed in SI 1.3.

In providing estimates of the cost of powering GB with wind and solar generated electricity supported by storage, Li-ion batteries are chosen as a representative of the first of the three categories of technologies in table 4.

In category two, ACAES is chosen as an exemplar of many relatively high efficiency technologies that are suitable for storing energy for weeks or possibly months (but not years) because it could in principle provide up to 20 TWh of storage in GB and it has recently been deployed on a significant scale in China: its likely cost is hard to estimate, but this is also true of the alternatives. The choice of ACAES should not be taken as implying a belief that it will play a dominant role – in practice a variety of 'large-scale medium-term-turnover' storage technologies may well be deployed.

For the third category, hydrogen storage is chosen because it is cheaper than the alternatives. However, while the potential capacity of solution-mined salt caverns in GB is more than adequate, their possible locations are limited. An estimate was therefore also made of the cost of using ammonia, which could be deployed anywhere across GB, but it was found that using ammonia rather than hydrogen would increase the average cost of electricity by at least £5/MWh (see SI 8.1).

8.2 Additional costs

The cost of electricity fed into the grid includes not only the costs of wind and solar energy and large-scale energy storage, but also:

- **The cost of transmitting wind and solar generated electricity to the point where it will be stored.**
  This is likely to be cheaper than transporting hydrogen, unless it could be done with repurposed gas pipelines. On the basis of current transmission charges and losses, this would cost £2.1/MWh if wind plus solar power costs £35/MWh or £2.2/MWh it costs £45/MWh. The government's view[110] is that, as the electricity sector grows, the cost of transmission per MWh will 'stay broadly the same or even decrease given wider efficiencies and the greatly increased supply of electricity'. In view of the uncertainties, and the fact that losses in transmission from remote wind farms will be above average, it will be assumed – conservatively – that it will cost £3/MWh in 2050.

- **The cost of providing rapid response grid services.**
  This does not require large amounts of energy. It can therefore be ignored in modelling other stores, but its impact on the average cost of electricity should be included. It will be assumed that 15 GW of power will be needed in 2050 to provide these grid services, and that it will be provided by 1-hour Li-ion batteries that are kept on stand-by, fully charged, for use when called upon by the operator. Using NREL's medium 2050 capital cost projection, this would add £0.64/MWh to the average cost of electricity assuming a 5% discount rate, and £0.83/MWh with 10%.

To allow for these two costs, a total of £4/MWh is included in the following estimates of the average cost of electricity.

TABLE 4

Large-scale electricity storage technologies.

Technology	Maximum unit capacity**	Round-trip efficiency	Technology readiness level and comments*
Storage time: minutes to months – limited by need to recover investment			
Non flow batteries	Largest installation today 3 GWh	≲ 90%	Lithium-ion – TRL 9; other chemistries at lower TRL
Storage time: hours to weeks, in some cases months			
Flow batteries	Largest today is 400 MWh. Many GWh possible.	70 – 80%	TRL 7 – 8
ACAES	Single cavern ≲ 10 GWh	≲ 70%	Compressors, Expanders, storage caverns and thermal storage are at TRL9. Complete systems are around 7 – 8.
Large Carnot battery	GWh	45%	TRL 7 with resistive heating.
Pumped Thermal Energy Storage	< GWh	50%	TRL 4 – 6
Liquid air energy storage	< GWh	≲ 55%	Systems in operation – TRL 9. Larger / more advanced systems – TRL7.
Able to provide months or years of storage			
Synthetic fuels	Single large tank ~ TWh	≲ 30%	TRL 6 – 7. Expected to play a role in transport, but outclassed by ammonia and hydrogen for electricity storage.
Ammonia	Single large tank ~ 250 GWh	≲ 35%	Production and storage – TRL 9. Conversion of pure ammonia to power – TRL 5. More expensive than hydrogen, but could be deployed across GB. May play a role as an imported fuel.
Hydrogen	Single large cavern ~ 200 GWh	~ 40%	At grid scale electrolysers – TRL8. 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.

*TRLs defined in the glossary

**Capacity is defined here as the electrical energy delivered on full discharge

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.

Assumptions for 2050	Input £ / kW_e	Storage £ / MWh_e – delivered	Output £ / kW_e
Capex – low / base / high	167 / 333 / 500	485 / 727 / 970	222 / 315 / 472
Opex p.a.	1.5% of capex	1.5% of capex	1.5% of capex
Financial Life	30 years	30 years	30 years
Efficiency	74%	Round-trip 40.7%	55%
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 / offshore) and 20% solar supply			

FIGURE 23

Breakdown of average cost of electricity.

Breakdown of the average cost of electricity for different levels of wind and solar supply, with the base costs for hydrogen storage and a 5% discount rate. The cost of wind and solar supply dominates the total (note the suppressed zero).

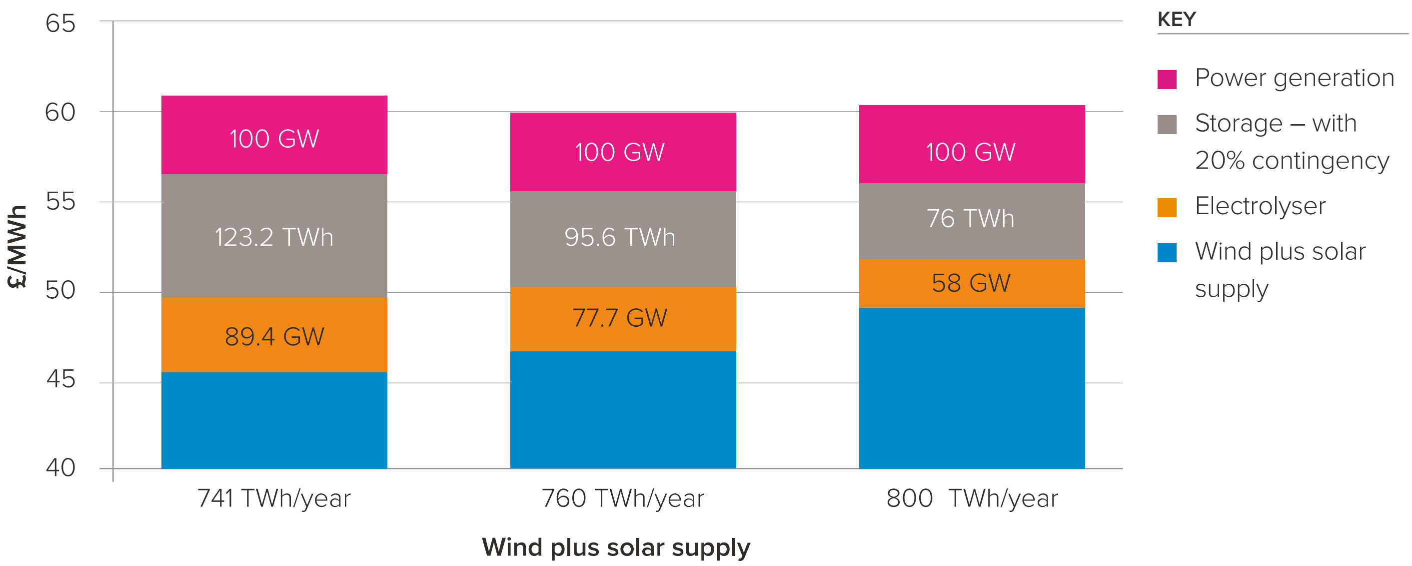


TABLE 6

Annualised costs corresponding to the base costs in table 4 for a 5% discount rate.

Base costs + 5% discount rate	Electrolysers	Storage	Electricity Generation
Annualised cost (capex and OM)	£26.7 M / GW	£32.1 M / TW_{LHV}	£25.2 M / GW

8.3 Provision of all flexible power by a single type of store

The use of hydrogen alone is considered first because in all cases some large-scale hydrogen storage will be needed to meet long-term needs and it provides a benchmark for comparison with other cases.

8.3.1 Hydrogen without baseload

The assumptions that will be used in costing hydrogen storage are collected in table 5.

The annualised costs that correspond to the base costs in table 4 are shown in table 6 for a 5% discount rate (see SI 8.3 for the results with a 10% discount rate, and for details of how the contributions of ACAES and Li-ion batteries are calculated). The contribution that, for example, the cost of electrolysers makes to the average cost of power is then given by:

£[26.7 x (electrolyser power in GW) / 570]/MWh for demand of 570 TWh/year.

The corresponding breakdown of the average cost of electricity, which was plotted in figure 14, is shown in figure 24. This figure shows the way in which the rise in the cost of providing wind and solar power is compensated by the fall in the size and cost of providing storage.

Figure 24 shows the minimum cost for the three different assumptions about the 2050 cost of an 80 / 20 mix of wind plus solar generated electricity in table 5 (which were discussed in section 2.5), assuming 5% and 10% discount rates, for the low, base and high costs of storage in table 5.

For comparison:

- the wholesale price of electricity (which is slightly larger than the amount paid for power fed into the grid as it includes a 0 – 5% location dependent Transmission Adjusted Loss Factor) hovered around £46/MWh (not corrected for inflation) in 2010 – 20. In most of 2022 it was over £200/MWh.
- The strike prices (indexed up to March 2023) for power being generated from biomass at Drax and nuclear power that will be provided by Hinkley C are £142/MWh and £128/MWh respectively.

The average cost of electricity is relatively insensitive to estimates of storage costs. This is because storage only provides some 15% of the electricity fed into the grid, whose average cost is dominated by the cost of the wind and solar supply.

FIGURE 24

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 15 GW of 1-hour batteries to maintain grid stability.

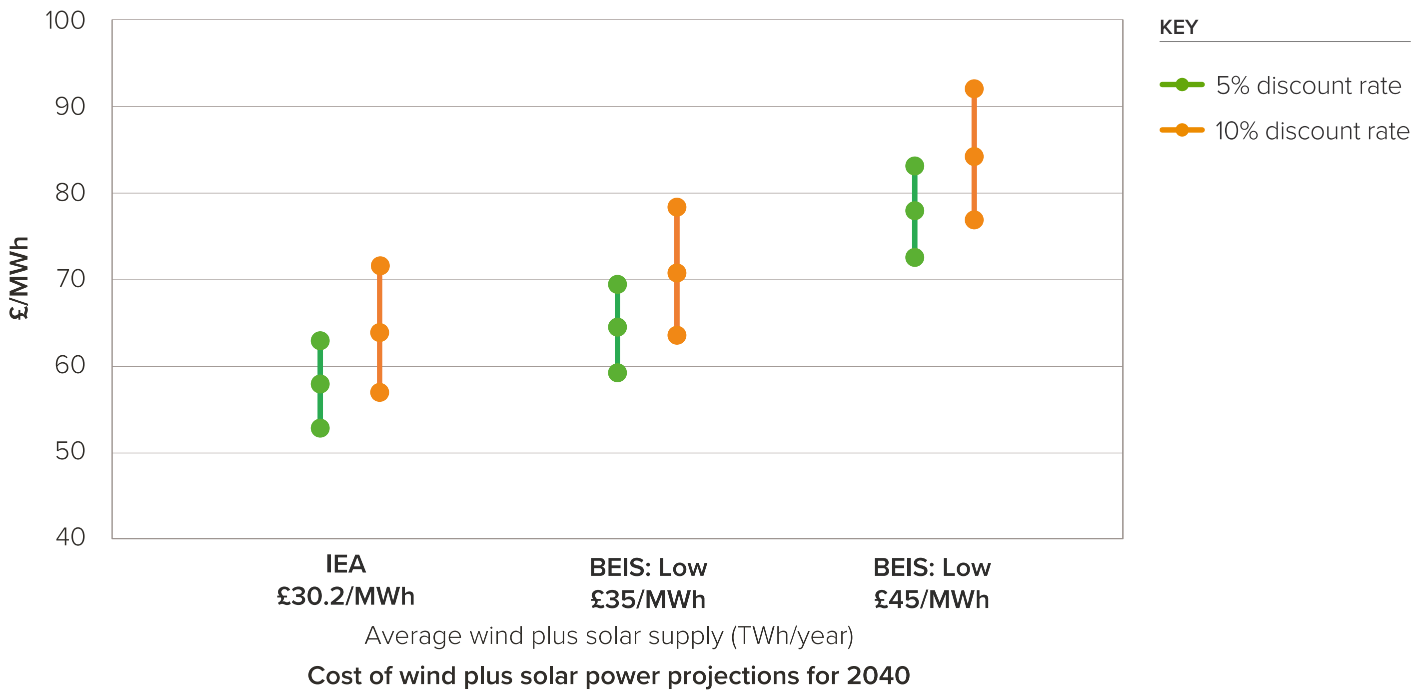
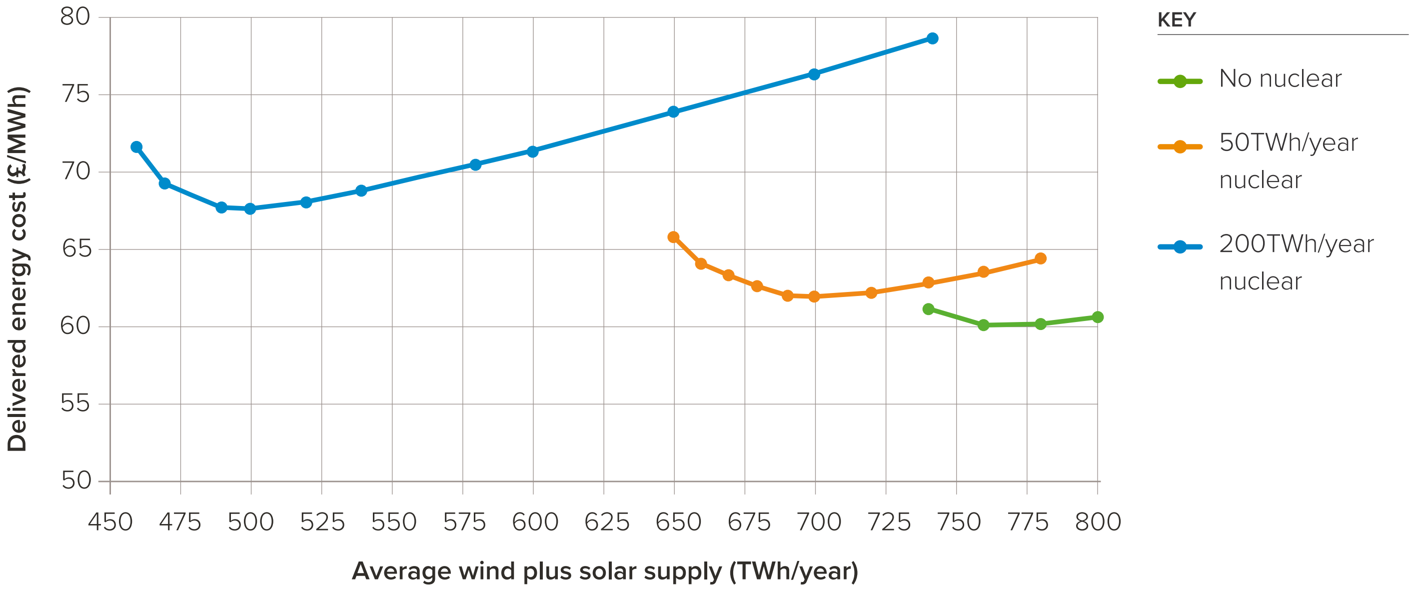


FIGURE 25

Average cost of electricity into grid with and without nuclear.

Average cost of electricity fed into the grid without nuclear and with 50 and 200 TWh/year of nuclear baseload costing £78/MWh (with the load factor assumed by BEIS, a generating capacity of 25 GW would be needed to provide 200 TWh/year). The cost of providing grid services and transmitting power from wind and solar farms to storage is not included in this plot.



Other factors to which the average cost of electricity is potentially sensitive include:

1. The assumed efficiencies. If electrolyser efficiency was 10% lower than the assumed value of 74%, the average cost of electricity would be just under 1% higher. The cost is more sensitive to the efficiency of power generation because it affects the required store size and electrolyser power: reducing the assumed 55% by 10% to 49.5%, would increase the cost by just under 3%. Reducing the efficiency of both the electrolysers and generation by 10% would increase the cost by 5.3% (see SI 8.3). This is for the central cost assumptions and wind plus solar costing £35/MWh. If it costs £45/MWh, 5.3% would increase to 6.5%.

2. The 20% contingency included in the store size, which contributes £0.92 MWh for a 5% discount rate (£1.4/MWh for 10%).

3. The assumption that 100 GW of generating capacity is needed. This is slightly more than the AFRY model's maximum demand of 98.3 GW, but it could be argued that it should be increased to allow for surges. In the base case, 100 GW of generating power contributes £4.6 MWh to the average cost of electricity for a 5% discount rate (£6.7/MWh for 10%) and allowing for 10 or 20% more or less generating power would only have a modest impact.

4. The 80 / 20 wind solar mix. It turns out (see SI 8.3) that the average cost of electricity is not very sensitive to the mix. This is reassuring as it will be partly determined by non-technical and financial factors, such as planning permission, the availability of onshore sites for solar and wind, and the appetite of investors.

8.3.2 Hydrogen storage with (nuclear) baseload generation

If constant baseload supply is added, the demand that has to be met by wind plus solar supply, supported by storage, is reduced by a constant amount. This allows the size of the wind, solar and storage system to be reduced. However, the cost per MWh of the electricity that wind, solar and storage provides will increase because removing a constant increases the volatility of the remaining demand that they have to meet. It follows that the cost of electricity will be increased by the addition of baseload unless its cost is less than the average cost of electricity without baseload. In the case of nuclear baseload, this will only happen if the cost of nuclear is towards the bottom of the range shown in Table 2 and / or the cost without nuclear is towards the top of the projected range shown in figure 24.

This conclusion is illustrated in figure 25 in the case of BEIS's central projection of £78/MWh for the 2040 cost of nuclear power, the central values for the cost of hydrogen storage, a 5% discount rate and wind plus solar power costing £35/MWh. Without baseload, the minimum in the average cost of electricity, which is reached with average wind plus solar supply of around 760TWh/year, is £60.1/MWh (without the cost of providing grid services or transmitting power from wind and solar farms to store). With 50TWh/year of nuclear baseload costing £78/MWh) the minimum in the average cost of electricity (which is reached at around 700 TWh/year of wind plus solar supply), increases to £61.9/MWh. With 200TWh/year of nuclear at £78/MWh, the minimum (which is reached at 500 TWh/year) is £67.6/MWh[z].

Nuclear 'cogeneration' of electricity and hydrogen might lower costs. The electricity would be used directly when needed, and at other times be used to produce hydrogen. The heat from nuclear could be used to improve the efficiency of electrolysis, though the gain is modest except at high temperature reactors which are not likely to be widely deployed in the foreseeable future. Modelling (see SI 8.3) of a constant nuclear supply of 10 GW finds that with a PWR cogeneration would only reduce the average cost of power (relative to the case with hydrogen storage only) if nuclear generated electricity costs less than £60/MWh. Cogeneration of electricity and heat, to be used by industry or to provide space heating, could be attractive if a large-scale flexible need for heat provided by nuclear reactors could be identified, and / or suitable district heat networks were in place[82].

Baseload could also be provided by

- natural gas generation equipped with CCS which is discussed in section 8.5; or
- BECCS. With BEIS's central 2040 projection of £181/MWh_e for cost, adding BECCS would increase the average cost of electricity. However, if the carbon it saves attracted a carbon credit of more than £100 / (tonne CO_2 saved) it could reduce the cost, depending on the cost before it was added[aa].

z With 200 TWh/year [50 TWh/year] the cost/MWh of the wind, solar and storage increases by 2.8% [0.4%] relative to what it would be without nuclear, and the addition of nuclear would only lower the average cost of electricity if it costs less that £57.1 /MWh [£59.7/MWh].

aa A credit of over £139/tonne would offset the generating cost. If BECCS were entirely paid for by carbon credits, then with 50 TWh/year of BECCS, the average cost of electricity would be £55/MWh, with wind plus solar costing £35/MWh, storage provided by hydrogen, with the base costs, and 15 GW of batteries, and a 5% discount rate.

TABLE 7

Costs used in modelling the impact of advanced compressed air energy storage (ACAES).

Assumptions for 2050	Input £ / kW_e	Storage £ / MWh_e – delivered	Output £ / kW_e
Capex	Up to £500/kW*	3911	Up to £500/kW*
Opex p.a.	4% of capex	2% of capex	4% of capex
Financial Life	30 years	30 years	30 years
Efficiency	√round-trip	Range**	√round trip

*Full cost for powers of around 80 MW. The cost / kW is thought to vary as (power rating)$^{-0.4}$

**The modelling used in this report found 68%: a range was considered in costing ACAES

8.4 Multiple types of store

8.4.1 ACAES and hydrogen

Table 7 gives the costs used in modelling the impact of ACAES.

ACAES, which is used here to represent a class of storage technologies, costs more than hydrogen per unit of energy stored, but it is more efficient. While it cannot remove the need for hydrogen storage[ab], it can reduce the average cost of electricity when combined with hydrogen, as shown in figure 26. With 68% round-trip efficiency, the value found in Chapter 4 for the ACAES system that was modelled, adding ACAES to a storage system would lead to a cost reduction, provided compressors and expanders each cost less than £500/kW (see also SI 8.5). The analysis in Chapter 5 suggests that the 2050 cost of large compressors and expanders manufactured in significant numbers may very well be under £450/kW, although this is not assured.

ab Modelling with both ACAES and hydrogen storage never finds cases in which ACAES alone is cheaper than hydrogen alone, nor a combination of ACAES and hydrogen. If the condition that ACAES provides all storage is imposed, it is found that the cost is much higher than using hydrogen alone, (eg with compressors and expanders are assumed to cost £300/kW and around-trip efficiency of 65%, the difference in the average cost of electricity provided to the grid would be 14%) and that an ACAES capacity of 20 TWh_e would be required, which is approaching the maximum that could theoretically be provided onshore in GB. Furthermore, the ACAES costs used in this report ignore heat losses from the thermal store – which are negligible if ACAES is cycled on a time scale of weeks but would be important if ACAES were used provide all storage, which would require storing some of the content for many years.

FIGURE 26

Percentage reduction in the cost of electricity with ACAES + H_2 storage compared to H_2 storage only.

Reduction in the average cost of electricity with hydrogen storage and ACAES relative to the cost with only hydrogen storage for different assumptions about the costs of compressors and expanders (which are assumed to cost the same) and the round-trip efficiency.

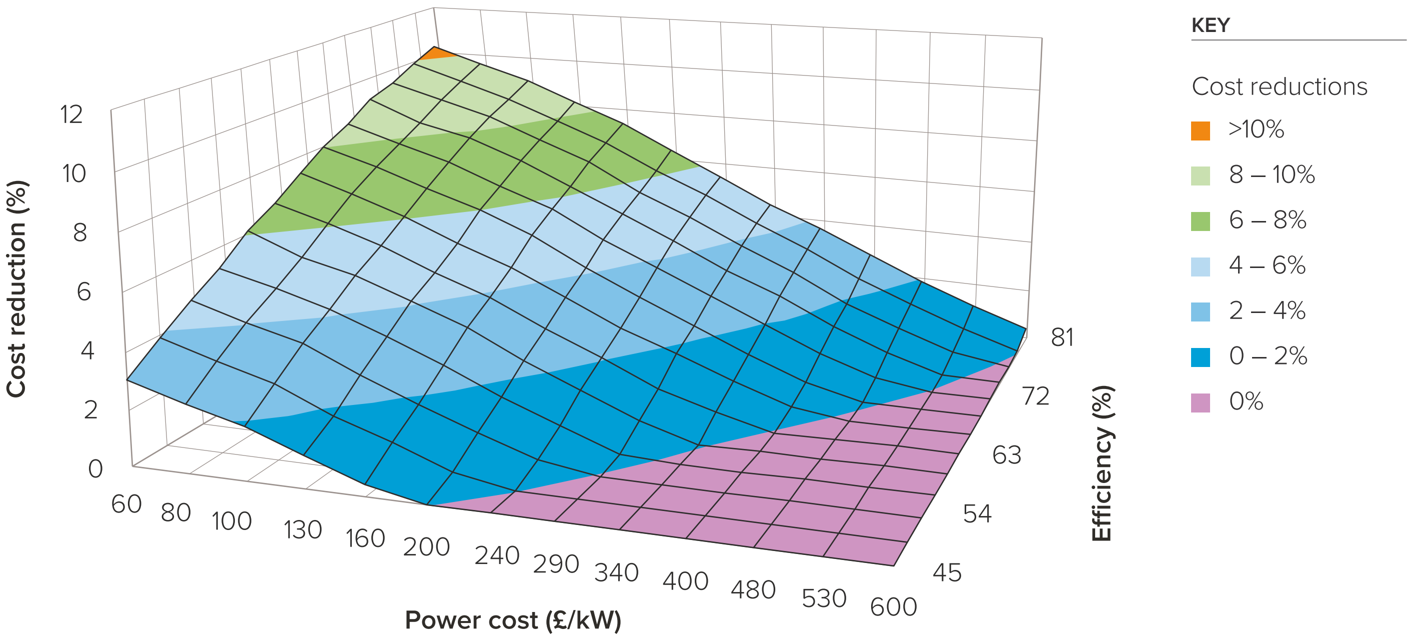


TABLE 8

Example of storage parameters for hydrogen storage (base costs) together with ACAES, with compressor and expander costs of £340/kW and 66% round trip efficiency without contingency.

The addition of ACAES lowers the level of wind and solar supply that is needed because it is more efficient than hydrogen. Correspondingly, it increases the amount of energy that has to be provided by storage.

	Hydrogen only	Hydrogen + ACAES	
		Hydrogen	ACAES
Capacity to deliver per cycle TWh_e	56	32.5	2.4 [6.8 GWh_e / cavern]
Electrolyser / compressor power GWe	77	40	29 [82 MW_e / cavern]
Generation / expander power GWe	88	65	23 [65 MW_e / cavern]
Annual delivery TWh_e	85	36	52

The impact of adding ACAES on the scale of hydrogen storage, and the ACAES parameters that minimise the cost, are illustrated in one particular case (to which no particular significance should be attached) in table 8. Note that although the capacity of ACAES is a fourteenth that of the hydrogen store, it delivers more energy / year, because it is cycled much more frequently.

The number of clusters of caverns that would be needed turns out to be 84 (without contingency) with hydrogen only, and also in the case with ACAES, in which 35 caverns are needed for hydrogen (to which contingency should be added) and 49 for ACAES .

8.4.2 Adding batteries

Batteries can be and are being used to store energy for short periods to provide peak shaving, which attracts high payments and generates revenue from arbitrage, as well as providing grid services. However, according to the modelling and costings used in this report, once hydrogen storage and ACAES are available, they will be able to meet these needs at a lower cost than batteries, unless battery costs fall much faster than anticipated. However, neither hydrogen storage nor ACAES can provide grid services (frequency regulation and voltage stability).

8.5 Use of natural gas with CCS

8.5.1 Introduction

The cost of using wind plus solar energy and storage to provide GB's electricity might be lowered by allowing some use of gas with CCS. This would have to be subject to ensuring that:

- Fugitive CO_2 emissions are costed at a level that would pay for their removal (in competition with removing emissions from much harder to abate sectors).
- Methane emissions, which are currently not penalised financially, are kept to a very low level.
- Risks to energy security from rises in the price of gas, and increasing dependence on imported gas, are accepted.
- Adequate storage of natural gas is available.

For comparison, 55 Mt of carbon dioxide were emitted by power generation in the UK in 2021. The climate impact factor of methane is taken to be 128 times that of carbon dioxide. This is the relative size of the temperature rises caused by steady emissions of equal masses of carbon dioxide and methane 20 years after the emissions start (rather than the Global Warming Potential which describes rises caused by emitting single pulses of each).

8.5.2 Use of natural gas with CCS to generate electricity

Three options were studied using BEIS's 2020 estimates of the 2040 cost of electricity generated by gas with post combustion CCS (for details see SI 8.5). BEIS presented results for an assumed future gas price of 65p/therm [£22.4/MWh_{HHV}], at which level it contributes £47/MWh_e to the cost of electricity, and a carbon price of £220/t CO_2, at which level it contributes £8/MWh_e. For comparison, the wholesale cost of gas fluctuated around 40p/therm from October 2015 to October 2020, but was over 100p/therm from October 2021 to March 2023.

Using gas + CCS to provide baseload power

Adding baseload to a 'hydrogen storage only' system will only lower the average cost of electricity if the cost of the baseload is less than the cost without baseload. With BEIS's assumptions, the 2040 cost of baseload electricity provided by gas + CCS would be £82/MWh, which is towards the top of the range without baseload shown in figure 24. If gas costs 95p/therm (as assumed in a 2021 BEIS report on the cost of blue hydrogen), the cost of gas + CCS would be well outside the range. If it costs 40p/therm, gas + CCS would cost £64/MWh (or £72/MWh if the carbon price were twice that assumed by BEIS), which is in the middle of the range. Adding enough gas plus CCS to have a significant impact on the average cost of electricity would produce substantial greenhouse gas emissions. The addition of 150 TWh_e/year, for example, would generate fugitive CO_2 emissions of 5.7Mt/year, plus a 'CO_2 equivalent' of 13.3Mt/year from methane leakage, assuming 47% generation efficiency, that 90% of the CO_2 is captured, and methane leakage can be limited to 0.5%.

Using gas + CCS to provide the flexibility needed to complement wind and solar

Using forecasts of supply and demand, it could be possible for CCGTs equipped with CCS to provide most of the flexibility needed to match variations in wind and solar supply and demand.

Using BEIS's estimate of the cost of gas plus CCS, if gas plus CCS were used to provide all flexibility, then with a gas price of:

- 65p/therm and wind plus solar costing £35/MWh (or £45/MWh), the average cost of electricity would be above (or close to) the top of the range of costs (see figure 24) found if storage provides all flexibility.
- 40p/therm and wind plus solar at £35/MWh (or £45/MWh), the cost would be in the middle (or at the bottom) of the range in figure 24.

Using gas plus CCS to provide all flexibility would therefore cost more than using storage unless the future gas prices are low and storage costs are high.

More seriously, it would lead to large greenhouse gas emissions. With, for example, gas at 65p/therm and wind plus solar at £35/MWh, the average cost of electricity would be minimised with wind plus solar supply of about 400TWh/year.

Some 375 TWh/year of this could be used to meet demand directly (the remaining 25 TWh would be curtailed), leaving 195 TWh_e/year to be met by gas + CCS, which would generate fugitive CO_2 emissions of 7.4Mt/year, plus a 'CO_2 equivalent' of 17.2Mt/year from methane leakage.

Using gas + CCS flexibly in combination with hydrogen storage

Combining gas plus CCS with storage could lower the cost of electricity as it would reduce the level of wind and solar supply that is needed and the size of the storage system. The addition of 20 GWe of gas generated power, assumed to be available when needed, was modelled (see SI 8.5). This would lead to fugitive CO_2 emissions of 2.1 Mt/year, assuming 90% capture, to which methane leakage would add 4.8Mt/year 'CO_2 equivalent'. It would lower the average cost of electricity significantly if BEIS's central estimate of the cost of gas plus CCS is correct, gas costs 64p/therm, and hydrogen storage costs are in the upper half of the range in figure 24. The size of the reduction depends sensitively on the assumed costs and on how gas generation is operated, but is relatively insensitive to the carbon price.

With 20 GWe of gas generated power available on demand, the cost would be minimised for average solar plus wind supply of 620 TWh/year (compared to 760 TWh/year with no gas), with 50 GW of electrolysers and a 57.7 TWh hydrogen store (compared to 76.9 GW and 80.2 TWh without gas, with no contingency in either case). While it would have a major impact on the level of wind and solar supply and the size of the storage system, the addition of gas with CCS would not remove the need for the tens of TWh of long-term storage that are required to cope with the long-term variability of wind power.

8.5.3 Use of blue hydrogen

Blue hydrogen can be made by Steam Methane Reforming (SMR) or Auto-Thermal Reforming (ATR). ATR is considered here because, according to a report for BEIS, it is 84% efficient (HHV) and 95% of the CO_2 can be captured, while for SMR the corresponding figures are 74% and 90%. In contrast to SMRs, there is some scope for ramping ATRs up and down, although at a far slower rate than electrolysers, and they cannot be readily turned on and off. BEIS concludes that 'ATR acts very much as a baseload producer'. Combining baseload power generated by blue hydrogen with storage of green hydrogen would put up the overall cost, unless the future cost of gas is less than 47p/therm. Alternatively, blue hydrogen could be fed into the hydrogen store, when it is not full. Simple modelling (see SI 8.5) finds that this would increase the average cost of electricity unless the future cost of gas (which dominates the cost of blue hydrogen production) is lower than the 95p/therm assumed by BEIS in this case, and the cost of storage is in the upper part of the range found in this report. With a continuous supply of 20 GW_{LHV} of hydrogen, the cost would be minimised with about 600 TWh/year of wind plus solar, a 65 TWh_{LHV} store and 30 GW of electrolysers. With the 95% capture anticipated in ATR, a steady supply of 20 GW_{LHV} of blue hydrogen would lead to CO_2 emissions of 2.5Mt/year and 'CO_2 equivalent' methane emissions of 7.7Mt/year.

8.5.4 Conclusion

There are plausible circumstances in which combining hydrogen (together with other forms of) storage with flexible supply from gas plus CCS would lower costs, although fugitive CO_2 emissions and methane leakage could not be avoided, and there are some – more circumscribed – conditions in which the other uses of gas + CCS and blue hydrogen considered here could lower costs. The circumstances depend on the costs of providing storage, wind and solar power, natural gas and gas plus CCS, and the carbon price. This possibility would be worth analysing in more detail as estimates of future costs become firmer.

Adding gas plus CCS would provide diversity, but it would expose GB's electricity supply to any large increases in the price of gas, and increasing reliance on imports as GB's gas reserves decline. However, it would not remove the need for large-scale long-term storage.

8.6 Possible uses and value of surplus electricity

The average cost of electricity is sensitive to the value, if any, of the residual surpluses that remain after the demand that was modelled has been met (see figure 14). Possible uses to which they could be put (which are considered in more detail in SI 8.6) include:

- Producing green hydrogen for purposes other than storing electricity, for which there could be a demand of tens of TWh[5]. Co-production of green hydrogen for different purposes would be expected to lead to lower costs. One US study[111] found that producing hydrogen for other markets could reduce the cost of electricity delivered by hydrogen systems by up to 39%.
- Exporting electricity through interconnectors. GB became a net exporter of electricity during 2022 for the first time in twelve years. In some of BEIS's scenarios[112] GB will be a net importer in 2050, but it will be a net exporter according to all the FES[113] (of 148 TWh/year in one scenario). The volume of imports and exports will depend on renewable capacity in GB and the rest of Europe, and generation costs when there are surpluses (which will often occur at the same time in different places). Since GB has a very large wind resource, it is possible that it could be exporting on a 100 TWh scale in 2050, while also importing solar energy from southern Europe.
- Heating, or topping up thermal stores connected to district heat networks.
- Meeting new needs that may arise that can make good use of spasmodic power, such as drying biomass.

Using residual surpluses might not be straightforward as they vary by large amounts from year to year (see figure 9 and SI 3.2). However, meeting some of the possible uses to which they could contribute, such as co-production of green hydrogen for different purposes, could warrant additional investment in generating capacity.

8.7 Contingencies against periods of low supply

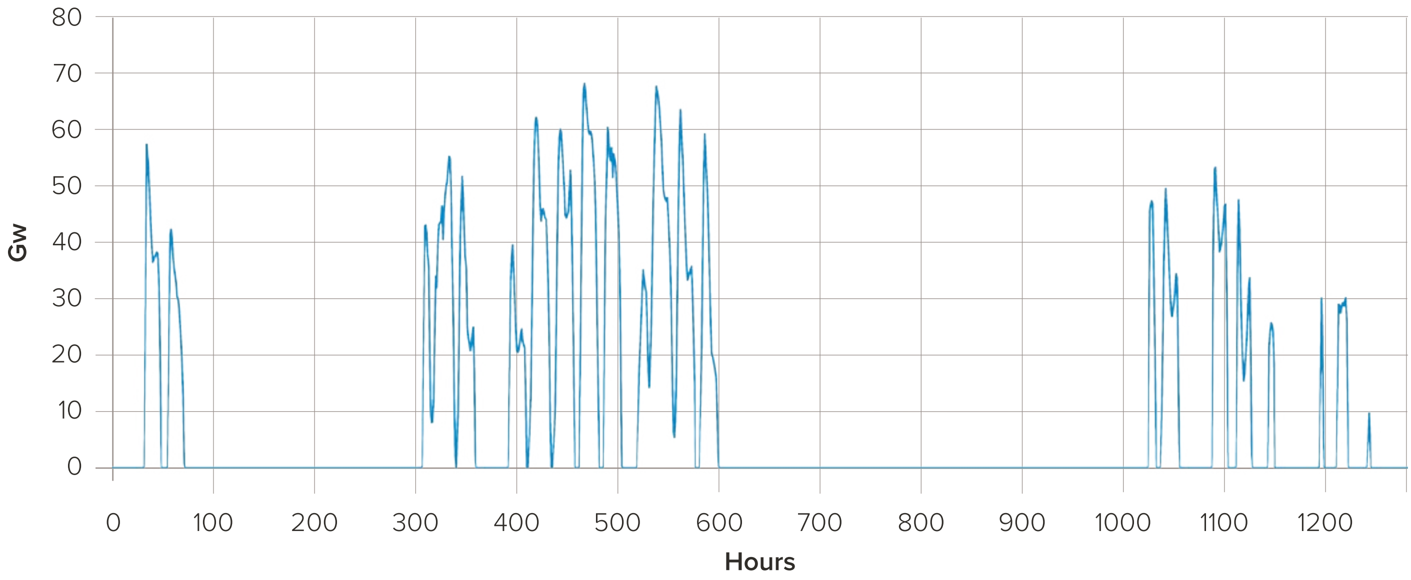
A range of unknowns have been outlined in this report, not least the variability of the wind and sunshine. For this reason, 20% contingency was added to the size of the hydrogen store in estimating the average cost of electricity, which contributes about £1/MWh to the cost of electricity. To understand whether this contingency could be provided in other ways, consider what would have happened if the need for storage had been underestimated and the store had been made 20% smaller than needed to meet demand over the 37 years studied (thereby saving ~ £1/MWh). In that case, demand could have been met in all but 322 hours, in a period of 1,211 hours in March – May 2011 (see figure 13), when it would not have been possible to meet 11.5 TWh of demand.

In those 322 hours, the average unmet demand, shown in figure 27, was 35 GW, compared to an average demand of 65 GW. It would be prohibitively expensive to keep other sources, capable of providing tens of GW, available for use in just 0.1% of the time in 37 years (see SI 8.7). Furthermore, it is impossible to imagine demand management compensating for these clusters of large amounts of unmet demand. However, as discussed in section 3.3, long-range forecasting can be used to anticipate prolonged periods of low supply, during which measures such as those discussed in section 2.7 could have been used to reduce demand and prevent the store becoming empty. This deserves more analysis (see SI 8.7 for a preliminary investigation).

FIGURE 27

Unmet demand with an undersized hydrogen store.

Demand that could not have been met using hydrogen storage in March – May 2011, with a hydrogen store that is 20% smaller than needed to meet all demand in the period 1980 – 2016.



Without a better understanding of the vagaries of the weather, it is unclear how much contingency is needed. By the time large amounts of storage have been built, however, improved modelling (and studies of earlier periods of low wind) should make it possible to understand better the scale of the need for contingency, and the scope for pre-emptive demand management.

8.8 Different levels of demand

To provide a feeling for what would happen if basic demand were higher or lower than 570 TWh/year, models were studied (see SI 8.8) with demands of 440 and 700 TWh/year, which are at the lower and upper ends of the range of current projections for 2050. With higher demand, the level of wind solar supply and the size of storage system would have to be much greater. However, the cost of electricity was found to increase by under 2% in moving from 440 to 700 TWh, despite the profile of demand becoming much more skewed between winter and summer as more heating was assumed to be electrified in the second case.

8.9 Other studies of the cost of storage in Great Britain

A number of studies have been made of residual demand and the need for electricity storage in GB[114, 115, 116, 117, 118, 119], and of the cost of providing it, including by Barrett et al (the first to study multi-decadal weather sequence, see SI2 Annex 2), and one in the context of Europe as a whole, allowing for the possibly of greater interconnection[118].

All but one of these studies, whose assumptions and approaches are summarised and compared in SI 8.9, were based on weather in consecutive years, over periods ranging from 9 years[114, 115] (which the authors noted is probably not enough), through 21 and 27 years, to the 37 years[117] used in this report. These studies reached similar conclusions on the need for storage relative to the assumed scale of demand.

Studies by AFRY management consultancy carried out for BEIS[119] the National Grid/ESO, and the Climate Change Committee , which used them as input to their report *Delivering a Reliable Decarbonised Power System*[120], looked only at individual years, without allowing for any inter-annual storage (these reports are analysed in SI 3 Annex 2). While this work casts helpful light on the need for short-term storage, studies that do not consider long sequences of years underestimate the need for long-term storage. Studies of single years cannot cast light directly on the need for storage lasting over 12 months and overestimate the need for other supplies[ac].

Despite using different methodologies, and making very different assumptions about storage costs, the studies that used multi-year weather sequences to cost systems with high levels of wind and solar supported by long-term storage found average costs of electricity that are not dissimilar (see SI 8.9). This is because the cost of providing storage only contributes a small fraction of the average cost of electricity, which is dominated by the cost of wind and solar power. The studies that allowed for a contribution from nuclear baseload[105, 106] found that it will put up the average cost of power unless the cost of nuclear is near or below the current range of expectations.

ac In order to balance supply and demand, a much greater level of supply is required from other sources, and / or wind and solar, than would have been required if storage had been allowed to transfer energy between years (especially in low wind years, such as 2010, which was one that AFRY studied, when the amount needed from other sources would have been far more than in most other years, as can be seen in Figure 2). This effect is exacerbated by AFRY's study of calendar years since periods of exceptionally low wind and solar supply typically run from December to March (as seen in figures SI 2.5 A and B).

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 (see SI 9 for a more detailed analysis).

9.1 The grid

The transmission grid will have to be enlarged to connect new solar and wind farms at dispersed and often remote sites. It will also have to be strengthened to deal with larger fluctuations, dominated by variations in supply, and higher peak loads. The distribution networks will also have to be strengthened to handle additional loads created by charging electric vehicles and electrification of heating and accommodate an increasing number of renewable sources connected to it directly.

Ensuring that supply remains reliable (ie designed and operated so that it is uninterrupted) and resilient (ie can be restored quickly if it fails) will become increasingly important as the role of electricity grows. Reliability and resilience are currently mainly provided by dispatchable unabated gas generation. However, in a net zero future, with systems in which high levels of renewable supply are supported by storage, reliability will depend critically on the provision of dispatchable storage.

In conventional power stations, the electricity that is fed into the grid is 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, an urgent 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. New support tools based on advanced stochastic methods will have to be developed that take account of the uncertainty in wind and solar supply and different ways of scheduling the use of storage.

9.2 Markets issues

Decisions on the major investments that will be needed during the energy transition must ensure an appropriate balance between generating capacity, different storage technologies, and transmission and distribution, and enable flexible demand. Close coordination between generators and operators of storage will be needed in order to schedule the use of storage cost-effectively and ensure that demand for electricity can be met reliably. It is very unlikely that GB's current wholesale market arrangements, in which both long-term investment decisions and short-term dispatch are largely governed by a single price signal (ie the system marginal cost), will be able to meet these aims even with a very high carbon price.

Investors in generation and storage are dependent on revenue streams over long (20+ years) asset lives, during which prices, regulations and government policy will change in unpredictable ways. In the case of storage, 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. These investors will require some form of long-term contractual assurance. It could be provided by a regulated asset base approach, or government commitments, for example through Contract for Difference (CfDs) or feed in tariffs[121]. 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 report 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[122].

Traditional spot markets, which were developed to deal with gas and coal powered generation, are not automatically suitable for or adaptable to technologies which are subject to more complex, intermittency and operating constraints, such as wind, solar, and storage. Finding alternative 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.

9.3 Possible reforms

It is widely recognised that reaching net zero emissions cost-effectively will require an unprecedented level of coordination and a 'whole system' approach that extends across the energy sector. It is difficult to imagine existing markets and regulations delivering a portfolio of generation and storage that would lead cost-effectively to a net zero electricity system or ensuring the operational coordination necessary to control costs. If alternatives are not adopted before large-scale storage is needed, not enough will be built.

Possible alternatives, presented purely to provoke discussion, include:

1. Centrally driven coordination of investment plans, which are quite common internationally (examples include France's EDF and Germany's *Energiewende*[123]).

2. 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) and / or reverse auctions of the obligation to provide 'firm', dispatchable, power[124] (which would require cooperation between generators and providers of storage).

3. 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.

Conclusions, further steps and opportunities

10.1 Conclusions

Great Britain's demand for electricity could be met largely (or even wholly) by wind and solar energy supported by large-scale storage at a cost that compares favourably with the costs of low-carbon alternatives, which are not well suited to complementing intermittent wind and solar energy and variable demand. The following list of chapter-by-chapter headlines supplements the narrative synthesis of conclusions in the Executive Summary, while table 4 provides a summary of the characteristics of storage technologies that are considered in this report. While this report focusses on GB, the methodology and conclusions on storage technologies are, however, generally applicable.

10.1.1 Chapters one – three: Introduction; electricity demand and supply in the net zero era; modelling the need for storage.

In order to assess the need for storage it is necessary to examine as long a period of weather data as possible. Studies of period of a few years, or even one or two decades, can seriously underestimate the need for storage.

The long-term variability of wind creates a need to store tens of TWhs for many years.

The need to curtail wind and solar power in GB is minimised for a wind / solar mix around 80 / 20. With this mix, residual demand / energy averaged is small in all four quarters of the year when averaged over many years, but it varies enormously from year to year, ie it is variability rather than seasonality which is the issue.

The same storage needs can be met (within limits) by a relatively small storage capacity charged rapidly or a larger capacity charged relatively slowly. The lowest cost configuration depends on the relative costs of converting electricity to a storable form and storing it.

When several different types of store are deployed, a procedure for scheduling their use is required. Operating protocols designed to minimise the cost will require close cooperation between generators and operators of storage.

10.1.2 Chapter four: Green hydrogen and ammonia as storage media.

Hydrogen and ammonia are technically viable options for storing power, although the round-trip efficiencies are low, and the costs are high. Hydrogen production is already fully commercialised for some electrolyser types. Hydrogen end-use technologies are still developing. Electrochemically-driven ammonia production has been practiced extensively in Norway, but ammonia end-use technologies lag those using hydrogen.

Provided hydrogen can be stored underground, ammonia will not be able to compete head-to-head with hydrogen for storing power in the UK (unless or until much cheaper ways of making ammonia are developed, by a process that can load follow). It may, however, play a role in areas in which it is not possible to store hydrogen underground and the capacity to transmit power from other regions is limited.

The UK has a more than adequate potential for underground hydrogen storage, although it is limited to East Yorkshire, Cheshire and Wessex. Building the number of caverns that this report finds will be needed by 2050 will be challenging, but not impossible.

10.1.3 Chapter five: Non-chemical and thermal energy storage.

Many different forms of storage were described in this Chapter: ACAES, thermal and pumped thermal storage, thermochemical storage, liquid air energy storage, gravitational storage (including pumped hydro) and storage designed to deliver heat. Most could potentially store TWh of energy, using multiple distributed units with storage capacities up to multiple GWh and outputs from a few kW to hundreds of MW. Most would benefit from further research and development and need to be demonstrated at scale, and it needs to be shown that actual efficiencies can approach theoretical efficiencies. However, they are potentially low cost compared to batteries, have low self-discharge rates with potentially good round trip efficiencies, and could play important roles in short to intermediate-term storage. Only thermochemical storage has the potential to play a major role in really long-term storage, but it is at a very early stage of development.

10.1.4 Chapter six: Synthetic fuels for long-term energy storage.

Synthetic Fuels are expected to play a role in transport but are outclassed by ammonia and hydrogen for electricity storage. Liquid organic hydrogen carriers could play a role in distributed combined heat and power systems.

10.1.5 Chapter seven: Electrochemical and novel chemical storage.

Lithium-ion batteries are already deployed in support of the electricity grid and home storage and are very likely to play a major role in providing very rapid response grid-services. Although their costs are falling, the modelling in Chapter 8 finds that at grid-scale, they are likely to be outclassed by hydrogen, ACAES or other forms of storage for providing peak shaving and short-term arbitrage, if / when they are deployed. Among the alternatives, sodium-ion batteries could in principle be cheaper, but high costs when they are produced initially in relatively small numbers may be a barrier to achieving manufacture at scale.

If a significant fraction of GB's future fleet of electric vehicles were from time to time under the control of the operator of the electricity grid, the flexible power reserve that they would provide would make an extremely valuable contribution to manging the system.

Flow batteries, whose capacities and power ratings are independent, offer highly flexible and scalable storage. The all-vanadium design is the most commercially mature but is expensive. If / when flow batteries that use significantly cheaper materials become available, they could play an important role in grid-scale storage.

10.1.6 Chapter eight: Powering Great Britain with wind and solar energy and storage.

With wind and solar supply supported by hydrogen storage (and some batteries), it was found that, with the range of input assumptions made in this report, the average cost of electricity fed into the grid in 2050 would be between £52/MWh and £92/MWh in 2021 prices (see figure 23). The addition of inflexible 'baseload' supply, for example from nuclear or gas with CCS, would increase the average cost of electricity unless the cost per MWh of the baseload is less than that of the average without baseload. BECCS would satisfy this condition if the generating cost is offset by the carbon credits that it should attract as a carbon negative source.

Combining ACAES (or other types of stores for which it served as an exemplar) with hydrogen storage could lower the average cost of electricity by up to 5%, or possibly more, depending on what is assumed about its cost and efficiency.

Using a combination of storage and gas plus CCS to provide the flexibility required to match wind and solar supply could lower costs significantly. Whether it would lower costs depends sensitively on the costs of storage, of wind and solar power, and of gas plus CCS, and the price of 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.

10.1.7 Chapter nine: The Grid, electricity markets and coordination

Ensuring that electricity supply is reliable will become increasingly important as the role of electricity grows in transport, heating and industry. In systems in which high levels of renewable supply are supported by storage, reliability will depend critically on the provision of enough storage including contingency: if stored energy runs out, the lights really will go out when the wind is not blowing and the sun not shining.

Gas powered electricity, which is generated by synchronised rotating machinery whose mechanical inertia provides stability, is increasingly being replaced by wind and solar generation that uses power electronics to provide AC power to the grid. If this 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, an urgent need for engineering research to guide how the increasingly ubiquitous power electronic converters should be designed and used.

In GB's current wholesale electricity markets, both long-term investment decisions and short-term dispatch are largely governed by a single price signal (ie the system marginal cost). The large-scale long-term storage that this report finds will be essential, could never recover its capital costs in such a system since it will be idle much of the time. Existing markets and regulations will also not be able to deliver the operational coordination between wind and solar generators and operators of storage that will be needed to schedule the use of different types of store cost effectively and ensure that they do not become empty. There is an urgent need to recognise these problems and explore possible solutions.

10.2 Further steps

This report focusses on the large-scale storage that GB will need in 2050. This need should be incorporated in models of GB's electricity system that take account of factors what were not considered here, including contributions from burning waste and biomass, hydro power and interconnectors, and the relative locations of supply, storage, and demand, and their implications for the grid.

There is also a need to:

- Model the provision of green hydrogen for storing electricity and meeting other needs together, based on views of the scale, flexibility and temporal profile of other needs;
- Take account of the possible use of a combination of storage and gas + CCS to provide the flexibility needed to complement wind and solar supply;
- Study possible barriers to the rapid construction of the large numbers of salt caverns that will be needed for hydrogen storage;
- Explore / develop alternatives ways of scheduling the use of storage, which could take account of long- (as well as short-) term weather forecasts;
- Examine the impact of improved performance of wind turbines at low wind speeds, and assess where they would best be sited taking account of the system value of minimising correlations in their outputs;
- Develop models of electricity demand that take proper account of correlations with the weather in the years studied and include demand management measures in the modelling.

The underlying assumptions on the cost of storage and of providing wind and solar power should be underpinned by detailed engineering estimates, which should be updated periodically in the light of experience gained from building real systems or demonstrators.

The cost of providing an electricity system of the kind envisaged in this report should be analysed in detail. 200 GW of wind and solar capacity and 100 TWh of storage capacity will be needed, assuming 570 TWh/year demand (these capacities are approximately proportional to demand but would obviously be reduced if substantial nuclear capacity is available). The required investments would be of the order:

- £210 billion for wind and solar capacity (mixed as assumed in this report), according to BEIS's 2020 estimates of the costs and capacity factors, assuming commissioning in 2040;
- £100 billion for storage; and
- £100 billion between now and 2050 to enlarge and strengthen the transmission grid, according to National Grid[101].

These cost estimates, which are sensitive to commodity prices, assume that essential materials will be available. The IEA finds[125] that lack of critical materials will not prevent the transition to a low carbon economy, although temporary shortages or disruptions could lead to 'a more expensive, delayed or less efficient energy transition', and it could close some avenues, including the widespread deployment of PEM electrolysers, which appears to be the only technology considered in this report that is really seriously threatened in their current form.

Given the outlines of what it might comprise, models of possible pathways to a net zero electricity system powered largely by wind and solar can be developed. In order to move to a high wind and solar plus storage system, the necessary wind, solar and storage capacities would have to be in place before carbon dioxide emitting sources are switched off. The possible pathways will depend on the rate at which capacity can be installed, which needs to be studied in detail. In the case of wind and solar generation capacity, the current rate would have to increase in order to reach 200 GW in 2050. The National Grid's scenarios[ad] suggest that this would be possible, although it might be easier with somewhat less solar and more wind than assumed here (which would have very little impact on the average cost of electricity).

Market mechanism will have to be in place that make investment in large-scale storage attractive before it is actually needed and can accommodate a mixture of supply provided by wind and solar directly (at low cost) and via storage (at low marginal but high absolute cost). If the required reforms are not identified and implemented relatively soon, GB could become locked into a sub-optimal mixture of infrastructure.

R&D is needed. Although it is unlikely that 'new science' will be able to make a major contribution by 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 improving existing technologies, and combining them in new ways, for example in wind-integrated-storage, and reversible electrolysers / fuel cells and compressors / expanders, and there are specific R&D challenges, such as reducing or eliminating iridium in PEM electrolysers.

ad With BEIS's 2040 projections of capacity factors and the wind/solar mix espoused in Chapter 2, generating 741 TWh/year would require capacities of 60 GW onshore wind + 70 GW offshore wind + 150 GW solar. In comparison, the range of 2050 projections in the National Grid's 2022 FES[5] are: 34-47 GW onshore wind, 89-110 GW offshore wind and 57-92 GW solar, and envisage the installation of 10 to 40 GW of domestic solar PV while the UK government's British Energy Security Strategy proposes 2030 targets that include increasing solar capacity from its current level of 14 GW to 70 GW and offshore wind from 11 GW to 50 GW.

ae In November 2022 BEIS announced further funding (£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. Hydrogen related projects are described in the next footnote.

af In April 2023, the Government published a Hydrogen Net Zero Investment Roadmap https://www.gov.uk/government/publications/hydrogen-net-zero-investment-roadmap. This is welcome, but the Roadmap does not recognise the need for hydrogen storage to support electricity generated by wind and solar, and the three examples of hydrogen stores (on page 13) would only provide a small fraction of the storage that will be needed. On 30/3/23 the government published a short list of projects involving electrolytically produced hydrogen, totalling up to 250 MW, with the intention of awarding contracts in the last quarter of 2023 – https://www.gov.uk/government/publications/hydrogen-production-business-model-net-zero-hydrogen-fund-shortlisted-projects/hydrogen-business-model-net-zero-hydrogen-fund-shortlisted-projects-allocation-round-2022. SSE's Aldbrough Hydrogen Pathfinder project is the only that involves storage in a deep salt-cavern (previously used to store natural gas) and is one of the three examples of storage given in the Road Map: it is unclear whether/how the other two might be funded.

10.3 Demonstrators, deployment and opportunities

Demonstrators are needed before large-scale energy storage systems can be widely deployed, to identify and solve engineering and integration issues[ae].

In the case of large-scale hydrogen storage, supplied by electrolysers powered by wind and solar energy, enough is known to start construction now[af], as is happening elsewhere[ag]. How much hydrogen storage will ultimately be needed to support the electricity system will depend on what other forms of supply and storage are built, but it will be TWhs, and there are expectations that green hydrogen is likely to play many roles.

Construction of a large green hydrogen production and storage facility would appear to be a no-regrets option. It would provide a much better idea of what hydrogen will cost and set GB on the road of cost reduction through learning. The construction of others should follow quickly.

Building large scale hydrogen storage facilities[ah], which UK companies are well positioned to do, would provide the UK with an opportunity to take a leading role in the energy transition. However, the construction of large caverns is currently not justifiable commercially, and they will not be built until mechanisms to reward investors are in place.

Other countries have ambitious plans to develop hydrogen storage starting now. If the UK does not emulate them, the electricity storage necessary to ensure low carbon, reliable and affordable energy supply will not be available when it is needed.

ag One example in a rapidly developing spectrum of projects: ACES Delta (https://aces-delta.com/) is developing 'the world's largest renewable energy hub' to produce, store, and deliver green hydrogen in Utah with the support of $500 million of debt financing from the US Department of Energy https://www.energy.gov/lpo/articles/innovative-clean-energy-loan-guarantees-gathering-momentum-new-conditional-commitment. It will eventually use a salt cavern to store 5,500 tonnes of hydrogen, provided at a rate of over 450 t/day by over 1 GW of electrolysers. More construction is needed on this scale, which is that of just one of the ten caverns in the clusters that the H21 NE[26] consortium has designed for construction in East Yorkshire.

ah Electrolysers: INEOS are considering the manufacture of alkaline electrolysers for hydrogen production, building on long experience of making and using them to produce caustic soda and chlorine. ITM power is a leading manufacturer of Proton Electrolyte Membrane (PEM) electrolysers. Ceres is a world leader in the design of Solid Oxide Electrolysers.
Underground storage: The H21 NE consortium has designed clusters of 10 300,000 m^3 salt caverns in East Yorkshire. INOVYN has planning permission to build a cluster of 17 350,000 m^3 salt caverns in Cheshire to store natural gas and is applying for permission to use them to store hydrogen. SSE is ready to convert some natural gas storage at Aldbrough to hydrogen storage, and Centrica has plans to convert the offshore Rough gas storage facility.
Power generation from hydrogen using fuel cells or four-stroke engines: Johnson Matthey and many other UK companies are involved in the supply chain for PEM fuel cells (as they are for electrolysers). Ceres design Solid Oxide Fuel Cells, which have the potential to work also as electrolysers. JCB have produced a prototype four-stroke hydrogen engine which looks as if it could be scaled up to provide a relatively cheap and efficient way of generating power.

ANNEX A

Glossary and abbreviations

Advanced compressed air energy storage (ACAES)
Advanced compressed air energy storage, in which the heat of compression is stored and used to prevent freezing when the air expands. It is often called Adiabatic compressed air energy storage although the air compression is closer to isothermal.

Adiabatic
Occurring without loss or gain of heat.

Baseload
A term used in this report to mean electricity supplied at a constant rate.

Basic demand
Demand for electricity, before transmission and distribution losses, excluding demand for the electrolytic production of hydrogen (for storing electricity or other purposes). The corresponding quantity after losses is known by the National Grid as 'customer demand'.

Bioenergy with Carbon Capture and Storage (BECCS)
The extraction of energy from biomass, assumed in this report to be by burning it and generating electricity, followed by the capture and burial of the carbon-dioxide that is produced.

Compressed air energy storage (CASE)
This term, which is often used for all forms of compressed air energy storage, but is only used here to describe cases in which fossil fuels are burned to prevent freezing when the air expands. See ACAES (advanced compressed air energy storage).

Capex[ai]
Capital investment in machinery and infrastructure.

Carbon capture and storage, or sequestration (CCS)
Capture of carbon-dioxide and then burying it underground.

Carnot battery
A system that uses a resistive heater or a heat pump to turn electricity into heat that is stored and later used to generate electricity.

Contract for Difference (CfD)
CfDs are the UK government's main mechanism for supporting low-carbon electricity generation. Successful developers of renewable projects enter into a contract with the government-owned Low Carbon Contracts Company (LCCC). When the market price for electricity generated by a CfD Generator (the reference price) is below the Strike Price set out in the contract, the LCCC pays the Generator to the difference. When the reference price is above the Strike Price, the Generator pays LCCC the difference. A CfD provides a degree of certainty for the generator.

Curtailment
Describes temporarily stopping a source of electricity (eg a wind or solar farm) exporting power.

Diabatic
Involving the transfer of heat.

Discount rate
The interest rate used to convert future cash flows or outputs into an equivalent one-off upfront sum, known as the Net Present Value. In estimating the levelised cost of electricity (LCOE) the discount rate is typically taken to be an estimates of the investor's Weighted Average Cost of Capital.

ai For an introduction to issues related to the cost of capital see http://CO2economics.blogspot.com/2022/08/bluffers-guide-to-cost-of-capital.html. For more complete definitions of the terms involved see https://www.investopedia.com/financial-term-dictionary-4769738 (accessed 18 May 2023).

Dispatchable[ai]
Dispatchable supplies of electricity are those that are (normally) fully under the control of the operator.

Electrolyser
A system that uses electricity to split water into hydrogen and oxygen. This process is called electrolysis.

Energy arbitrage
Shifting electrical energy from low-value times or locations to high-value ones.

Flow battery
A rechargeable device in which energy is provided by active components dissolved in liquids, stored in tanks that are pumped through a cell between electrodes on opposite sides of a membrane (see figure 22). As they involve oxidation-reduction reactions (in which electrons are transferred between two species) they are often called 'Redox' flow batteries (RFBs). The capacity of the battery, which is determined by size of the tanks, is decoupled from the power of the battery, which is determined by the active area of the electrodes / cell.

Frequency regulation
The rapid and often automatic adjustment of inputs or withdrawals of electrical energy by a balancing authority to maintain the oscillation frequency of the alternating current in an electric power system within a specified tolerance of the scheduled value.

Gigawatt (GW)
A unit of power equal to a billion Watts.

GW_e
A gigawatt of electrical power.

Grid services
Various services that keep the frequency and voltage of the electricity grid stable.

Higher (or upper) heating value (HHV)
The amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to 25°C. It includes the latent heat of vaporisation that is released when steam condenses. Since not all combustion devices can take advantage of this latent heat, it has become conventional to define efficiencies in terms of lower heating values. However, in some regions, such as the US and the UK, natural gas is sold by its higher heating value.

Interconnectors
Connections between electricity (or gas) transmission grids in different countries or regions.

Isobaric compressed air storage
Uses a fluid to maintain the compressed air at a constant pressure.

Isothermal
Changes (eg in the volume and / or pressure of a gas) that take place at constant temperature.

Kilowatt (kW)
A unit of power equal to a thousand Watts.

kW_e
Kilowatt of electrical power.

Levelised cost of electricity (LCOE)[1]
A measure of the average cost of generating electricity given by dividing the (discounted) lifetime costs by the lifetime output (discounted at the same rate), as spelled out below. LCOE enables comparison of different generating technologies (eg wind, solar, natural gas, nuclear) with different life spans, capacities, capital and operational costs, risks, and rates of return. It does not take account of the different system values resulting from guaranteed or non-guaranteed availability and reliability.

Formally:

LCOE = (Net Present value [NPV] of costs) / (NPV of electricity generation), where:

NPV of costs = ∑n (total capex and opex in year n) / (1 + discount rate)n

NPV of electricity generation = ∑n (net generation in year n) / (1 + discount rate)^{n}

In the case of a storage system, net generation = energy output.

In most of this report a number of simplifying assumptions and approximations are made, including:

Assuming that all capital costs occur in year zero.

Ignoring decommissioning costs.

Assuming constant annual output through the facility's lifetime, beginning in year one (an exception is made for batteries, whose performance deteriorates with age).

Assuming that opex is a fixed annual amount and / or a constant λ times net annual generation.

In this case:

LCOE = (capex / 'Discount Factor'+ annual opex) / (net annual generation) + λ

Where n runs from 1 to the N years (the facility's lifetime), and the 'Discount Factor' = [1 –(1/(1+d)N]/d
(note that as the discount rate d ➞ 0, the discount factor ➞ N)

LCOE represents what firms that invest in generating capacity think will have to be paid for electricity in order to provide the return demanded by holders of shares and bonds (what is actually paid will depend on market conditions). The appropriate discount rate for calculating the LCOE is therefore the investor's Weighted Average Cost of Capital.

Levelised cost of storage (LCOS)
The cost of a unit of electricity discharged from a storage device, accounting for all costs incurred and the energy produced throughout its lifetime (see SI 1.5).

Lithium-ion (Li-ion) battery
Rechargeable battery that uses solid compounds at both the negative and positive electrodes as hosts for reversible lithium-ion storage. During discharge, lithium ions move through an electrolyte from the negative electrode to the positive electrode, while electrons move in the same direction through an external circuit, powering the device to which the battery is connected. During charge, the process is reversed, with lithium ions migrating from the positive to the negative electrode under voltage supplied by an external power source.

Load following
An increase or decrease in the level of dispatchable generation and / or the net withdrawal from dispatchable energy storage to match changes in electricity demand.

Lower heating value (LHV)
The amount of heat released by combusting a specified quantity, initially at 25°C, and returning the temperature of the combustion products to 150°C, assuming that the latent heat of vaporisation of water in the reaction products is not recovered. Manufacturers of turbines, fuel cells and electrolysers normally define their efficiencies in terms of the lower heating value of the fuel consumed or produced.

Megawatt hour (MWh)
Energy generated by one million Watts of power operating continuously for an hour.

MWh_e
A megawatt hour of electrical energy.

MWh$_{th}$
A megawatt hour of thermal energy.

MWh$_{LHV}$
A megawatt hour of thermal energy content measured with the Lower Heating Value.

North Atlantic Oscillation (NAO)
Refers to changes in the atmospheric pressure gradient over the North Atlantic, which influences weather in Europe and North America. It is driven by atmospheric pressure differentials between the Azores, which have high atmospheric pressure, and Iceland, which has low pressure. When there is a greater-than-usual pressure difference between the regions (a positive NAO phase), Europe typically experiences warmer, windier, and rainier conditions than usual. When the difference is weaker (a negative NAO phase), Europe will experience cooler, calmer, and drier-than-usual conditions.

Operation and maintenance (O&M)
The cost of O&M may be either Fixed (FOM) or Variable (VOM), dependent on (generally proportional to) use.

Opex
The cost of Operation and maintenance.

Overprovision / overcapacity
A term used by some authors to describe situations in which the average supply of variable renewable electricity is greater than demand (renewable energy is sometime restricted to just wind and solar). Others use it to describe situations in which it is greater than demand minus baseload supply. In the absence of dispatchable generation, overprovision is required to offset inefficiencies in storage; provision greater than required to compensate for inefficiencies reduces the size (and cost) of the storage system that is needed. With constant baseload, some authors define and quantify overprovision relative to demand; others relative to demand minus baseload.

Photovoltaic
The direct conversion of light into electrical energy, or more generally the generation of a voltage when radiant energy falls on the boundary between dissimilar substances, typically two different semiconductors of a solar panel.

Pumped hydro
Use of two water reservoirs at different levels with water pumped from the lower to the higher at times of low electrical demand and excess electricity generation. At times when demand exceeds electricity generation, water is released from the higher reservoir to flow to the lower reservoir through a penstock and turbines generating electricity.

Pumped thermal
Storage that uses excess electrical energy to charge a well-insulated heat store using a heat pump which is later discharged through a heat engine to generate electricity.

Redox flow battery (RFB)
See Flow battery.

Regulated Asset Base (RAB)
A method used in the UK to finance large-scale infrastructure assets such as water, gas and electricity networks, under which a company receives a licence from an economic regulator to charge a regulated price to consumers in exchange for providing the infrastructure in question. The model enables investors to share some of the project's construction and operating risks with consumers, thereby significantly lowering the cost of capital.

Renewable energy
Energy from natural sources (wind, solar, biomass, hydro, geothermal and the ocean) that are replenished at a higher rate than they are consumed.

Residual demand
Demand for electricity (basic demand in this report) minus demand met directly by variable renewables (usually meaning wind and soar in this report).

Residual energy / power
Demand met directly by variable renewables (usually meaning wind and soar in this report) – demand for electricity (basic demand in this report), when the former is larger than the latter.

Resistive heating
Production of heat by passing an electric current through a resistive element / conductor.

Specific energy (or gravimetric energy density)
A mass-based measure of energy density, often expressed in watt-hours per kilogram.

SMR
Small Modular (nuclear) Reactor, or Steam Methane Reformation of natural gas to make hydrogen.

Technology Readiness Level (TRL)
TRLs are defined by the European Commission as follows:
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 and;

TRL 9 – Actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or in space).

Thermal energy
The internal energy of system (in a state of thermodynamic equilibrium) by virtue of its temperature.

Volumetric energy density
A volume-based measure of energy density, often expressed in watt-hours per litre.

Weighted Average Cost of Capital (WACC)[ai]
Represents a firm's average after-tax cost of capital from all sources (shares, bonds, and other forms of debt). WACC, which is the average rate a company expects to pay to finance its assets, expresses the return that both bondholders and shareholders demand in order to provide the company with capital. A firm's WACC is likely to be higher if its stock is relatively volatile or if its debt is seen as risky because investors will require greater returns. WACC is normally expressed net of inflation.

Wholesale electricity market
The buying and selling of power between generators and resellers. Resellers include electricity utility companies, competitive power providers, and electricity marketers.

Exchange Rates

Cost estimates in the report are first quoted in \$s or €s when that was the currency used in the original source, and then converted at £1.00 = \$1.35 = €1.18

ANNEX B

Contents of supplementary information

Note that the supplementary information is not a Royal Society publication and is provided online as background information only. Visit **royalsociety.org/electricity-storage**

SI 1	**Inroduction** **1.2 Supply and demand in a net zero context** Plots related to Figures 1A and 1B that take account of inefficiencies. **1.3 Storage** Energy stored in gas in the transmission and distribution grid. **1.4 Cost considerations** Levelised cost of storage. **Annex 1** Key questions about storage technologies.
SI 2	**Electricity demand and supply in the net zero era** **2.2 Future electricity demand in Great Britain** Daily profile of electricity demand. **2.3. Weather, wind and sun** Wind variations. Extreme weather events and periods of low supply. Weather correlations. Siting of wind farms. Correlations between weather, wind and solar supply, and demand. Wind droughts and periods of high demand. Climate change. Use of historical weather data. **2.4. Matching demand and direct wind and solar supply** Optimising the wind / solar mix. **2.5 Residual demand, energy and power** Residual energy. Residual power. Periods of high demand. UCL ESTIMO model. **2.6 Generating costs** Wind and solar. Complementary generation – nuclear, gas with CCS, bioenergy with CCS, other renewable sources, blue hydrogen, ammonia, gas peaking plants: comparison of flexibility of different sources. CO2 Leakage in CCS, Methane leakage, and Direct air capture. Interconnectors. **2.7 Demand management** Residential and industrial demand. Imposed and emergency reductions in demand. **Annex 1** Supply / demand correlations in a simple model of with high electrification of heat. **Annex 2** Input provided by the EnergySpaceTime group, UCL Energy Institute.
SI 3	**Modelling the need for storage** **3.1 Introduction** Key Factors (size of the grid, length of weather sequence, solar/wind mix, efficiencies, time scales, interplay of charging rates, storage capacities and the level of wind and solar supply, scheduling). Selected estimates of the need for storage in different regions (including the USA, Europe, Germany and Great Britain). Estimates of the cost of powering Great Britain with high levels of wind and solar and storage. **3.2 Modelling and costing with a single type of store** Constructing figure 12. Finding the minimum average cost of electricity. Surpluses. **3.3 Modelling and costing with several types of store** Scheduling. **Annex 1** MIT Report. **Annex 2** AFRY reports.

SI 4	**Green hydrogen and ammonia as storage media** **4.1 Introduction** Definition of lower and higher heating values. **4.2 Hydrogen and Ammonia Production** Electrolysers – alkaline, polymer electrolyte membrane, solid oxide, anion exchange membrane, high temperature ceramic, reversible, flexibly fuelled, methane with CCS. Offshore Electrolysis. Ammonia Production. **4.3 Transport** **4.4 Storage. Hydrogen. Ammonia.** **4.5 Electricity generation** Hydrogen options – fuel cells (proton exchange membrane, phosphoric acid, solid oxide), combustion (turbines, 4-stroke engines). Ammonia – fuel cells, combustion. Power generation options in 2050. **4.6 Safety** **4.7 Climate impact** **Annex** Concluding remarks.
SI 5	**Non-chemical and thermal energy storage** **5.1 Introduction** Remarks on costs. **5.2 Advanced Compressed Air Energy Storage** Existing systems. Underground storage capacity in GB. Modelling ACAES. Charging and discharging. Cost of compressors and expanders. **5.3 Thermal and pumped thermal energy storage** Sensible and latent heat storage. Carnot batteries. **5.4 Thermochemical storage** **5.5 Liquid Air Energy Storage** **5.6 Gravitational storage** Pumped hydro. Other gravitational storage. **5.8 Conclusions** Comparative characteristics and areas for further research. **Annex 1** Wind Integrated Storage. **Annex 2** Compressed CO_2 storage.
SI 6	**Synthetic fuels for long-term energy storage** Covers the same ground as Chapter 6 in the report but in very much greater depth
SI 7	**Electrochemical and novel chemical energy storage** **7.1 Electrochemical storage** Material availability. Costs. Grid-connected batteries in electric vehicles. Flow batteries. **7.2 Chemical storage** Choice of redox process and metals. Choice of oxidation process. Routes to long term, large-scale novel chemical storage. Other potential options. **Annex to SI 7** Novel chemical storage.

SI 8	**Powering Great Britain with wind plus solar energy and storage** **8.1 Introduction** Cost of ammonia storage. **8.3 Provision of all flexible power by a single type of store** Calculation of costs. Sensitivity to electrolyser and generation efficiencies. Different wind / solar mixes. With nuclear baseload. Nuclear co-generation. **8.4 Multiple types of store** Combining ACAES with hydrogen storage. **8.5 Use of natural gas with CCS** Methane emissions; availability of gas; flexibility; cost; as baseload; to provide all flexibly; to provide flexibly in combination with storage; possible use of blue hydrogen – as baseload, to replenish hydrogen stores. **8.6 Possible use and value of surpluses** **8.7 Contingencies against periods of low supply** Demand management. Adding other sources of supply. **8.8 Different levels of demand** **8.9 Other studies of the need for and cost of storage in Great Britain** **Annex** Multi-year UK renewable energy systems with storage – cost Investigation (T Roulstone and P Cosgrove).
SI 9	**The grid, electricity markets and co-ordination** Covers the same ground as chapter 9 in the report but in very much greater depth.
Annex A	**Glossary**

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The conclusions of this report draw heavily on a study of storage needs in GB by P Cosgrove and T Roulstone (2021 *Working Paper on Energy Storage – Multi-Year Studies Royal Society WG Working Paper on Energy Storage – Preliminary Multi-Year Studies*. doi:10.13140 / RG.2.2.12555.41760), who also laid the foundations for the analysis of weather effects in chapter two. The modelling described in chapter three and used to cost storage in chapter eight was carried out by C Llewellyn Smith and R Nayak-Luke for single types of store, and S Garvey for mixtures of types of store.

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