Jacobs

Strategy for Long-Term Energy Storage in the UK

Future role to meet Net Zero Emissions Targets

Strategy for Long-Term Energy Storage in the UK

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We have also consulted extensively with industry leaders of the UK electricity Capacity Market, including several major UK power utilities, and wish to thank them for their advice and support.

Abbreviations

BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department of Business Energy & Industrial Strategy
BSUoS	Balancing Services Use of System
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenditure
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Usage & Storage
CFD	Contracts for Difference
CO_2	Carbon Dioxide
DECC	Department of Energy & Climate Change
EFC	Effective Firm Capacity
EMR	Electricity Market Reform
ESO	National Grid Electricity System Operator
EU	European Union
FES	Future Energy Scenarios
FFR	Fast Frequency Response
FR	Firm Reserve
GHG	Greenhouse Gas Emissions
GW	Gigawatt
GWh	Gigawatt hours
HVDC	High Voltage Direct Current
HRS	Hours
KWH	Kilowatt hours
LAES	Liquid Air Energy Storage
LI	Lithium Ion
MW	Megawatt
MWh	Megawatt hours
NG	National Grid
NIC	National Infrastructure Commission
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
OCGT	Open Cycle Gas Turbine
OPEX	Operating Expenditure
PEM	Polymer Electrolyte Membrane
PSH	Pumped Storage Hydro
PV	Photo Voltaic
RAB	Regulated Asset Base
RAE	Royal Academy of Engineering
SSE	Scottish & Southern Energy
STOR	Short Term Operating Reserve
TWh	Terawatt hours
UK	United Kingdom
US	United States

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Executive Summary

Background

Energy storage in the UK has primarily been provided in the past by medium-term storage technologies (comprised of both conventional hydro and pumped storage) that have been used for energy arbitrage, initially for balancing the fixed base load generation of nuclear stations. Following the expansion of gas turbine generation in the 1990s that could fulfill this role more easily, pumped storage was increasingly used for maintaining grid stability by providing ancillary services under the National Grid Electricity System Operator (ESO) balancing mechanism. More recently, solid-state batteries have entered the market as another technology capable of providing short-term balancing services.

However, the recent expansion of renewable generation, particularly wind and solar, has resulted in greater intermittent generation and hence the need to provide increased operating reserve in both the short-term and longer term. While pumped storage plants can provide medium-term and short-term 'shallow' storage over several days, there is currently insufficient reservoir storage capacity at these plants to provide the necessary long-term 'deep' storage over several days or even weeks that is needed for balancing of renewables.

There is thus a perceived need for increased energy storage both to meet the short-term (shallow) storage requirements of the National Grid (NG) balancing mechanism as well as longer term (deep) storage for improved balancing of intermittent renewables. This could be provided by a combination of both long-term and medium-term energy storage technologies on the supply side, with short-term storage technologies located on the demand side.

This paper considers the need for developing additional long-term energy storage to increase the use of surplus renewables generation, which will itself increase as further intermittent renewables generation is implemented, including provision of daily load-following capability for new nuclear generation as required. This is then compared with providing alternative backup thermal generation based on combined cycle gas turbine (CCGT) plants fitted with carbon capture and storage (CCS) capability. While the latest pressurized water reactors and small modular reactors are capable of load-following to a certain degree, it is generally accepted that this is not the most economic mode of operation, Thus, for the purposes of this paper, we have assumed that all nuclear plants would be operated at high load-factors, as used currently, and would certainly not be suitable for operating at low load-factors needed for balancing the highly variable output of intermittent renewables.

A range of energy storage technologies have been investigated, including existing proven technologies as well as those that are newly emerging. A set of alternative development programmes were then formulated and evaluated using the results of this investigation, targeted at meeting the UK's net zero carbon emissions targets by 2050, at least-cost.

Future Energy Scenarios

In 2019 National Grid ESO produced a set of future energy scenarios (FES 2019), which serve as a useful reference for identifying the future energy storage needs of the UK system up to 2050. The FES framework comprises the following four primary scenarios:

- Community Renewables
- Two Degrees
- Steady Progression
- Consumer Evolution

These scenarios represent different possible pathways, however they should not be regarded as forecasts but rather possible futures, so the actual pathway followed would likely be a combination of them.

In Community Renewables, local energy schemes flourish, consumers are engaged and improving energy efficiency is a priority. In Two Degrees, large-scale solutions are delivered to meet the 2050 target, including increased renewable capacity and new technologies such as carbon capture and storage. In Steady Progression, the pace of the low-carbon transition continues at a similar rate to today but then slows towards 2050. In Consumer Evolution, there is a shift towards local generation and increased consumer engagement, largely from the 2040s. A further Net Zero scenario was later formulated, following the Paris Agreement, aimed at meeting the UK's net zero carbon targets by 2050, which is a variant of the Two Degrees scenario.

The FES framework is based on two drivers - the speed of decarbonization and the level of de-centralization. One of the key objectives of the first two scenarios was to achieve 80% emissions reduction by 2050, which was the original emissions target, with the fifth scenario aimed at achieving the updated target of net zero carbon emissions by 2050. The primary purpose of this paper is to identify what role long-term energy storage could play in achieving these emissions reduction targets.

More recently National Grid updated their future energy scenarios (FES 2020), published on 27th July, whose impact are assessed as a separate sensitivity analysis in Section 6.

Projected Energy Generation Profiles

In order to determine the potential system needs for long-term energy storage from 2018 to 2050, we have carried out a high-level modeling exercise using historic generation data provided by Elexon, together with historic demand and interconnector data provided by National Grid.

A future projection for the expected situation in 2030 and 2050 has been prepared by factoring the 2018 Elexon data to reflect the predicted generation capacities and demand projections given for the Two Degrees and Net Zero future energy scenarios. This covers the projected reductions in CCGT capacity and phased retiral of existing nuclear plant with the projected increase in new nuclear and renewables (solar and wind) and 12 GW of European interconnector capacity, together with the projected increase in energy storage capacity for alternative storage technologies.

Note that the FES scenarios provide total generation demand forecasts on an annual basis for 2030 and 2050, but not the hourly, daily, weekly or seasonal distributions for these demand projections. Thus, we have used the Elexon actual generation data for 2018 as a proxy for the likely generation variability (in percentage terms) for future years. Clearly the demand variability in the future will not be exactly the same as it is now, but for this paper is a reasonable assumption for comparison purposes.

The purpose of this modeling exercise has been to show how the provision of additional long-term storage could not only assist in balancing the future planned nuclear and intermittent renewables capacity, but also reduce the dependency on CCGT backup generation, fitted with CCS, that would otherwise be required.

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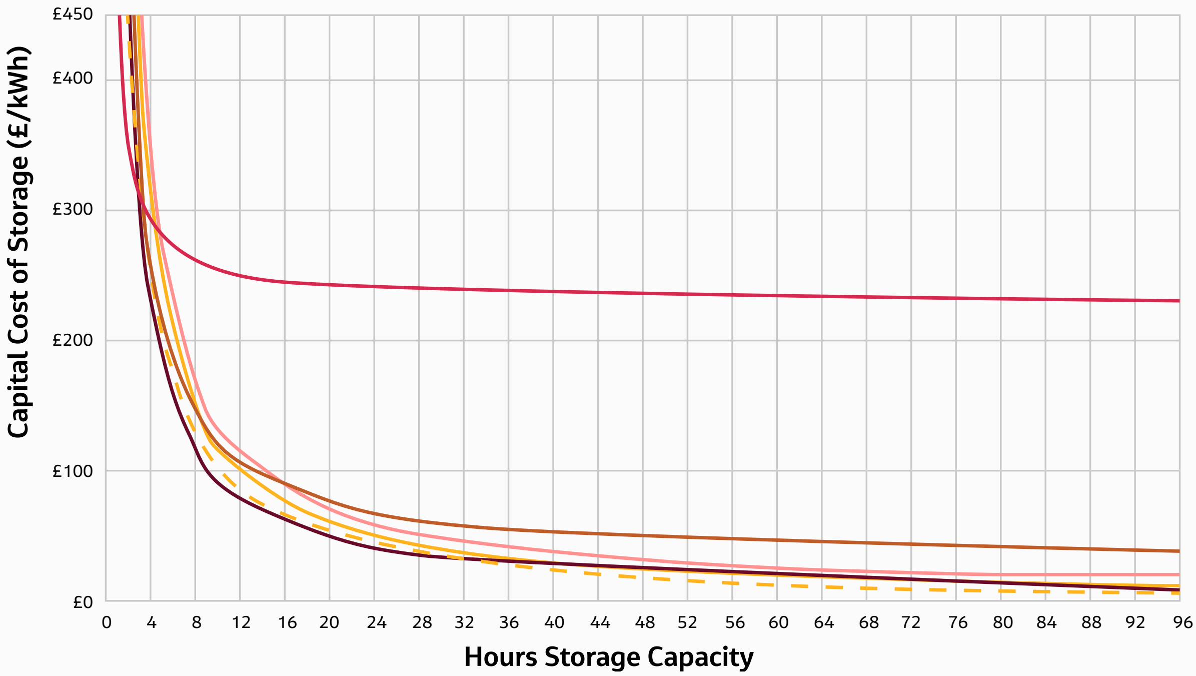
Alternative Energy Storage Technologies

We have compared the costs of various energy storage technologies and divided them into short-term and long-term energy storage. Costs have been compiled from various published sources to determine not only the capital cost and cost of storage, but also the unit levelized cost of generation. We have then compared the derived levelized costs from these alternative energy storage technologies with the unit cost of generation from other net zero carbon generation sources.

We have identified a range of alternative short-term storage technologies such as lithium-ion batteries and liquid air energy storage (LAES), and derived both storage cost and levelized generation cost curves for different storage durations for each of the different technologies. We have then evaluated the principal long-term energy storage technologies, comprising pumped hydro storage, hydrogen (via hydrolysers) with gas storage and CAES, and derived levelized generation cost curves for different storage durations for each of these technologies as well.

Note that the long-term energy storage options would be used in two ways, firstly for conventional daily load balancing and secondly for balancing renewables by absorbing excess generation during periods of surplus and regenerating again during periods of deficit. For pumped hydro this would be achieved by reversible pump-turbines located between an upper and lower reservoir (as currently practiced), while for hydrogen storage this would comprise hydrolysers to produce hydrogen during periods of surplus, for storage in underground caverns, which would be regenerated later using hydrogen fueled CCGT or open cycle gas turbine (OCGT) plant. For LAES and CAES this would comprise either liquifying or compressing air during periods of surplus and regenerating later by re-heating the air before passing it through a turbo expansion plant.

Capital cost curves for each technology type have been derived from cost functions based on median cost data provided in the Department of Energy & Climate Change (DECC) levelized generation cost study (2016), where applicable, or from published costs provided by technology suppliers. These curves show the relative capital cost per kWhr stored against storage duration (hrs) as presented in the attached figure.



Capital cost of Energy Storage Capacity for Alternative Storage Technologies

Relative capital cost per kWhr stored against storage duration (hrs)

This shows that LI batteries have the lowest cost of storage for durations less than 4 hours, although the cost per kWh stored is high, but that for longer durations there is a marked reduction in storage cost for the other technologies such as pumped hydro, hydrogen storage, CAES and LAES, thus demonstrating the economies of scale that can be achieved with these latter technologies.

Having established capital cost curves for each technology, simulations were then carried out to determine the increase in useful generation that could be achieved by each technology, at increasing increments of installed capacity from 500 megawatts (MW) to 10 gigawatts (GW), and also to determine their relative operating costs in order to estimate the levelized generation cost for each type of technology for a range of storage durations.

These cost curves were derived using the energy outputs from both daily load balancing of based-load plant as well as longer term balancing of intermittent renewables generation predicted for 2050 and combining the associated capital and operating costs to derive an approximate levelized unit generating cost against storage capacity, for each type of storage technology.

The comparative unit cost of generation by technology type, for a typical plant of 500 MW installed capacity at a range of different storage durations from 1 hour to 4 days, is presented in the following figure.

These curves are necessarily approximate as they are based on generic cost functions derived for each technology, including assumptions on wind variability based on 2018 data and assuming a total wind generation capacity of about 90 GW, as forecast in the Net Zero scenario for 2050, nevertheless they do provide a valid comparison of the relative merits of each technology.

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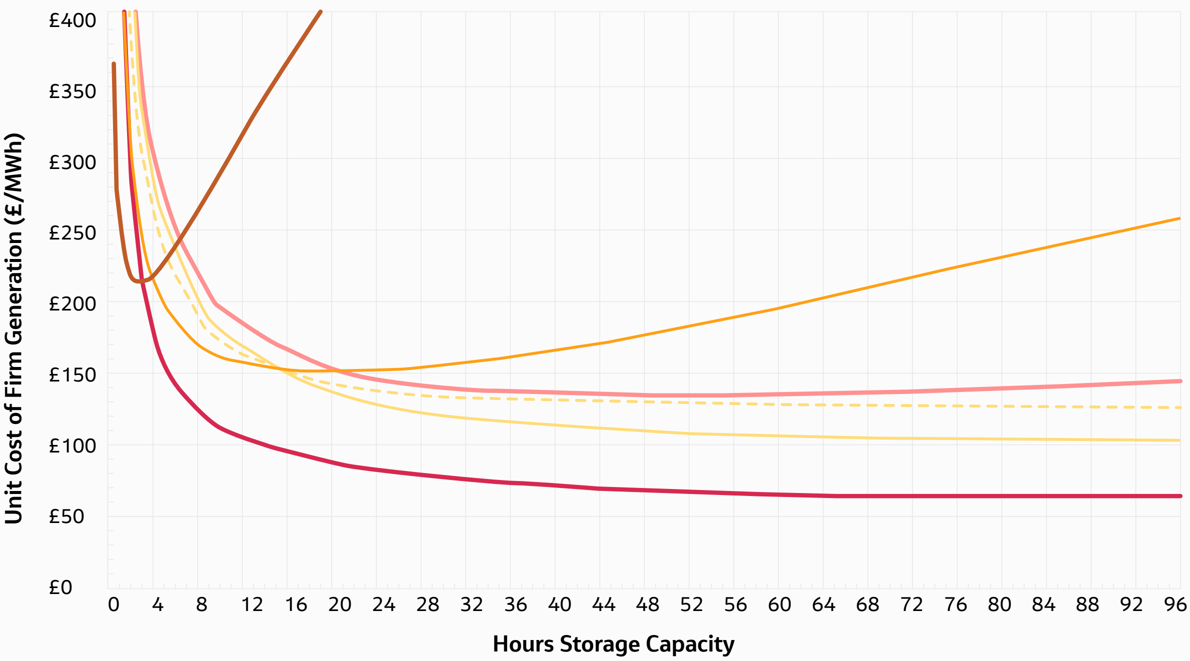
Comparative Unit Cost of Generation for Balancing Intermittent Renewables 'Two Degrees' Scenario – 2050



- Lithium-ion Battery Storage
- Liquid Air Energy Storage (LAES)
- Compressed Air Energy Storage (CAES)
- Hydrogen hydrolyzer + OCGT
- Hydrogen hydrolyzer + CCGT
- Pumped Hydro 500 MW increments

The comparative unit cost of generation by technology type, for a typical plant of 500 MW installed capacity at a range of different storage durations from 1 hour to 4 days

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From these analyses, we have derived generic levelized generation costs for each technology type, based on the simulated generation estimated for reference year 2050, as given in the table below:

Generic Levelized Unit Generation Costs @8% discount rate (£/MWh)– 2050

Duration (hrs)	Short-Term Storage		Long-Term Storage			
	LI Batteries (£/MWh)	LAES (£/MWh)	Pumped Hydro (£/MWh)	Hydrogen CCGT (£/MWh)	Hydrogen OCGT (£/MWh)	CAES (£/MWh)
144	£1,530.6	£339.7	£70.3	£101.4	£122.1	£159.3
96	£1,065.5	£258.3	£64.1	£103.0	£125.5	£144.2
72	£871.9	£217.3	£63.9	£104.6	£127.4	£137.3
48	£675.9	£176.2	£67.5	£109.7	£129.3	£134.3
24	£454.1	£151.6	£82.0	£128.0	£137.3	£145.4
12	£317.6	£158.0	£105.6	£169.5	£163.5	£184.9
8	£266.0	£171.3	£125.4	£204.0	£191.8	£219.4
4	£217.5	£216.5	£178.9	£286.7	£265.7	£304.2
2	£217.9	£320.5	£294.6	£434.8	£387.2	£458.0
1	£259.7	£540.7	£522.8	£749.1	£627.0	£786.2
0.5	£365.2	£989.3	£991.1	£1,367.7	£1,111.7	£1,432.9

This shows that pumped hydro is clearly the least-cost technology for long-term storage, closely followed by hydrogen storage with CCGT and CAES. Pumped hydro is also the most mature and well-proven technology, having been the mainstay of medium-term energy storage over the past 60 years, and thus could be a prime contender at least for initial developments. Other emerging technologies, such as hydrogen storage (via hydrolysers) and CAES have yet to be developed at scale, but could still be likely contenders for later developments, which would allow time for their further development and potential capital cost reduction.

This also shows that Lithium-ion batteries are clearly the least-cost technology for short-term storage, for durations of less than 2 hours, LAES and hydrogen storage with OCGT are also potential contenders.

Short-term storage would best be located on the demand side (at distribution level), where it could also be used to balance variation in demand and hence reduce stress from peak demands on the transmission system.

Comparison with backup CCGT fitted with CCS

Much of the existing backup generation capacity in the UK system currently comprises 35 GW of unabated CCGT plant. However, in order to meet the net zero carbon targets, this entire CCGT fleet would need to be replaced by 2050 with new CCGT plants fitted with carbon capture and storage.

The FES report and the CCC Net Zero Technical report of May 2019 both propose that the most appropriate carbon capture technology for the power sector would be pre-combustion CCS using steam reformed methane to produce hydrogen to fuel the CCGT (or OCGT) plants. The recent BEIS Carbon Capture Technology report (2018) gives the levelized cost CCGT with pre-combustion carbon capture and storage as £100/MWh at 100% load-factor.

However, our analyses have shown that for the FES Net Zero scenario in 2050, with 90 GW of wind generation capacity installed, the predicted load-factor for CCGT plants used as backup generation for intermittent renewables would likely be in the region of between 20% and 25%. Thus, by applying these load factors to the cost model supplied with the BEIS report gives a levelized cost for CCGT with CCS nearer £250/MWh, when used in this application. This indicates that long-term energy storage would likely be a lower cost alternative to CCGT with carbon capture and storage, as well as being a fully renewable solution.

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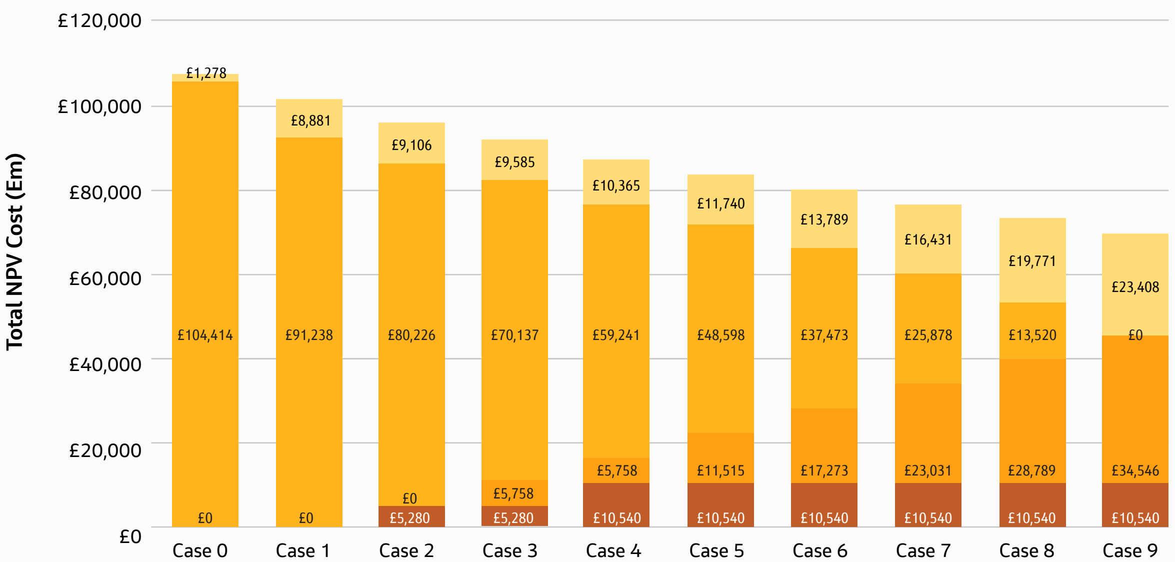
Long-Term Storage Development Strategy

In order to determine the least-cost power development arrangement that can meet the net zero targets by 2050, we have evaluated a range of alternative development cases comprising different combinations of the following potential technologies:

- Natural gas CCGT with carbon capture and storage;
- Pumped hydro storage;
- Hydrogen storage via hydrolysers (with hydrogen-fueled CCGT);
- Compressed air energy storage (CAES); and
- European interconnectors.

Ten alternative development cases have been analyzed to show how increasing levels of long-term storage can be used to reduce overall generation costs. These cases include different combinations of pumped hydro, hydrogen storage and supporting CCGT with CCS, with and without the planned increase in interconnector capacity, and have been evaluated over a 50-year period, with their estimated overall lifetime net present value (NPV) costs (@8% discount rate) estimated as follows:

Case	Components	NPV Cost
Case 0	Existing 12 GW interconnectors with 48 GW of CCGT+CCS	£106 billion
Case 1	Future 20 GW interconnectors with 40 GW of CCGT+CCS	£100 billion
Case 2	5 GW pumped hydro storage with 35 GW of CCGT+CCS	£94 billion
Case 3	10 GW pumped hydro with 30 GW of CCGT+CCS	£88 billion
Case 4	10 GW pumped hydro & 5 GW hydrolysers with 25 GW of CCGT+CCS	£85 billion
Case 5	10 GW pumped hydro & 10 GW hydrolysers with 20 GW of CCGT+CCS	£82 billion
Case 6	10 GW pumped hydro & 15 GW hydrolysers with 15 GW of CCGT+CCS	£78 billion
Case 7	10 GW pumped hydro & 20 GW hydrolysers with 10 GW of CCGT+CCS	£75 billion
Case 8	10 GW pumped hydro & 25 GW hydrolysers with 5 GW of CCGT+CCS	£72 billion
Case 9	10 GW pumped hydro & 30 GW hydrolysers with no CCGT+CCS	£68 billion



NPV Total CAPEX & OPEX Costs 'Net Zero' Scenario - 2050

The total NPV of capital (CAPEX) and operating (OPEX) costs for each case

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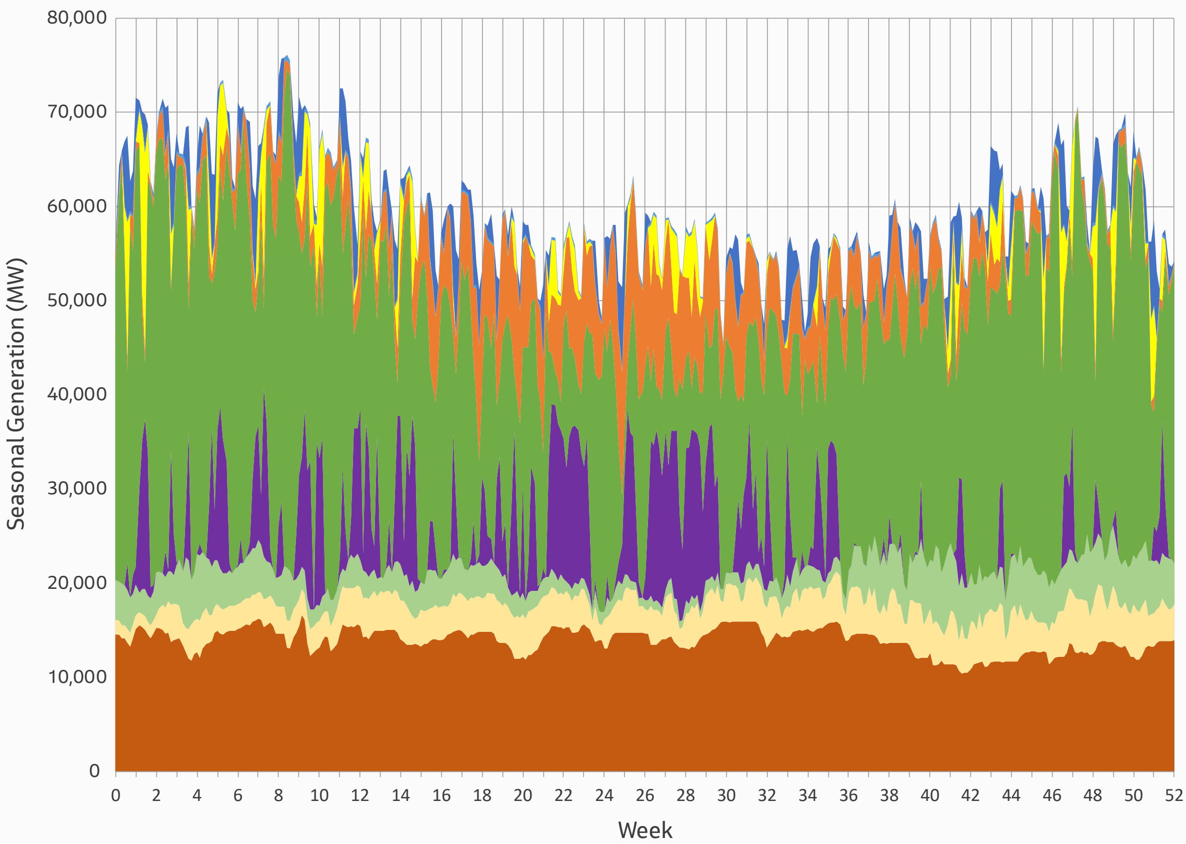
These result show there is a clear economic benefit in increasing long-term storage by up to 40 GW by 2050 for the purposes of balancing intermittent renewables, thereby eliminating the need for backup CCGT plant fitted with CCS. Gas turbine plant would still be required but would either be CCGT or OCGT plant fueled by 'green' hydrogen, from hydrolysers, rather than by 'blue' hydrogen derived from steam-reforming of methane from natural gas, which is both non-renewable and would also require high cost CCS.

The results for Case 9 show that by implementing 40 GW of long-term energy storage, comprising 10 GW of pumped hydro and 30 GW of hydrogen (via hydrolysers) with hydrogen cavern storage, could yield a net saving of about £32 billion (@ 8% discount rate), compared to Case 1, i.e. an overall net saving of some 32%.

The chart below, representing conditions under Case 9, shows how 10 GW of pumped hydro storage and 30 GW of hydrogen (via hydrolysers), with hydrogen cavern storage and associated 30 GW of CCGT plant fueled by 'green' hydrogen, could balance intermittent renewable generation comprising 90 GW of wind and 40 GW of solar PV, for a typical year by 2050:



Projected Seasonal Generation - FES 'Net-Zero' Scenario 2050

10 GW Pumped Storage and 30 GW Hydrogen Storage with 20 GW Interconnectors.

This shows how pumped hydro and hydrogen storage can provide full backup generation to the intermittent renewable generation in 2050. This also demonstrates how long-term energy storage, with associated CCGT plant fueled by 'green' hydrogen, in conjunction with nuclear generation and the European interconnectors, could thus displace higher cost CCGT plant fueled by steam-reformed methane (from natural gas) with carbon capture and storage.

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Development Plan for Long-Term Storage

Such a major development would necessarily need to be phased to ensure the net zero carbon targets can be met by 2050. A potential phased implementation programme (e.g. based on Case 7) could be as follows:

- **Stage 1:** Initial 5 GW of pumped hydro with 5 GW of hydrogen storage by 2030;
- **Stage 2**: Further 5 GW of pumped hydro with 5 GW of hydrogen storage by 2035;
- **Stage 3:** Further 5 GW of hydrogen storage or CAES with 5 GW of CCGT+CCS by 2040;
- **Stage 4:** Further 5 GW of hydrogen storage or CAES with 5 GW of CCGT+CCS by 2045.

This would enable the full development to be completed by 2045, thus giving a five-year float for any overruns.

This approach could thus allow a start to be made using existing proven long-term energy storage technologies and provide time for other emerging storage technologies to be developed and refined further, potentially also at reduced cost. In this way, the optimum level of long-term energy storage could be built up gradually, with the balance made up by CCGT fitted with carbon capture and storage.

Whatever generation mix is eventually decided to meet the net zero emissions target by 2050, there is clearly a compelling case for developing at least 10 GW of long-term deep energy storage by 2030, with a further similar development by 2035. The question of how much additional long-term energy storage would be needed can thus be decided later, using the principles of adaptive planning.

The principles of adaptive planning involve formulating a range of alternative development pathways (similar to the cases derived in this paper) and then dividing them into stages. An initial development path is selected at the outset with decisions made at each stage on whether to continue on the same path, or switch to another path depending on changed circumstances. In this way, an initial path (say Case 7) would be embarked upon and a Stage 1 development decided for 2030. Then, when Stage 1 was complete in 2030 the next path could be chosen (e.g. Case 6, 7 or 8) which would define the Stage 2 development for 2035. Thus, if Case 8 was decided to be the best path for Stage 2, a further decision could be made in 2035 to choose the next path (e.g. Case 7, 8 or 9) for Stage 3 by 2040, with the process repeated for the remaining stages. This would allow the development plan to be adapted periodically to take account of a range of uncertainties such as demand, costs, technological advances and/or environmental considerations etc.

This technique should also be compatible with the UK energy market approach, as each decision stage could be represented as a set of storage capacity auctions (or whatever incentive mechanism is to be adopted) held at periodic intervals.

Market Incentives for Long Term Storage

From the foregoing analysis, it is clear there is merit in developing substantial long-term storage capacity in the UK for balancing renewables generation, not only to provide backup generation during periods of low wind, but also for reducing stress on the UK transmission system and providing flexibility for operation of the European interconnectors. However, currently there is no suitable market incentive mechanism in place for the promotion specifically of long-term energy storage.

The Electricity Market Reform process provides suitable incentive mechanisms for the development of other renewable and nuclear generation, under their Contracts-for-Difference and Capacity Market auctions, but there appears to be no suitable mechanism applicable to long-term energy storage projects with storage durations in excess of 5.5 hours. Also, the Capacity Market T-4 auctions are currently restricted to projects that can be constructed within four years, which rules out major energy storage projects with longer development and delivery periods to commercial operation.

An alternative incentive mechanism that could be considered is the Cap & Floor model, currently framed to encourage investment in electricity interconnectors. A feature of the Cap & Floor model is that all revenue streams are taken account of in arriving at the target upper and lower price band, which would thus give a minimum level of assurance to potential investors, covering not only market arbitrage risk but also the risks associated with revenues from balancing services. In this way, it may be possible to frame an investment arrangement that could both mitigate much of the market risk to investors, while at the same time providing best value to electricity customers.

At the Electricity Market Reform Conference held at Westminster in November 2019, the question of long-term energy storage was raised at one of the panel sessions and the view of the panel was that the Cap & Floor model was likely to be the best approach and recommended that this should be followed up with BEIS.

Benefits to the Consumer

The merits of employing long-term energy storage to support achieving a net zero position in 2050 have been reviewed in this White Paper. While the environmental imperatives of reducing the output of carbon and providing energy security of the UK is of prime concern, it must also be recognized that these objectives add cost. The cost of transitioning to a zero-carbon future will either be covered indirectly through taxation and fiscal measures, or directly by consumers through electricity tariffs at the meter. Savings from wise selection of the optimum storage solution will be realized by the consumers. The energy consumers of the UK need to be confident that they are benefiting financially from the best technical solutions for energy storage being available for selection, with full support from the government and market operators.

Key Recommendations

From the analyses presented in this paper, it is clear there will likely be several types of energy storage required for future balancing of the UK power system, in order to assist in meeting the net zero emissions targets. This could range from short-term storage (for a few hours), to medium-term storage (up to a day) and long-term storage (for days/weeks), but the precise requirements for both the demand side and the supply side in terms of capacity and location have yet to be established. Also, the costs for many of the new emerging storage technologies are still highly uncertain, as are the costs for providing carbon capture and storage for backup CCGT plant used for balancing intermittent renewables generation.

There are already existing provisions for short-term storage, for providing ancillary services under National Grid's balancing mechanism and medium-term storage, for providing arbitrage services for meeting daily variations in demand. However, currently there is no explicit provision for long-term storage that could be used to better utilize intermittent renewables and hence reduce the dependency on potentially higher cost non-renewable backup CCGT fitted with CCS.

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Executive Summary

Our key recommendations are as follows:

- Given the Government's stated objectives of achieving net-zero by 2050, our analyses show that there is a compelling case for developing a further 40 GW of long-term storage, with a storage capacity of some 5,000 GWh, primarily for balancing the proposed 90 GW of intermittent wind generation planned to be in place by 2050, but also for providing grid balancing ancillary services as well as reducing dependence on imports via the European interconnectors;
- Our analyses also indicate that the provision of 40 GW of long-term storage could also eliminate the need for providing backup CCGT generation fitted with CCS, that would otherwise be required, at a potential cost saving of some £32 billion for the FES 2019 scenarios and potentially even greater for the latest FES 2020 scenarios;
- To achieve this objective will require a major development programme for long-term storage comprising not only pumped hydro, but also hydrogen storage as well as other technologies such as CAES and LAES, implemented in 10 GW stages between now and 2050, with the first stage being implemented by 2030.

We would therefore suggest that a development road map for energy storage be drawn up, framed to address the following issues:

- Identification of precise future requirements for short, medium and long-term storage;
- Determination of required energy storage capacities, including duration, on both the demand side and supply side;
- Detailed analysis on the benefits of energy storage on both the UK primary transmission system and European interconnectors;
- Detailed evaluation of alternative long-term storage or other options, including costs and risks, needed to meet net zero emissions targets by 2050; and
- Comparison of alternative incentive mechanisms for promotion of long-term energy storage within the UK energy market.

Overview

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Historically, energy storage in the UK has primarily been provided by pumped storage plants that have been used for energy arbitrage, namely to provide daily and weekly load balancing by pumping during off-peak and generating during peak periods and was developed primarily for balancing the fixed base load generation of nuclear stations. Following the expansion of gas turbine generation in the 1990s there was little need for further pumped storage development, as gas turbines could also be used for following variations in daily load demand and providing short-term operating reserve as well as other grid ancillary services. This has resulted in pumped storage being used increasingly for maintaining system stability by providing firm frequency response (FFR) and fast reserve (FR) services under the balancing mechanism operated by National Grid. More recently, solid-state batteries have entered the market as another technology capable of providing short-term balancing services.

However, the recent expansion of renewable generation (particularly wind and solar) has resulted in greater intermittent generation – which has increased the need to expand operating reserve in both the short-term and longer term. While pumped storage plants can currently provide short-term 'shallow' storage over several hours, there is currently insufficient reservoir storage capacity at these plants to provide the necessary long-term 'deep' storage over several days or even weeks that is needed for supporting intermittent renewables.

A more critical failing of wind and solar is that it supplies an asynchronous supply of power, which cannot provide grid stability to frequency disturbances on the grid. This stability is provided by synchronous generators which, by nature of their rotating masses, are able to provide the necessary inertia to the system. Recent failures in Australia and the UK were as a result of the wind turbines tripping due to underfrequency on the grid, where they could not provide any additional power to support the shortfall on the system. As the penetration of renewables is set to increase, a concurrent frequency support mechanism also needs to be provided, for which pumped-storage hydro is ideally suited.

There is thus a perceived need for increased energy storage both to meet the short-term (shallow) storage requirements of the NG balancing mechanism as well as longer term (deep) storage for improved balancing of intermittent renewables. This could be provided by a combination of increased long-term pumped storage capacity and/or hydrogen storage on the supply side, with short-term solid-state batteries and/or other storage technologies, together with demand-side-response, on the demand side.

Such energy storage developments would need to be implemented in parallel with the current expansion of the power transmission network, particularly the recently commissioned 2GW Western High Voltage Direct Current (HVDC) link and the planned 2GW Eastern HVDC link between Scotland and England/Wales, as well as the proposed 1.4GW North Connect HVDC link between Norway and Northern Scotland.

Analyses carried out by Jacobs for the levelized generation cost study produced for the (DECC) in 2015/16 showed that to provide the necessary support for intermittent wind generation, as installed at that time, would require the development of at least a further 5 GW of long-term (deep) storage with a total energy storage capacity of some 1,500 GWh overall. With the predicted acceleration in the development of off-shore wind generation, in order to meet the UK Government's target of net zero carbon emissions by 2050, this will likely require the implementation of still further long-term energy storage to maximize the effective firm capacity of the total installed intermittent renewables. This in turn could not only reduce the requirement for further interconnector capacity that would otherwise need to be implemented but would also reduce the dependency on imports from Europe.

Parallels can be made with the water sector, whereby large long-term storage reservoirs are provided on the supply side, to maintain security of supply over many seasons to provide a buffer for attenuating highly variable inflows prior to transmission over fixed flow trunk mains. On the demand side, small short-term service reservoirs are provided at distribution level to meet short-term variations in demand and thus reduce the required trunk main capacity. In the power sector, pumped storage can provide a similar function by regulating a variable resource (in this case wind) on the supply side and concurrently reducing the necessary interconnector capacity. Batteries on the other hand can provide storage on the demand side to meet short term fluctuations in demand, enhancing grid stability. Although the concept is the same, the application is different.

Reference Documents

2.0

The reference documents set out in this section have been used as the basis for the paper.

Electricity Market Reform - BEIS

2.1

In its report on Implementing Electricity Market Reform, the Department of Business, Energy & Industrial Strategy (BEIS), then the Department of Energy & Climate Change, presented a comprehensive overview of Electricity Market Reform (EMR) as follows:

"The Government is reforming the electricity market in response to the challenges facing the electricity sector:

- *The UK was facing very rapid closure of existing capacity as older, more polluting plant go offline.*
- *The generation mix needed to respond to the challenge of climate change and meet our legally-binding carbon and renewable targets.*
- *Electricity demand is expected to continue to grow over the coming decades as we increasingly turn to electricity for heat and transport.*
- *These reforms enable the UK to develop a clean, diverse and competitive mix of electricity generation, which will deliver security of supply and ensure that the lights can stay on.*
- *There are two key mechanisms to provide incentives for the investment required in our energy infrastructure.*
- *Contracts for Difference (CFDs) provide long-term price stabilization to low carbon plant, allowing investment to come forward at a lower cost of capital and therefore at a lower cost to consumers.*
- *The Capacity Market provides a regular retainer payment to reliable forms of capacity (both demand and supply side), in return for such capacity being available when the system is tight.*

In developing these mechanisms, affordability for consumers has been a key consideration. Both CFDs and the Capacity Market work with the market and encourage competition, in order to minimize costs, while also delivering the required investment."

This strategy paper explores how long-term energy storage could contribute to meeting these objectives and reviews the potential mechanisms available to provide necessary incentives for the required investment.

UK Energy Policy – RAE

2.2

A report was prepared by the Royal Academy of Engineering (RAE) in 2015, on behalf of the Prime Minister's Council for Science and Technology, which reviewed current UK energy policy and identified what needs to be done to deliver the UK's future energy system. Extracts of the report are reproduced below:

"The main conclusion was that there remained serious risks in the delivery of the optimal energy system for the UK and that substantial investment is needed, largely by the private sector, to meet the challenges of decarbonisation, across multiple interconnected sectors, where the full technical solution is not obvious.

The whole energy system faces massive changes to deliver against all aspects of the 'trilemma' - cost, security and decarbonisation. So far, despite the obvious challenges, the system is on course to meet the targets set by UK and EU, but only just, and all the easiest actions have already been taken. Progress in the electricity sector will only get more difficult and there is a serious risk of non-delivery... Time is of the essence, with decisions taken now affecting what the system will look like in 2030 and beyond."

As far as supply is concerned the report also concluded that:

"While consideration of the whole system is vitally important, the most immediate concern is to maintain supply in the electricity system and ensure that new capacity is built. Decarbonisation of the electricity system remains a central pillar of all credible future scenarios, but uncertainty over the past few years while market reform was completed has resulted in serious underinvestment. Government now needs to allow the new Electricity Market Reform mechanisms to bed in. Developers and investors need time to work with the new system in order to reduce financial risks and compete to lower costs.

2.2

UK Energy Policy – RAE

Particular focus needs to be given to the three main technologies that can deliver low carbon electricity at scale:

- *Nuclear*
- *Offshore wind*
- *Carbon capture and storage*

Maintaining security of supply is essential which will require focus in three main areas:

- *Provide other low carbon energy generation, to complement the variable renewables, that cannot be relied on to generate at all times, to match demand;*
- *Ensure that demand side response, storage and interconnectors are fully able to participate in the new capacity mechanism;*
- *Ensure that wider system characteristics such as inertia, reactive power and frequency control, normally delivered by traditional thermal generation, are not adversely affected as the system evolves."*

This strategy paper examines how long-term energy storage can be a cost-effective measure to assist both in regulating intermittent renewables, while at the same time meeting the short-term requirements of system stability, by providing a wide range of National Grid ESO balancing services such as inertia, frequency response, reactive power, black-start and constraint management etc.

2.3

Smart Power – NIC

The National Infrastructure Commission (NIC) recently produced its Smart Power report, which can be summarized in brief as follows:

"Our energy sector is changing fundamentally. Two-thirds of our existing power stations are expected to close by 2030 as our coal, nuclear, and oldest gas fired power stations reach the end of their lives. This report makes recommendations to help ensure that our electricity system is fit for the future.

The Commission's central finding is that Smart Power – principally built around three innovations, Interconnection, Storage, and Demand Flexibility – could save consumers up to £8 billion a year by 2030, help the UK meet its 2050 carbon targets, and secure the UK's energy supply for generations.

Part 1: All change

Our existing infrastructure was designed for a post-war world where homes and businesses were supplied almost exclusively from large fossil fuel generators. As we modernize and decarbonise our energy system we need to find new ways to manage the network in the most efficient way possible. This represents a serious challenge and an enormous opportunity. If we get this right, it will provide the efficient, flexible and secure energy infrastructure our country will need to thrive. DECC and Ofgem have already made a start.

Part 2: Smart power

In the coming decades the UK is uniquely placed to benefit from three innovations which could help fire a smart power revolution.

- ***Interconnection** – connecting our electricity network to our continental neighbors is already bringing down bills and helping to balance the system. More connections to cheap, green power supplies, such as Norway and Iceland could bring great benefits to the UK. Government should redouble its efforts to open new connections.*
- ***Storage** – technology is accelerating at a remarkable speed. The UK could become a world leader in making use of these technologies, not through subsidies, but by ensuring that better regulation creates a level playing field between generation and storage.*
- ***Demand flexibility** – A new generation of hi-tech systems means consumers can* save money and cut emissions without inconvenience. Government should ensure the UK benefits by improving regulation, informing the public of its benefits and piloting schemes on its own estate.

This strategy paper examines how long-term energy storage can be a cost-effective measure to assist both in regulating intermittent renewables, while at the same time meeting the short-term requirements of system stability, by providing a wide range of ESO balancing services such as inertia, frequency response, reactive power, black-start and constraint management etc.

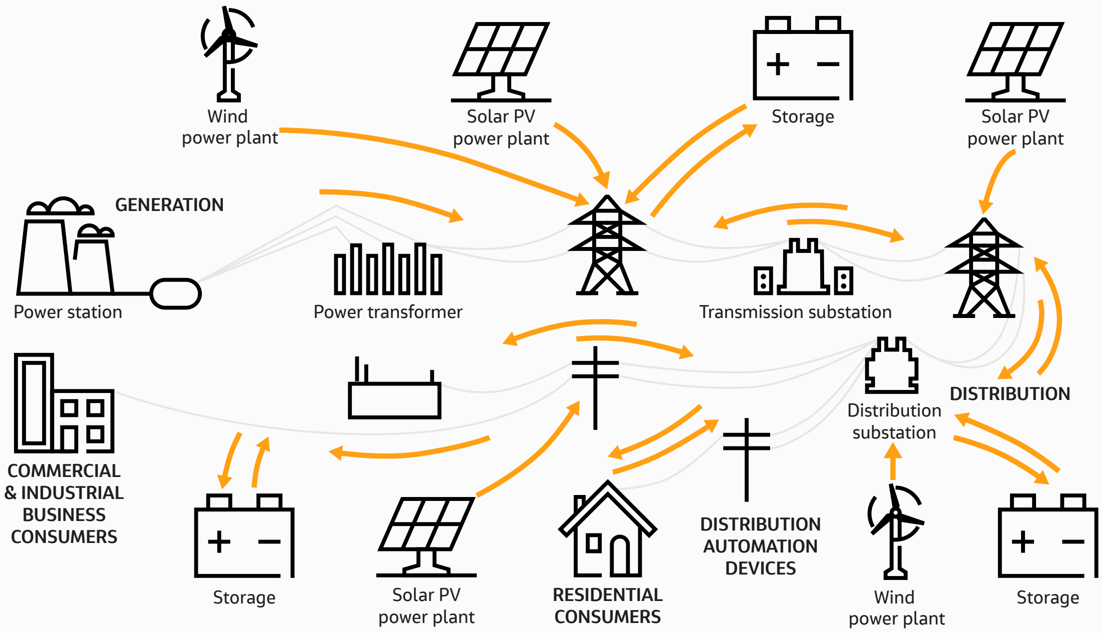
2.3

Smart Power – NIC

Part 3: Maximizing the benefits of a more flexible market

For the smart power revolution to realize its full potential we must ensure that our networks and systems keep up. This requires more active management of our local electricity networks, a national system operator able to keep up with an increasingly complex system, and a strategic approach to upgrading our network. The UK is uniquely placed to lead the world in a smart power revolution. Failing to take advantage would be an expensive mistake."

Its diagram portraying the vision of the future power system is reproduced (courtesy of NIC) below:



This shows that storage will be required on the supply-side and the demand-side. This can take the form of not only short-term storage for regulating demand, but also long-term storage for regulating supply. As outlined by the NIC, one of the key innovations of Smart Power is energy storage:

"Storage allows consumers and suppliers to take energy from the grid, or a generator, and store it so that it can be used when it is most needed. Electricity has historically been difficult and expensive to store. The UK's current main source of storage is pumped hydro, for which water is pumped upwards into reservoirs from where it can be released to generate power. However, the last decade has seen a great deal of innovation, and there is now an increasing range of other ways to store energy including chemical batteries, compressed air and supercapacitors etc.

Storage technology is now on the verge of being able to compete with power stations for some of the services they provide. Crucially, it will not need subsidy to be attractive to investors, but it does need changes to the existing electricity market frameworks. When our electricity markets were designed these technologies did not exist. The result is a market that is opaque, closed to storage technology, and regulated in a way that often disadvantages storage providers. This makes it harder for them to establish a viable business model, as they are unable to participate across the various electricity markets in the same way as generators.

In this way, barriers to the market are preventing a technology from being effectively deployed that could increase the resilience of the electricity system, prevent the need for additional power stations and help secure the power mix needed to hit our legally binding climate change targets. The benefits of storage could be substantial. It can help reduce the impact of peak demand, provide an outlet for power stations at other times of day, and ease constraints on our grids."

This strategy paper thus explores the most cost-effective role for energy storage in the new smart energy network, both in terms of short-term (shallow) storage and long-term (deep) storage and identifies barriers to the market that are preventing such storage technologies from being effectively deployed.

2.4

Net Zero, The UK's contribution to stopping global warming – CCC

In this report, the Committee on Climate Change recommends a new emissions target for the UK: net zero greenhouse gases by 2050.

Key messages in the Executive Summary included:

- "The UK should set and vigorously pursue an ambitious target to reduce greenhouse gas emissions (GHGs) to 'net zero' by 2050, ending the UK's contribution to global warming within 30 years.
- A net zero GHG target for 2050 will deliver on the commitment that the UK made by signing the Paris Agreement. It is achievable with known technologies, alongside improvements in people's lives, and within the expected economic cost that Parliament accepted when it legislated the existing 2050 target for an 80% reduction from 1990.
- However, this is only possible if clear, stable and well-designed policies to reduce emissions further are introduced across the economy without delay. Current policy is insufficient for even the existing targets."

In Chapter 6, Delivering a net zero emissions target for the UK, the following key near-term actions to put the UK on track to net zero GHG emissions by 2050, applicable to the power sector, are highlighted:

- ***"Power sector decarbonisation.*** *More rapid electrification must be accompanied with greater build rates of low-carbon generation capacity, accompanied by measures to enhance the flexibility of the electricity system to accommodate high proportions of inflexible generation (e.g. wind). The Energy White Paper planned for 2019 should aim to support a quadrupling of low-carbon power generation by 2050. While key options like offshore wind look increasingly likely that they can be deployed without subsidy, this does not mean they will reach the necessary scale without continued Government intervention (e.g. continued auctioning of long-term contracts with subsidy-free reserve prices).*
- ***Hydrogen and CCS.*** *In order to develop the hydrogen option, which is vital in our scenarios, significant volumes of low-carbon hydrogen must be produced at one or more CCS clusters by 2030, for use in industry and in applications that would not require initially major infrastructure changes (e.g. power generation, injection into the gas network and depot-based transport). More broadly, plans for early deployment of CCS must be delivered with urgency - CCS is a necessity not an option for reaching net zero GHG emissions."*

Also, Chapter 2 of the Net Zero Technical Report covers hydrogen storage via electrolysis and assumes that:

"*The core scenario in 2050 would require a significant fleet of gas-fired plant, that could be partly decarbonised by capturing its emissions, using CCS, or burning a low-carbon fuel such as hydrogen, or by alternative options for cutting power emissions such as:*

- *Increased electricity system flexibility;*
- *Energy storage, which could allow for further variable renewables to be integrated into the system, thus reducing requirements for gas CCS plant on the system;*
- *Deployment of further nuclear power or alternative renewable technologies could also reduce emissions further.*

New forms of energy storage - such as storage with multi-day duration, or converting electricity to other energy vectors like hydrogen - could improve the economics of renewable generation. Alternatively, continued falls in the cost of renewable generation could reduce the overall cost of installing renewables, even if some generation is wasted".

[The above extracts from the CCC's Net Zero Report of 2019 are Copyright of the Committee on Climate Change.]

This strategy paper investigates the energy storage alternatives, including the most effective processes for hydrogen storage (via hydrolysers) and long-term storage for regulating renewables, together with the cost-effectiveness of carbon capture and storage.

2.5

Future Energy Scenarios – National Grid ESO

Electricity storage

In National Grid's Future Energy Scenarios, *"electricity storage capacity is set to increase in all scenarios, … to support generation from intermittent renewables … and, in particular, there is a need for larger, longer duration storage to support decarbonisation"*.

The report observes that recently there has been *"continued growth and developments in electricity storage"* and that going forward, *"a number of electricity storage technologies need to be considered, including batteries, liquid and compressed air projects and pumped hydro"*. Whilst hydrogen can also be used to convert and store energy, this is regarded as not electricity-specific and so is considered separately.

"In the last year, around 50 storage projects have been commissioned in the UK, providing around 500 MW of capacity. Many of these are short duration batteries, but also include other technologies such as a new liquid air facility. There has been continuing co-location of storage with generation, so projects can access a broader range of markets. Most co-located projects are with solar and wind generation, but there are co-located gas, hydro or tidal projects as well."

National Grid ESO has assumed that "*electricity storage projects will need multiple income streams to be commercially viable. Potential revenues could include price arbitrage, or balancing and ancillary services, and providing services to network operators.*"

Long and short duration of electricity storage

The FES report also makes a distinction between long and short duration storage: "*two electricity storage projects can have the same connection capacity (measured in MW) they may have different storage durations. For example, shorter duration projects could meet small periods of increased demand; or provide flexibility services such as frequency response. Longer duration storage is well suited to covering longer periods of, for example, high or low wind, potentially co-located with generation.*"

The FES report proposes that for the Two Degrees scenario, there are likely to be "*bigger, longer duration projects such as transmission connected pumped hydro.*"

This strategy paper therefore evaluates the benefits of both short-term (shallow) storage and long-term (deep) storage and identifies the best mix, not only for short term ancillary services to maintain grid stability, but also for long term balancing of renewables in order to meet the net-zero emissions targets by 2050.

2.6

The Benefits of Pumped Storage Hydro to the UK – Scottish Renewables

This report was prepared by DNV GL Energy Advisory and commissioned by Scottish Renewables on behalf of the Pumped Storage Hydro Working Group. Funding partners were Scottish Power, Scottish & Southern Energy (SSE) and the Scottish Government. An extract from the Executive Summary is given below:

- *"The Pumped Storage Hydro Working Group is a newly formed group consisting of UK industry and government representatives with an interest in pumped storage hydro (PSH). The group's purpose is to ensure that the interests of pumped storage hydro developers are accurately reflected within the Scottish Renewables Storage Network in response to a range of ongoing work streams and consultations expected over the year ahead.*
- *In this report DNV GL conducts an exhaustive analysis of the multiple benefits of PSH for power systems, as well as the many issues that obstruct its development.*
- *The benefits of PSH for the operation of power systems and the integration of variable renewable energy are widely acknowledged. However, the large majority of the benefits derived from the deployment of PSH schemes are subjective or not quantifiable, which proposes a challenging task for regulators in developing market arrangements and mechanisms to allow measuring and monetizing those benefits so as to fairly compensate PSH operators.*
- *From an economic perspective, current market conditions and business models in liberalized electricity markets for energy storage, and specifically for PSH, do not provide the right incentives to attract investors. Revenues and policy uncertainty are the main sources of risk for PSH investment. Only electricity markets that still have a degree of monopolistic structure show large deployments of PSH."*

Recommendations of the report were as follows:

- *"The full range of benefits that PSH can offer to the UK needs to be recognized in order to create awareness in the regulator, and also in the end consumer, of the long-term implications that promoting the technology can have.*
- *New market arrangements and mechanisms need to be created in order to find the ways for compensating PSH for the whole range of benefits that cannot be directly measured and monetized. This will also require a mind-set change in the population and other industry stakeholders that will face new charges derived from those benefits.*
- *The regulation for energy storage operation needs to be developed and also new business models need to be proposed and understood in order to create the revenue streams for supporting the deployment of energy storage at multiple levels in the UK. In the specific case of PSH, long-term supporting schemes and market arrangements will be necessary in order to reduce the risk exposure of PSH investors.*
- *A collaborative and coordinated work between PSH developers and the regulator is required given the large-scale and long-term nature of PSH development.*
- *Providing further support for the development of new PSH units and upgrades to existing PSH units will contribute to grid reliability, facilitate a larger expansion of variable renewable energy, and thereby reduce UK power system emissions.*
- *The large-scale deployment of intermittent renewable generation is changing the investment and operation economics of conventional generation. The traditional operational regime of conventional generation is changing towards one where there a significant increase in the cycling frequency and more prominent power variability of power plants. New market mechanism to remunerate flexibility contributions need to be created to promote the investment in flexibility."*

3.0

Future Energy Scenarios (FES 2019)

National Grid ESO has produced a set of future energy scenarios in 2019 that serve as a useful reference for identifying the future energy storage needs of the UK system up to 2050 (data courtesy of National Grid). FES includes four scenarios representing different possible pathways, however these should not be regarded as forecasts but rather possible futures, so the actual pathway followed would likely be a combination of these.

3.1

FES Framework

The FES framework comprises the following four scenarios:

- Community Renewables
- Two Degrees
- Steady Progression
- Consumer Evolution

The framework is based on two drivers: The speed of decarbonisation and the level of de-centralization. Note that while the first two scenarios meet the UK's original 80% carbon reduction targets by 2050, none of these scenarios meet the current 2050 net-zero carbon reduction targets. A further Net Zero scenario was thus subsequently formulated, that aims at meeting the UK's net-zero carbon targets by 2050.

Community Renewables

This scenario achieves the 2050 decarbonisation target in a de-centralized energy landscape.

In Community Renewables, local energy schemes flourish, consumers are engaged and improving energy efficiency is a priority. Policy supports onshore generation and storage technology development, bringing new schemes which provide a platform for other green energy innovation to meet local needs.

Key issues affecting UK generation include:

- Earlier growth in electricity storage capacity;
- Reduced solar capacity; and
- Increased offshore wind capacity and decreased nuclear capacity.

Two Degrees

This scenario achieves the 2050 decarbonisation target with large-scale centralized solutions.

In Two Degrees, large-scale solutions are delivered to meet the 2050 target. Increasing renewable capacity, improving energy efficiency and new technologies such as carbon capture and storage are policy priorities.

Key issues affecting UK generation include:

- The highest peak and annual electricity demand scenario;
- Hydrogen from electrolysis introduced;
- Small modular nuclear reactors introduced; and
- Increased offshore wind capacity and decreased nuclear capacity.

Steady Progression

This scenario makes progress towards decarbonisation through a centralized pathway, but does not achieve the 2050 target.

In Steady Progression, the pace of the low-carbon transition continues at a similar rate to today but then slows towards 2050. Although hydrogen blending into existing gas networks begins, limited policy support means that new technologies such as carbon capture, usage and storage and battery storage develop slowly.

Key issues affecting UK generation include:

- Higher hydrogen supply with roll-out of blended hydrogen into the gas network; and
- Increased offshore wind capacity and decreased nuclear capacity.

3.1

FES Framework

Consumer Evolution

This scenario makes progress towards decarbonisation through de-centralization but does not achieve the 2050 target.

In Consumer Evolution, there is a shift towards local generation and increased consumer engagement, largely from the 2040s. Cost-effective local schemes are supported but a lack of strong policy direction means technology is slow to develop, e.g. for improved battery storage.

Key issues affecting UK generation include:

- The lowest peak and annual electricity demand scenario;
- No small modular nuclear reactors; and
- Increased offshore wind capacity and decreased nuclear capacity.

Two of these scenarios, Community Renewables and Two Degrees, do achieve an 80% carbon reduction target by 2050. They possess the combined themes of:

- Increased offshore wind;
- Increased energy storage; and
- Introduction of hydrogen from electrolysis.

Net Zero Reduction Scenario

Following the Paris Agreement a further Net Zero Carbon Reduction scenario has been drawn up that aims to achieve a net-zero carbon target by 2050. It is based on the Two Degrees scenario but includes the following further criteria that affect the power sector:

- Increased electrification;
- Increased hydrogen via electrolysis;
- Increased carbon capture usage & storage (CCUS); and
- Increased bioenergy with carbon capture and storage (BECCS).

3.2

FES Key Statistics

National Grid ESO has published the following key statistics in its FES-in-5 summary report, which covers the existing situation as at 2018 together with future projections for 2030 and 2050:

	2018	2030				2050			
Electricity		CR	TD	SP	CE	CR	TD	SP	CE
Annual demand (TWh)	285	283	300	299	288	413	422	376	370
Peak demand (GW)	60	57,4	63.8	63	59.8	72.4	82.5	74.9	68.7
Total installed capacity (GW)	108	154	158	140	131	233	227	175	176
Low Carbon and renewable capacity (GW)	52	102	95	76	70	161	162	106	101
interconnector capacity (GW)	4	17	20	15	12	17	20	15	12
Total storage capacity (GW)	4	13	12	8	7	38	31	21	27
Vehicle-to-grid total capacity (GW)	0	1.3	1	0.2	0.2	20.4	16.6	15.2	19

This presents the predicted growth in annual demand together with the anticipated increase in renewables capacity, interconnector capacity and energy storage capacity. The Net Zero Carbon scenario gives an annual electricity demand of 491 TWh (115 GW peak demand) by 2050, an increase of some 16% above that for the Two Degrees scenario.

This gives the existing storage capacity of 4 GW (principally existing pumped hydro) and the anticipated increase in energy storage capacity up to 2050. Given the declared aim of achieving net-carbon neutrality by 2050 as required by the Community Renewables and Two Degrees scenarios, these show a net increase in energy storage by 8 GW to 12 GW by 2030, with a further increase in storage by 10 GW to 22 GW by 2050 (excluding about 10 GW for vehicle/grid batteries). The projected storage requirement for the Net Zero scenario is given as 23 GW, which is broadly similar to that in the Two Degrees scenario.

Of the above, the planned increased energy storage of 8 GW by 2030 and further 10 GW by 2050 could be provided by a combination of pumped hydro in conjunction with other technologies such as battery storage, hydrogen electrolysis and storage, liquid air energy storage and compressed air energy storage. In all cases, it is envisaged that the energy source for these storage options would be from surplus renewables generation, mainly wind. In addition, these technologies could also be used to offset the requirement backup CCGT gas turbine plant with CCS, if it was found to be economic to do so. A breakdown of the anticipated growth patterns of the various energy sources, by scenario, is presented in the following sections.

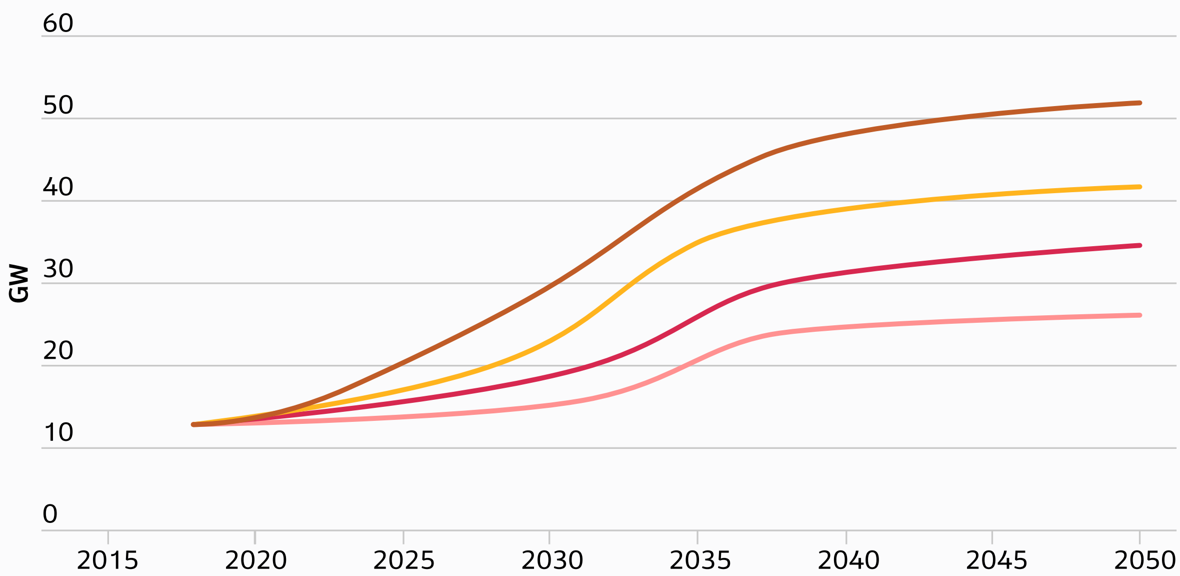
Renewable Generation

The projected increase in renewables generation comprises principally solar, wind and other renewables.

It is not clear from the FES report what other renewables comprise, so it is assumed this is principally conventional hydro, tidal and other private renewable generation schemes. The predicted generation capacity in this category is estimated at about 13 GW by 2030/2050, for the Two Degrees and Community Renewables scenarios, and 18 GW for the Net Zero scenario by 2050.

Solar Generation

The predicted future solar generation capacity (as projected by National Grid ESO) is estimated between 23 to 30 GW by 2030 and between 42 to 50 GW by 2050 for the Two Degrees and Community Renewables scenarios respectively, as shown in the figure below:



Solar capacity by scenario

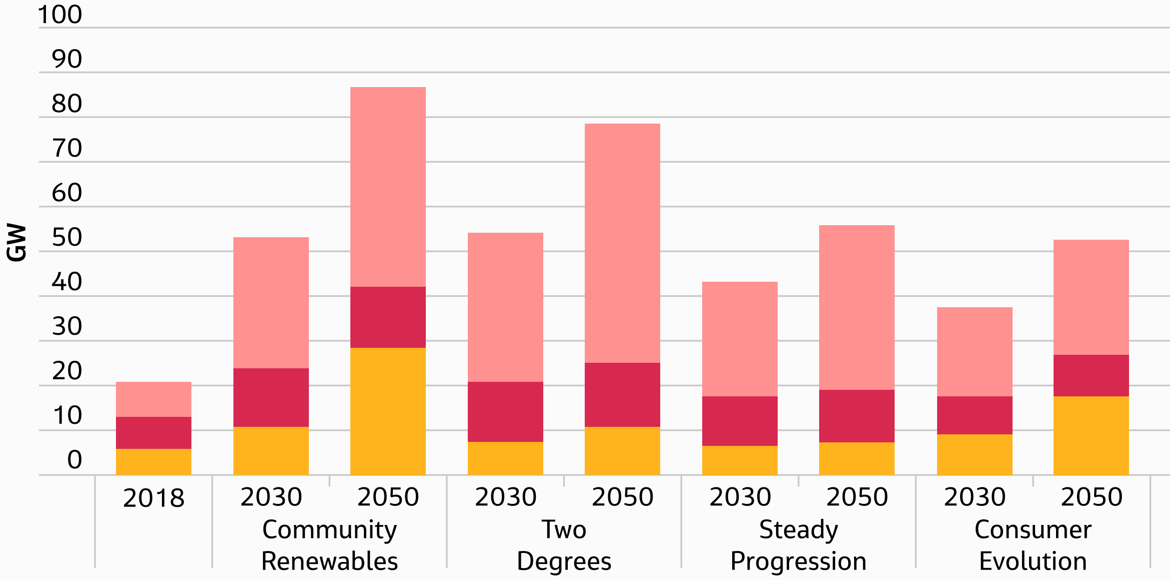
The solar generation capacity for the Net Zero scenario is projected to be 42 GW by 2050, i.e. the same as for the Two Degrees scenario.

3.3

Renewable Generation

Wind Generation

The predicted future onshore and offshore wind generation capacity (as projected by National Grid ESO) is estimated at 54 GW by 2030 and between 80 to 87 GW by 2050 for the Two Degrees and Community Renewables scenarios respectively, as shown in the figure below:



Wind capacity by scenario

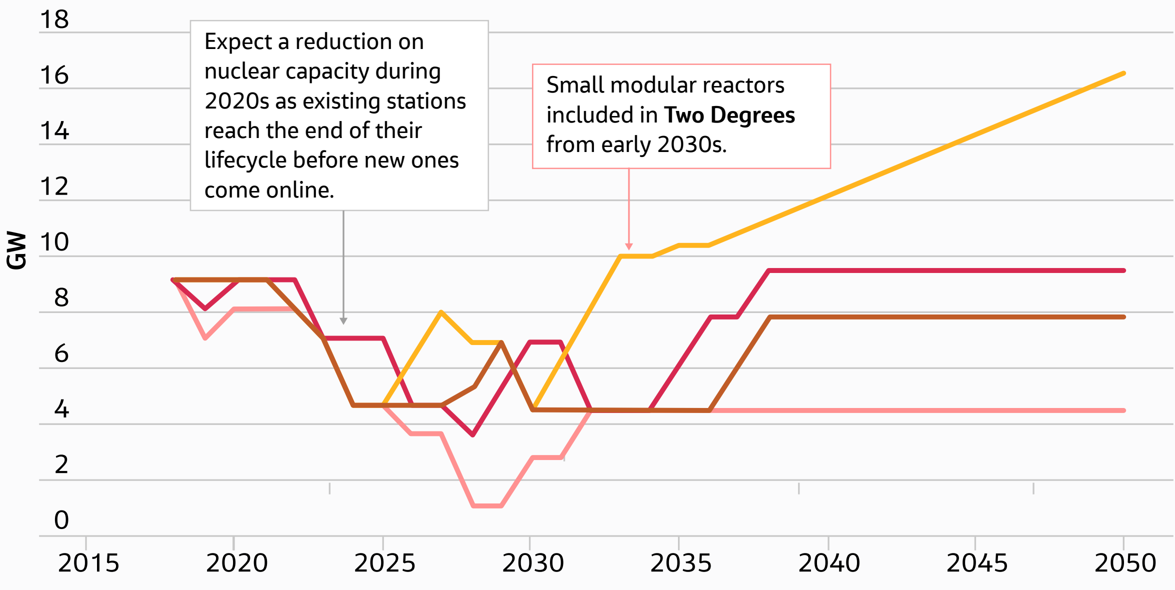
The wind generation capacity for the Net Zero scenario is projected to be even higher at 92 GW by 2050.

3.4

Thermal Generation

Nuclear Generation

The predicted future nuclear generation capacity (as projected by National Grid ESO) is estimated at approximately 5 GW by 2030, with about 8 GW by 2050 for Community Renewables and about 16 GW by 2050 for the Two Degrees scenario, as shown in the figure below:



Installed nuclear capacity

This reflects the gradual decommissioning of existing nuclear and the later phased introduction of new nuclear.

3.4

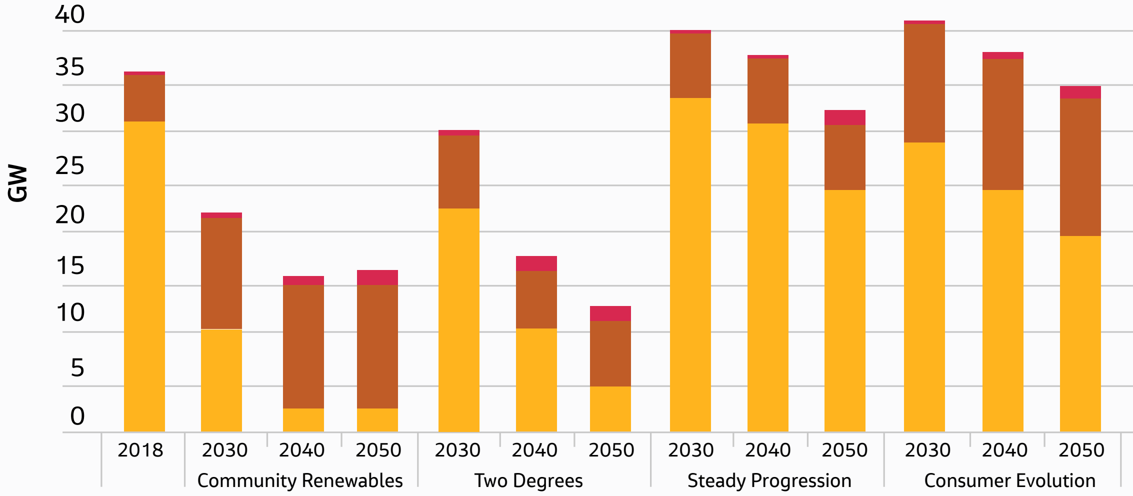
Thermal Generation

CCGT Generation

The predicted phased reduction in unabated CCGT generation capacity (as projected by National Grid ESO) is estimated at 6 GW (from 37 GW to 31 GW) by 2030 with a further 18 GW (from 30 GW to 13 GW) by 2050 for the Two Degrees scenario, as shown in the figure below:

It should be noted that 12 GW of CCGT with CCS should also be added to the forecast capacity for the Two Degrees scenario in 2050, giving a total CCGT capacity of 25 GW by 2050 for that scenario. However, for the Net Zero scenario it appears that the remaining unabated CCGT capacity (31 GW in 2030) is planned to be decommissioned by 2050 and replaced with 43 GW of CCGT with pre-combustion CCS fueled by steam-reformed methane from natural gas.

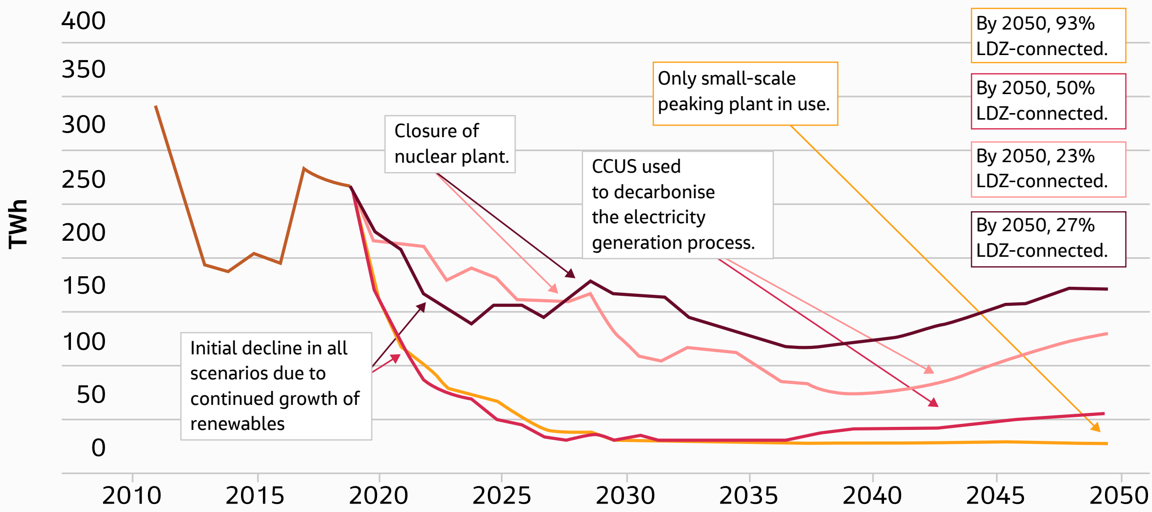
Total gas-fired generation capacity



Micro
Distribution connected gas
Transmission connected gas

The predicted major increase in renewables capacity (particularly offshore wind) will have the effect of displacing the need for CCGT generation in future and significantly reduce the load factor of the remaining CCGT plant, particularly under the Community Renewables and Two Degrees scenarios, as shown in the figure (provided by National Grid ESO) below:

Gas demand for electricity generation across all scenarios



History
Consumer Evolution
Steady Progression
Two Degrees
Community Renewables

This reduction in load factor will inevitably increase the cost of generation from the proposed backup CCGT plant with CCS. It therefore may be worthwhile looking at an alternative solution to providing backup generation, such as long-term energy storage supplied by surplus intermittent renewables generation, which could not only be provided at lower cost, but would also minimize the need for steam-reformed natural gas.

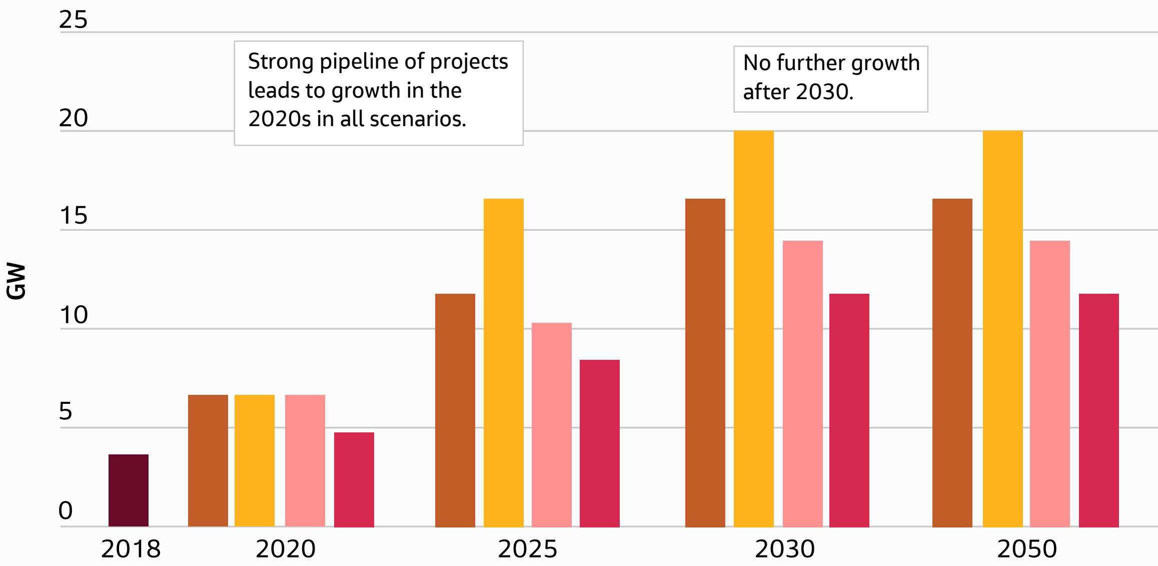
3.5

European Interconnectors

Interconnector Capacities

The predicted future interconnector capacity (as projected by National Grid ESO) is estimated at about 17 GW by 2030 for Community Renewables and about 20 GW by 2030 for the Two Degrees scenario, with no further growth after 2030, as shown in the figure below:

Installed interconnector capacity

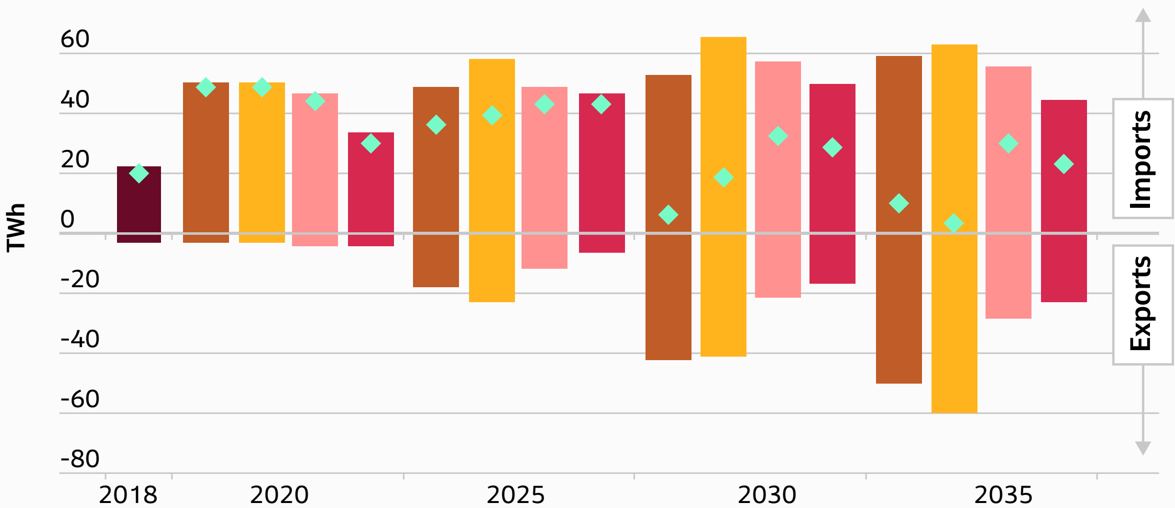


Interconnector flows

The predicted increase in renewables generation (particularly offshore wind) will allow interconnectors to export excess wind generation to Europe during periods of high wind and potentially import from Europe during periods of low wind, up to the capacity of the interconnectors, should conditions and markets permit.

The anticipated mean interconnector imports and exports are likely to be greatest for the Community Renewables and Two Degrees scenarios, as shown in the figure (provided by National Grid ESO) below:

Interconnector annual flows



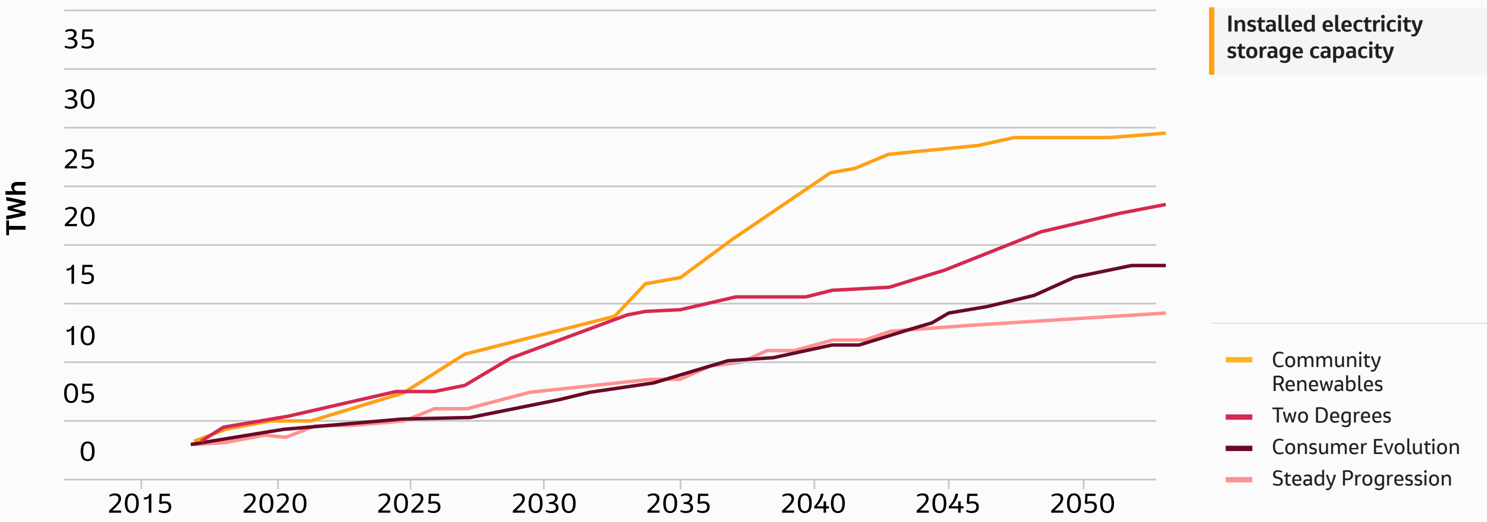
Provision of additional long-term storage would allow attenuation of such interconnector flows (by providing peak-lopping for both imports and exports) and thus increase the effective transfer capacity of the available interconnectors. This could also provide greater flexibility for optimizing transfers to and from Europe to suit prevailing market conditions.

Energy Storage

3.6

Electrical Energy Storage

The predicted future electricity energy storage (as projected by National Grid ESO) is shown in the figure below:



Installed electricity storage capacity

This shows the anticipated increase in both long-term and short-term energy storage capacity up to 2050. As discussed in Section 3.2, this includes an estimate for the component of vehicle-to-grid battery storage that needs to be separated out, which results in increased energy storage requirement of about 8 GW by 2030, with a further increase of 10 GW by 2050. This is in addition to the current energy storage capacity of about 4 GW. Note that these capacities do not include hydrogen storage requirements which are considered separately (see below).

As set out in the FES report, this storage requirement comprises both short-term storage (up to a few hours) and long-term storage (several days/weeks), which could be provided by the following alternative technologies:

Short-Term Storage Technologies

- Lithium-Ion batteries
- Liquid air energy storage

Long-Term Storage Technologies

- Conventional hydro
- Pumped hydro storage
- Hydrogen from hydrogen & storage
- Compressed air energy storage

This list is not definitive but gives an indication of the range of the feasible technologies available. Long-term storage options may also be used to provide short-term storage (and vice-versa), however the economic feasibility of so doing is largely technology dependent. This is discussed further in section 5.

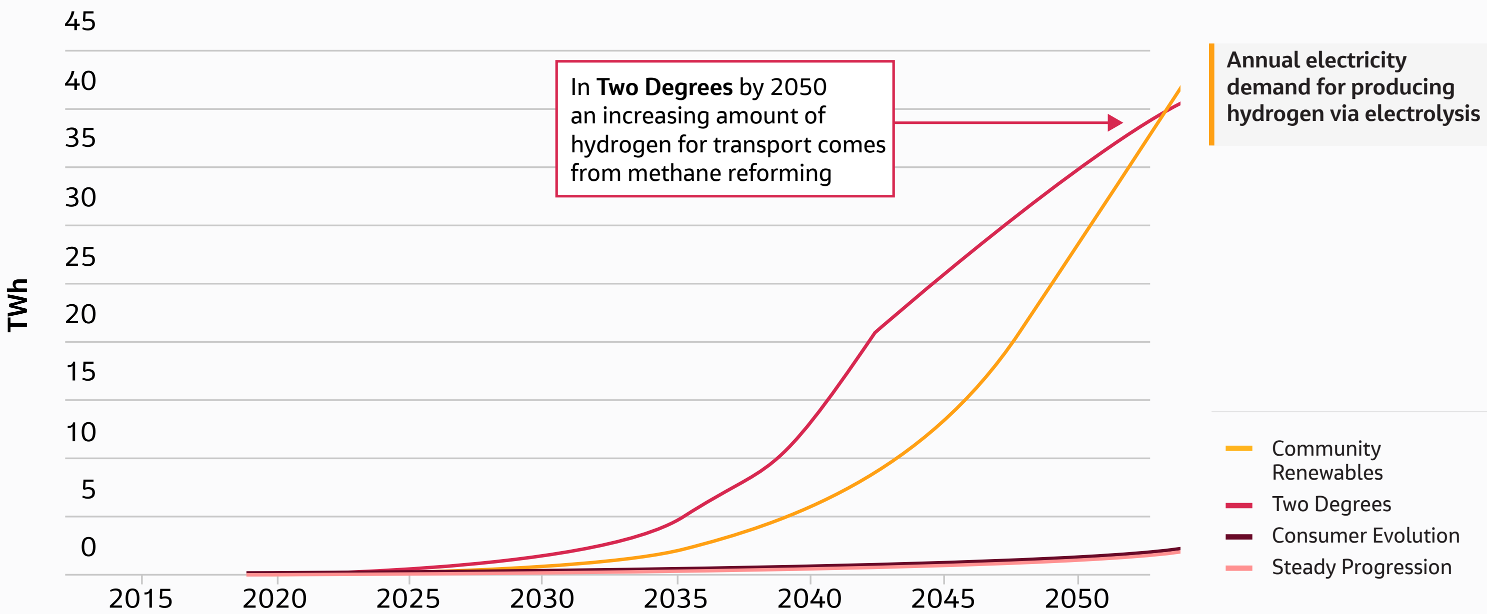
3.6

Energy Storage

Hydrogen Energy Storage

In addition to the predicted future electricity energy storage requirements described in the previous section, there is also a separate energy projection for producing hydrogen via electrolysis from surplus renewables generation. The hydrogen produced could be stored in gas storage caverns for later generation or other uses. The predicted future energy demand for hydrogen production via electrolysis (as projected by National Grid ESO) is shown in the figure below:

This gives a projected energy demand for hydrogen production via electrolysis of 42 TWh by 2050, which if supplied by surplus renewables generation (e.g. wind), would require a total hydrogen hydrolyzer plant capacity of approximately 20 GW, assuming a load factor of 20%, based on the availability of surplus renewables generation.



Annual electricity demand for producing hydrogen via electrolysis

3.7 & 3.8

Use of the FES Data in this Report

Given the authority and robust modeling of the Future Energy Scenarios, we have used these scenarios as the basis for building our models of the alternative pathways to net-zero carbon.

Updated FES 2020 Scenarios

More recently National Grid updated their future energy scenarios (FES 2020), published on 27th July 2020, which comprised four further updated scenarios as follows:

- Steady progression;
- Consumer transformation;
- System transformation;
- Leading the way.

While our main analyses are based on FES 2019, further sensitivity analyses have been carried out, using the latest FES 2020 data, to asses the impact of any changes in these scenarios on our findings which are presented in Section 6.

Projected Energy Generation Profiles

4.0

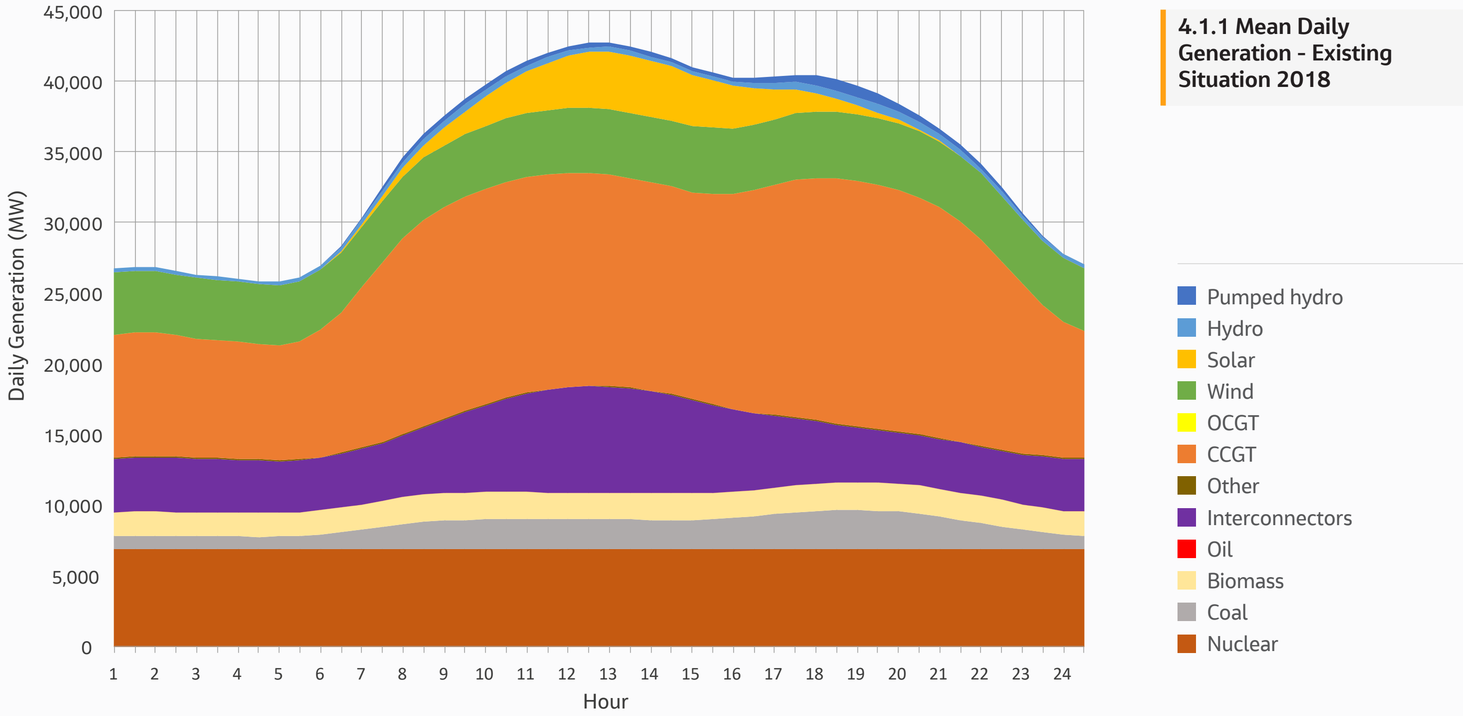
In order to determine to the potential system needs for long-term energy storage from 2018 to 2050, we have carried out a high-level modeling exercise utilizing historic generation data provided by Elexon (via Grid Watch), together with historic demand and interconnector data provided by National Grid (Data Explorer).

Existing Generation Profile – 2018

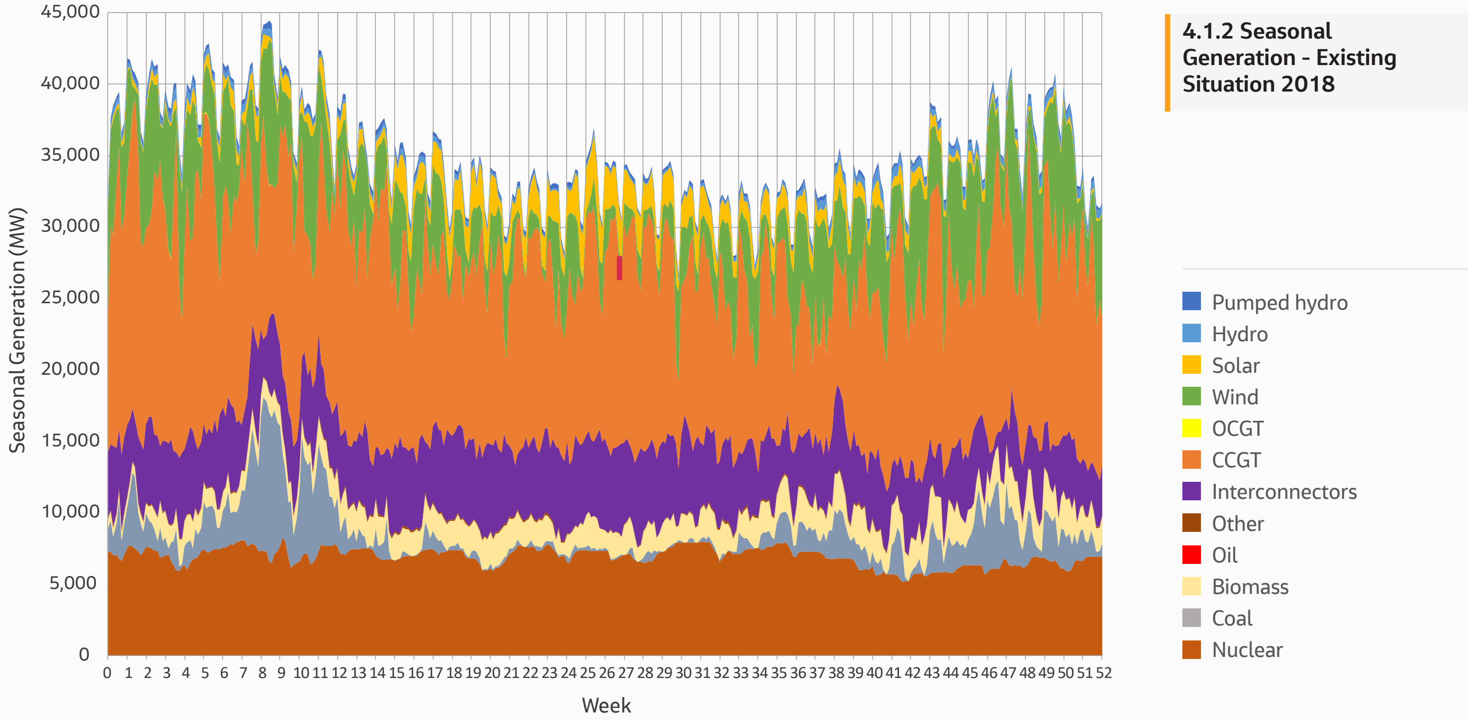
4.1

The base case daily and annual generation profiles, using actual data for 2018, are shown in the figures below.

4.1.1 Mean Daily Generation - Existing Situation 2018



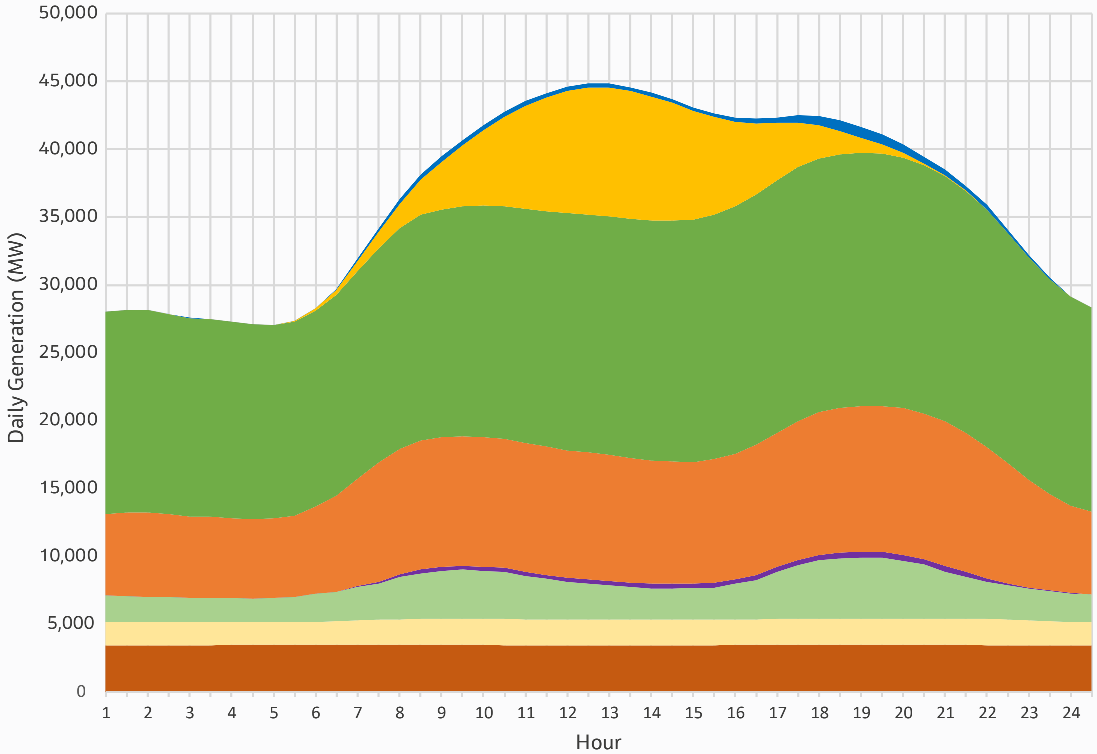
4.1.2 Seasonal Generation - Existing Situation 2018



4.2

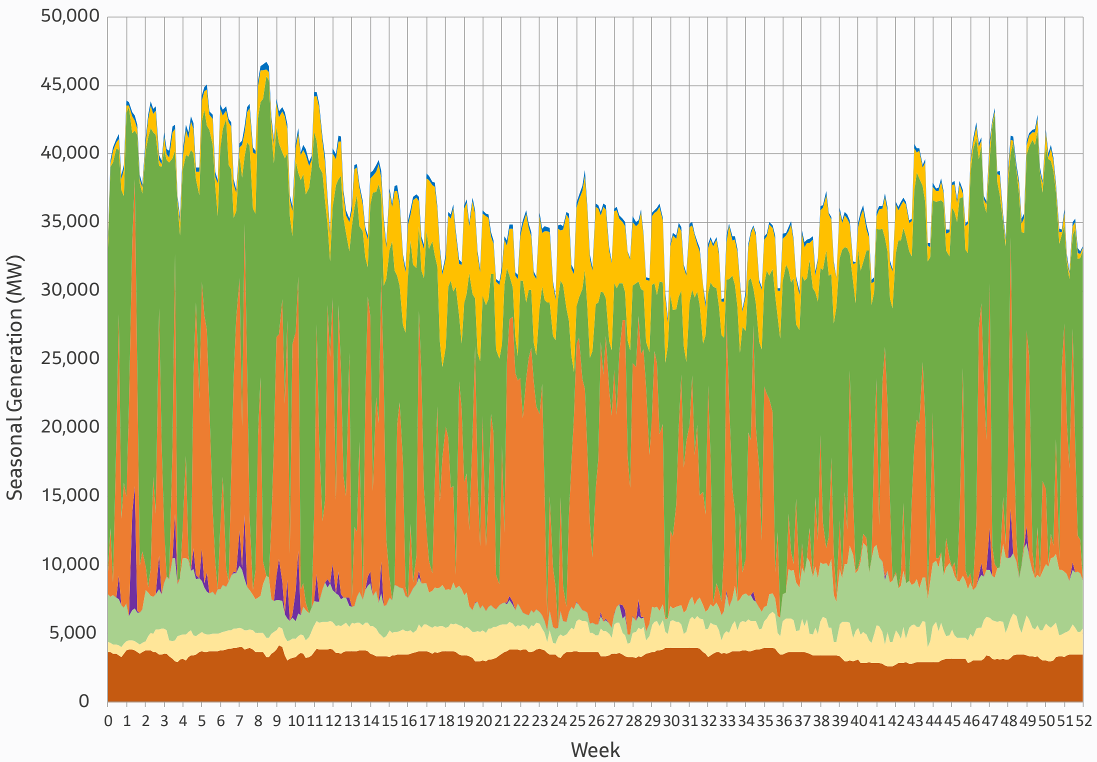
Medium Term Generation Profile – 2030

A future projection for the expected situation in 2030 has been prepared by factoring the 2018 Elexon data to reflect the predicted generation capacities and demand projections given in Future Energy Scenarios. This covers the projected reductions in nuclear and CCGT capacity with the projected increase in renewables (solar and wind) and 12 GW of European interconnector capacity, with no increase in long-term energy storage. The 2030 projections presented in the figures below are for the Two Degrees scenario, for the case with 3 GW of existing pumped hydro and 30 GW of planned CCGT plant with CCS.



4.2.1 Projected Mean Daily Generation - FES "Two Degrees" Scenario - 2030

Existing 3 GW Pumped Hydro with planned 50 GW wind, 20 GW Solar, 30 GW CCGT+CCS and 20 GW Interconnectors



This shows the high dependence on CCGT plant with CCS for supporting intermittent renewables in 2030.

4.2.2 Projected Seasonal Generation - FES "Two Degrees" Scenario - 2030

Existing 3 GW Pumped Hydro with planned 50 GW wind, 20 GW Solar, 30 GW CCGT+CCS and 20 GW Interconnector

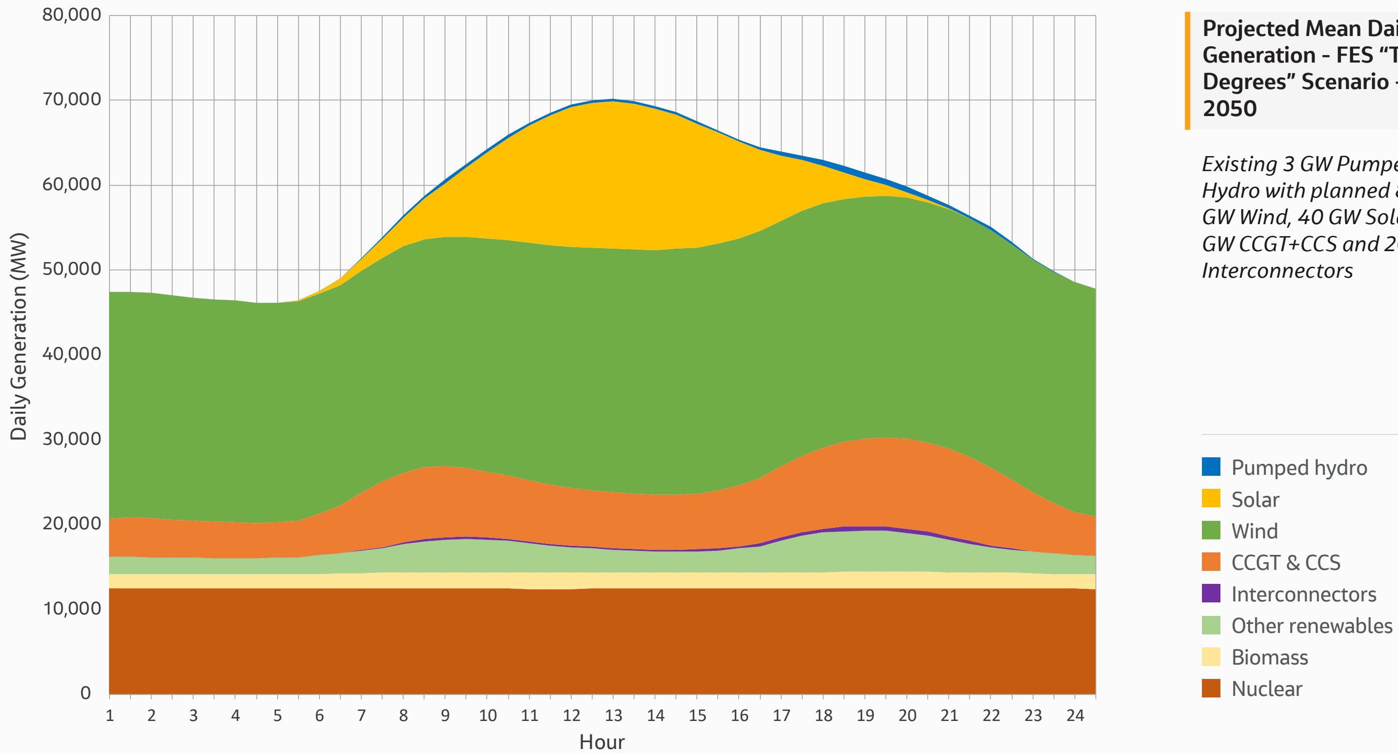
4.3

Long-Term Generation Profile – 2050

A projection for the expected situation in 2050 has also been prepared by factoring the 2018 Elexon data to reflect the predicted generation capacities and demand projections given in future energy scenarios. This covers the continued reduction in CCGT capacity with the projected increase in nuclear and renewables (solar and wind) and 20 GW of European interconnector capacity, with no increase in long-term energy storage. The 2050 projections presented in the figures below are for the Two Degrees scenario, for the case with 3 GW of existing pumped hydro and 30 GW of planned CCGT plant with CCS.

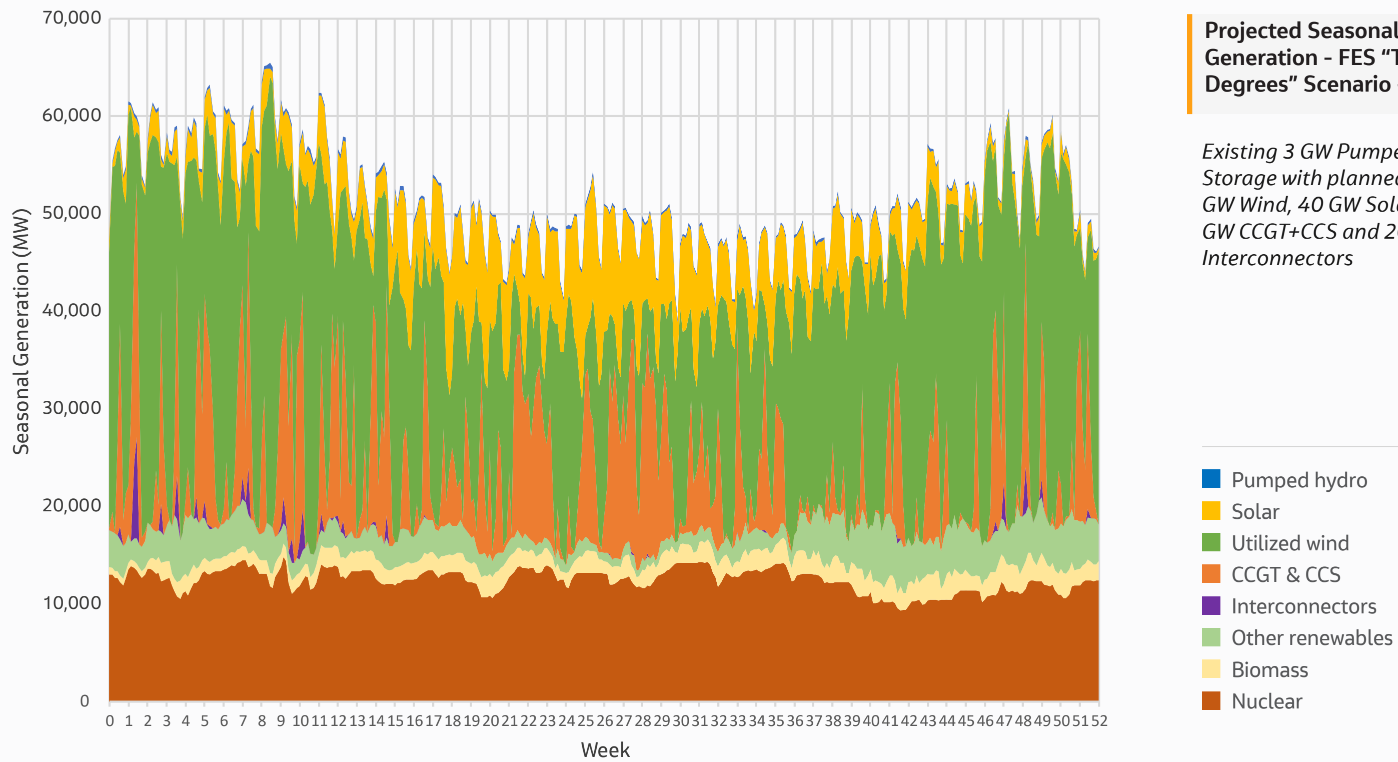
Projected Mean Daily Generation - FES "Two Degrees" Scenario - 2050

Existing 3 GW Pumped Hydro with planned 80 GW Wind, 40 GW Solar, 30 GW CCGT+CCS and 20 GW Interconnectors



Projected Seasonal Generation - FES "Two Degrees" Scenario - 2050

Existing 3 GW Pumped Storage with planned 80 GW Wind, 40 GW Solar, 30 GW CCGT+CCS and 20 GW Interconnectors



This shows the continued high dependence on CCGT plant with CCS for supporting intermittent renewables in 2050.

Alternative Energy Storage Technologies

5.0

We have compared the costs of various energy storage technologies and divided them into short-term and long-term energy storage. Costs have been compiled from various published sources to determine not only the capital cost (in £m/MW) and cost of storage (in £/kWh stored), but also the unit cost of generation (in £/MWh). We have then compared the unit cost of generation from these alternative energy storage technologies with the unit cost of generation from other net-zero carbon generation sources.

Short-Term Storage Technologies

5.1

The range of short-term energy storage technologies that have been evaluated are described below.

Lithium-Ion Batteries

We have determined capital costs for utility scale lithium-ion storage systems from costs provided by the US National Renewable Energy Laboratory (NREL) and derived cost functions for the following storage durations.

Note the steep increase in capital cost with increasing storage duration. Using the NREL data, 200 MW capacity with 0.5 hr duration would cost approximately £69m, which is very close to the bid price of the recent National Grid FFR auction of £66m for 201 MW of storage capacity secured (KPMG market briefing Sept 2016).

Lithium-Ion Battery Storage – Capital Cost Functions

Duration hrs)	Capital Cost (£m/MW)	Storage Cost (£/kWh)
12	£3.02	£252
8	£2.10	£262
4	£1.17	£292
2	£0.70	£350
1	£0.46	£464
0.5	£0.34	£686

Liquid Air Energy Storage (LAES)

We have obtained estimated costs for LAES systems from published figures provided by Highview Power who recently commissioned a 5 MW pilot plant that had a stated capital cost of £8m, with a round-trip efficiency of 25%. Highview has recently announced plans for a 50 MW plant with 5 hours of storage (250 MWh) and give typical capital costs of approximately £1m per MW installed for a plant with 4 hours of storage.

They also claim that a 200 MW plant with 10 hours of storage could have a unit generation cost of about £110/MWh generated, which implies a load factor of 24% and assumes a round-trip efficiency of 50%, although this is as yet unproven. Cost functions have been derived using the above figures for the following storage durations:

Liquid Air Energy Storage – Capital Cost Functions

Duration (hrs)	Capital Cost (£m/MW)	Storage Cost (£/kWh)
12	£1.27	£106
8	£1.15	£143
4	£1.02	£256
2	£0.96	£481
1	£0.93	£931
0.5	£0.92	£1,831

5.2

Long-Term Storage Technologies

We have evaluated various long-term energy storage technologies covering pumped hydro storage, which could include both new build pumped storage as well as adaption of existing conventional hydro plants, hydrogen storage, using hydrolysers to produce hydrogen in conjunction with underground cavern storage supplying gas turbines, and compressed air energy storage, that would use air compressors and recovery turbines also in conjunction with underground cavern storage.

Pumped Hydro Storage

As part of the levelized generation cost study, carried out for DECC in 2015 by Jacobs and published by BEIS in 2016, we prepared generic cost functions for pumped storage based on engineering studies carried out for a range of potential pumped storage sites in Scotland. This includes the estimation of all civil works, including dams, tunnels, power caverns and mechanical & electrical plant, for typical installations. These costs represent the median range and are only indicative, as actual costs will vary from site to site. Cost functions have been derived for the following storage durations:

Pumped Hydro Storage – Capital Cost Functions

Duration (hrs)	Capital Cost (£m/MW)	Storage Cost (£/kWh)
144	£1.54	£11
96	£1.32	£14
72	£1.22	£17
48	£1.11	£23
24	£1.00	£42
12	£0.95	£79
8	£0.93	£116
4	£0.91	£228

The round-trip efficiency for pumped storage is taken as 75%, based on the combined overall efficiencies of the pump/turbines during pumping and subsequent generation at varying output (the maximum theoretical conversion efficiency at full load is over 80%, but rarely actually achieved in practice).

Hydrogen Storage from Electrolysis

We have also prepared a generic cost function for hydrogen storage based on electrolysis, which is appropriate for balancing of intermittent renewables (as opposed to steam-reforming of natural gas), which includes combined estimates for the hydrolyzer plant, gas cavern storage and a CCGT plant. Hydrolyzer costs have been based on those provided by ITM power, which says its PEM hydrolyzers are currently below €1m/MW and could fall to around £0.7m/MW in future. Gas cavern storage costs have been estimated from SSE's Aldbrough natural gas storage facility with a reported capital cost of £290m for a gas storage capacity of 370 million cubic meters (factored for the lower energy density), with hydrogen fueled CCGT plants based on published levelized costs of £0.5m/MW.

Hydrolyzer with CCGT – Capital Cost Functions

Duration (hrs)	Capital Cost (£m/MW)	Storage Cost (£/kWh)
144	£1.25	£9
96	£1.24	£13
72	£1.23	£17
48	£1.22	£26
24	£1.22	£51
12	£1.22	£101
8	£1.21	£152
4	£1.21	£303

5.2

Long-Term Storage Technologies

The round-trip efficiency assumed for hydrogen storage is taken as 40%, based on 80% efficiency for the hydrolyzer plant, 53% efficiency for the hydrogen fired CCGT plant and allowing 3% losses for gas compression and de-compression.

As the CCGT plant would be expected to operate at a low load factor of about 20%, we have also costed an alternative solution utilizing an OCGT plant, which has a lower capital cost (£0.3m/MW) but would have a reduced round-trip efficiency of about 25%, based on 80% efficiency for the hydrolyzer plant, 34% efficiency for the OCGT plant and allowing 3% losses for gas compression & de-compression. Cost functions have been derived for the following storage durations:

Hydrolyzer with OCGT – Capital Cost Functions

Duration (hrs)	Capital Cost (£m/MW)	Storage Cost (£/kWh)
144	£1.05	£7
96	£1.04	£11
72	£1.03	£14
48	£1.02	£21
24	£1.02	£42
12	£1.02	£85
8	£1.01	£127
4	£1.01	£253

Compressed Air Energy Storage (CAES)

Obtaining reliable costs for compressed air energy storage has been difficult, but we have estimated capital costs for CAES systems from published costs from Hydrostor for a 250 MW plant with an 8 hour storage capacity. The cost for this is given as $440m, equivalent to a capital cost of $1.76m/MW (£1.35/MW) and a storage cost of $220/kWh (£169/kWh) for the stated 8 hours' storage of 2 GWh. The division of cost between the electro-mechanical plant and the underground storage is not stated so we have estimated cavern storage costs at approximately £5/kWh based on those published in the International Renewable Energy Association report on Electricity Storage and Renewables (2017) which give costs in the range of $1/kWh to $30/kWh depending on rock type. Cost functions have thus been derived on the above basis, for the following storage durations:

Compressed Air Energy Storage - Capital Cost Functions

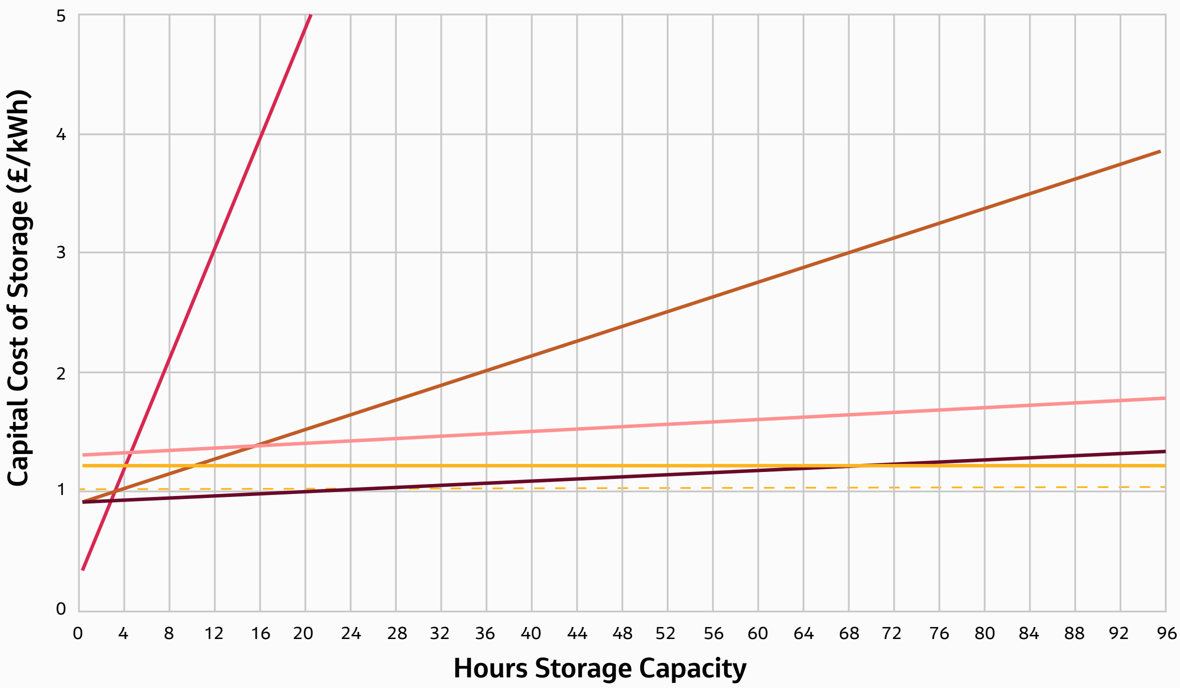
Duration hrs)	Capital Cost (£m/MW)	Storage Cost (£/kWh)
144	£2.03	£14
96	£1.79	£19
72	£1.67	£23
48	£1.55	£32
24	£1.43	£60
12	£1.37	£115
8	£1.35	£169
4	£1.33	£334

There is significant variance in the claimed round-trip efficiency that can be achieved by this technology, but research by the University of Denmark has shown that it is reasonable to assume a round-trip efficiency of approximately 40%, which includes an allowance for the energy required for re-heating the air after de-compression.

5.3

Capital Cost Comparison of Alternative Technologies

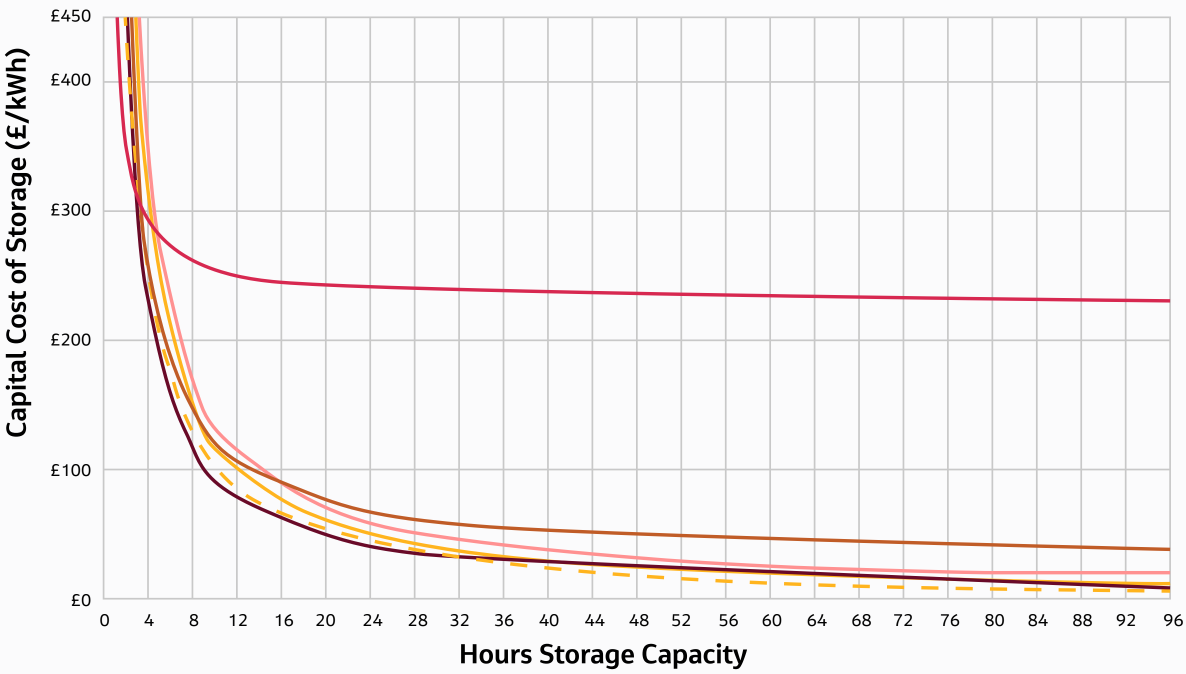
A capital cost comparison has been carried out for the range of alternative storage technologies for the cost per MW installed, as shown in the figure below:



Capital Cost per MW Installed Capacity for Alternative Storage Technologies

- Lithium-ion Battery Storage
- Liquid Air Energy Storage (LAES)
- Compressed Air Energy Storage (CAES)
- Pumped Hydro 500 MW increments
- Hydrogen hydrolyzer + CCGT
- Hydrogen hydrolyzer + OCGT

A similar cost comparison for the storage cost per kWh installed for the range of alternative storage technologies, is shown in the figure below:



Capital Cost per MW Installed Capacity for Alternative Storage Technologies

- Lithium-ion Battery Storage
- Liquid Air Energy Storage (LAES)
- Compressed Air Energy Storage (CAES)
- Hydrogen hydrolyzer + CCGT
- Pumped Hydro 500 MW increments
- Hydrogen hydrolyzer + OCGT

5.3

Capital Cost Comparison of Alternative Technologies

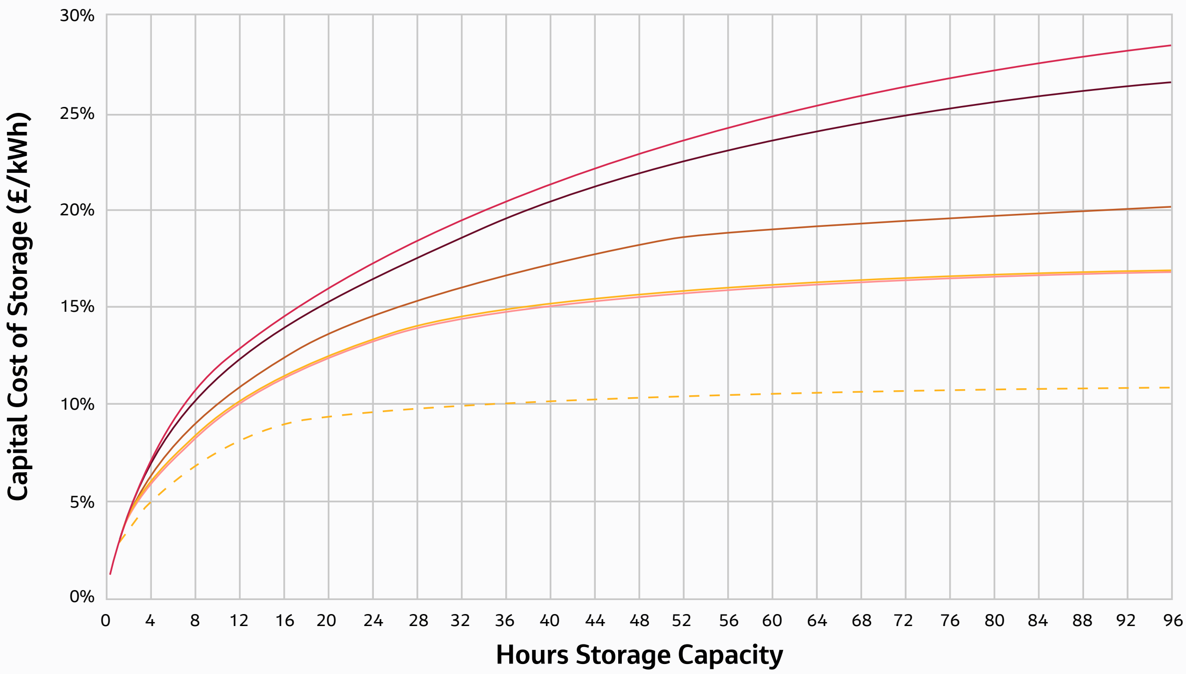
These graphs show that for Lithium-Ion batteries, there is a pronounced increase in the cost per MW installed and for the cost of storage for increasing storage durations. This is because much of the cost of Lithium-Ion batteries is in storage medium, the cost of which increases proportionately with storage duration, whereas the cost of the rectifiers and inverters is fixed for a given installed capacity (MW). In the case of pumped hydro, the main capital cost is in the tunnels, power cavern and pump-turbines and for hydrogen storage the main capital cost is in the hydrolysers and gas turbines, which is fixed for a given installed capacity (MW), whereas the incremental cost of the storage for pumped hydro (reservoirs) and hydrogen or CAES storage (caverns) per GWh stored is very low. This makes pumped hydro, hydrogen and CAES storage more suitable for the long-term storage of intermittent renewables.

5.4

Estimated Load Factors for Alternative Storage Technologies

One of the key factors that affects the unit cost of generation or levelized generation cost of these alternative storage technologies is the load factor, which in turn is dependent on a combination of the availability of surplus renewable generation (e.g. wind), the storage capacity of each technology and its round-trip efficiency. The availability of surplus renewable generation is a function of the system demand at any given time, the available system capacity and the total installed capacity of renewable generation, which is different for each Future Energy Scenario and also varies each year. We have therefore estimated the average load factor for each technology using our simulation based on the Two Degrees scenario for 2050. The estimated load factors (%) against storage duration (hours) for each storage technology applicable to this scenario in 2050 is presented in the figure below.

Achievable Load Factors for Alternative Energy Storage Technologies 'Two Degrees' Scenario 2050



This shows that lithium-ion batteries and pumped hydro storage have the highest load factor due to their higher round-trip efficiencies, whereas CAES and hydrogen storage (particularly with OCGT) have the lowest outputs due to their lower round-trip efficiencies. The round-trip efficiency therefore has a major bearing on the unit generation cost for each technology. Notice also that the load factor increases with storage duration, reflecting the ability of increased storage to better utilize the available surplus renewables generation.

Although we estimate that surplus wind generation could be available for approximately 40% of the time by 2050, the actual load factor achieved by respective technologies would be less than this due to their different round-trip efficiencies. Pumped hydro would be able to achieve a load factor of

25% for 72 hours' storage, whereas hydrogen storage and CAES would only be able to achieve a load factor of 17% for the same duration when used for balancing renewables. This therefore demonstrates that different technologies are more efficient at balancing renewables than others.

It can also be seen that short-term storage technologies with storage durations of less than 4 hours can only achieve a maximum load factor of 7% and would thus be very inefficient for balancing renewables. This inevitably has an impact on the cost-effectiveness of such technologies for this application.

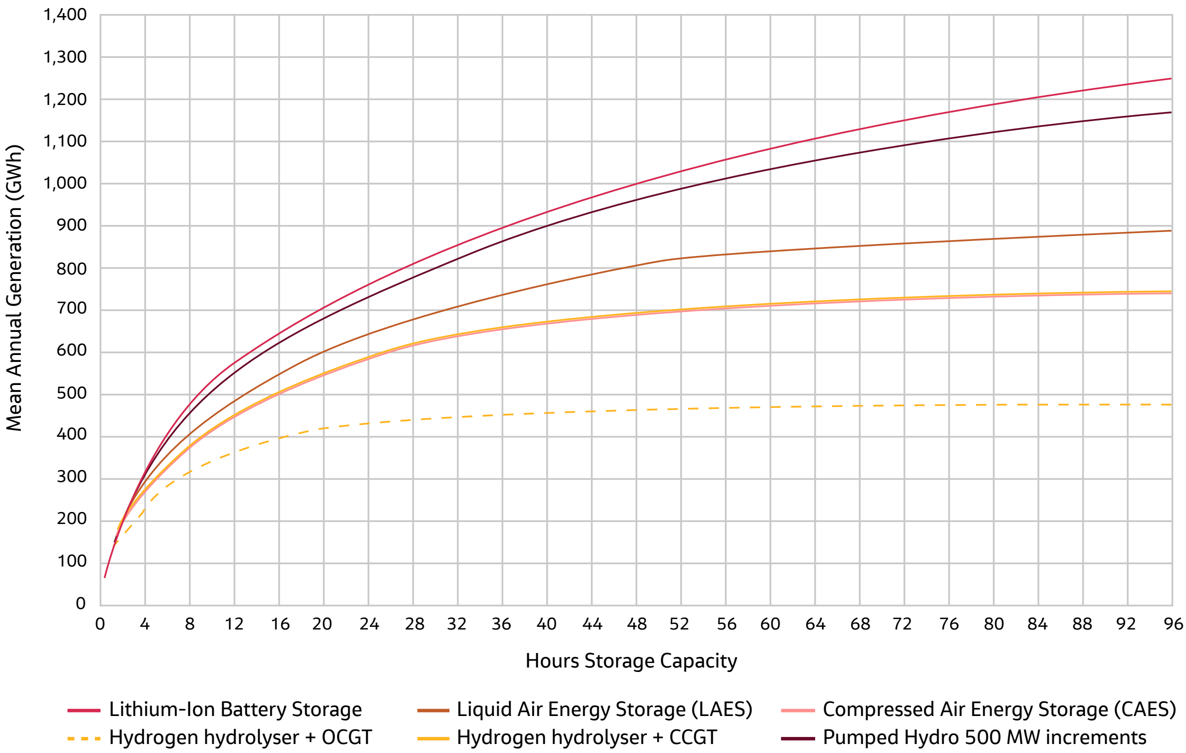
5.4

Estimated Load Factors for Alternative Storage Technologies

5.5 Simulated Generation Outputs from Alternative Technologies

Using the system simulations presented in the Section 4, we have been able to estimate the annual generation (GWh/yr) that could be achievable from a typical 500 MW energy storage plant for each type of storage technology, for a range of energy storage capacities. The situation for a 500 MW plant based on the Two Degrees scenario for 2050 is presented in the figure below.

Annual Generation 500 MW of Installed Storage for Balancing Renewables 'Two Degrees' Scenario 2050



Lithium-ion Battery Storage
Pumped Hydro 500 MW increments
Liquid Air Energy Storage (LAES)
Compressed Air Energy Storage (CAES)
Hydrogen hydrolyzer + CCGT
Hydrogen hydrolyzer + OCGT

5.6 Estimated Unit Generation Costs for Alternative Technologies

From the estimated energy outputs from utilizing surplus renewables generation for 2050 and combining the associated capital and operating costs, it has been possible to derive an approximate unit generating cost curve against storage capacity for each type of storage technology.

These curves are necessarily approximate as they are based on generic cost functions derived for each technology, including assumptions on wind variability based on 2018 data and assuming a total wind generation capacity of 80 GW by 2050. It has been estimated by simulation that for the given demand projections, the mean annual generation achieved from wind would amount on average to some 30 GW, thus operating at a load factor of about 40%. Of this it has been estimated that by 2050 an average of about 25% would be surplus to requirement, which could either be available to be stored, put to other uses or curtailed.

This compares with the projected situation for 2030, where the predicted total wind generation capacity would be 50 GW with an estimated mean annual generation from wind of about 20 GW. Of this about 12.5% would be surplus to requirement, which

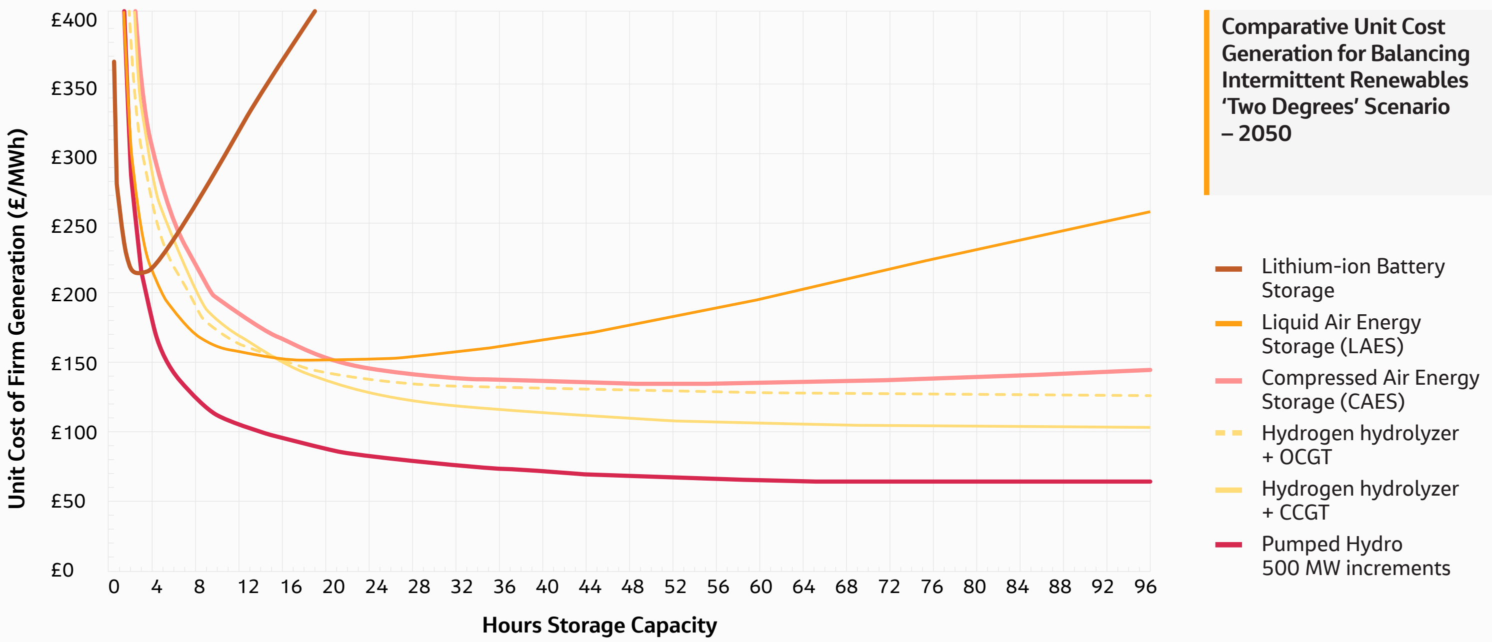
5.6

Estimated Unit Generation Costs for Alternative Technologies

demonstrates that in percentage terms, the amount of surplus wind energy would likely double between 2030 and 2050 for the FES Two Degrees scenario.

These derived unit-generating costs are net at the point of generation and exclude Balancing Services Use of System (BSUoS) or other charges. It has also been assumed that the market price for such surplus wind generation would be near parity (+/-) and thus close to zero on average over the year. For the purposes of these analyses we have assumed a discount rate of 8%, which is equivalent to that used for deriving levelized generation costs, although higher than the Treasury Green Book rate of 3.5%. The comparative unit cost of generation by technology type for a plant of 500 MW installed capacity at a range of different storage durations, based on the Two Degrees scenario for 2050, is presented in the following figure:

Comparative Unit Cost Generation for Balancing Intermittent Renewables 'Two Degrees' Scenario – 2050



The discounted generation costs by technology type for reference year 2050 are given in the table below:

Unit Generation Costs @8% discount rate (£/MWh)

	Short-Term Storage		Long-Term Storage			
Duration (hrs)	**LI Batteries (£/MWh)**	**LAES (£/MWh)**	**Pumped Hydro (£/MWh)**	**Hydrogen CCGT (£/MWh)**	**Hydrogen OCGT (£/MWh)**	**CAES (£/MWh)**
144	£1,530.6	£339.7	£70.3	£101.4	£122.1	£159.3
96	£1,065.5	£258.3	£64.1	£103.0	£125.5	£144.2
72	£871.9	£217.3	£63.9	£104.6	£127.4	£137.3
48	£675.9	£176.2	£67.5	£109.7	£129.3	£134.3
24	£454.1	£151.6	£82.0	£128.0	£137.3	£145.4
12	£317.6	£158.0	£105.6	£169.5	£163.5	£184.9
8	£266.0	£171.3	£125.4	£204.0	£191.8	£219.4
4	£217.5	£216.5	£178.9	£286.7	£265.7	£304.2
2	£217.9	£320.5	£294.6	£434.8	£387.2	£458.0
1	£259.7	£540.7	£522.8	£749.1	£627.0	£786.2
0.5	£365.2	£989.3	£991.1	£1,367.7	£1,111.7	£1,432.9

5.6 Estimated Unit Generation Costs for Alternative Technologies

As can be seen from these results, the unit cost of generation for each technology type is highly sensitive to the design storage duration, with the lowest generation cost for each technology being as follows:

Lithium-ion batteries	£217.5/MWh – 4 hrs
Liquid air storage	£151.6/MWh – 24 hrs
Compressed air storage	£134.3/MWh – 48 hrs
Hydrogen OCGT	£122.1/MWh – 144 hrs+
Hydrogen CCGT	£101.4/MWh – 144 hrs+
Pumped storage	£63.9/MWh – 72 hrs

This demonstrates that for long-term storage, pumped hydro is clearly the lowest cost solution for balancing intermittent renewables (mainly wind), with hydrogen storage the next best solution, followed by compressed air storage (CAES).

However, this also shows that for short-term storage with durations of less than 4 hours, battery storage is the lowest cost short-term solution and is therefore more suitable for providing short-term balancing services. Lazard's levelized cost of storage analysis (Nov 2019) gives the unit cost for large scale Lithium-Ion batteries with a storage duration of 4 hours, in the range $165-$305 per MWh. This gives a mean generation cost in the range £127-£235/MWh for 4 hours of storage, which compares well with the figure of £217.5/MWh based on the NREL data.

LAES occupy the middle ground, being lower cost than hydrogen storage for storage durations between 4 and 12 hours, although higher cost than pumped storage over this range. However, our analyses have shown that the unit generation cost for LAES is more likely to be in the region of £195/MWh for a 10-hour storage plant, which is higher than the £110/MWh claimed in section 5.1.2. This is likely due to the lower load factor (10%) achievable when using LAES intermittently for regulating renewables, combined with the low efficiency of the process.

5.7 Comparison with CCGT & OCGT with CCS

We have compared the above long-term storage options with the alternative of providing CCGT and OCGT with and without CCS comprising:

- Conventional combined-cycle gas turbine without CCS (natural gas);
- Combined-cycle gas turbine with pre-combustion CCS (steam-reformed methane);
- Combined-cycle gas turbine with post-combustion CCS (natural gas); and
- Open-cycle gas turbine with post-combustion CCS (natural gas).

Conventional CCGT

Currently, the principal source of generation used to back up the intermittency of renewables are conventional combined-cycle or open cycle gas turbines (CCGT/OCGT). Typical levelized generation costs for CCGT and OCGT as determined by the BEIS Electricity Generation Cost report (2016) and by Lazards (2018) are as follows:

BEIS Levelized Generation Costs – UK (2020 prices)

New build CCGT base load plant	£61/MWh
New build OCGT plant (2000 hrs)	£128/MWh
New build OCGT plant (500 hrs)	£159/MWh

Lazards Levelized Generation Costs – Northern Europe (2018 prices)

New build CCGT base load plant	£60/MWh
New build OCGT peaking plant	£158/MWh

The figures show that CCGT has a lower unit cost of generation (at £60/MWh) compared to pumped storage or other storage technologies but is neither renewable nor carbon-neutral without carbon capture or fueled by 'green' hydrogen produced by hydrolysers.

5.7

Comparison with CCGT & OCGT with CCS

CCGT and OCGT with Carbon Capture & Storage

In order to meet net-zero carbon targets by 2050, the existing fleet of conventional CCGT plants will either need to be phased out or replaced with plants fitted with CCS.

There are two different approaches to applying carbon capture and storage to gas turbine plants:

- Post-combustion CCS which involves capturing and storing the CO2 emissions from the exhausts of conventional CCGT and OCGT plants; or
- Pre-combustion CCS which involves steam-reforming of methane from natural gas into hydrogen and then capturing CO2 from the reforming process, prior to generation by CCGT or OCGT plants.

Typical levelized generation costs for CCGT and OCGT with CCS as presented in the Electricity Generation Cost report (BEIS 2016) are as follows:

BEIS Levelized Generation Costs with CCS (2016)

Retrofitting existing CCGT plant with post-combustion CCS	£60/MWh
New build CCGT plant fitted with post-combustion CCS	£110/MWh
New build CCGT plant fitted with pre-combustion CCS	£118/MWh
New build OCGT plant fitted with post-combustion CCS	£166/MWh

The figures show that the lowest cost carbon capture option would be to retrofit post-combustion CCS to existing CCGT plants (at £94/MWh). However, these existing plants would be due for retirement before 2050 so new build CCGT plants with post-combustion CCS (at £110/MWh) would likely be required. The next lowest cost option would be new-build CCGT plants with pre-combustion CCS (at £118/MWh) by steam-reforming of methane into hydrogen, and the highest cost option would be OCGT with post-combustion CCS (at £166/MWh).

In addition, we have also obtained costs for CCGT with CCS from the more recent UK Carbon Capture Technology report (BEIS 2018) as follows:

UK Carbon Capture Report Generation Costs (2018)

Case 0 – Reference Case – Unabated natural gas CCGT	£74/MWh
Case 1 – Natural gas CCGT with post-combustion CCS	*£70/MWh
Case 2 – Natural gas CCGT with pre-combustion CCS	£100/MWh

** Note the figure for CCGT with post-combustion CCS appears anomalous as it is less than that for unabated CCGT.*

The FES 2019 report and the CCC Net Zero report both propose that the most appropriate carbon capture technology for the power sector would be pre-combustion CCS using steam-reformed methane to produce hydrogen to fuel the CCGT (or OCGT) plants. It appears that post-combustion CCS is not efficient for low load factor operation, as the target 90% carbon capture from the exhaust gases from such plants can only realistically be achieved at high load factors. The technology of interest here would be CCGT plant fitted with pre-combustion CCS - the levelized generation cost of this is estimated at £118/MWh in the earlier BEIS Electricity Generation Cost report and £100/MWh in the more recent BEIS Carbon Capture Technology report.

5.7

Comparison with CCGT & OCGT with CCS

For this paper we have adopted the updated figure of £100/MWh, however it should be appreciated that this is the levelized cost for plants operating at 100% load factor (at 85% availability) and that applying different load factors to the cost model (supplied with the BEIS report) gives the following levelized generation costs for the case with natural gas CCGT with pre-combustion carbon capture and storage:

Estimated Generation Costs for CCGT with CCS at varying load factors

100% load factor	£100/MWh
80% load factor	£110/MWh
60% load factor	£125/MWh
40% load factor	£160/MWh
20% load factor	£260/MWh

We estimate that CCGT plants used as backup generation for intermittent renewables would need to operate at a load factor between 20% and 25%. This means that the relevant levelized cost for CCGT with CCS would be nearer to £250/MWh when comparing this option with the alternative energy storage options that would also be operating at a similar load factor.

5.8

Lowest Cost Option Ranking for Balancing Intermittent Renewables

From the above analyses we have been able to produce an indicative lowest cost ranking of the range of options available for balancing renewables:

Renewables Balancing Generation Cost Ranking

Pumped hydro storage (72hrs):	£64/MWh
Hydrogen storage & CCGT (144hrs+)	£101/MWh
Hydrogen storage & OCGT (144hrs+)	£122/MWh
CAES - Compressed air storage (48hrs)	£134/MWh
LAES - Liquid air storage (24hrs)	£152/MWh
Lithium-Ion battery storage (4hrs)	£217/MWh
CCGT with CCS (20%-25% load factor)	£250/MWh

Note that this ranking is based purely on the costs for providing long-term storage for balancing of renewables and does not take account of any further benefits than could be accrued from providing additional short-term balancing services. However it must be emphasized that these generation costs should be regarded as approximate at present as there are many uncertainties in the assumptions used to derive these, such as the predictions of wind variability, the future market price of surplus wind energy (+/-) and the accuracy of the criteria assumed for hydrogen electrolysis, liquid air storage, compressed air storage and the achievable cost of carbon capture and storage. Nevertheless, these costs should still be valid for comparison purposes and we consider give a useful picture of the relative merits of the range technologies investigated.

European Interconnectors

Another potential contender for regulating renewables is the use of the European interconnectors to import energy from the continent when there is insufficient renewables generation, and to export energy when renewables generation is in surplus.

The current interconnector capacity between the UK and Europe is about 4 GW and there is another 8 GW of committed capacity to France, Belgium, Denmark and Norway, which is due to be commissioned by 2030 and a further 8 GW is planned which would bring the total capacity to 20 GW by 2050.

Our high-level analyses have shown that for every 5 GW of long-term storage provided, it should be possible to reduce either the future required interconnector capacity, or the future required CCGT+CCS capacity, by a similar amount.

Thus if 5 GW of pumped storage and 10 GW of hydrogen storage (from electrolysis) is in place by 2030, this could enable the planned additional 8 GW of interconnector capacity of the proposed new interconnectors or CCGT and CCS plants to be reduced as follows:

- Either deferring 8 GW of further planned interconnectors and 7 GW of CCGT plants fitted with CCS; or
- Reducing the capacity of the required CCGT plants fitted with CCS by 15 GW.

This aspect is analyzed further in the next section. For that analysis we have based the interconnector costs on those currently in the process of being implemented between the UK and Norway, at a capital cost of approximately £1.25m/MW.

Long-Term Storage Development Strategy

6.0

In section 5 we have presented the relative unit costs of generation for alternative energy storage technologies and derived an indicative lowest cost ranking.

In this section we have formulated a range of potential development cases providing different levels of long-term storage, with the necessary CCGT with CCS and interconnector capacities needed to meet the net zero carbon targets by 2050. The alternative development cases comprise various combinations of long-term storage technologies that could provide increasing levels of long-term storage for balancing the intermittent renewables generation. This could be achieved by increasing the effective firm capacity of wind generation, thereby enabling the reduction of backup CCGT capacity and/or interconnector capacity.

Alternative Development Cases to meet Net Zero Targets

6.1

According to the FES Net Zero scenario, it is envisaged that renewables in conjunction with gas-fired gas turbine plant, fueled by hydrogen (derived either from electrolysis or from methane reforming of natural gas with CCS), will play a key role is meeting the increased demand of the Net Zero scenario in 2050.

There is currently a provision of some 40 GW of CCGT plant fitted with pre-combustion CCS, fueled by 'blue' hydrogen from steam-reformed methane, in the Net Zero scenario to meet this requirement. As highlighted in Section 5, the cost of CCGT with carbon capture & storage, operating at low load factors for providing backup generation for renewables, is particularly high. We thus present in this paper a range of alternative long-term storage options that could provide the required backup generation capacity but at lower cost.

We have evaluated a range of alternative long-term energy storage configurations, based on the implementation of different long-term storage technologies at 5 GW increments in order of lowest cost, as follows:

- **Case 0** – No long-term storage, but with 48 GW of CCGT+CCS plus existing 12 GW interconnectors;
- **Case 1** – No long-term storage, but with 40 GW of CCGT+CCS plus planned 20 GW interconnectors;
- **Case 2** – 5 GW pumped hydro storage with 35 GW of CCGT+CCS;
- **Case 3** – 10 GW pumped hydro storage with 30 GW of CCGT+CCS;
- **Case 4** – 10 GW pumped storage and 5 GW hydrolysers & storage, with 25 GW of CCGT+CCS;
- **Case 5** – 10 GW pumped storage and 10 GW hydrolysers & storage, with 20 GW of CCGT+CCS;
- **Case 6** – 10 GW pumped storage and 15 GW hydrolysers & storage, with 15 GW of CCGT+CCS;
- **Case 7** – 10 GW pumped storage and 20 GW hydrolysers & storage, with 10 GW CCGT+CCS.
- **Case 8** – 10 GW pumped storage and 25 GW hydrolysers & storage, with 5 GW of CCGT+CCS;
- **Case 9** – 10 GW pumped storage and 30 GW hydrolysers & storage, with no CCGT+CCS.

As CCGT plants have a service life of 25 years, it is assumed that all existing CCGT plants would be due for retirement before 2050 and thus any CCGT capacity thereafter would be new-build CCGT plants fitted with pre-combustion CCS.

We have assumed that hydrogen storage plants would comprise hydrolysers powered from surplus wind energy to produce 'green' hydrogen by electrolysis that would either be stored in caverns or absorbed by the proposed hydrogen network, with re-generation being carried out by hydrogen fueled conventional CCGT or OCGT plants. Likewise, it has been assumed that CAES would be powered from surplus wind energy with compressed air stored in underground caverns. We have assumed that other new CCGT plants would be fueled by 'blue' hydrogen, derived by steam-reforming of methane from natural gas.

Note: Cases 1-9 all include 20 GW of European interconnectors.

6.1

Alternative Development Cases to meet Net Zero Targets

In all scenarios, it is assumed the capacities of other generation plant such as nuclear, biomass, conventional hydro, existing pumped storage, wind and solar are all as set out in the National Grid's Net Zero future energy scenario, which is essentially a variation of its Two Degrees scenario. There is currently 12 GW of European interconnector capacity already committed, with a further 8 GW planned.

Case 0

This is the base case with no long-term energy storage. This is equivalent to the FES Net Zero scenario and assumes that the existing unabated CCGT plant is all phased out by 2050 and would be replaced by 48 GW of new CCGT plant, fueled by hydrogen produced from steam-reformed methane and fitted with pre-combustion CCS. It also assumes that the current committed interconnector capacity of 12 GW is implemented by 2030.

Case 1

This is essentially the same as Case 0 but with an additional 8 GW of interconnector capacity implemented by 2050, bringing the total capacity of European interconnectors up to 20 GW, which should enable the required capacity of the proposed CCGT plants fitted with CCS to be reduced from 40 GW to 30 GW.

Case 2

This case assumes 5 GW of pumped hydro storage. This would allow the capacity of the CCGT plant with pre-combustion CCS to be reduced by 5 GW to 35 GW.

Case 3

This case assumes 10 GW of pumped hydro storage. This would allow the capacity of the CCGT plant with pre-combustion CCS to be reduced by a further 5 GW to 30 GW.

Case 4

This case assumes 10 GW of pumped storage and 5 GW of hydrolysers with hydrogen cavern storage, together with the associated 5 GW of CCGT plant fueled by hydrogen. This would allow the capacity of the CCGT plant with pre-combustion CCS to be reduced by a further 5 GW to 25 GW.

Case 5

This case assumes 10 GW of pumped storage and 10 GW of hydrolysers with hydrogen cavern storage, together with the associated 10 GW of CCGT plant fueled by hydrogen. This would allow the capacity of the CCGT plant with pre-combustion CCS to be reduced by a further 5 GW to 20 GW.

Case 6

This case assumes 10 GW of pumped storage and 15 GW of hydrolysers with hydrogen cavern storage, together with the associated 15 GW of CCGT plant fueled by hydrogen. This would allow the capacity of the CCGT plant with pre-combustion CCS to be reduced by a further 5 GW to 15 GW.

Case 7

This case assumes 10 GW of pumped storage and 20 GW of hydrolysers with hydrogen cavern storage, together with the associated 20 GW of CCGT plant fueled by hydrogen. This would allow the capacity of the CCGT plant with pre-combustion CCS to be reduced by a further 5 GW to 10 GW.

Case 8

This case assumes 10 GW of pumped storage and 25 GW of hydrolysers with hydrogen cavern storage, together with the associated 25 GW of CCGT plant fueled by hydrogen. This would enable the capacity of the CCGT plant with pre-combustion CCS to be reduced to only 5 GW.

Case 9

This case assumes 10 GW of pumped storage and 30 GW of hydrolysers with hydrogen cavern storage, together with the associated 30 GW of CCGT plant fueled by hydrogen. This would allow the need for CCGT plant with pre-combustion CCS to be eliminated entirely.

Sensitivity Analyses

A separate sensitivity analysis has been carried out using compressed air energy storage (CAES) instead of hydrogen hydrolysis and storage to compare the difference in costs between the two technologies.

Further sensitivity analyses have also been undertaken for a range of alternative long-term energy storage configurations, based on the FES 2020 Leading the Way scenario.

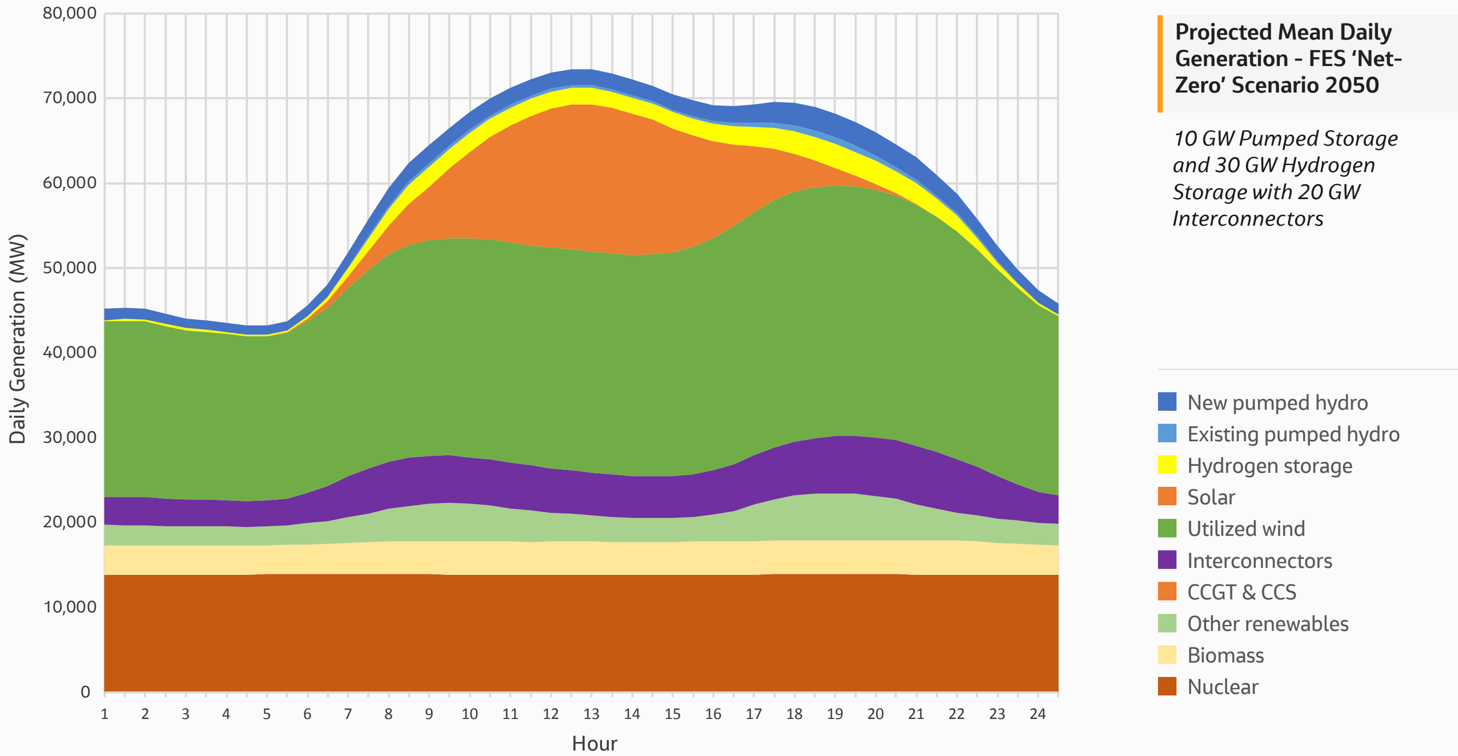
6.2

Long-Term Energy Storage Simulations

To illustrate how long-term storage could potentially operate under development conditions for the Net Zero FES scenario in 2050, we present below weekly operational charts showing the simulated generation over the season for a typical year, based on extrapolation of Elexon actual generation data for 2018 for Cases 7 & 9.

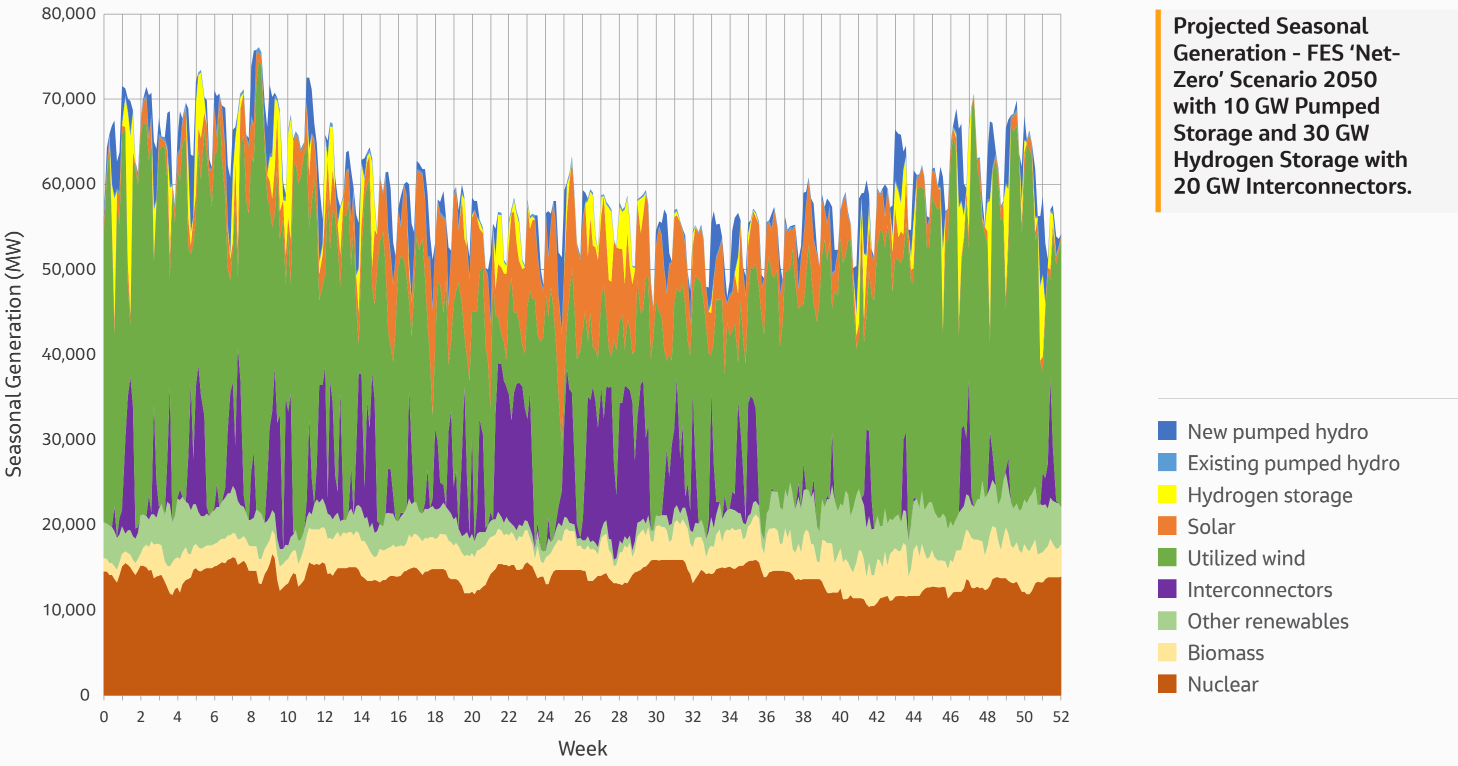
Seasonal Generation with Energy Storage – 2050

The charts below represent conditions under Case 9, comprising 10 GW of pumped hydro storage and 30 GW of hydrolysers with hydrogen cavern storage and associated 30 GW of CCGT plant fueled by 'green' hydrogen. This shows how this case could balance intermittent renewable generation comprising 90 GW of wind and 40 GW of solar PV, for a typical year by 2050:



Projected Mean Daily Generation - FES 'Net-Zero' Scenario 2050

10 GW Pumped Storage and 30 GW Hydrogen Storage with 20 GW Interconnectors



Projected Seasonal Generation - FES 'Net-Zero' Scenario 2050 with 10 GW Pumped Storage and 30 GW Hydrogen Storage with 20 GW Interconnectors.

6.2

Long-Term Energy Storage Simulations

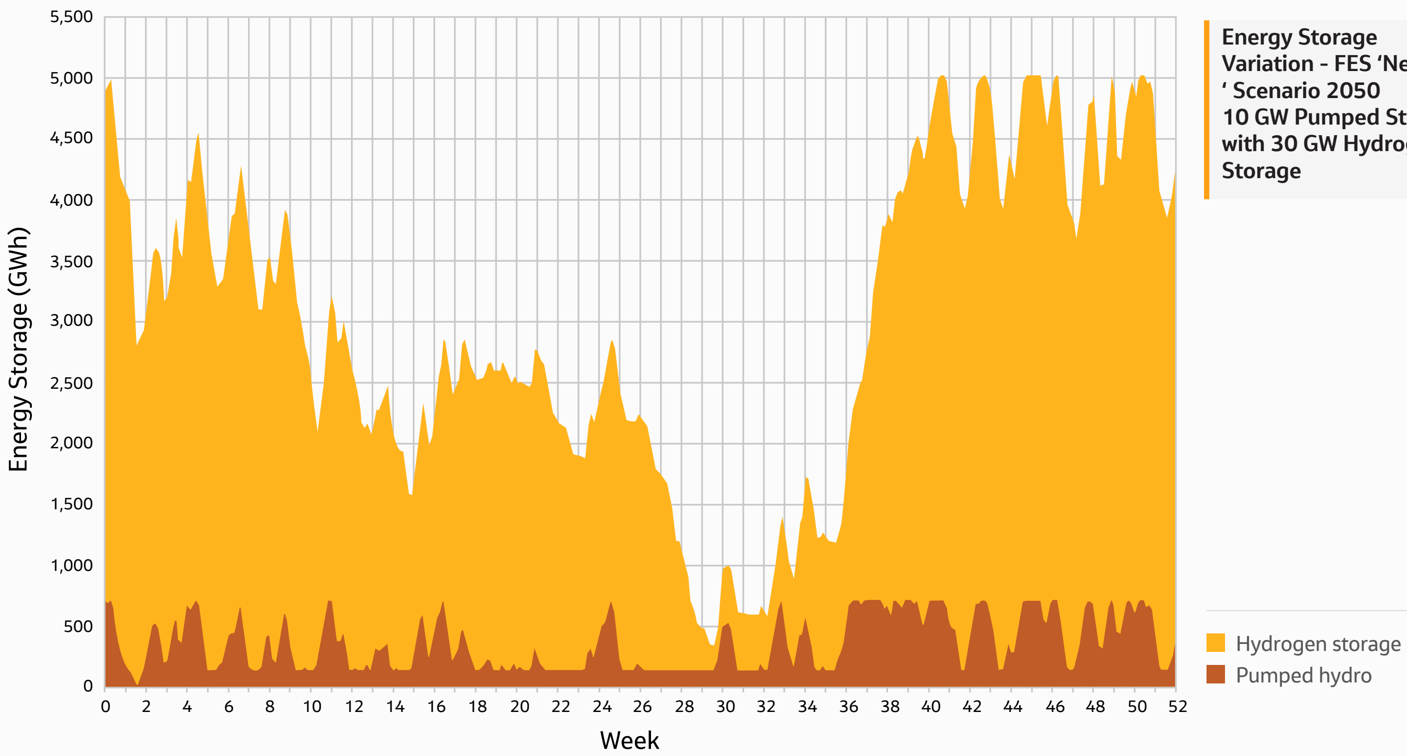
These charts show how pumped hydro and hydrogen storage can provide full backup generation to the intermittent renewable generation. Notice also how pumped hydro and hydrogen storage can be used to peak-lop in times of renewables generation deficit (or surplus), thereby increasing the effective transfer capability of the European interconnectors whose installed capacity is limited to 20 GW (assuming 18 GW available capacity).

This demonstrates how long-term energy storage with associated CCGT plant fueled by 'green' hydrogen, in conjunction with nuclear generation and the European interconnectors, could displace higher cost CCGT plant fueled by steam-reformed methane (from natural gas) with carbon capture and storage for electricity generation. However, steam-reformed methane from natural gas would still be required for producing 'blue' hydrogen for the industrial and domestic gas grid, which is a separate but related issue.

Typical Seasonal Storage Variation – 2050

The chart overleaf shows the simulated energy storage variation for 10 GW pumped storage (720 GWh @ 72hrs) and 30 GW hydrogen storage (4,320 GWh @ 144 hrs), total 5,040 GWh, for Case 9 in 2050.

This simulation shows how pumped hydro (with 72hrs duration) can provide effectively weekly energy storage, whereas hydrogen storage (with 144hrs duration) can provide effectively seasonal energy storage when operated in conjunction with the European interconnectors.



Energy Storage Variation - FES 'Net Zero ' Scenario 2050 10 GW Pumped Storage with 30 GW Hydrogen Storage

6.2

Long-Term Energy Storage Simulations

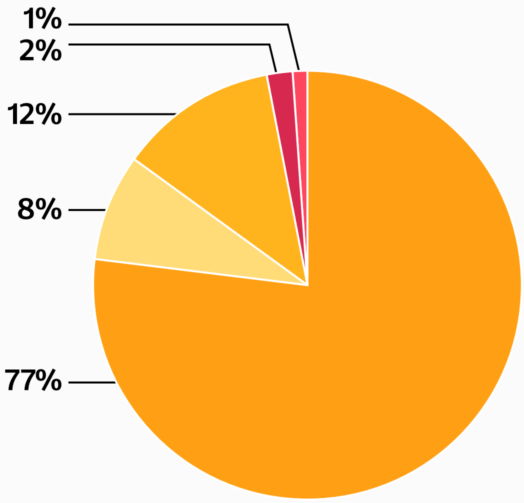
Increased Energy from Balancing Surplus Renewables Generation

The chart below presents the estimated increase in utilized wind generation, for 10 GW of pumped storage and 30 GW of hydrogen storage as in Case 9.

Thus, for Case 9, the predicted wind utilization for the Net Zero scenario in 2050 is as follows:

- 77% utilized directly by the network;
- 20% absorbed by long-term storage and re-generated later;
- 2% available for export via the interconnectors; and
- 1% curtailed.

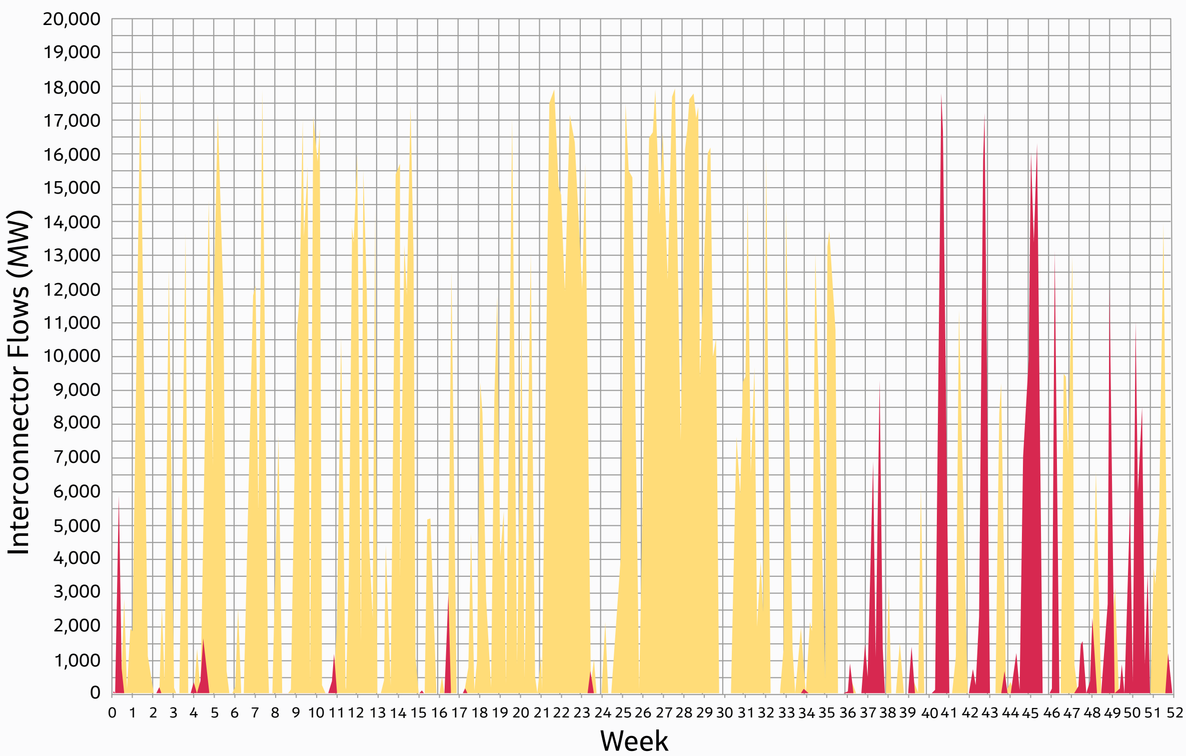
Wind Generation Utilisation (%) - FES 'Net Zero' Scenario 2050: 10 GW Pumped Hydro & 30 GW Hydrogen Storage with 20 GW European Interconnectors



Typical Interconnector Imports and Exports – 2050

The chart below shows the simulated average daily imports and exports via the European interconnectors for Case 9, assuming a total interconnector capacity of 20 GW for the FES Net Zero Scenario in 2050:

European Interconnector Imports and Exports - FES 'Net Zero' Scenario 2050 10 GW Pumped Storage with 30 GW Hydrogen Storage & 20 GW of European Interconnectors



Note: That this assumes 90% availability of the European interconnectors.

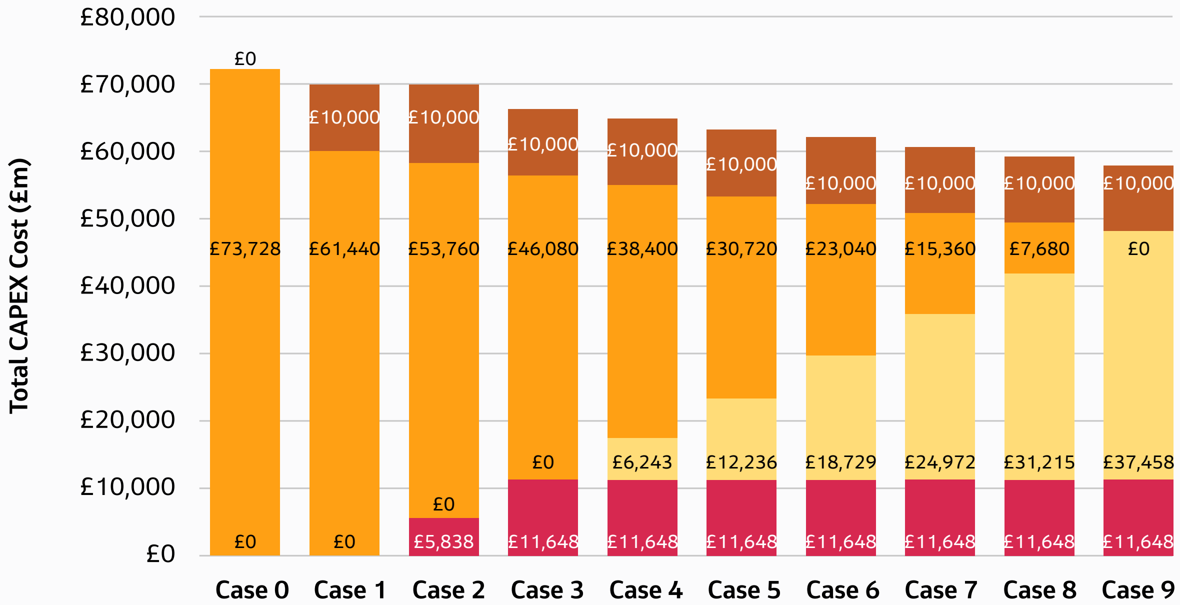
Analysis of Alternative Cases – FES 2019 Net Zero Scenario

6.3

Each case has been evaluated to determine the level of investment required in terms of CAPEX and OPEX to provide increasing levels of storage for balancing renewables that could displace the equivalent level of investment for CCGT with pre-combustion CCS for the FES Net Zero scenario by 2050.

6.3.1. CAPEX Cost Comparison

A comparison of CAPEX costs for each case is shown in the figure below:



Total Installed CAPEX Costs 'Net Zero' Scenario - 2050

This gives the estimated CAPEX costs for each Case, for FES Net Zero Scenario in 2050, as follows:

Case 0	Existing 12 GW interconnectors with 48 GW of CCGT+CCS	£74 billion
Case 1	Future 20 GW interconnectors with 40 GW of CCGT+CCS	£71 billion
Case 2	5 GW pumped hydro storage with 35 GW of CCGT+CCS	£70 billion
Case 3	10 GW pumped hydro storage with 30 GW of CCGT+CCS	£68 billion
Case 4	10 GW pumped hydro & 5 GW hydrolysers with 25 GW of CCGT+CCS	£66 billion
Case 5	10 GW pumped hydro & 10 GW hydrolysers with 20 GW of CCGT+CCS	£65 billion
Case 6	10 GW pumped hydro & 15 GW hydrolysers with 15 GW of CCGT+CCS	£63 billion
Case 7	10 GW pumped hydro & 20 GW hydrolysers with 10 GW of CCGT+CCS	£62 billion
Case 8	10 GW pumped hydro & 25 GW hydrolysers with 5 GW of CCGT+CCS	£60 billion
Case 9	10 GW pumped hydro & 30 GW hydrolysers with no CCGT+CCS	£59 billion

Case 1 represents the base case for the FES Net Zero scenario, assuming 20 GW of European interconnectors are in place by 2050, while Case 0 represents the situation with the existing 12 GW interconnector capacity.

Cases 2-9 represent the situation with different levels of long-term energy storage being implemented.

Case 1 shows that implementing a further 8 GW of European interconnectors would have a lower capital cost than implementing the equivalent capacity of CCGT plants with CCS.

Cases 2-9 show that the incremental implementation of long-term energy storage results in a progressive reduction in the total capital cost and that implementing 40 GW of long-term storage, comprising 10 GW of pumped hydro and 30 GW of hydrogen storage, could potentially eliminate the need for thermal CCGT generation fitted with CCS, yielding a capital cost saving of about **£12 billion** - a CAPEX saving of some 16%.

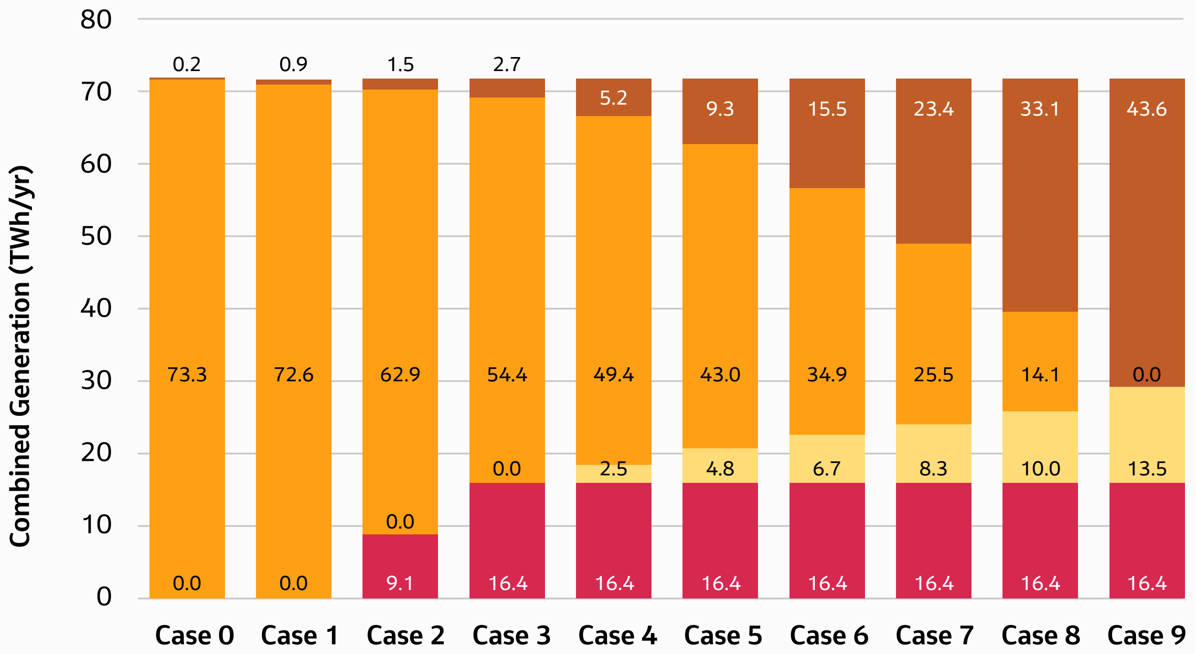
6.3

Analysis of Alternative Cases – FES Net Zero Scenario

Annual Energy Generation

The figure below illustrates how the division of energy generation between sources changes as long-term storage capacity is increased and CCGT capacity with CCS is reduced. This shows how long-term energy storage can not only be useful for balancing renewables, but also can improve the utilization (and hence load factor) of the European interconnectors.

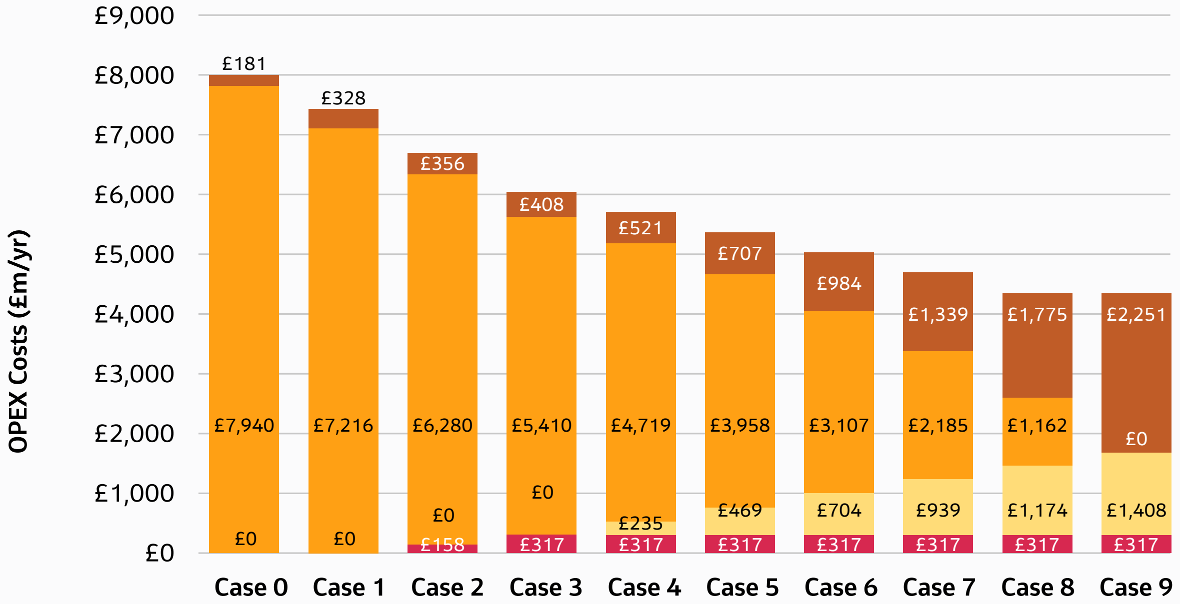
Annual OPEX Costs 'Net Zero' Scenario – 2050 Pumped Hydrogen Storage & CCGT+CCS



OPEX Cost Comparison

A comparison of OPEX costs for each case is shown in the figure below:

Annual OPEX Costs 'Net Zero' Scenario – 2050



6.3

Analysis of Alternative Cases – FES Net Zero Scenario

This gives the estimated OPEX costs for each Case, for FES Net Zero Scenario in 2050, as follows:

Case 0	Existing 12 GW interconnectors with 48 GW of CCGT+CCS	£8.1 billion/yr
Case 1	Future 20 GW interconnectors with 40 GW of CCGT+CCS	£7.5 billion/yr
Case 2	5 GW pumped hydro storage with 35 GW of CCGT+CCS	£6.8 billion/yr
Case 3	10 GW pumped hydro storage with 30 GW of CCGT+CCS	£6.1 billion/yr
Case 4	10 GW pumped hydro & 5 GW hydrolysers with 25 GW of CCGT+CCS	£5.8 billion/yr
Case 5	10 GW pumped hydro & 10 GW hydrolysers with 20 GW of CCGT+CCS	£5.5 billion/yr
Case 6	10 GW pumped hydro & 15 GW hydrolysers with 15 GW of CCGT+CCS	£5.1 billion/yr
Case 7	10 GW pumped hydro & 20 GW hydrolysers with 10 GW of CCGT+CCS	£4.8 billion/yr
Case 8	10 GW pumped hydro & 25 GW hydrolysers with 5 GW of CCGT+CCS	£4.4 billion/yr
Case 9	10 GW pumped hydro & 30 GW hydrolysers with no CCGT+CCS	£4.0 billion/yr

Case 1 shows that implementing a further 8 GW of European interconnectors would have a lower annual operating cost compared to that of the equivalent capacity of CCGT plants with CCS.

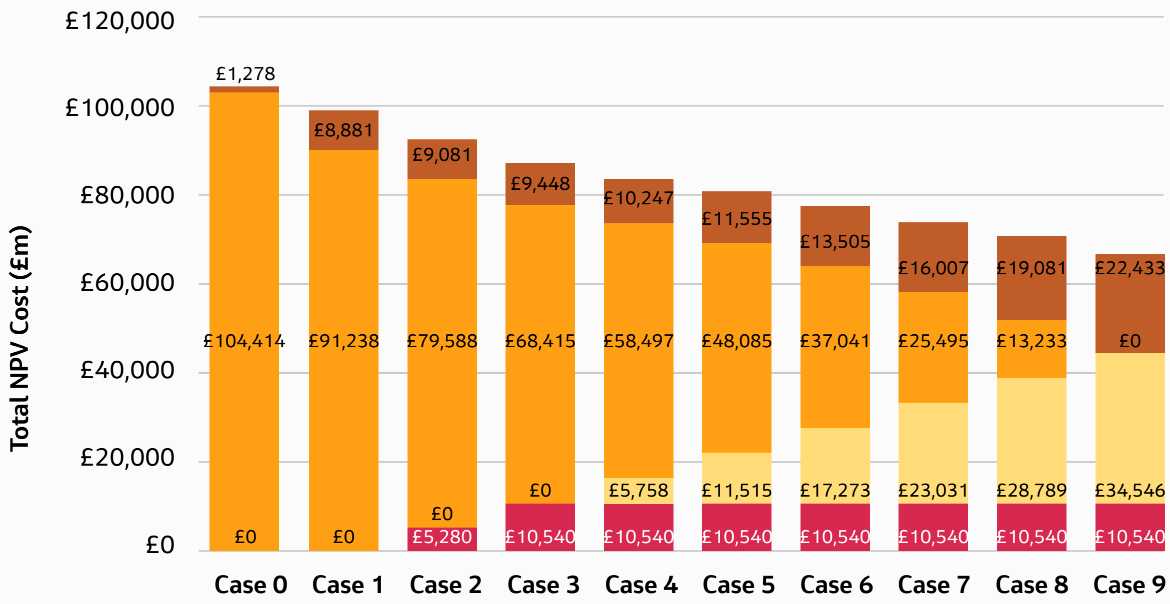
Cases 2-9 show that by implementing 40 GW of long-term energy storage, comprising 10 GW of pumped hydro and 30 GW of hydrogen storage, could achieve an operating cost saving of about **£3.5 billion** per year, i.e. an OPEX cost saving of some 45%.

These OPEX savings are due principally to the avoided fuel and carbon capture costs associated with CCGT plants fitted with carbon capture and storage.

NPV CAPEX & OPEX Costs

The total NPV costs for each case have been derived by discounting the CAPEX and OPEX costs at 8% over 50 years, assuming a construction period of six years for pumped storage hydro schemes and four years for hydrogen hydrolyzer plants, CCGT and OCGT plants and for European interconnectors.

The total NPV of CAPEX and OPEX costs for each case is presented in the figure below:



NPV Total CAPEX & OPEX Costs 'Net Zero' Scenario – 2050

6.3

Analysis of Alternative Cases – FES Net Zero Scenario

This gives the total NPV costs for each Case, for FES Net Zero Scenario in 2050, as follows:

Case 0	Existing 12 GW interconnectors with 48 GW of CCGT+CCS	£106 billion
Case 1	Future 20 GW interconnectors with 40 GW of CCGT+CCS	£100 billion
Case 2	5 GW pumped hydro storage with 35 GW of CCGT+CCS	£94 billion
Case 3	10 GW pumped hydro storage with 30 GW of CCGT+CCS	£88 billion
Case 4	10 GW pumped hydro & 5 GW hydrolysers with 25 GW of CCGT+CCS	£85 billion
Case 5	10 GW pumped hydro & 10 GW hydrolysers with 20 GW of CCGT+CCS	£82 billion
Case 6	10 GW pumped hydro & 15 GW hydrolysers with 15 GW of CCGT+CCS	£78 billion
Case 7	10 GW pumped hydro & 20 GW hydrolysers with 10 GW of CCGT+CCS	£75 billion
Case 8	10 GW pumped hydro & 25 GW hydrolysers with 5 GW of CCGT+CCS	£72 billion
Case 9	10 GW pumped hydro & 30 GW hydrolysers with no CCGT+CCS	£68 billion

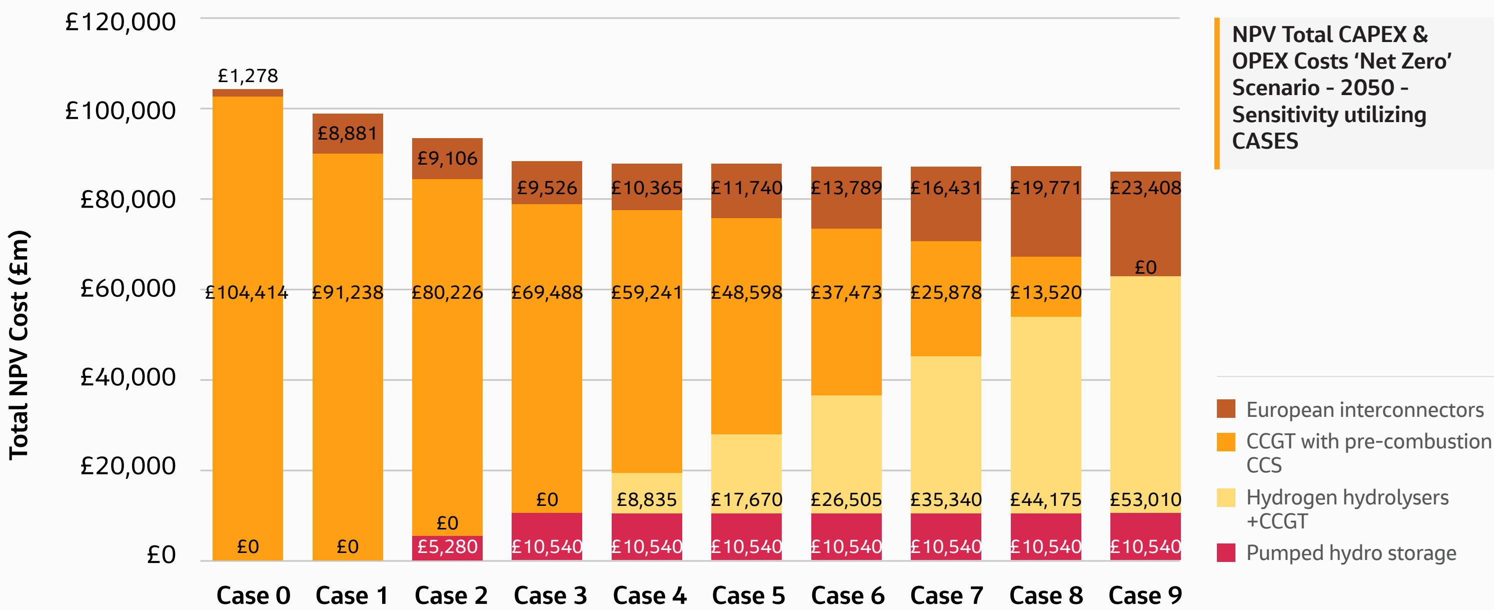
Case 1 shows that implementing a further 8 GW of European interconnectors could result in a net saving of some £6 billion (@ 8% discount rate) in the long run, compared to the alternative of providing the equivalent CCGT plants fitted with CCS.

Case 7 shows that by implementing 30 GW of long-term energy storage, comprising 10 GW of pumped hydro, 20 GW of hydrolysers with hydrogen cavern storage, and 10 GW of CCGT with carbon capture and storage could yield a net saving of about **£25 billion** (@ 8% discount rate), compared to Case 1, i.e. an overall net saving of some 24%.

Case 9 shows that by implementing 40 GW of long-term energy storage, comprising 10 GW of pumped hydro and 30 GW of hydrolysers with hydrogen cavern storage, could yield a net saving of about **£32 billion** (@ 8% discount rate), compared to Case 1, i.e. an overall net saving of some 32%.

Sensitivity Analysis utilizing CAES

A separate sensitivity analysis has been carried out, utilizing CAES in conjunction with pumped hydro, instead of hydrogen hydrolysis and storage, to compare the difference in costs between the two technologies. The total NPV of CAPEX and OPEX costs for each case utilizing CAES, for FES Net Zero Scenario in 2050, is presented in the figure below:



NPV Total CAPEX & OPEX Costs 'Net Zero' Scenario - 2050 - Sensitivity utilizing CASES

6.3

Analysis of Alternative Cases – FES Net Zero Scenario

This shows that although there is still the same cost saving from pumped hydro storage, there is no appreciable NPV cost saving from compressed air storage when compared with the alternative backup generation from CCGT with carbon capture and storage. The CAPEX costs of CAES are in fact higher than that for CCGT with CCS, although the lower OPEX costs for CAES approximately offset the difference. This analysis is based on current CAES costs as provided by Hydrostor (see Section 5.2.3) for its pilot plant. However, if CAES were to be developed at scale, then it is quite possible that the capital costs for CAES could be significantly reduced, making CAES potentially competitive with CCGT with CCS.

However, it is also likely that once hydrolysers are developed at scale, the cost of hydrogen storage via hydrolysers could fall as well.

6.4 Sensitivity Analyses – FES 2020 Leading the Way Scenario

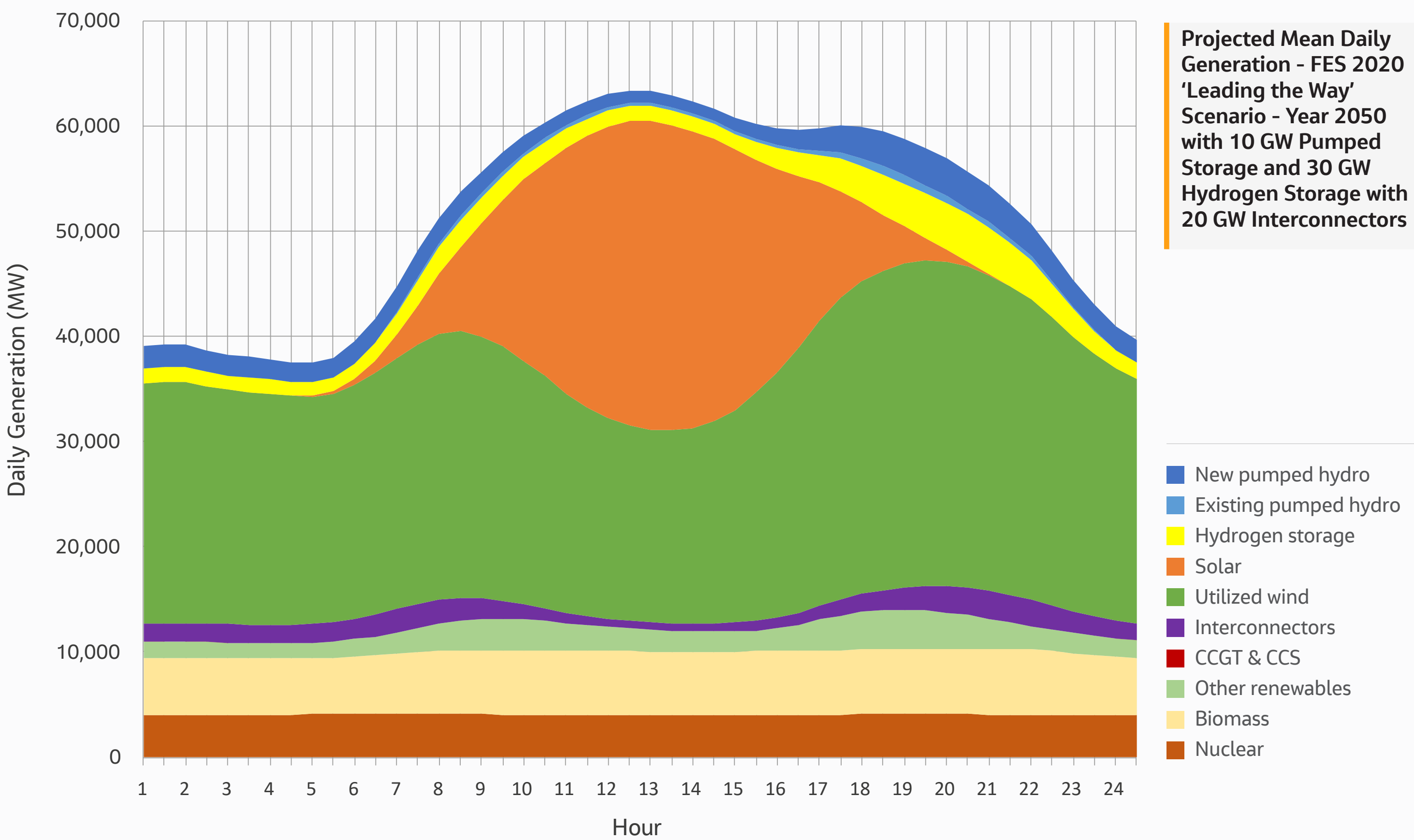
Sensitivity analyses have also been carried out for the latest FES 2020 Leading the Way scenario for 2050, for comparison with the FES 2019 Net Zero scenario.

FES 2020 Leading the Way Scenario Generation Profile

The analyses below represent conditions under the FES 2020 Leading the Way scenario, comprising 10 GW of pumped hydro and 30 GW of hydrolysers with hydrogen cavern storage and associated 30 GW of CCGT plant fueled by 'green' hydrogen.

This shows how this scenario could balance intermittent renewable generation comprising 100 GW of transmission connected wind and 70 GW of solar PV, an increase in renewables generation of some 30 GW compared to the FES 2019 Net Zero scenario.

The mean daily generation chart below presents how the increased renewables generation reduces imports via the European interconnectors, compared to the FES 2019 Net Zero scenario:

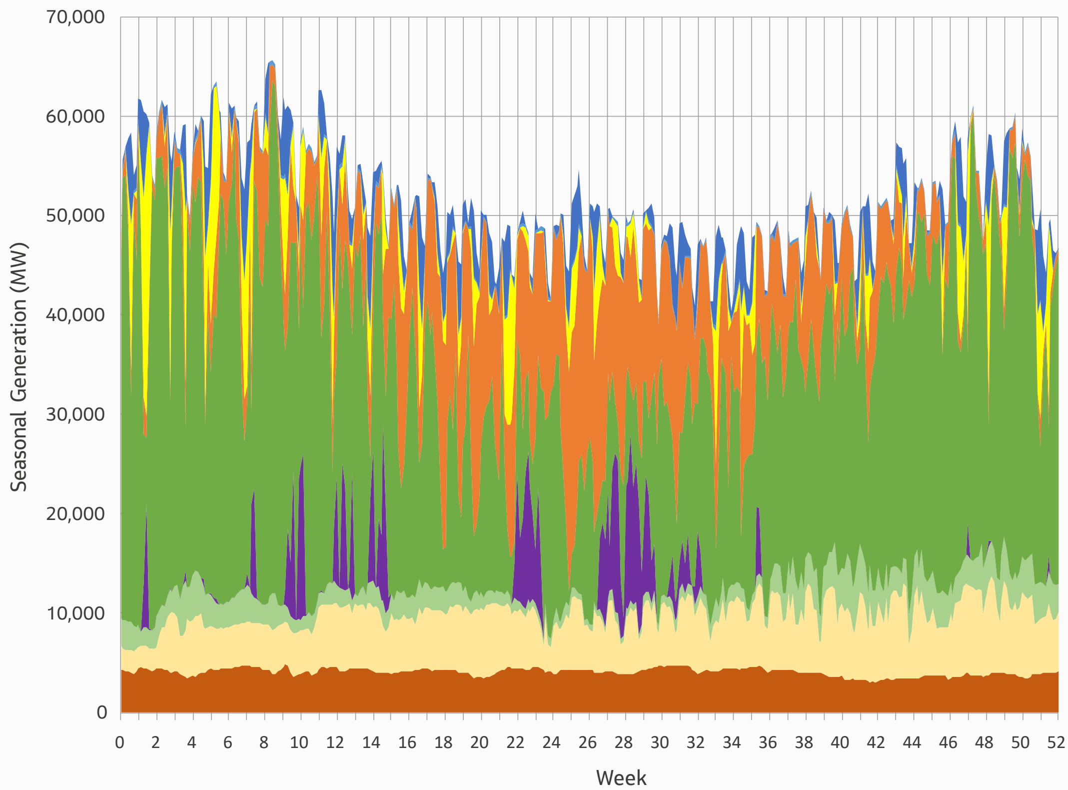


Projected Mean Daily Generation - FES 2020 'Leading the Way' Scenario - Year 2050 with 10 GW Pumped Storage and 30 GW Hydrogen Storage with 20 GW Interconnectors

6.4

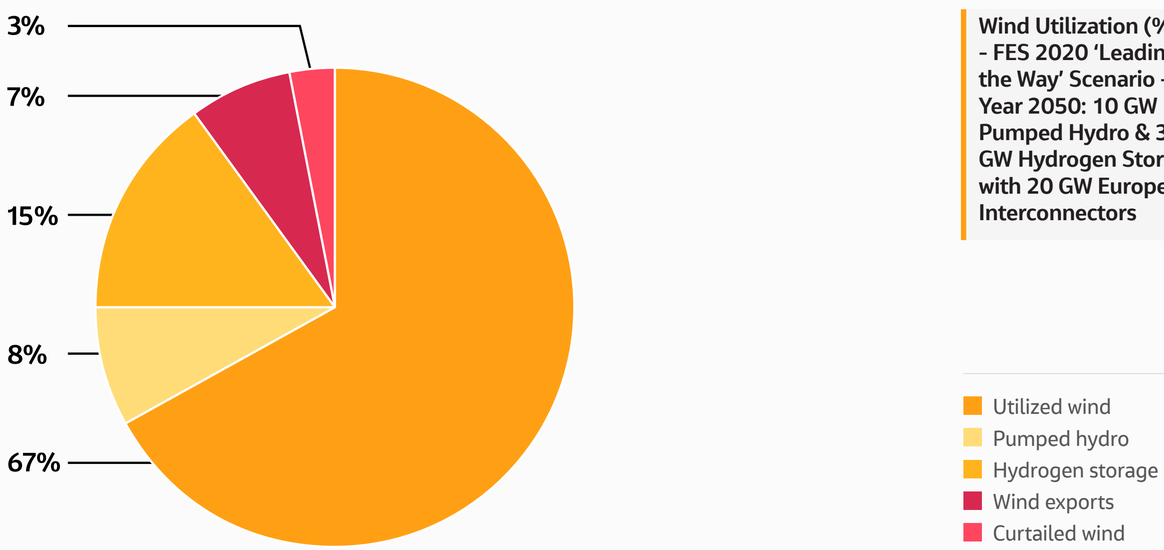
Sensitivity Analyses – FES 2020 Leading the Way Scenario

The projected seasonal generation chart below shows that a similar level of long duration storage is required for balancing the intermittent renewables generation, compared to the FES 2019 Net Zero scenario, while requiring interconnector imports less frequently.



The chart below presents the estimated increase in utilized wind generation, for FES 2020 Leading the Way scenario, and shows how 10 GW of pumped storage and 30 GW of hydrogen storage can provide increased renewables balancing compared the FES 2019 Net Zero scenario:

Wind Utilization (%) - FES 2020 'Leading the Way' Scenario - Year 2050: 10 GW Pumped Hydro & 30 GW Hydrogen Storage with 20 GW European Interconnectors



This shows that due to the increased intermittent renewables planned under this scenario, only 67% of the forecast wind generation would be utlizable without long-term storage, but the use of long-term storage in conjunction with the European interconnectors can increase wind utilization to approximately 97% resulting in only 3% needing to be curtailed.

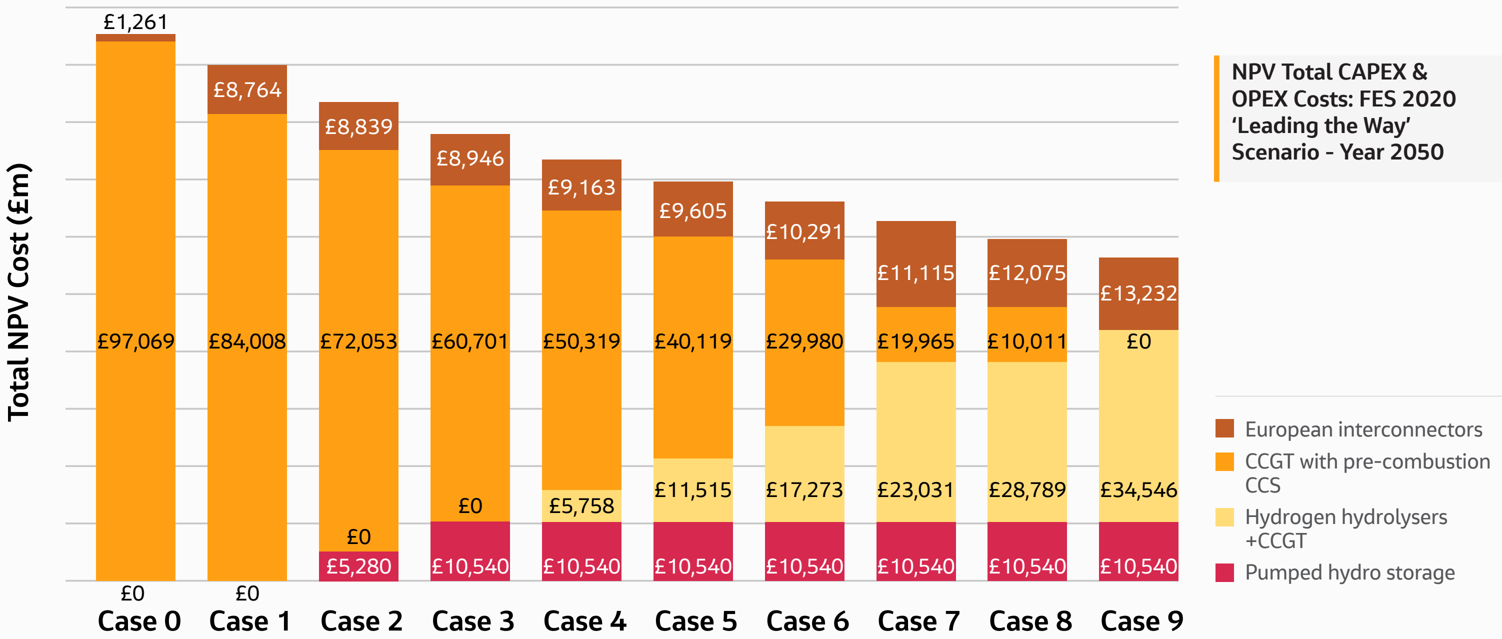
6.4

Sensitivity Analyses – FES 2020 Leading the Way Scenario

FES 2020 Leading the Way Scenario Total NPV Costs

The total NPV costs for the latest FES 2020 Leading the Way scenario, with the required level of long-term storage, is presented in the chart below:

NPV Total CAPEX & OPEX Costs: FES 2020 'Leading the Way' Scenario - Year 2050



This shows that for the FES 2020 Leading the Way scenario, with 40 GW of long-term energy storage, comprising 10 GW of pumped hydro and 30 GW of hydrolysers with hydrogen cavern storage, could yield a net saving of about £34 billion (@ 8% discount rate), compared to Case 1, i.e. an increased overall net saving of some £2 billion, compared to the FES 2019 Net Zero scenario.

This demonstrates that the benefits of long-term storage for the FES 2020 scenarios are potentially even greater than those that could be realized from the FES 2019 scenarios.

6.5

Energy Storage Implementation Phasing

Clearly such a major development would need to be phased to ensure the net zero carbon targets can be met by 2050. This could be achieved by implementing the required 40 GW of long-term energy storage and/or CCGT with carbon capture in say 10 GW increments over four stages at five yearly intervals. To illustrate this, a typical phased implementation programme for Case 7 could comprise:

- **Stage 1:** Initial 5 GW of pumped hydro with 5 GW of hydrogen storage by 2030;
- **Stage 2:** Further 5 GW of pumped hydro with 5 GW of hydrogen storage by 2035;
- **Stage 3:** Further 5 GW of hydrolysers & storage or CAES with 5 GW of CCGT+CCS by 2040; and
- **Stage 4:** Further 5 GW of hydrolysers & storage or CAES with 5 GW of CCGT+CCS by 2045.

This would enable the full development to be completed by 2045, thus giving five years' float for any overruns etc.

This approach could allow a start to be made using existing proven long-term energy storage technologies and provide time for other emerging storage technologies to be developed and refined further. In this way, the optimum level of long-term energy storage could be built up gradually, with the balance made up by CCGT fitted with carbon capture and storage (CCS) well before the target date of 2050. The actual programme could be adapted after each stage to reflect changes in circumstances, under the principles of adaptive planning.

Development Options for Long-Term Storage

7.0

As presented earlier, a potential lowest cost development for balancing renewables that would meet the net zero carbon targets by 2050 would be Case 9, which could comprise the following long-term storage options operated in conjunction with backup CCGT capacity fitted with CCS, together with the future planned European interconnectors:

- 10 GW of pumped hydro storage;
- 30 GW of hydrogen (via hydrolysers) with cavern storage and hydrogen CCGT plants; and
- 20 GW of interconnector capacity between the UK and Europe.

As discussed previously, this proposed combination could potentially replace the 40 GW of CCGT plants fitted with CCS, as currently envisaged for the FES Net Zero scenario in 2050.

Of the 10 GW of proposed further pumped hydro storage capacity, this could be provided by adapting and expanding existing conventional hydro plants or implementing further pumped storage schemes, configured for balancing renewables.

Existing Hydro Storage Assets

7.1

Conventional hydro

The total installed capacity of conventional hydro plants in the UK amounts to approximately 1,700 MW, which provides a combination of both base-load and peak-load operation by utilizing the energy storage capability of dams and reservoirs.

Pumped Hydro Storage

The total installed capacity of existing pumped storage plants in the UK amounts to some 2,900 MW as listed in the table below:

Pumped Storage Project	Installed Capacity (MW)	Energy Storage (GWh)	Storage Duration (hrs)
Cruachan	440	10.0	22.7
Foyers	300	6.3	21.0
Dinorwig	1728	9.1	5.3
Ffestiniog	360	1.3	3.6
Total	**2828**	**26.7**	**9.4**

Future Hydro Storage Options

7.2

Conventional Hydro Expansion

There is potential for adapting the existing hydro plants by either increasing the installed capacity of some of these plants to allow increased generation during periods of low wind generation or adding pumping stations to the existing hydro stations to effectively convert them into pumped storage plants. Schemes currently identified by SSE include Sloy by Loch Lomond, as well as other sites in the northern and central highlands of Scotland. According to SSE, there is approximately 850 GWh of storage in its existing high load-factor hydropower schemes that could be re-purposed by increasing installed capacity, including the addition of pumping, to make them more flexible for balancing intermittent renewables generation.

There may also be possibilities for adapting and expanding other conventional hydro plants currently owned by other operators and/or those used by industry. Many of these schemes are high-load factor plants that are not currently suitable for intermittent operation. These schemes could also potentially be adapted by increasing their installed capacity to reduce their load factor, thereby enabling them to be used for balancing intermittent renewables at grid level.

7.2

Future Hydro Storage Options

Pumped Hydro Storage

There are existing plans for the development of schemes comprising 4 GW of pumped storage capacity, mainly in Scotland, with an energy storage capacity of about 150 GWh. The proposed schemes are:

- Coire Glas (1,500MW) - SSE
- Cruachan Expansion (600MW) - Drax
- Glenmuckloch (400MW) - Buccleuch Estates
- Red John (450MW) - Intelligent Land Investments
- Ben Alder (800MW) - Intelligent Land Investments
- Loch Awe (520MW) - Intelligent Land Investments
- Eishken (150 MW) - Eishken Estate, Outer Hebrides
- Glyn Rhonwy (100 MW) - Quarry Battery Company

In addition, we assisted SSE in evaluating a further 3 GW of pumped storage schemes under a study conducted in 2006, as follows:

- Balmacaan (600 MW)
- Craigroyston (600MW)
- Ardvorlich (600 MW)
- Breaclaich (600MW)
- Lawers (600MW)

Developers have also identified further potential projects, including adaption of existing conventional hydro schemes for longer term balancing of renewables and enhancing the energy storage capacity of the current pumped hydro plants.

As such, it is not inconceivable that up to 10 GW of potential sites could be found, with a target storage capacity of some 500 to 700 GWh; i.e. more than twenty times the UK's current energy storage capacity. Also, the potential development of seawater pumped storage should not be ruled out.

However, many of these other schemes will require further studies/investigations and have yet to receive development consent. Some are also located in areas of outstanding beauty, special conservation areas or even in national parks, so although they can play a key role in de-carbonizing the UK power system, this all needs to be taken account of in determining the optimum renewable mix that can best meet the net zero carbon targets.

7.3

Hydrogen Energy Storage

There is potentially no limit to the number of hydrogen storage (via hydrolyzer) projects that could be developed, although these would likely need to be located close to wind farms with suitable sites for gas storage caverns. The associated CCGT re-generation plant could be sited either at the location of the hydrogen storage caverns or anywhere along the proposed hydrogen gas distribution network, once developed. For 30 GW of hydrogen hydrolysers, our simulations show that 144hrs of gas storage should be sufficient for balancing of renewable generation, provided this was used in conjunction with imports/exports using the European interconnectors. We estimate that about 4.3 TWh of gas storage would be needed to provide the necessary six days' storage for seasonal wind balancing, which is the same level of capacity of the existing 4 TWh gas storage cavern located at Aldbrough in East Yorkshire, for example.

Given the predominance of pumped storage sites in Scotland/Wales, it would make sense to locate any future hydrogen storage sites near the offshore wind farm clusters along the English coast.

7.4

Future Potential Role for Pumped Storage

Arbitrage

Historically, energy storage in the UK was provided by pumped storage plants that had been used for energy arbitrage, namely to provide daily and weekly load balancing by pumping during off-peak and generating during peak periods and was developed primarily for balancing the fixed base load generation of nuclear stations. Following the introduction of CCGT generation in the 1990s, it was found that it was more economic (although less environmentally sustainable) to use CCGT plant for this role so no further pumped storage plants have been developed since that time.

However, with the phasing out of conventional natural gas fired CCGT plants to meet the net zero carbon targets and the high cost of carbon capture and storage, it is likely that the need for pumped storage plants to fulfill this role could return.

7.4 Future Potential Role for Pumped Storage

NG Ancillary Services

The introduction of gas turbine power plant in the 1990s reduced market opportunities for arbitrage services and resulted in pumped storage being used increasingly for maintaining system stability by providing fast frequency response and fast reserve ancillary services under the balancing mechanism operated by National Grid. More recently, solid-state batteries have entered the market as an alternative technology more capable of providing FFR and FR to the system.

Balancing of Renewables

However, with the recent expansion of renewable generation (particularly wind and solar) there has been greater intermittent generation and hence the need to provide increased operating reserve in both the short-term and longer term. While pumped storage plants can currently provide short-term 'shallow' storage over several hours, there is currently insufficient reservoir storage capacity at these plants to provide the necessary long-term 'deep' storage over several days or even weeks, needed for balancing of renewables.

In this paper, we have demonstrated how pumped storage hydro could be re-configured and expanded to provide economically attractive longer-term 'deep' storage to assist in the balancing of intermittent renewables in conjunction with hydrogen storage via hydrolysers. If developed at sufficient scale, this could also assist in de-carbonizing the UK power generation system by obviating the need for the alternative non-renewable and higher cost CCGT plants fitted with carbon capture and storage.

Re-Purposing Pumped Storage

This means that pumped storage in the UK could be usefully re-purposed to provide the following new dual role:

- Long-term 'deep' storage (with up to 72 hrs' storage duration) for balancing of renewables, as well as for providing traditional arbitrage services, in conjunction with hydrogen hydrolysis & storage and CAES; and
- Short-term 'shallow' storage (with up to 4 hrs' duration) for providing grid balancing services, in conjunction with other technologies such as solid-state batteries and LAES.

An example 1500 MW pumped storage hydro project, configured with 500 MW installed capacity with 72 hrs long-duration storage (three days) and a further 1000 MW installed capacity with 4 hours' short-duration storage, is shown in the table below:

This could enable multiple dually-configured projects, at say 500 MW increments (each with 36 GWh storage) for balancing renewables, with up to say a further 1000 MW added (plus additional 4 GWh storage) for providing ancillary grid services. The optimum configuration would need to be determined individually on a project by project basis.

Potential Pumped Storage Project Configuration for a typical 1500 MW Plant

Pumped Storage 1500 MW	Storage Duration	Installed Capacity (MW)	Generation Duration(hrs)	Storage Capacity (GWh)
	Long	500	72	36
	Short	1000	4	4
	Total	**1500**		**40**

Market Incentives for Energy Storage

8.0

There are currently several market incentive mechanisms and supply contracts available to generators to participate in the electricity markets:

- BEIS Electricity Market Reform Contracts; and
- National Grid Balancing Services Contracts.

Electricity Market Reform Contracts

8.1

As set out in the BEIS EMR policy document, there are two key mechanisms to provide incentives for the investment required in energy infrastructure:

- Contracts for Difference (CFDs) provide long-term price stabilization to low carbon plant, allowing investment to come forward at a lower cost of capital and therefore at a lower cost to consumers; and
- The Capacity Market provides a regular retainer payment to reliable forms of capacity (both demand and supply side), in return for such capacity being available when the system is tight.

Capacity Market

Under the current Capacity Market rules, we have identified the following issues that would need to be addressed in order to incentivize the development of long-term energy storage in the foreseeable future:

- The Capacity Market currently does not appear to differentiate between renewable or non-renewable generation or between mean output and firm output, making it difficult for energy storage projects that effectively increase the firm capacity of renewables to compete with existing non-renewable plants;
- At present there are three types of auction namely T-1, T-3 and T-4 that have capacity lead-in times of 1, 3 or 4 years, however for major construction projects (such as pumped storage) the lead-in time would more likely be up to 6+ years, which would require at the very least a T-6 auction; and
- It appears that only short-term storage projects with storage durations of up to 5.5 hours are currently credited, giving little value to providing longer term storage needed for balancing of renewables.

It would seem therefore that major revisions to the Capacity Market rules, including possible changes in primary legislation, may be required to allow the development of long-term energy storage under this mechanism. Thus, the Capacity Market (as it currently stands) may not be the most appropriate incentive mechanism for promoting the development of long-term storage for balancing renewables to meet the net zero carbon targets by 2050.

Contracts-for-Difference Model

The CFD incentive model was introduced specifically for the development of net zero carbon renewable generation such as wind, solar, biomass and nuclear. However, this model is based around a strike-price that in effect means that such generation is produced on a take-or-pay basis and that all energy generated, whenever it is produced, qualifies for payment at that strike-price.

As long-term energy storage depends on its ability to absorb excess renewable energy during times of surplus and to re-generate the stored energy later when needed, this would be difficult to control under a CFD model. Optimal operation of such long-term energy storage systems would probably be best undertaken by the ESO, in the same way that short-term balancing services are managed, as in effect long-term energy storage could be regarded as a long-term balancing service.

As currently framed, the CFD model may not therefore be the most appropriate incentive mechanism for promoting the development of long-term energy storage.

Regulated Asset Base Model

An alternative to the Contracts-for-Difference model is the Regulated Asset Base (RAB) model which is currently used widely to fund infrastructure projects in gas, electricity and water sectors. The RAB model has recently

8.1

Electricity Market Reform Contracts

been adapted to fund infrastructure projects such as the Thames Tideway wastewater project in London. The difference between the two models can be summarized as follows:

- In the CFD model, a strike price (in £/MWh) is agreed in advance of construction and provides a guaranteed revenue rate over a fixed period (usually 15 years), with construction and overrun risk being borne by the developer and investors; and
- In the RAB model, the developer recovers its expenditure and a rate of return, with an agreed revenue being accrued from the start of construction. Under this arrangement, the developer takes on a share of the risk of cost and time overruns with an element of risk (for unforeseen events) being borne by electricity consumers.

The advantage of this model is that the revenue accrued from the project is independent of the net energy generated and thus the ESO would have complete control over how and when the scheme was operated, to suit the operational needs of the grid. However, this model would pass part of the cost of construction risk and over-runs on to electricity consumers, which may not be acceptable.

Cap & Floor Model

Ofgem created the cap and floor model in order to encourage investment in electricity interconnectors, but it may also be possible, with the agreement of BEIS, for this model to be extended to energy storage. It strikes a balance between commercial incentives and appropriate risk mitigation for project developers.

As set out by Ofgem, electricity interconnectors developed under the cap and floor regime would earn revenue from the provision of interconnector capacity and may also earn additional revenue streams, such as from participating in the Capacity Market and/or providing Balancing Services to the system operator.

- The floor is the minimum amount of revenue that an energy storage project could earn. This means that if a storage project does not receive enough revenue from its operations, its revenue will be 'topped up' to the floor level. The funds would be transferred from the electricity system operator, who would in turn recover the shortfall from balancing mechanism charges, applied to users on the national electricity system.
- The cap is the maximum amount of revenue that an energy storage could earn. This means that, should a storage project's revenue exceed the cap, the developer would transfer the excess revenue to the ESO, who in turn would reduce balancing mechanism charges.

There could be a wide band of 'merchant' exposure between the cap and the floor, but as revenues would normally be expected to remain within this band, it is likely that revenues would only occasionally fall below the level of the floor, but would be compensated when revenues exceeded the cap. This should thus provide both the best value to consumers, while at the same time providing the necessary level of surety to investors with an acceptable rate of return.

At the recent Electricity Market Reform Conference held at Westminster in November 2019, the question of long-term energy storage was raised at one of the panel sessions and the view of the panel was that as energy storage was similar in concept to an interconnector, a Cap & Floor model was likely to be the most suitable mechanism, having been originally framed for the implementation of interconnectors.

8.2

NG Ancillary Services Contracts

Apart from revenues derived from net-energy sales (from renewables balancing) through arbitrage payments, as well as through the Capacity Market, energy storage projects can also derive additional revenues by providing ancillary services to the system operator.

Current Ancillary Services

Current ancillary balancing services provided by existing pumped storage hydro plants include:

- Firm frequency response (FFR);
- Fast reserve (FR);
- Short term operating reserve (STOR);
- Spinning reserve (SPIN-GEN); and
- Black Start

Certain services are secured by open bids and others are through bi-lateral agreements. Also, not all existing plants provide the full range of balancing services listed above.

8.2 NG Ancillary Services Contracts

Future Ancillary Services

From recent discussions with National Grid ESO, we understand that a new range of ancillary balancing services are currently being drawn up under its Pathfinder project covering:

- Inertia;
- Frequency response;
- Voltage management; and
- Network constraint management.

The above services are all likely to be let as contracts to provide short-term balancing services, but do not currently cover long-term energy storage specifically. However, it is understood from National Grid that it is looking into the potential of long-term storage as part of a new network constraint management service under its current Network Innovation Project.

It is also understood from discussions with National Grid that future balancing services contracts are likely to be moving towards real-time auctions, thus obviating the need for long term contracts in future.

8.3 Current Entry Barriers for Long-Term Storage

Although it is clear from the foregoing sections that long-term energy storage could provide a key role in de-carbonizing the UK power generation system by 2050, it would seem there are several barriers that are currently preventing large scale new-build energy storage projects from entering the market:

- The Contracts-for-Difference model, as used for other forms of generation (wind, nuclear etc.), applies to generation plants operating continuously on a 'take-or-pay' basis, which is not appropriate for energy storage projects that need to be operated at specific times to meet system requirements;
- Currently the Capacity Market auctions are not applicable to long-term storage projects (of duration over 5.5 hrs), or with a construction period in excess of 4 years;
- Although the Ofgem 'cap and floor' model used for funding interconnectors, provides a 25-year term, this is currently not yet available for energy storage projects;
- The National Grid ESO ancillary balancing services contracts are too short to provide a sufficient revenue stream to attract investors, whereas the Energy Market Reform contracts provide a 15-year term;
- It is also not currently possible to apply for Grid balancing services contracts in advance, to allow for long construction lead times (6 years);
- It is understood that the proposed National Grid ESO constraint management contract would cover short-term storage (200 MW for 2hrs) for 2 or 5-year terms, which is still likely to be too short for long term investments;
- We understand that there are, as yet, no plans for a long-term constraint management contract that could provide the necessary long-term storage for supporting intermittent renewables generation, although National Grid is looking into this under its Network Innovation Project.

It is clear therefore that if large scale long-term energy storage is to be able to contribute to realizing the objectives of de-carbonizing the UK power generation system by 2050, modification of certain aspects of the EMR process may be needed to enable this to happen.

Conclusions & Recommendations

9.0

In this paper, we have carried out a review of the future need for energy storage within the UK power generation system in terms of providing both long-term 'deep' energy storage suitable for regulating intermittent renewable generation as well as short-term 'shallow' energy storage for supplying ancillary grid balancing services for National Grid ESO.

Alternative Energy Storage Technologies

9.1

We have investigated a range of alternative energy storage technologies that could meet both the long-term energy storage requirements for supporting intermittent renewables generation as well as the short-term requirements for providing ancillary services for the NG balancing mechanism.

As the economic storage range for each technology is different, we have compared the unit generation cost against a range of durations for each type of storage technology. This has identified the optimum operating range in terms of storage duration to determine the most appropriate technologies for long, medium and short-term energy storage, ranked in order of lowest cost:

Long-Term 'Deep' Storage

72hrs-144 hrs (3-6 days) storage duration (up to a week or more):

1	Pumped hydro storage	£64/MWh
2	Hydrogen storage with CCGT	£101/MWh
3	Hydrogen storage with OCGT	£122/MWh
4	Compressed air energy storage (CAES)	£137/MWh

Medium-Term 'Intermediate' Storage

8 hrs to 24 hrs storage duration (up to a day):

1	Pumped hydro storage	£106/MWh
2	Liquid air energy storage	£158/MWh
3	Hydrogen storage with OCGT	£164/MWh
4	Compressed air energy storage	£185/MWh

Short-Term 'Shallow' Storage

1 hr to 4 hrs storage duration:

1	Lithium-ion batteries	£218/MWh
2	Pumped hydro storage	£294/MWh
3	Liquid air energy storage	£320/MWh
4	Hydrogen storage with OCGT	£387/MWh

9.1

Alternative Energy Storage Technologies

This shows that pumped hydro is still clearly the lowest cost technology for both long-term and medium-term storage, closely followed by hydrogen storage with CCGT, with compressed air storage (CAES) also being a potential contender. Pumped hydro is also the most mature and well proven technology, having been the mainstay of medium-term energy storage over the past 60 years, and thus should be the prime candidate for at least the initial developments required by 2030. The other emerging technologies, such as hydrogen storage via hydrolysers and CAES, have still to be developed at scale so could be likely candidates for later developments, by which time the cost of these newer technologies could have likely reduced.

This also shows that Lithium-ion batteries are clearly the lowest cost technology for short-term storage for durations of less than 2 hours, although LAES and hydrogen storage with OCGT are also potential contenders. Of note, as discussed earlier, is that short-term storage would likely be best located on the demand-side (at distribution level) where it could also be used to balance variation in demands and hence reduce stress on the transmission system. Lithium-ion batteries and liquid air storage would therefore to be better suited for this application, as they can be located anywhere on the network. Also, hydrogen storage with OCGT could also be applicable here, as the associated compact OCGT plants do not need to be co-located with the hydrolysers and could thus also be located at distribution level, potentially being fueled by 'green' hydrogen directly from the gas network.

9.2 Comparison with Backup CCGT Generation

Much of the existing backup generation capacity in the UK system currently comprises 35 GW of unabated CCGT plant. However, in order to meet the net zero carbon targets this entire CCGT fleet would need to be replaced by 2050 with new CCGT plants fitted with carbon capture and storage.

The FES report and the CCC Net Zero Technical both propose that the most appropriate carbon capture technology for the power sector would be pre-combustion CCS using steam reformed methane to produce hydrogen to fuel the CCGT (or OCGT) plants. The recent BEIS Carbon Capture Technology report (2018) gives the levelized cost CCGT with pre-combustion carbon capture and storage as £100/MWh at 100% load-factor.

However, our analyses have shown that for the FES Net Zero scenario in 2050 with 90 GW of wind generation capacity installed, the predicted load-factor for CCGT plants used as backup generation for intermittent renewables would likely be in the region of between 20% and 25%. Applying these load factors to the cost model (supplied with the BEIS report) gives a levelized cost for CCGT with CCS nearer £250/MWh when used in this application. This shows that long-term energy storage could be a significantly lower cost alternative to CCGT with CCS, as well as being a fully renewable solution.

9.3 Development Strategy to meet Net Zero Targets

In order to determine the lowest cost power development arrangement that can meet the net zero targets by 2050, we have evaluated a range of alternative development cases comprising different combinations of the following potential technologies:

- CCGT with carbon capture and storage;
- Pumped hydro storage;
- Hydrogen from electrolysis & storage;
- Compressed air energy storage (CAES); and
- European interconnectors.

Ten alternative development cases have been evaluated, comprising:

- Cases 0 & 1 which utilize exclusively CCGT with carbon capture and storage with different capacities of European interconnector, without any provision of long-term storage to balance intermittent renewables; and
- Cases 2 to 9 which have different levels of energy storage for balancing intermittent renewables, with a progressive reduction in the need for backup CCGT generation with CCS.

9.3

Development Strategy to meet Net Zero Targets

The results for Case 1 show that implementing a further 8 GW of European interconnectors could result in a net saving of some **£6 billion** (@ 8% discount rate) in the long run, compared to the alternative of providing the equivalent CCGT plants fitted with CCS.

The results for Case 7 show that by implementing 30 GW of long-term energy storage, comprising 10 GW of pumped hydro, 20 GW of hydrolysers with hydrogen cavern storage, and 10 GW of CCGT with carbon capture and storage could yield a net saving of about **£24 billion** (@ 8% discount rate), compared to Case 1, i.e. an overall net saving of some 24%.

The results for Case 9 show that by implementing 40 GW of long-term energy storage, comprising 10 GW of pumped hydro and 30 GW of hydrolysers with hydrogen cavern storage, could yield a net saving of about **£32 billion** (@ 8% discount rate), compared to Case 1, i.e. an overall net saving of some 32%.

While Case 9 is clearly the least-cost solution, it could be more vulnerable to imports from Europe and there might therefore be advantages in providing some backup CCGT capacity fitted with CCS to provide greater system resilience with less reliance on European imports. Thus Case 7, comprising 30 GW of long-term energy storage and 10 GW of CCGT plant fitted with CCS, may be a more acceptable solution, but at a reduced saving of **£24 billion.**

This shows that the optimum solution could perhaps lie between Cases 7 & 9, implemented in say 10 GW increments at say five yearly intervals between 2030 and 2045, to ensure completion by 2050.

9.4

Future Development Plan

As discussed in Section 6, such a major development would necessarily need to be phased, to ensure the net zero carbon targets can be met by 2050. A potential phased implementation programme (e.g. based initially on Case 7) could be as follows:

- **Stage 1:** Initial 5 GW of pumped hydro with 5 GW of hydrogen storage by 2030;
- **Stage 2:** Further 5 GW of pumped hydro with 5 GW of hydrogen storage by 2035;
- **Stage 3:** Further 5 GW of hydrogen storage or CAES with 5 GW of CCGT+CCS by 2040; and
- **Stage 4:** Further 5 GW of hydrogen storage or CAES with 5 GW of CCGT+CCS by 2045.

This would enable the full development to be completed by 2045, giving a five year float for any overruns.

This approach could allow a start to be made using existing proven long-term energy storage technologies and provide time for other emerging storage technologies to be developed and refined further, potentially also at reduced cost. In this way, the optimum level of long-term energy storage could be built up gradually, with the balance made up by CCGT fitted with CCS. Thus an initial development approach based on say Case 7 could be initiated now, which could be extended to say Case 9 later.

Whatever generation mix is eventually decided, that best meets the net zero carbon targets by 2050, there is clearly a compelling case for developing at least 10 GW of long-term energy storage by 2030, with a further similar development by 2035. The question of how much additional long-term energy storage would be needed can thus be decided later, using the principles of **adaptive planning**.

The principles of a**daptive planning** involve formulating a range of alternative development pathways (similar to the Cases derived earlier) and then dividing them into stages. An initial development path is selected at the outset with decisions made at each stage to decide whether to continue on the same path, or switch to another path depending on changed circumstances. In this way, an initial path (say Case 7) would be embarked upon and a Stage 1 development decided for 2030. Then, when Stage 1 was complete in 2030 the next path could be chosen (e.g. Case 6, 7 or 8) which would define the Stage 2 development for 2035. Thus, if Case 8 was decided to be the best path for Stage 2, a further decision could be made in 2035 to choose the next path (e.g. Case 7, 8 or 9) for Stage 3 by 2040, with the process repeated for the remaining stages. This would allow the development plan to be adapted periodically to take account of a range of uncertainties such as demand, costs, technological advances and/or environmental considerations.

Market Incentives

9.5

From the foregoing analysis, it is clear there could be merit in developing significant long-term storage capacity in the UK for balancing renewables generation, not only to provide backup generation during periods of low wind, but also for reducing stress on the UK transmission system and providing flexibility for optimal operation of the European interconnectors. However as highlighted in Section 8, there appears to be no suitable market incentive mechanism in place at present for the promotion specifically of long-term energy storage.

The Electricity Market Reform process provides suitable incentive mechanisms for the development of other renewable and nuclear generation under their Contracts-for-Difference and Capacity Market auctions, but there appears to be no suitable mechanism applicable to long-term energy storage projects with storage durations in excess of 5.5 hours. Also, the Capacity Market T-4 auctions are currently restricted to projects that can be constructed within 4 years, which rules out major energy storage projects with longer construction periods.

An alternative incentive mechanism that could be considered is the Cap & Floor model, currently framed to encourage investment in electricity interconnectors. A feature of the Cap & Floor model is that all revenue streams are taken account of in arriving at the target upper and lower price band, which would thus give a minimum level of assurance to potential investors, covering not only market arbitrage risk but also the risks associated with revenues from balancing services. In this way, it may be possible to frame an investment arrangement that could both mitigate much of the market risk to investors, while at the same time providing best value to electricity customers.

At the earlier Electricity Market Reform Conference held at Westminster in November 2019, the question of long-term energy storage was raised at one of the panel sessions and the view of the panel was that the Cap & Floor model was likely to be the best approach and recommended that this should be followed up with BEIS.

Benefits to the Consumer

9.6

The merits of employing long term energy storage to support achieving a net zero position in 2050 have been reviewed in this White Paper. While the environmental imperatives of reducing the output of carbon and providing energy security of the UK is of prime concern, it must also be recognized that these objectives add cost. The cost of transitioning to a zero-carbon future will either be covered indirectly through taxation and fiscal measures, or directly by consumers through electricity tariffs at the meter. Savings from wise selection of the optimum storage solution will be realized by the consumers. The energy consumers of the UK need to be confident that they are benefiting financially from the best technical solutions for energy storage being available for selection, with full support from the government and market operators.

9.7

Key Recommendations

From the analyses presented in this paper, it is clear there will likely be several types of energy storage required for future balancing of the UK power system, in order to assist in meeting the net zero emissions targets. This could range from short-term storage (for a few hours), to medium-term storage (for a few days) and long-term storage (for weeks/seasons), but the precise requirements for both the demand side and the supply side in terms of capacity and location has yet to be established. Also, the costs for many of the new emerging storage technologies is still highly uncertain, as are the costs for providing carbon capture and storage for backup CCGT plant used for balancing intermittent renewables generation.

There are already existing provisions for short-term storage for providing ancillary services National Grid's balancing mechanism, and medium-term storage for providing arbitrage services for meeting daily variations in demand. However, currently there is no explicit provision for long-term storage that could be used to more fully utilize intermittent renewables and hence reduce the dependency on potentially higher cost non-renewable backup CCGT fitted with carbon capture and storage.

Our key recommendations are as follows:

- Given the Government's stated objectives of achieving net zero by 2050, our analyses show that there is a compelling case for developing a further 40 GW of long-term storage, with a storage capacity of some 5,000 GWh, primarily for balancing the proposed 90 GW of intermittent wind generation planned to be in place by 2050, but also for providing grid balancing ancillary services as well as reducing dependence on imports via the European interconnectors;
- Our analyses also indicate that the provision of 40 GW of long-term storage could also eliminate the need for providing backup CCGT generation fitted with CCS, that would otherwise be required, at a potential cost saving of some £32 billion for the FES 2019 scenarios and potentially even greater for the latest FES 2020 scenarios;
- To achieve this objective will require a major development programme for long-term storage comprising not only pumped hydro, but also hydrogen storage as well as other technologies such as CAES and LAES, implemented in 10 GW stages between now and 2050, with the first stage being implemented by 2030.

We would therefore suggest that a development road map for energy storage be drawn up, framed to address the following issues:

- Identification of precise future requirements for short, medium and long-term storage;
- Determination of required energy storage capacities, including duration, on both the demand side and supply side;
- Detailed analysis on the benefits of energy storage on both the UK primary transmission system and European interconnectors;
- Detailed evaluation of alternative long-term storage or other options, including costs and risks, needed to meet net zero emissions targets by 2050; and
- Comparison of alternative incentive mechanisms for promotion of long-term energy storage, within the UK energy market.

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