Department for
Business, Energy
& Industrial Strategy

Benefits of Long Duration Electricity Storage

A report to BEIS

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Contents

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1. Executive Summary

The net zero challenge for flexibility

Meeting the economy-wide net zero ambition will rely heavily on a rapid decarbonisation of our electricity system, underpinned by two key trends:

- significant expansion in renewable generation capacity – for example, by 2030, the UK Government is now targeting 50GW of offshore wind, and by 2050 renewable capacity may be in the order of 155 to 240GW;[1] and
- growth in electricity demand reflecting the underlying expectation of increased electrification in the transport and heating sectors.

However, this transition from a fossil fuel-driven to a weather-driven generation mix means the requirements of the electricity system will alter. Maintaining security and stability of supply will need to address:

- changing patterns of, and variability in, residual demand (demand net of renewable output);
- a reduction in the proportion of synchronous plant connected and available to support system frequency; and
- a shift in the location of generation reflecting resource (wind and solar) distribution.

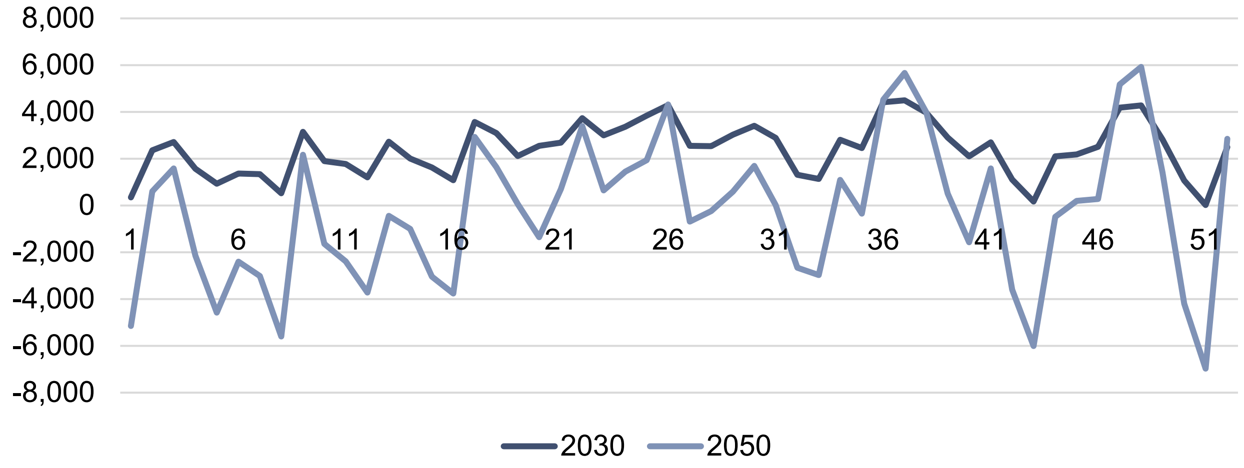
More variability in residual demand[2] will increase the need for flexibility solutions across multiple timeframes

There will be an increasingly volatile pattern of ***residual demand*** from the greater reliance on renewable generation sources as the system transitions towards net zero, as illustrated by Exhibit 1.1. Flexibility is needed to maximise the use of renewables when there is an excess, and to fill the supply gaps in periods of shortfall. In this study we have observed that, in addition to increasing the need for flexibility within-day, the system of the future will have greater seasonal volatility, and extended periods of days or weeks where there are prolonged excesses, or shortfalls, of renewable output. There is a need for both sufficient capacity and energy production.

[1] BEIS Net Zero and the Power Sector Scenarios, Annex O of the Energy and Emissions Projections (EEP) Interim Update in December 2021 https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

[2] Residual demand defined as final consumption, excluding electrolysis, minus renewable generation.

Exhibit 1.1 – Weekly net total residual demand variability, illustrative patterns based on 2014 weather pattern (GWh)

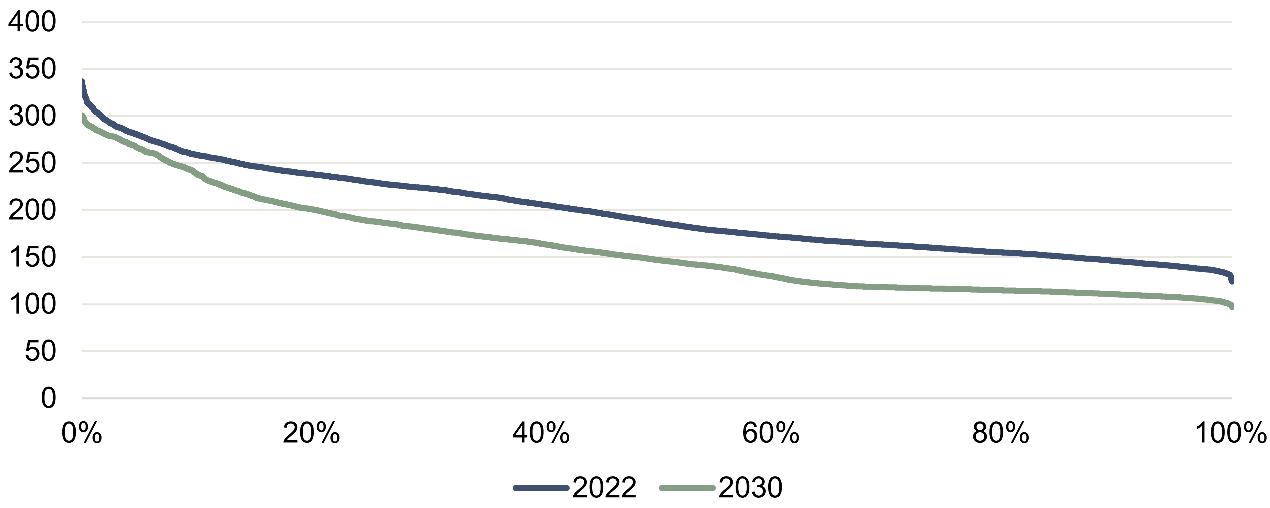


Note: Positive values indicate a deficit and negative values indicate a surplus of generation

More renewables will increase the need for system services

As renewables replace thermal generation the proportion of synchronous generation on the system falls, reducing the levels of inertia readily available for secure operation of the system, as shown in Exhibit 1.2[3].

Exhibit 1.2 – Duration curve of modelled half hourly system inertia (GWs)



Source: AFRY modelling

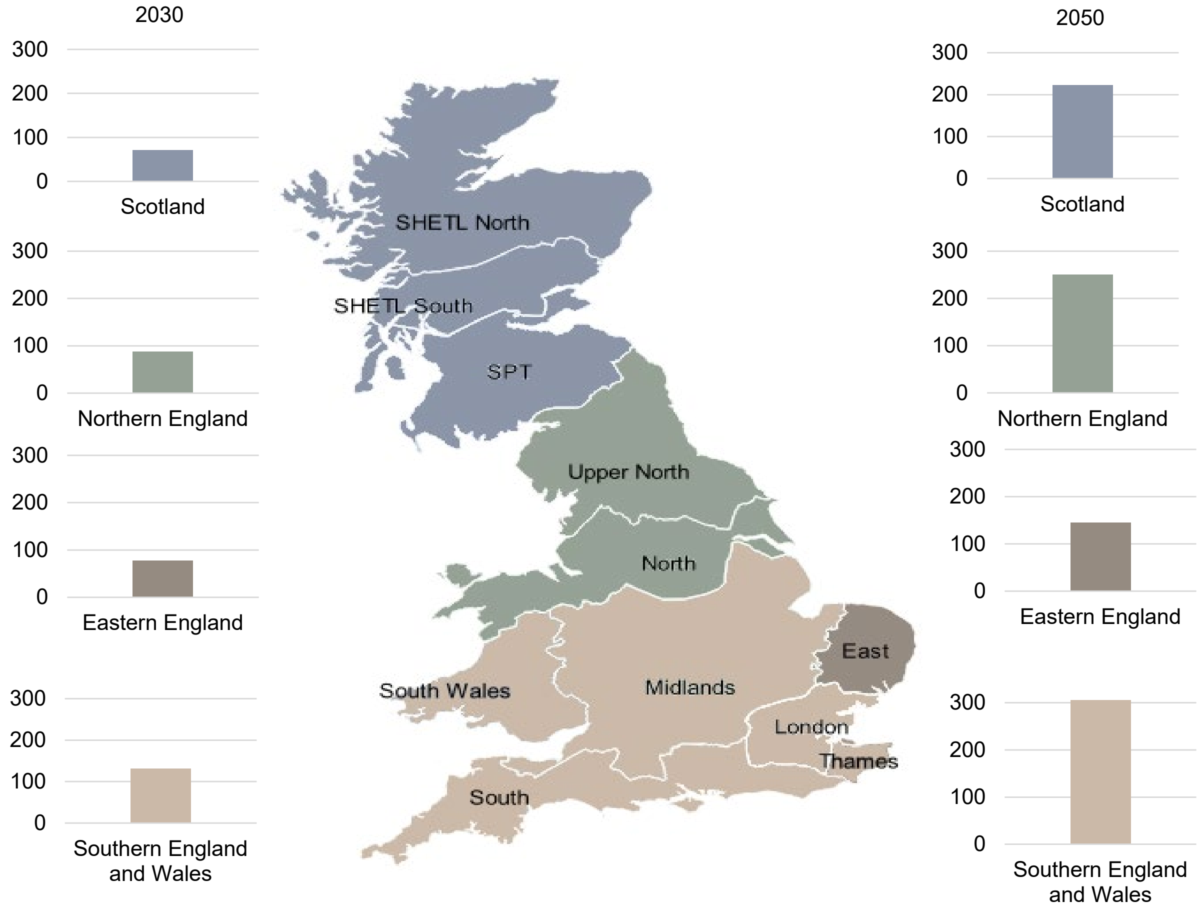
In addition, it is also more likely that transmission lines will be more lightly loaded at times, increasing the need for voltage support services.

[3] Inertia is an inherent property of synchronous machines, such as conventional power stations. It helps keep the system frequency close to 50Hz and therefore is one aspect of preventing blackouts. Without such provision, the system is less likely to operate in a stable range close to this value.

New generation locating at high renewable resource locations may exacerbate network congestion issues

Wind and solar resources are not evenly distributed across the country and it is likely that much of this generation will be sited further from demand centres, to access the best locations. An illustrative scenario of how the balance of generation may change over time is shown in Exhibit 1.3. Additional flexibility can avoid expensive network reinforcement or renewable curtailment.

Exhibit 1.3 – Illustrative locational total generation volumes (TWh)



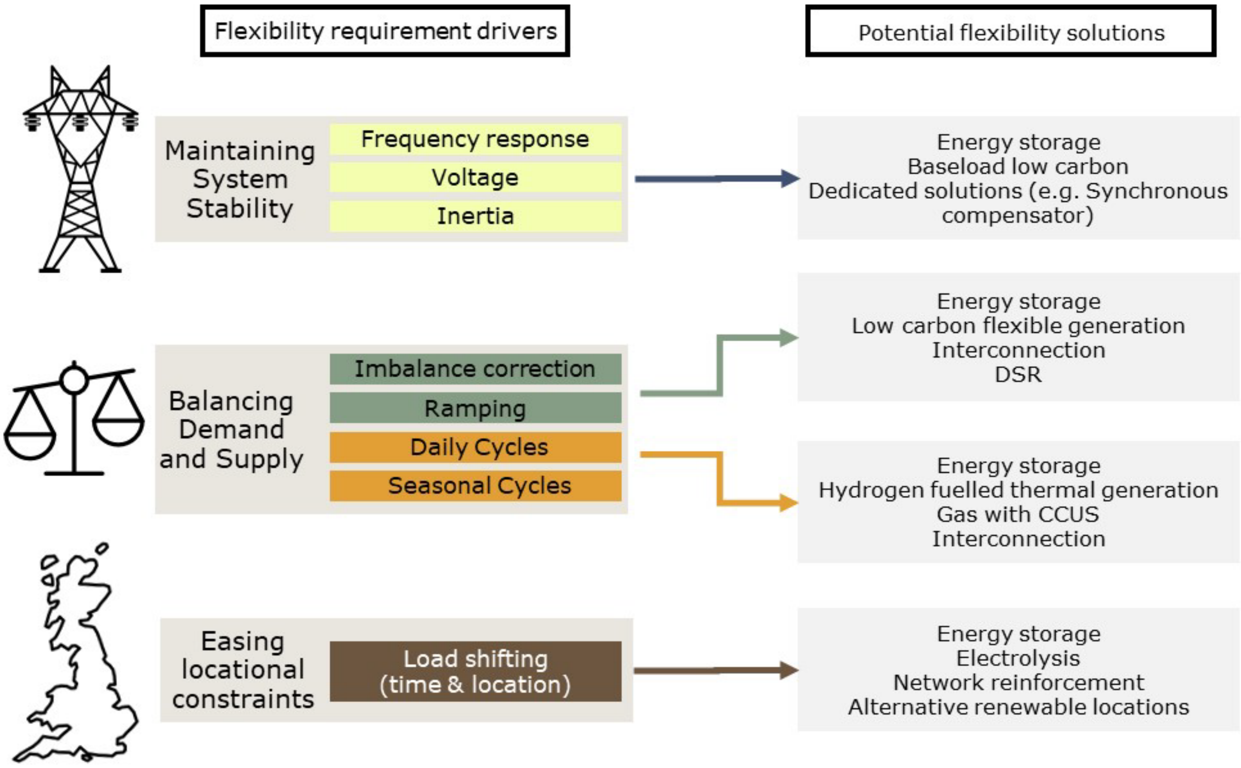
Source: AFRY modelling

Options for addressing these challenges

At present there are a range of technologies that can, in principle, provide solutions to (some of) the issues identified above. These include flexible generation, demand side response (DSR), interconnection and energy storage, as summarised in Exhibit 1.4.

Energy storage captures a variety of technologies that differ in terms of the speed, scale and duration of the services they can provide. The duration of storage they offer is particularly important for their ability to meet some of the flexibility requirements (notably balancing demand and supply and locational constraints).

Exhibit 1.4 – Technology options for addressing the system flexibility requirements



Notes: 'Baseload low carbon' is assumed to include nuclear, biomass and biomass with CCS capacity. Low carbon flexible capacity is assumed to include hydrogen fuelled and gas with CCS capacity.

To understand the relative benefits of different types of energy storage we have, within this report, distinguished three broad categories of storage:

- Short Duration Storage (SDS) with durations of 4 hours or lower, suited to addressing short duration balancing needs;
- Medium Duration Storage (MDS) with durations of over 4 hours, up to 12 hours, suited to addressing within day balancing; and
- Long Duration Storage (LDS) with durations of over 12 hours, required for multi-day and seasonal balancing needs.

Within each category of storage there are many technology options available, as illustrated in Exhibit 1.5, and the choice of technologies will depend on a range of factors including cost, availability, build time and risk.

Therefore, the focus of the study is primarily on the portfolio of different storage durations that can best meet the future system requirements, described above. It should therefore be viewed in a technology neutral context, particularly when considering the technological and cost uncertainties associated with some storage solutions.

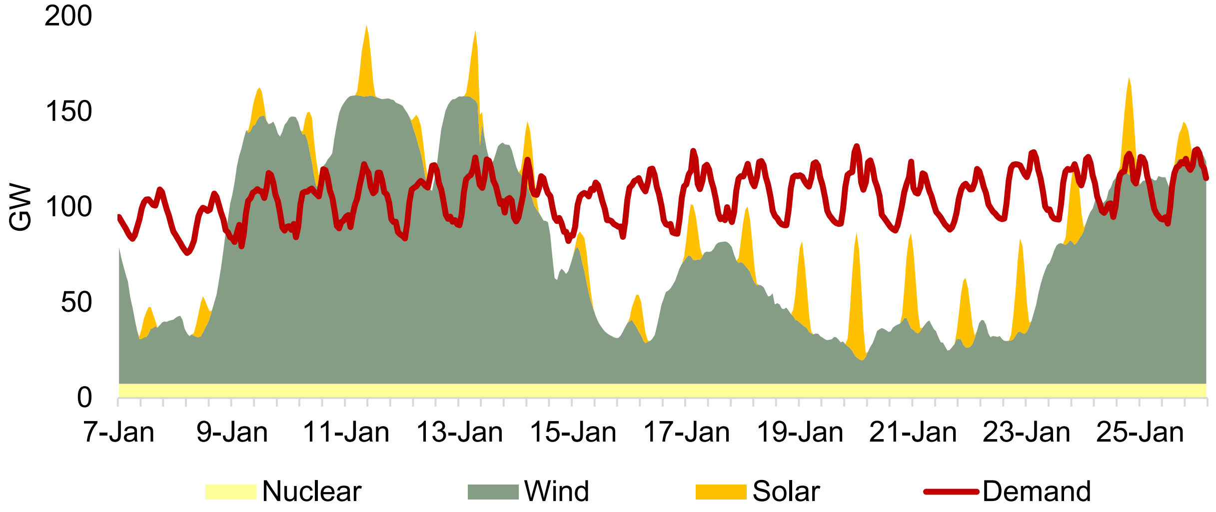
Exhibit 1.5 – Sample technologies to help balance the system at different durations

Short duration storage technologies	Medium duration storage technologies	Long duration storage technologies
Li-ion batteries	Li-ion batteries	Hydrogen salt cavern storage
Gravity storage	Pumped hydro	Pumped hydro
Vehicle-to-grid	Liquid air	Compressed air
Super capacitors	Compressed air	Thermal energy storage
Fly wheels	Flow batteries (e.g., Iron, Vanadium)	
Hydrogen tank storage	Hydrogen fuel cells	
Other forms of chemical storage		

Net zero systems increase the benefits from energy storage, but challenges still exist for large-scale, longer-duration solutions

Storage is well suited to managing the trends in residual demand that will become more prevalent over time. Exhibit 1.6 shows simulated demand and low-carbon generation output on an hourly basis for a sample 3-week period in 2050. Intermittent renewables, in this example, result both in periods where generation is significantly greater than demand (up to 50GW in a given period) and periods when generation is significantly lower than demand (100GW).

Exhibit 1.6 – Generation and consumption gap (illustrative, across a period with January 2017 weather, with 2050 demand and renewable capacity mix)



These patterns should be more effectively addressed through long-duration storage solutions than multiple short duration technologies. However, as highlighted through the government's recent Call for Evidence[4] on facilitating the deployment of large scale, long duration electricity storage, there are concerns that long duration storage solutions, despite delivering anticipated reductions in system costs, face barriers to their deployment:

- Longer Duration Storage technologies are capital intensive.
- In many cases, they have long lead times from the investment decision to plant commissioning.
- There are few, if any, long-term contracted revenue streams on which to base an investment decision.

Understanding the value of longer duration storage

The primary aim of this study is to improve our understanding of the potential benefits to the system from medium and long duration storage solutions and investigate the relative attractiveness of the various technology options available (now or in the future).

We did this through a comparative assessment, looking at the difference in system costs between a situation when SDS technologies were the only solutions available to provide flexibility and one where MDS and LDS technologies were also available.

This comparison was conducted for three scenarios defined by BEIS, to cover a range of outlooks that could drive different requirements for LDS:

- The core scenario #1 was based on BEIS Net Zero High Demand modelling assumptions for demand and technology costs at the time the study was commissioned.[5]
- Scenario #2 was based on the BEIS Net Zero Low Demand scenario, and featured lower electrification but higher hydrogen demand.
- Scenario #3 was the same as scenario #1 in most aspects, but policy support and lower capex for long duration storage technologies was included.

All scenarios modelled in this project reach net zero in 2050 following the UK carbon budgets. These scenarios are a subset of a wider range of future possible scenarios, but they provide a starting point for thinking about the potential role of MDS and LDS in the energy system.

In addition, we modelled several sensitivities against the core scenario #1, to consider the implications of two key areas of uncertainty around MDS and LDS technologies:

- Technology risk – many of the technologies modelled are uncertain and require some level of technological breakthrough.
- Competing solutions – different availability of other sources of flexibility, such as DSR or interconnection, may affect the need for, and benefit from, MDS and LDS.

[4] BEIS call for evidence: Facilitating the deployment of large-scale and long duration electricity storage

[5] The same cost and demand assumptions as used in the Net Zero High scenarios from Annex O of the Energy and Emissions Projections (EEP) Interim Update in December 2021 https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

Key Results[6]

Longer duration storage solutions reduce net zero system costs by between £13bn and £24bn[7] **in the scenarios modelled in this report**

The savings arise because MDS and LDS can more effectively address the increasingly seasonal balancing requirements that emerge in a weather-driven system. In the modelling, the largest savings arise when flexibility is delivered through a combination of hydrogen storage and hydrogen CCGTs. This is because system balancing continues to rely on large amounts of flexible low-carbon thermal capacity, either hydrogen or gas with CCS, to balance the system cost effectively during long periods of low wind and high demand

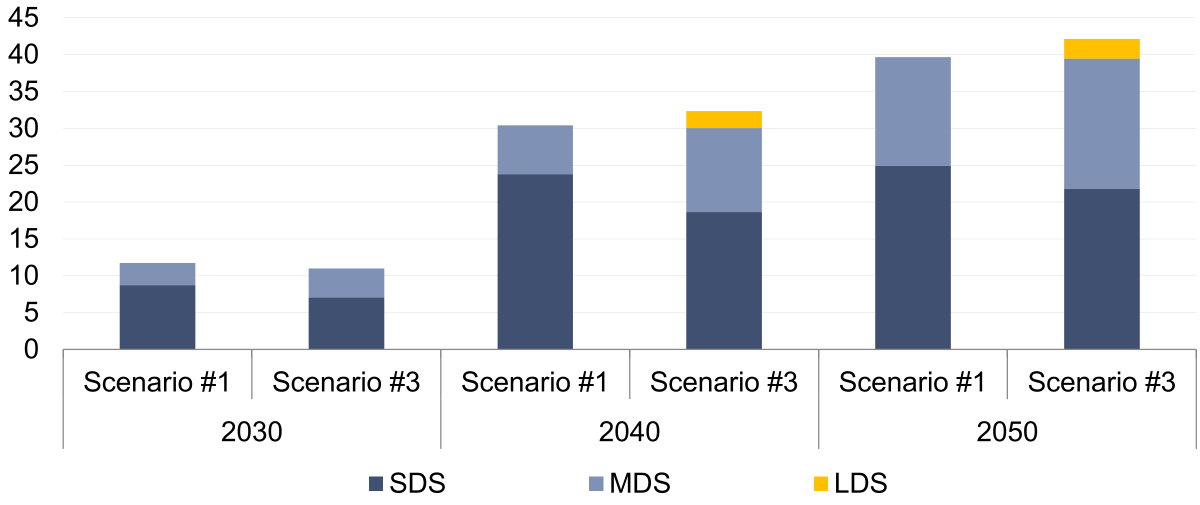
Longer duration storage solutions can deliver the required greater volumes of storage more cheaply than short duration storage alternatives

The reduction in system costs is as a result of a shift from SDS capacity to MDS and LDS. When we exclude MDS and LDS, the system required over 40GW of SDS capacity. Introducing MDS and LDS led to a fall in the capacity of SDS of between 15 and 22GW, to be replaced by between 12 and 21GW of MDS/LDS technologies. This capacity difference came with a significant increase in storage volumes.

Regardless of scenario, we find that between 2.5 and 3GW is a low regrets level of additional power long duration storage by 2050

Power LDS refers to technologies such as pumped storage, Compressed air energy storage (CAES) and Liquid air energy storage (LAES), that do not rely on hydrogen as a storage medium.

Exhibit 1.7 – Power storage capacity, scenario #1 vs scenario #3, all durations (GW)



[6] This study was performed prior to the UK's commitment to decarbonise electricity system by 2035 (subject to security of supply) and the publication of the British Energy Security Strategy. These announcements will bring forward a greater need for flexibility on the network.
[7] Section 2.4 gives a fuller description of the way these NPV values are calculated. These values are in real 2019 money and discounted from the perspective of 2030 (as the first modelled year).

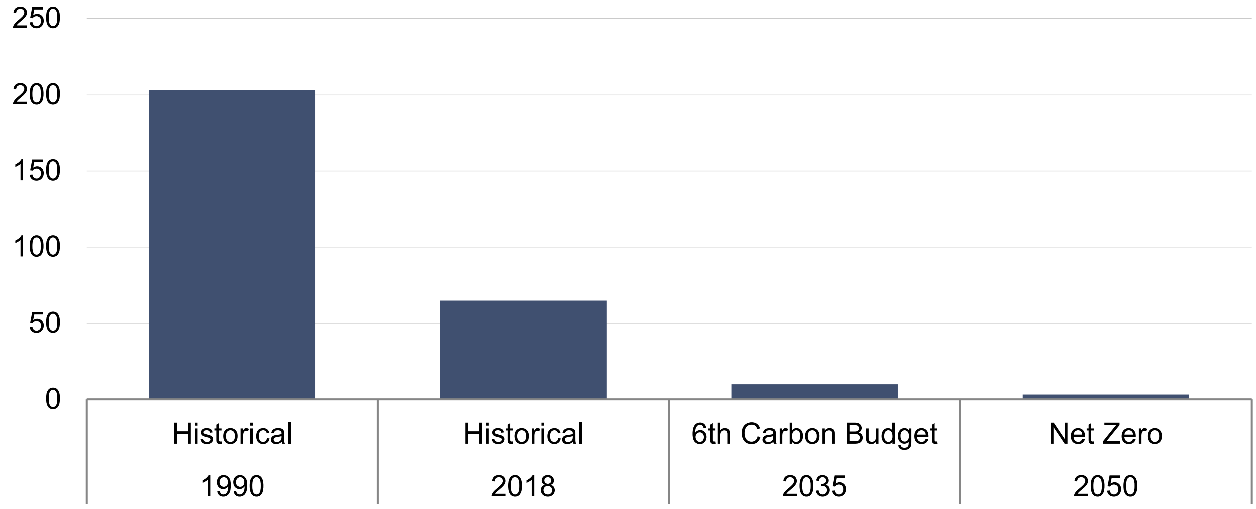
The low regrets level of power LDS emerges because it can mitigate some of the deployment uncertainty for emerging, innovative, novel solutions (like hydrogen) in the 2030-2040 period. Exhibit 1.7 illustrates that where this risk mitigation effect of power LDS was seen in the modelled scenarios, the capacity was typically brought on prior to 2040, rather than towards 2050.

2. Introduction to net zero energy systems and longer duration storage

2.1 Background and context

The UK's legal commitment to deliver net zero emissions by 2050 will require transformational changes across our energy system. By 2035, to meet the Committee on Climate Change's Sixth Carbon Budget, the GB generation mix will need to be almost zero-emission (10gCO2/kWh), as shown in Exhibit 2.1.[8]

Exhibit 2.1 – Gross power sector emissions, historical values and future caps for the 6th Carbon Budget and Net Zero Target (gCO2/kWh)



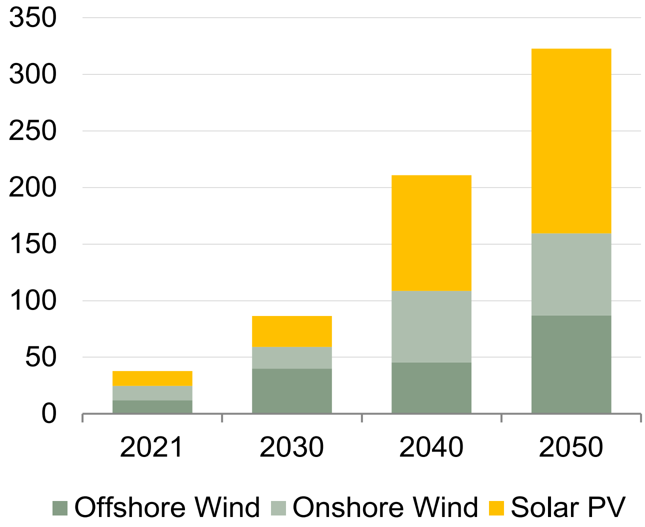
Source: BEIS, CCC 6th Carbon Budget

While there are many different possible pathways to net zero, there is general agreement that the generation and demand mix in the power system will be fundamentally different to today:

- the backbone of a low-carbon generation mix will be renewables, predominantly intermittent wind and solar resource, which, as shown in Exhibit 2.2, could be up to ten times higher in 2050 than today.
- Electrification of heating, transport and some industrial processes may result in final electricity consumption being more than double current levels by 2050, as is shown in Exhibit 2.3.

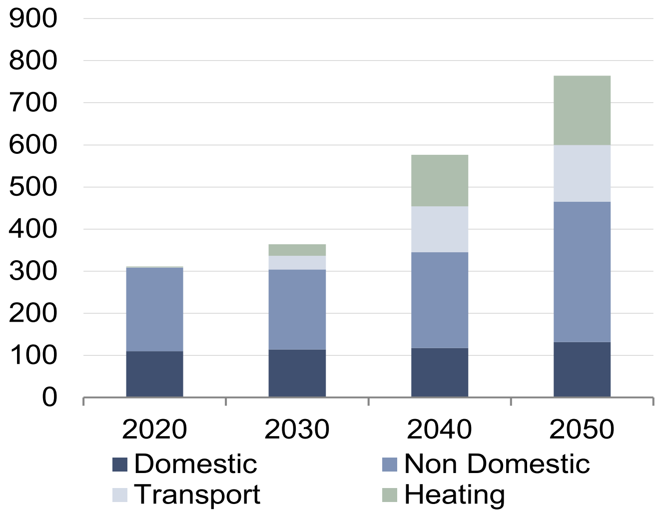
[8] This study was performed prior to the UK's commitment to decarbonise electricity system by 2035 (subject to security of supply).

Exhibit 2.2 - Illustrative renewable generation capacity scenario to meet net zero (GW)



Source: AFRY analysis

Exhibit 2.3 – Impact of electrification on final power consumption, by end-use sector (TWh)



Source: BEIS reference case (2021)

2.2 Study objective and questions

Central to delivering a cost-effective, net zero system is flexibility (the ability to shift in time or location the consumption or generation of energy). Several studies[9] have suggested that increased flexibility can materially lower the system costs of decarbonisation. However, some of the same studies ignore larger-scale and longer-duration storage solutions, focusing on the benefits of more flexible demand and short-duration (<4 hour) battery storage.

In this report we provide an independent assessment of the potential benefits of longer duration storage to a net zero energy system in Great Britain. AFRY have modelled the potential need and associated system benefits of deploying a range of long duration electricity storage in the energy system to meet net zero, at least cost, through a combination of scenarios and sensitivities.

The assessment focuses mainly on the power and hydrogen sector specific impacts, estimating the full range of benefits that electricity long duration storage technologies can provide, the impacts of deploying these technologies at different points in time and how long duration storage interacts with other technologies.

A series of research questions were identified by BEIS at the outset.

[9] Examples of reports that have highlighted the value of long duration storage include:
BEIS: Call for Evidence (2021)
Imperial: Whole System Value of Long Duration Energy Storage in a net-zero emission Energy System for Great Britain (2021)
Carbon Trust: Flexibility in Great Britain (2021)
McKinsey: Net-zero power: long duration energy storage for a renewable grid (2021)

Main Research question: What is the impact of long duration storage on system costs as we transition to a decarbonised power sector?

Sub questions:

How much long duration storage, in terms of both capacity and generation, is required to minimise system cost at a given level of emission intensity or total emissions?

Is there a 'low regrets' amount of long duration storage that should be deployed in the power sector?

What are the main drivers of the requirement for long duration storage?

What are the relative benefits of different long duration storage technologies?

What is the impact of long duration storage on other technology types?

How much electricity demand is likely to be met by long duration storage under a range of credible scenarios?

How does the system impact of long duration storage change over time?

What are the possible operating regimes for long duration technologies?

2.3 Structure of report

This report addresses the research questions and is structured as follows:

- Chapter 3 outlines the changing flexibility requirements in a net zero system and introduces the potential sources of flexibility at a high-level. It also looks in detail at the energy storage options available, the range of services they can provide and their relative cost competitiveness.
- Chapter 4 introduces the modelling of scenarios and sensitivities which were used to address the research questions.
- Chapter 5 shows the key results from the modelling and draws the scenario and sensitivity results together.
- Chapter 6 presents conclusions and research question answers.

Further detail on the modelling approach, assumed technology investment costs, details of modelling of ancillary services and transmission constraints, plus further sensitivity analysis is presented in annexes A to F.

2.4 Conventions and sources

All monetary values quoted in this report are in GB Pounds Sterling in real 2019 prices, unless otherwise stated. All figures have been appropriately rounded and therefore some of the different numbers may not correlate directly due to the effect of this rounding.

Annual data relates to calendar years running from 1 January to 31 December, unless otherwise identified.

The Net Present Values (NPV) provided in this report are calculated over a 33-year appraisal period from 2028 to 2060 inclusive, assuming a 3.5% discount rate. Modelled years were 2030, 2035, 2040, 2045 and 2050, with each year deemed to represent 5 years (two years before, the year itself, two after). 2050 was deemed to represent more years, extended to 2060. Each future year is given a discounted value, starting with 2030 indexed to a value of 1. This includes all years, both modelled years and years in between. Final system costs included direct capex values from the modelled years. Variable and annual fixed costs from each modelled year are counted for each of the years the modelled year represents. The NPV values are therefore 2030 values for a 33-year period. Further discounting of the values would be needed in order to bring them to a 2022 indexed value.

Unless otherwise attributed the source for all tables, figures and charts is AFRY Management Consulting.

3. Net zero flexibility requirements

In this chapter we assess how changes in the generation mix influence the flexibility needed to maintain system stability, at least cost, and then outline the capabilities of the various sources of flexibility.

3.1 Flexibility needs will change as we transition to net zero

The electricity network facilitates the delivery of electricity generated by producers to be taken by consumers. It is a complex system that needs to balance generation and demand at all times, operating within specific parameters to ensure system security and reliability. In their Smart System and Flexibility Plan, BEIS presented the following definitions:

Flexibility is the ability to shift in time or location the consumption or generation of energy.

Smart means the ability of a device to respond in real time to communication signals, using digital technologies, to deliver a service.

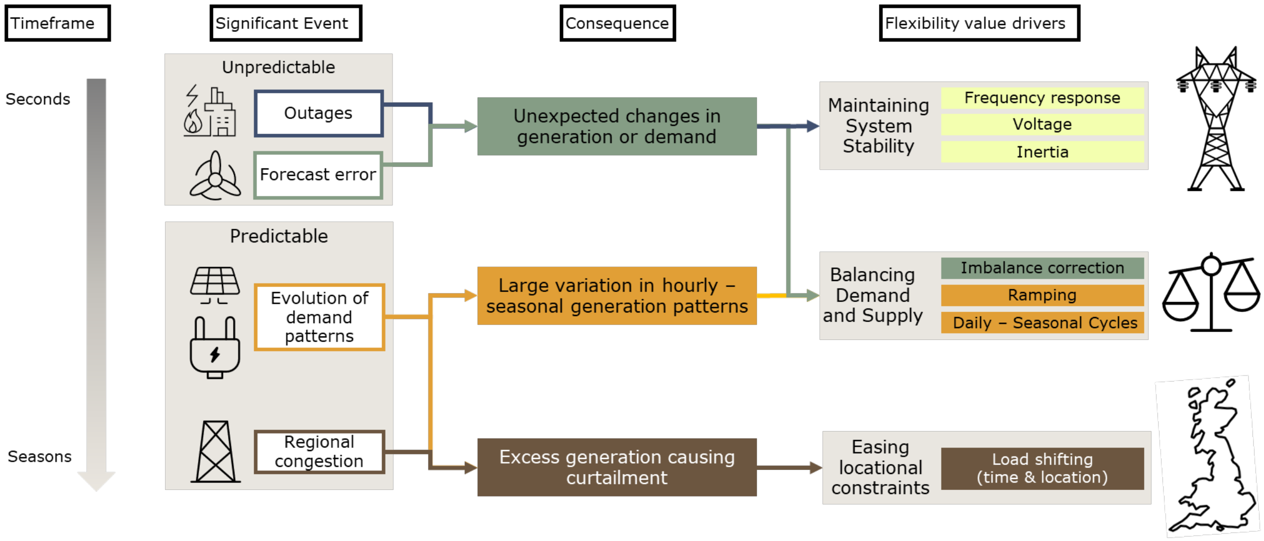
A **smart and flexible system** is one which uses smart technologies to provide flexibility to the system, to balance supply and demand and manage constraints on the network.

Flexibility requirements arise for several reasons, as summarised in Exhibit 3.1. A heavy dependency on renewable generation sources in a net zero system will alter the levels and type of flexibility required to maintain system stability. Relative to today, we can expect future flexibility requirements to respond to changes across three key drivers:

- The **variability and patterns of residual demand** on the system (residual demand defined as final consumption, excluding electrolysis, minus renewable generation. Positive values indicate a deficit and negative values indicate a surplus of generation).
- The **higher proportion of non-synchronous generation** and its impact on maintaining system frequency.
- The **changing location of generation** in response to resource (wind and solar) distribution and impacts on (transmission) network constraints.

Below we outline how each of these drivers may evolve in Exhibit 3.1.

Exhibit 3.1 – Drivers of flexibility requirements

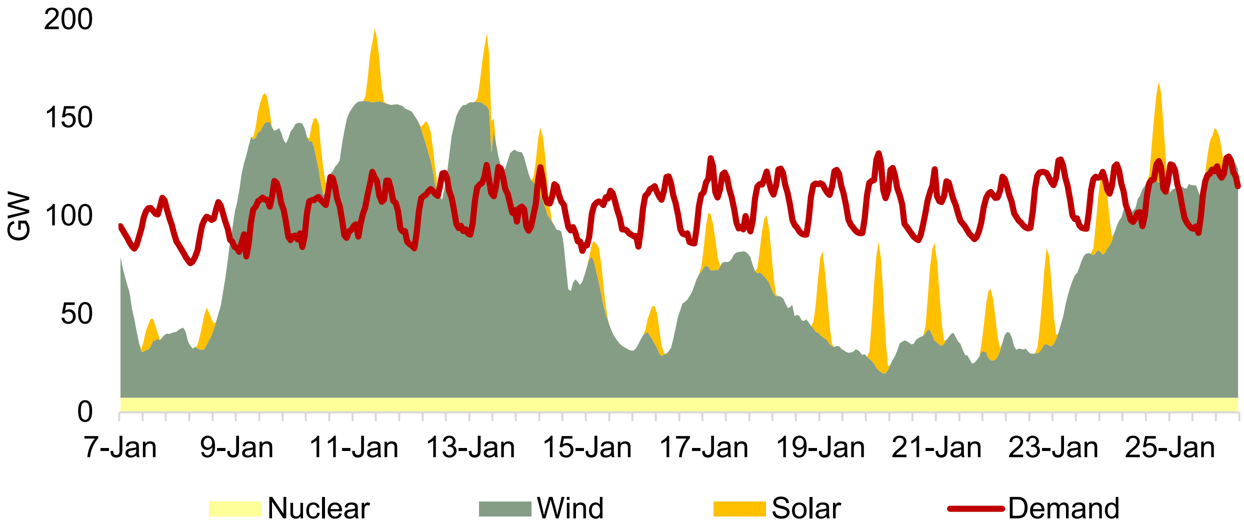


3.1.1 Balancing supply and demand will become more challenging across multiple timescales

The challenge of balancing a low-carbon, weather driven, system is illustrated in Exhibit 3.2 for a sample 3-week period. This shows simulated demand and low-carbon generation output on an hourly basis. Intermittent renewables, in this example, result in both excess power (e.g., up to 50GW in excess of demand) and shortfalls in generation volumes. Over a 5-day period, there are times when there is up to a 100GW deficit, and a cumulative shortfall of over 8TWh.

Flexibility is needed to maximise the utilisation of renewables when there is an excess, and to fill the supply gaps in periods of shortfall.

Exhibit 3.2 – Generation and consumption gap (illustrative, across a period with January 2017 weather, with 2050 demand and renewable capacity mix)



As we move towards a net zero system, the balancing issues become more challenging with both more extreme residual demand positions to manage (Exhibit 3.3) and greater volatility across time (Exhibit 3.4). Exhibit 3.3 shows how, by 2050, in addition to weeks with higher residual demand, the system of the future is also likely to feature weeks with high excess renewable output.

Exhibit 3.3 – Weekly net total residual demand duration curve, for a typical weather pattern, modelled for 2030 and 2050 (GWh)

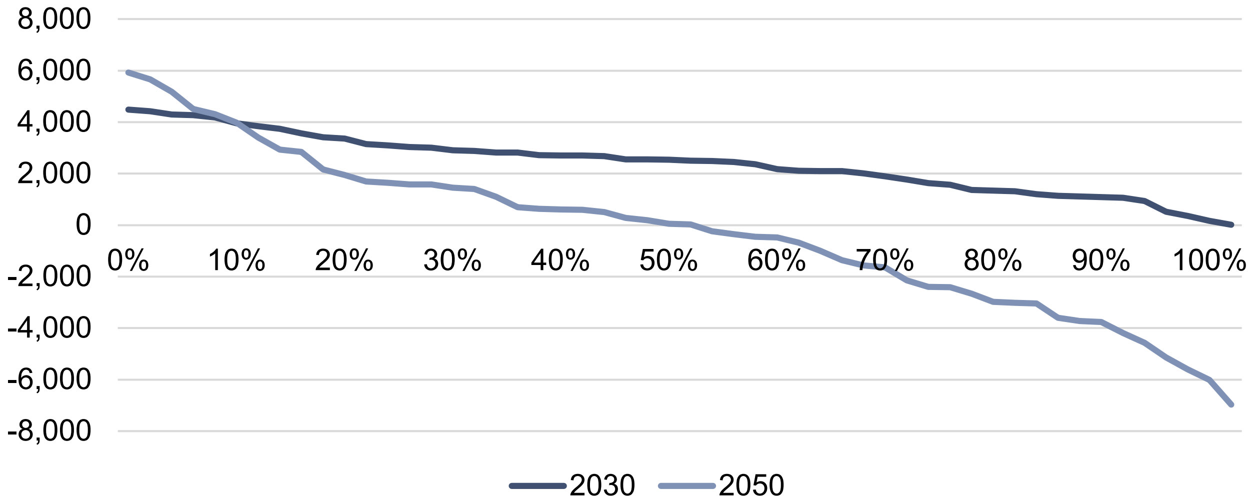
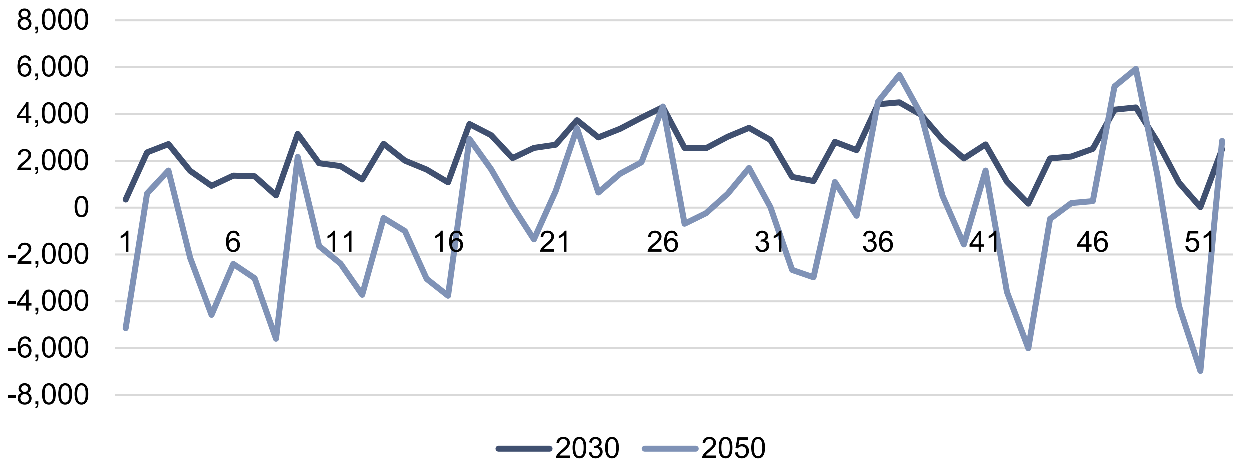


Exhibit 3.4 – Weekly net total residual demand variability, illustrative patterns based on 2014 weather pattern (GWh)

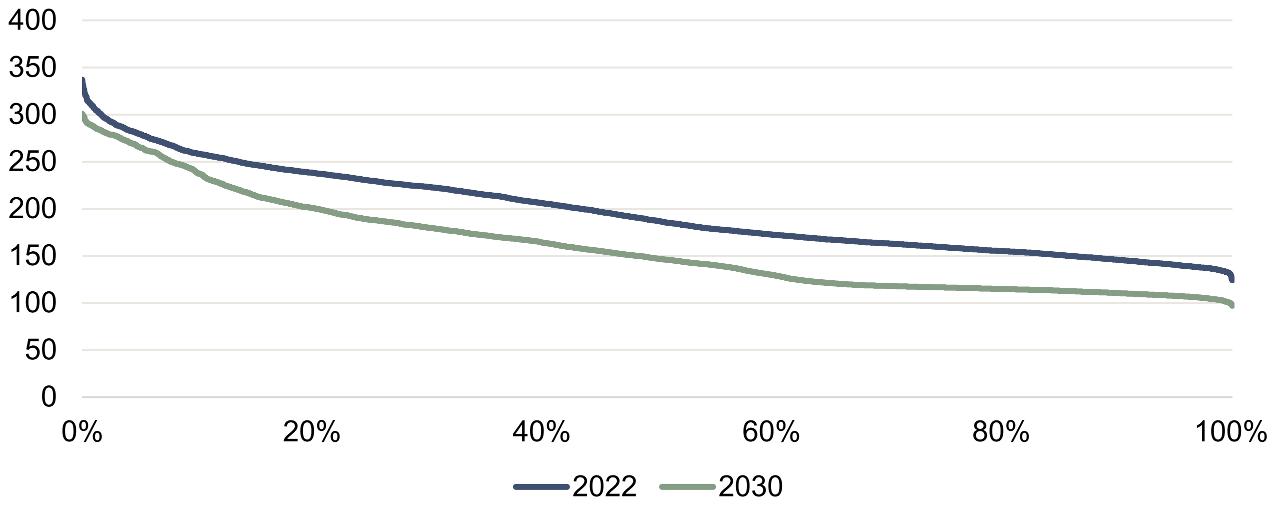


Notes: Residual demand defined as final consumption, excluding electrolysis, minus renewable generation. Positive values indicate a deficit and negative values indicate a surplus of generation

3.1.2 Intermittent renewables will reduce system stability

From the perspective of system stability, large growth in non-synchronous renewable generation will reduce the levels of inertia of the system and make secure operation of the system at 50Hz more complex. This fall in inertia levels is an existing trend that will continue out to 2030 and beyond, as illustrated in Exhibit 3.5.

Exhibit 3.5 – Duration curve of modelled half hourly system inertia (GWs)



Source: AFRY modelling

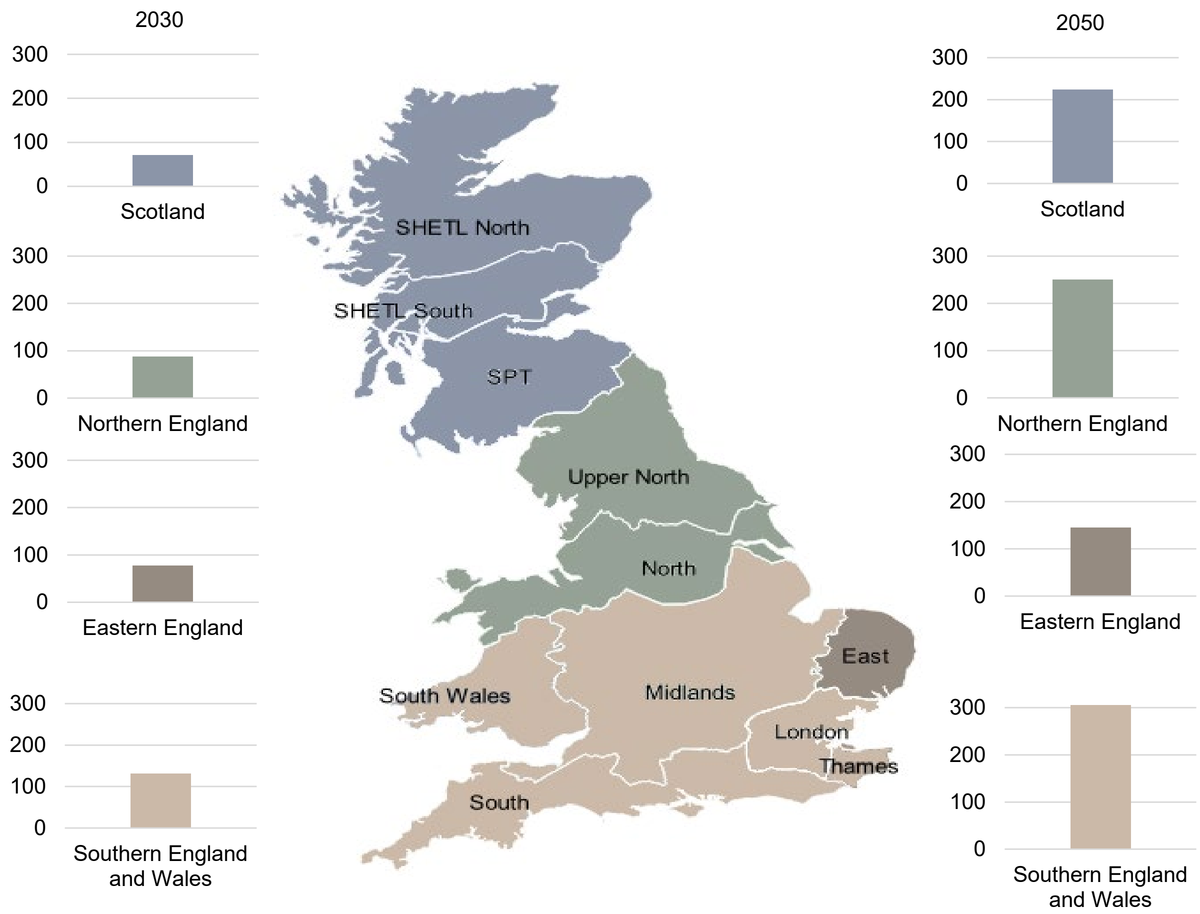
It is likely that maintaining a stable voltage level will be more challenging. Voltage stability is needed to ensure that power is transferred across the network. With more renewables, power transmission lines are likely to be lightly loaded more frequently, leading to reduced voltage stability. This will drive the need for voltage support (typically reactive power absorption). Provision of the right levels of voltage support, maintaining sufficient inertia and responding to deviations in system frequency will be more challenging in a more weather driven system.

Forecasting output from generation will also be harder, due to the inherent uncertainty in weather forecasts. Larger forecast errors from weather-driven renewables are likely to lead to a greater need to manage imbalances at short notice.

3.1.3 Utilising geographically diverse wind and solar resource potentials will increase power network congestion

There will also be a greater need for flexibility to manage the locational changes expected to occur. Wind and solar resources are not evenly distributed across the country. To maximise the potential of these technologies (locations with the best wind speeds and to a lesser extent, highest solar irradiation), growing quantities of generation will be located further from demand centres. Exhibit 3.6 illustrates this trend.

Exhibit 3.6 – Illustrative locational total generation volumes (TWh)

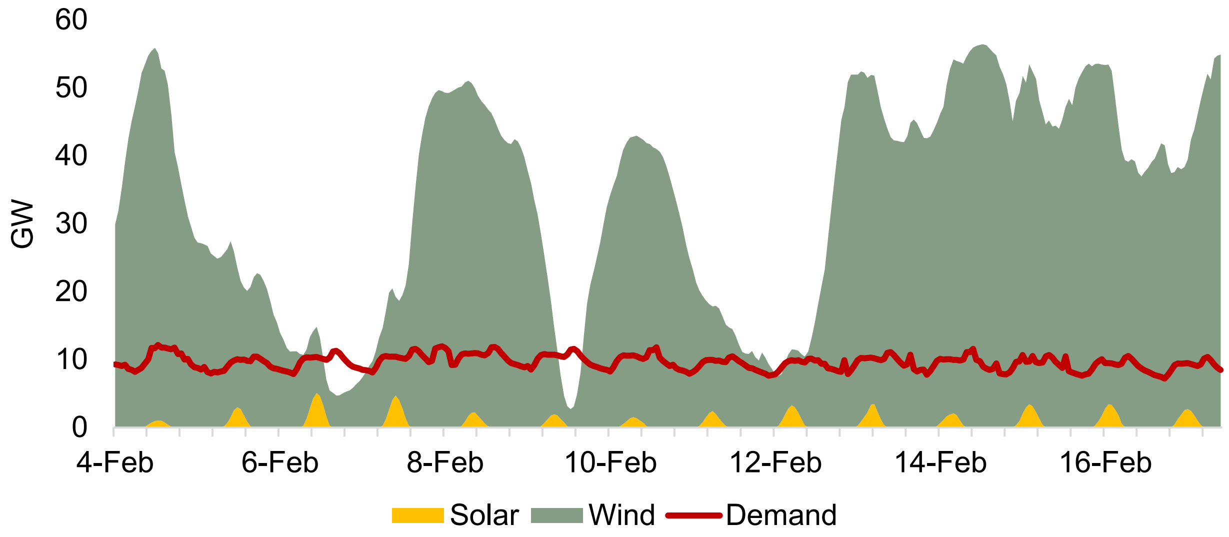


Source: AFRY modelling

The location of generation is uncertain and will depend on technical and policy developments which are unknown. Our modelling can however provide a cost optimal view of where this generation might be sited given relative technology costs and assumed renewable resource potentials. In this illustration, total generation increases in all regions, due to rising power demand, but the larger relative increases are in Scotland, Northern England and Eastern England. The share of generation in Scotland not only increases in absolute terms by more than a factor of 3, but it also grows from 19% to 25% of the total generation. Scotland, Northern and Eastern England are all regions likely to see transmission network congestion.

The potential impact of these locational trends on the network are illustrated by Exhibit 3.7, which shows the Scottish wind and solar generation against the demand, for a selected 2-week period in 2050. The power transmission network has experienced significant congestion in recent years, due to the high levels of wind capacity in Scotland in particular. Although other parts of the transmission network have historically been constrained, the Scotland-England border is the biggest single driver of this. This part of the network (or boundary B6 in National Grid terminology) often requires wind curtailment to ensure power flows are kept within safe operational limits.

Exhibit 3.7 – Illustrative hourly snapshot of Scottish generation, 2050, weather year 2017 (GW)



Limited capability to transmit this power to the major demand centres in England could result in wind curtailment and the running of replacement generation on parts of the network that are not congested. This could result in wasted renewable output and potentially also increased emissions from the generation outside the constrained region.

If capacity is located to maximise the potential of the highest wind resource locations, the existing power network will become overloaded. To avoid curtailing renewable output, due to locational network congestion, it may be necessary to significantly increase transmission capability. An alternative to this would be to have flexibility offered by storage technologies, to soak up excess generation.

3.2 There are a range of flexibility solutions available to meet differing system needs

As we move towards net zero, the system will need both faster responding, and longer lasting, flexibility solutions. The diverse nature of flexibility requirements is mirrored by a similarly diverse set of technologies which we group into four broad categories of flexibility sources – flexible generation, energy storage, demand-side response and network solutions.

As illustrated in Exhibit 3.8, categories of flexibility resource offer different types of flexibility, at different time frames, and in different combinations and are therefore more, or less, suited to meeting the flexibility requirements of a net zero system. For example, many types of storage have limited capability to offer longer duration response services, whereas flexible generation cannot provide load shifting services (unless considered as part of an integrated hydrogen storage solution, as discussed below).

Exhibit 3.8 – Flexibility capabilities of different technologies

		Maintaining stability			*Energy balancing*		*Response duration*		*Response types*		
	Technology	1 *Frequency response*	2 *Inertia*	3 *Voltage control*	4 *Imbalance correction*	5 *Ramping*	6 *Daily cycles*	7 *Seasonal cycles*	8 *Load shifting*	9 *Positive reserve*	10 *Negative reserve*
Generation	OCGT / Gas Engines	✗	✗	~	✓	✓	✓	✓	✗	✓	✗
Generation	CCGT[1,2]	~	~	~	~	~	✓	✓	✗	~	~
Generation	Biomass & Waste	✗	✓	✓	✗	✗	~	~	✗	~	~
Generation	Intermittent	✗	✗	✓	✗	✗	✗	✗	✗	✗	✓
Storage	0.5-2hr Battery[3]	✓	~	~	✓	✓	~	✗	✓	✓	✓
Storage	LAES	✗	✓	✓	✓	✓	✓	✗	✓	✓	✓
Storage	CAES	✗	✓	✓	✓	✓	✓	~	✓	✓	✓
Storage	Pumped Hydro	~	✓	✓	✓	✓	✓	~	✓	✓	✓
Storage	Hydrogen via electrolysis	~	✗	~	✓	✓	✓	✓	✓	~	✓
	Demand Side Response	~	✗	✗	~	✓	~	✗	~	✓	✓
Networks	Interconnection	~	✗	~	~	~	✓	✓	✓	~	~
Networks	Transmission Network	✗	✗	✗	✗	✗	✗	✗	✓	✗	✗

✓ Typically provides service ~ Provide service in some circumstances ✗ Unlikely or unable to provide service

Notes: (1) Whilst CCGTs do provide frequency response, inertia and voltage support, they are typically only capable of doing so when operating. In a high renewable, low carbon system this is a significant disadvantage. Therefore, these are scored lower to reflect this limitation. (2) Gas with CCS would share similar characteristics to CCGTs but are expected to have a slightly lower level of flexibility for fast ramping, due to the inflexibility of the CCS technology. (3) Batteries can be enhanced to provide inertia through the addition of either grid forming capability on the inverter.

Existing flexibility provision is dominated by gas fired generation. Combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs) form the backbone of the system. In recent years, growing numbers of fast responding reciprocating engines (gas and diesel) have come onto the system. This is supplemented by 2.8GW of pumped storage plants (PSP) and around 1.4GW of short duration li-ion battery storage at present. Alongside this, levels of interconnection and DSR have also increased.

However, in the future, unabated thermal generation will need to reduce to meet net zero. New sources will need to be deployed from either low carbon thermal (such as hydrogen, gas with CCS, biomass or biomass with CCS generation) or storage technologies.

3.2.1 Storage technologies

Storage technologies have potential to offer multiple types of flexibility. These include the ability to:

- Balance supply and demand across very short to longer timescales.
- Integrate renewables in periods of high output.
- Store power for periods of high demand.
- Provide system stability services (such as inertia and frequency response).

- Manage transmission network congestion.

As such, storage can contribute to all three of the main flexibility requirements identified in Exhibit 3.1: it offers system stability services, can help balance supply and demand at different scales, and by virtue of being a storage technology can also help manage locational constraints. There are a range of different technologies that can store electricity, with different possible durations and flexibility characteristics.

As they are the focus of this report, storage technologies are split into three categories defined according to duration (i.e., the length of time taken for the storage to empty when starting from 100% full, and outputting at maximum rate until the storage is empty):

- Short Duration Storage (SD”): Durations of 4 hours or lower, suited to addressing short duration balancing needs with very fast flexibility.
- Medium Duration Storage (MD”): Durations of over 4 hours, up to 12 hours, suited to addressing within day balancing.
- Long Duration Storage (LDS): Durations of over 12 hours, required for multi-day and seasonal balancing needs. The category also includes long duration hydrogen storage.

These categories were informed by the working definition of LDS having greater than 4 hours of storage, included in the BEIS call for evidence on LLES. A further distinction was drawn between MDS and LDS, based on considerations of system needs and technology characteristics. This reflects differences across longer duration storage solutions. Chief among these is that there is a distinction made between those technologies that can provide within day balancing across a 24-hour period, and those that provide multi-day or seasonal storage. The technology solutions required for these two system needs can be quite different in their characteristics, although there are some common options in both.

Where the storage technology is a closed loop of power-X-power, this is referred to as ‘power LDS’ or ‘power MDS’. The key attribute is that the technology solution – e.g., PSP, CAES, LAES, etc – is a single asset. The maximum duration of power LDS considered was 72 hours. Whilst some technologies may be able to provide longer duration storage than this, this value was chosen as a reasonable ceiling on power LDS durations.

In contrast, since hydrogen storage has the potential to be used to meet hydrogen demand outside the power sector, the hydrogen storage is treated as a separate category of “hydrogen LDS”. This reflects the fact that multiple assets are required to produce the hydrogen (e.g., electrolysis), store the hydrogen (e.g., salt caverns) and then convert to power again (e.g., hydrogen CCGTs).

A range of technologies can be used to store hydrogen, either in a gaseous, liquid or solid-state. In this study the primary hydrogen storage solutions considered are longer duration Salt Caverns and shorter duration Pressurised Tanks, both storing hydrogen in its gaseous state and relying on established technology from the gas sector. The former has the ability to store hydrogen to meet seasonal swings in demand, but requires specific geology, the latter is more viable for storing hydrogen in small quantities for short periods.

We further sub-divide hydrogen solutions into:

- Hydrogen SDS: Durations of 12 hours or lower.
- Hydrogen LDS: Durations of over 12 hours.

The maximum duration for hydrogen LDS modelled was 720 hours (~1 month).

Examples of these storage technologies are shown in Exhibit 3.9.

Exhibit 3.9 – Sample technologies to help balance the system at different durations

Short duration storage technologies	Medium duration storage technologies	Long duration storage technologies
Li-ion batteries	Li-ion batteries	Hydrogen salt cavern storage
Gravity storage	Pumped hydro	Pumped hydro
Electric Vehicle to grid	Compressed air	Compressed air
Super capacitors	Liquid air	Thermal energy storage
Fly wheels	Flow batteries (e.g., Iron, Vanadium)	
Hydrogen tank storage	Hydrogen fuel cells	
Other forms of chemical storage		

The study focuses on a mix of the most prevalent archetypes of storage technologies, with the aim of producing an adequate range for the evaluation of the role for storage providers. The study is not assessing which is the best technology but rather aims to highlight the role of the different storage providers in meeting the future system requirements and the ‘flexibility gaps’ described above. This study should therefore be viewed in a technology neutral context, particularly when considering the technological and cost uncertainties sitting with the more novel providers.

3.3 How might storage technologies help minimise costs?

This chapter has introduced three broad categories of flexibility requirements: maintaining system stability, balancing supply and demand, easing locational congestion. Each of the potential flexibility solutions identified have differing cost characteristics; many of the options are based around innovative technologies, whose ability to deploy at scale is uncertain. The options also differ in their ability to address the complex flexibility requirements of a net zero system.

The key benefit of MDS and LDS technologies is that they possess the ability to offer all three types of flexibility. Instead of relying on multiple assets to each provide some of these services, storage has the potential to help deliver a net zero system more efficiently. Investment in storage could help reduce the need to utilise multiple other assets. If MDS and LDS can be brought forward at scale, it therefore has the potential to reduce overall costs.

However, a complication arises due to these technologies being differentially affected by existing market arrangements. A particular challenge for many of the medium and long duration storage technologies is that they are impacted by three related challenges:

- These technologies are capital intensive.
- In many cases, they have long lead times from the investment decision to plant commissioning.
- There are few, if any, long-term contracted revenue streams on which to base an investment decision.

Whilst therefore the system has seen growth in SDS, there has not been growth in new LDS and MDS capacity. It is uncertain that the current system will deliver LDS technologies. There is also growing evidence that, in a cost optimal electricity system, medium and longer duration storage solutions would be likely to lead to a reduction in the cost of delivering a net zero system.[10]

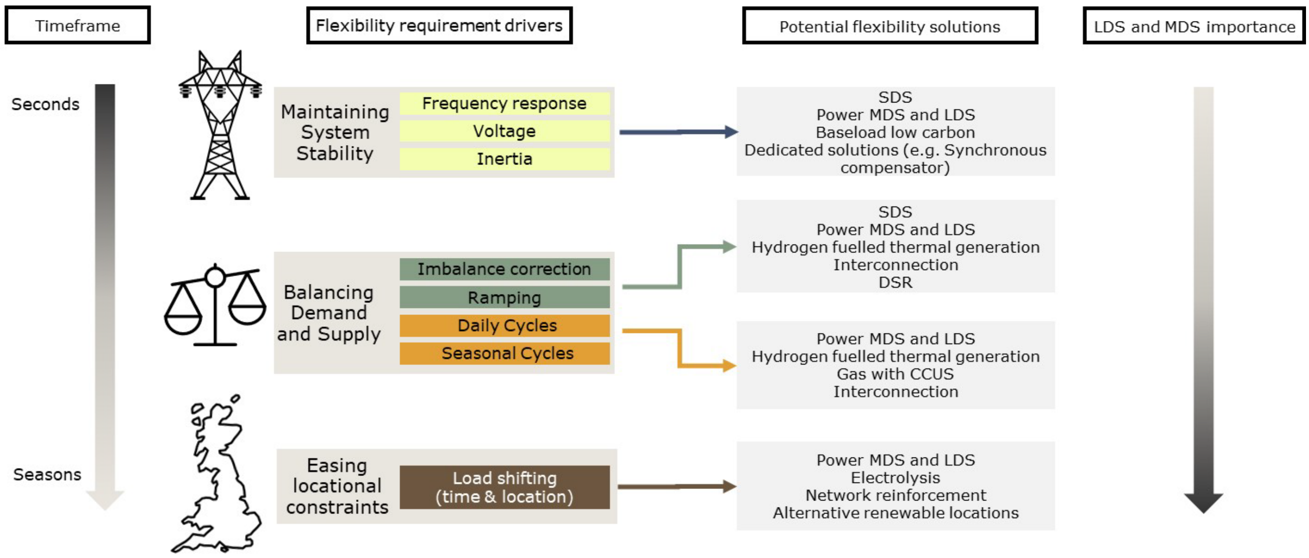
3.3.1 Storage technologies need to be cost competitive with other flexibility options

As the system transitions to net zero, the provision of flexibility will need to move from traditional firm and carbon intensive capacity to emerging low-carbon technologies. The future flexible capacity mix, including storage technologies, will be determined by how technology costs develop. Long duration storage technologies will be competing against a range of other technologies. For example, against batteries and demand side response (DSR) at fast response timescales, or against interconnectors and low carbon thermal generation for longer duration flexibility.

Exhibit 3.10 summarises the flexibility needs of a low carbon system with the potential solutions. For each dimension there are a variety of technologies that will compete with MDS and LDS. Power LDS will have a comparative advantage in longer duration dimensions, even though it can also offer flexibility across shorter periods. There are likely to be fewer competitors at the longer timeframes and many of the alternatives are lesser established technologies.

[10] Reports that highlight this challenge for long duration storage include:
REA: Longer Duration Energy Storage (2021)
BEIS: Call for Evidence (2021)
Imperial/Vivid: Accelerated Electrification and the GB Electricity System (2019)

Exhibit 3.10 – Competitors to long duration storage across the different flexibility requirements



Notes: 'Baseload low carbon' is assumed to include nuclear, biomass and biomass with CCS capacity. Low carbon flexible capacity is assumed to include hydrogen fuelled and gas with CCS capacity.

With regards to balancing supply and demand and easing locational constraints, a more weather driven system is likely to see more extreme events than are seen today. This drives a need for longer durations of storage than the market is delivering at present. Further analysis of the role of long duration storage in extreme periods is shown in Annex C.

3.4 Comparing storage solutions

This section analyses the costs of storage. It draws on the modelling done at a high level. However, the primary focus is to introduce assumptions made. The scene is set for how the modelling will address the research questions.

The previous section highlights the main flexibility requirements: the need to balance supply and demand, to maintain system stability and to manage locational congestion. It identifies that storage could potentially reduce the costs of net zero, due to its ability to offer services in each of these categories. However, this is attractive only in so far as storage can do this cost competitively.

3.4.1 Relative costs of LDS technologies

This section presents the relative commercial attractiveness of different solutions using levelised cost metrics. Building on the flexibility options outlined in Section 3.2, the relative costs of these are analysed. These are done using base cost assumptions, provided by BEIS and supplemented by further AFRY analysis.

Levelised Costs

These are a measure of the average net present cost of generation over a plant's lifetime. They are used to compare different technologies on a consistent basis. The Levelised Cost of Electricity (LCOE) also represents the average revenue per unit of electricity generated required to recover the costs of building and operating the plant. It is calculated as the ratio between all the discounted costs over the lifetime of the generating plant, divided by a discounted sum of the energy delivered.

The Levelised Cost of Storage (LCOS) gives an equivalent measure for storage. However, since it is not a direct source of production, the calculation is done by taking the ratio between all the discounted costs over the lifetime of the storage plant, divided by a discounted sum of the energy throughput of the storage (or volume of energy cycled through the plant).

The Levelised Cost of Hydrogen (LCOH) represents the same measure but for technologies that are producing hydrogen.

The values presented in this chapter are chiefly drawn from the BEIS central scenario. Many of these costs are uncertain. The values presented here were used for the core scenario modelling, with sensitivity analysis focussed on availability of certain technologies (rather than costs). The details of these sensitivities are set out in Section 4.4.

There are a range of solutions to provide flexibility services with different cost and operating characteristics. The costs of providing flexibility are dependent on how a technology is used and how that relates to its mix of upfront and variable costs. Innovation and learning may change relative costs, and a given technology's competitiveness may change over time. For technologies other than storage, Annex B presents levelised costs assumed for these, including for hydrogen technologies.

3.4.2 Levelised cost of electricity storage

Exhibit 3.11 shows a set of base assumed costs for the different storage technologies modelled in this study.

Exhibit 3.11 – Storage technology investment costs (real 2019 money)

	Duration (hours)	2030 Capex (£/kW)	2050 Capex (£/kW)	2030 Opex (£/kW)	Hurdle rate (%, real basis)	Build time (years)	Financial Lifetime (years)
Li-ion battery	1	331	231	5	7.3%	1	15
	2	449	301	7	7.3%		
	4	696	427	10	7.3%		
	6	930	560	11	7.3%		
	9	1328	791	13	10%		
LAES	6	1085	1018	13	10%	2	25
	9	1178	1105	13			
	12	1270	1192	13			
CAES	6	993	931	13	10%	2	25
	20	1385	1299	13			
	72	1640	1539	13			
PSP	6	1478	1426	19	10%	4	30
	20	1680	1624	22			
	72	2088	2015	27			

Source: BEIS, supplemented by AFRY

These technologies were chosen as a representative selection of the wider array of storage technologies. The choice was made on the basis that these possible storage archetypes are representative of the wider range of chemical, mechanical and hydro-electric based storage types.

The lifetimes presented are financial, rather than technical. For the calculation of the LCOS, the payback period (by which financial investors would expect to recoup the capex) is the relevant lifetime to consider. In terms of the modelling done in BID3,[11] it is assumed that after the technical lifetimes, further capex costs are incurred.

[11] More information on the BID3 model can be found in Section 4.1, Annex A and the supplementary methodology paper.

To calculate comparative LCOS values, assumptions around the potential level of storage cycling are also required. The LCOS captures the investment costs of storage - the final cost is, however, sensitive to the asset's utilisation level. For storage this is expressed as the level of cycling attainable (one cycle consists of a full capacity charge and discharge). Under higher cycling conditions, the asset is producing more MWh, and therefore the capital costs are spread over more hours of the year.

Based on the duration of the storage, different levels of cycling are possible. These values will also be influenced by the round-trip efficiency of the technology and the extent to which system volatility enables cycling.

Exhibit 3.12 presents assumed round trip efficiency values, and minimum and maximum cycling rates. These are theoretical values to illustrate the relative costs of the storage technologies but were informed by modelled values.

Exhibit 3.12 – Storage round trip efficiencies and plausible ranges for cycles per year

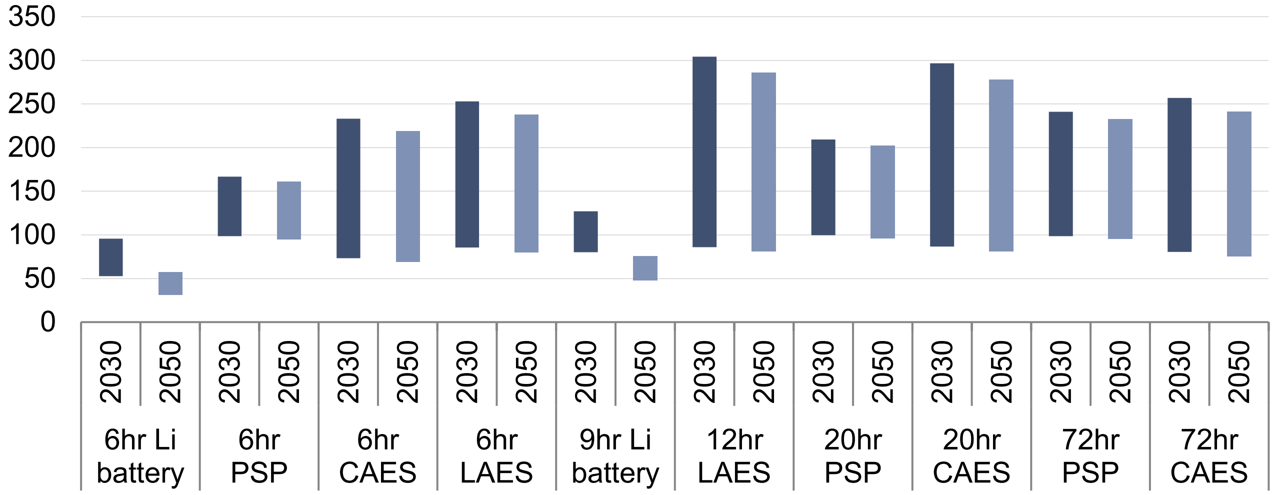
	Duration (hours)	Round trip efficiency (%)	Lower cycles per year	Upper cycles per year
Li-ion battery	1	85%	730	1095
	2		480	730
	4		365	520
	6		200	365
	9		165	260
LAES	6	55%	90	270
	9		70	200
	12		45	155
CAES	6	60%	90	290
	20		30	100
	72		15	35
PSP	6	75%	180	340
	20		55	115
	72		20	40

Theoretically, all these technologies could cycle more often than this. However, in practise volatility in the system does not necessarily exist to allow this to happen. For example, where demand net of renewables is relatively flat, then storage cycling opportunities are limited. From a price perspective, where prices do not exhibit much volatility, this also limits cycling. The values chosen are deemed to be plausible bounds based on modelled ranges, accounting for expected levels of volatility and round-trip efficiencies of different technologies.

The rationale for presenting plausible ranges of possible cycling is to illustrate how the LCOS is highly dependent on the amount of cycling these technologies can achieve.

Based on the investment costs and assumed cycling rates above, Exhibit 3.13 presents the levelised cost of electricity storage. Exhibit 3.13 highlights the impact of potential technology cost reductions by comparing the range of LCOS between 2030 and 2050. The numbers for 2050 reflect the same cycling rates but include reduced LCOS values based on assumed learning rates in technology costs. Ranges presented (for each technology and year individually) reflect the influence of different cycling rates on the LCOS; cycling rates used to create the ranges are those values from Exhibit 3.12.

Exhibit 3.13 – Range of levelised costs for medium and long duration electricity storage (£/MWh) at different cycling levels



From these assumptions, it is clear that Li-ion batteries are very competitive on a unit cost basis. This is clear from looking at the 6hr storage duration options across the different technologies. To achieve longer durations of storage it is likely to be lower cost to build multiple 6hr li-ion battery assets. However, this is not necessarily the case: if the system needs much longer durations, or storage is needed prior to any declines in battery cost, other technologies offering longer durations may be preferable.

Learning rates for different technologies are a significant source of uncertainty. All power storage solutions are expected to benefit from cost reductions; however some technologies' costs are assumed to decrease more sharply than others:

- Li-ion battery cost reductions are driven by the expectation of a rapidly expanding global li-ion battery market, creating room for economies of scale and raising competition in this market. Li-ion batteries have relatively well-known capex, due to the prevalence of this technology in the market today.
- Some technologies (e.g., LAES and CAES) are only emerging now. Declining investment costs for these will make them more attractive and reduce the costs of the system obtaining the necessary flexibility. Some cost reductions are assumed already by 2030.

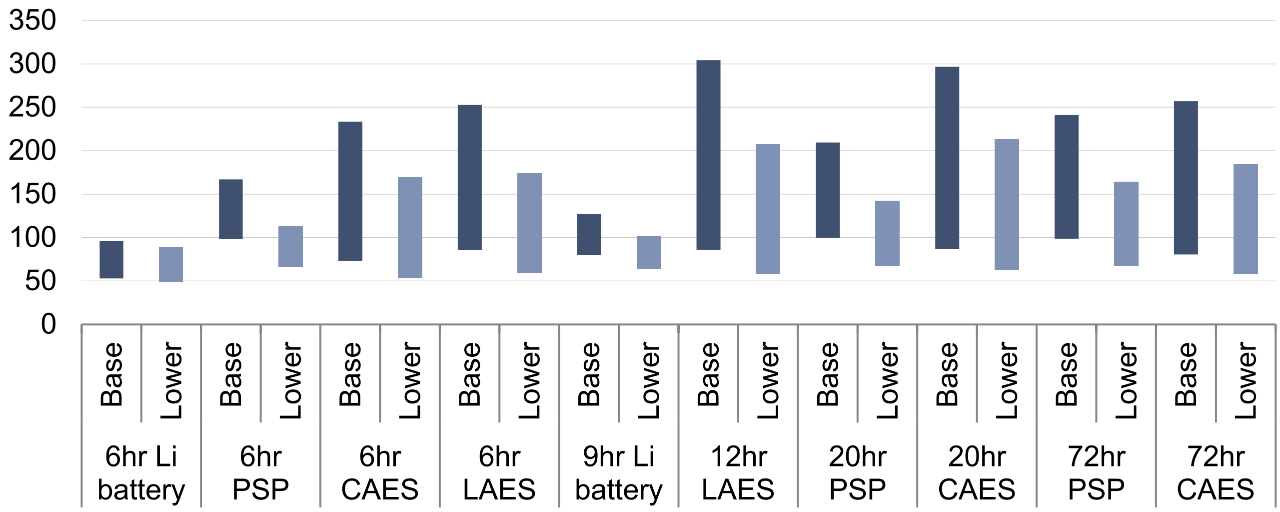
In the same way that the LCOE is not only a measure of investment costs, but also a measure of required margins to recover investment costs, the LCOS can also be treated in this way. The LCOS can be applied as a measure to express the required price spread for the storage asset, to meet the required hurdle rates.

The required spread between buy and sell prices is much larger if storage assets are only able to cycle infrequently. This illustrates that LDS technologies are relatively capital-intensive flexibility solutions. Therefore, the most effective operating mode for them will be when achieving high numbers of cycles per year. At lower cycling levels, it is more likely that peaking thermal generation will be a more cost-effective solution, for example.

By virtue of being capital intensive, technology hurdle rates are also crucial to determining the relative costs of LDS. In the basic assumptions used initially, a 10% real hurdle rate is used for technologies other than li-ion batteries. This was chosen to reflect the risks surrounding investment in capital intensive technologies, with long lead times and few long-term contracted revenues.

Exhibit 3.14 shows the same values as the 2030 values in Exhibit 3.13, but with a comparison of the impact of lower discount rates (6% real). These lower values are used for the modelling of scenario #3, as explained later in Section 4.3.

Exhibit 3.14 – Comparing the impact of base versus lower (6%) discount rates on LCOS values for LDS, at different cycling levels, with 2030 costs (£/MWh)



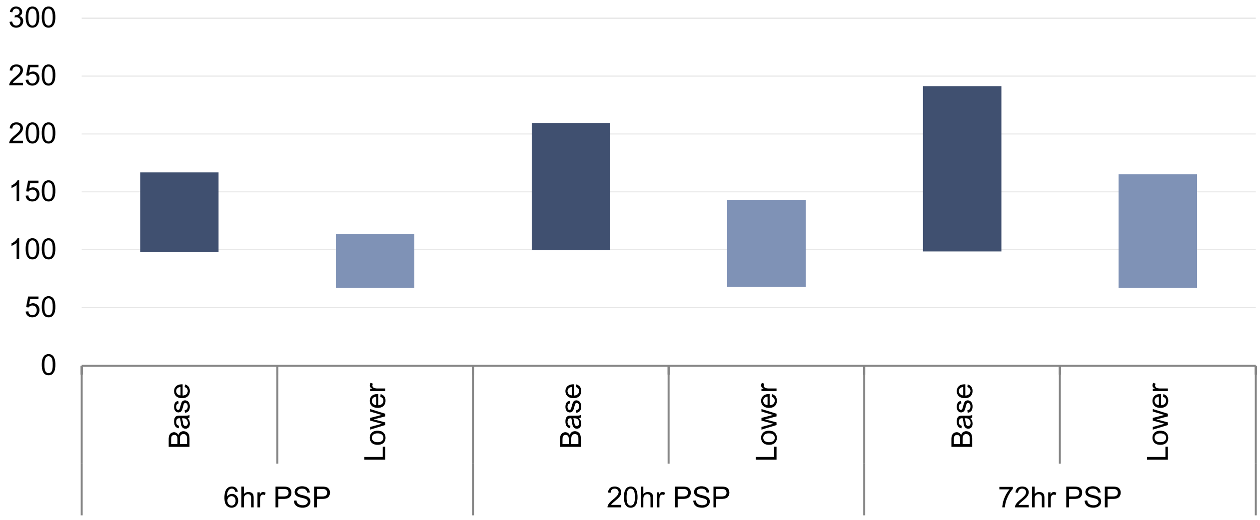
Note: All discount rates are in real money terms

The impact is that the price spreads that would theoretically be required from the market are reduced. The ability to reduce the risk associated with investing in such technologies would make them more competitive and more likely to reduce overall system costs (as opposed to relying on combinations of other technologies to achieve the same flexibility service provision).

In addition to cycling rate and hurdle rate uncertainty, the basic capex values presented in Exhibit 3.11 are subject to differing levels of uncertainty. In the case of Pumped Storage, the geography of the site for each individual storage will be unique and will give rise to differing capex. There is also significant difference between a greenfield location, and options such as extending existing PSP sites or converting reservoir hydro to be able to operate as pumped storage.

Exhibit 3.15 illustrates this, by presenting the 2030 values for pumped storage with the base capex, and with a reduced capex value. These lower values were also applied in scenario #3 (see Section 4.3). The lower value is set at a 35% reduction to the base value. This was chosen based on analysis of capex values of pumped storage projects reported in several European countries, to reflect a plausible lower level of capex that might be achievable in advantageous geographical locations.

Exhibit 3.15 – Comparison of impact of base versus lower capex (-35%) on LCOS values for pumped storage plants, at different cycling levels (£/MWh)



A final degree of uncertainty regarding required price spreads is worth noting. In the preceding analysis, the round-trip efficiency has not been included in the calculation of the LCOS. If a storage can fill/charge when the price of electricity is zero, then the LCOS values presented are a fair reflection of the sell price that the storage would need to achieve on average in order to recover all investment costs. However, for greater than zero buy prices, lower efficiency storage options would need to be able to achieve proportionally greater sell prices to compete against higher efficiency alternatives.

Further analysis of assumed investment costs for power generation and hydrogen technologies is presented in Annex B.

3.5 Summary of the opportunities for LDS technologies

There are a range of technology options available that can provide the flexibility that the system needs across the different needs and timescales. Comparisons of costs against the levels of operating margin will determine the profitability of generators. Cost competitiveness comes down to investment costs, variable operating costs and utilisation.

For storage the consideration is complex, and is one of relative costs for storing power, and available prices for generating. The important factor is the availability of sufficient price spreads at different timescales. Short duration storage is likely to dominate at the shorter timescales, such as intra-day. This will force other storage solutions to seek value over longer timescales. If volatility in residual demand is relatively low at longer durations, then price spreads would need to be much higher at these more seasonal time frames. The reverse is true if LDS technologies can achieve high cycling rates.

What are the main drivers of the requirement for long duration storage?

The preceding chapter has highlighted that there are three main flexibility requirements in a low carbon power system (maintain system stability, meet peak demand, manage locational congestion). LDS can contribute to all of these needs.

A system transitioning towards high renewable generation and net zero emissions will require solutions with fast response times and longer durations. At the shorter durations, alternative technologies are likely to be able to offer the services at lower cost. Where these requirements involve longer durations, LDS (either power or hydrogen) is more likely to be a competitive flexibility solution.

There are also fewer competitors, to storage technologies, for meeting demand and managing locational congestion at the longer durations.

What are the possible operating regimes for long duration technologies?

By virtue of being relatively capital intensive technologies, power LDS needs to operate at the higher end of possible cycling rates. If the higher cycling rates are achievable, then power LDS is likely to compete with not only SDS options but is also likely to become more competitive against hydrogen LDS.

However, if volatility in the system exists more towards extremely seasonal rather than daily or weekly durations, then hydrogen based long duration storage can become more competitive, as this is more clearly seasonal in nature than the power LDS options. Lower cycling rates make power LDS options relatively more expensive flexibility solutions.

Where only lower cycling rates are achievable, power MDS and LDS technologies would need to provide additional system stability services in order to mitigate the relatively lower value achievable from energy trading.

4. Modelled scenarios & sensitivities

This section describes the assessment framework used for the analysis. It provides an overview of the scenarios developed by BEIS and AFRY in order to capture a range of different outlooks for the system in Great Britain.

4.1 Modelling methodology

To address the research questions, we have undertaken scenario-based modelling of the GB electricity market to quantify the need and associated benefits of long duration electricity storage in different configurations of the future energy system. For each specific market scenario, the model was run for both:

- A reference case, where the only form of storage available was short duration storage. This is done by disabling the model's ability to invest in new medium and long duration storage.
- An 'all storage durations' case, which includes medium and long duration storage assets in the model's investment decisions.

For a given market scenario, all the inputs to these two runs are identical, with the exception of the addition of medium and long duration storage assets in the 'all durations' case.

AFRY performed market modelling using their BID3 model. BID3 models the full system, including both power and hydrogen sectors, using a sophisticated capacity expansion module (the "Auto Build") to build the scenarios. Inputs into the model include levels of demand, technology costs, commodity prices, RES generation profiles, some exogenous investments (e.g., capacity online in 2030) and plant technical parameters. The capacity expansion model then provides optimal system investments to ensure security of supply, system stability and meet net zero at minimum cost. A further description of the BID3 model is provided in Annex A.

This approach was designed to test what a system would look like when current market imperfections are not addressed, and LDS technologies are not deployed. By adding the LDS, it is then possible to quantify the benefits that it can bring to the system.

In each case the model produces a set of outputs (including capacity mix, investment costs, transmission investment, fuel costs, interconnector flows etc) which were used to compare the system benefit that arises if LDS is made available.

These model outputs are used to compare system costs for the different scenarios and cases. System costs include:

- generation capacity (including power storage) investment costs;
- fuel costs;
- carbon costs;

- hydrogen production investment costs;
- transmission network investment costs;
- interconnection investment costs; and
- hydrogen storage investment costs.

The costs associated with the existing transmission network and generation capacity that will already exist in 2030 were excluded. Costs of distribution networks were also ignored. The net costs of imported and exported power are included within fuel costs.

4.2 Modelling context and caveats

The modelling for this study was performed based on a set of high-level principles, that underpin the specifics of the model architecture:

- Least cost solutions: the BID3 optimisation minimises total system costs. This includes both investment costs and variable costs. Investment costs for generation, storage, transmission, and interconnection are all included in the model. This can be thought of as analogous to a central system planner or perfectly efficient market driven investment outcome.
- Economically rational: the capacity optimisation process is performed iteratively, such that all new investments achieve their technology investment hurdle rates. No technology should be systematically over or under-achieving its specific hurdle rate.
- Perfect foresight: investment decisions are made based on perfect foresight of the modelled future revenues and costs. It is worth noting, however, that five weather patterns were included, to span a plausible range in weather uncertainty.
- Effective markets: the modelling is predicated on the assumption that price signals will exist with sufficient clarity to deliver the least cost and economically rational outcomes. This impacts both the types of technology that result in each scenario, the timing of any investments and the location in which different investments are built.
- Effective network investment: the modelling further assumes that there are effective signals for network investment, and that the supporting infrastructure investment required is completed in a timely manner.
- No forced build of any technology: the scenarios assumed a certain renewable capacity mix for 2030, based on stated government policy at the time of this study.[12] Beyond 2030, the only technology with a fixed deployment trajectory was that of new nuclear. All other technologies were built based on their relative economics and their maximum deployment rates. In addition to power generation, transmission, interconnection and storage, this also includes deployment of hydrogen production, storage and, in certain sensitivities, transmission.

[12] This study was performed prior to the UK's commitment to decarbonise electricity system by 2035 (subject to security of supply) and the publication of the British Energy Security Strategy.

Considering these high-level principles that govern the modelling, there are several caveats that should be born in mind when assessing the scenario results:

- BEIS commissioned AFRY to model a limited number of scenarios, which therefore captured only a subset of all possible uncertainties. In particular, the BEIS scenarios considered the same commodity prices and technology investment costs. In addition, the sensitivities modelled did not cover all possible uncertainties that could have been explored, but instead focussed on key technological uncertainties.
- In reality, investors have limited foresight of future market developments, have to make decisions based on incomplete information, and have different levels of risk aversion. It is not atypical for modelling of the kind undertaken here to give limited treatment to these realities. However, when considering long lead time and long technical lifetime investments (such as many of the power LDS technologies), it is an important assumption to highlight. This assumption may tend to lead to both an over-optimism and/or an over-pessimism regarding investments. On the one hand, the model can deliver power LDS technologies to be built at the right time and in the right place. In practise, this may not be possible; investments may be taken with over-optimistic views of deployment capability and future market outcomes which may lead to stranded assets. On the other hand, having some long lifetime power LDS in place may act as a hedge against other undesirable market outcomes; having made the investment decision, a long lifetime asset has the potential to reduce system costs over an extended period.

4.3 Scenario definition

Three scenarios were defined by BEIS, to cover a range of outlooks that could drive different requirements for LDS; two with different demand projections (for both power and hydrogen) and one with different long duration storage technology cost assumptions. All scenarios modelled in this project reach net zero in 2050 following the UK carbon budgets. These scenarios present a subset of a wider range of possible scenarios, but they provide analysis of the potential role of LDS in the energy system broadly consistent with previous analysis of a net zero system performed by BEIS.

Each scenario was constructed using BEIS assumptions where available, supplemented by AFRY assumptions, as detailed in the separate Methodological Annex.

As described in Section 4.1, each scenario was modelled with two cases, to demonstrate the impact of introducing MDS and LDS on the scenario.

4.3.1 Scenario #1: higher electrification & lower hydrogen demand

This is a scenario characterised by high electrification of the transport and heat sectors, leading to high total electricity demand. Total hydrogen demand is lower in this scenario, primarily coming from industry and transport. This scenario used BEIS' central view for technology costs.[13]

4.3.2 Scenario #2: lower electrification & higher hydrogen demand

This scenario is characterised by lower electrification of the transport and heat sectors compared to the first scenario. Total hydrogen demand is therefore higher, with additional demand primarily coming from the residential sector. Again, the BEIS central view for technology costs is used.

4.3.3 Scenario #3: supported power long duration storage investment

The third modelled scenario assesses the impact of providing support for investment into power MDS and LDS technologies. Hurdle rates for each MDS and LDS technology are reduced from 10% to 6% (real money basis). Capex was reduced for new PSP projects by 35%, to reflect the lower bound of what might be possible, given the uncertainty and range of possible capex values for this technology. These are the assumptions explored in Exhibit 3.14 and Exhibit 3.15 in the exploration of storage investment costs. Scenario #3 assumes the same total electricity and hydrogen demand as scenario #1.

Exhibit 4.1 – Scenario Matrix

	Demand	Technology Costs	Decarbonisation	Commodities
Scenario #1	BEIS Net Zero higher demand	BEIS Central view	Net Zero by 2050	BEIS Central view
Scenario #2	BEIS Net Zero lower demand	BEIS Central view	Net Zero by 2050	BEIS Central view
Scenario #3	BEIS Net Zero higher demand	BEIS Central view with supported power LDS	Net Zero by 2050	BEIS Central view

13 Costs are consistent with those used in Annex O of the Energy Emissions Projections December 2021 Interim Update https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021.

These are summarised in the scenario matrix in Exhibit 4.1, with the key differentiating assumptions detailed in Exhibit 4.3 and Exhibit 4.4.

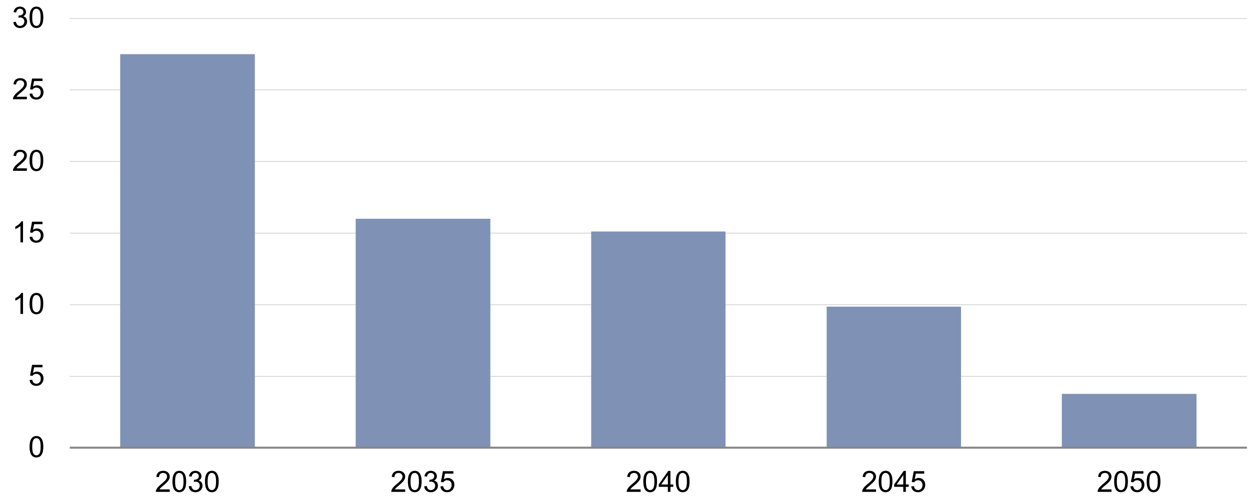
In all scenarios, for both storage cases, the following targets had to be met:

- Annual carbon emissions had to be below the limits set out in Exhibit 4.2. These limits covered both power and hydrogen production.
- Security of supply was required to ensure lower than 3 hours of loss of load expectation.
- All investment options had to respect resource potentials and build rate limits. These are particularly relevant for intermittent renewable technologies, where both national and locational limits are applied.

Where unabated thermal capacity is left on the system for security of supply purposes, it would therefore operate only at such load factors that emissions limits are respected.

These targets and limitations were fully kept in the sensitivities modelled as well, except where explicitly mentioned as part of the sensitivity design.

Exhibit 4.2 – GB power and hydrogen sector gross emissions limits (Mt CO2)



Source: BEIS
Notes: Where negative emissions technologies are available, the impact of these was not to allow power sector emissions to increase above these values, since the negative emissions were assumed to contribute not only to the power sector, but also towards other hard to decarbonise sectors of the economy.

Exhibit 4.3 – GB annual electricity demand, scenario #1 vs scenario #2 (TWh)

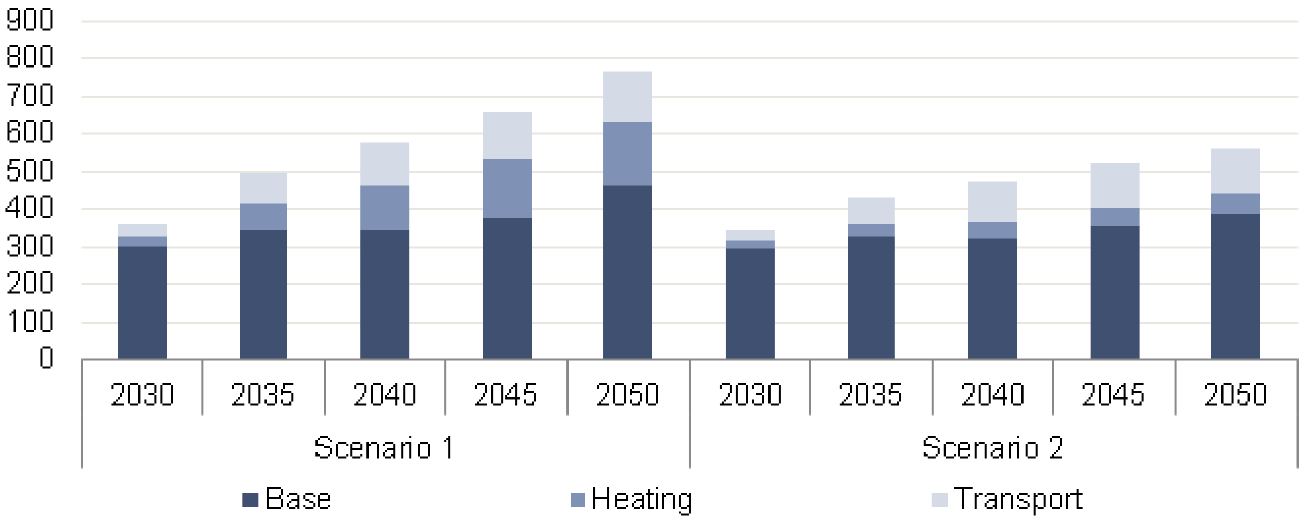
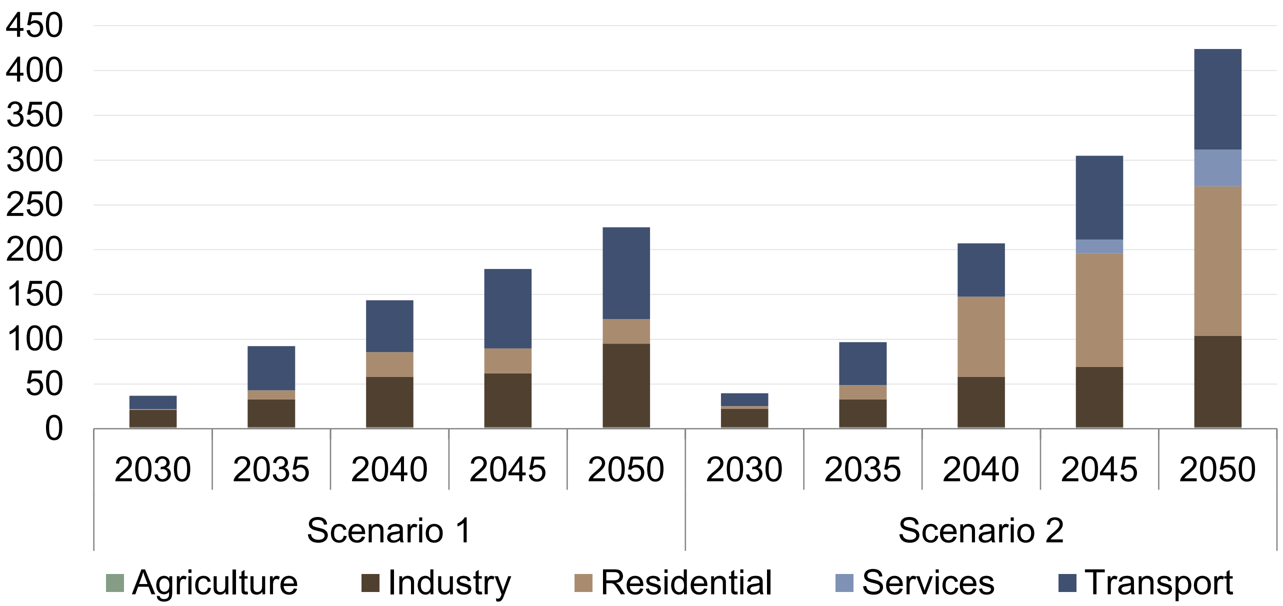


Exhibit 4.4 – GB annual hydrogen demand, scenario #1 vs scenario #2 (TWh)



4.4 Sensitivity definition

In addition to the core market scenarios, the study included the design and assessment of further sensitivities. The purpose of the sensitivities is to complement the evidence from the core scenarios, to answer the research questions and explore uncertainties.

The sensitivities can be grouped into two high-level themes:

- **Sensitivities #A-#E:** Wider power system questions, how do competing technologies affect MDS and LDS and its role in the power system.
- **Sensitivities #1-#6:** Technology risk, many of the technologies modelled are uncertain and require some level of technological breakthrough.

The sensitivities were designed to explore dimensions of uncertainty within the core scenarios, namely:

- technology risk,
- technology cost, and
- competing versus complementary technologies.

Technology risk existed in the scenarios where the technologies modelled are not currently fully mature. Blue hydrogen technologies, such as SMR combined with CCS, are currently at demonstration scale. Hydrogen storage in salt caverns and hydrogen transmission are also not currently widely deployed. To reflect these risks, sensitivities were run that limit the role of such technologies. Technology costs are also uncertain, with potential for large cost reductions in technologies, such as electrolysis, as they emerge.

Sensitivities were also designed to examine power-hydrogen sector coupling – in particular the capability of the hydrogen sector to store hydrogen and therefore the flexibility to interact with the power sector.

Exhibit 4.5 below summarises the technology risk sensitivities carried out, describing the areas of uncertainty tested, the modelling approach taken. The relative storage capability of the hydrogen sector for the ‘technology risk’ sensitivities is also shown.

There were also wider power system uncertainties around technologies that may compete with LDS or complement LDS. These included DSR, interconnection and nuclear. Sensitives were run to explore how much these overlap with LDS technologies. Exhibit 4.6 details the sensitivities modelled.

The sensitivities were only performed on the core market scenario #1 all durations case. If the sensitivities were run on scenario #3, where power MDS and LDS have lower hurdle rates and some technologies had lower capex, we would expect there to be greater deployment of power MDS and LDS. Scenario #1 was chosen as the basis for the sensitivities in order to show the benefit of MDS and LDS technologies in the absence of any direct policy support.

A further summary of the modelling approach is provided in Annex A.

Exhibit 4.5 – High-level overview of 'technology risk' sensitivities

	Sensitivity	Approach	Hydrogen storage capability
1	What if the availabilities of several key novel technologies are delayed?	CCS capacity (including gas with CCS, SMR CCS and ATR CCS) build out limited Delivery of hydrogen salt cavern storage is more expensive and more difficult to realise Full cost of hydrogen transmission network development is incurred.	4
2	What is the impact of more extreme weather on the system and what are the relative benefits of different technologies in these cases?	Technology mix from core scenario #1 is applied to a wider range of weather patterns to stress test the capacity results	4
3	What if the salt cavern storage proves impossible to realise and long duration storage is not available in the hydrogen sector?	Exclude hydrogen salt cavern storage from the investment options. Hydrogen storage only available through short duration tank storage	1
4	What if blue hydrogen is significantly more difficult to produce and ATR+CCS capacity is limited?	Enforce a maximum capacity on SMR and ATR (+CCS) technologies, leading the model to rely much more heavily on green hydrogen from electrolysis.	4
5	What if the transport of hydrogen is harder and hydrogen pipeline capacity is not developed across GB as a whole?	Hydrogen demand is allocated to distinct zones, without any transportation between the zones.	2
6	What if the transport of hydrogen is harder, and costs of a new national hydrogen transmission network are directly considered?	Hydrogen demand is allocated to distinct zones costs, and costs are incurred to develop a hydrogen pipeline network.	3

Exhibit 4.6 – High-level overview of 'system question' sensitivities

	Sensitivity	Approach
A	What if a higher volume of power LDS technologies is brought forward via direct support?	Introduce a minimum power MDS and LDS commitment of 15GW by 2050
B	How does significant new nuclear capacity drive different storage requirements?	Include a minimum of 4 new nuclear power stations after Sizewell C is commissioned.
C	To what extent does DSR compete with long duration storage?	Halve the DSR capabilities included compared to the base scenario.
D	To what extent does interconnection compete with long duration storage?	Cap & Floor for interconnectors does not continue beyond 2030 and additional new capacity is more expensive (11% discount rate).
E	To what extent does reduced emissions drive the need for storage?	The emissions reduction pathway towards 2050 is less strong and CO2 reductions are backloaded Additionally, power LDS is modelled with the lower investment costs (as per scenario #3) to test the levels of regret associated with supporting power LDS when the desired emissions reductions are not realised.

5. Results

This section provides an assessment of the impact on the energy sector in Great Britain for each core scenario and sensitivity. More specifically, the assessment looks at the possible effects of long duration electricity storage on system costs in a decarbonised power sector.

Scenario results summary

In all core scenarios, the introduction of MDS and LDS led to system cost savings. The NPV of the savings were:[14]

- Scenario 1: £20bn
- Scenario 2: £13bn
- Scenario 3: £24bn

When MDS and LDS are available, they substitute for some of the SDS otherwise required. Additionally, where hydrogen LDS is available then this technology delivers most LDS requirements under the core cost assumptions. However, where there is uncertainty over delivery, or different cost assumptions, power LDS solutions substitute for some of the hydrogen capacity. In scenario #3, support for power MDS and LDS leads to 5.5GW additional build of power MDS and LDS. Of this, 2.6GW was power LDS.

The system favours the longest possible durations of storage to balance seasonal swings in supply and demand. Increased flexibility of the hydrogen sector, through hydrogen LDS, means that CCGT hydrogen plants are well placed to provide seasonal balancing when all duration technology options are available. Hydrogen LDS also plays a key role in enabling increased electrolysis utilisation, (for end use in either power or non-power sectors). 15TWh of hydrogen LDS is built in the scenario #1 all durations case.

Increased electrolysis in the all durations case further supports increased RES capacity, displacing gas in the generation mix (both reducing reliance on gas with CCS power generation and blue hydrogen).

Locating electrolysis in zones with constrained power transmission is a key solution chosen by the model for reducing the costs of constraints and new network investment.

The system also requires substantial new investment in SDS and MDS, used primarily to provide the balancing required over shorter time frames. Given the available technology choices, battery storage solutions are the most cost-effective options for meeting this requirement.

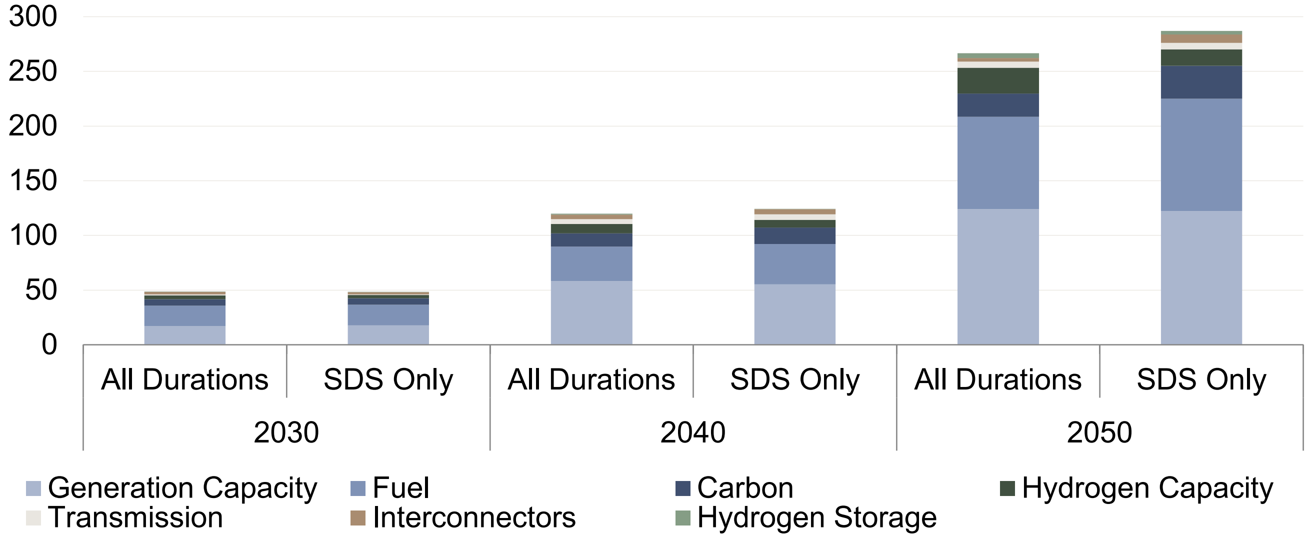
[14] Section 2.4 gives a fuller description of the way these NPV values are calculated. These values are in real 2019 money and discounted from the perspective of 2030 (as the first modelled year).

System services are primarily provided by SDS and peakers for response and reserve. Inertia is provided by a combination of dedicated inertia providing technologies and baseload low carbon. System stability services were not a driver of new LDS, therefore.

5.1 Scenario #1: deployment of MDS and LDS technologies reduce system costs, especially the use of hydrogen long duration storage for the key seasonal flexibility

Comparing undiscounted system costs for the two versions of scenario 1, shows that the majority of the benefits are found towards the end of the modelled timeframe.

Exhibit 5.1 – Undiscounted system costs, scenario #1 (£bn)



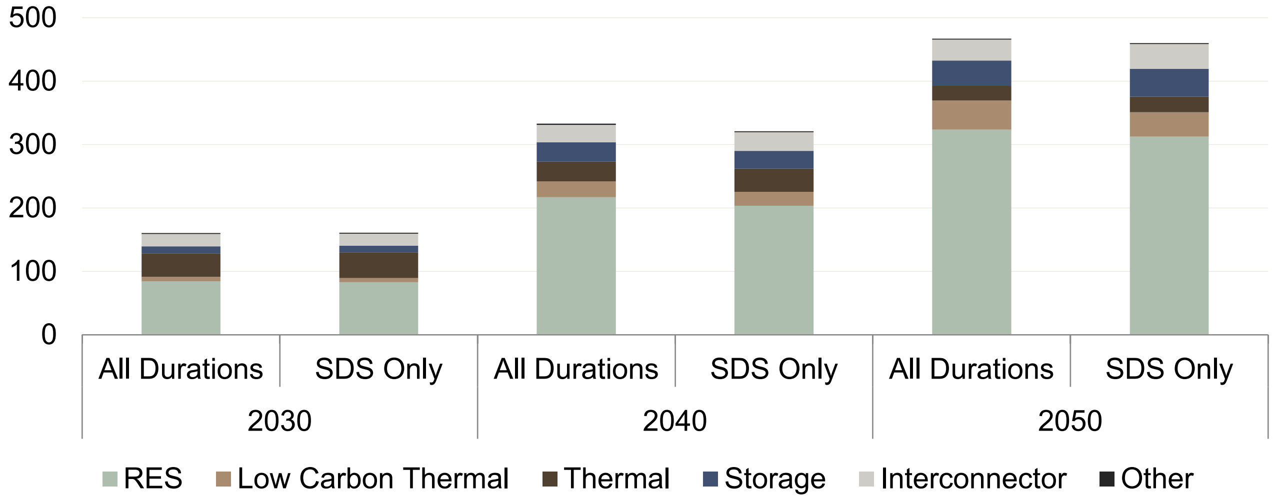
Note: Hydrogen capacity includes hydrogen production technologies. Hydrogen storage costs are shown separately. Power storage investment costs are included in the generation capacity investment costs. Transmission only includes capex. Fixed build assumed prior to 2030 is ignored.

This reduction in system costs towards 2050 emerges later in the period because that is when the real requirement for longer duration flexibility emerges. The following sections examine the underlying drivers of this result, with reference to the three flexibility requirements.

5.1.1 Balancing Supply and Demand

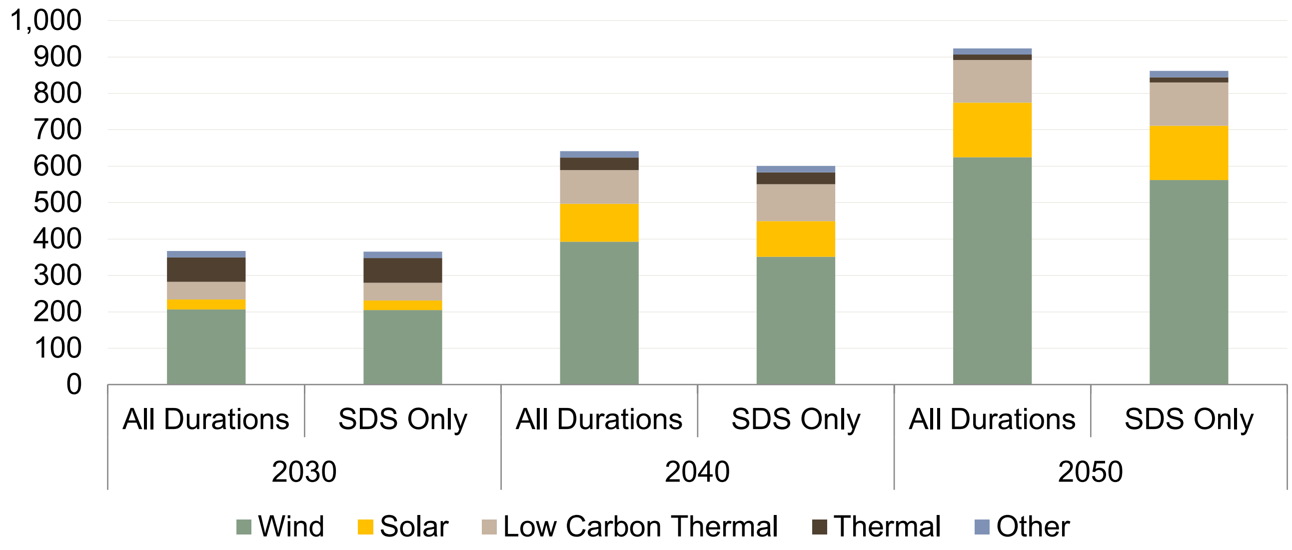
In scenario #1, the optimal capacity mix provided by the model was dominated by renewables, through a combination of wind and solar. Additional capacity came from interconnection, thermal, and storage technologies. DSR was also included, but this was treated as a fixed input volume of flexibility in the modelling, rather than an output.

Exhibit 5.2 – Power capacity mix results, scenario #1 (GW)



The introduction of MDS and LDS, and in particular hydrogen LDS, enables the system to be more RES based with less reliance on gas for either blue hydrogen or powering gas with CCS, as shown in Exhibit 5.3. In part, this increase in RES capacity is driven by the ability of electrolysers to better utilise excess renewable generation and store the resulting hydrogen.

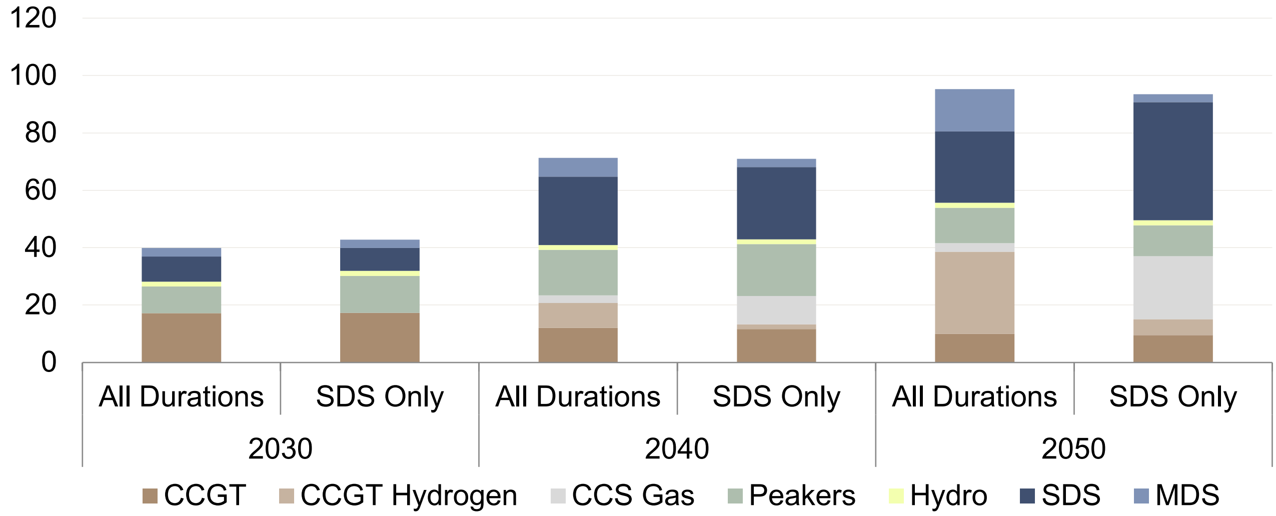
Exhibit 5.3 – High-level generation mix, scenario #1 (TWh)



Balancing generation or decreases in demand are required to meet 'production gaps' – periods which have significant inflexible demand net renewables. These gaps can range from short within-day balancing to monthly periods of low renewable output that require seasonal provision of balancing energy.

This balancing energy must be provided by flexible capacity, that can be dispatched to meet the residual demand. This was provided through a mix of different technologies, as shown in Exhibit 5.4, but no additional power LDS is built in scenario #1. The model favours longer duration salt cavern storage and low carbon dispatchable technologies, such as hydrogen CCGTs or gas with CCS (where you only have SDS) for seasonal balancing and shorter duration storage for short-term balancing.

Exhibit 5.4 – Flexible capacity, scenario #1 (GW)



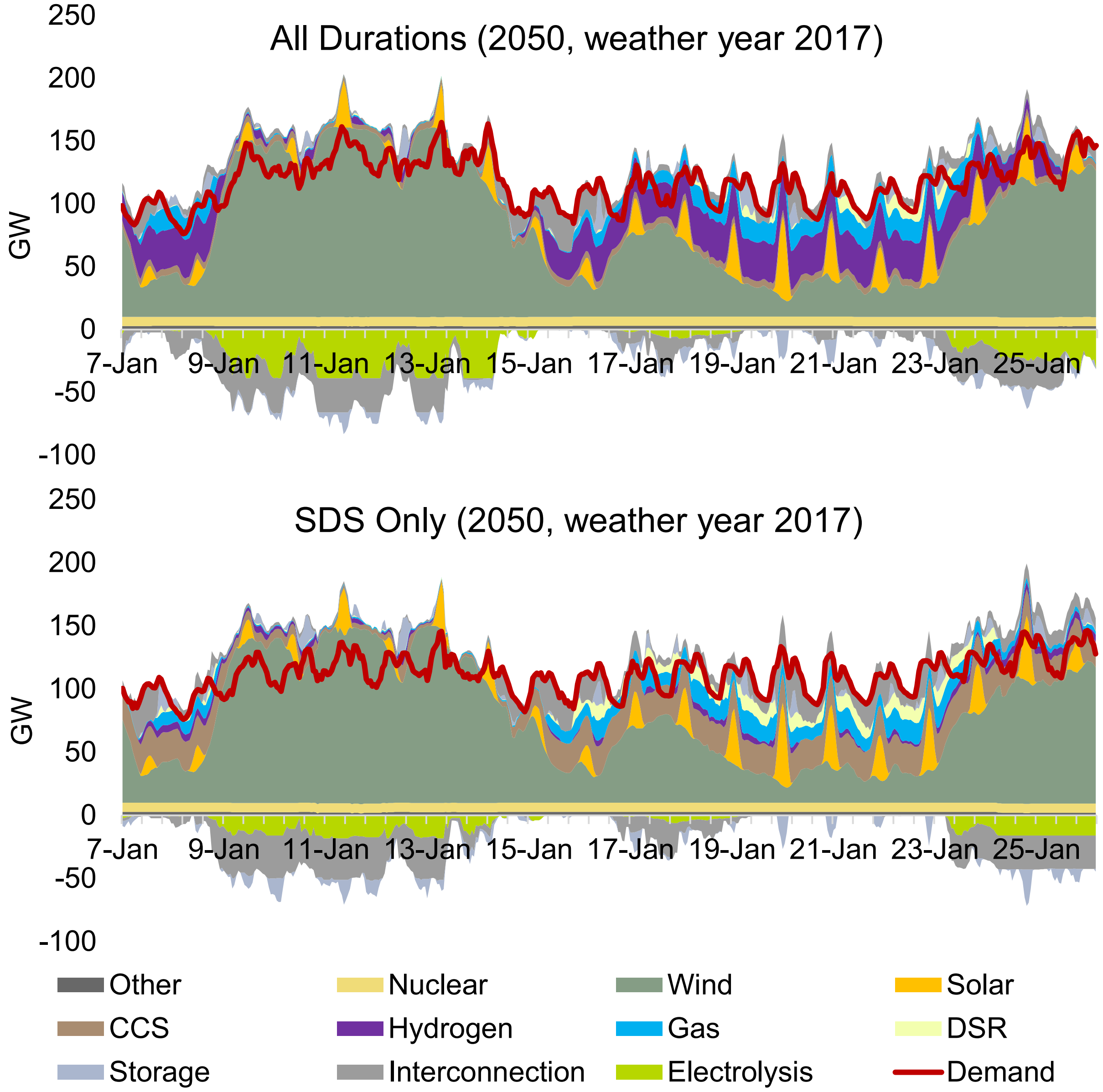
Notes: (1) Existing pumped storage capacity is assumed to be in the MDS category. In the SDS only case, this is the only MDS capacity. Whilst some existing pumped storage has longer than 12 hours duration, the aggregate of the existing pumped storage places it within the MDS category, and for simplicity, these plants are always presented in the MDS category, therefore. (2) The slight increase in SDS capacity in 2030 for the All durations case is due to other minor variations in the 2030 flexible capacity mix and also differences in the overall capacity mix in later years.

Significant SDS and MDS capacity is built in scenario #1. However, due to their limited duration of storage, they are restricted to providing short-term balancing. The inclusion of additional MDS capacity in the modelling of the All Durations case meant that less power storage capacity is built by 2050 in capacity terms. The MDS capacity was entirely 6-hour li-ion batteries and did not include any new storage of other technologies. On the one hand, this reflects the relatively low investment costs for these batteries, but on the other hand also reflects a need for some MDS capacity in the optimal 2050 capacity mix.

The presence of MDS and LDS didn't eliminate the need for flexible low carbon thermal generation. In both cases, around 40GW of dispatchable low carbon capacity was required to ensure security of supply in extended low wind periods. Where there is unabated gas, this was typically running at very low factors and the requirements for offsetting were covered by the presence of biomass with CCS generation.

The 'hourly snapshot' in Exhibit 5.5 illustrates the differing approaches to seasonal balancing in the All durations and SDS only cases by showing the hourly generation mix over a period with excess wind followed by a prolonged period of low wind output.

Exhibit 5.5 – Low wind period hourly generation, scenario #1 all durations vs SDS only 2050, weather year 2017 (GW)



In the All durations case, the production gap is primarily filled with generation from CCGT Hydrogen. Storage, DSR and interconnection also provide some balancing energy, but with comparatively lower volumes. By contrast, in the SDS only case this balancing energy is mostly provided by gas with CCS with a greater reliance on short duration storage and interconnection. Increased volumes of DSR also provide turn-down of consumption, from Industrial and Commercial consumers.[15]

Crucially, in both cases, dispatchable thermal capacity is required since significant volumes of sustained energy are needed to fill the production gaps.

[15] DSR was modelled as having fixed volumes available in both SDS Only and All durations cases. However, the utilisation was different, depending on the prevailing energy prices for a given modelled point of time in each scenario.

5.1.2 System Stability

In terms of the requirements for maintaining system stability, the various requirements from reserve, response and inertia are not big drivers of new power LDS in this scenario. Further details on the modelling of the range of system stability and ancillary services can be found in Annex D.

The analysis showed that across the range of system services considered, power LDS, while capable of providing the services, was not necessarily required to minimise system cost. This is because SDS and MDS li-ion battery solutions were generally more cost effective.

Modelled reserve and response services were dominated by SDS li-ion batteries with some MDS as well. The slower reserve services (such as STOR) continued to be supplied by peaking plants such as engines and OCGTs.

Inertia and voltage support are pressing challenges for the power system today, but therefore only present an opportunity to storage technologies in the shorter-term. The emergence of new, low-cost technological solutions on the grid today (batteries with grid forming capability, synchronous condensers, other inverter led voltage and inertia solutions) plus the emergence of significant DSR and fully merchant battery capacity (including in the MDS category) are likely to make ancillary service markets far more competitive than at present. It is not clear that MDS and LDS technologies will be required to fulfil ancillary service roles.

In summary, whilst MDS and LDS technologies help maintain system security, the modelling shows that there are other technologies that are potentially more suitable for these system services. MDS and LDS options may play a role but will have to compete against relatively low-cost alternatives, leading to a significant reduction in value of ancillary services for MDS and LDS compared to the situation today.

5.1.3 Locational Congestion

A renewables dependent system will result in a different distribution of generation and demand to today. This is likely to exacerbate locational constraints on the system. Locational constraints arise when the best renewable resources, especially wind, are located away from demand centres and insufficient transmission capacity is available. This was previously illustrated in Exhibit 3.7.

Power LDS and Hydrogen LDS are both candidate technologies for managing transmission network congestion. Both can soak up excess renewable power that would otherwise be curtailed. In this context, electrolysis and power LDS are competing technologies. This is true for Scotland, but other areas as well, wherever there is large wind resource potential, limited demand and limited existing network capability.

A further discussion of the modelling of transmission constraints can be found in Annex E.

In scenario #1, electrolysis and hydrogen storage were available as an alternative to transmission network reinforcement. Electrolysis supported by salt cavern storage can, based on the modelling assumptions, absorb excess wind for greater prolonged periods and was preferred in this scenario as a solution to network congestion management (alongside grid reinforcement). The resulting green hydrogen is available either for non-power sector use or can be distributed to hydrogen storage for future use in the power sector.

The model opted for hydrogen as the preferred solution as opposed to power MDS and LDS; the available durations of power MDS and LDS were not long enough to provide an economic alternative to a combination of transmission system reinforcement and hydrogen.

However, there are a number of key assumptions made in this context that should be borne in mind:

- Hydrogen transmission: Scenario #1 did not include any constraints on the distribution of hydrogen. The core scenarios have assumed that hydrogen transmission will develop to support non-power sector hydrogen. They further assume that power sector use of hydrogen will be possible such that there are no locational constraints on hydrogen, as can be achieved with the gas network today. This assumption, concerning hydrogen supporting infrastructure, was tested as part of the sensitivity analysis (sensitivities #5 and #6). If there is uncertainty over the ability to deploy electrolysis solutions then there is likely to be an additional need to deploy power LDS solutions and with limited sites, likely that this would be in Scotland; this is explored further in sensitivity #5.
- Locational price signals: It also assumed that storage (both power and hydrogen) would receive price signals to build in the right place from a constraint perspective. The scenarios show that locational considerations of hydrogen are significant, due to the benefit that can be raised through locating electrolysers in power flow constrained regions. It is unclear at present whether the price signals will develop in order to facilitate this outcome. The modelling here assumed that the system benefit of building power LDS or electrolysis in certain areas is sufficiently clear to the market.

5.2 Scenario #2: lower electrification leads to a similar mix of system balancing

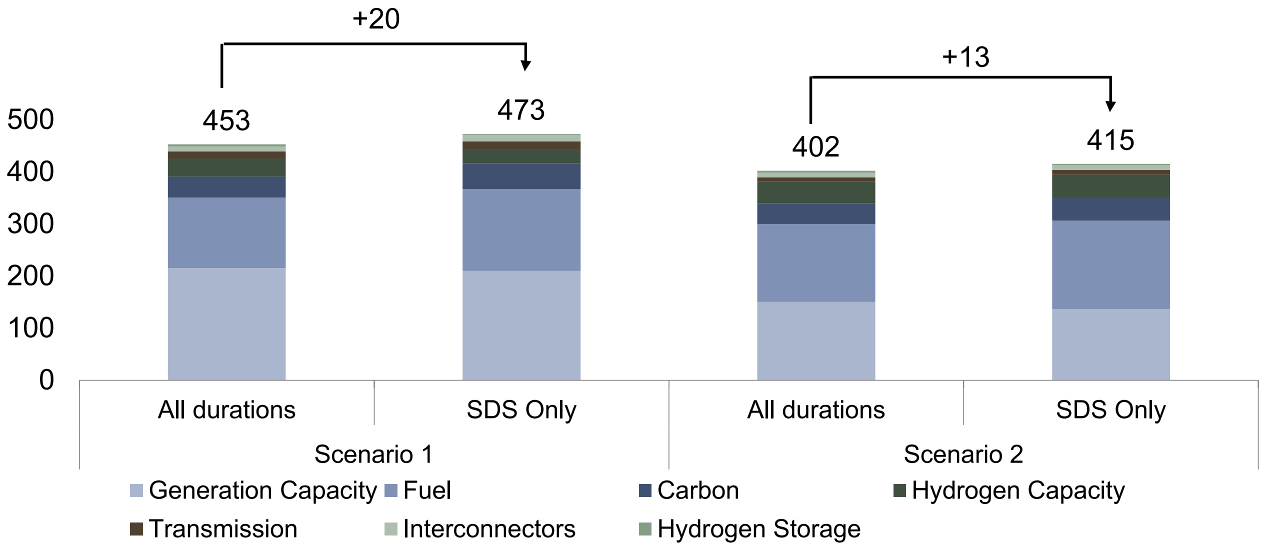
The modelling of scenario #2, in which power demand is lower and hydrogen demand higher than in scenario #1, leads to a similar optimal capacity mix and the same approach to seasonal balancing. No additional power LDS is built, with balancing energy primarily provided by hydrogen CCGTs in the All durations case and by gas with CCS in the SDS only case.

Both scenario #1 and #2 have significant system cost reductions in the All durations case, however this saving is lower in scenario #2, as shown in Exhibit 5.6.

LDS and MDS deliver savings with a 2030 NPV of £20bn in scenario #1, primarily through more optimal use of low carbon power capacity and corresponding reduction in gas usage.

In the higher H2 demand scenario, LDS and MDS deliver system cost benefits with a 2030 NPV of £13bn. Again, reduced gas usage is the main cost saving, particularly in hydrogen production.

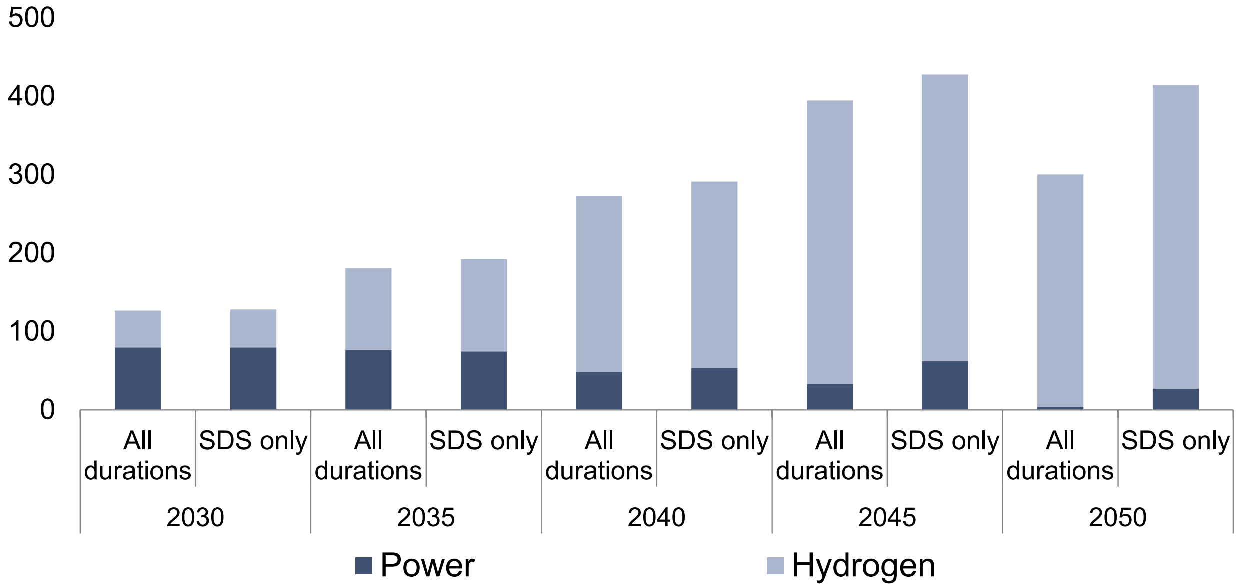
Exhibit 5.6 – Total system costs, scenario #1 and scenario #2 (£bn 2030 NPV)



Note: Whilst the NPV of system costs are lower in scenario #2 overall, this does not imply that the costs of net zero are lower in this scenario, since the costs of converting the end use of energy in heat and transport (to either use power or hydrogen) are not considered here.

From this comparison of system costs in the first two scenarios, one of the key benefits of MDS and LDS is to reduce fuel and carbon costs. This emerges because there is lower use of gas, as shown in Exhibit 5.7. The presence of longer duration storage reduces the use of gas in gas with CCS, in the production of hydrogen (from blue hydrogen sources) and in peaking gas generation. The difference in 2050 is over 100TWh of gas consumption.

Exhibit 5.7 – Change in gas consumption due to introduction of MDS and LDS in scenario #2 (TWh)



Notes: Power sector gas use includes CCGT, gas with CCS, CHP and gas peaking capacity. Hydrogen sector gas use includes blue hydrogen production (SMR with CCS and ATR with CCS). Hydrogen demand in this scenario is much higher than in scenario #1 due to increased prevalence of hydrogen for heating and transport.

The reduction in power sector gas use comes from avoided gas with CCS generation and faster retirement of existing gas generation. In the hydrogen sector, the presence of LDS facilitates greater electrolysis and reduced blue hydrogen.

To test the extent to which this benefit is sensitive to variations in weather, a sensitivity was run including more variation in the weather patterns. This is shown in Section 5.7.

5.3 Scenario #3: policies that support and de-risk longer duration power storage improved competitiveness and led to a further 5.5GW of new MDS and LDS capacity compared to scenario #1

In scenario #3, support for investments means that the optimal build in the model incorporates 2.6GW of new power LDS and 14.6GW of new MDS capacity. As shown in Exhibit 5.8, most of the investment into power LDS capacity happens pre-2040, prior to the establishment of a large hydrogen sector.

Of the MDS capacity increase, the majority of this came from longer duration li-ion batteries. However, some other novel technologies (incl. CAES and LAES) were built; this was around 5GW of the additional MDS.

Although there is an increase of MDS and LDS compared scenario #1, this additional power LDS volume displaces SDS capacity. Additionally, much of the MDS would have been built without any support, so the net increase in storage is 2.5GW overall (5.5GW additional MDS and LDS, but 3GW less SDS).

Exhibit 5.8 – Power storage capacity, scenario #1 vs scenario #3, all durations (GW)

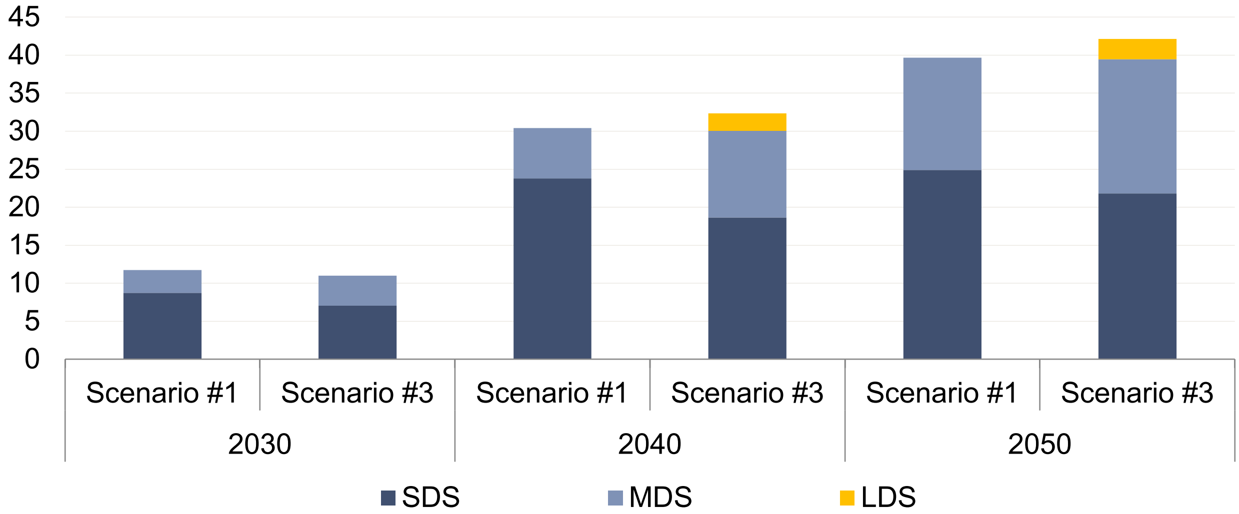
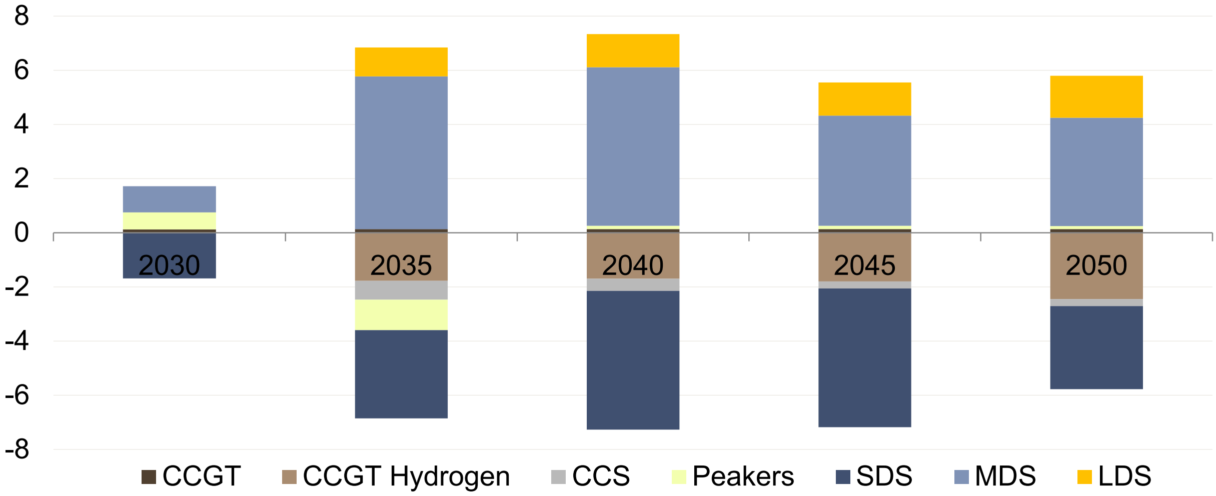


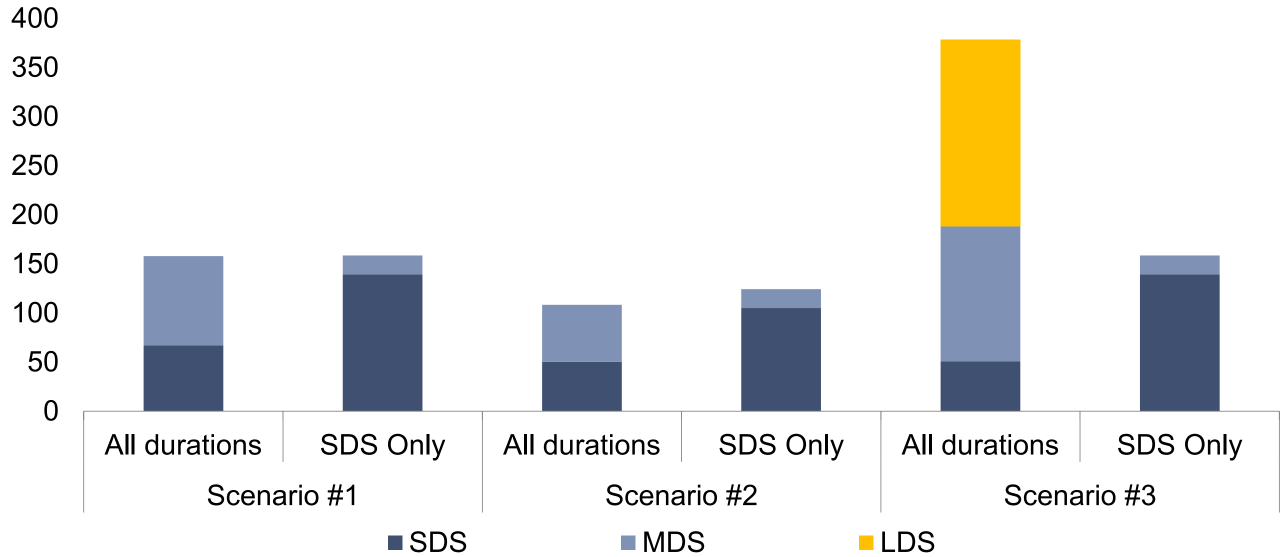
Exhibit 5.9 shows that as well as a reduction of 3GW of SDS, 2.5GW of hydrogen CCGT are also displaced by 2050. Hydrogen CCGTs are still built to 25.5GW compared to 28.6GW in scenario #1. Even with investment support in place, in this scenario, it is still more expensive to fill the largest production gaps with power LDS than with dispatchable hydrogen.

Exhibit 5.9 – Difference in flexible capacity, scenario #3 - scenario #1, All durations (GW)



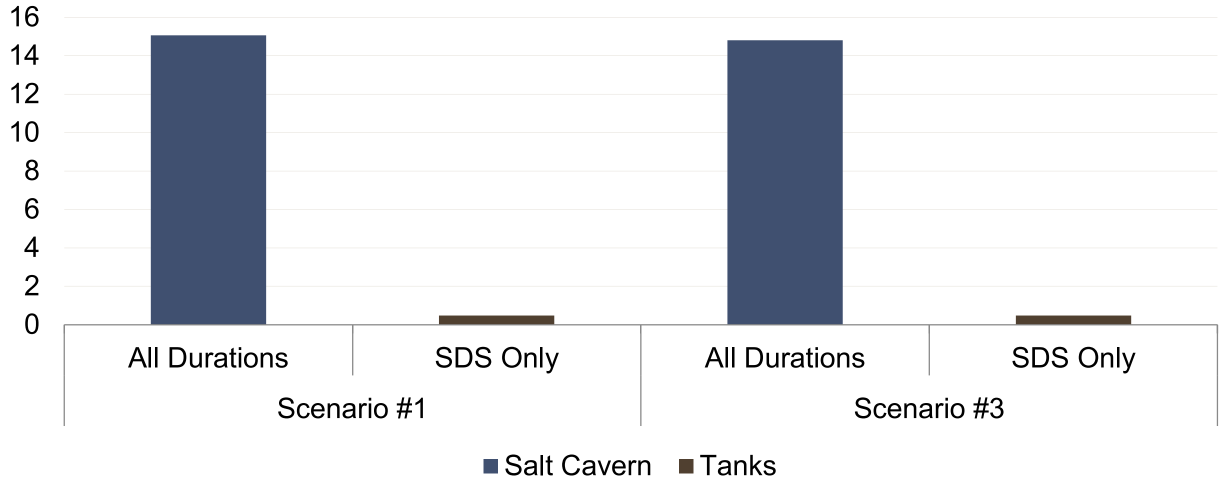
While supporting power LDS does enable some build, the impact is mostly clearly seen on the storage volumes. There is over twice the volume of storage in scenario #3 than in any other scenario, as shown in Exhibit 5.10.

Exhibit 5.10 – Power storage volume, excluding hydrogen, 2050 (GWh)



As shown in Exhibit 5.11, the modelling did not produce a significant reduction in hydrogen storage volume even though hydrogen CCGT capacity is reduced. This shows that, while electrolysers and hydrogen storage do provide flexibility for the power sector, they could also have a crucial role in providing hydrogen to the non-power sector. Where hydrogen is deployed in the future economy is uncertain and could limit the potential availability for use in the power sector. However, if a significant hydrogen sector develops, then this electrolysis capacity is liable to be built regardless of system needs of the power sector. The nature of hydrogen demand modelled here was such that hydrogen LDS was required to integrate the electrolysis.

Exhibit 5.11 – Hydrogen storage volume, scenario #1 vs scenario #3 2050 (TWh)



This has a knock effect on LDS as well, due to the function of electrolysis to reduce power sector volatility. Very little power LDS capacity was built by the model in scenario #3 post 2040, corresponding with the emergence of the hydrogen sector.

5.3.1 Impact of LDS on transmission constraints in scenario #3

As shown in Exhibit 5.12, electrolysers in the modelling are mostly built in Scotland, close to significant wind capacity. Power MDS and LDS build is more spread out across GB. This is partly because of the geographical constraints of some forms of power storage, but also partly because in the modelling, it is crowded out by hydrogen. MDS options also tend to be built close to the solar PV capacity.

Exhibit 5.13 illustrates this further, showing that cost optimal levels of renewable curtailment are consistently in the range of 15 to 25TWh over the period 2035 to 2050, based on the costs of reinforcement assumed here.

Under scenario #3 (with supported power MDS and LDS) the inclusion of the net additional 5.5GW of power MDS and LDS results in a 20% reduction in renewable curtailment volumes from 2035 onwards (compared to scenario #1).

Exhibit 5.12 – Scenario #3, All durations, capacities for electrolysis and power LDS in 2050, split by location (GW)

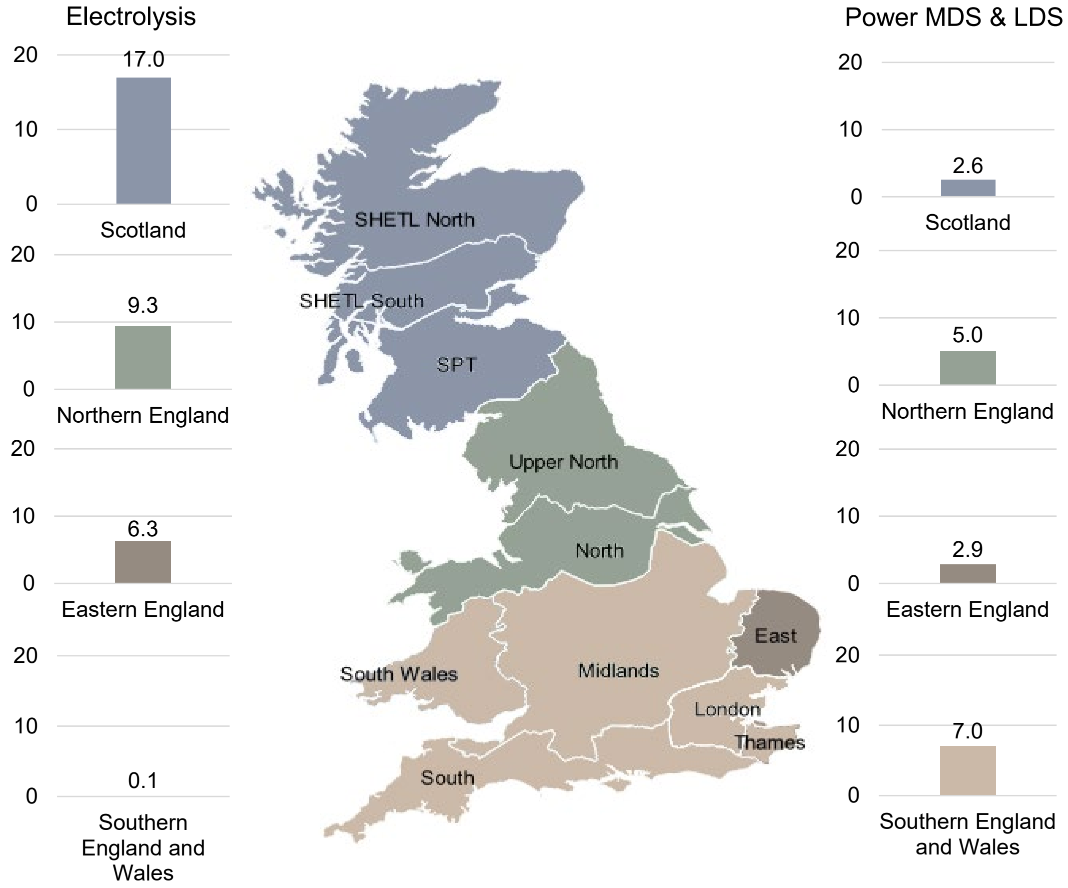
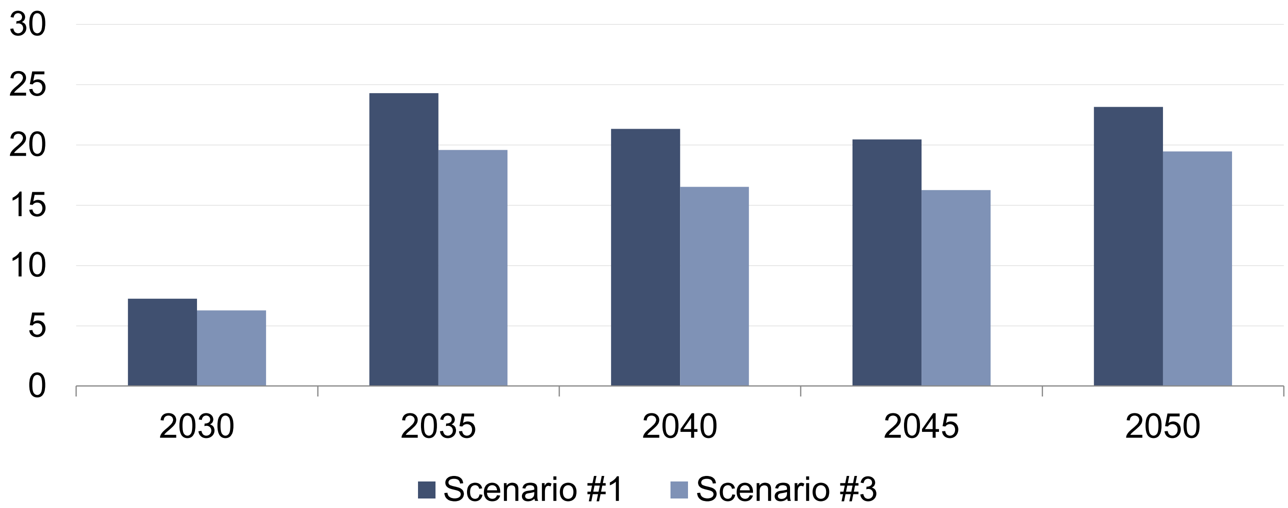


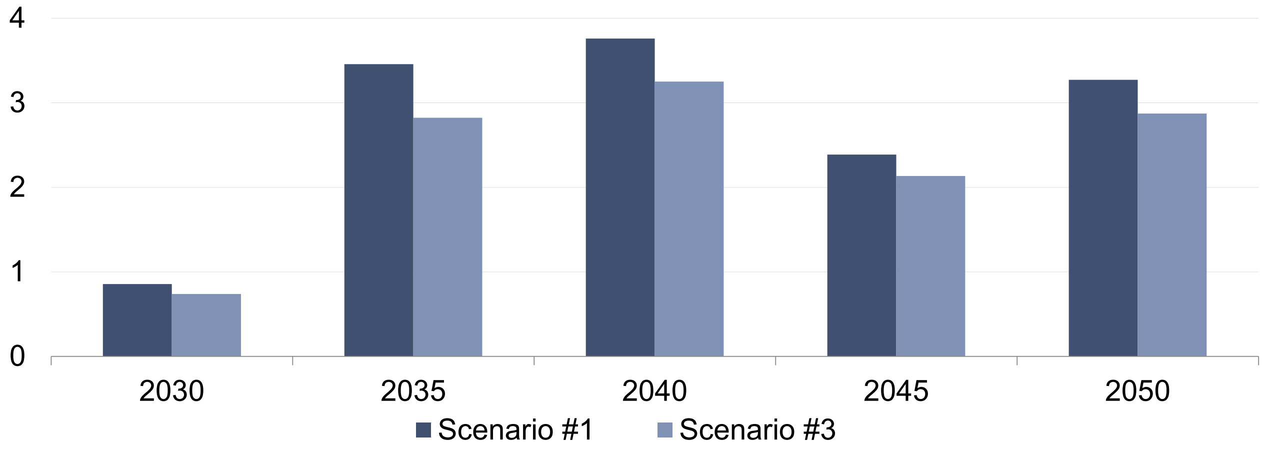
Exhibit 5.13 – Levels of annual renewable curtailment for scenario #1 and #3, all durations (TWh)



Note: 2030 has lower values due to the assumption that network reinforcements currently planned are included in the base network. These levels of curtailment are significantly higher than the current 1-2TWh per year but come at much lower cost due to the assumption that post-subsidy renewables are curtailed at 0£/MWh, as opposed to the opportunity cost of the relevant subsidy.

Furthermore, Exhibit 5.14 below shows that this is also achieved along with a slight reduction in network reinforcement costs. Network reinforcement was also optimised in each scenario and sensitivity, and costs are broadly similar despite differing levels of power LDS.

Exhibit 5.14 – Annual transmission network capex costs for scenario #1 and #3, all durations (£bn)[16]



Despite the additional power LDS, significant new network capacity is still required. Without the network capacity, the ability of the storage to discharge could be limited behind constraints. With additional MDS and LDS coming online behind constraints in 2035-2040, network spend was slightly reduced, but at a similar overall level, in order to prevent this storage being sterilised behind constraints.

This shows that the role of power LDS is not solely as an alternative to network reinforcement. While power LDS can mitigate some of the curtailment that would otherwise occur, it does not necessarily lead to a significant amount of avoided network capex. As in scenario #1, the durations of constraint events are expected to increase beyond the duration of many technology options.

The longer duration constraint events, therefore, will require new network investment (either power or hydrogen). This is born out in the preference seen in the modelling for locating electrolysis behind key power transmission constraints.

The modelling here demonstrates that hydrogen and power transmission network reinforcement need to be considered together. Investment may be in hydrogen infrastructure as opposed to electricity (i.e., there will be a need to consider this from a whole systems perspective).

[16] 2030 values are lower as the necessary reinforcement associated with the currently planned projects is included. The projects marked to proceed from the NG ESO NOA 2021 process are included as a base line network capability across all scenarios.

However, even in a scenario where a hydrogen transmission network is a given, there can still be a role for power LDS.

- Power LDS can help manage the residual constraint volumes, complementing optimal network reinforcement levels. Power LDS will also help reduce transmission constraints in periods where constraint durations are lower. This enables some use of excess renewable generation, making this power available subsequently. The stored power from the avoided curtailment can then be used in place of running other (potentially emitting thermal) generation in subsequent periods, after wind output has fallen and the network is no longer congested.
- Transmission network reinforcement projects are large infrastructure projects that take many years to realise. Having access to storage behind transmission constraints can help store residual renewable excess output prior to reinforcement.

Research question: What are the possible operating regimes for long duration technologies in the scenarios?

Power LDS solutions are relatively capital intensive and are likely to be relatively cost uncompetitive unless they are able to achieve high levels of cycling. Without significant value from providing stability services, it will be important for Power LDS to be deployed such that high utilisation is possible.

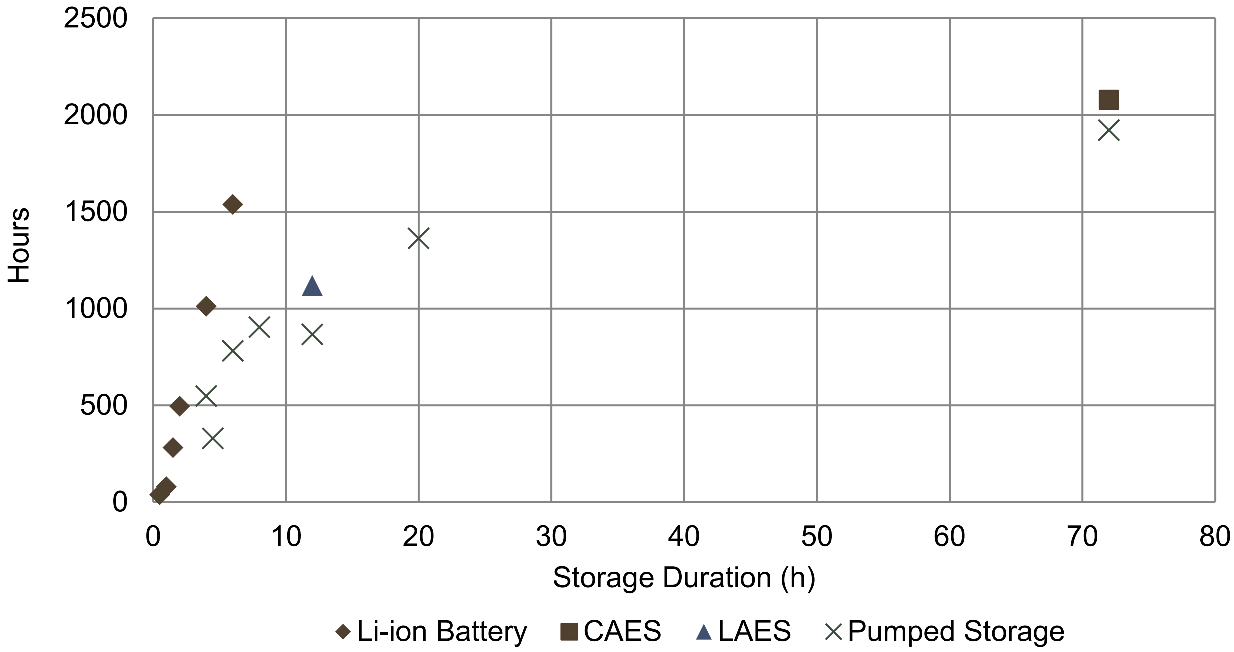
However, with such significant volumes of electrolysis on the system in the modelled scenarios #1-3, it is less likely that power LDS can achieve such high cycling levels. This is shown in Exhibit 5.16, where the relatively lower cycling rates for the longest LDS options are shown compared to the cycling rates of the SDS and MDS options for scenario #3.

This also reveals that there are some basic flexibility needs on the system that create synergies with SDS and MDS options. In particular, short-term balancing and integration of daily peaks of solar PV output are key for driving the relatively higher levels of cycling achieved by the SDS and MDS options.

The system also requires substantial new investment in SDS and MDS, used primarily to provide the balancing required over shorter time frames. Given the available technology choices, battery storage solutions are the most cost-effective options for meeting this requirement.

System services are primarily provided by SDS and peakers for response and reserve. Inertia is provided by a combination of dedicated inertia providing technologies and baseload low carbon. System stability services were not a driver of new LDS, therefore.

Exhibit 5.15 – Average modelled output hours in 2050 for different storage technologies, as a function of storage hours, scenario 3 all durations.



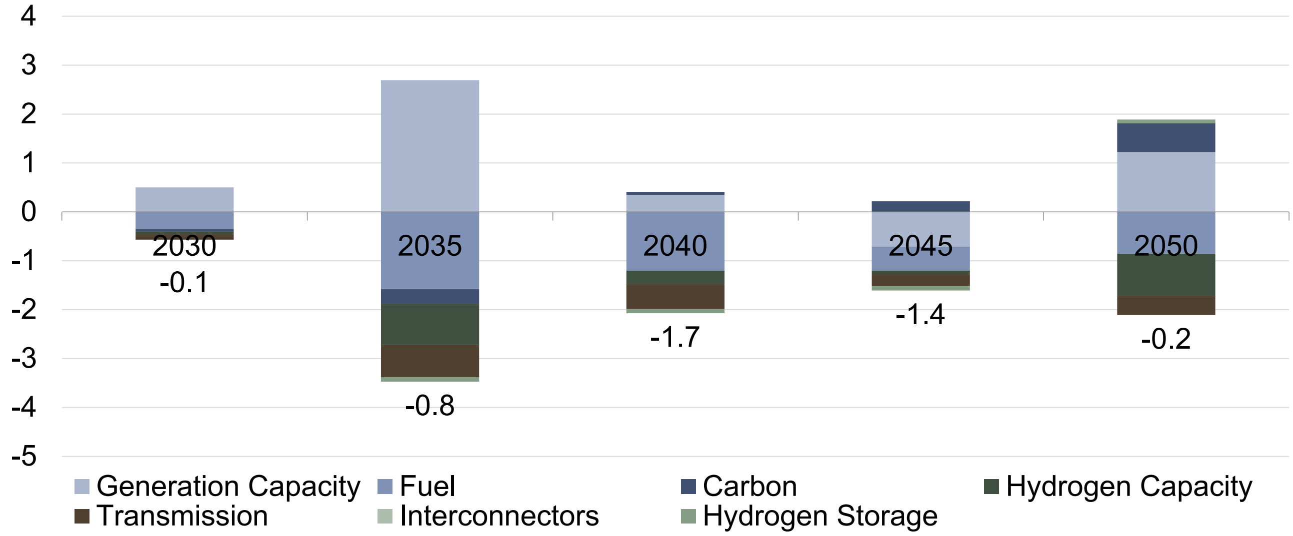
Note: Relatively lower cycling rates for Pumped storage reflect its location behind transmission constraints. The value of absorbing excess renewable output is high, but due to the long duration of constraints, serves to reduce overall cycling rates compared to other technologies. Provision of significant reserve services also has a similar impact on some pumped storage units.

Research question: How does the system impact of long duration storage change over time (2030-50)?

Exhibit 5.17 shows a comparison between the undiscounted system costs for Scenario #3 and Scenario #1, for the versions including LDS options. By supporting power LDS, there is a further reduction in system costs from 2035 to 2045. However, by 2050 this system benefit is no greater than in scenario #1.

In scenario #3, hydrogen is still the most cost-efficient means of providing LDS, especially in 2050. However, there is a reduction in system costs achieved through the support offered to LDS between 2035 and 2045.

Exhibit 5.16 – Undiscounted system costs difference, scenario #3 – scenario #1 all durations (£bn)

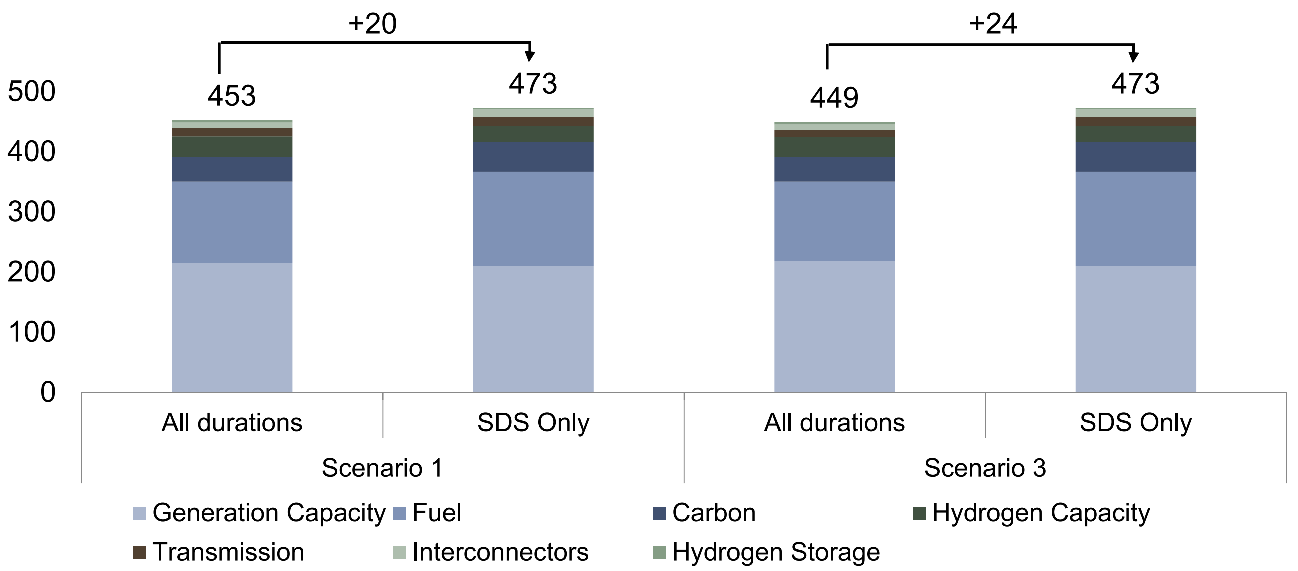


Note: System costs do not include the cost of supporting the LDS technologies

5.3.2 Impact of support for power LDS compared to scenario #1

LDS delivered system cost savings with a NPV of £24bn in scenario #3, as shown in Exhibit 5.17. By reducing the capex and hurdle rates of power LDS, £4bn of additional costs savings are achieved in scenario #3 when compared against scenario #1. Without these capex reductions, the benefit would have been reduced by £1bn to an additional saving of £3bn compared to scenario #1. The cost associated with delivering the reduction in hurdle rates is not factored into this assessment. There was no modelling of a reduction in costs for other technologies.

Exhibit 5.17 – Total system costs, scenario #1 and scenario #3 (£bn 2030 NPV)



5.4 Sensitivity modelling introduction

In scenarios #1 and #2, there was no power LDS deployed. The power MDS deployed was exclusively 6hr li-ion batteries. Scenario #3 included other power MDS and LDS capacity. From these results, it is apparent that there is a benefit to bringing forward more MDS and LDS technologies. In particular, where there are cost reductions included for power MDS and LDS technologies, in scenario #3, there are larger benefits.

The first sensitivity considered, therefore, tests what happens to system costs when even larger volumes of power MDS and LDS are brought forward. This is shown in Section 5.5.

The system cost results of the core scenarios are all dependent on a particular set of technology costs and deployment availability assumptions. The technology risk sensitivities are designed to test these. The aim is to see whether some of the more established technologies in the power MDS and LDS categories can mitigate the risks associated with the lesser established and emerging technology options.

Key results from the sensitivities are presented in Sections 5.5 to 5.6. More detail sensitivity results are present in Annex F.

5.5 Sensitivity A: deploying power MDS and LDS capacity reduces the need for SDS capacity, can deliver larger storage volumes more efficiently but there is a limit to system cost benefits.

In this sensitivity, 10GW of power LDS and 5GW of MDS capacity was imposed on the model as an input, rather than optimised by the model. The minimum 5GW of MDS included technologies other than 6-hour li-ion batteries (which were already built in scenario #1). Since no power LDS (only hydrogen LDS) was built in the optimal capacity mix of scenario #1, this sensitivity was designed to test what would happen if LDS capacity was forced on. Investment costs and hurdle rates for storage were the same as in the scenario #1.

This resulted in £4bn of additional system costs compared to the All durations version of scenario #1. This reduced the benefit of MDS and LDS to £16bn, compared to the SDS only variant of scenario #1. The additional costs emerge for two reasons:

- There was some inefficiency in the timing and location of the LDS capacity forced in; and
- The capex used for this sensitivity was higher than in scenario #3, with support for LDS technologies.

With higher power LDS capacity, the storage volumes achieved from power storage were much higher in this sensitivity. Despite some inefficiency in the timing and location of the LDS capacity deployed, this benefit to the system ensured that the deployment of the power LDS was a relatively low regret decision.

Research question: What is the impact of long duration storage on other technology types?

As shown in Exhibit 5.19, the main impact of adding this power LDS capacity was to reduce other flexible capacity by an equivalent amount. Most of the capacity reductions come from SDS, MDS and CCGT hydrogen. The imposed MDS and LDS resulted in an overall reduction in MDS capacity, due to fewer 6-hour li-ion batteries being built.

Despite the reduction in hydrogen CCGT capacity, 25GW is still built by the model in this sensitivity. This technology still formed a key portion of the flexible capacity in this scenario. Flexible low carbon thermal power remained cost effective for meeting demand in extended low wind periods.

Introducing more MDS and LDS in the modelling reduces the frequency of low power price periods and has a knock-on effect of reducing green hydrogen capacity, as shown in Exhibit 5.20.

The additional power storage acts to soak up excess renewable output, especially in periods of high wind & solar generation and low demand, in turn reducing the ability of electrolysis to access low-cost power. This highlights that electrolysis and power LDS are competing technologies from a power sector perspective, both aiming to access low and zero power prices.

Exhibit 5.18 – Change in power generation capacity, sensitivity B more power LDS – scenario #1, all durations (GW)

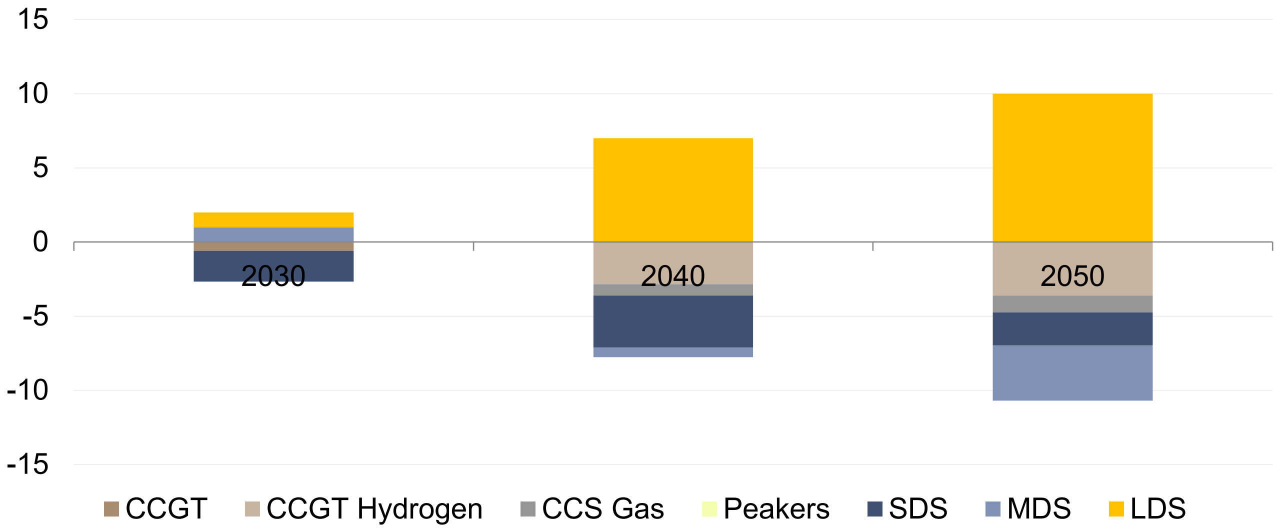
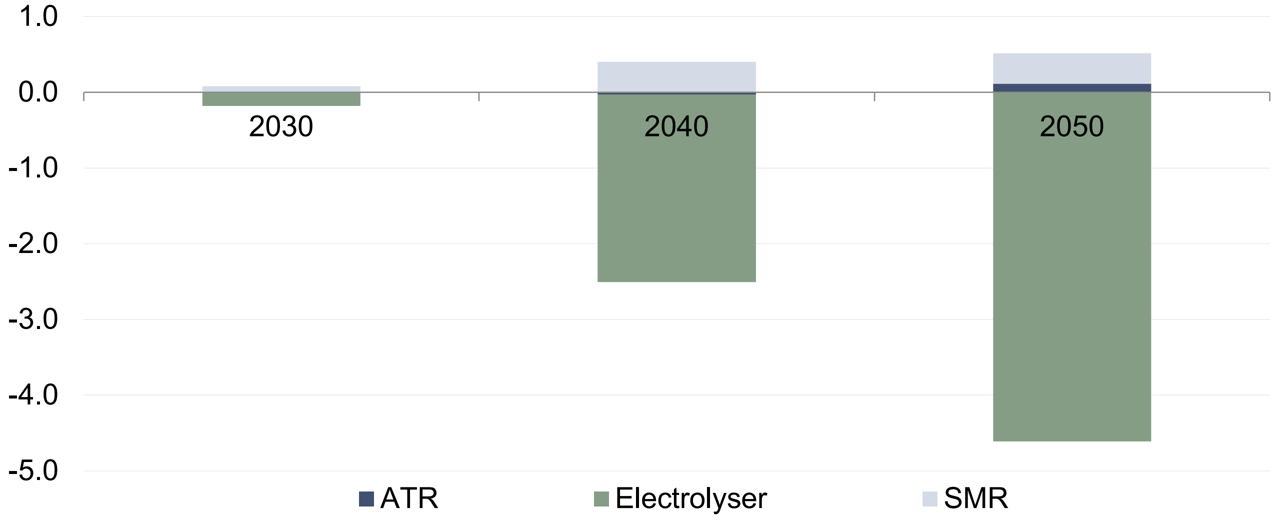


Exhibit 5.19 – Change in hydrogen production capacity, more power LDS sensitivity – scenario #1 all durations (GW)



5.6 Other wider power system sensitivities

Sensitivities were also modelled to test the effect of other technologies on the role and operation of LDS. In most cases this involved the introduction of non-optimised capacity imposed on the model. Further details of these sensitivities are available in Annex F.

Sensitivities #B, #C and #D explored 3 uncertainties from the core scenarios. The sensitivities explored to extent to which DSR is a direct competitor with power LDS, whether supporting interconnection through cap and floor is reducing the need for LDS, and whether more nuclear would lead to more inflexibility that increases the need for LDS.

The sensitivities examined reasonable bounds on these areas of the scenario design. The results show that support to encourage deployment of DSR or interconnection do not materially impact the need for power LDS. Increased nuclear capacity was also not a driver of increased LDS.

Sensitivity #E explored uncertainties around the extent to which carbon prices may drive additional power LDS investment. Less power LDS is built by the model compared to scenario #3. Tighter emissions limits and higher carbon prices are required for power LDS to be cost competitive with more traditional forms of energy balancing. However, the decision to support power LDS does not lead to significant regret if overall power system emissions reductions are slow to be achieved.

5.7 Technology risk sensitivities

In the core modelled scenarios, hydrogen storage plays a major role in balancing the power system. Power MDS and LDS do play a role, but the vast majority of the storage volumes are from hydrogen storage. However, there are number of key risks around the development of hydrogen LDS, and it is uncertain whether the potential benefits can be realised. Doing so requires the following:

- Investment in new salt cavern storage for the hydrogen sector, when GB natural gas storage has remained relatively low.
- Development of CCS to facilitate production of blue hydrogen from AMR/ATR with CCS.
- Development of hydrogen pipeline transmission network to connect up geographically diverse electrolysis capacity with both storage locations and end-user demand.

Each of these points are also subject to cost risks as well as the technology risks.

Given the current lack of maturity of these technologies and the challenges of developing the transportation and storage system, the modelling considered how several risks would affect the system via 6 key technology risk sensitivities.

5.7.1 Technology sensitivity #1 – power MDS and LDS solutions can help mitigate the risks associated with emerging technologies

Sensitivity #1 models a combination of technology risks: a limit on CCS technologies in the model (2GW gas with CCS and 10GW blue hydrogen production), making salt cavern storage harder and more expensive to build and modelling hydrogen zones alongside the cost of developing hydrogen transmission capacity. The NPV of system costs were as follows:

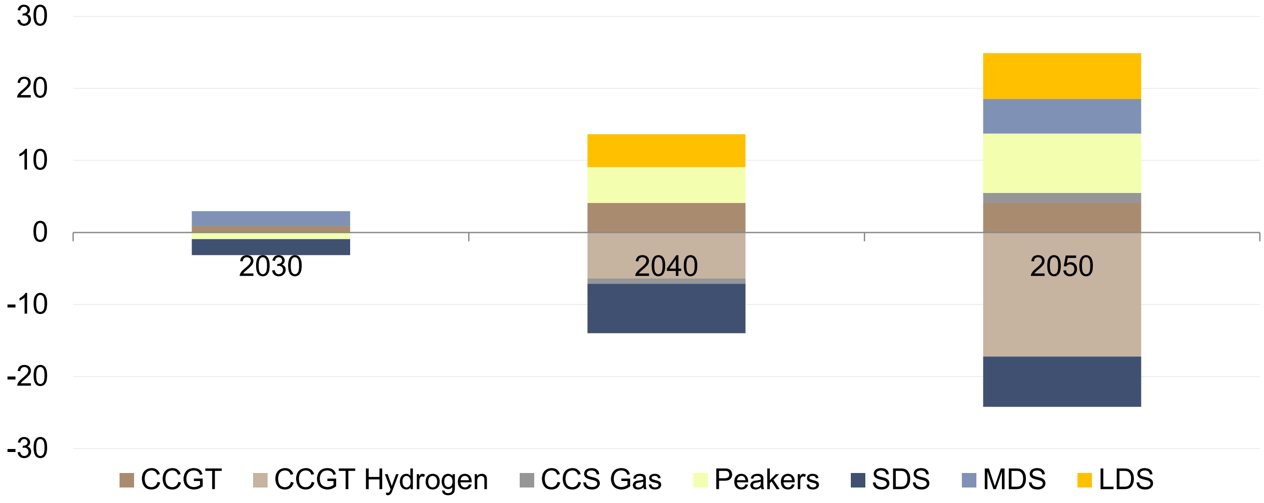
- Technology risk of all durations: £469bn.
- Technology risk with SDS only: £504bn[17], leading to a system cost benefit of £35bn for this sensitivity.

The main savings were achieved by the system being able to access salt cavern storage of hydrogen, despite these being more expensive that in the core scenario, rather than relying on hydrogen tank storage. This also led to savings from deployment of hydrogen fuelled plants.

As shown in Exhibit 5.20, the model reduced hydrogen CCGT capacity significantly, with 6.4GW of new power LDS in its place. This resulted from the hydrogen LDS being more expensive. 2.6GW of extra power MDS, peakers (primarily GTs) and some CCGTs were also brought forward as replacement capacity. The low load factors of the unabated gas ensured carbon limits were still kept. SDS capacity is reduced as this additional LDS capacity can also provide daily cycling and fast response flexibility.

[17] These calculations were done via a high level analysis of investment costs and system requirements, rather than a full modelling analysis with BID3

Exhibit 5.20 – Difference in flexible capacity, sensitivity #1 - scenario #1 all durations (GW)



Since salt caverns were much more expensive, and the costs of hydrogen transmission were fully included, the model minimised hydrogen demand. This meant avoiding additional power sector demand where alternatives to hydrogen-fired power generation exist.

Instead of blue hydrogen, electrolysis is required to meet both non-power sector hydrogen demand. However, due to the cost of storing hydrogen, the model avoids coupling this with hydrogen CCGT generation. The gap in supply previously met by hydrogen CCGTs is now partially met by power LDS, where possible.

5.7.2 Technology sensitivity #2 – storage technologies can help reduce technology risks during low wind periods

In the event of a prolonged lower wind output period, different technologies offer different levels of security of supply, as shown in Exhibit 5.21.

The benefit of power MDS and LDS is that it does not require as much supporting infrastructure as other fuelled technologies. However, it is less useful for extremely prolonged wind drought events.

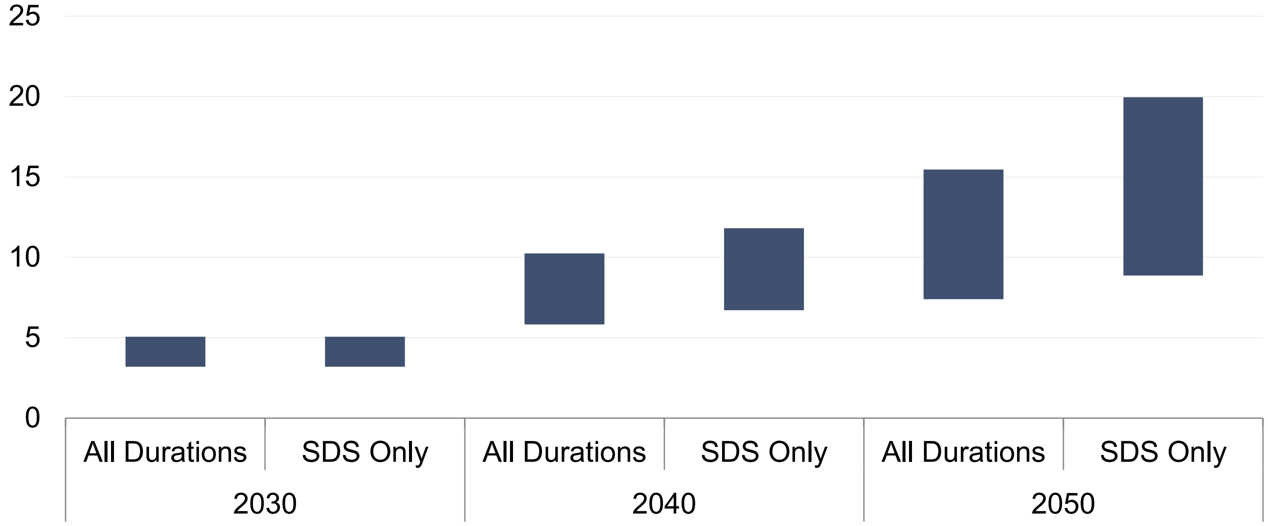
Each scenario and sensitivity were run using weather patterns from 5 years, which were chosen to capture a reasonable range of weather patterns. In this sensitivity, the system dispatch model was rerun using all weather patterns from 2009 to 2019 to explore the impacts of more extreme weather on the system. This includes 2010, which is assessed to be the most extreme year for high demand and low wind output based on analysis of 30 years of weather data.

Exhibit 5.22 shows the range in fuel costs across these weather years in the All durations case against a case with SDS only. It can be seen that in cases with SDS only, the system was more susceptible to high fuel costs from extreme weather. Periods of very low wind output are liable to result in high gas consumption; MDS and LDS help reduce the reliance on gas in more extreme weather periods.

Exhibit 5.21 – Technology security of supply contributions in low wind periods

Technology class	Benefits	Risk factors
Unabated gas	Firm capacity available to meet demand for extended periods	Produces emissions Requires gas availability and a supporting gas network Risk of some generator forced outages
Gas with CCS	Low carbon firm capacity available to meet demand for extended periods	Requires gas availability and a supporting gas network Requires a CO2 network and sufficient storage capacity Risk of some generator forced outages
Hydrogen fuelled generation	Low carbon firm capacity available to meet demand for extended periods	Requires hydrogen to be available on demand. Requires either: (i) on demand blue hydrogen production, and therefore a supporting gas network, CO2 transportation and storage; or (ii) a supporting hydrogen network and access to long duration hydrogen storage Risk of some generator forced outages
Nuclear	Low carbon firm capacity available to meet demand for extended periods	Risk of generator forced outages less frequent but more material than for other technology classes, due to typically long outage durations for nuclear power stations
Power MDS and LDS	Capacity available to the extent that storage durations map onto wind drought durations	Likelihood that many options have storage durations that only provide limited security of supply

Exhibit 5.22 – Range in fuel costs, sensitivity #2, 2009 – 2019 weather patterns, all durations vs SDS only (£bn)



In this scenario, the presence of hydrogen salt cavern storage ensured that the system is less exposed to high gas costs in extended low wind periods. However, this requires that the associated infrastructure of hydrogen transmission and storage is strategically dimensioned to cope with the extended wind drought. This infrastructure is required such that hydrogen CCGT capacity can continue generating through these periods, in a similar way that the gas network allows unabated gas to operate at present. A low regret decision would be to over-size seasonal hydrogen storage, with some utilised at a low rate of cycling. Adding 5TWh additional working volume of hydrogen storage at a capex cost of £2.5bn would give significant extra resilience to the system and help reduce reliance on gas generators for security of supply.

Some of the power LDS and MDS options do offer additional security of supply, but their benefit to the system can be limited in the more extreme weather events. This is further discussed in Annex C, which examines the role of storage in extreme weather periods.

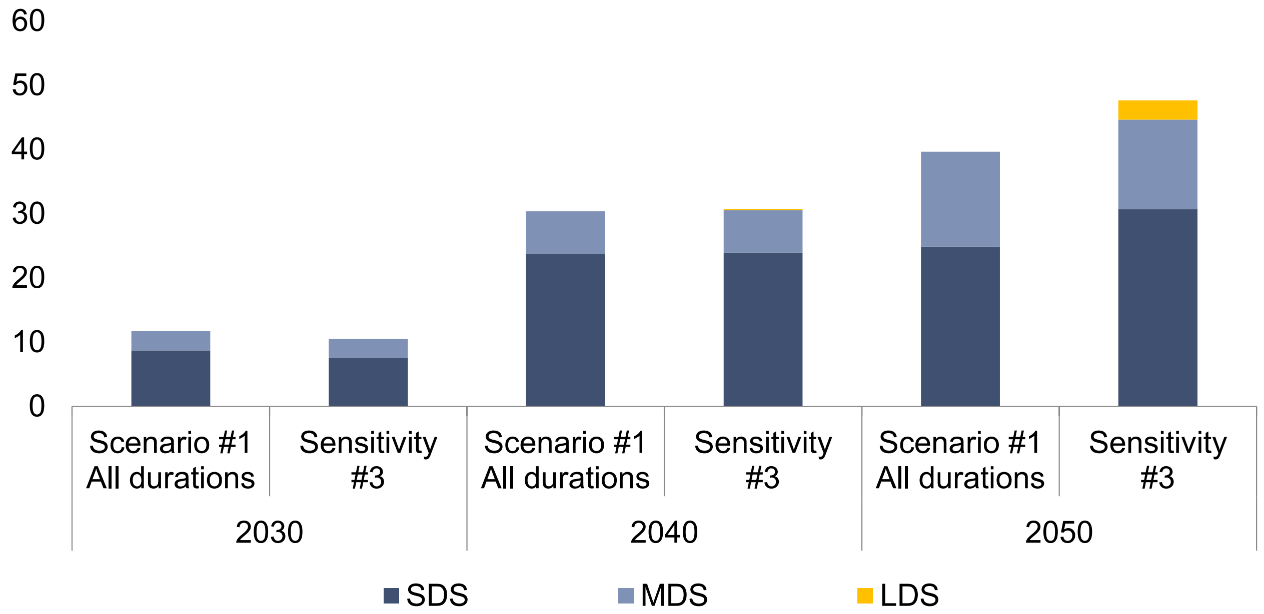
This sensitivity only considered the variation in demand and intermittent output in differing weather events. No changes to gas prices were considered, which would potentially be a further driver of higher costs, were gas demand to be higher for longer due to extended low wind output.

5.7.3 Technology sensitivity #3 – no access to long term salt cavern hydrogen storage makes gas with CCS preferable to hydrogen fuelled generation and increases the need for power storage

Technology sensitivity #3 modelled a case where salt cavern storage of hydrogen proves impossible to bring forward. Without the hydrogen LDS, the less flexible hydrogen sector largely only retains blue hydrogen to meet non-power sector demand. Electrolysis becomes less profitable as green hydrogen is harder to store. Gas with CCS is relied on instead of Hydrogen CCGTs for seasonal balancing.

A limited volume of 3GW more power LDS is also built in the absence of salt cavern storage. The reduction in electrolysis capacity meant that some power LDS is needed to manage variation in residual demand.

Exhibit 5.23 – GB power storage capacity, scenario #1 vs sensitivity #3 (GW)



5.7.4 Technology sensitivity #4 – reduced blue hydrogen capacity leads to increased electrolysis, which is deployed in preference to power LDS technologies.

In sensitivity #4, blue hydrogen production capacity was limited in the model to 10GW. The NPV of system costs benefit from MDS and LDS was £27bn for this sensitivity.

As in the core scenarios, the main savings were achieved by the system being able to access salt cavern storage of hydrogen, rather than relying on hydrogen tank storage.

More electrolysis is built to meet the demand for hydrogen compared to scenario #1. Electrolysis and power LDS are again in competition for low power prices, and, in this sensitivity, flexibility is already available from green hydrogen production. This electrolysis flattens the volatility of power generation, removing the need for power LDS to balance supply and demand.

5.7.5 Technology sensitivity #5 – excluding the transmission of hydrogen between zones reduces the benefit that hydrogen storage can bring to the power sector

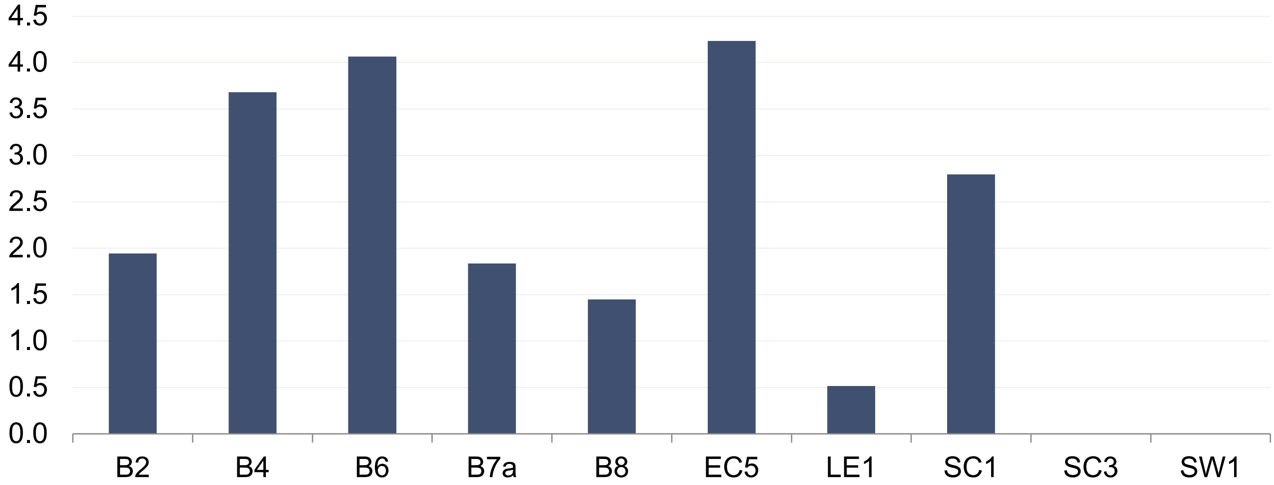
Sensitivity #5 introduced the modelling of hydrogen transmission limits. This was done through modelling hydrogen zones, with no option to build hydrogen pipelines between zones. The inability to transport hydrogen meant that hydrogen must be produced in the same zone that it was consumed.

Similar quantities of hydrogen are required by the power sector, and also passed through the salt cavern storages. However, the wider system benefits are diminished as additional power transmission is required. System costs were £11bn lower in the all durations case than in the SDS only case.

However, no power MDS or LDS was additionally built behind the constraints that were most congested.

Exhibit 5.24 shows the additional power network capacity required in the absence of hydrogen transmission. A further 4GW increase across the B6 boundary by 2050 is required, roughly equal to two further offshore HVDC cables.

Exhibit 5.24 – Extra power network capacity required by 2050, sensitivity #5 (without hydrogen transmission capability) – scenario #1 2050 (GW)



5.7.6 Technology sensitivity #6 – introducing costs for the development of a new hydrogen transmission system leads to trade-offs between hydrogen transmission costs and benefits to the power sector from hydrogen storage

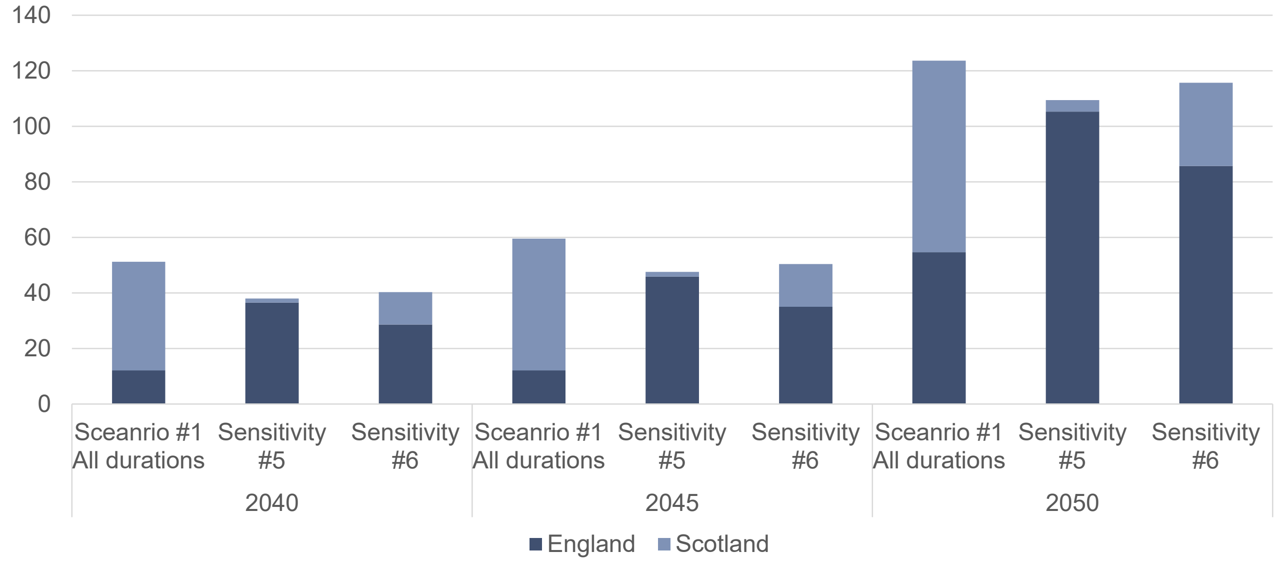
As discussed in section 5.3, one of the key results from the core scenario modelling was that hydrogen storage (via electrolysis) can reduce the costs associated with power transmission network congestion. The core scenarios assumed a hydrogen network would be developed to support the non-power hydrogen demand, and that the power sector use of hydrogen would benefit from this. However, the model did not directly incur these costs. This sensitivity tests this assumption and investigates the relative benefits of hydrogen versus power network reinforcement. This sensitivity shows how these compare to power LDS solutions to constraints.

The modelling of sensitivity #6 included hydrogen transmission as an explicit cost faced by the model. A balance is achieved so that:

- Scottish electrolysis is integrated; and
- power transmission network reinforcement is avoided.

As shown in Exhibit 5.25, more Scottish electrolysis can be integrated into the system compared to the case where hydrogen cannot be transported between zones. Less is integrated compared to scenario #1 due to the additional costs faced to develop the hydrogen transmission network.

Exhibit 5.25 – Electrolysis production by location, scenario #1 all durations vs sensitivity #5 vs sensitivity #6 (TWh)



Overall system costs in sensitivity #6 were £2bn lower than in sensitivity #5 (2030 NPV basis). Compared to Scenario #1, All durations, the system costs were £7bn higher.

Power LDS does not play a greater role, in this sensitivity, due to relatively high costs compared to network capacity reinforcement.

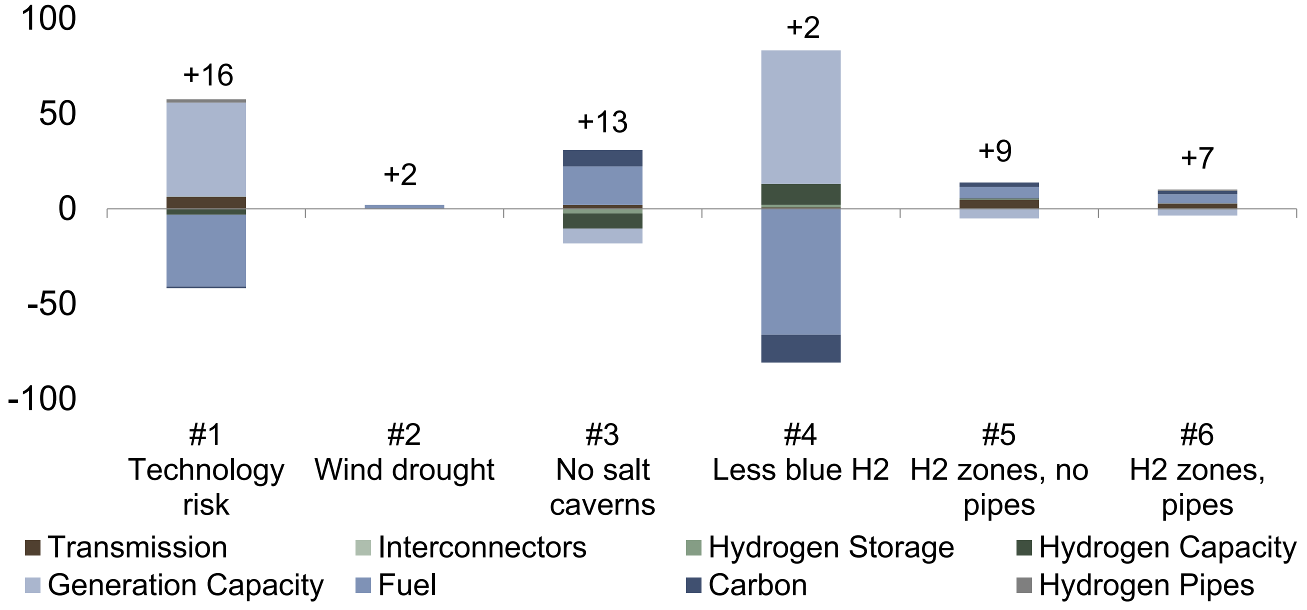
5.7.7 Technology risk sensitivities – summary

The sensitivities presented in the previous section explored key technical uncertainties and tested some of the drivers of the benefits brought to the system by LDS. Of these drivers, access to salt cavern storage was shown to be most critical. Sensitivities #1 and #3 have the greatest loss of benefits, as show in Exhibit 5.26. In sensitivities #5 and #6, despite hydrogen production and transmission being more difficult and costly, a more significant proportion of the benefits from hydrogen LDS remain.

Where the hydrogen sector is slower to come forward, as in sensitivities #1 and #3, it is shown that power LDS can play a role in providing seasonal balancing, replacing hydrogen CCGTs.

However, despite some sensitivities having an increased role for power LDS, none of the sensitivities modelled led to a significant reduction in requirements for dispatchable thermal capacity to ensure security of supply. The 2050 generation mix always included a mixture of gas with CCS, hydrogen CCGTs and peakers. This was necessary to ensure not only sufficient MW are on the system, but also that sufficient energy volumes were available for low wind weeks.

Exhibit 5.26 – Relative 2030 NPV system cost increases for the modelled sensitivities, compared to scenario #1 all durations (£bn)



Note: Sensitivity #2 presents the average increase in fuel costs due to greater weather variation across the modelled weather years, rather than the maximum increase seen in the extreme years

5.8 Benefits of long duration storage across time

The system requires balancing across different timescales and the scenarios show a trend towards a need for greater close to real-time balancing and much longer duration balancing capability, reflecting the impact of the growing penetration of intermittent renewables. The modelling done highlights how power LDS is often squeezed out by competing technologies.

These patterns of balancing favour particular flexibility solutions. Over the short timeframes, cheap SDS or DSR are most attractive, with MDS batteries also supporting the integration of solar PV. As the production gaps grow over time and are sustained for longer periods, there is real value from LDS.

However, the suitability of power LDS for this purpose is dependent on the levels of volatility in residual demand (demand net of renewables). This needs to be such that the LDS technologies can achieve a high enough number of cycles, in order to be cost competitive.

- Power LDS technologies are relatively expensive compared to large scale hydrogen LDS.
- Presence of significant electrolysis (often required for non-power sector hydrogen demand) reduced the utilisation of power LDS by competing for the same excess renewable volumes.
- A wind driven system will feature extended periods of both high demand and excess renewable output, often beyond the durations available from power LDS.

The modelling showed that the number of cycles achievable for LDS technologies is likely to be limited as system storage duration requirements increase. The impact of electrolysis here is key:

the fundamental volatility in residual demand is capped by the potential presence of the additional electrolysis demand in high wind periods. The fundamental shape of demand, wind and solar lead to LDS achieving lower levels of cycling. Low levels of power LDS cycling make the technologies relatively uncompetitive; other less capital intensive options are more cost-efficient, as discussed in Section 3.4.1. There is a risk that power MDS and LDS options are squeezed out by competing flexibility options at both ends of the spectrum.

Despite these observations, the anticipated rapid decarbonisation of the power sector opens the possibility that the need for longer duration balancing emerges more quickly than the infrastructure for hydrogen storage can be delivered. In these circumstances, the modelling indicated a larger role for power LDS in supporting the system before the hydrogen storage arrives.

Additionally, network infrastructure often has large lead times, so it is difficult to ensure that network reinforcement perfectly matches the supply and demand in different regions. Power LDS, if strategically placed, could help to reduce constraint costs in the years in which this mismatch occurs.

Although they have not been modelled here, a scenario where some of these scenarios and factors occur together would be likely to increase the relative benefits of power LDS.

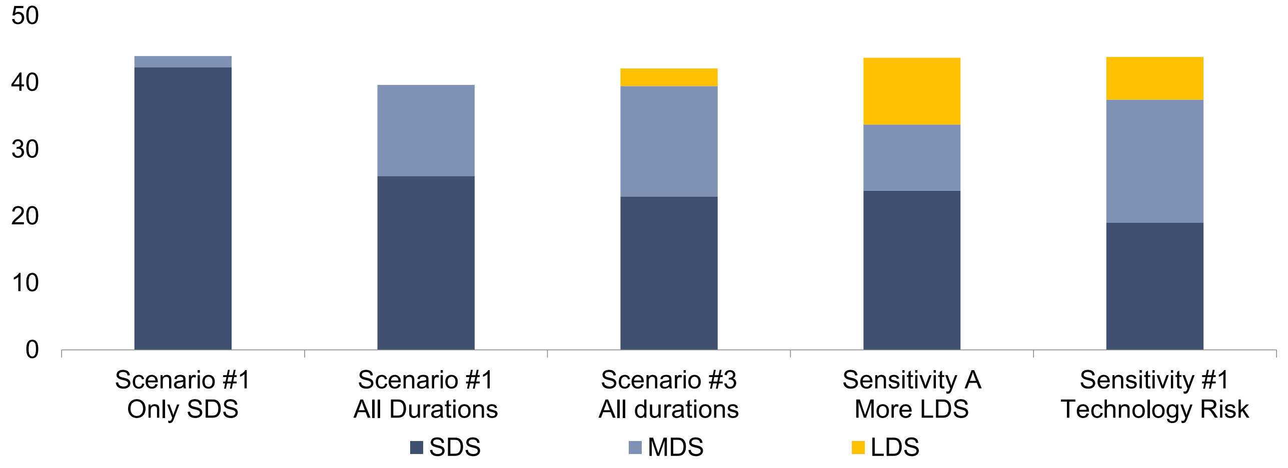
5.8.1 From the perspective of 2050

All modelled scenarios ultimately relied on significant volumes (up to 65GW) of dispatchable thermal generation in 2050 as the primary means of balancing supply and demand on a seasonal basis.

Power LDS predominantly displaces SDS li-ion batteries from the capacity mix and can only marginally reduce the thermal capacity required to back up the wind, if at all. Power LDS was not able to substitute for significant quantities of the dispatchable thermal capacity needed to ensure security of supply.

Without material cost reductions MDS li-ion batteries were preferred to other forms of power LDS. However, if other longer-term flexibility solutions, such as hydrogen LDS, are slow to emerge then this increases the need for power LDS. This is shown from Exhibit 5.27 below.

Exhibit 5.27 – Storage capacity mix in 2050 from scenario #1, supported LDS scenario #3, more LDS sensitivity A and the technology risk sensitivity (GW)

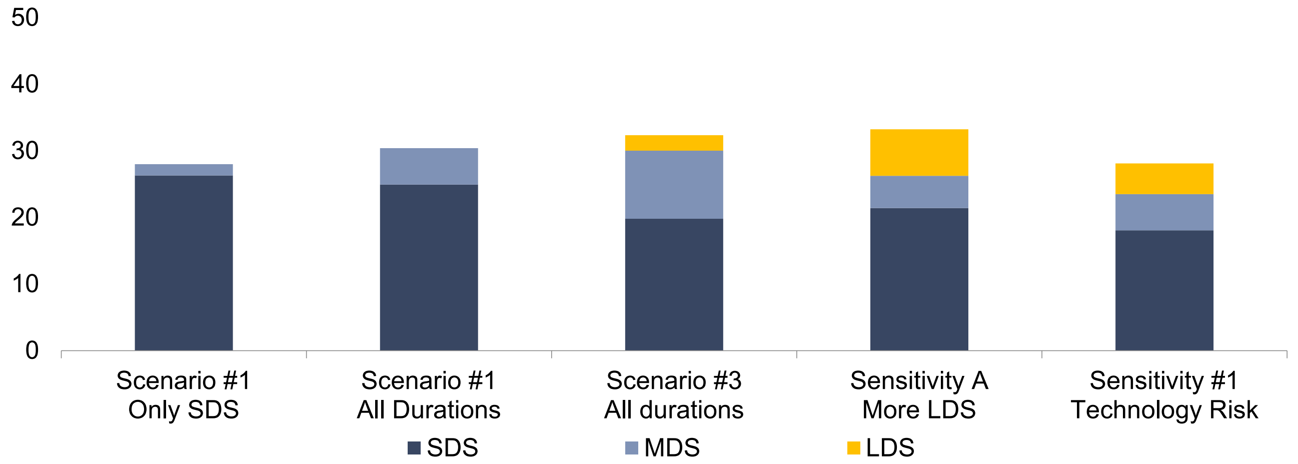


5.8.2 Before 2040

Where the modelling did lead to power LDS being commissioned as part of the optimal technology mix was in the 2030-2040 timeframe. At this point in time, the hydrogen infrastructure modelled was on a smaller scale. The system is beginning to move towards the required level of low carbon thermal capacity that can ensure security of supply in 2050. However, unabated gas fired generation is still required for security of supply due to the relative lack of low carbon thermal capacity. Power LDS was therefore able to reduce existing gas fired generation remaining on the system for longer into the future.

Exhibit 5.28 below shows that the power MDS and LDS required was generally commissioned prior to 2040.

Exhibit 5.28 – Storage capacity mix in 2040 from scenario #1, supported LDS scenario #3, more LDS sensitivity A and the technology risk sensitivity #1 (GW)



By offering support to achieve cost reductions in power MDS and LDS technologies, this can help manage the technology and cost uncertainties associated with low carbon, emerging technology, thermal capacity types. Having power LDS on the system is an advantage if these are slow to emerge.

Nevertheless, the scenarios showed that large investment in low carbon thermal capacity is critical to a net zero system. Investment in acceleration of commercialisation of hydrogen and development of the supporting infrastructure is a low regret decision. If this proves possible to achieve, there is a risk the power LDS brings lower benefits to the system and would be utilised less as the emerging technologies could be preferred.

Research questions: What are the relative benefits of different long duration storage technologies?

The modelling highlights that the introduction of LDS in the timeframe of 2030 to 2040 can help manage the risk associated with the emergence of new technologies required in 2050.

As such, in the 2030 to2040 timeframe, power LDS can help the transition away from gas fired capacity and mitigate the risks around emerging low carbon technologies.

Research question: How does the system impact of long duration storage change over time?

At present, there are large quantities of relatively flexible gas fired generators on the system. This operates relatively flexibly at the timeframes of hours to seasons. However, this can only continue so long as the emissions generated do not lead to emissions targets being breached. Given the context of the target to decarbonise the power sector by 2035 (subject to security of supply), gas-fired generation will need to operate at increasingly low load factors.

It is therefore possible that the existing bulk flexibility of gas fired generation will only be usable in the short-term. Post-2030, MDS and LDS may be needed to ensure that lower carbon flexibility is available.

Given the relative immaturity of hydrogen as a source of flexibility in the power sector, it is also possible that there will be a need for power MDS and LDS prior to the hydrogen sector becoming more fully established. However, if this sector develops more quickly, then power LDS technologies will need to compete with hydrogen-based LDS.

6. Conclusions

This section presents an overview of conclusions stemming from the assessment of the scenarios and highlights key uncertainties in this study.

6.1 LDS technologies help reduce the system costs of achieving net zero

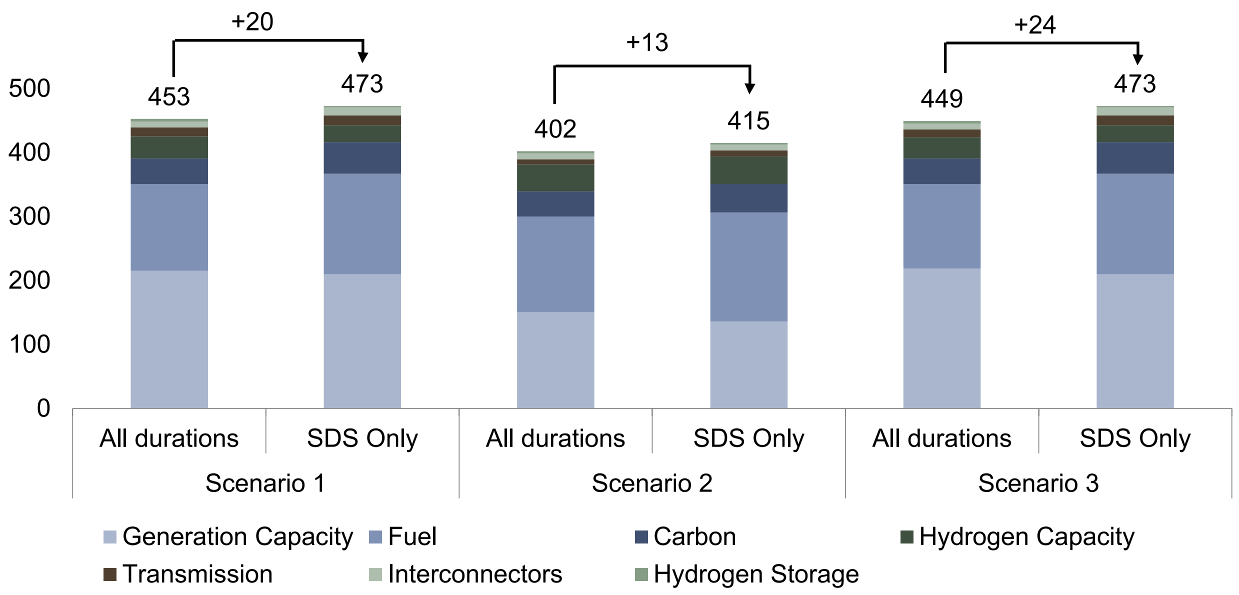
The key research question posed at the start of the study asked:

What is the impact of long duration storage on system costs as we transition to a decarbonised power sector?

Over the modelled period from 2030 to 2050, access to LDS can save between £13bn and £24bn on a NPV basis.

Exhibit 6.1 shows the relative system cost savings that can be achieved through having access to medium and long duration storage, across both power and hydrogen sectors.

Exhibit 6.1 – Relative system costs in the base scenarios, with and without the inclusion of LDS technologies (£bn, 2030 indexed NPV)



In addition to the core scenarios, sensitivity analysis showed that this benefit could increase to up to £36bn (in sensitivity #1, modelling greater technology risk, this is the difference between the All durations and SDS only cases). Power LDS brings the most benefit in the scenarios and sensitivities where emerging technologies are delayed in coming forwards or cannot be deployed at the desired scales.

6.2 Hydrogen provides the majority of the necessary long duration storage, as it has the durations required to support a wind dominated system

MDS and LDS can lower overall system costs. The main source of this benefit arises in dealing with the variability in output in the power sector. From the core modelling scenarios, the preferred solution is large scale hydrogen storage as its technological characteristics fit better with the longer periods of both excess and insufficient generation.

Access to hydrogen storage for the power sector is complex and requires a range of technologies all to be available. This could include technologies such as:

- Electrolysis near to renewable generation, to soak up excess output.
- Hydrogen pipelines to transport the hydrogen to the long duration storage.
- Salt cavern storage for weekly or seasonal storage of hydrogen.
- Hydrogen fuelled generation such as CCGTs to covert the stored hydrogen back to power.

If all of these technologies are available, then hydrogen LDS has the potential to offer the largest system cost savings of the modelled storage options. Hydrogen LDS also has the benefit of reducing costs of meeting non-power sector hydrogen demand.

In the scenarios modelled with support for power MDS and power LDS technologies, de-risking these investments led to greater system cost reductions.

These conclusions are dependent on the relative cost assumptions made for investment in power LDS technologies.

Research question

How much long duration storage (GW and GWh) is required to minimise system cost at a given level of emission intensity or total emissions?

How much electricity demand is likely to be met by long duration storage under a range of credible scenarios?

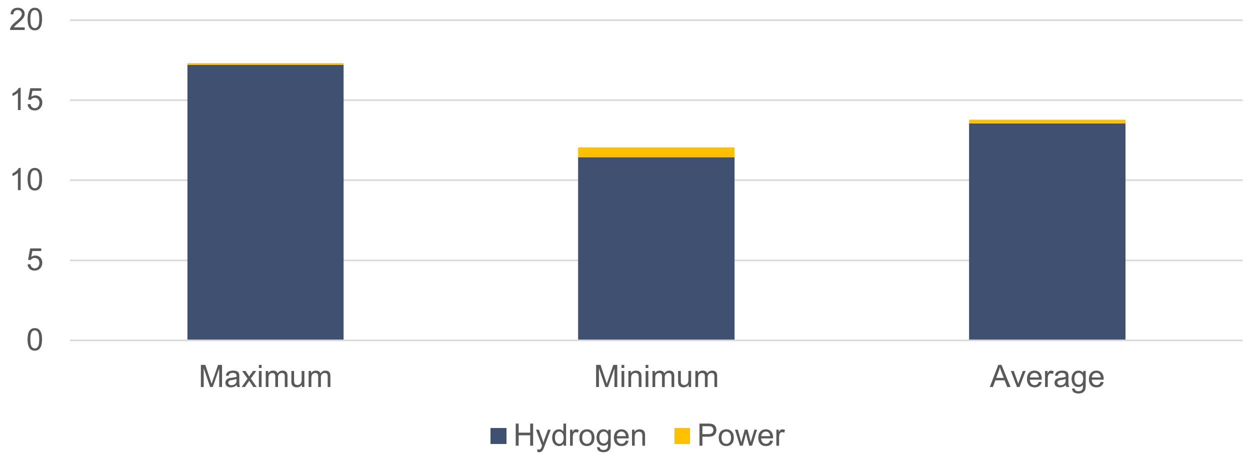
Across all modelled scenarios and sensitivities, the key dimensioning factor for security of supply is not GW so much as GWh. Prolonged periods of low wind and high demand render a mere GW figure less relevant, especially in a system with high SDS volumes, along with MDS and LDS. From the versions modelled with MDS and LDS investment options available, the following storage volumes were seen;[18]

[18] The sensitivity where salt cavern hydrogen storage was excluded from the model is not counted here. This sensitivity included only 0.4TWh of storage by 2050, with 0.1TWh of hydrogen tank storage and 0.3TWh of power

- By 2050, the required storage volumes ranged from 12TWh to 17.4TWh.
- Of these, the hydrogen LDS volumes modelled within the given scenarios ranged from 11.4TWh to 17.2TWh.
- Power MDS and LDS volumes ranged from 0.1TWh to 0.6TWh across the modelling. This often includes significant volumes of 6-hour li-ion batteries alongside other forms of power storage.

These results are shown in Exhibit 6.2.

Exhibit 6.2 – Range of storage volumes required across modelled scenarios and sensitivities, All durations versions, by 2050 (TWh)



These volumes are broadly in line with the production gaps during low wind/high demand periods (as per in Exhibit 6.2). The hydrogen volumes of storage here are sufficient to allow for around 6-9TWh of production from hydrogen CCGTs. The storage was provided by different technologies depending on the circumstances in the specific scenario or sensitivity. Where sensitivities resulted in lower hydrogen storage volumes, it was replaced by some power LDS and some smaller scale hydrogen tank storage.

6.3 Power LDS can help mitigate the risks associated with emerging technologies

As discussed in Section 6.2, in order to realise the benefits of hydrogen LDS, a number of technologies are required. Many of these are emerging technologies, with associated risks around their deployment at scale and cost of delivery. Additionally, CCS in both power and hydrogen sectors is an emerging technology that is liable to similar risks.

In the core scenarios modelled, it was assumed that these key low carbon technologies would be available. This meant that hydrogen derived flexibility solutions (and solutions involving CCS)

LDS. This sensitivity in many ways quite closely resembled the variant of scenario 1 where only SDS options are available: without the hydrogen storage, gas with CCS was preferred for seasonal balancing of supply and demand. In these circumstances, there is limited LDS and system costs are therefore higher than in scenario #1 All durations by £12bn.

were deployed in preference to power LDS. This was so that sufficient energy would be available in the lowest wind periods. However, in the sensitivities where the risks around these emerging technologies were modelled, the optimal capacity mix included more significant quantities of power MDS and LDS.

Therefore, a key conclusion from this is that whilst hydrogen LDS may deliver the largest reduction in system costs, power LDS can help mitigate the risks associated with the emerging technologies required for hydrogen LDS. Hydrogen has many potential uses and it is not certain where its use should be prioritised. If prioritised to other areas, or electrolyser deployment is limited, this could also lead to potential delays in hydrogen deployment in the power sector.

In the context of mitigating the risks associated with deployment of hydrogen LDS, of the various technologies considered, the greater benefits were delivered by the power LDS technologies. There was a need for flexibility from multi-day storage with the longest durations, with lower benefits from some of the MDS options.

6.4 Supporting LDS technologies to mitigate deployment barriers is a relatively low regret decision

Research question

Is there a ‘low regrets’ amount of long duration storage that should be deployed in the power sector?

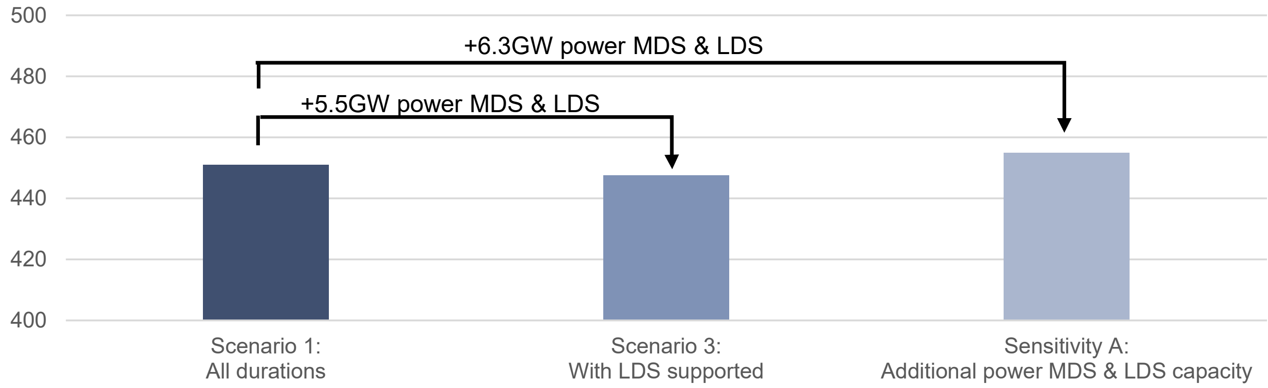
As discussed in Section 6.1, LDS solutions can help reduce system costs. Across the modelled scenarios and sensitivities, the minimum levels of LDS deployed was 12TWh (11.4TWh of hydrogen, 0.6TWh of power LDS). Regardless of the precise technology mix, there was always some volume of storage that will provide benefit, and this corresponds to a low regret level.

Based on the modelling, it is not clear that specifically power LDS options are the correct technology to support. In this context, it is important to consider how much regret may be associated with a decision to support investment in specifically power LDS technologies.

Nevertheless, by reducing risks and costs of deployment of power LDS, it is possible to unlock the benefits. In doing so, the modelling demonstrated that further system cost savings can be achieved. These benefits are greater where the risks associated with emerging technologies are factored in. Power LDS technologies can help mitigate the delivery risks associated with hydrogen deployment.

Exhibit 6.3 shows the NPV of system costs for scenario #1, scenario #3 and the sensitivity with higher levels of power LDS. All three of these scenarios have, as a counterfactual, the same system costs for a SDS only world (£471bn). By supporting power LDS, system costs savings are still realised, as can be seen from the relatively similar levels of system costs here.

Exhibit 6.3 – System costs changes due to increased power LDS capacity due to direct policy support (£bn NPV in 2030)



In scenario #3, investment support and lower assumed capex for PSP led to 5.5GW of additional MDS and LDS capacity compared to scenario #1. Total power MDS and LDS capacity was 19GW by 2050. This led to a reduction in system costs compared to scenario #1.

In Sensitivity A, with a minimum of 15GW power MDS and LDS included, the net increase was 6.3GW, due to a reduction in MDS capacity that was already included in scenario #1. System costs were slightly higher in this sensitivity, due to some relative inefficiencies in the choices of power LDS technologies and the higher investment costs associated with them.

In both cases, support for these storage technologies resulted in a reduction in SDS and some other unsupported MDS capacity. The net gain in storage is relatively small in GW terms, but much more important in GWh terms. The presence of power MDS and LDS helped reduce overall gas consumption.

There is significant cost uncertainty around the power LDS technologies, and it may be that further research and development funding for these options could lead to further cost decreases and create larger system cost savings.

Within the context of this study though, the system cost impact of power LDS is a relatively low regret decision, and support for around 2.5GW to 3GW of power LDS would be a low regret quantity.

In addition to this finding regarding power LDS, hydrogen storage is a clear no regret decision, if a significant hydrogen sector is possible to realise.

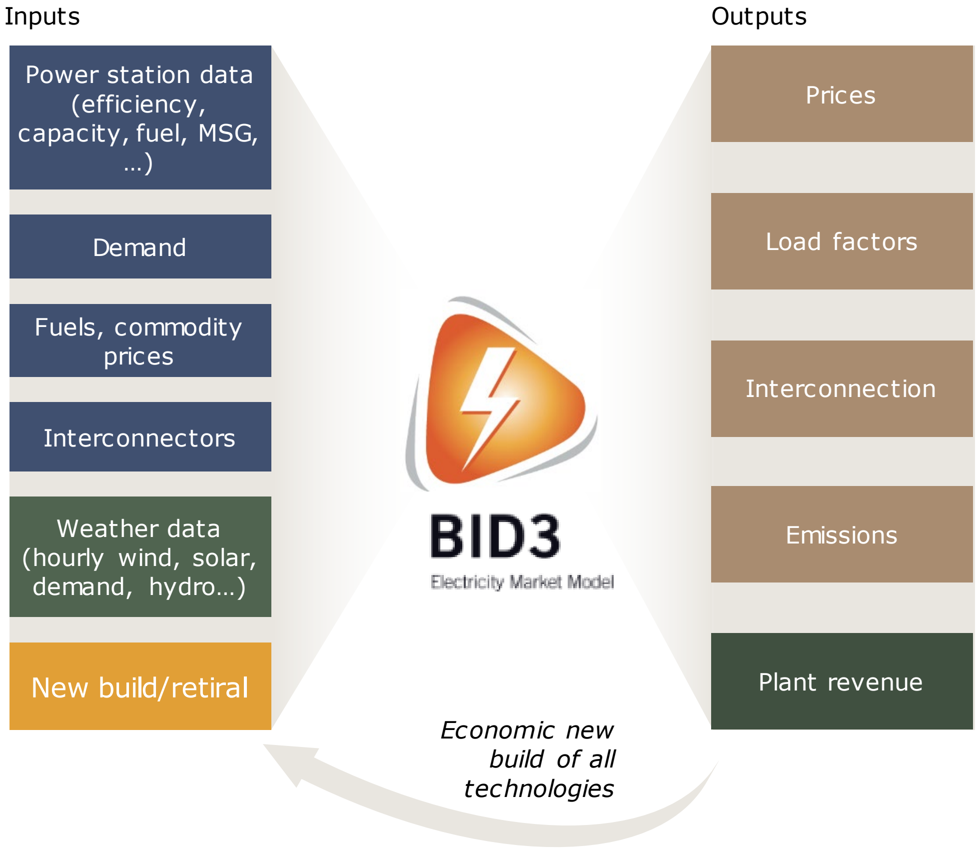
Annex A: Modelling approach

A.1 BID3 overview

For the purposes of this research, market modelling was performed using AFRY's proprietary software, BID3. A fuller description of the model and the way that it was used in this context are provided in the methodological annex, published alongside this report.[19]

BID3 is an economic dispatch model based around optimisation. It simulates the dispatch of all power plants and interconnectors on the system, on an hourly (or sub-hourly) basis. Based on this, it creates power market metrics – electricity prices, reserve and balancing market prices and system costs. The costs associated with sector coupling (e.g., hydrogen), inertia, and transmission constraints are also output. Key inputs and outputs are summarised below.

Exhibit A.1 – BID3 overview, inputs & outputs



Each future year is simulated under multiple historical weather patterns, to reflect a range of possible outcomes for uncertain, weather-driven features of power systems. This includes demand for power, as well as production from wind and solar. Detailed modelling of renewable

[19] BID3 is used by many major utilities and TSOs. Further details of the BID3 market model can be found here: https://afry.com/en/service/bid3-power-market-modelling

output on a locational basis is included, to represent both expected improvement in renewable load factors and also the relative achievable load factors for renewables in different areas.

In order to create the scenarios and sensitivities, extensive use of the BID3 'Auto Build' module was made. This module exists to endogenously determine the optimal, least cost, future plant capacity of a given scenario. It does so fully reflecting the input weather patterns. In addition to power plants, the module also includes endogenous investment in interconnectors, transmission grid reinforcement, and the production, storage and transmission capacity of hydrogen.

These model runs are subject to multiple constraints; including security of supply standards, emissions limits to meet net zero, reserve requirements, inertia requirements, frequency response requirements and build resource limits.

Following the determination of the optimal capacity mix, the model performs a detailed hourly dispatch. This provides the results that are presented in this report, to assess the relative benefits of different storage technologies across different scenarios and sensitivities.

A.2 Modelling of storage in BID3

Power storage plants are represented in BID3 with a detailed set of parameters. These include, amongst others:

- Output capacity.
- Round trip efficiency.
- Hours to empty the storage.
- Hours to fill the storage.[20]
- Minimum stable input and output levels (SIL and SEL).
- Forced outage and scheduled outage assumptions.
- Ability of the storage to provide different types of reserve and response (e.g., does provision of a certain service require a certain mode of operation).
- Inertia provision.

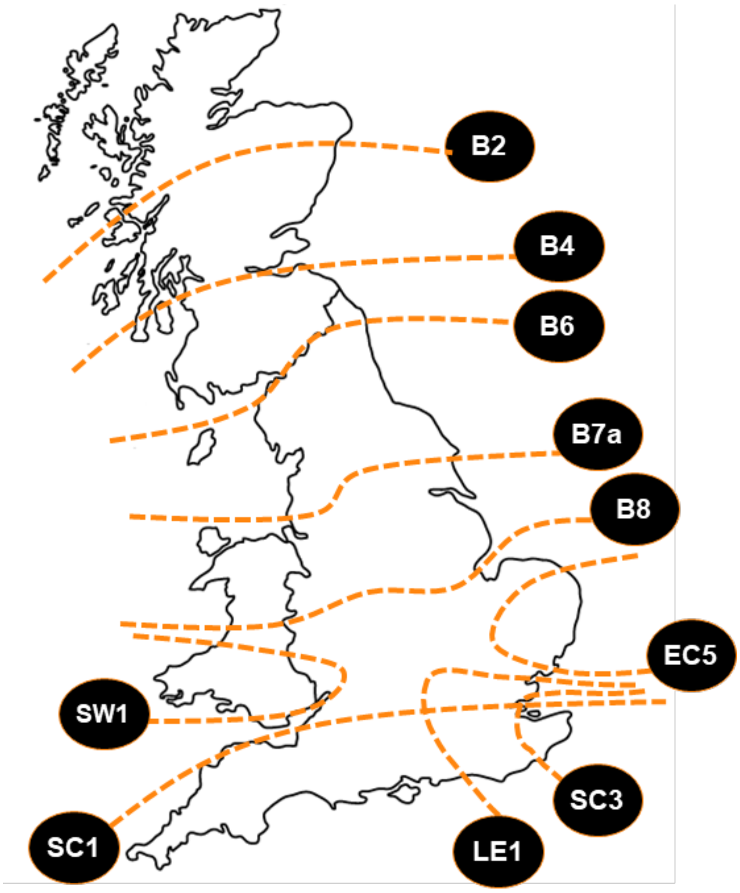
These input parameters are used to constrain the ability of storage to operate in the model. In particular, a state of charge constraint ensures that output and charging is done consistently with the fill level of the storage. This includes the operation of storage plants in both wholesale and balancing markets.

[20] From these first 4 parameters, the pumping or charging capacity is also defined in the model.

A.3 Transmission constraints in BID3

The modelling also included GB on a locational basis, with 11 separate power zones applied for this project. The modelled zones are shown in Exhibit A.2.

Exhibit A.2 – Modelled GB boundaries, representing the transmission limits considered



These were determined by the key constraints that exist in the power transmission network at present and in the future. The model had to balance the system not only for a national energy market but also to balance constraints on a zonal basis.

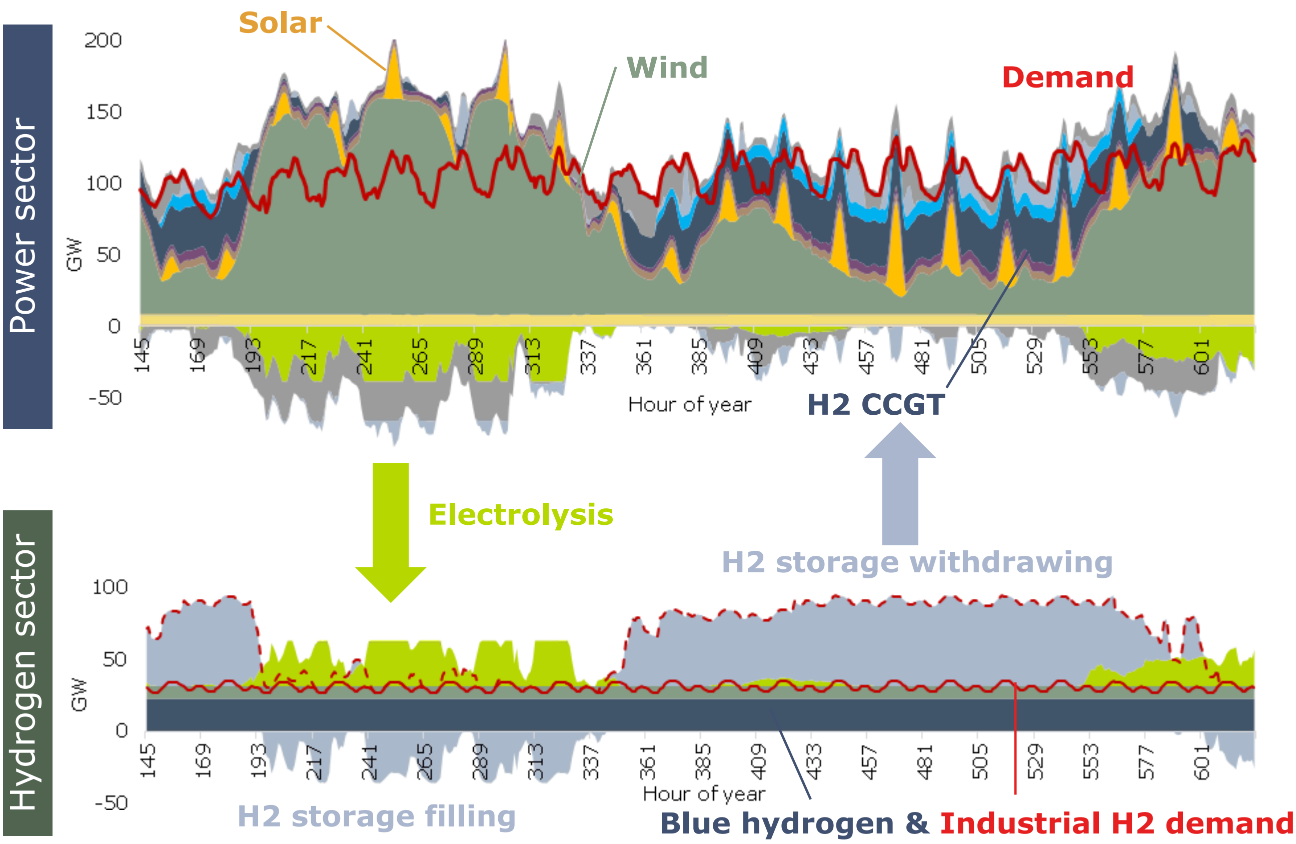
The core scenarios also assumed that a hydrogen pipeline ‘backbone’ is developed within GB separately, and therefore hydrogen transmission was unconstrained within the base scenarios. This assumption was tested separately in sensitivity analysis, in order to further quantify the importance of location for hydrogen storage.

A.4 Hydrogen dispatch and assumptions in BID3

In BID3, a specific level of non-power sector hydrogen demand is required to be met through a combination of ATR, SMR with CCS (producing blue hydrogen) and electrolysis (producing green hydrogen) at least cost and coupled with the use of storage where necessary. Power sector hydrogen fuelled plants increase the hydrogen demand. Both sectors are optimised simultaneously in order to ensure full consistency. This is illustrated in Exhibit A.3, which shows the consistent operation of the two sectors and the dispatch of the different technologies present in each.

Exhibit A.3 – Illustrative modelling of power and hydrogen sector coupling for a 3 week period in 2050

BID3 co-optimises hydrogen and power sectors, and models energy flows between the sectors



Note: Hydrogen storage fill level is not zero at the start of this period and ends the period with a lower storage level than at the start. Electrolysis shown here in this period does not provide all of the hydrogen required for the H2 CCGTs.

Both blue and green hydrogen technologies are dispatched on a least cost basis in BID3. In practise, this will broadly mean that electrolysers will operate whenever the cost of power is lower than the variable cost of blue hydrogen production. There can be a variety of business models (and project configurations) for electrolysis; in this study the assumption is that hydrogen is produced via electrolysis with power taken from the grid. Co-location business models have not been explored in detail. In other words, electrolysis requires excess renewable generation, either due to national or locational excess renewables. Electrolysis located behind transmission constraints is an important option for easing location congestion, due to the ability it has to operate for extended periods of high wind output.

While in the long-term electrolysis was assumed to have lower capex and opex than ATR and SMR with CCS in the scenarios modelled, this is offset by electrolysis tending to run at a lower load factor. This results in electrolysis being the more capital-intensive option.

Hydrogen storage solutions (via pressurised tanks and/or salt caverns) are utilised to bridge mismatches between intermittent renewable generation and hydrogen demand profiles. The intermittent nature of solar and wind will likely bring issues of large mismatches between renewable generation and hydrogen demand patterns. Hydrogen fuelled power generation is most likely to operate in periods when electrolysis is not operating. Both hydrogen and power sector demand for hydrogen will require hydrogen storage.

A.5 Pipeline transmission for hydrogen in BID3

In this study's base scenarios –there are no limitations on hydrogen transmission, assuming that a hydrogen network is developed, and the costs socialised. The assumption made was that non-power sector hydrogen demand will lead to hydrogen transmission capacity being built. A further assumption was that hydrogen use in the power sector would be able to use this transmission capacity without extra costs.

The sensitivities (more details in Section 4) explore this assumption, modelling two specific cases related to the consideration of a hydrogen network:

- No transmission of hydrogen at all between geographical zones.
- Full costs of developing a transmission network. The model optimised investment in any transmission of hydrogen between zones for either power or non-power sector hydrogen.

In the former case, hydrogen zones were introduced in BID3 along the lines of the power zones. Hydrogen demand (outside the power sector) was disaggregated between these zones, with particular reference to the locations of the industrial clusters that give rise to the majority of the hydrogen demand. Non-industrial, non-power sector hydrogen demand was split according to the share of population in each zone. In the latter sensitivity case, the model optimised the investment in hydrogen pipeline transmission capacity, alongside the optimisation of other sources of capacity and network infrastructure.

This consideration is important in the context of electrolysis, since it has the potential to play an important role in managing congestion in the power transmission network. Ability to locate electrolysis close to RES, where potential to be curtailed due to power transmission congestion, is beneficial. However, this may potentially require transmission of the hydrogen to the end users. Salt caverns are also geographically limited in their availability, and the ability of green hydrogen production to access salt cavern storage is another important consideration.

Annex B: Comparison of storage LCOS with other technologies

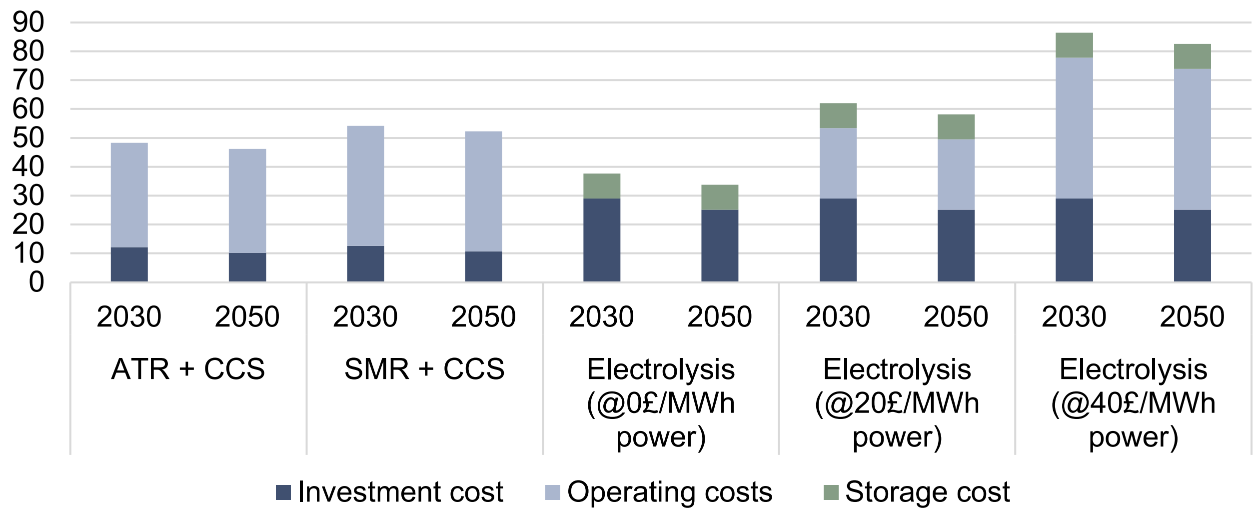
This annex presents the assumed investment costs for the core scenario modelling. It is based around the BEIS Central scenario.

In order to compare the relative cost efficiency of power storage technologies, it is also necessary to analyse the levelised costs of hydrogen and electricity technologies. Hydrogen is relevant not only as it is an alternative form of storage, but also because hydrogen production costs determine the LCOE of hydrogen fuelled generation technologies.

B.1 Levelised cost of hydrogen including storage (LCOH)

Various elements make up the total cost of producing hydrogen. Exhibit B.1 shows the levelised cost of hydrogen (LCOH), including the investment and operating costs of both system (electrolyser or ATR and storage) and storage costs (where directly applicable e.g., electrolysis).

Exhibit B.1 – Full levelised cost of hydrogen (production + storage) in 2030 and 2050 (£/MWh, higher heating value basis)



Note: Investment costs include both capex and opex. Operating costs include both fuel and carbon costs. ATR and SMR are assumed to operate at 6500 hours and electrolysis at 3000 hours (values informed by AFRY modelling). Transport costs are not included here.

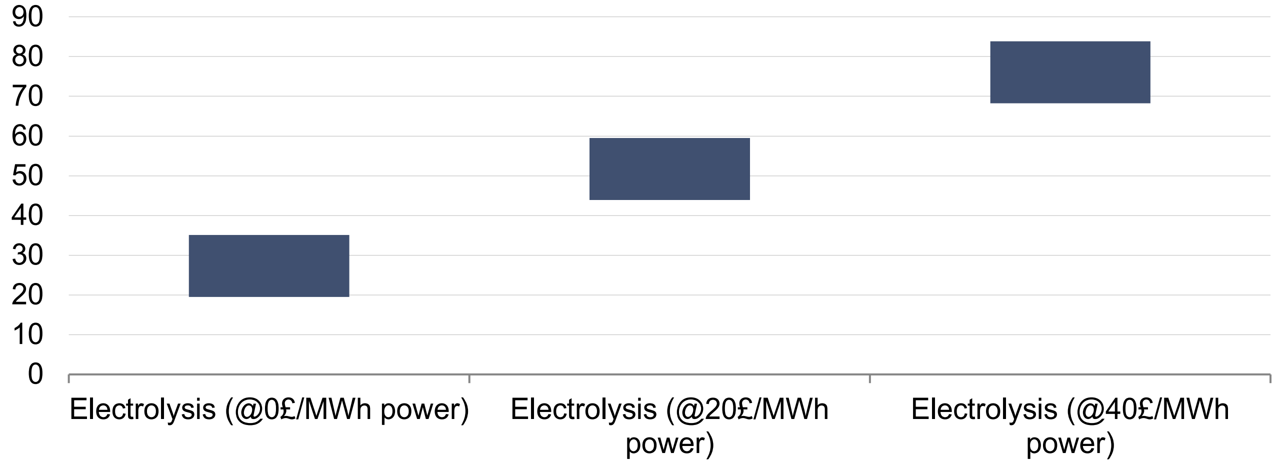
In general ATR with CCS is the least cost class of technology in producing hydrogen, with fuel costs making up the bulk of the costs at ~75% of the LCOH. Total costs are slightly higher for SMR, primarily due to higher operating costs, arising from a lower CO2 capture rate increasing carbon emissions costs.

A variety of electrolysis technologies are available in reality. In this study, the focus was on PEM (Polymer Electrolyte Membrane) electrolysers, as the likely most cost-efficient technology due to its higher efficiency. The costs for electrolysis show large variability, primarily arising from factors such as the project configuration and price of electricity for the electrolyser. In this study, electrolysers are assumed to be directly connected to the power grid. Due to the variability in prevailing power prices, it is more likely the electrolysers need to be coupled with hydrogen storage.[21]

- At times of very low electricity prices (near £0/MWh at times of excess renewable generation and/or management of locational constraints) its LCOH is lower than both ATR and SMR. This relative cost advantage changes rapidly as the power price assumed increases to £20/MWh and even more so at £40/MWh.
- The hydrogen storage costs can be significant and make up ~25% of the total capital investment (before considering the variable incurred through the consumption of electricity). When considering the total capital and operation cost, the storage accounts for 10-25% of the LCOH, depending on the power price. In this instance, salt cavern storage has been assumed as necessary to utilise the green hydrogen; this may not be necessary outside the power sector but is very likely from a hydrogen use in the power sector perspective.[22]

The load factor at which the electrolysers can operate also has a significant bearing on the effective LCOH, as this varies the number of hours over which the investment costs are distributed. Exhibit B.2 illustrates this by showing the range LCOH for electrolysers that result from plausible different operating hour levels. The values chosen were informed by AFRY modelling of operating hours for a grid connected electrolyser.

Exhibit B.2 – Range of LCOH for electrolysers at different operating hours and prevailing power costs in 2050 (£/MWh)



Note: Operating hours range from 2000 to 4000. Power price levels were chosen on the basis that electrolysers will operate flexibly in the periods with lowest power prices. Higher power prices would further increase the LCOH but

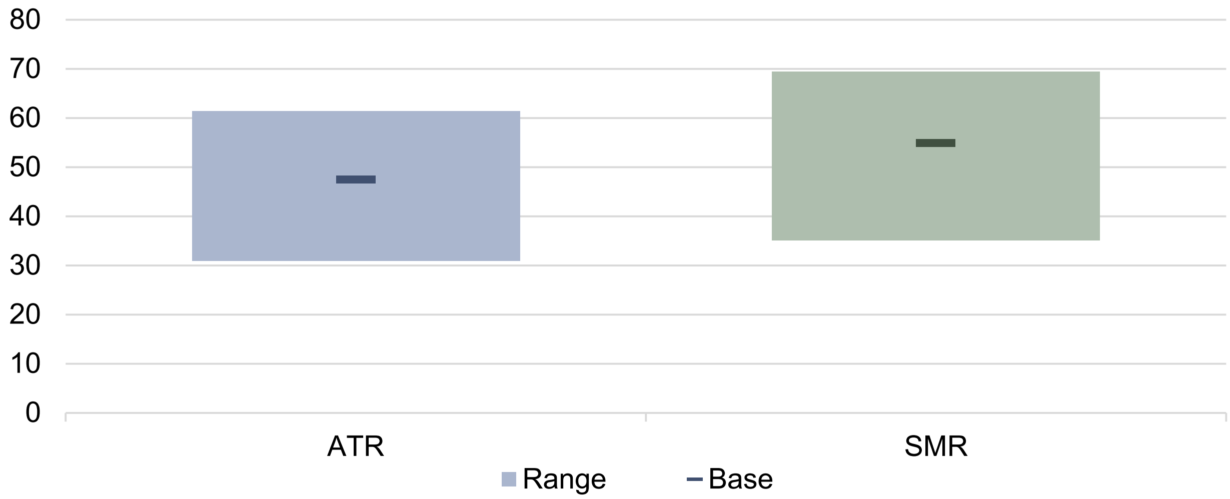
[21] Blue hydrogen production may also require hydrogen storage, depending on the characteristics of the hydrogen demand. However, this is less of an issue than for grid connected green hydrogen production.

[22] In this instance, salt cavern storage with 168 hours duration was used, with an assumed 6 cycles per year achieved. This relatively low value corresponds to the number of cycles achievable by the marginal storage unit, to reflect an upper bound on the costs of storage. If an average achieved cycles were applied, this would reduce the costs of this storage. The rationale for this approach was informed by AFRY modelling, where it was observed that some hydrogen storage is required that operates at low utilisation levels.

are not considered here due to relative LCOE of renewables applied in this study, and the modelled flexibility of electrolysers to avoid operating in periods of high power prices.

Whereas electrolyser costs are sensitive to power price and operating hours, blue hydrogen costs are less likely to depend on these factors. Operating hours for blue hydrogen are likely to be relatively high due to the inflexibility of the technology. By contrast, there is a sensitivity of levelised cost of hydrogen production from SMRs and ATRs to commodity prices. This is shown in Exhibit B.3. For illustrative purposes this takes a range of +/- 50% for gas prices and +/- £100/t for carbon prices, around an assumed base price, along with 2050 investment assumptions for each technology.

Exhibit B.3 – Range of levelised costs of hydrogen for varying commodity prices, 2050 (£/MWh)



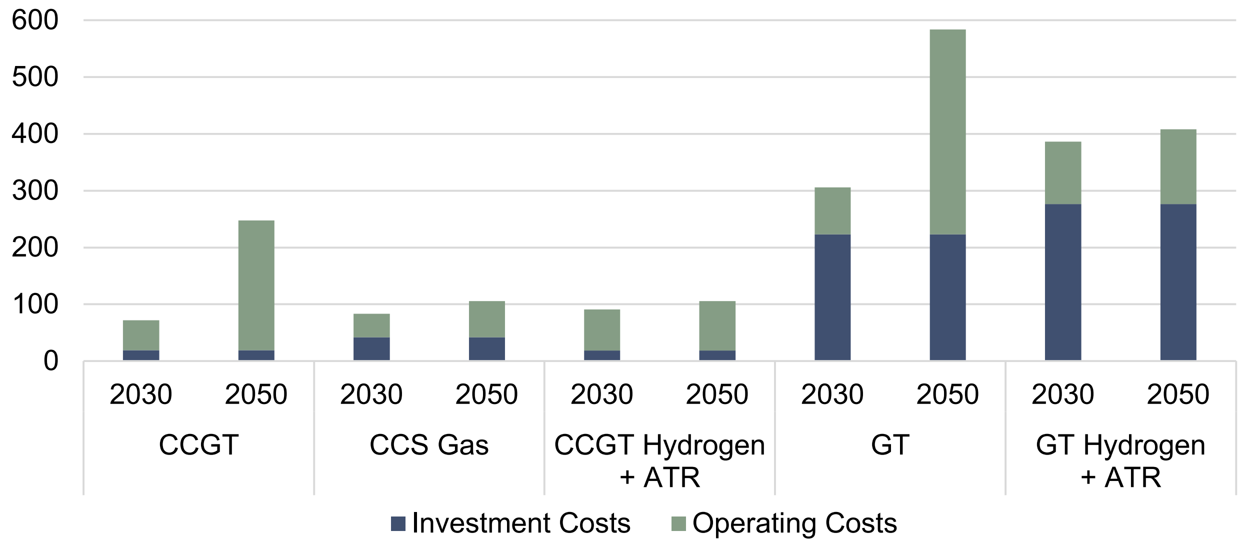
With higher commodity costs, especially related to gas, blue hydrogen from ATRs and SMRs becomes less competitive than the more capital intensive electrolysis. With improved CCS efficiency, the ATR technology becomes slightly more competitive when carbon prices rise. Conversely, if commodity costs are at overall lower levels, then electrolysis would need to have access to lower electricity prices to remain competitive. As recent changes to commodity prices have shown, there is significant uncertainty even beyond the sensitivities shown here.

It is important to note that the market for hydrogen is in its infancy. There remains a great deal of uncertainty around the future scale and cost of hydrogen alongside which sectors of the economy it is most likely to be used for. While we have attempted to test a range of sensitivities, these do not encompass the full potential scale of uncertainty around the cost of hydrogen and its potential to deploy in the power sector.

B.2 Levelised cost of electricity (LCOE)

Having considered the costs of hydrogen, this section focusses on the LCOE for flexible power generation. The main technologies discussed in this section are CCGT & GT, hydrogen CCGT & GT and gas with CCS. The gas with CCS technology consists of a CCGT coupled with post-combustion carbon capture and storage. The hydrogen CCGT investment costs are modelled as a function of CCGT costs. Some of these solutions – like low-carbon CCGT H2 and GT H2 – rely on the use of hydrogen as a fuel and therefore some of the considerations made for the LCOH in Section B.1 are applicable here as well. Exhibit B.4 shows assumed LCOE values for these different thermal technologies, in 2030 and 2050. Assumed generation patterns for these technologies were informed by AFRY modelling.

Exhibit B.4 – Scenario levelised cost of electricity for thermal generation (£/MWh)



Notes: (1) These values are derived from BEIS investment costs and hurdle rates but use AFRY values for efficiencies and assumed carbon prices. (2) Operating hours are informed by AFRY modelling and are assumed to be CCGT: 4000 hours, gas with CCS: 4000 hours, CCGT hydrogen:4000 hours, GT: 175 hours, Hydrogen GT: 175 hours. (3) The values for hydrogen CCGTs coupled with hydrogen produced by an electrolyser (instead of an ATR) would vary according to the relative costs of the hydrogen, as determined by relative LCOH values.

In general, thermal generation options are relatively low capex flexibility solutions. A far greater proportion of their costs relate to variable operating costs.

The LCOEs shown in Exhibit B.4 display large variability between GT and CCGTs – the different operating modes and low utilisation of GT technology results in high LCOE, despite lower capex figures assumed against CCGTs.

In the long-term, the cost of novel, low-carbon solutions (hydrogen CCGTs & GT, CCS) remain similar as investment costs in 2030 are assumed to be in line with those in 2050. However, the costs of unabated gas-fired generation technologies increase driven by higher assumed carbon costs.

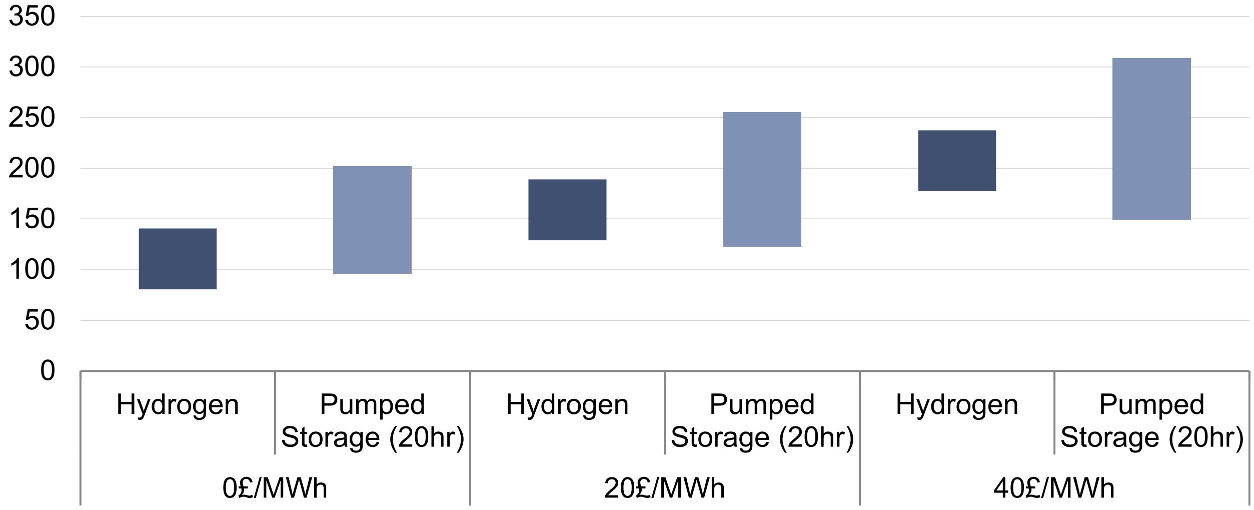
When comparing LDS options against thermal generation options, it is worth noting that the price at which storage can sell power will be closely related to the generation costs of the alternatives. A system that is able to deploy efficient gas with CCS and hydrogen CCGTs is likely to offer lower sell prices for storage, than one which does not feature these technologies, but relies on unabated gas plants and peakers.

Even if LDS is able to buy power at close to £0/MWh (e.g., in periods of excess renewable output), it may not have price volatility at the right timeframes to make power LDS economic. This depends on the extent to which low or zero price periods extend beyond the duration of the storage, or whether they cluster together in durations similar to the hours it takes to fill the storage. For low prices driven by solar, this lends itself well to MDS and LDS technologies. Wind driven low price events can also map well onto durations of MDS and LDS technologies, but can also last for periods extending into weeks, reducing the effectiveness of some storage technologies.

B.2.1 Cost competitiveness of power and hydrogen storage

From the preceding analysis, it is possible to compare pure power LDS options against the use of hydrogen as an LDS solution. Although incomplete, since it does not account for all flexibility services that different technologies can provide, it is informative for understanding the relative merits of different flexibility solutions. Taking the analysis of levelised costs of individual technologies, and combining them together, is shown in Exhibit B.5. This just shows 20hr duration pumped storage as a representative power LDS technology. Values are shown for 0£/MWh, 20£/MWh and 40£/MWh underlying power costs (to fill the storage / run the electrolysers). Ranges reflect the possible numbers of operating hours (cycling levels) considered in Exhibit 3.13.

Exhibit B.5 – Comparison of scenario LCOS using pure power LDS and hydrogen LDS combined with electrolysis and a hydrogen fuelled CCGT, in 2050 (£/MWh)



Notes: (1) Hydrogen assumes the electrolysis operates between 2000 and 4000 hours per year, and that this is matched by corresponding levels of hydrogen CCGT operation, accounting for efficiency losses. (2) Salt cavern storage is assumed for the hydrogen storage.

To make this comparison, the cost of investment and operating the electrolysers was adjusted to reflect the efficiency losses through the hydrogen salt cavern storage and also the hydrogen CCGT.

The cost-competitiveness of these two technology solutions is likely to depend to a large extent on the frequency with which the technologies can operate. This will depend on the underlying trends on volatility of supply and demand. A further implication is that if hydrogen electrolysis becomes widespread, this has the potential to erode the need for pumped storage.

This analysis uses investment costs from the BEIS Central scenario. Other scenarios for future costs could lead to different outcomes. By way of example:

- cost declines for electrolysis technologies are relatively uncertain; and
- pumped hydro storage costs may also increase once the best (and therefore likely to be the cheapest) sites have been developed.

Annex C: The role of LDS in extreme periods

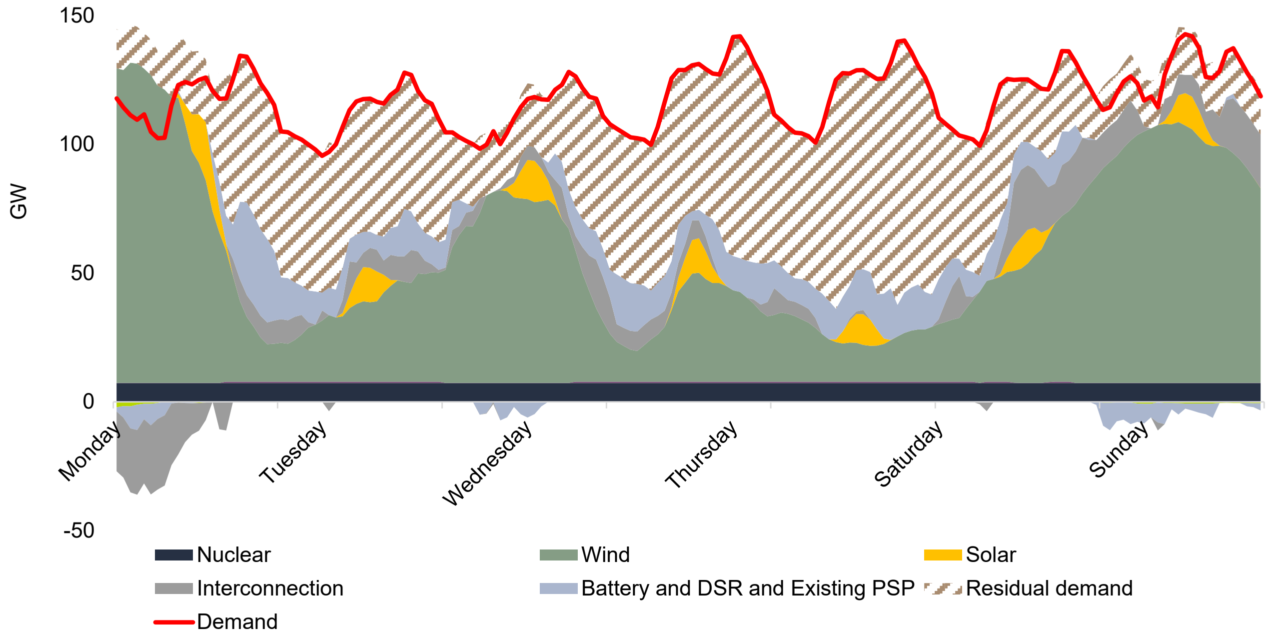
Section 3.4.1 showed that the relative benefits of LDS technologies depend, amongst other factors, on the levels of utilisation that storage can achieve. This is determined by a range of factors, but not least the level of other capacity required on the system to provide adequate flexibility and security of supply.

This annex examines some extreme events. The characteristics of these extremes (e.g., duration, magnitude and location) may drive certain forms of capacity. The need for long duration storage is considered in two particular extremes: firstly, high demand and low wind output, and secondly, low demand and high wind output on a locational basis.

C.1 Meeting demand in key high demand periods

For storage technologies, a key consideration is the duration of periods of high demand and low wind output. A sample period where these conditions persist for a prolonged period is shown in Exhibit C.1.

Exhibit C.1 – Illustrative energy gap in a critical 2050 extended period of high demand and low wind (2010 weather pattern, January week)



The week shown here was from an extended cold spell with the 2010 weather pattern modelled with illustrative 2050 capacities. Peak residual demand is 114GW and the overall energy requirement is 8.7TWh over the week. In order to balance supply and demand, both GW and TWh values are relevant for storage.

Based purely on capex considerations, Exhibit C.2 shows relative costs of building sufficient capacity to meet demand across this week. This analysis is theoretical but illustrates the challenge the very long duration high demand, low wind events and the role of LDS.

Exhibit C.2 – Candidate technologies for balancing supply and demand during this extended low wind period in 2050[23]

Candidate technology	Capacity, GW	CAPEX, £bn
Wind	1299	1757
Nuclear	120	526
Gas with CCS	120	173
CCGT Hydrogen	120	73
2-hour li-ion battery	4588	1380
6-hour li-ion battery	1529	857
LAES (12 hour)	765	972
PSP (20 hour)	459	745
CAES (72 hour)	127	196
Combination, including:	921	643
Wind	120	156
Nuclear	10	44
6-hour li-ion battery	791	443

Considering only capex, it is clear that the most competitive options for maintaining security of supply are the low carbon thermal plant options, rather than power LDS options. Peaking thermal capacity would be even cheaper still purely on a per MW cost basis. In the case of CCGT hydrogen plants, the ability of long duration hydrogen storage to store the volumes of hydrogen is key. Salt cavern storage can make it possible for these plants to generate continuously for extended periods such as this.

By contrast, the power LDS options are apparently typically less efficient. The relatively infrequent but critical weeks would theoretically require much of the power LDS to operate at low cycling rates. This is a relatively cost inefficient means of balancing the seasonality of the system.

In the full scenario modelling, opex and variable costs are considered in full detail, but this analysis is illustrative of the challenge from these key dimensioning periods of low renewable

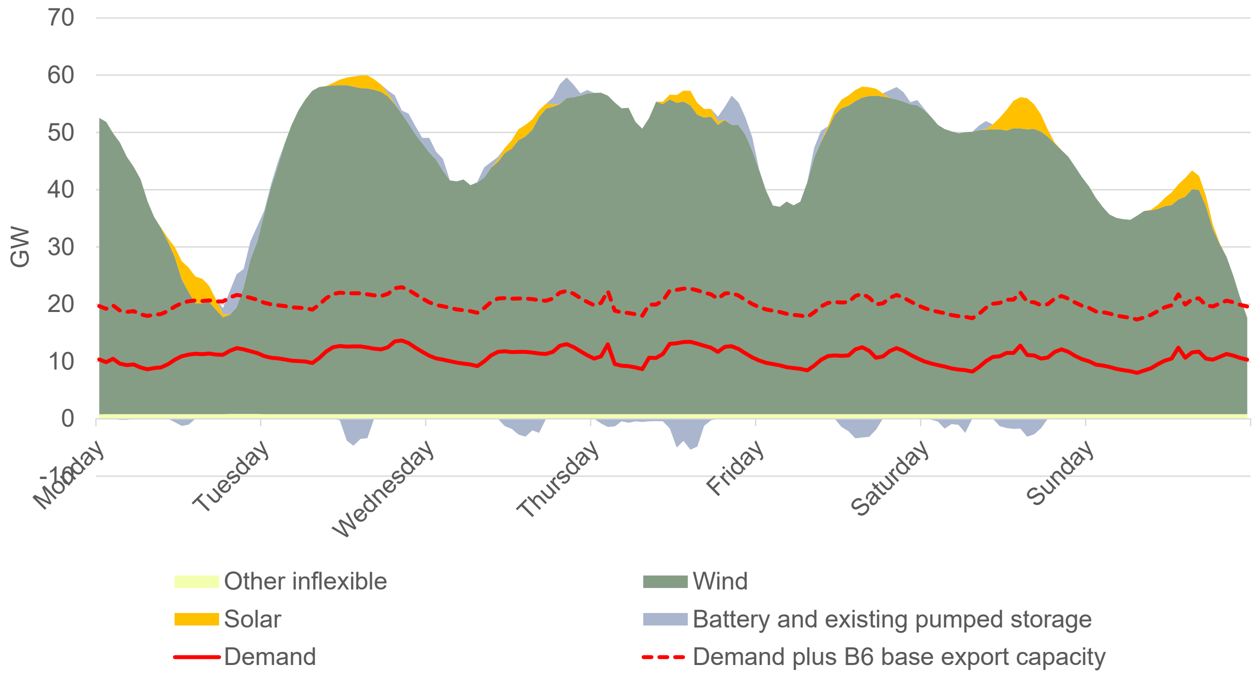
[23] Analysis here ignored dynamics parameters of thermal generation, including ramp rates or technical minimum output levels. Wind capacity calculations were based on the relative load factors of wind in every hour, with a representative mix of onshore and offshore, and calculated for the hour where most capacity would be needed to supply the residual demand. Storage options were assumed to be 100% full at the start of the week, except for the final combination option, where the storage was assumed to be 1/3rd full initially.

output. Operating costs are ignored here, since they are small compared to the cost of capacity required to ensure adequate security of supply in such a period.

C.2 Managing locational constraints in key high wind periods

The scale of the challenge for integrating wind into the network is illustrated in Exhibit C.3. For this analysis, the generation and demand in Scotland was considered for a particularly high wind period, where the B6 boundary transmission constraint was liable to be constraining generation.

Exhibit C.3 – Illustrative excess energy produced in Scotland for a critical 2050 extended period of high wind (January 2017 weather)



Over this weekly period, generation exceeds demand in Scotland by a cumulative 6TWh, with a peak at 48GW. Taking account of the transmission network assumed starting point for 2030, the base network had a transfer capacity across B6 of 10GW over this period. This reduces the cumulative excess energy to 4.4TWh with a peak of 38.5GW.[24] There are a number of options for utilising this renewable energy, that must otherwise be curtailed and wasted. These options are set out in Exhibit C.4.

[24] In BID3, there are multiple transmission constraints modelled across Scotland, and therefore this is a simplification of the situation. Nevertheless, it is illustrative of the challenges that large volumes of excess wind generation create for the system

Exhibit C.4 – Candidate solutions for utilising excess Scottish generation in a high wind period in 2050, presenting the capacity required and gross capex costs[25]

Candidate technology	Capacity, GW	CAPEX, £bn
Curtail wind and run other generation in England	Zero capex, but inefficient use of the available wind output plus balancing constraint costs associated with subsidy opportunity costs and constrained generation replacement	
Locate wind capacity in other parts of the country and network	Not considered here, but is likely to increase overall system costs due to sub-optimal use of national wind resource potential	
Reinforce power transmission network	45	28
Electrolysis plus hydrogen pipeline to storage facilities and end-user demand	40	24
2hr li-ion battery	2338	703
PSP (6 hour)	390	556
PSP (20 hour)	234	380
PSP (72 hour)	65	131
Combination, including:	45	42
Transmission network	30	18
PSP (20 hours)	15	24
Residual wind curtailment	*13GW peak curtailment, 0.5TWh total curtailment*	-

This analysis suggests that a large amount of network reinforcement is unavoidable, due to the relative costs. This could be either power or hydrogen network, depending on the relative demand for hydrogen or power. Increasing the network capability represents a more efficient means of reducing renewable curtailment and using the locationally constrained power. Network reinforcement, when considering capex alone, presents a more attractive option than many of the power LDS options available.

[25] None of the options considered the avoided costs of alternative generation or the value of the power/hydrogen that ends up in the different storages. Hydrogen and/or power transmission networks are assumed to need reinforcement from Scotland as far south as northern England, a similar level of reinforcement distance as the Western Link HVDC cable, which added 2.2GW of network capability at a cost of 1.3£bn. The hydrogen network would need slightly less overall capacity, since some hydrogen produced in Scotland could be used locally and doesn't need piping to the hydrogen demand and/or storage available in northern England. All storage options are assumed to be fully empty at the start of the week. Transmission options have an assumed availability factor applied.

In the case of hydrogen, it was assumed that no salt cavern storage would be possible locally, and so a hydrogen pipeline would be needed to access such storage in Northern England.[26] Despite the additional cost of the electrolysers, the lower cost of hydrogen pipelines compared to power transmission lines makes this the lowest cost option in this instance, followed by the expansion of the power network. Conversion of the gas network could reduce costs beyond those presented here. However, ensuring electrolysers link to such a network could make these costs much higher.

Significant interest in short duration storage for constraint management exists at present. AFRY’s analysis of the BM suggests this has clear value in reducing the constraint costs associated with more extreme negative bid prices; these revenues would need stacking with other services. However, by 2030, these are largely expected to disappear, due to the changing nature of renewable subsidy schemes. Without large negative bid prices, the volume of excess renewable output over this week is likely to make short duration storage options inefficient from a cost perspective. To have enough TWh of storage, a much larger GW investment is required. Even the longest duration pumped storage plant option would be relatively expensive if it were the only technology deployed to solve constraints, due to the large number of GW required. It is unlikely that storage can remove the need for network reinforcement. Indeed, there is a risk that storage behind constraints can become sterilised if the constraint durations extend far beyond storage durations and storages cannot effectively discharge.

Our analysis suggests that network solutions are ultimately cheaper than using power LDS technologies to utilise the excess renewables. This relates to the very extended duration of the high wind output in this example; the extended duration of the constraint is beyond the duration of any of the power LDS technologies considered.

Where an illustrative combination of network reinforcement and storage is considered, this is still relatively more expensive than the scenario where only network solutions are used. Storage is not expected to operate solely for constraint management. This is not to say that storage does not have any role to play in alleviating constraints though. Clearly, at other times in the year, short duration constraints could be managed by a range of different technologies. These events are likely to be relatively frequent, and as such, a smaller quantity of storage has a role to play where mismatches between renewable capacity and network capability arise. Storage could also have a role to play in mitigating any inefficiency of network reinforcement delivery.

However, this analysis illustrates that with very long duration constraints likely in the future, there is a limit to efficiency of storage as the primary solution to the problem of network congestion.

[26] Although an emerging technology and subject to some cost uncertainty, hydrogen pipelines are in principle similar to natural gas pipelines, and so expected costs are relatively well understood.

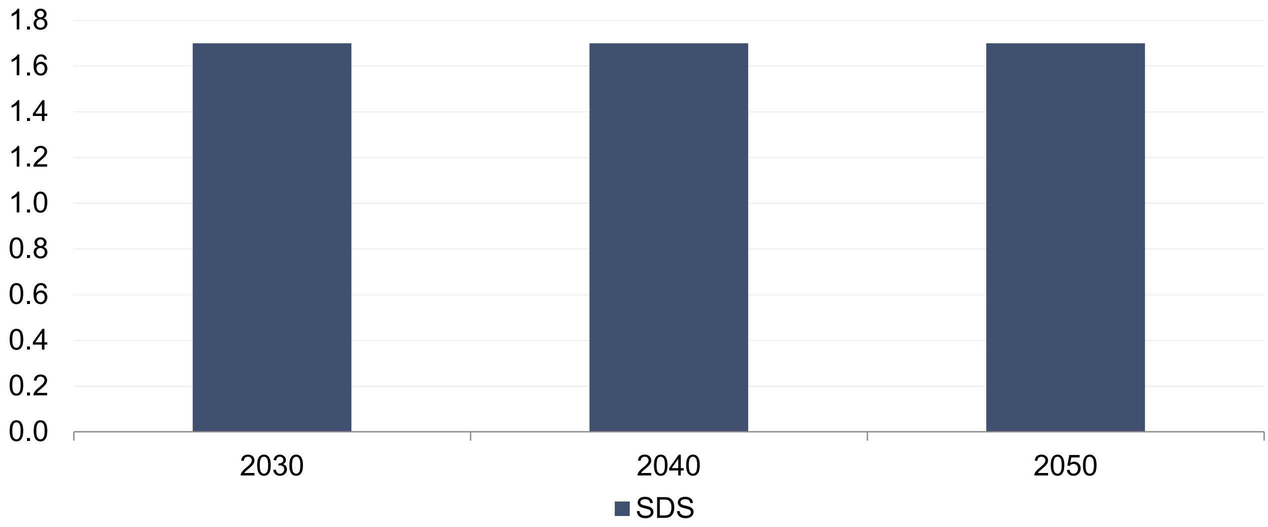
Annex D: Modelled results for system stability requirements

This annex presents further detail on the modelling of system stability requirements and ancillary services. In terms of the modelling, similar conclusions would be drawn in all 3 core scenarios; the results are therefore presented only from scenario #1.

D.1 Reserve and response

Short duration storage dominates the response requirement, as shown in Exhibit D.1. Short duration storage has advantages from both a technical and cost perspective.

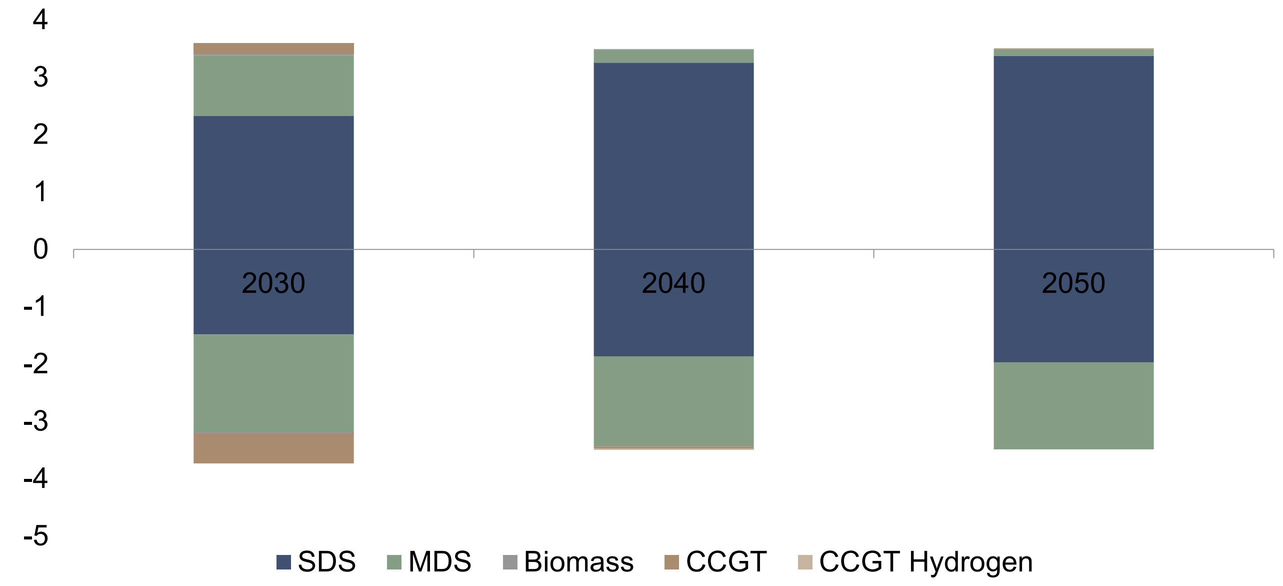
Exhibit D.1 – Annual average frequency response provision, scenario #1 all durations (GW)



Future regulating reserve requirements were derived from AFRY analysis of potential imbalance volumes in 2030. Increased uncertainty around forecasts, as RES capacity grows, means that regulating reserve volumes rise to 3.5GW.

SDS and MDS combined with the existing pumped storage capacity are the main providers of reserve capacity, as shown in Exhibit D.2.

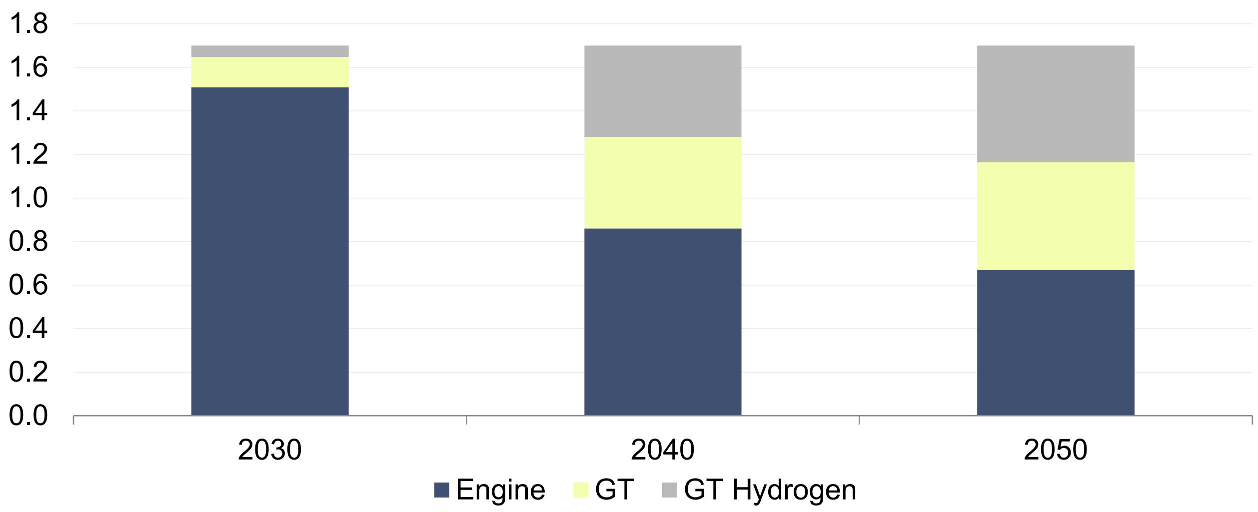
Exhibit D.2 – Annual average regulating reserve headroom (+ve) and footroom (-ve) provision, scenario #1 all durations (GW)



Where MDS and LDS were used in regulating reserve provision, the cost of reserve provision was not significantly reduced as a result. Most of the regulating reserve was provided by storage in all scenarios. Where MDS and LDS were used, this was to displace li-ion batteries. Longer duration batteries can provide these services at relatively low cost.

STOR is also procured to operate on a post-fault basis, and it is cheapest to maintain this reserve through peaking thermal capacity, as shown in Exhibit D.3

Exhibit D.3 – Annual average STOR provision, scenario #1, all durations (GW)



Whilst theoretically MDS and LDS could provide STOR, storage is more cost efficient when operating at a high cycling rate and therefore, from the perspective of having a standing reserve available, peaking capacity is likely to be cheaper for this flexibility requirement.

For voltage support and inertia, these were found not to be key drivers of new MDS and LDS.

D.2 Voltage support

The modelling assumes that NG ESO will introduce new markets for voltage support, and that a range of low carbon technologies and dedicated reactive power solutions would compete for these. Again, it was assumed that these new market arrangements would be in place by 2030 and that voltage support would not be a driver of new entrant MDS and LDS beyond 2030. Evidence emerging from recent Voltage Pathfinder tenders is consistent with this result. The cost of Transmission Owner led solutions, such as Static Compensators and Shunt Reactors are very cost-efficient means of managing voltage. Wind farms (and other inverter led solutions) can also provide some voltage support services.

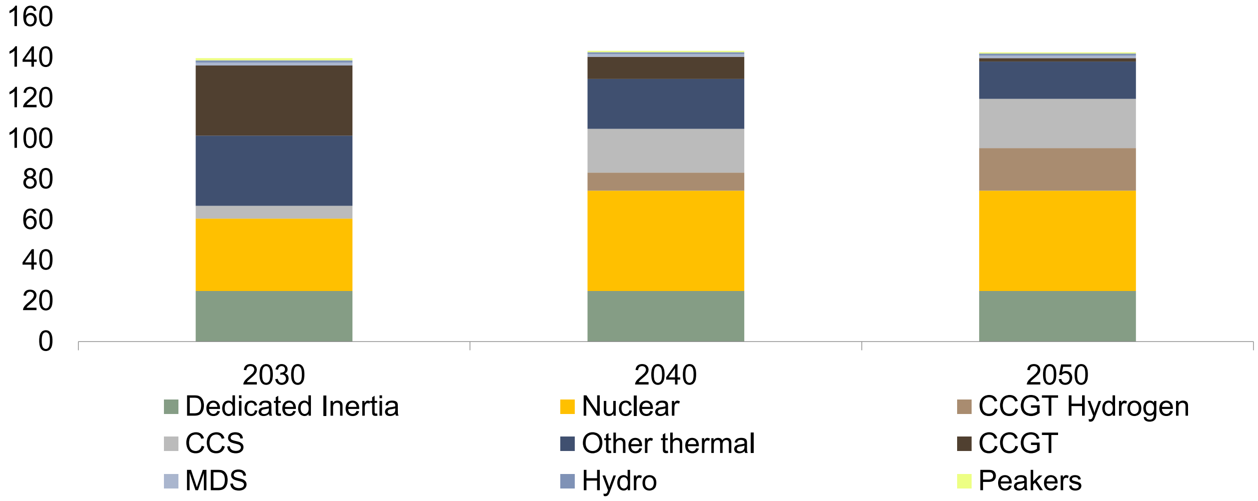
A limitation for some MDS and LDS technologies is that voltage support is a highly locational system requirement, which does not necessarily map onto the available locations for deploying some of these technologies. The technologies with greater locational deployment flexibility have an advantage here; this includes SDS, MDS, LDS and other dedicated voltage support solutions.

D.3 Inertia

A net zero system is likely to be a much lower inertia system than the system of today. While this potentially offers an opportunity for MDS and LDS, the expectation is that the challenge of operating a low inertia system needs to be overcome by 2030. It is likely that there will be sufficient inertia in the system by this point and therefore this will not be a key source of value for LDS.

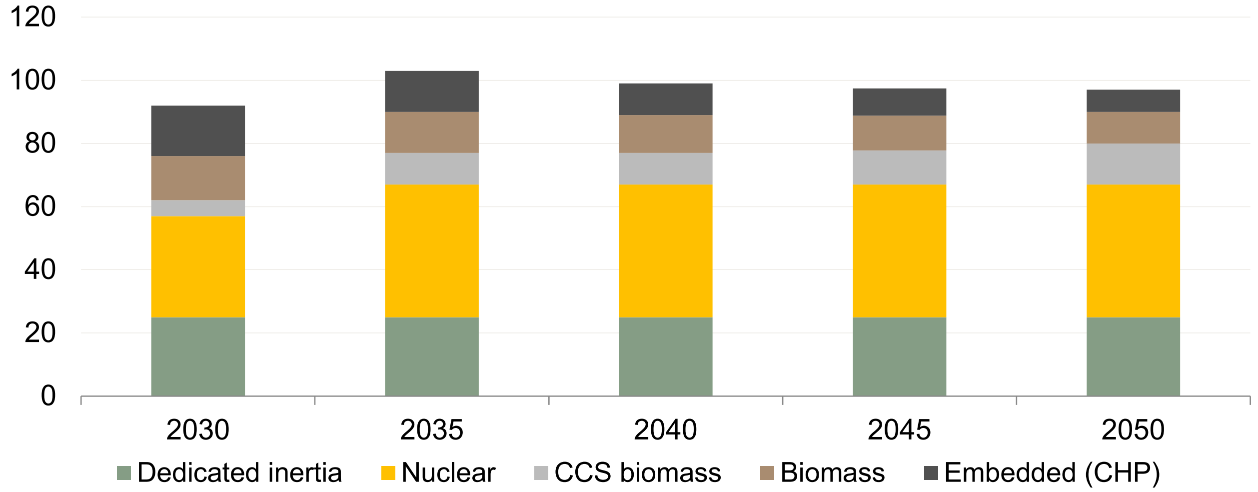
Key to this finding is the inertia provided by baseload low carbon technologies, as shown in Exhibit D.4. NG ESO has signalled that they will require over 30GW.s of inertia from dedicated inertia providers by 2025. These volumes, procured from Stability Pathfinder tenders, are assumed to be present throughout the modelled time frame, supported by a new inertia market. Whilst some existing pumped storage plants have won some of these contracts, the modelled 25GW.s of inertia from synchronous condensers (or other equivalent technologies) here ensures that the incremental inertia required from long duration storage technologies was low. As has been seen in the results of recent tenders, battery storage can provide inertia through grid forming capability at very low cost.

Exhibit D.4 – Annual average inertia, scenario #1 all durations (GW.s)



Against a modelled minimum instantaneous inertia of 110GW.s, the inertia from baseload low carbon power can be seen to fulfil almost all of this requirement. This can be seen from the baseload inertia results below in Exhibit D.5. Whilst inertia requirements vary at different times, the key result here is that most of the required inertia will be delivered through baseload low carbon generation and dedicated inertia sources. These will likely deliver inertia irrespective of prevailing wholesale market conditions.

Exhibit D.5 – Annual average baseload inertia from low carbon sources (GW.s) in scenario #1



We conclude that inertia requirements will not be a big driver of the need for additional long duration power storage. Even at times of low demand and high renewables, baseload low carbon power provided most of the required inertia. Given that this inertia will be on the system independently of any decisions around supporting LDS, we can see that in scenarios with significant baseload low carbon generation, inertia will be a much lower value service for LDS than at present.

For inertia to be an important service for LDS, the system would need to see much lower levels of baseload low carbon generation. Even in this eventuality, inertia from inverter led solutions with grid forming capability is likely to be a highly competitive alternative on a unit cost basis.

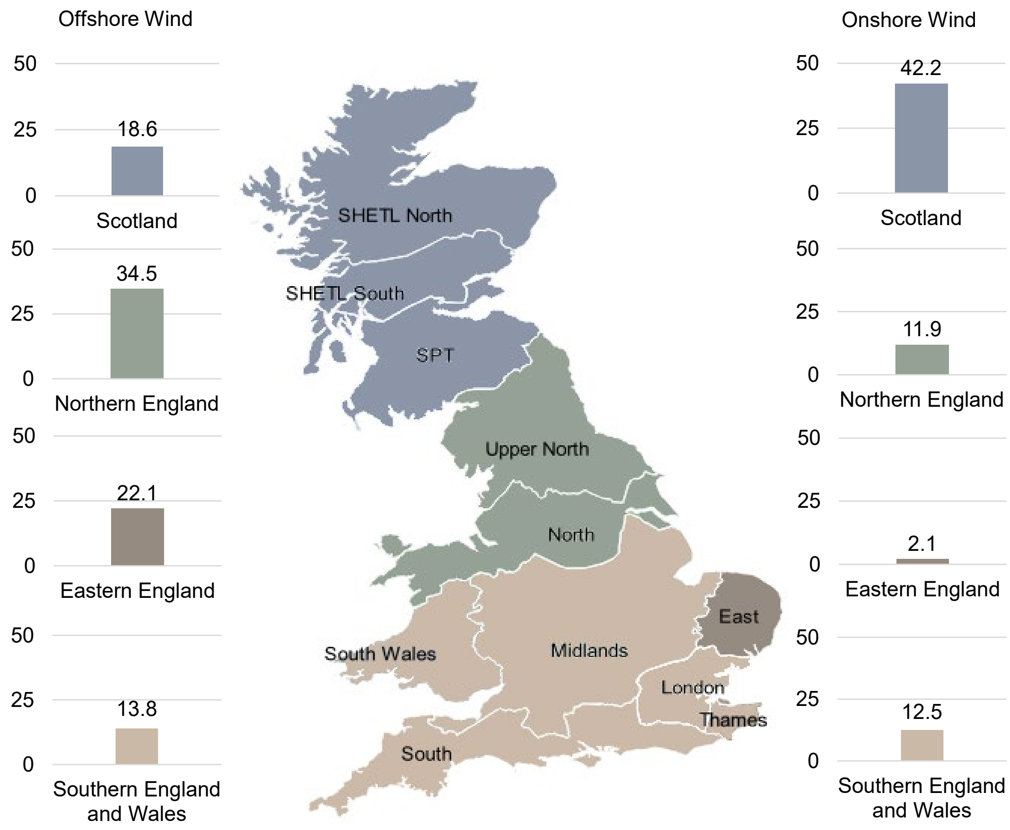
Annex E: Modelled results for transmission constraints

This annex presents further detail on the modelled outcomes relating to location congestion, drawn from scenario #1. Other core scenarios showed similar results.

E.1 Renewable capacity locations

As shown in Exhibit E.1, the modelled optimal capacity mix included large quantities of onshore wind in Scotland in scenario #1. Large quantities of offshore wind are also deployed in Northern England, off the East Coast and in Scottish Waters.

Exhibit E.1 – Final results for offshore wind capacity (left) and onshore wind capacity (right), scenario #1 all durations 2050 (GW)[27]



[27] The scenario framework specified an overall build cap and build rate limit for each technology. Regional build caps were also applied; these were based on the regional renewables capacity that is present in NG FES scenarios. This was used to create a share of the total wind resource potential for each region. The derived maximum share of wind capacity for each region was then applied to the overall technology build caps. The resulting build in each region is therefore determined by the resource potential, the effective levelized costs, and capture prices achievable in each location. The capacity expansion included an optimisation of further wind build in different locations, along with the additional costs of the grid to allow the transmission of this power to relevant demand locations.

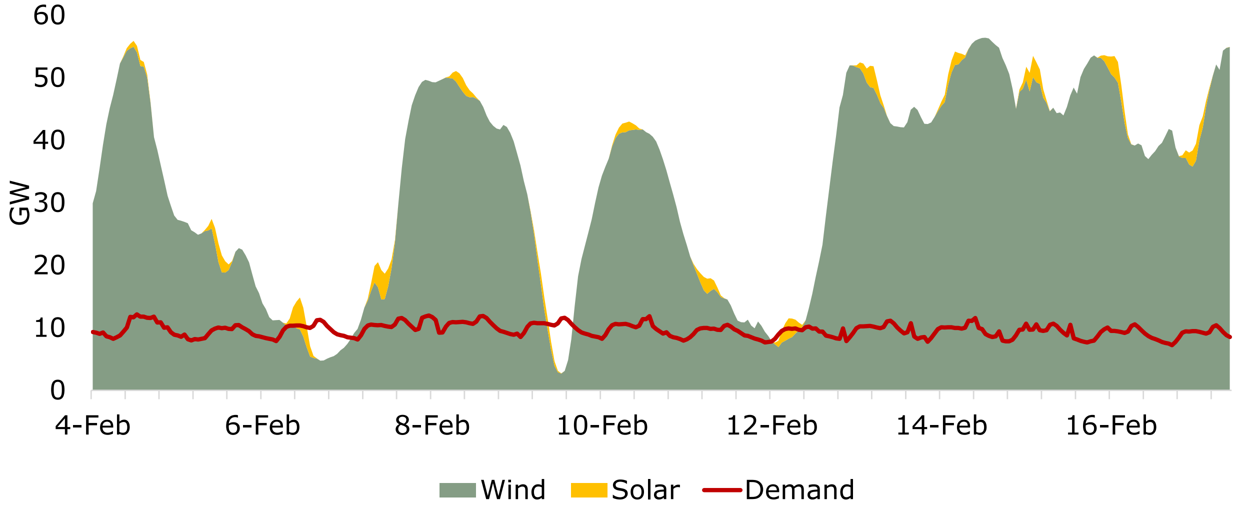
These are all locations that are relatively far from demand centres, and therefore building wind in these locations drives the need for further expansion of the transmission network.

E.2 The need for transmission reinforcement

The difference in wind speeds is such that despite the extra transmission reinforcement costs in the model, it is still preferable to locate wind in these regions. Without reinforcement, there would be a strong need to curtail wind located in the best wind resource locations, or alternatively, build the wind in less optimal regions from a wind resource and system cost perspective.

Exhibit E.2 illustrates the locational congestion issue using an hourly snapshot of generation and demand in Scotland. The power demand in Scotland is low but it has a high wind resource potential. This leads to Scotland producing more power than it requires to meet its own demand and therefore exporting to the south. These periods of excess wind generation can be prolonged and lead to high constraint volumes over several consecutive days. To alleviate these constraints, boundary capacities need to be reinforced to incorporate the extra wind, beyond the 10GW B6 capability assumed for 2030.

Exhibit E.2 – Scotland hourly generation snapshot, 2050 weather year 2017 (GW)

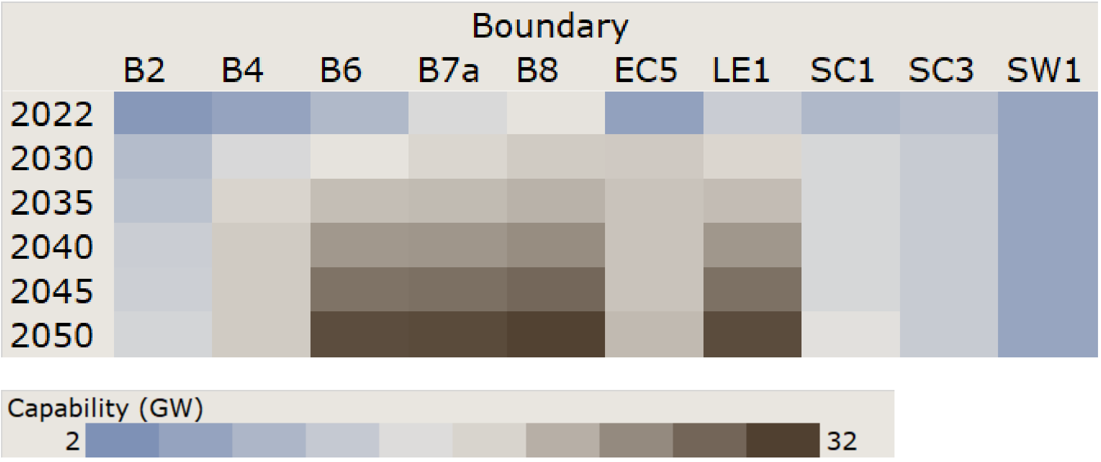


E.3 Modelled transmission grid reinforcement results

The modelling assumed that network expansion is possible; political and planning constraints were not considered on either the deployment of renewables or of other supporting infrastructure.

The heatmap in Exhibit E.3 shows the optimised level of reinforcement required for the modelled boundaries. The largest reinforcements are required for boundaries B6, B7a and B8, for transfer of wind energy from Scotland to demand centres in the South, and for LE1, around London, which is required for North-South energy transfer as well as energy from offshore wind off the Eastern coast of England.

Exhibit E.3 – Transmission network reinforcement heat map, scenario #1 all durations (GW)



E.4 The role of storage in constraint management

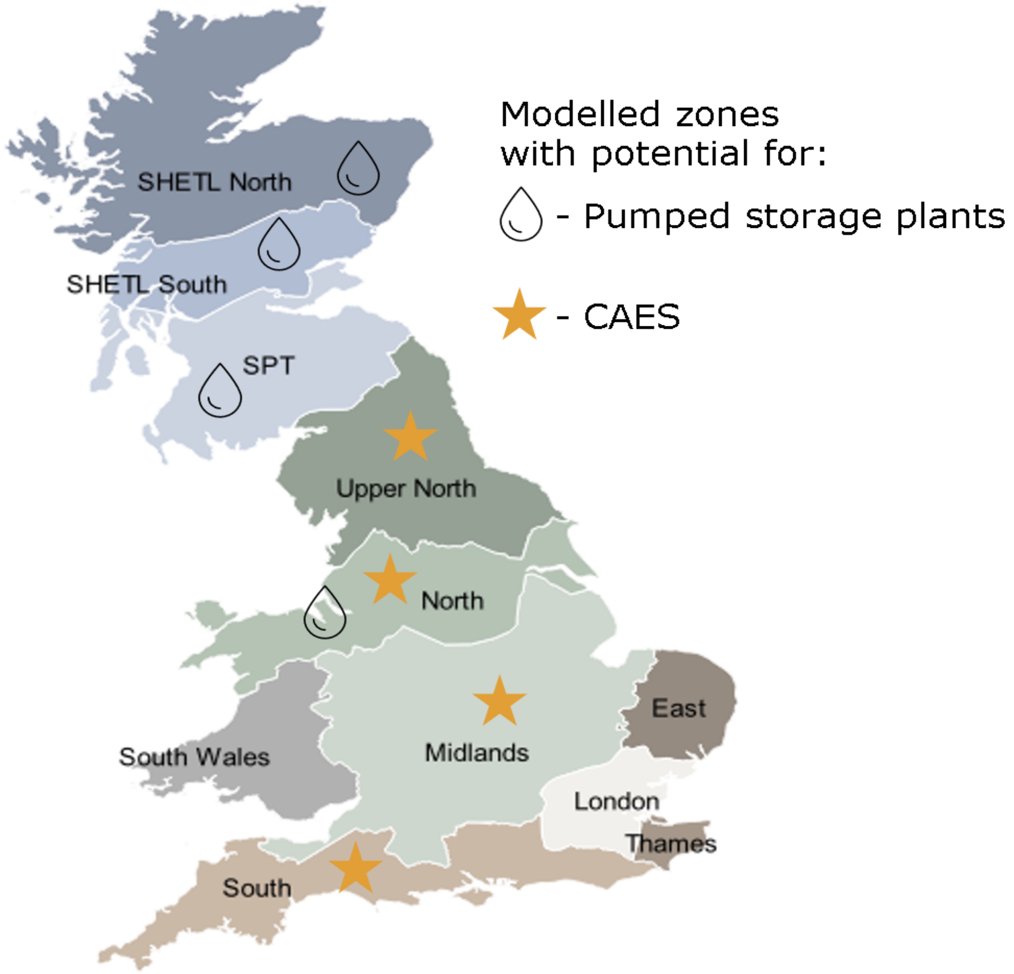
This offers opportunities for LDS – to reduced curtailment of renewables and also to provide alternatives to transmission reinforcement.

The ability of these technologies to manage transmission constraints is dependent on their location. As shown in Exhibit E.4, CAES was only considered feasible in certain English zones and PSP only in Scotland and the 'North' zone in the model inputs.

This means that for CAES to store excess wind generation from Scotland, the energy would have to pass over key congested northern boundaries; since it is not behind the constraints, it is therefore only able to effectively manage congestion on boundaries further south. This does include English offshore wind though.

Other potential MDS and LDS technologies are less geographically constrained and therefore have greater potential for managing locational congestion.

Exhibit E.4 – Modelled PSP and CAES available new build sites



Annex F: Other sensitivity results

This annex presents more detailed modelling results from the sensitivities. It supplements the analysis presented in sections 5.6 and 5.6.

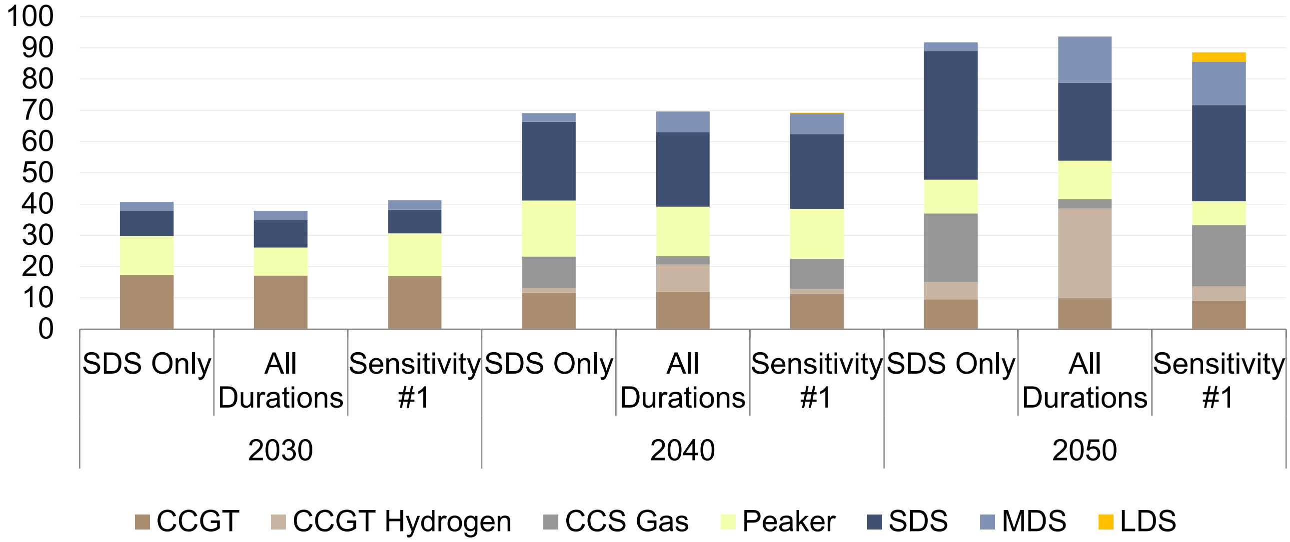
F.1 Technology sensitivities

F.1.1.1 Technology sensitivity #3 – no access to long term salt cavern storage makes gas with CCS preferable to hydrogen fuelled generation and increases the need for power storage

Sensitivity #1 modelled a case where salt cavern storage of hydrogen proves impossible to bring forward. As shown in Exhibit F.1, the inability to store hydrogen in salt caverns results in a scenario much closer to the SDS only case. Gas with CCS is relied on instead of CCGT hydrogen for seasonal balancing. Gas with CCS plants were modelled with a greater level of flexibility than blue hydrogen production, making hydrogen CCGTs linked to blue hydrogen production less attractive. Without the hydrogen LDS, the less flexible hydrogen sector only retains blue hydrogen to meet non-power sector demand. Electrolysis becomes less profitable as green hydrogen is harder to store, leading to reduced build.

There is still a relative system cost saving compared to the SDS only case, as the ability to build longer duration batteries and power LDS technologies displaces GT capacity and some gas with CCS.

Exhibit F.1 – GB flexible power capacity, scenario #1, SDS Only and all durations, vs sensitivity #1 (GW)



As shown in Exhibit F.2, 3GW more power LDS is built in the absence of salt cavern storage, primarily driven by the decrease in electrolysis capacity. Electrolysers and power LDS compete to access excess renewable output. If electrolysis cannot effectively store the hydrogen that it produces, then its flexibility to access the cheapest power prices is diminished. There is more excess renewable output available for power LDS in this sensitivity.

Exhibit F.2 – GB power storage capacity, scenario #1 vs sensitivity #1 (GW)

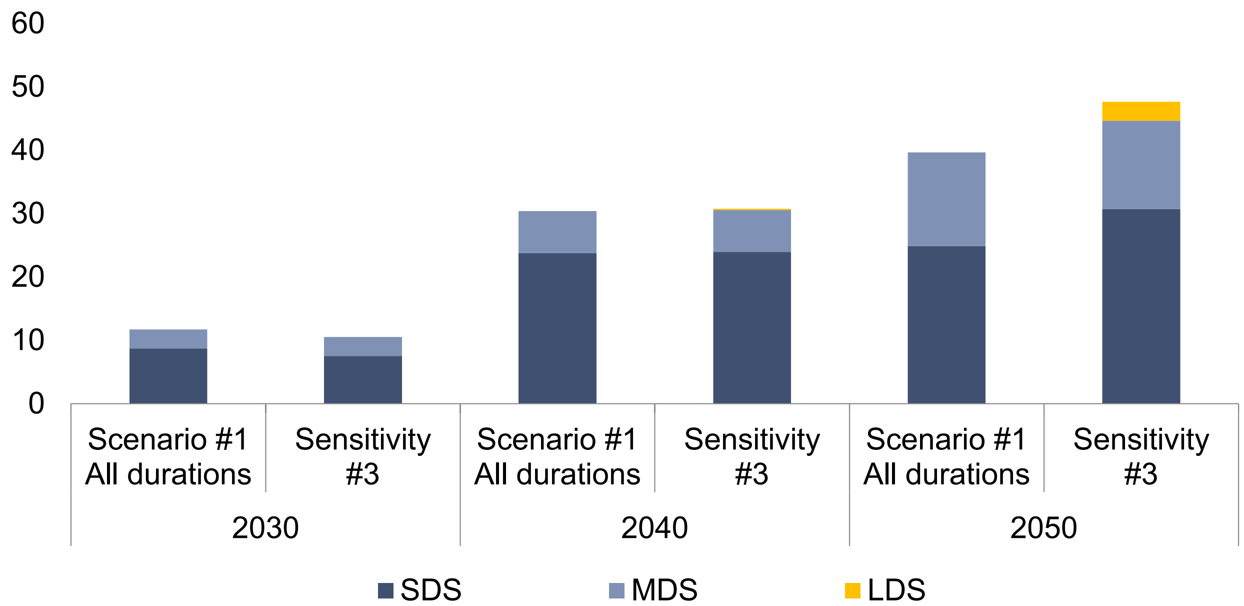
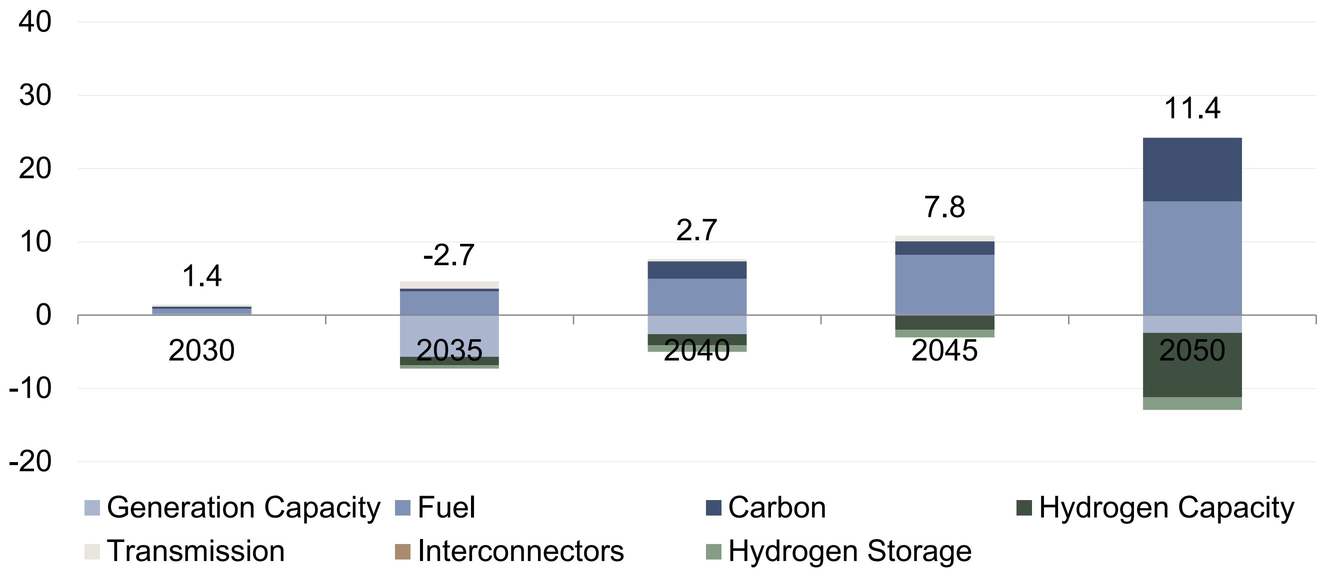


Exhibit F.3 shows the difference in undiscounted system costs for Sensitivity #1 compared to Scenario #1. This shows that the majority of the benefit to the system enabled by hydrogen LDS comes post 2040, where the hydrogen sector is more established.

Exhibit F.3 –Undiscounted system cost difference, sensitivity #1 - scenario #1 all durations (£bn)



F.1.2 Technology sensitivity #4 – reduced blue hydrogen capacity leads to increased electrolysis, which is deployed in preference to power LDS technologies.

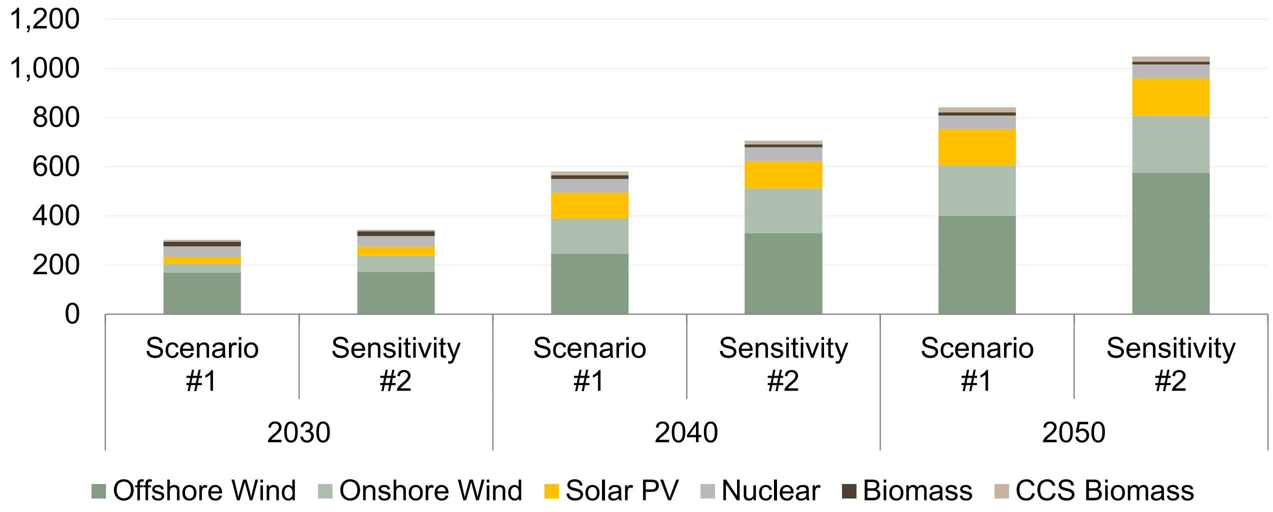
In sensitivity #4, blue hydrogen production capacity was limited in the model to 10GW. The NPV of system costs benefit from MDS and LDS was £27bn for this sensitivity.

As in the core scenarios, the main savings were achieved by the system being able to access salt cavern storage of hydrogen, rather than relying on hydrogen tank storage. This also led to a savings from deployment of hydrogen fuelled plants instead of more expensive CCS.

The overall system cost benefit in this sensitivity is slightly larger than in the core scenarios, as the limit of blue hydrogen in addition to no hydrogen LDS in the SDS only case increased costs.

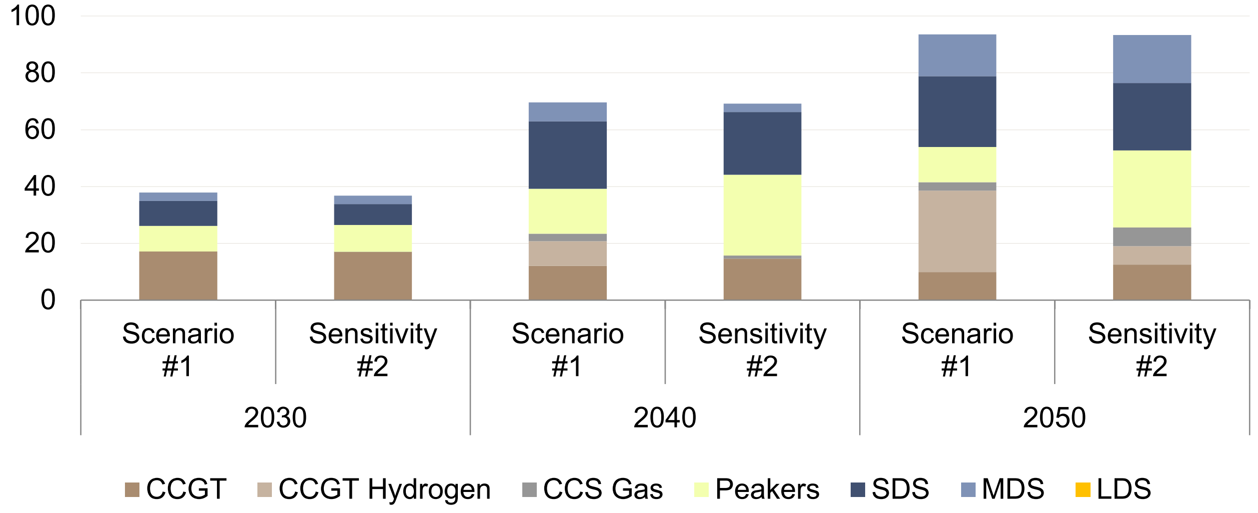
Total spend on hydrogen production capacity increased compared to scenario #1. More electrolysers are required to replace SMRs and ATRs to meet (the fixed input) hydrogen demand. Larger investments into RES, particularly offshore wind, are required to feed this extra electrolyser capacity. As shown in Exhibit F.4, this results in significantly more inflexible generation.

Exhibit F.4 – GB inflexible generation, scenario #1 all durations vs sensitivity #4 (TWh)



It might be expected that this large increase in inflexibility within the power sector would lead to greater scope for power LDS to be required. However, Exhibit F.5 shows that more peaking capacity (either gas or hydrogen fuelled) is preferred to power LDS or gas with CCS to balance the additional inflexible generation.

Exhibit F.5 – GB flexible power capacity, scenario #1 all durations vs sensitivity #4 (GW)



This happens for two reasons. Firstly, contrary to the previous sensitivity, more electrolysis is built to meet the demand for hydrogen compared to scenario #1. Electrolysis and power LDS are again in competition for low power prices, and, in this sensitivity, flexibility is already available from green hydrogen production. This electrolysis flattens the volatility of power generation, removing the need for power LDS to balance supply and demand.

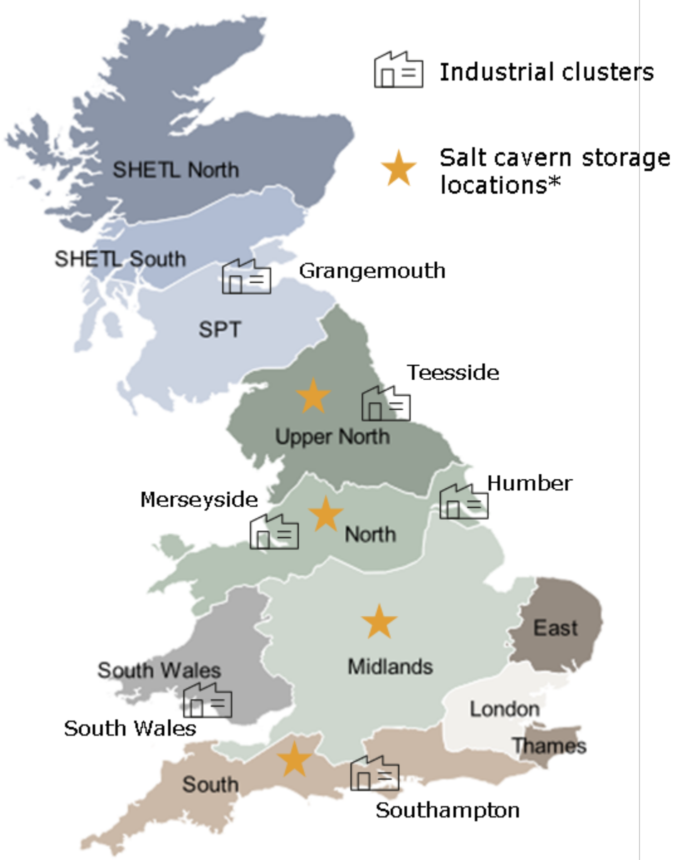
Secondly, offshore wind capacity credit means that the residual demand is smaller, and therefore more suited to peaking capacity rather than CCGTs. The relative overbuild of offshore wind, driven by extra electrolysis, means that cheaper peaking capacity can fill the supply gaps in low wind periods. Any additional emissions from these peakers are offset by the reduction in emissions from blue hydrogen.

F.1.3 Technology sensitivity #5 – excluding the transmission of hydrogen between zones reduces the benefit that hydrogen storage can bring to the power sector

Sensitivity #5 introduced the modelling of hydrogen zones, with no option to build hydrogen pipelines between zones. The inability to transport hydrogen meant that hydrogen must be produced in the same zone that it was consumed.

As shown in Exhibit F.6 , it is assumed that there are no viable hydrogen salt cavern storage sites within Scotland. When combined with the absence of hydrogen transport between zones, this significantly reduces the usability of Scottish electrolysers. For example, green hydrogen produced in the ‘SPT’ zone can only serve either industrial demand in Grangemouth or the Scottish heating, transport or localised power sector demand for hydrogen. It cannot access the salt cavern storage in the ‘Upper North’ zone. This opens the potential for hydrogen transmission limits to be important considerations. In optimal sector coupling for 2050, locational constraints on both power and hydrogen should be weighed against each other.

Exhibit F.6 – GB hydrogen zonal representation with industrial cluster and hydrogen salt cavern storage locations



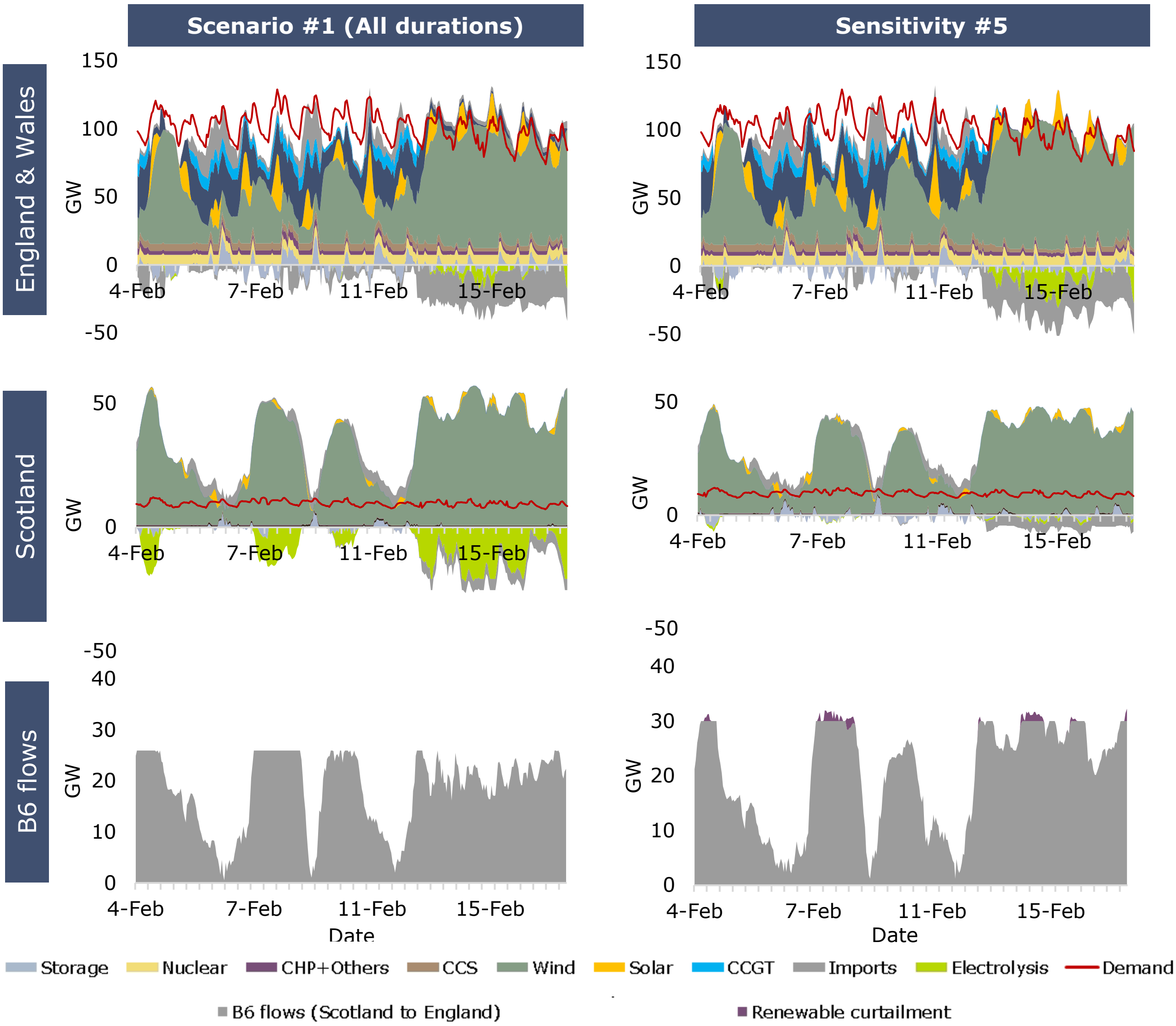
*Note: Locations represent the zones that storage is built in, not geographic location of the salt caverns

Exhibit F.7 illustrates these geographical constraints at an hourly level. The set of charts on the left shows that electrolysers in Scotland can be used to resolve power transmission congestion where a full hydrogen transmission network is available. Electrolysers consume significantly in high wind periods, producing green hydrogen. This is then transmitted to English salt caverns, stored and then made available for future use to balance either power or non-power demand.

The charts on the right show the same hours with hydrogen transportation constraints in place and zero hydrogen transmission available. In this sensitivity there is almost no hydrogen production in Scotland as it cannot be stored for long durations and cannot be transported to other zones. As a result, a much higher proportion of electrolysis hydrogen production takes place in England, where hydrogen can be stored for use in hydrogen CCGTs.

The bottom pane of charts shows the increased reliance on power transmission across the B6 boundary along with increased RES curtailment. Without electrolysis in Scotland, the power transmission network requires further reinforcement, and renewable curtailment is also increased.

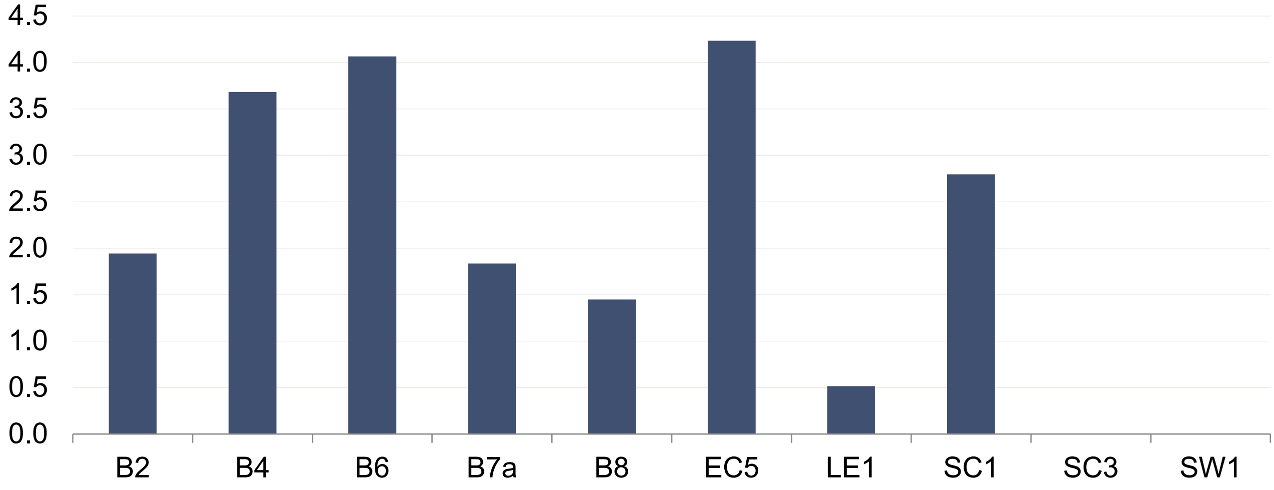
Exhibit F.7 – Hourly 'snapshots' of generation and flows with and without hydrogen transmission constraints, 2050 weather year 2017 (GW)



Despite these locational constraints the hydrogen sector is not significantly smaller without hydrogen transmission; non-power sector hydrogen demand is a fixed input, but power sector hydrogen consumption also remains constant. Similar quantities of hydrogen are required by the power sector, and also passed through the salt cavern storages. However, the wider system benefits are diminished as additional power transmission is required.

Exhibit F.8 shows the additional power network capacity required in the absence of hydrogen transmission. A further 4GW increase across the B6 boundary by 2050 is required.

Exhibit F.8 – Extra power network capacity required, sensitivity #5 (without hydrogen transmission capability) – scenario #1 2050 (GW)



F.1.4 Technology sensitivity #6 – introducing costs for the development of a new hydrogen transmission system leads to trade-offs between hydrogen transmission costs and benefits to the power sector from hydrogen storage

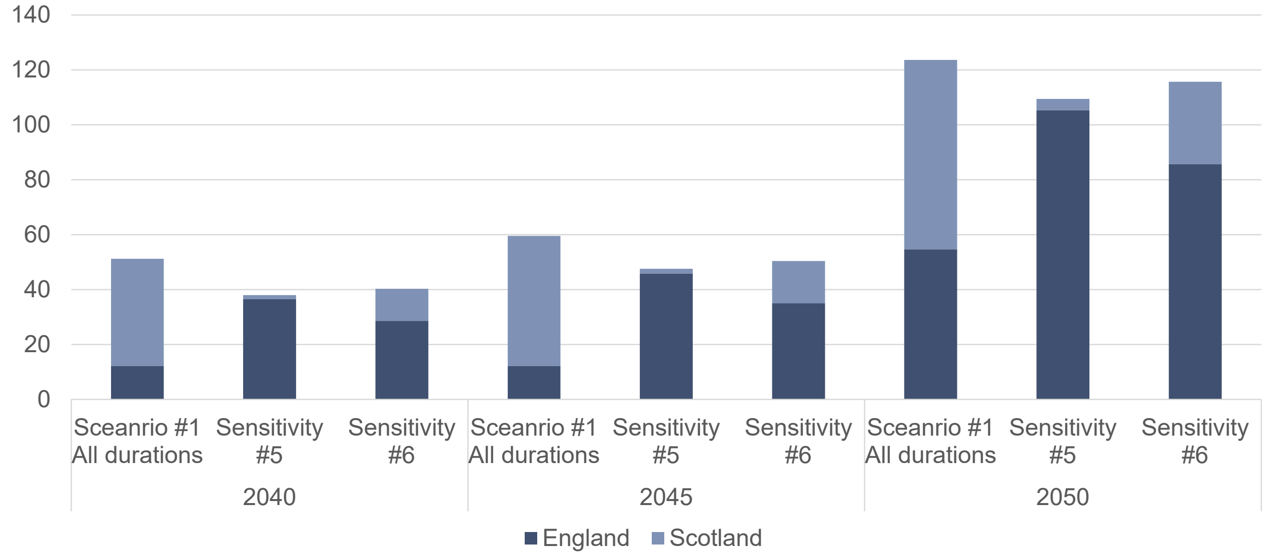
The core scenarios assumed a hydrogen network would be developed to support the non-power hydrogen demand, and that the power sector use of hydrogen would benefit from this. However, the model did not directly incur these costs. This sensitivity tests this assumption and investigates the relative benefits of hydrogen versus power network reinforcement. This sensitivity shows how these compare to power LDS solutions to constraints.

The modelling of sensitivity #6 included hydrogen transmission as an explicit cost faced by the model. A balance is achieved so that:

- Scottish electrolysis is integrated; and
- power transmission network reinforcement is avoided.

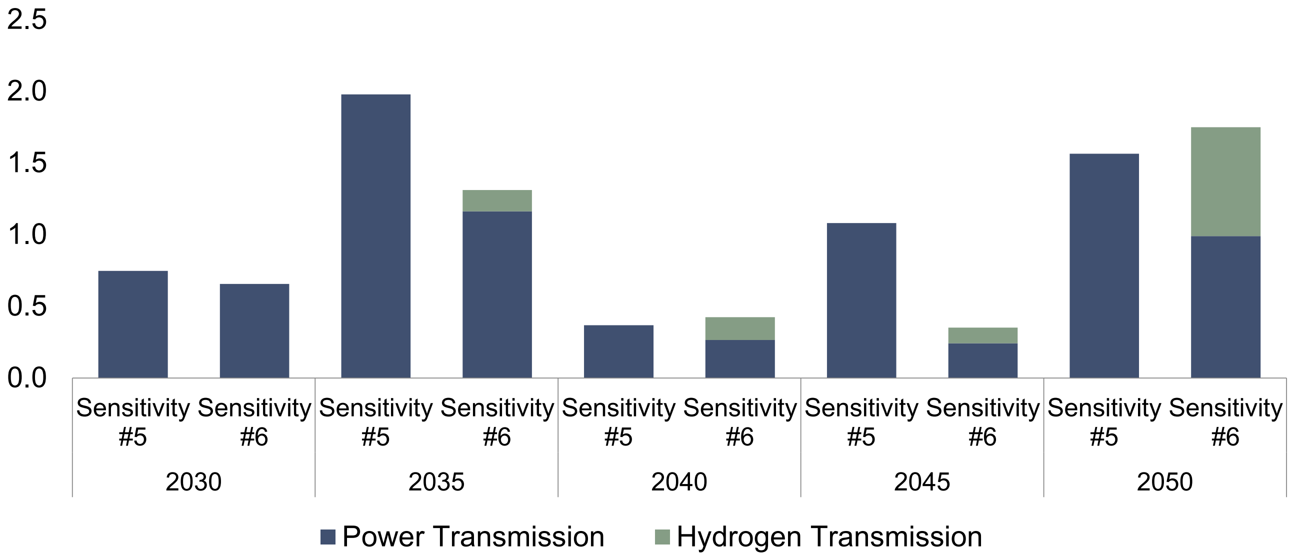
As shown in Exhibit F.9, more Scottish electrolysis can be integrated into the system compared to the case where hydrogen cannot be transported between zones. Less is integrated compared to scenario #1 due to the additional costs faced to develop the hydrogen transmission network.

Exhibit F.9 – Electrolysis production by location, scenario #1 all durations vs sensitivity #5 vs sensitivity #6 (TWh)



Overall system costs in sensitivity #6 were £2bn lower than in sensitivity #5 (2030 NPV basis). Compared to scenario #1, all durations, the system costs were £6bn higher. Although there were additional costs of investing in hydrogen transmission, as shown in Exhibit F.10, these were more than offset by the benefit of being able to transport hydrogen between zones.

Exhibit F.10 – Increase in undiscounted power and hydrogen transmission costs, sensitivity #5 and sensitivity #6, compared to scenario #1 all durations (£bn)



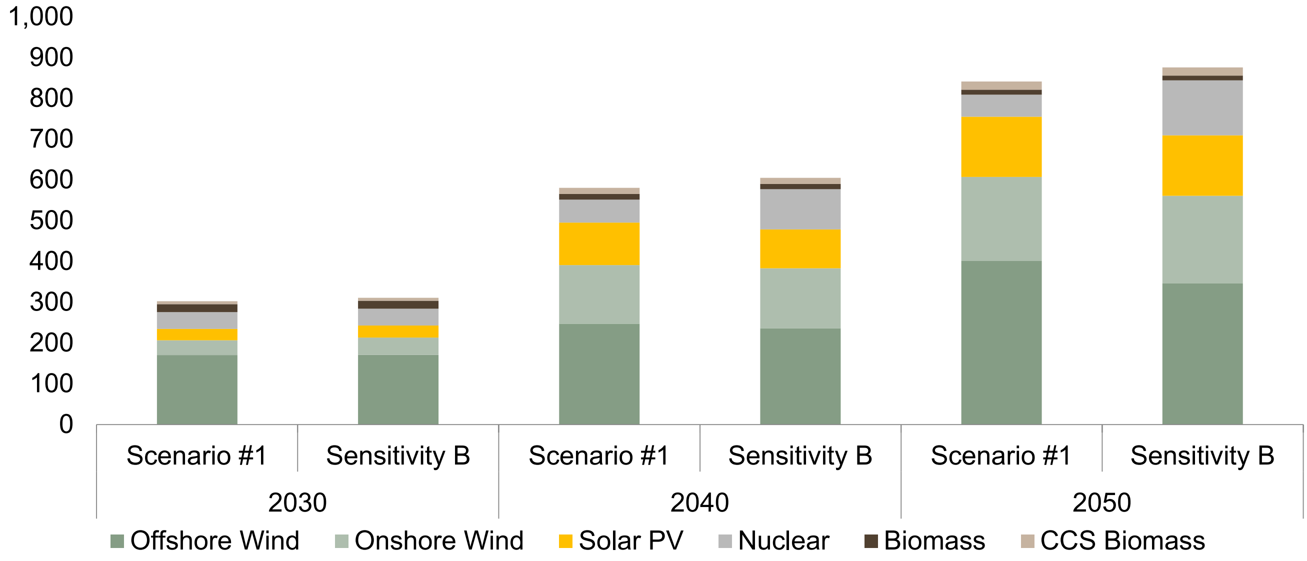
Power LDS does not play a greater role, in this sensitivity, due to relatively high costs compared to network capacity reinforcement.

F.2 Wider system sensitivities

F.2.1 Wider system sensitivity #B – more nuclear

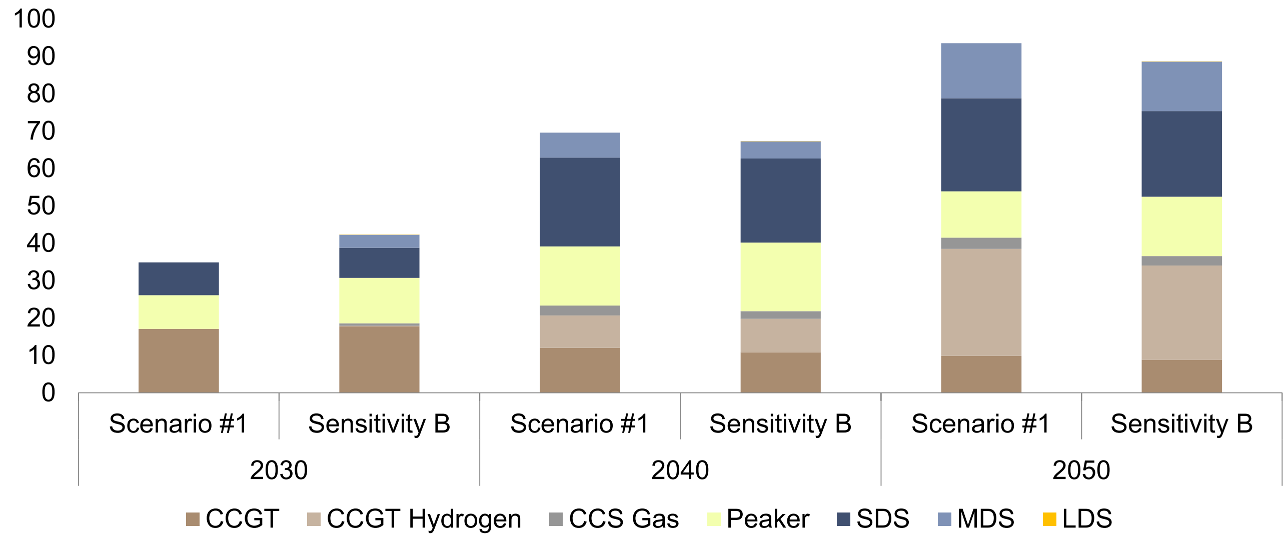
The additional nuclear capacity in this sensitivity primarily displaces offshore wind and SDS capacity, incurring an overall net £8bn increase in total system costs. Exhibit F.11 shows this increase in nuclear generation and corresponding decrease in offshore wind.

Exhibit F.11 – Inflexible generation, scenario #1 all durations vs sensitivity #B (TWh)



Nuclear generation replaced offshore wind. Although there is an overall increase in inflexible generation in this sensitivity, less flexible capacity is required. The mix of flexible capacity, shown in Exhibit F.12, shows a small decrease, primarily in SDS capacity. The sensitivity sees a slight increase in peaking capacity and other low-carbon thermal. The overall power balance was also different due to different flows across interconnectors.

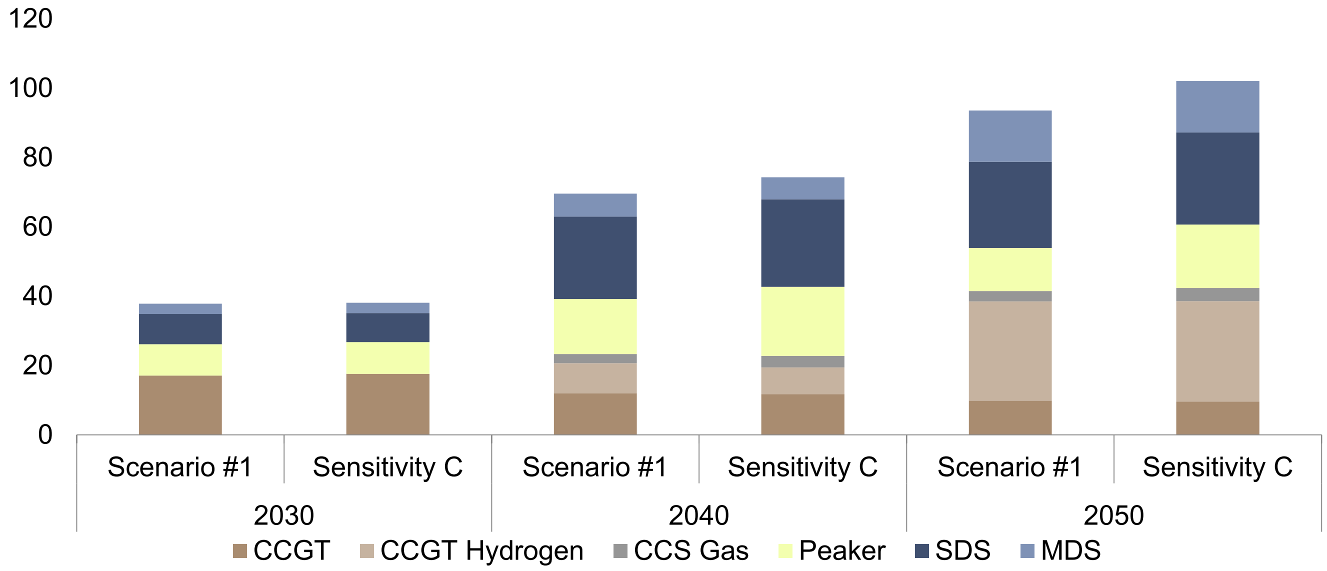
Exhibit F.12 – Flexible capacity, scenario #1 all durations vs sensitivity #B (GW)



F.2.2 Wider system sensitivity #C – less DSR

This sensitivity has an additional £3bn incurred to the system costs, through having access to lower volumes of DSR. No additional power LDS is built as there are cheaper options. As shown in Exhibit F.13, GT and batteries are most cost-effective replacement capacity.

Exhibit F.13 – Flexible capacity, scenario #1 all durations vs sensitivity #C (GW)



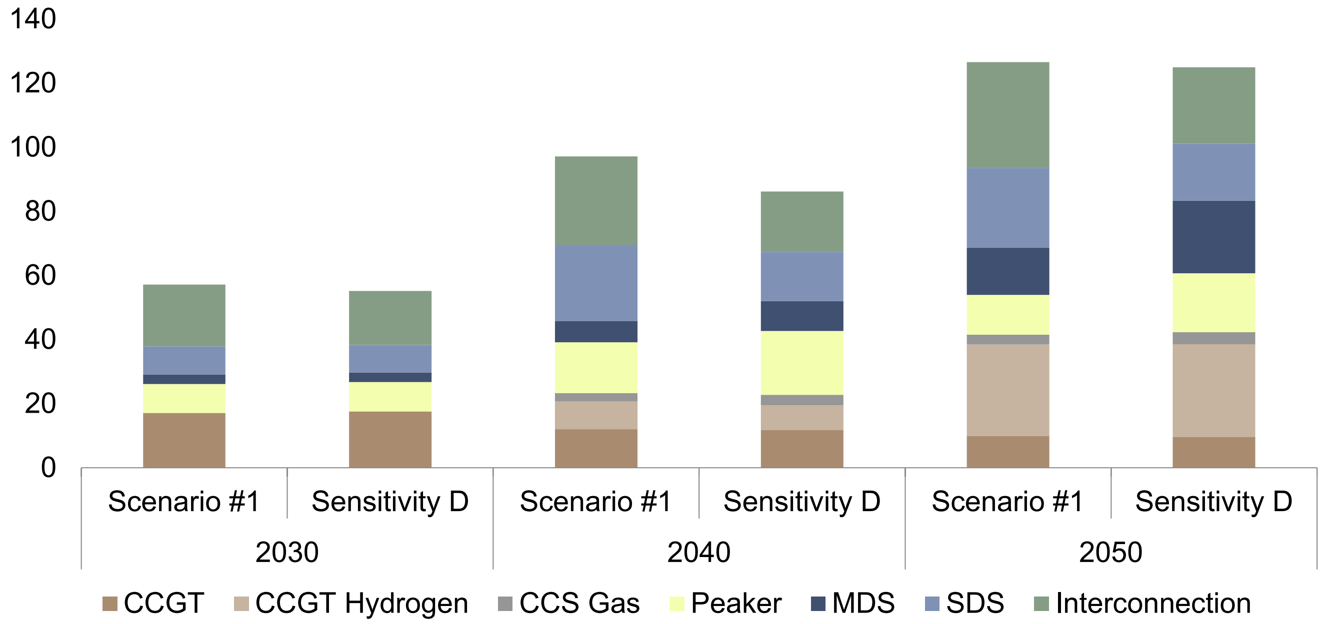
DSR technologies are primarily either akin to short duration storage (from EVs for example) where the flexibility is approximately available across a day, or similar to peaking capacity (such as turn down industrial and commercial DSR). Therefore, incentives to bring DSR to the system are not a major factor to reduce the viability of long duration storage.

F.2.3 Wider system sensitivity #D – unsupported interconnectors

There is an additional system cost of £2bn, due to no ability to deliver interconnection capacity as cheaply as in the core scenarios. Removing support for IC build led to an increase in MDS and peaking plant. Exhibit F.14 shows that no new power LDS capacity is built. Due to the low load factors on these GTs, emissions limits are still kept.

This highlights that interconnectors are not operating as an alternative to LDS, but rather as a form of short-term flexibility. This follows from the way that weather systems cover a large geographical area, with periods of high and low wind relatively correlated across significant areas. As a result, interconnectors are less likely to provide balancing between high wind and low wind markets. Thus, removing support from interconnection leads to a transfer of short-term flexibility options into the GB market.

Exhibit F.14 – Flexible power capacity, scenario #1 vs sensitivity #D (GW)



F.2.4 Wider system sensitivity #E – higher CO2 limits

Sensitivity #F explored a case where CO2 reductions are more backloaded. This sensitivity doesn't meet the BEIS emissions reduction targets. This sensitivity is, however, combined with the same support for power LDS as modelled in Scenario #3 to investigate the impact of carbon policy on the effectiveness of supporting LDS. It examines the level of regret where CO2 reductions are not achieved.

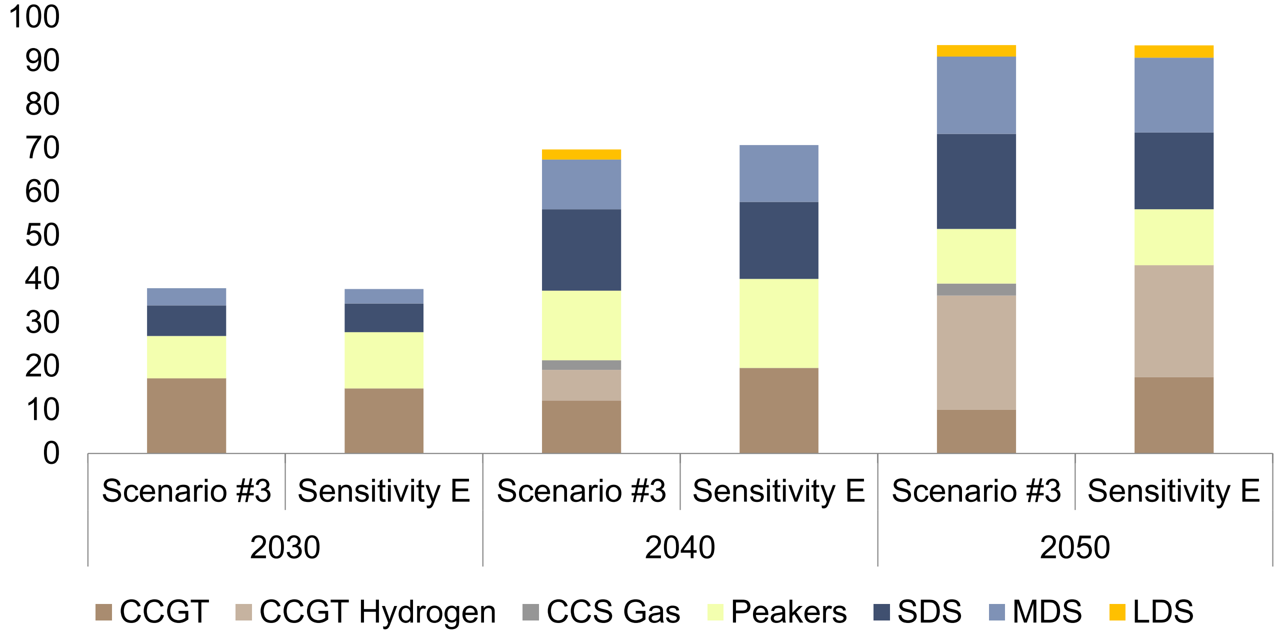
The NPV of system costs were as follows:

- higher CO2 limits all durations: £453bn; and
- higher CO2 limits with SDS only: £469bn, leading to a system cost benefit of £16bn for this sensitivity

The main savings were achieved by the system being able to access salt cavern storage of hydrogen, rather than relying on hydrogen tank storage.

Higher carbon limits in the earlier years means that additional CCGT capacity is built and persists out to 2050, where it can run at very low load factors. There is nearly 2GW less new power LDS capacity in this sensitivity compared to scenario #3 (both having supported power LDS investments). This is shown in Exhibit F.15.

Exhibit F.15 – Flexible power capacity, scenario #3 vs sensitivity #E (GW)



Levels of power LDS build are lower in this sensitivity compared to scenario 3, but the difference is relatively small, showing that the decision to support power LDS is not a high regret decision, even if emissions reductions are slower to be realised across the power sector as a whole.

F.3 Final power storage capacity results

The final storage capacities for power SDS, MDS and LDS, across all modelled scenarios and sensitivities are presented below. Storage capacity is similar in each case, but MDS and LDS are deployed at higher levels in the sensitivities where alternative flexibility options are not available in 2040, or are relatively more expensive.

Exhibit F.16 – 2040 Power storage capacities, all durations, all scenarios and sensitivities (GW)

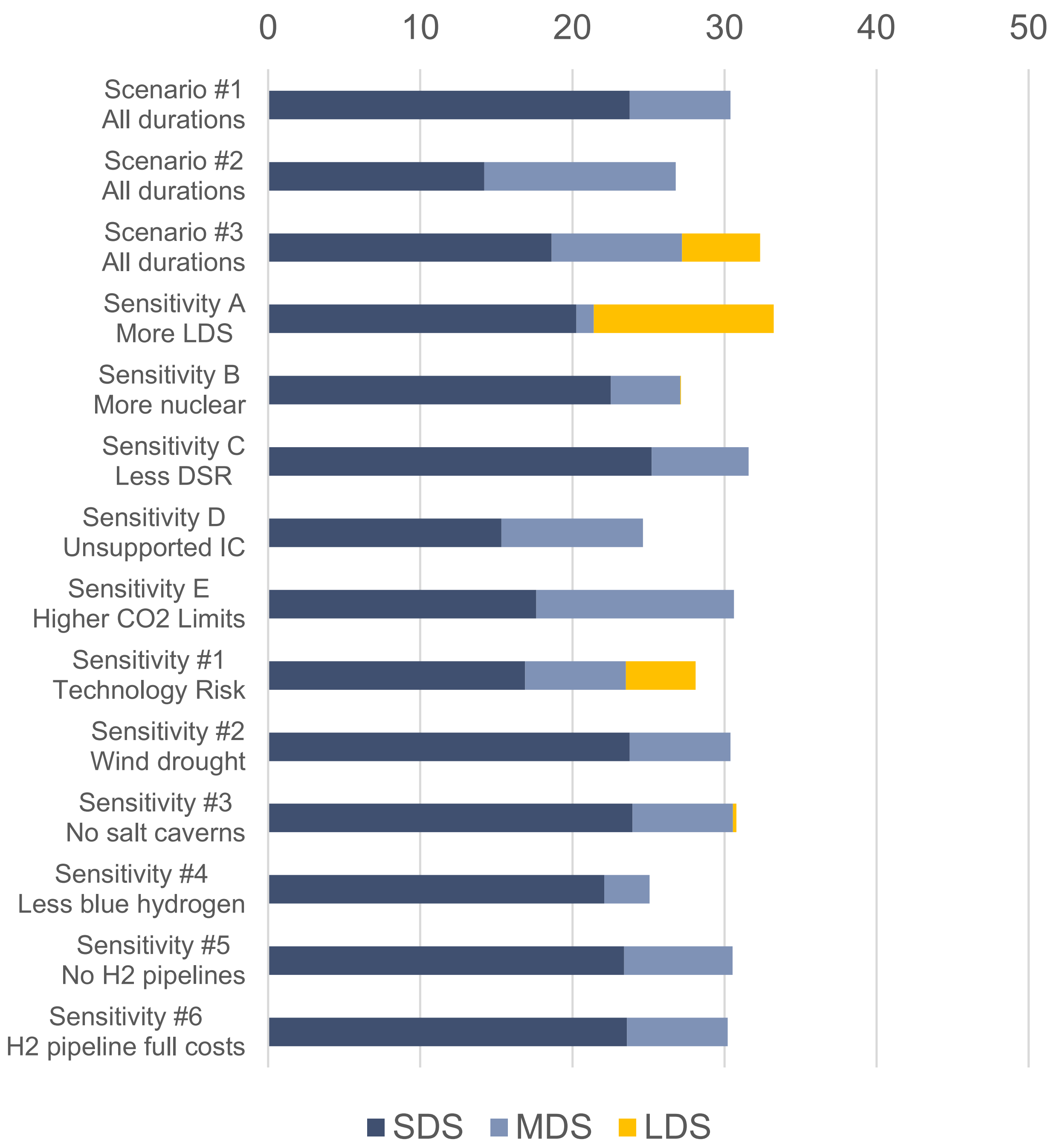
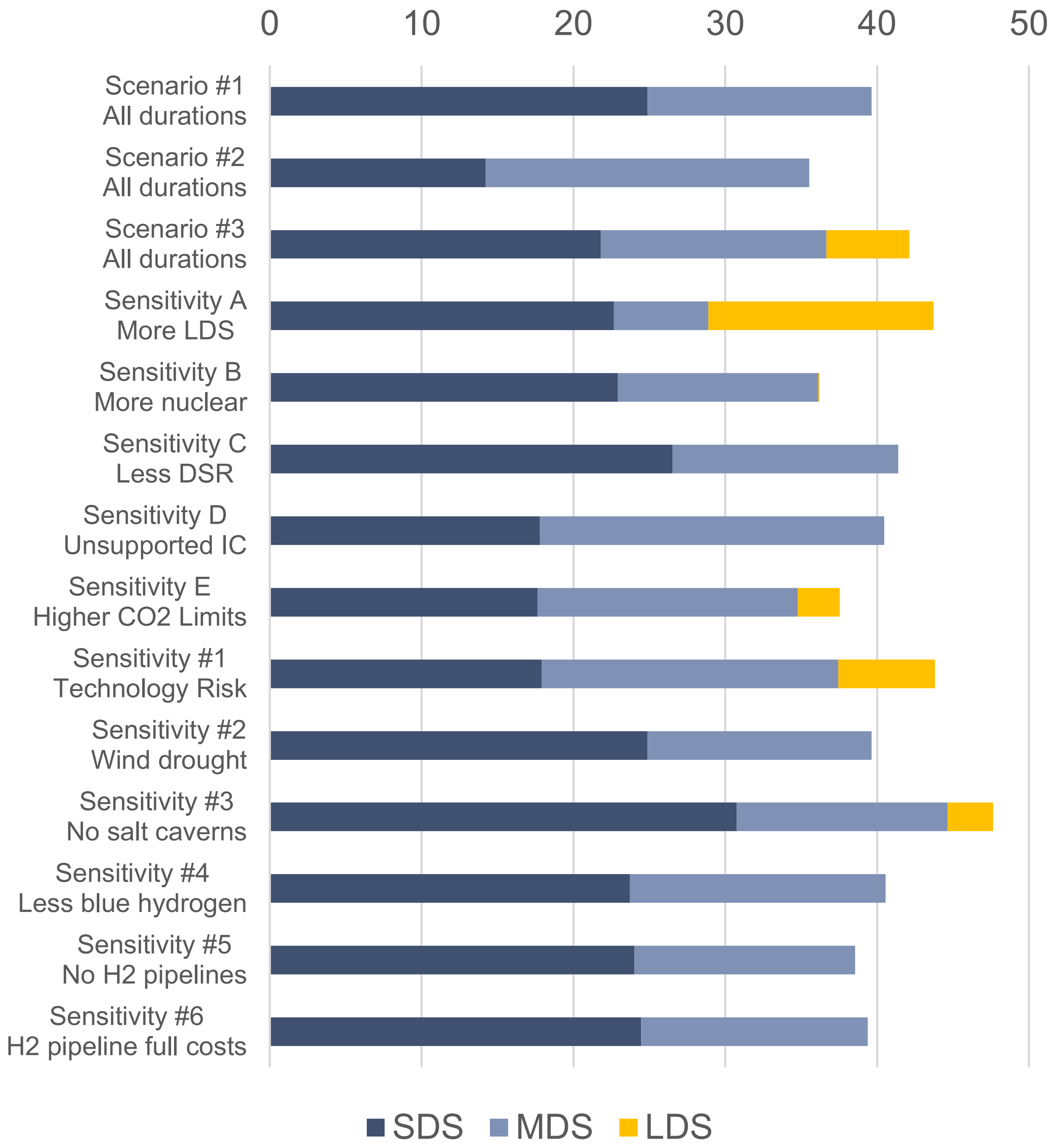


Exhibit F.17 similarly shows that where power LDS is deployed by 2050, it is in the sensitivities where other flexibility options, especially from the hydrogen sector, are more expensive to deploy or less easy to support with other required infrastructure. Similarly, MDS options tend to be included more where other flexibility sources are less available or more expensive.

Exhibit F.17 – 2050 Power storage capacities, all durations, all scenarios and sensitivities (GW)



Annex G: Table of Exhibits

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