Carbon Trust

Imperial College London

Can storage help reduce the cost of a future UK electricity system?

Results from a project on opportunities from the deployment of energy storage, contributed to by government, industry & academic partners

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Nils Lehmann, Andrew Lever, David Sanders, Manu Ravishankar and Michael Ashcroft from the Carbon Trust wrote this report based on independent research and analysis. The team has engaged expert stakeholders and project partners from government, industry and academia for this work. The Carbon Trust's mission is to accelerate the move to a sustainable low carbon economy. It is a world leading expert on carbon reduction and clean technology. As a not-for-dividend group, it advises governments and leading companies around the world, reinvesting profits into its low carbon mission.

Goran Strbac, Marko Aunedi, Fei Teng and Danny Pudjianto from Imperial College London conducted dedicated modelling of the UK's electricity system for this report. This team has led the development of novel advanced analysis approaches and methodologies that have been extensively used to inform industry, governments and regulatory bodies about the role and value of new technologies and systems in supporting the cost effective evolution to a smart low carbon future.

We are grateful for the support of the many experts in industry, government, and academia who agreed to be interviewed for this report.

Contents

Report Highlights

- *The UK can realise significant cost savings if market arrangements for the electricity system allow for an efficient deployment and use of energy storage, alongside other flexibility options such as demand response and interconnectors*
- *There are several barriers to energy storage deployment that have created a market failure and currently prevent a wider deployment of storage solutions*
- *Energy storage is a multi-benefit, multi-stakeholder opportunity which requires coordinated action across policymakers, regulators and industry to realise available benefits*
- *Certain market framework adaptations could more broadly enable a viable business case for storage for all stakeholders, and ensure that the UK will be able to benefit from storage deployment. Many of these changes are likely to be cost neutral and require no additional funding from the government*
- *The scale of these cost savings increases markedly if policymakers, regulators and industry act now to maximise the benefits storage can provide for the UK*

Executive Summary

The United Kingdom's (UK) electricity system is undergoing significant changes to provide electricity that is secure, affordable and ultimately low carbon. Energy storage, alongside other flexibility options such as demand response and interconnectors, can provide the flexibility required by a future system that may see an increasing share of intermittent renewables and more distributed generation.

This report assesses the benefits of flexibility solutions for a future UK electricity system using the example of energy storage. It examines potential scenarios the UK could face and the impact storage might have in terms of cost to bill payers across these scenarios. Understanding the optimal role for storage in a future electricity system requires advanced energy system modelling: the uncertainty around the costs of storage technologies, the costs of different sources of power generation and network infrastructure, future policy, and the nature of the future energy system itself creates a complex picture. Given the complexity of the electricity system, this analysis focuses on storage for power applications only and does not consider additional opportunities for storage in heat applications.

Energy storage

Energy storage can be divided into three main types: bulk (e.g., pumped hydro, compressed air); distributed (e.g., lithium ion battery, sodium sulphur battery, vanadium redox flow battery, liquid air storage, pumped heat storage); and fast that can provide instantaneous response (e.g., flywheels and supercapacitors).

This report distinguishes between different types of storage and the services a storage solution can provide. It takes a technology agnostic perspective, i.e. the report does not make recommendations on the benefits of specific technologies.

This report is the result of a collaborative project led by the Carbon Trust with support from partners representing government, industry and academia. The objective of the project was to specifically address the following questions:

1. Can integration of storage reduce the cost to customers in a future UK electricity system?
2. What barriers prevent potential benefits from storage from being realised commercially and therefore prevent investment in storage?
3. What practical steps can be taken to overcome these barriers?

This report has benefitted from multiple discussions with all project partners. The results are supported by systems analysis performed by the Carbon Trust for which the team conducted more than 50 interviews with UK and international experts from key industry and government stakeholders and academia, as well as dedicated whole electricity system modelling led by Professor Goran Strbac and his team at Imperial College London.

The quantitative analysis is based on data published by the UK's Department of Energy and Climate Change (DECC) where available, and is complemented by data from widely referenced sources or expert assessments where required. The analysis builds on scenarios published by the National Grid which are themselves the result of broad industry consultations. Key assumptions were reviewed by expert steering groups and discussed with senior decision makers in industry and government as well as with leading research academics and are provided in the annex of this report. It is nevertheless important to stress that the quantitative results of this report should be interpreted as indicative only – like any other modelling outputs for the UK's future electricity system.

Key Findings

The UK can realise significant cost savings if market arrangements for the electricity system allow for the use of energy storage

To illustrate the scale of potential savings, modelling carried out for this report suggests that deploying energy storage could significantly reduce the overall cost of a future UK electricity system. Depending on the scenario assumptions made for such a future system, the need for flexibility solutions varies, and the cost reductions enabled range from small benefits to savings of up to c. £2.4 billion[1] per year in 2030. If 50% of this saving was simply passed on to domestic customers it could reduce the average electricity bill per household by c. £50[2] per year.

In order to quantify possible benefits of storage, and to better understand the requirements on which a viable case for storage depends, various scenarios and sensitivities were analysed based on the National Grid's 'No Progression' as well as its 'Gone Green' scenarios.

The National Grid scenarios do not currently consider storage beyond a limited build of pumped hydro. The annual saving of up to c. £2.4 billion per year is based on additional storage that is retrospectively, rather than incrementally, added to the 2030 generation portfolio and network infrastructure as described by the National Grid's 'Gone Green' scenario.

The scale of these cost savings increases markedly if action is taken as early as possible to allow efficient evolution of the electricity system's topology to maximise the benefits storage can bring

A third scenario, called 'Market-driven Approach', was used to investigate potential cost savings if storage is integrated into the UK's energy system sooner. To allow for already committed investment decisions and adaptation of market frameworks to take place, the 'Market-driven Approach' scenario assumes the next eight years are the same as the National Grid's 'Gone Green' scenario. After 2023, the 'Market-driven Approach' scenario assumes that new assets including storage are only deployed if they are the best choice for the electricity system[3].

Under this scenario, an annual cost saving of up to £7 billion in 2030 is achieved; £2 billion of this from the deployment of storage, and a further £5 billion primarily from improved utilisation of existing generation assets and optimised and reduced investment in new generation assets. The report documents these cost savings and assumptions in detail as well as sensitivity analyses, and the results show that the findings are robust under a range of assumptions.

[1] All numbers are quoted in 2016 pounds sterling.

[2] Assuming the number of 2030 UK households to be 26 million (Department for Communities and Local Government, 2015)

[3] For the 'Gone Green' and 'No Progression' scenarios, generating plants are built or closed only according to the figures provided for these scenarios, but its output and so fuel costs are adjusted in response to the added system flexibility storage provides, in order to reach a carbon target. In the 'Market-driven Approach' scenario, the model makes new build or early close decisions based on profitability and energy system cost impact (including carbon). Limits are imposed on the number of plants which can be closed for each generation technology.

The value that storage can provide to a future UK electricity system is contingent on: the extent to which the UK will achieve its carbon targets, the removal of barriers currently still faced by industry actors who deploy storage solutions, and the cost reduction of the storage technologies themselves.

There are a number of different applications and business cases for storage in the energy system. To illustrate the opportunities and challenges to realise novel storage solutions this report explored two example business cases. Both business cases show that the deployment of storage can yield benefits today if market and regulatory barriers are removed. The cases illustrate opportunities for distributed storage as some of the opportunities driving the underlying business cases are relatively new. It should be noted, however, that currently viable storage solutions are predominantly based on pumped hydro bulk storage which has been playing a critical role in the UK's electricity system already for decades.

Business cases for distributed storage

The first case looks at combining storage with a large scale wind energy asset. The second case looks at distributed solar PV with storage.

Insights from the large scale wind and storage business case include:

- Reduced curtailment of wind output increases the utilisation of wind assets which creates savings for customers because target volumes of low carbon energy are generated from less installed capacity and may also create savings for bill payers by reducing the cost of curtailment payments
- If wind plus storage displaces more expensive forms of generation, this will lower the overall UK generation cost as well as the cost of meeting carbon emissions reduction targets
- If the addition of storage is more economically attractive than network reinforcements, this will lower the cost of transmission, distribution and local network investment

Insights from the distributed solar PV and storage business case include:

- Distributed storage at household level with no interaction with the network is neither the most economically attractive solution for end users, nor most beneficial to the network
- Aggregation of distributed storage leverages varied demand profiles, reducing payback times
- Dynamic pricing through time-of-use tariffs can further improve the attractiveness of storage
- Centrally-managed distributed storage can also support the system through frequency regulation
- Distributed storage is an opportunity for network operators to manage network congestion

There are several barriers that currently prevent the wider deployment of storage solutions

There is a broad consensus among experts across industry, government and academia interviewed for this project that the UK can significantly benefit from the integration of storage with a future UK electricity system, a view that is also supported by scenario outcomes modelled for this report. However there are significant barriers to the wider deployment of storage solutions in the UK. These barriers reduce the commercial viability of storage to investors by increasing risk or reducing revenue potential. This leads to reduced deployment of storage than would be beneficial from a societal perspective and may result in higher costs for customers.

Key barriers include:

- **Policy risk** – Future revenues of storage are linked to policy decisions which drive the need for flexibility services such as substantial decarbonisation targets. Concerns over the long-term predictability of relevant policies are a key risk factor for investors in storage assets. Such policy risk raises the financial returns investors require. This leads to under-investment in storage solutions from a societal benefit perspective and may result in higher costs for customers.

- **Failure to recognise externality benefits to society** – This report provides evidence for opportunities to reduce the cost of the UK's future electricity system by deploying flexibility solutions such as storage. However, unless a sufficient share of these positive externalities is made available to storage actors, business cases may not be viable and neither the general public nor industry can realise the full benefits of this opportunity. This means that unless these externality benefits are also sufficiently reflected in market prices, or alternative market mechanisms, the resulting under-investment in storage solutions will lead to a more costly electricity system.

- **Revenue cannibalisation risk** – Storage assets can offer a wide range of different services, but the demand for these services is finite, so there is a risk that some sources of revenues may be eroded as further new storage assets are built. Investors have to take the risk into account that revenues from a storage asset may become lower than they expected when they made the investment decision.

- **Distorted market price signals** – Key stakeholders (regulators, network operators, and technology and service providers) do not yet share a joint perspective on the value or roles storage could have in the future energy system, or the most appropriate market structures and price signals required to incentivise efficient investment decisions. Parties who benefit from today's market distortions may view these perverse market price signals as unsustainable deterring investment, while parties who are discriminated against by today's market distortions may see the current market arrangements as uneconomic for investment. These market distortions cause unnecessary uncertainty and increase investment risk. As with other barriers discussed, this leads to under-investment in storage solutions from a societal benefit perspective and may result in higher costs for customers.

- **Disintegrated market structures** – A key driver for the viability of storage solutions is their ability to provide multiple services. However, many of these services are provided in markets governed by different regulatory frameworks, characteristics and rules. This often limits the opportunities for a single storage asset to provide multiple services, reducing the viability of storage deployment.

- **Multiple stakeholders, multiple benefits** – The above barriers are even more relevant because in order to capture the overall system benefit that a storage solution can provide, multiple benefiting stakeholders are usually required to collaborate. There is a lack of incentive for any single player to take the lead. It is unlikely for a group of companies to collaborate on a storage solution unless every one of them has a viable business case for doing so.

These barriers to energy storage deployment have created a market failure which needs to be addressed to avoid sub-optimal deployment levels not only of storage, but more generally of flexibility solutions in the electricity system.

There are feasible solutions to overcome the barriers that currently prevent the wider deployment of energy storage

The most important recommendations are policy-related. The UK's future electricity system will look different and will face different challenges to the electricity system for which most current regulation has been designed. A more cost benefit reflective market environment is needed to ensure that best solutions for the future needs of the UK's electricity system will be adopted. It should in particular take requirements and capabilities of flexibility solutions such as storage into account. End customers would benefit from reduced system costs while such a market environment can be expected to strengthen the business case for storage because of the positive societal externalities it can provide. Many of these policy changes are likely to be cost neutral and require no additional funding from the government. It is beyond the scope of this report to make detailed policy proposals. However, the following points should in particular be addressed:

- **Align incentives and remove barriers** – Further align incentives to reflect the needs of a future electricity system and remove barriers to the deployment of flexibility solutions such as storage, so that the market can determine the least cost way to manage the system. For example, introduce dynamic electricity pricing for appropriate customer groups so that the true cost of the electricity system is better reflected; allow a single storage asset to provide layered services;

- **Monetise system benefits** – Realise further societal benefits from the deployment of storage by providing industry stakeholders with a sufficient share of these benefits to make a wider range of business cases viable. For example there are several services that storage provides such as deferring/avoiding investments in network and generation capacity, and improving cycling of conventional generation that reduces the cost to consumers. There are however, no markets to compensate the storage developer for such services.

- **Reduce policy uncertainty** – Reduce policy uncertainty by keeping policy commitments which are critical to the long-term planning of stakeholders to the UK's electricity system such as decarbonisation targets and adapt regulation in long-term predictable ways;

- **Engage broad stakeholder group** – Although storage can produce an overall cost saving for the UK, care has to be taken to engage a broad stakeholder group in adapting market structures as changes will affect organisations beyond the storage industry;

- **Demonstrate cost and performance of storage** – In order to inform discussions on required key policy / market changes for which project based evidence is lacking, joint industry projects designed to demonstrate specific cost or performance characteristics of storage solutions should be realised;

- **Define performance and operating standards for storage** – Define performance and operating standards for storage solutions to provide guidance to new technology providers and build confidence with electricity system operators. This should include the technical performance of the storage asset and also standardised data transfer and communication protocols for efficient integration with the network.

These recommendations, along with other more detailed proposed solutions to the market, technology and commercial challenges, are documented in more detail in the full report.

It is important for policymakers, regulators and industry to act now to capture maximum benefits. Early action on the report's recommendations will help to identify technical requirements, guide investment towards the development of most effective storage solutions, support industry and supply chain development, and ensure the storage solutions will be available at the required scale and cost when needed. If the suggested changes to the market environment were implemented as soon as possible, then this analysis indicates that savings of up to £7 billion per year can be realised in 2030.

While this report focuses on assessing the system cost savings from storage, it is worth stressing that storage can also make the UK's electricity system more secure by reducing dependency on imported fossil fuels and also imported electricity via interconnectors. This in particular reduces the risk exposure of a future electricity system to gas price fluctuations. A delay in creating a more cost benefit reflective market environment will likely result in sub-optimal short term investments. It is, therefore, in the UK's strategic interest to act now in order to ensure that the significant future opportunities from storage and further flexibility solutions can be captured.

2 Energy trends, impacts and the potential role for storage

2.1 Summary

This chapter highlights the key trends expected to shape the future UK's electricity system. These trends will increase the need for (and the value of) flexibility solutions for the electricity system. A brief overview is provided on the role different flexibility solutions such as storage, demand side response, flexible generation and interconnections can play to address these increasing system needs.

This report focuses on storage solutions as an important example which can provide a range of such flexibility services. However, it makes no judgement on the merits of one type of flexibility solution over another. While the different flexibility solutions complement each other in many ways, they may compete in others. Benefits identified from the deployment of storage solutions therefore are to a degree illustrative of benefits which can be more generally realised from the deployment of a carefully selected portfolio of flexibility solutions.

Although the report takes a technology agnostic perspective on storage, this chapter provides an overview of different types of energy storage and their characteristics that were used in the underlying analysis. The chapter concludes with a discussion of the key services that storage solutions can provide to the electricity system. Further details, including an overview of the UK electricity system, are provided in Section 7.1 of the annex to this report.

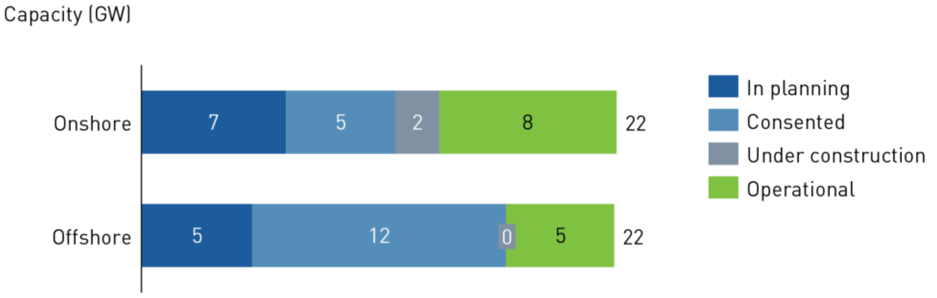
2.2 Trends in the UK electricity system

The way that electricity is generated, transported and consumed in the UK is changing in fundamental ways. The three drivers of the energy trilemma (security of supply, cost and carbon emissions) are causing a number of trends in the UK energy system.

Large-scale deployment of wind power

Greater deployment of low carbon generation will be required in order to meet the 2020 EU-mandated targets, as well as EU targets for renewable generation by 2030 and EU mandated carbon targets to be achieved on the way to 2050. The UK currently has, at operational level, 8.3GW of onshore wind capacity and 5.1GW of offshore capacity (RenewableUK, 2015). If all projects under construction, consented or planning become operational, the total UK installed capacity of wind power would rise to 44.6GW, evenly split between onshore and offshore wind (Figure 1).

Figure 1 - UK onshore and offshore wind deployment by state of development of projects in the UK Wind Energy Database (UKWED) as of September 2015 (RenewableUK, 2015)



Shift towards distributed generation

Growth of distributed generation has accelerated rapidly in the UK over the last few years owing to the introduction of feed-in tariffs, cost reductions of low carbon technologies, and changing attitudes towards self-generation. For example, installed solar PV capacity has seen a five-fold increase in the UK between 2011 and 2014.

Closure of large conventional generation plant

The European Union (EU) Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED) caused the closure of a number of UK coal-fired power stations. As a result, the current installed coal-fired capacity in the UK has already reduced by 9GW since 2011 (Department of Energy and Climate Change, 2015).

Changing demand profiles

Electricity generation accounted for 36% of UK carbon emissions in 2014 (Department of Energy and Climate Change, 2015). Savings must therefore also be made in other polluting sectors, such as transport and buildings (heat), if the UK is to meet the target of an 80% reduction in greenhouse gas emissions, on 1990 levels, by 2050. Electrification of heat and transport could significantly reduce carbon emissions if the electricity comes from low-carbon sources, and electrification may become a dominant trend. However, unless demand-side response (DSR) schemes are deployed, the electrification of heat and transport is likely to result in significant increases in peak demand on the system that are disproportionately greater than the additional requirements for electricity to supply these sectors.

2.3 Resulting system impacts

Each of these trends, among others, will result in a number of impacts within the electricity system that will need to be addressed. This section discusses the nature of these impacts.

Balancing supply and demand

A common (and valid) criticism of many renewable energy sources is that supply may be available when there is limited demand, or there may be limited supply available at times of peak demand. Similarly, other forms of low carbon generation such as biomass, nuclear and carbon capture and storage (CCS) face strong technical and economic incentives to operate at a flat level of baseload generation, so these are also unable to increase output at times of peak demand and are likely to require price signals similar, or more extreme than wind generators to reduce output at times of low demand.

Maintaining adequate capacity margin

The capacity margin is a crucial element of an energy system that must ensure security of supply. While the current capacity margin is viewed as sufficient to handle shocks, there are several factors that will adversely impact the capacity margin in the medium and long term. This will need to be countered by the Capacity Mechanism to ensure sufficient capacity margin is maintained.

Increased need for flexibility to maintain system reliability

With greater integration of intermittent renewables in the UK network, more flexibility is required to support a stable power system, which must withstand greater variations of generation owing to forecasting errors and short-term events of over or under supply (Imperial College London; NERA Consulting, 2012). Flexibility services which have previously been provided by carbon emitting generators such as open cycle gas turbines (OCGT) and closed cycle gas turbines (CCGT) need to be sourced from lower carbon alternatives not only because this can reduce system cost as analysed for this report, but also to achieve the carbon reduction targets for the electricity sector. Alternative sources of system reliability services need to avoid the system problems which would otherwise be caused by the technical limitations of CCGTs. For example, if CCGTs are to provide inertia or upward flexibility then they must generate at a must-run minimum load causing additional carbon emissions.

Reduced efficiency of conventional plants

Increasing penetration of solar and wind power will displace conventional plants, such as gas and coal by pushing them further down the merit order owing to marginal cost differences. Therefore, plants that traditionally provided baseload must endure quicker ramp ups and downs, more start-ups and greater overall cycling. This has negative consequences for these plants with higher maintenance costs, greater wear and tear, shorter lifetimes and greater environmental impact due to lower efficiency and higher emissions per unit output.

Localised distribution network impacts

When distributed generation is connected to the distribution network in large volumes it can affect the local network. Reverse power flows and possible congestion are problematic for the distribution network, which was traditionally designed to passively distribute power from the transmission system to the end customers. More cost reflective price signals are needed for distribution connected demand and generation to incentivise efficient investment decisions.

2.4 Role of system level solutions

This section provides an overview of solutions that can be used to address the discussed system impacts. Some of these solutions can provide the same services, and so there is an element of competition between them. Similarly, each could feasibly occupy a specific niche or provide a range of services alongside others.

This report investigates the role energy storage can play to reduce the cost of the UK's future electricity system in providing solutions to the discussed system needs. Storage solutions are unique in their ability to operate in a range of different markets across the electricity system to provide multiple services to different stakeholders. An important advantage of storage as a technology is that it can provide a whole system solution instead of only a service for a specific need of a single stakeholder. This means that the cost of a single storage asset can simultaneously displace the cost of a range of different technologies which may be more limited in the services they can provide. Brief comment is provided below on how further such technologies may compete with or complement storage solutions.

The diversity of storage benefits does, however, also contribute to the complexity and uncertainty of the business case for investment in storage. Advanced energy system modelling is required to better understand optimal combinations of services storage solutions should supply in order to reduce the total cost of a future electricity system. Multiple scenarios and sensitivities were employed for this analysis to identify value drivers and their robustness in the face of these uncertainties. This report is an attempt to explore the potential for storage as a key example of some of the potential scenarios the UK could face and the impact storage might have, in terms of cost, across these scenarios.

Energy storage

There are several other types of energy storage relevant to energy supply including strategic oil reserves, hot water tanks, and natural gas in pipelines. While using the more general term of 'energy storage' throughout this report, for reasons of scope, this report focuses on what might more accurately be referred to as 'electricity storage'.

A single electricity storage asset can contribute many different services including system adequacy by providing capacity to meet peak demand, while also reducing the cost of meeting carbon targets by avoiding curtailment of low carbon energy, contributing to system reliability by providing a range of flexible fast response services and also network services by avoiding, or delaying the need for network reinforcements.

Flexible generation

With peaking plants historically relying on ancillary services (e.g. Short Term Operating Reserve (STOR) and reserve markets, the introduction of the Capacity Market is causing some changes in the UK energy market. The UK's two capacity market auctions have not provided the necessary clearing price for new CCGTs (also to existing plants to an extent) and instead have brought forward smaller scale plants such as diesel generators.

With a significant capacity not getting contracts through the two auctions, a secondary market called the Supplementary Balancing Reserve (SBR) mechanism is increasingly becoming the life support for flexible generators (TIMERA ENERGY, 2016). Storage is able to contribute to capacity adequacy and therefore compete with alternatives sources of capacity such as carbon emitting peaking and dispatchable plants, e.g. OCGTs and CCGTs.

Interconnections

There are several new interconnector proposals that are being considered at different stages including those to Belgium, Norway, France, Iceland, Denmark and Sweden. While interconnectors could bring significant benefits, there are caveats relating to future energy scenarios and the extent of convergence across EU energy markets. Storage is able to compete with and may displace the need for interconnection since storage similarly provides economic use for energy during periods of surplus generation from low marginal cost generators and also provides a source of energy during periods of peak prices.

Conventional network reinforcement

Conventional network reinforcement will play an integral role in providing the network infrastructure to allow efficient integration of low carbon technologies into the electricity network. Greater use of smart grids, and associated technologies enabling demand flexibility, will allow for better utilisation of existing assets thus reducing the frequency of grid upgrades. Storage can compete with investment in network infrastructure by delaying, or reducing the need for both transmission and distribution network reinforcement.

Active Network Management (ANM)

It is important to note that the more advanced ANM schemes have demand side response and energy storage integrated within them to ensure a robust and cost effective solution to integrating renewable energy and avoiding large capex investment from conventional reinforcement. ANM is likely to play an important role as an enabler of energy storage deployments in electricity networks.

Demand Side Response (DSR)

The smart meter roll-out is one of the key elements that will enable the deployment of DSR and allow it to play an important role in a future energy system of the UK. However, given concerns around its reliability and the true costs of deploying large scale programmes, DSR is likely to co-evolve with energy storage as a complementary solution in providing flexibility in the medium to long term. DSR, from commercial and industrial consumers, is likely to continue to grow and evolve in providing different services to the grid while much slower progress is expected in the domestic sector.

2.5 Overview of storage technologies

The main storage technologies are summarised below.

Bulk storage technologies are primarily located in the transmission network with relatively long duration storage capacities to provide large scale storage and discharge of electricity according to the grid needs and include:

- Pumped hydro storage is the most technologically mature of all the storage technologies considered and is also the most widely deployed. The response time for pumped hydro systems are fast (or the order of seconds) and can achieve high ramp rates.
- Compressed Air Energy Storage (CAES) uses electricity to compress air through a compressor which is then stored either in underground caverns or above-ground vessels. The stored air is then expanded through turbine-alternators to generate electricity.

Distributed storage technologies tend to be smaller in nature, relative to bulk storage with relatively short duration storage capacities. They therefore tend to be more suitable for use cases where it is necessary to connect at medium – or low-voltage distribution networks. Example technologies include:

- Lithium-ion (Li-ion) batteries are emerging as one of the fastest growing battery technologies for grid applications. They have significantly benefited from RD&D investment aimed at commercialising their use in transport applications. They are presently deployed globally from small scale distributed systems (1-10 kW) to large fast-responding systems for frequency services and energy time shifting (1-50 MW).
- Sodium sulphur (NaS) batteries are considered to be a commercial technology with several grid applications. This battery is attractive due to its long discharge times, quick

response capability and high cycle life. The combination of some safety issues and lack of diversified supply chain has somewhat slowed its global uptake.

- **Vanadium redox flow batteries** are part of a class of batteries known as flow batteries, in this case with vanadium ions present in an aqueous acidic solution. Vanadium flow batteries have distinct advantages such as no cross contamination of the electrolytes, minimal self-discharge, high cycle life and separation of power and energy components rendering storage capacity addition far easier and cost effective.
- **Liquid air storage** uses electricity to drive an air liquefier to produce liquid air which is then stored in insulated vessels. This technology is driven by Highview Power in the UK where it runs a pre-commercial demonstration alongside a landfill gas generation plant.
- **Pumped heat storage** uses a heat pump/engine to convert electrical energy to heat, which is then stored in gravel-filled insulated vessels.

Fast storage technologies are categorised by their ability to provide high power for very short discharge durations of high power in the order of milliseconds to seconds, making them suitable for specific applications such as real-time voltage stabilisations:

- **Flywheels** store electrical energy as kinetic energy by increasing the rotational speed of a disk or rotor on its axis. Increasingly, flywheels have been finding success in grid applications, primarily for frequency regulation displacing conventional generation. This is mainly owing to its ability to provide up and down regulation and rapid response features.
- **Supercapacitors** are advanced capacitors that have higher energy storage capacity, so are able to discharge over longer time periods than conventional capacitors. Like flywheels, they are able to respond very quickly through both charge and discharge cycles, and can be used to provide a high power output within a very short response time, which is required for frequency regulation.

2.6 Services and system benefits storage can provide

This section provides an overview of the many services storage can provide to benefit the electricity system. It is important to distinguish between such services aimed at realising a system benefit and further storage applications focused on capturing a single stakeholder benefit which may or may not at the same time benefit the overall electricity system. The two business cases in Chapter 4 illustrate the difference between these two perspectives. Business Case II discusses how the perspectives can be reconciled for the question of where on the electricity network a storage asset is placed how it is operated. In Chapter 5 this report more generally argues that it is of key importance to ensure that commercial activity will at the same time drive societal benefit. For this more cost benefit reflective market environments are needed which provide incentives to individual stakeholders which are aligned to system needs.

2.6.1. Capacity adequacy

Meeting demand

A power system has to be designed for the annual peak in demand. Storage can provide the additional capacity required at peak times by time shifting energy. To ensure generation adequacy under a landscape of reducing conventional generation margin, UK has introduced a capacity market to compensate generators with a predictable revenue stream in return for either building new capacity or keeping existing ones online to deliver energy when needed during times of stress.

Energy time-shifting and improved integration of renewables generation

The inclusion of storage within the system permits electricity to be supplied regardless of the real-time electricity demand, enabling "wrong time" electricity to be stored and used at a later time of sufficient demand. Storage technologies that are capable of efficiently storing large amounts of electricity are best suited as it is the amount of energy traded, rather than the power rating of the system, which contributes to the revenue. Storage can be used for "capacity firming" to mitigate fluctuations in output experienced with intermittent renewable energy, particularly solar and wind, thus maintaining the committed level of capacity. Storage can also reduce generation curtailment. For example, although a wind farm operator may be compensated for loss of revenue by curtailment payments, this is an inefficiency of the system as it wastes electricity from a low-carbon source. This can increase the utilisation of low carbon generation assets as well as improve the quality of the power supplied.

Energy security

Storage can be used in conjunction with renewable generation to improve UK energy security by reducing reliance on imported fossil fuels. This service is so far provided as a positive externality to society, i.e., there currently is no traded market or support scheme explicitly designed to compensate market participants for providing energy security.

2.6.2. System reliability

Operating reserve

A STOR provider must offer a minimum of 3MW, deliver the full capacity within 4 hours of instruction, though typically response time are between 10 and 30 minutes, and provide the full output for at least 2 hours. The slower response times allow a much wider range of assets to be used, thus increasing competition. The temporal requirements may be prohibitive for some storage technologies (National Grid, 2015). The 'flexible' service under STOR which accommodates more variation in terms of availability, discharge duration and timing is more suited for storage technologies.

Frequency control

Storage is beneficial as it can provide both positive (additional generation or reduction in demand) and negative (additional demand or reduced generation) balancing power to the market. Storage, particularly electrochemical storage, is capable of providing "synthetic inertia" due to its fast response times and, unlike conventional fossil fuel generator, it does not have to be synchronized beforehand. A number of storage technologies, particularly the fast responding, are capable of providing frequency regulation. Additionally, storage is also capable of providing voltage support. The report differentiates between Primary Frequency Response (FR) and even more rapid response time requirements for Enhanced Frequency Response (EFR) services.

Black start

The black start generator is often a diesel generator. Storage can also play this role, and in combination with renewables generation assets can provide a zero carbon alternative. This service can be provided by using storage to provide power and energy to "energise transmission and distribution lines and provide power station power to bring them back online after failure of the grid" (Sandia National Laboratories, 2013). This requires storage to be places in a suitable location that is well connected to the power plant that is needed to be supported during a failure to be able to provide this service.

2.6.3. Network services

Network upgrade investment deferral or avoidance
Storage can be used to delay or avoid network investments as it can reduce the peak loading on the network and extend the operational life of existing assets. Storage can also contribute to managing power flows on local parts of the network to reduce the need to curtail generation which may otherwise be curtailed due to constraints on the local transmission network, distribution network, or individual generator grid connections.

Isolated grid support
The value of balancing and back-up services is higher in an isolated grid and could be provided by storage.

Uninterruptible Power Supply (UPS)
Storage technologies capable of fast response times are suited to acting as a UPS.

3 The societal case for storage

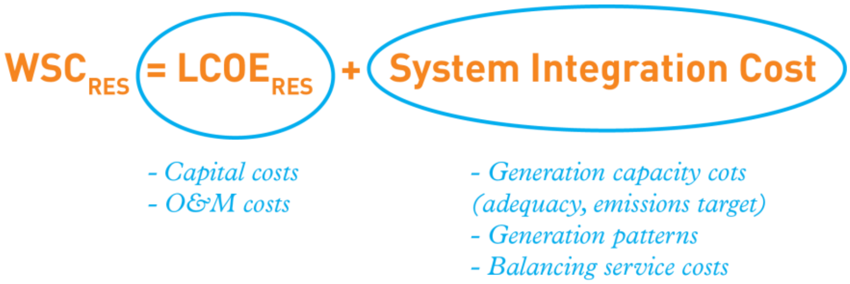
3.1 Summary

The deployment of storage can provide significant societal benefits by reducing the total cost of a future UK electricity system. The scenarios modelled show indicative savings of up to £2.4 billion per year by 2030. The benefits that storage can provide, increase with the stringency of future decarbonisation targets for the sector, and technology cost reductions that can be achieved for storage.

The analysis conducted takes a whole-system perspective to identify benefits from flexibility solutions such as storage for a future UK electricity system. This approach makes it particularly possible to quantify the system benefits and to identify the cost savings enabled by storage. It allows for the identification of both the demand for, and value of, benefits from storage along the value chain. The latter essentially captures the savings in operation costs, the amount and value of avoided investment in generation, transmission and distribution infrastructure (all netted off against the cost of storage).

In order to identify best solutions on a system level, a like-for-like cost comparison of generation, storage and other infrastructure assets has to be ensured. Care was therefore taken to include not only technology costs, but further costs that assets impose on the electricity system. For example, the Whole System Cost (WSC) of intermittent Renewable Energy Sources (RES), WSCRES, is calculated as the sum of the Levelised Cost of Electricity (LCOE) and the System Integration Cost. The System Integration Cost of renewable energy sources embodies costs associated with ensuring the security of generation capacity such as costs associated with providing balancing services (Imperial College London; NERA Consulting, 2015). The relationship between these variables is outlined in the following equation (Figure 2). A more detailed explanation of the modelling approach together with the input assumptions can be found in section 7.2.2.

Figure 2– Whole system cost as sum of LCOE and system integration costs

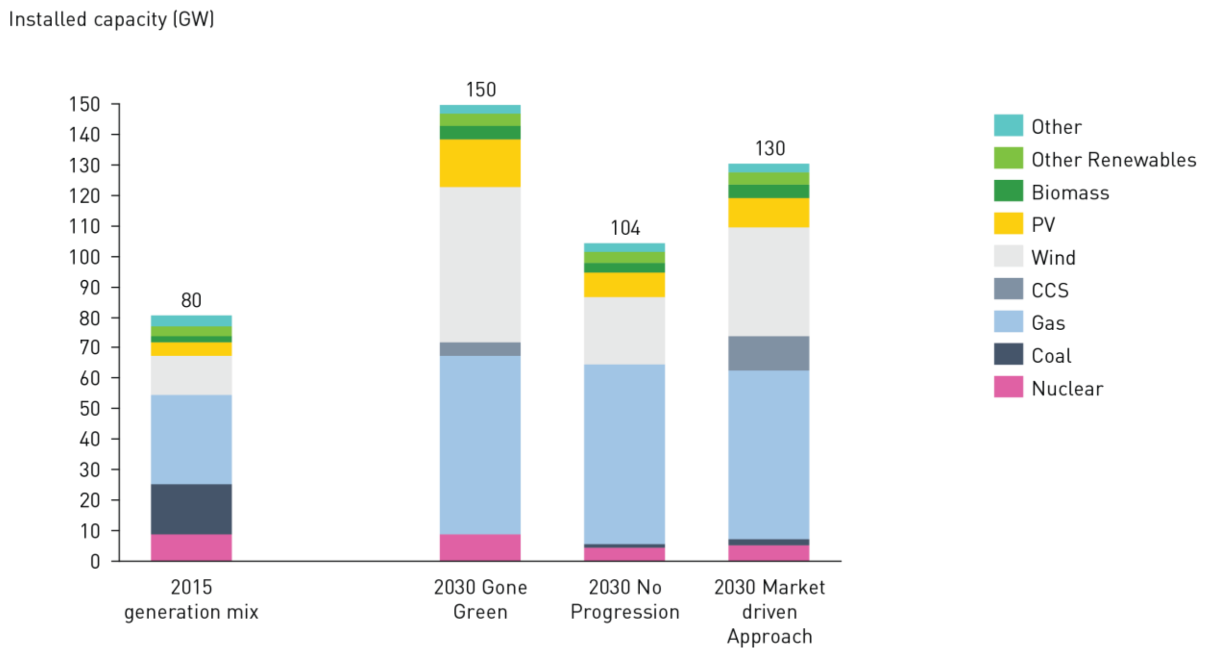


The widely referenced 'Gone Green' scenario published by the National Grid describes a possible pathway for the UK to meet its decarbonisation targets based on industry consultations. Analysis conducted for this report shows that even by simply 'retrofitting' storage solutions in 2030 for the electricity system described by this scenario, total system costs can be reduced by up to £2.4 billion per year. Retrofitting refers to relying on scenario assumptions for the generation portfolio of the electricity system in 2030 (basically without any new storage additions) and to ask how much savings may still be realised simply by then adding storage solutions to such a system. This result was contrasted with a model run based on the 'No Progression' scenario chosen because it most closely resembles a 'business as usual' approach amongst the four National Grid scenarios.

The use of the two National Grid scenarios made it possible to test wide ranges of key parameters between these two scenarios. For example, the 'No Progression' scenario assumes that the UK would effectively abandon further efforts to realise its decarbonisation targets for the electricity sector. A significant share of gas powered generation provides the system with a high degree of flexibility. This yields a much lower 'retrofit' value for the deployment of storage and the analysis shows that a robust carbon target is required for storage to provide a significant financial benefit to a future UK electricity system. Such a target will encourage the widespread deployment of low carbon technologies creating significant demand for flexibility services from storage.

A further 'Market-driven Approach' scenario developed for this report describes a least cost pathway for the UK to meet its decarbonisation target in 2030. It assumes the early inclusion of storage in the solutions mix for the future UK electricity system and a cost-benefit reflective market environment which encourages investment in an optimal portfolio of generation and network assets. Such a market environment could unlock additional benefits of up to £5 billion per year in 2030 compared to the 'Gone Green' pathway already without storage. A key driver for these savings is avoided capital expenditure (CAPEX) on generation as a result of better utilisation of the low carbon generation mix. The below Figure 3 shows a comparison of the 2030 generation mix described under the three scenarios. While the 'No Progression' scenario would expose the UK to a high dependency on fossil fuels and carbon emissions resulting from unabated gas, the 'Gone Green' scenario describes an unnecessarily expensive pathway to meeting the UK's carbon targets in particular due to low utilisation of deployed intermittent renewables. The chart shows how the 'Market-driven Approach' suggests a less "asset heavy" generation mix to reaching the same decarbonisation targets.

Figure 3 - 2030 installed generation capacity mix under the considered scenarios



The modelling results demonstrate how the contribution that storage can make to reduce the cost of the future electricity system becomes more significant with further cost reductions achieved for storage solutions. Cost competitive storage could reduce renewable energy curtailment and increase the utilisation of wind power, while reducing the cost and risks of fossil fuel dependency to the system. Figure 4 below puts the identified savings in perspective by showing a comparison of total annual system costs[4] for the three considered scenarios in 2030. It has to be stressed that these numbers can be interpreted as indicative only.

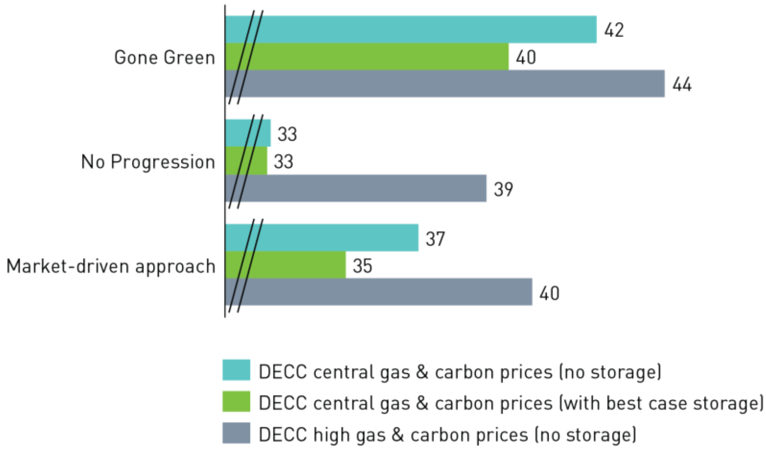
The 'Gone Green' and 'Market-driven Approach' scenarios describe alternative pathways to reach the UK's decarbonisation target. Comparing total system costs across the three scenarios demonstrates the benefit of creating a more cost-benefit reflective market environment (a key assumption for the 'Market-driven Approach' scenario) which would in particular encourage early deployment of flexibility solutions such as storage: The difference in cost between the 'Gone Green' and 'Market-driven Approach' scenarios is larger than between the 'Market-driven Approach' and the 'No Progression' scenarios despite of the latter describing a scenario with four times higher carbon emissions.

A 'business as usual' scenario with high reliance on natural gas as illustrated by 'No Progression' may be interpreted as the potentially least expensive, but highest risk option amongst the three scenarios. It is of least cost for the three considered sensitivities. However, comparing the effect of an increase in gas and carbon prices on system cost across the scenarios already, without considering further benefits from storage, shows how much more a future UK electricity system

[4] The costs illustrated in Figure 4 represent total annualised generation CAPEX and OPEX as well as annualised incremental cost of transmission and distribution networks. They do not include the annualised cost of the existing transmission and distribution network infrastructure. The numbers can therefore help to compare system costs between the scenarios, but absolute numbers need to be interpreted with caution.

under the 'No Progression' scenario would be exposed to the risk of fossil fuel price volatility and increased carbon prices.

Figure 4 - Total system cost comparison for considered base scenarios showing storage benefit as well as effect of high gas and carbon price assumptions



The results show that prioritising storage alongside further flexibility solutions is a 'no regret' option for the UK. To maximise benefits to the system, a more cost-benefit reflective market environment is needed which encourages the adoption of best solutions for the electricity system.

3.2 Introduction

The potential role and value of energy storage will come from unlocking benefits across the whole electricity system by avoiding construction of unnecessary generation assets, utilising existing assets more efficiently and deferring network infrastructure. These outcomes can be considered as benefits to society that will reduce customer energy bills if savings are passed on to them. This chapter explores and quantifies these societal benefits by evaluating the role of storage within the future electricity system given a range of future contexts and assumptions regarding the potential capabilities and costs of various energy storage technologies.

The discussion of system value in this chapter assumes perfect information and that there are no market, technology or commercial barriers that might restrict storage from being deployed or from capturing its full potential value. The true accessible share of this value will depend on overcoming any barriers and implementing projects with appropriate business models.

The systems models used in this analysis build on certain National Grid scenarios introduced in the summary of this chapter. Based on industry consultations, these widely referenced scenarios vary according to their sustainability and affordability. The two scenarios used for this analysis are the 'Gone Green' scenario which describes a pathway to meeting the UK's decarbonisation commitments for its electricity system and can be seen as the most ambitious decarbonisation scenario with highest required investment. Compared to the 'No Progression' scenario, which while abandoning the UK's decarbonisation target, describes a 'business as usual' approach which will require less investment. The scenarios were not chosen based on an assessment of their likelihood to materialise, but because between them they describe a range of possible developments which will likely contain the unknown future design of the UK's electricity system. This allowed for the underlying analysis conducted for this report to identify drivers and barriers to realising a least cost approach for a future UK electricity system that will at the same time be secure and low carbon. This 'Market-based Approach' scenario describes the possible societal benefits of encouraging best solutions for such a future electricity system, including from flexibility solutions such as storage, based on a more cost-benefit reflective market environment. The scenarios and key results for this chapter are discussed in more detail in Section 7.2 of the annex.

3.3 Value of retrofitted storage

The retrofit approach assumes that the electricity system in 2030 is developed without any new energy storage, which is a possible outcome if barriers specific to storage are not removed or incentives better aligned. If energy storage is then added to the system ('retrofitted'), its value to the electricity system will depend on the 2030 generation portfolio, carbon targets as well as on the cost of storage as compared to system alternatives. These will themselves be influenced by policy ambitions and available investment over the period between now and 2030.

3.3.1 Energy storage can provide most value to systems with strong demand for flexibility solution such as low carbon electricity systems

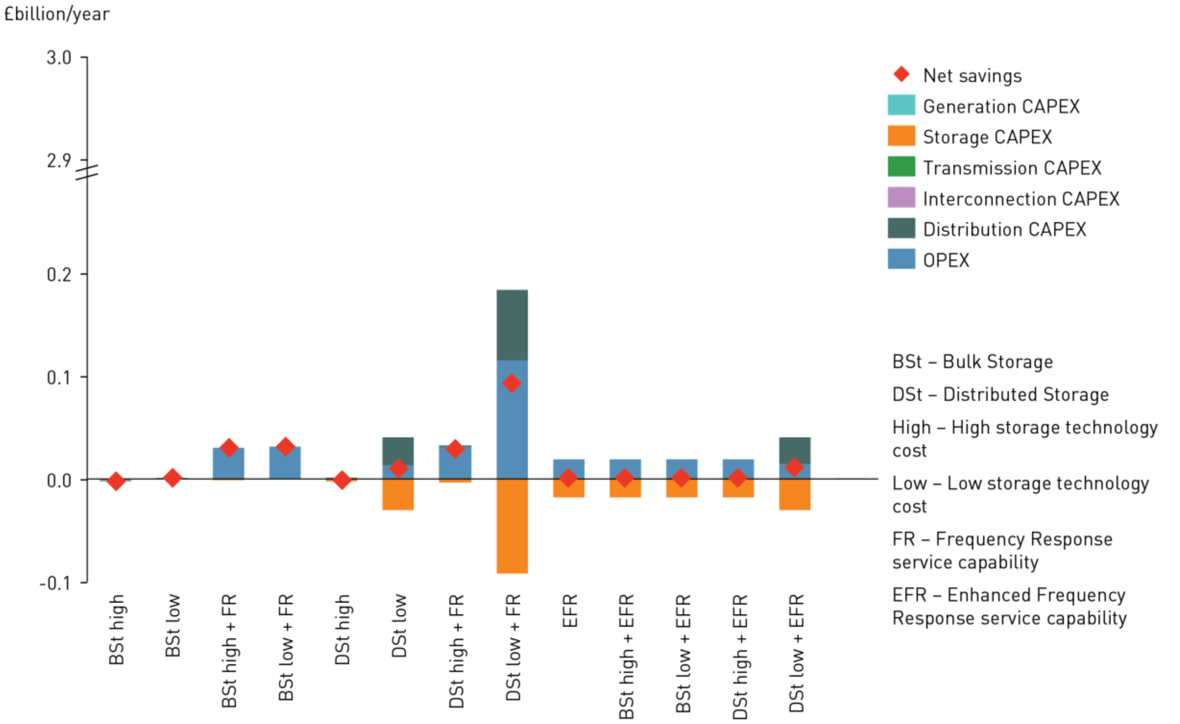
In the absence of strong carbon targets there will be less pressure to decarbonise the electricity system, and the 2030 system may see a large proportion of unabated gas both for baseload and flexible supply, with some renewable and nuclear energy depending on cost assumptions5. This is reflected in the National Grid's 'No Progression' scenario, which assumes weak carbon reduction ambitions and limited available investment. This report uses a 2030 decarbonisation target of 50 gCO2/kWh for the UK's power sector. The Committee on Climate Change identified this target as suitable in order for the UK to reach its 80% carbon reduction target by 2050 (Committee on Climate Change, 2013). This target will be achieved under the 'Gone Green' and 'Market-driven Approach' scenarios, whereas carbon emissions are assumed to still be at four times the target level by that time under the 'No Progression' scenario. The 'No Progression' scenario assumes a high penetration of flexible, unabated gas and low penetration of intermittent renewables resulting in a highly flexible system with few opportunities for energy storage to materially improve efficiency. The value of 'retrofitting' energy storage under these assumptions is low, at between c. £10m and £100m per year, predominantly from offsetting the use of a small proportion of gas for flexibility, along with some deferral of investment to upgrade the distribution network.

However, as a result of its high share of gas powered generation, the total system cost for this scenario is characterised by a high operational cost due to its significant reliance on natural gas. The relative cost performance of the overall system for the 'No Progression' scenario is therefore highly dependent on a future price for natural gas and carbon emissions. Under the 'No Progression' scenario the UK would also be significantly more exposed to financial risk due to gas price volatility as well to security of supply risks resulting from a higher dependency on imported fuel.

[5] Throughout this analysis we have used the full lifecycle cost of each technology as quoted in the Electricity Generation Costs 2013 (Department of Energy and Climate Change, 2013) , however, for nuclear this does not include additional costs like insurance. We have therefore carried out additional analyses that consider both the DECC stated cost of nuclear for projects starting in 2019 as well as an estimate of a higher nuclear cost when a share of the insurance cost is included.

Figure 5 below shows the annual cost savings resulting from storage in the 'No Progression' scenario in 2030 under a number of different sensitivities, with the 'red diamond' in each bar highlighting the net saving. The operational expenditure (OPEX) saving shown in the grey bars in Figure 5 relates to avoided fossil fuel costs. Sensitivities have been run for both bulk and distributed storage, they test the relevance of storage technologies meeting expected cost reduction targets ('low') and their ability to supply primary (FR) or instantaneous (EFR) frequency response services. As can be expected, the value storage solutions can provide for the highly flexible system described by this scenario is very low across these sensitivities.

Figure 5 - Annual cost saving across whole system resulting from deploying different storage types in the 'No Progression' scenario in 2030 against a base case of no additional storage



3.3.2 Energy storage can increase utilisation of renewable energy and gas CCS while reducing utilisation of CCGT and OCGT

Generation output from renewable sources such as wind and solar PV depends on the availability of the natural resources that drives them. However, wind and PV generation benefit from very low, or zero marginal cost of generation, so they will tend to remain in merit and continue to choose to generate even if the wholesale price became very low, or in some cases negative. Wind and PV are both very flexible in a downward direction, but their low marginal cost of generation means that it would be more efficient for the system to obtain downward flexibility by turning down other higher cost generation technologies instead when possible. Wind and PV are also able to provide upward flexibility if they are already operating at part load, but they are not able to provide upward flexibility beyond the natural resources which is available at any particular time. In the absence of widespread use of alternatives such as demand side response and interconnection, upward flexibility is currently primarily achieved through the flexible use of conventional generators, including OCGT and part-loaded CCGT.

While these conventional generators are effective in providing flexibility to integrate the intermittent renewables, in this mode of operation they are less efficient and hence more carbon intensive. For example, CCGT turbines operate most efficiently at full capacity, however in order to provide flexibility in output they must run part-loaded, so as to create 'head room' into which their output can be increased if needed. This part loading of CCGTs creates an additional problem for the system because it represents carbon emitting must-run generation which may result in even higher volumes of renewable generation being curtailed to make space to operate these inefficient, carbon emitting, part-loaded CCGTs. Similarly, OCGT plants, while very quick to respond, are inherently inefficient as a result of their open cycle design.

Such a system represents a significant opportunity for energy storage to provide both upward and downward flexibility using energy absorbed from existing generation assets based on their marginal operational cost. This could result in increased utilisation of renewable energy as well as gas CCS and coal CCS where carbon is priced, and a significantly reduced utilisation of CCGT and OCGT. The utilisation of renewables increases owing to reduced curtailment. The utilisation of any gas CCS and coal CCS on the system increases because the marginal operational cost of these technologies is less than that of CCGT and OCGT in the presence of a robust carbon price.

By reducing the use of gas needed for flexibility and by better integrating low carbon energy sources, the carbon intensity of the grid with connected storage added can also be significantly reduced, in some cases well below intended targets. These savings could either be shared with other areas of the economy, or alternatively, savings may be found by not exceeding the carbon target and instead taking a 'Market-driven Approach' to system design (discussed in the below section on the ''Market-driven Approach'' scenario).

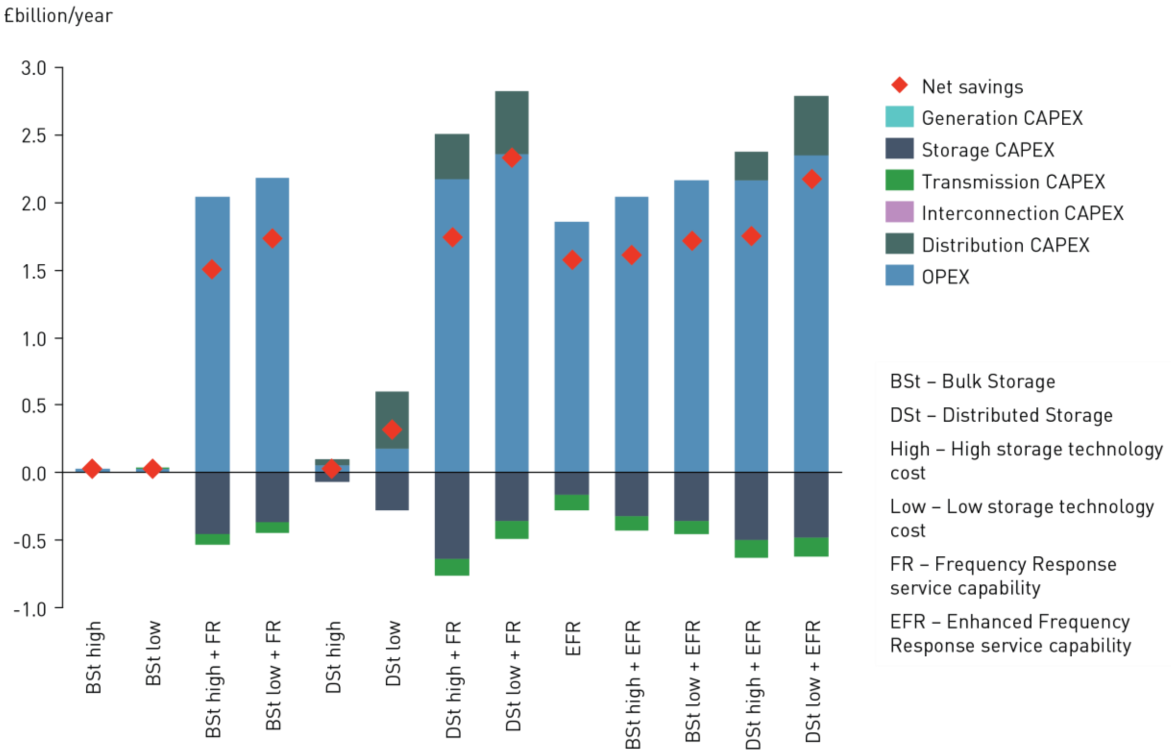
3.3.3 Energy storage could save up to £2.4 billion per year with strong carbon targets

In the presence of strong carbon targets there would be significant pressure for the 2030 electricity system to be significantly less carbon-intensive, which would need large-scale deployment of low carbon energy sources. These would include renewable sources such as wind and solar PV, gas CCS and coal CCS, and nuclear depending on relative cost reduction and technological readiness for large scale deployment. This is reflected in the National Grid's 'Gone Green' scenario, which assumes a world with strong carbon reduction targets and high available investment.

Due to the high penetration of renewables and reduced capacity of gas this system would be less flexible, which implies a greater role for energy storage to improve the operational efficiency of the system. Sensitivity analysis on the cost of storage shows that the potential value could be as high as c. £1.5 billion to £2.4 billion per year with fast responding storage, achieved mostly by reducing consumption of gas in CCGT and OCGT plants as discussed above. Another component of the total system savings for distributed storage is savings from deferring investment in the distribution network by reducing the peak load.

Figure 6 below analyses the annual cost savings from storage across a range of sensitivities. For the sensitivities, a single type of storage is considered by the model at a time, e.g., bulk storage. Two further factors are varied for the individual sensitivities, the cost reduction assumption for the considered type of storage and the assumptions around the services it will be able to provide. The results show that the costs savings are substantial for all sensitivities where the storage assets have frequency response or enhanced frequency response service capabilities (instantaneous). Such a service capability is more relevant for the system cost reduction potential of storage solutions than the type of storage which supplies it (bulk or distributed) or the cost reduction level achieved for the type of storage by 2030 within the considered range. Each type of storage was considered separately for methodological reasons only and for the future UK electricity system the deployment of an optimal mix of the different types of storage is to be expected. The estimates for each sensitivity can in this sense be interpreted as conservative.

Figure 6 – Annual cost saving across whole system resulting from deploying different storage types in the 'Gone Green' scenario in 2030 against a base case of no additional storage



3.4 Value of storage under a 'Market-driven Approach'

The ''Market-driven Approach'' scenario assumes that early and co-ordinated action is taken to ensure future network and generation investment decisions are made within a transparent and cost-reflective framework that takes full account of the role of storage and flexibility options. This will help to ensure that generation assets are installed and utilised so as to minimise costs across the system while achieving the same decarbonisation target for 2030 as for the 'Gone Green' scenario. Further details on discussed results for this chapter are provided in Section 7.2 of the annex.

3.4.1 Energy storage reduces renewable energy curtailment

As the market driven system is developed considering the proper integration of each component of the system, the curtailment of renewable energy sources is very low, even in the base case with no additional energy storage. In this case some system flexibility is provided by flexible OCGT. The addition of energy storage is able to further reduce or eliminate curtailment of renewable energy.

3.4.2 Storage reduces the need for OCGT capacity

When no storage is available, flexibility is provided by OCGT and part-loaded CCGT. Where energy storage is available at sufficiently low cost, it can partially or even fully displace installed OCGT capacity to provide flexible supply in a more carbon efficient way. The scale of this result is correlated with the cost reduction potential of storage – as cost of storage decreases it becomes more cost effective than new OCGT.

3.4.3 Low cost storage increases capacity and utilisation of solar PV and wind while decreases capacity and utilisation of gas CCS

In addition to displacing the installed capacity of OCGT, when storage is sufficiently inexpensive it allows for an increase in the installed capacity of solar PV and wind while reducing the installed capacity of gas CCS. This implies that in addition to providing flexible supply, low cost storage with solar PV and wind could provide a more cost effective means of supplying firm and dispatchable power than gas CCS. Fast storage increases capacity and utilisation of renewables, increases utilisation of CCGT and reduces capacity and utilisation of gas CCS. This is not in contradiction to the 'retrofit' case for storage considered for the 'Gone Green' scenario. In this case, for gas CCS capacity already available (and with plant CAPEX considered a sunk cost) it was economic to even increase utilisation rates. In the case of the 'Market-driven Approach' discussed here, however, a gas CCS plant has to compete on an LCOE basis.

3.4.4 Nuclear and gas CCS compete for additional baseload supply

Due to their own operating characteristics, nuclear and gas CCS would likely occupy similar niches in the electricity system, being best suited to supply baseload power. In the case of nuclear this is due to technical constraints, as nuclear output is not easily flexible with available technology. While gas CCS may be able to operate flexibly as technology develops, this will be less attractive due to the additional CAPEX and reduced operational efficiency of a CCS-equipped plant. This makes it less likely that gas CCS will be deployed for anything but baseload services when more flexible alternatives are available.

In the absence of storage, the deployment of gas CCS or nuclear in our model depends on their relative capital cost and assumptions around gas prices. This is reflected in sensitivities run for the systems model: When nuclear cost is low, and gas prices are in line with the DECC central or high scenario, then nuclear is favoured over gas CCS. However, if nuclear insurance cost[6] for operational risk specific to this technology is included in its levelised cost of energy, it becomes uncompetitive.

Furthermore, the maximum share of the system capacity that is provided by dedicated baseload supply (split between nuclear and gas CCS) is a relatively small share of the system total for the ''Market-driven Approach'', at about 16GW with no storage and as little as 5.6GW when low cost, fast storage is available, where 5.4GW of this is legacy nuclear.

When energy storage is available at low cost (c. 30% cost reduction from current levels), it is able to partially or fully displace gas CCS while improving utilisation of intermittent renewables, but only if this energy storage is also capable of providing frequency regulation. This implies that the combination of fast (and affordable) energy storage with renewables is more cost effective than gas CCS in providing baseload supply. Sensitivity analysis shows that this effect is largely independent of fuel price.

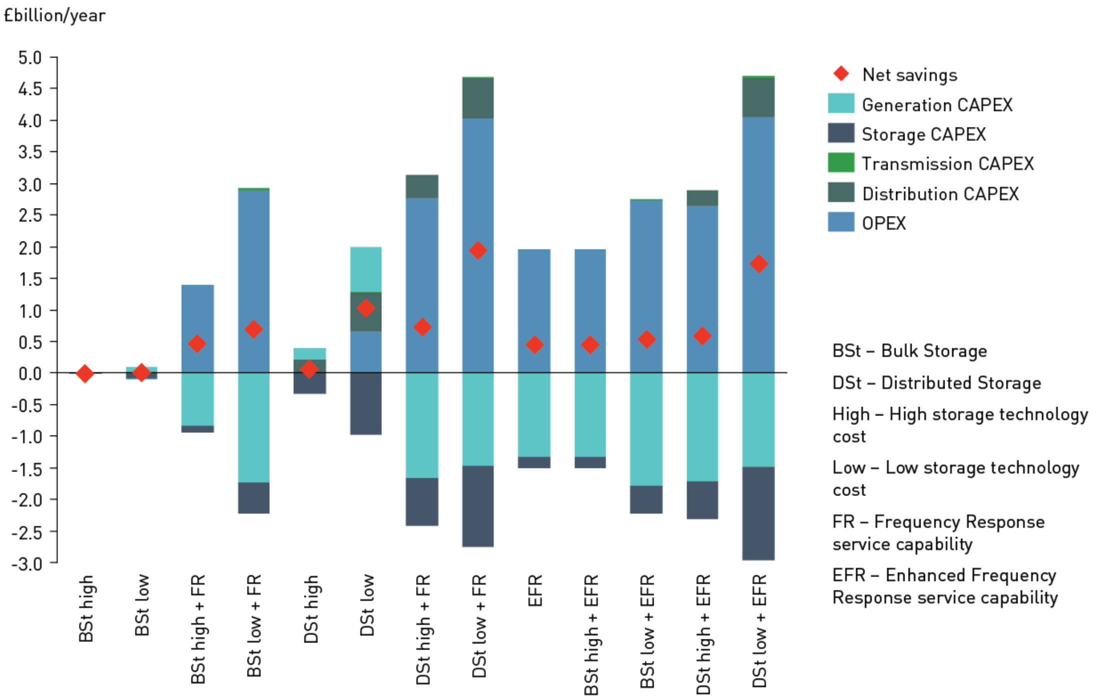
[6] Liabilities for operation risk – Further details are discussed in Section 7.2.8 of the annex

3.4.5 Energy storage can save up to c. £2 billion per year in 2030 in addition to £5 billion from system optimisation

There are significant opportunities for net cost savings available from optimising an electricity system which includes energy storage. The modelling undertaken for this report illustrates that net savings may range from a few hundred million to about two billion pounds per year across sensitivities run for different types of storage and assumptions for its cost and capabilities. The majority (c. 90%) of system cost reductions are from avoided fuel costs which result from a reduced need for gas CCS, as well as some additional savings from avoided/delayed investment in the distribution network made possible by storage. To enable these significant fuel savings, investing in storage and additional renewables assets is attractive (in addition to utilising existing generation capacity more effectively).

Additional value is apparent when considering the difference between a market where barriers for specific novel solutions such as storage are removed early and cost-benefit reflective solutions are encouraged early on, as compared to a less transparent market for which storage solutions would only be 'retrofitted' in the year 2030. As the 'Market-driven Approach' utilises assets more efficiently by design, by 2030 this scenario requires £5 billion per year less in investment to achieve the same grid carbon intensity of 51.9gCO2/kWh. Further savings available by introducing storage, as discussed above, are additional to this, i.e. total savings could be up to £7 billion per year for a coordinated system with low cost, fast storage available. Figure 7 below shows the sensitivities around the annual cost savings resulting from storage in the 'Market-driven Approach' scenario in 2030. The net savings from storage are substantial (at least £0.5 billion) in all sensitivities where storage solutions are capable of fast response type services and available at low cost.

Figure 7 - Annual cost saving across whole system resulting from deploying different storage types in the 'Market Driven approach' system in 2030 against a base case of no additional storage



4 The commercial case for storage

Chapter 3 discussed the value of storage to society through cost savings that can be achieved across the electricity system and that can be shared amongst all stakeholders: generators, network operators, third party service providers, and end customers. The underlying analysis showed that the substantial cost reductions that can be achieved for a future UK electricity system by deploying storage solutions are robust under a range of assumptions. However, this societal benefit may not be realised if industry actors do not have a viable business case to realise storage projects.

The two business case examples in this chapter are assessed from the perspective of an investor in a storage solution rather than from the societal benefit perspective used in the previous chapters. Due to the system nature of these services from storage it is important to also ensure that commercial incentives are aligned with system needs so that investors deploy storage in a way which is attractive to them while at the same time contributing to the societal benefit from storage which this report investigates. Otherwise realised solutions may benefit their owner at the expense of the general public resulting in higher rather than lower system cost.

This chapter illustrates both of these challenges. It discusses the kind of challenges industry currently faces in deploying storage solutions as well as possible solutions for the two business case examples. It also discusses commercial opportunities which may run counter to societal interest and explores how commercial and societal interests can be aligned.

The first business case explores opportunities for a wholesale electricity generator to increase the commercial viability of its operations by combining its wind generation assets with electricity storage. This case suggests key questions the generator will need to address in order to assess the viability of the underlying business case and to identify most attractive solutions. The importance of being able to provide layered services is discussed as is the relevance of where on the network to locate the asset.

The second business case investigates the potential benefits of combining distributed solar PV assets with storage. End customers are increasingly investing in rooftop solar PV systems, sometimes combined with battery storage. This trend is driven by substantial cost reductions achieved for both solar PV systems and large consumer lithium-ion batteries. The analysis first discusses the underlying business case from an end-customer perspective. It then examines the role aggregation of storage could play to increase the viability of distributed storage assets by additionally providing services for system needs.

The two case examples are of course not representative for storage opportunities in general. For example, both cases discuss opportunities for distributed storage while many current large scale and commercially viable storage solutions are for bulk storage applications.

Both business cases show that the deployment of storage can yield benefits today if market and regulatory barriers are removed. This is a major assumption, but shows the importance for policy makers to act now in order to allow industry stakeholders to deploy best flexibility solutions.

The cases also highlight the discussed importance of distinguishing between the societal benefit of a storage solution and the commercial interest of a storage developer. This is for example discussed in Business Case 2 for placing a storage asset behind the generation meter. This allows the owner of a storage asset to reduce his contribution to network cost recovery and retail tax charges. This would result in increased system costs if exploited at scale.

These examples illustrates that in order to capture the significant system benefits identified in the previous chapters, it is important to ensure that cost benefit reflective market environments are put in place such that commercial incentives are aligned with the broader societal objective to realise a low carbon electricity system for the UK that is affordable and secure. Given the significant societal benefits identified from the deployment of storage, it can be expected that even if some current and misaligned commercial incentives might be reduced under such more cost benefit reflective environments, this will overall significantly strengthen the commercial viability of storage solutions.

4.1 Business Case 1 – Energy storage with wind power

4.1.1 Summary

Storage can perform valuable services for a generator that holds wind assets within its portfolio. These services include wholesale electricity price arbitrage, integration of wind farm output by reducing imbalance charges, management of local network constraints and provision of ancillary services such as system level balancing and frequency regulation. A greater understanding of how these services might be able to increase revenues can help a generator decide whether there is value in investing in storage today.

While there is likely to be a primary driver for investing in storage, e.g. a local network constraint, the most valuable operation of storage assets will be in providing a number of layered services. The selection and number of services that could be layered by a single asset will depend on capabilities and cost of available technology, the extent to which the services are monetised through market mechanisms, and the complexity of managing such a project. Our analysis shows that layering services significantly increases revenue and in some circumstances may also reduce storage capacity degradation and so extends asset lifetime in comparison with provision of a single service.

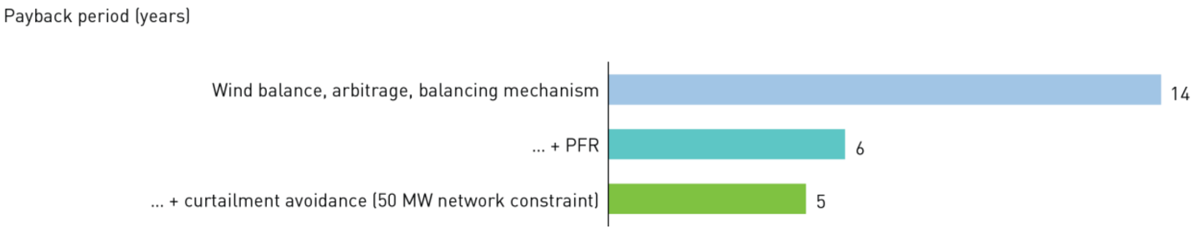
The services that storage can provide depend on its location in relation to a wind farm. For illustration our analysis considers a 100MW wind farm with 5MW and 25MW storage (separately) either located separately from it or co-located with it. When separated, the storage asset can provide the same services as when co-located with the exception of managing a local network constraint by charging up using the excess output and assisting the wind farm by reducing its imbalance penalties. It may also be commercially advantageous for a windfarm operator to reduce imbalance charges by deploying a behind the meter storage asset rather than to rely on the National Grid's Balancing Mechanism (BM) to meet his obligations. However, from a system perspective best outcomes are achieved if all storage assets compete on an equal basis for providing balancing services at lowest cost as compared to having operators use behind the meter storage to self-balance.

The presence of a local network constraint, e.g. an under-sized connection to the grid or heavy congestion at peak times significantly increases the value of energy storage on a unit basis. Network constraints may cause significant curtailment of wind output, which represents an opportunity to leverage storage to reduce export into the grid whilst simultaneously charging the storage system. Storage that is co-located with a wind farm behind a network constraint can absorb wind energy when it is produced and subsequently export it to the grid when the network is less congested. For the analysed example, the value that storage can provide to an investor is always greater in a co-located arrangement even though the value from separated operation is still significant. This stems from the ability to avoid or delay such a local network reinforcement as well as from exploiting the discussed commercial advantages of self-balancing. Given that our analysis sizes the storage asset relative to a wind farm, it does not consider the value of very large standalone storage assets (hundred MW scale) placed on the grid.

Provision of frequency response services is likely to be a valuable ancillary service if there is a lack of flexibility in the future grid, though accessing the full value will require changes to market structure. Currently, forward contracts for frequency regulation are entered into on a month-ahead basis, which limits the potential to maximise revenues from an optimal choice of services the storage asset provides. To understand better the value available from providing frequency response services from storage, our modelling considered the optimisation and dispatch of energy storage on a four hour basis.

The below chart illustrates how simple payback times may reduce for 25 MW storage asset collocated with a 100 MW windfarm depending on whether it can provide primary frequency response services beyond wind balance, arbitrage, and balancing market services, and finally how an additional local network constraint may further enhance the viability of operating such a storage asset. The example illustrates that storage can be viable with today's technology costs, assuming market and regulatory barriers are overcome. The estimated payback times should be interpreted as indicative only and depend on the underlying assumptions. Please refer to the annex for Chapter 4 - Business Case 1 on pages 92 to 100 for a more detailed discussion of assumptions and results.

Figure 8 - Payback periods for a 25MW storage asset when co-located with a 100MW windfarm depending on services supplied and local network constraint



4.1.2 Storage can provide a number of services to wind farm operator and system

Rather than being restricted to a single service, storage has the benefit of being able to provide multiple services, both to the wind farm operator and also to the wider system. These services within the context of this business case are described in Figure 9.

Figure 9: Services that could be provided by a storage asset either co-located with a wind farm or separated

Service	Description	Co-located operation	Separated operation
Wholesale electricity price arbitrage	Using market signals, the storage asset would charge (buy) at a low electricity price and discharge (sell) at a higher price	Yes	Yes
System balancing through Balancing Mechanism	The storage asset would be available to provide services through the Balancing Mechanism to help balance the system	Yes	Yes
Primary frequency regulation	The storage asset would be able to provide primary frequency regulation services to the system as an ancillary service	Yes	Yes
Wind balancing	The storage asset would aid wind farm balancing by narrowing contracted value and actual delivered energy	Yes	No[7]
Local network constraint management	The storage asset would improve integration of a wind farms where there exist local network constraints by shifting energy outputs in time away from peak times of congestion	Yes	No[8]

Each of these services can provide revenues to the generator if they are appropriately monetised, and there are examples where value that is created across the system may be accessed by innovative business models. For example, the generator would benefit from better integrating his output in the presence of a local network constraint, especially where it would otherwise be the responsibility or at the expense of the generator to reinforce this connection. However if the network becomes congested due to incremental changes within the network, then it may be the network operator's responsibility to invest in upgrades.

[7] Storage placed elsewhere on the system can only reduce imbalance charging if appropriate contracting arrangements are available, i.e. where imbalance charges are based on both the wind farm and storage rather than just the wind farm export meter.

[8] While a physically separated storage might have opportunities to provide network decongestion service depending on its location in relation to the constraint, here we consider curtailing and not losing the energy as the unique service provision a co-located storage could provide which a separated asset might not be able to provide.

4.1.3 Most value can be captured by layering services

One of the key opportunities for operating a storage asset in a commercially viable way is to deploy a single asset to provide multiple services. This can be done by providing different single services over time. However, it is also feasible for a single storage asset to provide more than one service at a given time by reserving given capacities of the asset for the respective services[9]. By 'layering' services within the bounds of contracting mechanisms, the storage asset can optimise the services it provides to maximise revenue based on the value of a service at a given time and its own state of charge. While there are trade-offs associated with delivering multiple services using storage, we find that the layered services such as primary frequency response are more than able to off-set the reduction from the base revenues such as arbitrage owing higher relative value.

Our analysis shows that in some instances it may also be the case that layering services actually reduces storage capacity degradation over time. This occurs where the value of availability to provide one service (but whilst not actually providing it) is higher than that for another service where service delivery is required. In the former case the storage would not be cycling but would still be generating revenue.

While layering could substantially broaden the range of viable business cases for a storage, there are still barriers to fully realising this opportunity. These include the development of technical capabilities to manage the storage asset and its interface with the system, contracting arrangements that fully allow layered services, and sufficient confidence from investors and project developers that larger revenues can be realised from such operation. It is also important to note that this analysis examined the case from a single installation's perspective and so there are considerations for larger scale deployment such as market saturation and impact of competition on price.

4.1.4 Co-located storage can avoid curtailment caused by a local network constraint

While storage located anywhere on the system can be of value to a generator who manages wind as part of its portfolio by providing system services, there are additional benefits to be gained in some circumstances by co-locating the storage with a wind farm. If there is a grid connection constraint, e.g. an existing but undersized connection given the size of the wind farm, the wind farm would have to curtail its output if a constraint prevents it from exporting to the grid, which will prevent available wind energy from being sold and reduces the revenues of the generator. This is distinct from curtailment due to local network constraints beyond its own grid connection, or system level curtailment deriving from system balancing, for which the generator is compensated through curtailment and balancing payments. This type of co-located storage is particularly useful to help defer new network capacity required to integrate greater wind generation by improving the utilisation of the existing infrastructure.

A co-located storage asset that is located on the wind farm side of the constraint can absorb surplus energy that would otherwise have been curtailed, and then discharge to the system when the network becomes decongested again. The value of this service increases with the size of the network constraint. The indicative results for this case show for example that a co-located storage asset of 25MW for a 100MW wind farm under a highly constrained network (50MW capacity) would

[9] The model allows for both types of layering of services. When modelling the provision of multiple simultaneous services, fixed shares of an asset were reserved for a contracted service for the contract duration in cases where a storage operator is paid for the availability of the asset (so that potentially idle capacity which is reserved, but may not be called upon cannot then be made available to provide another service).

enable a simple payback in ten years considering the costs of the storage system. This payback is estimated to increase to eleven years when the capacity of the network is higher (75MW), mainly owing to reduced revenue from curtailment savings.

4.1.5 Frequency regulation will require significant changes to market mechanisms

Storage could potentially earn significant revenues by providing primary frequency regulation, however, this will only be fully accessible if market mechanisms are changed. Currently contracts for primary frequency regulation are entered into on a month-ahead basis, which prevents storage from optimising its operation based on the needs of the system at the actual time of delivery. This arrangement means that the storage system is not able to get into a position in terms of state-of-charge that enables it to provide maximum benefit to the system when delivering frequency response services.

Our analysis shows that value increases significantly when contracts for frequency regulation can be closer to when the response is required, for example four hours ahead rather than month-ahead. Without this change, the sub-optimal provision of an attractive service reduces the overall revenue potential of the asset. From a commercial perspective, having a four hours ahead frequency response market enables the storage system to payback in six years (simple payback) by reorienting multi-service provision to maximise revenue, compared to a thirteen year payback for the scenario where there is an obligation to set service provision a month ahead and resulting in a part of the storage's capacity being reserved (20% in this case) for that time and which restricts the system to deliver multiple services optimally.

Analysis also shows that the value from primary frequency regulation is also highly dependent on the flexibility of the electricity system. An inflexible system will have a much greater need for frequency regulation, so prices from those services will reflect that. As system flexibility increases, the marginal value of frequency regulation decreases. On a large scale this means that as more and more suitable storage assets are deployed, the use of storage for frequency regulation may cannibalise its own value. Cost benefit reflective, but long-term predictable price signals can help to ensure an efficient allocation of best suited flexibility solutions. This will help to keep risk premiums to a minimum which investors in storage require to account for such uncertainty of future revenue streams.

4.1.6 Separated operation of storage is attractive with frequency service provision

Separated operation allows for the same service provisions that a co-located asset could provide except for reducing wind curtailment caused by network constraints and for helping the wind farm reduce its own imbalance penalties in relation to the energy system. This analysis has assumed distinct ownership models between these two ways to physically locate a storage asset. For the case of separated storage and wind assets, a third party owner of the storage asset is assumed to act in his own interest without a direct concern for the interest of the operator of the wind asset to improve his revenue or reduce costs. Our analysis indicates that the separated operation without primary frequency response (four hours ahead) is not very attractive with a payback time of sixteen years. Under this commercial model, curtailed wind energy cannot be exploited in the way this is possible for the assumed model for co-located storage. However, by providing frequency response (four hours ahead) a six year payback (simple) time can still be achieved for the 25MW storage asset.

4.2 Business Case 2 – Distributed storage with solar PV

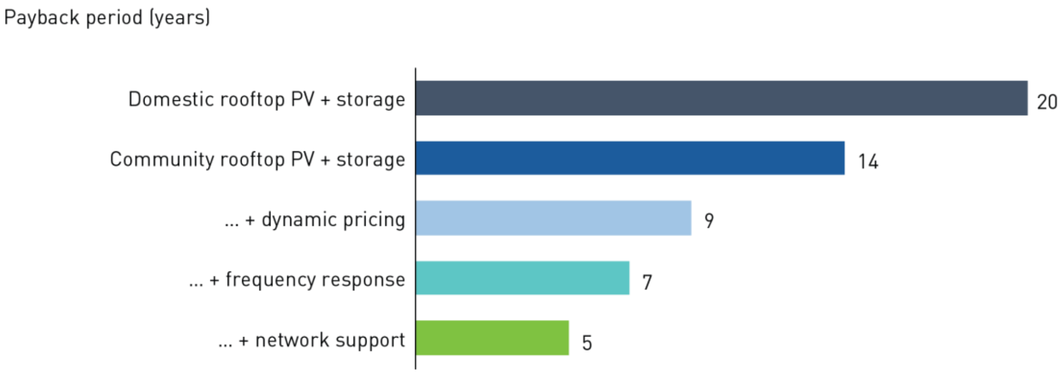
4.2.1 Summary

Business Case 2 explores the potential to deploy distributed energy storage with rooftop or community scale solar PV. Given rapid and continuing cost reduction of both solar PV and lithium-ion batteries in recent years, examples of such a domestic storage system are already coming to market, a high profile example of which is the Tesla Powerwall.

Small-scale energy storage can provide a number of services when integrated with the network and solar PV. These include household bill reduction through increased self-consumption of solar PV and retail price arbitrage (where available), demand management to alleviate network congestion and ancillary services such as primary frequency regulation. As in Business Case 1, there is likely to be a single objective that motivates an investment into a storage system, for example household energy bill reduction. This provides an opportunity for the market to develop varied products and services that can meet this objective[10].

Figure 10 below, shows the estimated payback periods resulting from distributed storage with solar PV, highlighting the benefit from using the storage asset to provide multiple services. Again, the numbers should be interpreted as indicative only:

Figure 10 – Comparative payback periods from distributed storage with solar PV when considering additional services



The simplest approach is standalone storage integrated with solar PV that provides a single service such as time shifting of energy. This storage system receives no information about the state of the network, and behaves 'selfishly' to reduce household bills. It is discussed in Section 4.2.2 that this operating model is not well suited for maximising the system benefit from storage. Analysis of this operating model at the same time indicates that it is not commercially attractive, either: A standalone storage installation that integrates with the household's PV system (but not with the network) has the longest payback of any configuration considered: over twenty years, considerably longer than the lifetime of the storage system. In the presence of a time-of-use (ToU) tariff, while the gap between cost and revenue is narrowed, the individual storage system still does not pay below twenty years using a simple cash flow analysis that includes cost of storage, and electricity

[10] As highlighted earlier in the report, an increasing level of consumer self-generation would also require an evolution of network pricing that enables more efficient use of the network by being able to allocate cost by actual use. It is acknowledged that such tariffs for domestic customers would require detailed consumption profiles which will be enabled by the roll out of smart meters.

retail market prices and feed-in tariffs. The increased value derived from a ToU tariff is also improved by increasing the variability of price signals throughout the day.

Beyond a simple standalone configuration per dwelling, larger community-scale units or multiple distributed storage devices could be aggregated across a regional group of installations. This aggregation would allow storage to manage multiple overlapping demand profiles. In some circumstances, aggregating individual assets improves the commercial viability of distributed storage by increasing the total possible revenue they can generate. Under a fixed tariff, the payback time of aggregated storage systems can fall to fourteen years when considering aggregation of multiple smaller storage assets.

Dynamic pricing through time of use tariffs is an example of a cost benefit reflective mechanism. It can further reduce the payback period. For example, using a representative ToU tariff, with peak hours included during weekdays and a flat tariff in the evening and weekends, the attractiveness of the aggregated configurations of storage further improves with payback falling to nine years.

Distributed storage can also be used to provide other services beyond the household, such as primary frequency regulation. However, this will require significant changes to how primary frequency regulation is contracted, and would necessitate the presence of a third party that can manage the distributed system. Estimated payback periods could be further reduced to seven years if primary frequency regulation is realised. Distributed storage can also reduce congestion within the local distribution network, and though this service would only be required for a few days per year, it could generate additional revenue to further reduce payback time. Estimated payback periods could be even further reduced to five years.

Provision of any services of greater complexity than the standalone configuration will require a third party that can aggregate or otherwise manage multiple distributed storage assets, enter into contracts with system participants and act as a trusted partner to attract any required external investment or financing.

4.2.2 Distributed storage is not attractive on a standalone basis at current prices

The simplest possible configuration of distributed storage is a standalone system that integrates with domestic rooftop PV and reduces household electricity bills. This is achieved by absorbing surplus energy from the solar PV system, when supply exceeds demand, and using it when electricity would otherwise need to be drawn from the grid. This reduces the total volume of energy that the household must purchase from a supplier and hence reduces bills.

The value that storage can provide in this configuration depends on the demand characteristics of the household, which are affected by household size and income. The analysis conducted considers nine representative demand profiles for combinations of one, two or three or more person households with incomes that fall into 'adversity', 'comfortable' and 'affluent' categories. Of these, household size is a great influence on the value that storage can provide, where larger households would expect greater benefit because of their higher consumption.

At current costs, this business case is the least attractive proposition of the configurations considered, with paybacks of over twenty years. Costs were derived from the Tesla Powerwall models suitable for daily cycling applications for this analysis.

Relating to the need to create cost benefit reflective market environments discussed at the beginning of this chapter, this case of stand-alone distributed energy with storage under the existing network tariff regime is not socially optimal in terms of reducing overall costs to all consumers. Under the current regulation, the consumer can arbitrage between the whole sale price (export tariff) and retail price of electricity (import tariff) where the latter includes energy costs, environmental and social levies, network costs and taxes. Storage in this case allows for greater reduction in purchase of electricity at retail prices (relative to only using distributed generation). This reduces revenues required to maintain and manage the grid[11] and could lead to higher retail prices for other end users.

4.2.3 Aggregation of distributed storage leverages varied demand profiles and can reduce payback time

Aggregation of distributed storage by a third party can unlock additional value by coordinating and optimising a large number of different demand profiles with a larger portfolio of storage and solar PV systems. Our analysis considers a community of 90 households behind a single point of connection with the distribution grid, with varying demand profiles and each with solar PV installations of 2kW.

This optimisation allows the storage unit to leverage other demand profiles in the community, which increases utilisation of storage compared with the single household case. For example, rather than using a household's own solar PV system to charge, when aggregated it can also absorb surplus energy from other households. These novel energy flows will lead to further reduction in energy that must be procured from the grid, which increases possible savings for the community as a whole.

This two-way energy flow between households with solar PV and storage is termed as peer-to-peer energy trading and this scenario represents a simplistic version of a P2P community network with storage and rooftop PV. While inter-household energy trading with optimised small scale storage is feasible, there will be commercial, technical and regulatory hurdles to be overcome to operationalise such a network.

Leveraging diverse demand profiles in a community significantly improves the revenue of the storage system. While providing the same demand shifting service to the consumer, the storage asset can provide a better commercial case that pays back in fourteen years. Since aggregation improves the utilisation of the storage system and returns higher value per unit of installed capacity, sizing the system down compared with a standalone system improves the commercial case.

4.2.4 Dynamic pricing through time of use tariffs can further improve the attractiveness of storage

The results discussed so far have assumed a flat electricity tariff. Under a dynamic Time of Use (ToU) tariff there is greater value available from using storage to reduce consumption at peak times. Recent innovation projects in the UK such as Low Carbon London have shown positive acceptance of such dynamic tariffs and potential for demand reduction through their use.

Using a representative ToU tariff, with peak hours included during weekdays and a flat tariff in the evening, the attractiveness of the aggregated configurations of storage improves. While the payback

[11] Investment into networks would be still required to cover peak demand under a worst case scenario of zero supply from distributed generation and so this is unlikely to reduce in costs without energy storage and cost reflective non-static price signals that could help shave peaks and consequently defer reinforcement. Currently the cost recovery is based on a volume/kWh based tariff i.e. based on energy consumed and since storage reduces the consumption ultimately in combination with distributed PV, the cost recovery reduces.

time in the standalone case still remains greater than twenty years, payback time in the aggregated case falls from fourteen years to nine years for a smaller 0.6kW storage unit.

In addition to Time of Use retail tariffs, it may also be possible to use dynamic network charges to alleviate congestion, which would add additional value to energy storage. Currently, some UK regions use dynamic Distribution Use-of-System charges, however this is not widespread and often excludes residential customers. Furthermore the time of use element is not made available to retail customers who pay a fixed rate, so use this mechanism would require changes to how tariffs are structured.

4.2.5 Distributed storage can support the system by performing frequency regulation

Distributed storage in households is technically capable of providing additional system level services, including primary frequency regulation. By expanding and layering the services that storage can provide there is significant potential to increase revenue and commercial attractiveness.

In order for distributed storage to perform frequency regulation, it is likely that a third party operator or aggregator will be required that can enter into appropriate service contracts with National Grid, as entry thresholds for provision of services are typically in the range of megawatts, and hence householders will either not be permitted or will not have the capabilities to do this themselves. Furthermore, it is likely that material changes will need to be made to how far in advance frequency regulation is contracted, as storage can provide most value when it can respond near to real-time to the needs of the wider electricity system.

The additional revenue for storage systems available from frequency regulation adds almost 50% to base revenues, which result from cost savings from demand shifting and subsequent reduced grid electricity purchase. Providing frequency regulation and generating additional revenues does not take away from base cost savings, which highlights the potential to optimise a storage asset to perform multiple services without having to forego revenues.

The trend of improved utilisation continues when performing multiple services, which also has implications for asset sizing. While larger storage assets generate more revenue, they also do so at a higher cost, which reduces overall viability. Using the 0.6kW battery unit to additionally provide frequency regulation brings down the payback in our simulations from nine to seven years.

4.2.6 Distributed storage represents an opportunity for network operators to manage network congestion.

The electrification of heat and transport and distributed generation in particular are contributing to the increased congestion of distribution networks. As such it is necessary for Distribution Network Operators to upgrade their networks, or look into novel approaches for deferring or avoiding this investment. Distributed energy storage may be able to alleviate congestion in the network by shifting energy flows away from peak times[12].

[12] UK Power Networks leveraging their "Low Carbon London" (LCL) project will be using DSR to replace traditional reinforcement schemes planned in their network as per their RIIO ED1 business plan. UKPN notes in the LCL learning report for industrial and commercial customers that distributed storage can provide "an equivalent" role to DSR and additionally provide wider services. Transitioning this service to domestic customers would require mandated participation or effective aggregation and this is assumed in this scenario.

If a distributed storage system is aware of congestion in the distribution network and can modify its operation appropriately, then alleviation of this congestion can be seen as another service that can be layered. However, this does depend on this service being appropriately monetised in a business model that would allow sharing of revenue between the householders, any third party operator and the Distribution Network Operator. As services required to ease network congestion would only be expected to occur a few days per year, the storage system is able to provide this service without foregoing significant revenue from other revenue sources.

Providing network support increases revenue by a further c. 40% compared with a scenario where demand shifting and frequency regulation are provided. This highlights the additional value the storage is able to unlock even on top of other revenues at existing capacity. This revenue layering scenario is estimated to be the most commercially attractive across those considered in this analysis and would pay back in five years of installation due to the high revenue generation potential.

5 Suggested solutions to address deployment challenges

5.1.1 Summary

In Chapter 3 this report discussed evidence for significant benefits from the deployment of storage for realising a future UK low carbon electricity system. In Chapter 4, the report explored two example business cases to illustrate commercial opportunities for storage which already exist under current market conditions and at current technology costs. These business cases showed that unless current market, technology and commercial challenges are addressed, the UK risks a future under-deployment of storage and other flexibility solutions preventing the capture of the systems benefits discussed in Chapter 3. These system benefits from storage are worth up to £2 billion savings per year in 2030.

This chapter discusses general market, technology and commercial challenges which need to be addressed to allow storage to be successfully deployed. The suggestions are based on expert interviews the Carbon Trust conducted with industry, government and academic experts, as well as independent analysis. This includes a review of international experience with storage in California and Germany.

There was broad consensus among experts interviewed for this report that it is critical to address existing market challenges that storage faces today. Market frameworks need to more accurately reflect the value to the electricity system that storage and other flexibility services can provide, and create a more level playing field to ensure that the best solutions are adopted. Secondly, market frameworks need to better enable companies to supply services that cut across multiple and independently regulated markets. To enable this, incentives need to reflect the value of a given service to the electricity system as well as each stakeholder group's contribution to providing the service. Many of these changes could be implemented through revenue neutral policies.

Key commercial challenges include the need for industry to develop and test novel business models. This may include the need for companies in the electricity system today to develop strategies to transition to a strong position in a substantially changed electricity system. To engage in an informed debate with government on how relevant market frameworks should be adapted and to ensure storage solutions will be ready on time and at the required scale, industry should conduct selected test and demonstration projects. These projects should aim to test the viability of business cases underlying the provision of key services that storage can supply for all required industry players and under real world conditions. Such projects can provide companies with important insights into novel business models and also experience in collaborating with novel partners from different industries.

While the measures mentioned above will increase the revenue potential for storage assets, a reduction in the cost of storage and the de-risking of technology deployment are also important. The UK should focus its technology innovation support on areas of relative UK competitive advantage where this can help UK companies create jobs and exports in a high-tech sector with strong growth potential. Storage costs will also be reduced by overseas expertise and experience. E.g., East Asian companies have cut the costs of lithium ion batteries, driven by applications in the electronics and automotive sectors. However, a UK roll-out of overseas storage solutions needs government and industry to collaborate to adapt and test such solutions for the requirements of the domestic market.

The report discusses key market, technology, and commercial challenges that suppliers or users of storage technologies face in developing and deploying storage solutions for today's system. It provides insights into the relevance of these challenges and into underlying causes. Suggested solutions are provided at the end of each section.

5.2 Market challenges and possible solutions

5.2.1 Policy risk is a key factor for investors in storage assets

Future revenues of storage are linked to policy decisions which drive the need for flexibility services such as substantial decarbonisation targets. Concerns over the long-term predictability of relevant policies are a key risk factor for investors in storage assets. Such policy risk raises the financial returns investors require. This leads to under-investment in storage solutions from a societal benefit perspective and may result in higher costs for customers.

5.2.2 Failure to recognise externality benefits of storage to society

This report provides evidence for opportunities to reduce the cost of the UK's future electricity system by deploying flexibility solutions such as storage. However, unless a sufficient share of these positive externalities is made available to storage actors, business cases may not be viable and neither the general public nor industry can realise the full benefits of this opportunity. This means that unless these externality benefits are also sufficiently reflected in market prices, or alternative market mechanisms, the resulting under-investment in storage solutions will lead to a more costly electricity system.

5.2.3 Revenue cannibalisation risk

Storage assets can offer a wide range of different services, but the demand for these services is finite, so there is a risk that some sources of revenues may be eroded as further new storage assets are built. Investors have to take the risk into account that revenues from a storage asset may become lower than they expected when they made the investment decision.

5.2.4 Distorted market price signals are obstructing efficient investment decisions

Key stakeholders (regulators, network operators, and technology and service providers) do not yet share a joint perspective on the value or roles storage could have in the future energy system, or the most appropriate market structures and price signals required to incentivise efficient investment decisions. Parties who benefit from today's market distortions may view these perverse market price signals as unsustainable deterring investment, while parties who are discriminated against by today's market distortions may see the current market arrangements as uneconomic for investment. These market distortions cause unnecessary uncertainty and increase investment risk. As with other barriers discussed, this leads to under-investment in storage solutions from a societal benefit perspective and may result in higher costs for customers.

5.2.5 Operating across markets to provide multiple services is currently complex or not allowed

It is technically possible for storage to provide multiple services simultaneously. A storage asset can therefore be expected to be operated in the most profitable way possible if regulation allows the asset to be deployed for an optimal combination of services at a given time. However, when an asset is contracted to be available to provide a given network service, under current rules it may not be available to provide another, even though it might not be utilised in that time. Unlike for storage, this market structure does not have a detrimental effect on the commercial viability of operating conventional generation assets such as flexible CCGT as they are earning revenues from their primary service (generation) anyway, and would simply adjust their output to provide the additional service.

5.2.6 Lack of compensation for enhanced quality of ancillary services such as speed and accuracy of frequency response

Since deregulation, additional market mechanisms have been introduced to enable further required system services, e.g. STOR to moderate short term peaks in demand, the Balancing Mechanism to enable settlement of imbalances outside of forward contracts, and various mechanisms to manage grid frequency.

Assets within the grid then bid into these market mechanisms in order to deliver the required service for a given length of time and at a predetermined price. However, it is generally not the case that a single asset type is limited in its ability to provide a set of most commercially attractive services. In addition, most conventional assets that are contracted for these services do so in order to earn secondary revenue streams alongside their primary function (e.g. generation). For storage, these system services are key for revenue generation.

Storage assets are often better suited to provide these services than conventional assets. "Over a wide variety of scenarios and a wide variety of turbine models, studies have found that, on average, energy storage provides x2.5 the performance of a combustion turbine" (Strategen Strategies for Clean Energy, 2011). This is mainly due to the slower ramp rate of gas turbines, which means that if there is a sudden loss in generation capacity, the system operator must call on multiple gas generators to reach target capacity in a short time. Lithium-ion batteries, by contrast, are able to follow the frequency regulation dispatch signal more accurately than flexible CCGT, and with greater efficiency, yet this benefit is not captured in the value of frequency regulation services. The new "enhanced frequency market" service to be procured by National Grid in early 2017 is starting to address the need for establishing a market for faster response. As this market is yet to start operation, there is no indication currently on the potential level of compensation for this enhanced service.

5.2.7 Inappropriate use of network charges for storage

Under the current regime, Use-of-System charges at the transmission, distribution and system levels are shared between system users, including owners of storage assets. However, one of the key reason for deploying storage is to provide services to the network rather than to simply make use of it, e.g., by providing ancillary services. It can be argued that the current charging structure is not sufficiently cost benefit reflective, and therefore needs altering to be fairer to storage and other flexibility sources[13].

In some instances, network charges may be double-counted: For example, when charging the asset, owners of a storage system are required to pay a range of levies just like other end users when consuming 1MWh. When this MWh is later discharged back into the grid it will subsequently be consumed by another end customer who then pays the levies again on the same MWh of electricity. This double-charging of some network charges ultimately leads to higher system costs for end users.

5.2.8 Lack of integrated planning and consultation across different stakeholders

To maximise value from a given storage asset, it needs to provide services to multiple and independently regulated markets such as network services, services provided to operators of generation assets, and end-customer services. The UK electricity system has been designed such that different parties are responsible for different elements of the system: Essentially, DECC is responsible for overall policy direction (security of supply, cost reduction and low carbon objectives) and Ofgem is responsible for economic regulation and value for money for consumers. National Grid and the various Distribution Network Operators (DNOs) are then responsible for the day-to-day operation of the grid.

While this split of responsibilities has advantages, the lack of a single entity that takes a systems perspective around long term planning at the same time creates challenges when it comes to enabling storage solutions. The systems benefits of storage are distributed among many stakeholders and without a more 'Market-driven Approach' by the responsible government bodies it will be difficult to realise the full economic benefit from storage for the UK.

5.2.9 Possible solutions

- Reduce policy uncertainty by keeping policy commitments which are critical to the long-term planning of stakeholders to the UK's electricity system such as decarbonisation targets and adapt regulation in long-term predictable ways.
- Further align incentives to reflect the needs of a future electricity system and remove barriers to the deployment of flexibility solutions such as storage, so that the market can determine the least cost way to manage the system. E.g., introduce dynamic electricity pricing for appropriate customer groups so that the true cost of the electricity system is better reflected; allow a single storage asset to provide layered services.

[13] Treatment/classification of energy storage in electricity networks requires many considerations given the multitude of services it could potentially offer and the potential alignment of those services (terms of power flow) during either the charge or discharge cycle with the benefit at that point in time of the network it is situated in.

- Realise further societal benefits from the deployment of storage by providing industry stakeholders with a sufficient share of these benefits to make a wider range of business cases viable. E.g. there are several services that storage provides such as deferring/avoiding investments in network and generation capacity and improving cycling of conventional generation that reduces the cost to consumers, however there are no markets to compensate the storage developer for such services.
- Building on current government and storage industry efforts, it may be effective to set-up a multi-stakeholder task force with participants from government, industry and academia to develop concrete proposals on adapting market frameworks such that barriers specific to flexibility solutions are removed. Example proposals include: regulating storage and other flexibility solutions in a way fairly reflecting cost and benefits to the electricity network; allowing for the provision of layered services; reviewing network charging codes; and introducing dynamic pricing structures. An inter-governmental working group with members from all relevant policy and regulatory bodies may also provide a helpful platform to discuss/coordinate related policy proposals.
- Government should encourage a multi-stakeholder effort to create a roadmap for storage and other flexibility options in the UK. Such a roadmap would help to prioritise activities, coordinate action to realise them and help provide investor confidence in the long-term commitment of government to realise storage opportunities for the UK.
- A single point of contact in government on flexibility solutions who coordinates government activities related to storage would be helpful for companies involved in storage. This role could oversee the implementation of the suggested roadmap for storage on behalf of government.
- It is important to ensure industry adopts robust methods to identify the best solutions that address grid congestion challenges, e.g., by developing methodologies for DNOs to compare costs and benefits of grid upgrades against system-level alternatives such as investments into storage solutions. Developing common methodologies to define functional requirements and performance standards will help target technology development and develop detailed business cases.

5.3 Technology challenges and possible solutions

5.3.1 Limited experience of technology selection and system design for complex services

A large share of the value in grid-scale energy storage lies in its ability to provide a number of services. The example from Business Case 1 (Chapter 4), where storage is used to improve the economics of an onshore wind farm, shows the diversity of services that could be provided by such a storage asset.

The same is true for behind the meter applications as seen in Business Case 2, where rooftop solar may be better integrated with a small-scale local storage device. The demands placed on this storage asset may be significantly different from an asset for large scale network applications. Customers (residential or small business) would expect the asset to be optimised for their own benefit first, with additional system services provided where possible, which may not always be the optimal use of the asset from a systems perspective.

Current procurement processes have not yet matured to the extent where technologies can be selected for optimum function, partly because it is still difficult to clearly outline the requirements for a storage asset. The approach taken to technology selection so far has been to choose a well-developed technology and test its effectiveness for a new application, which can result in sub-optimal outcomes.

Since experience in developing projects for multiple applications is limited, there is little data available from real world test cases that could be used to select the most appropriate technology for specific needs. There is also a lack of advanced and relevant modelling tools that could be used to determine applications and benefits of storage systems. Ideally, such tools would be combined with real performance data to help project developers better understand technology capabilities and economics in order to make procurement simpler and more transparent.

5.3.2 Lack of standardisation of components and network interfaces

A lack of standardisation of internal interfaces of storage components currently leads to increased system costs and reliance on particular supply chain companies.

In order for energy storage to provide system level services, the system should be able to assess the current condition (including state of charge) and availability of any storage asset connected to the network. Similarly, the more data the storage asset has about the state of the grid (e.g. frequency or short-term balancing forecasts), the more easily it can respond flexibly to prepare itself to provide system services and prevent unintended consequences of its operation.

5.3.3 Lack of standardised testing frameworks

Compounding the lack of performance data is an associated lack of standardised testing frameworks that would enable the collection of robust and comparable data. Such frameworks would apply a common methodology across a range of storage technologies and present outcomes in a consistent and comparable manner. There is an added complexity with storage, however, as is necessary to apply testing frameworks to different technology types (e.g. mechanical and electrochemical) as well as different usage patterns

Without standardised testing frameworks, performance data that is collected would lack the context that would allow informed procurement decisions. The development of these frameworks is challenging, however, given the difficulties in understanding how different storage technologies degrade in relation to their usage profiles.

5.3.4 Lack of performance data

As there are multiple alternative grid-scale energy storage technologies, most of which are at an early stage of commercialisation, there is a lack of performance data that would enable better technology selection and system design, provide increased confidence to investors to make long term investment decisions, and encourage collaborative innovation.

In many cases, a storage asset which is deployed in an optimal way can be expected to provide multiple services, e.g. wholesale market arbitrage, grid balancing and frequency response. This will result in complex cycling behaviour as depth of discharge may vary for each cycle depending on the service provided. The effect of this behaviour on system lifetime and future performance is currently poorly understood, and where data is available technology developers may be unwilling to share it as it is seen as commercially sensitive. Asset lifetime is often not as long as advertised, which can result in significant replacement costs incurred by project developers.

5.3.5 Possible solutions

- Government should consult with industry to develop standardised performance testing frameworks and run grid scale testing centres that run tests using theses standardised frameworks.
- In areas of UK competitive advantage, where there is the potential for jobs and exports, the UK should fund technology innovation and commercialisation efforts.
- Further actions should be aimed at reducing the overall system costs of storage solutions, e.g., by standardising storage interfaces or by running targeted technology demonstration projects to test service provision of storage.
- To facilitate industry collaboration and learning, clear rules need to be put in place on how to share, manage and use data.

5.4 Commercial challenges and possible solutions

5.4.1 Storage may not yet be an attractive investment compared with other more established options

Chapter 3 discusses the significant benefits storage can provide for a future UK electricity network under a broad range of assumptions. However, a combination of relatively high cost of storage technologies, and low monetisation of storage services, makes many business cases challenging. Where a conventional alternative to storage exists, e.g., reinforcing a network facing a constraint, companies will likely choose to make investment decisions in favour of such a better known and lower-risk alternative.

5.4.2 Standard procurement frameworks for storage are yet to be defined, which increases complexity and cost of purchase

Lack of data and standardised testing frameworks were discussed as technology barriers. As a result of these, there is also a lack of standard procurement frameworks for energy storage that would allow potential users to deploy the storage solution most appropriate for their needs. This introduces additional complexity in new projects, increases commercial risk and therefore also cost of energy storage systems.

5.4.3 Lack of a diversified supply chain increases procurement risk

Similarly, the current UK supply chain for energy storage is not well developed, featuring only a small number of developers that are often also small, early stage companies. This also leads to increased procurement risk, both commercial and technological, where those with an interest in procuring have additional concerns around selecting technologies that are either inappropriate or inadequately developed, or that the storage developer will be unable to fulfil the contract.

5.4.4 Provision of multiple services complicates business models, which increases risk for investors

Traditional business models in the electricity sector are predicated around an asset providing a single service (e.g. generation) at a price that can be estimated for a known minimum asset lifetime.

However, the most likely business models for emerging storage technologies are likely to be based around the provision of multiple services over the asset lifetime. When linked with the aforementioned technical challenge around understanding the impact of service layering on asset lifetime, these factors complicate business models and increase risk for investors

5.4.5 Developers have no incentive to share commercially sensitive performance data

Some data collected by developers, e.g. around storage asset performance and degradation, would help develop the energy storage industry if shared. This data would allow benchmarking of performance across technologies, decrease project risk by improving transparency, and enable targeted innovation programmes aimed at overcoming specific technology barriers. However, as this data is often commercially sensitive developers are reluctant to share it.

5.4.6 Possible solutions

> Run joint industry programmes to demonstrate, de-risk and further commercialise prioritised storage solutions.

> Develop cross industry collaboration e.g. DNOs could increase collaboration with third party storage developers to provide required services.

> Develop frameworks that enable developers to share data without compromising their commercial positions e.g. anonymising data or focussing on areas of non-competitive collaboration such as that realised by the Carbon Trust's Offshore Wind Accelerator.

> Develop novel commercial propositions, including with input from adjacent industries, which may be able to make relevant contributions to storage, e.g. move to a service offer rather than a technology offer or centrally manage shared distributed storage assets.

6 Conclusions and recommended next steps

This report seeks to inform the debate on how flexibility solutions can enable the UK to realise a future low carbon electricity system that is more affordable and more secure. It identifies and assesses conditions under which such solutions can enable a material benefit to the UK, using the example of energy storage. The focus of the underlying analysis has been to investigate value drivers of storage rather than to predict outcomes, to identify barriers to realising benefits, and to make suggestions on how to address these barriers.

The results show that if the UK continues to work towards the decarbonisation targets for its electricity system, then storage can enable considerable cost reduction. However, to realise this benefit it will be important that government and regulators allow the market to select the best solutions. This in particular requires allowing storage to compete on an equal playing field by removing specific barriers storage currently faces. Many of these policy changes are likely to be cost neutral and require no additional funding from the government. It is beyond the scope of this report to make detailed policy proposals. However, the following points should in particular be addressed:

> **Align incentives and remove barriers** – Further align incentives to reflect the needs of a future electricity system and remove barriers to the deployment of flexibility solutions such as storage,

so that the market can determine the least cost way to manage the system. E.g. introduce dynamic electricity pricing for appropriate customer groups so that the true cost of the electricity system is better reflected; allow a single storage asset to provide layered services;

- **Monetise system benefits** – Realise further societal benefits from the deployment of storage by providing industry stakeholders with a sufficient share of these benefits to make a wider range of business cases viable. E.g. there are several services that storage provides such as deferring/avoiding investments in network and generation capacity and improving cycling of conventional generation that reduces the cost to consumers, however there are no markets to compensate the storage developer for such services.
- **Reduce policy uncertainty** – Reduce policy uncertainty by keeping policy commitments which are critical to the long-term planning of stakeholders to the UK's electricity system such as decarbonisation targets and adapt regulation in long-term predictable ways;
- **Engage broad stakeholder group** – Although storage can produce an overall cost saving for the UK, care has to be taken to engage a broad stakeholder group in adapting market structures as changes will affect organisations beyond the storage industry;
- **Demonstrate cost and performance of storage** – Facilitate joint industry projects to demonstrate cost or performance potential. Ensure these demonstration projects are backed up by a robust value case and that they directly feed into a discussion of policy/market changes;
- **Define performance and operating standards for storage** – Define performance and operating standards for storage solutions to provide guidance to new technology providers and build confidence with electricity system operators. This should include the technical performance of the storage asset and also standardised data transfer and communication protocols for efficient integration with the network.

Opportunities for storage-enabled savings mainly result from avoided fossil fuel costs, better utilisation of existing generation and network assets, as well as superior performance of storage solutions in providing required network services. Depending on how substantial such opportunities to reduce system cost via the deployment of storage are for a considered scenario, savings have been estimated to range from c. £200 million at best for the 'No Progression' scenario to up to c. £2.4 billion per year in 2030 for the 'Gone Green' scenario. For a third scenario called 'Market-driven Approach' systems savings of up to c. £5 billion per year in 2030 were identified from introducing a more cost-benefit reflective market environment. Under this scenario, a further £2 billion per year could be saved by including flexibility solutions such as storage to optimise system performance.

To capture maximum benefits for the UK, it is important to develop a clear and comprehensive strategic approach towards storage and other forms of flexibility in a co-ordinated effort by key government and industry stakeholders. Elements of such an approach are outlined for storage below.

Given that the deployment of storage impacts a large number of system participants, often with diverging interests, a multi-stakeholder task force should be convened with participants across government, industry and academia. This task force should develop concrete proposals for adapting market frameworks, which could otherwise lead to a sub-optimal deployment of storage. Such market adaptations might include: removal of regulatory barriers for flexibility solutions such as storage; definition of required services and introduction of standards for these services, and introduction or alignment of incentives such that a more level playing field would encourage industry to realise the best solutions for the UK electricity system. This should include the identification and removal of perverse incentives and should result in a measurable net benefit to the UK as demonstrated by the analysis underpinning this report.

To support this task force in developing such proposals, detailed insights into the viability of storage business models should be derived from UK-based joint industry demonstration projects to date, as well as from further experience from leading international markets for storage. If the viability of business models requires changes to market frameworks, then this should be validated through targeted new joint industry demonstration projects.

To coordinate the adaptation of market frameworks across the multiple and independently regulated markets relevant for storage, it would be effective to establish an inter-governmental working group with members from the relevant bodies. This working group could then consider the suggestions developed by the task force referred to above.

The approach will need to ensure that appropriate storage systems will be available for deployment in the UK. In so doing it would also enable the UK to capitalise on storage technologies and systems that have been proven internationally by adapting and testing them for the domestic market. Achieving this would further require the definition of appropriate performance and operating standards for storage technologies and network interfaces, including monitoring and measurement for distribution networks. It would also provide guidance to new technology providers, build confidence among network operators and stimulate the development of new supply chains.

This approach would integrate with existing UK energy, industrial and innovation policy while identifying regional deployment opportunities of storage based on varying system contexts across the UK system. By integrating with wider UK strategic policy, this approach could also develop technology commercialisation strategies to provide support to sectors where the UK has a competitive advantage, such as power electronics and controls or thermal storage. Implementing this approach as part of a focussed strategy would also enhance opportunities to collaborate with international partners and markets.

7 Technical annex

7.1 Chapter 2 – Trends, impacts and system level solutions

In order to properly evaluate the role and potential value of electricity storage, it is necessary to understand the context in which it fits. This chapter provides that context by discussing the key trends affecting the UK electricity system and their impacts. It concludes with a discussion of the role of possible 'system-level' solutions, such as storage, to adapt a future UK electricity system in an optimal way.

While a detailed treatment of the UK electricity system is beyond the scope of this report, a brief introduction to the key concepts that will enable more accessible discussion of the role of electricity storage is provided below.

7.1.1 The structure of the UK electricity system

Great Britain (GB) operates an electricity system that exists to fulfil one primary function: to ensure that supply and demand for electricity are perfectly balanced at all times[14]. Historically the GB system was publicly owned and controlled, with the Central Electricity Generating Board (CEGB) owning and operating most of the generation and transmission assets on the system. The CEGB sold electricity to 12 local Area Boards, which in turn sold it on to local customers. Each of these entities operated as a regulated monopoly.

From the late 1980s, a series of successive privatisation measures were introduced by the government to form new marketplaces that aimed to increase competition. Under this new market regime, generators enter into bilateral contractual arrangements with suppliers through a wholesale market, who then sell electricity to customers through a retail market. The result is that customers are able to choose their supplier, regardless of geography, and suppliers are able to choose where to procure their electricity supply.

Since the GB electricity system is of key national importance, it remains heavily regulated despite its market structure. Management and oversight of the system falls to three main actors: government, regulator and network operators. Across the GB network, the Department of Energy and Climate Change (DECC) and the Office of Gas and Electricity Markets (Ofgem) are responsible for national policy direction, for example decarbonisation or alleviation of fuel poverty, and economic regulation to ensure value for money for customers, respectively.

Transmission Operators own, maintain and develop the high voltage arterial transmission network infrastructure. In England and Wales, the Transmission Operator is National Grid Electricity Transmission plc, while in Scotland it is Scottish Power Transmission Ltd and Scottish Hydro Electric Transmission Ltd that fulfil this role.

Across the GB system, National Grid also acts as the System Operator, responsible for stable and secure operation of the whole system, e.g., by matching supply and demand and managing system frequency. National Grid also manages a number of market mechanisms, which are discussed below.

[14] In this context the term 'GB' is used to refer to the synchronous grid serving England, Scotland and Wales, and excludes Northern Ireland, whose grid is partially integrated with the Republic of Ireland.

Between the transmission system and end customers are lower voltage distribution networks, which are operated by Distribution Network Operators (DNOs). These are regulated monopolies that serve specific geographic regions, and which own, maintain and develop their distribution networks.

7.1.2 GB electricity market mechanisms

An understanding of the GB electricity system and the constraints on its operation provides useful context around why these mechanisms have been designed as they have. As a result of the unique characteristics of electricity provision – in that supply must continuously match demand with limited existing opportunities for storage or demand management – the electricity market contains a number of mechanisms that guarantee continuous provision of electricity while allowing for the competition and freedom of choice.

Furthermore, there is a wide range of generation assets on the system, each of which has its own particular characteristics. These are detailed below, split into those with a high marginal cost, where the incentive is for the asset to generate when economic conditions allow for desirable revenues, and low marginal cost, where the incentive is for the asset to generate as much as possible once it has been built.

High marginal cost generation technologies include:

- **Combined Cycle Gas Turbines (CCGT).** CCGT plants, can provide both a baseload supply at an efficient full capacity, or can be run partially loaded to provide flexibility but with a penalty to efficiency.
- **Open Cycle Gas Turbines (OCGT).** OCGT plants operate at low efficiency, but are able to respond very quickly to provide flexibility to the system.
- **Coal.** Coal plants are not well suited to be run as flexibility options and are sometimes prioritised to provide baseload supply in the merit order.

Low marginal cost generation technologies include:

- **Nuclear**. Due to the carefully moderated nuclear fission process, nuclear plants are highly inflexible, and are run at full capacity as much as possible. Nuclear generation has a high fixed and a low variable cost component which means that it is best suited for a baseload demand profile allowing it to run at a steady and high utilisation rate.
- **Solar PV**. Representing a small but rapidly growing component of the generation mix, solar PV produces electricity during daylight hours and is found in both large scale commercial and small-scale configurations where the large scale is for generation while the smaller scale is a mix of local consumption and exporting to the grid.
- **Wind**. Both onshore and offshore wind power are a significant share of the total renewable energy on the system. Wind power may be available (or offline) at any time depending on conditions.

7.1.3 System balancing

Suppliers enter into forward contracts with generators to ensure that they will be able to procure the electricity they need to provide to their customers. These contracts cover half-hourly periods at a specific point in the future, where suppliers and generators promise to trade an agreed volume of electricity for an agreed price, regardless of the wholesale electricity price at that time. These contracts are agreed based on forecasts of both future demand and the wholesale electricity price as well as other considerations of each party e.g. as part of hedging strategies or electricity trading for financial purposes.

However, given that it is impossible to forecast future demand to the accuracy required, National Grid operates a Balancing Mechanism that provides incentives for generators or consumers to compensate for any shortfall or oversupply – the difference between total contracted generation and consumption, based on forecasts, and the real outcome. This is achieved using a System Buy Price and a System Sell Price, which allow generators with a surplus and suppliers with a deficit to balance the system outside of the forward contracts. These prices are structured so as to minimise the need for balancing by providing less value than accurately forecast contracts. Currently, as part of the cash-out reform, the market settlement is being modified to a "single cash-out price" instead of a separate sell and buy price to better incentivise flexibility provision and improve the efficiency of system balancing.

While the Balancing Mechanism is able to balance the system on a half-hourly basis, the system still requires instantaneous matching of generation and consumption as well as careful management of the grid frequency, which is itself used to balance supply and demand. This matching is achieved using the Reserve Services, which consist of two primary mechanisms: the Fast Reserve and the Short Term Operating Reserve (STOR).

The Fast Reserve is the fastest responding service (within two minutes) and is provided by flexible or standby generators and large sources of demand that are able to flexibly adjust their demand or supply in response to signals from National Grid. The Fast Reserve exists to deal with sudden and unpredictable changes in supply or demand. National Grid guidance lists examples of this (National Grid, 2013):

- **TV pickups** – large swings in demand caused by synchronised activity (e.g. boiling a kettle) based around the end of a popular television programme
- **Unpredictable short term demand** Increases – e.g., due to unexpected sudden cloud cover that causes lights to be switched on
- **Short term frequency control** – where automatic response systems are insufficient to maintain grid frequency within tolerances, primary and secondary frequency control can be performed by the Fast Reserve

The STOR also gives National Grid additional measures to balance supply and demand though with a longer time horizon than the Fast Reserve – up to 240 minutes. Generators that enter into contracts with National Grid under STOR receive payments for being available to provide a service (availability payments), and are paid again if they are actually utilised (utilisation payments).

Grid frequency

The frequency of the GB electricity system changes continuously and is determined by the balance between supply and demand: frequency will fall if demand exceeds generation and vice versa. National Grid is obligated to keep frequency within ±1% of the nominal system frequency (50.00Hz) and everything connected to the system is designed to operate at this frequency. If the frequency is allowed to vary outside this prescribed limit then generators will trip to protect equipment, which could lead to system failure. Some flexible generators and large sources of demand are equipped to monitor system frequency and manage their own operation to act to keep system frequency within tolerances automatically.

7.1.4 Ensuring adequacy

The UK government's Electricity Market Reform programme included the creation of a Capacity Market, which aims to provide incentives to developers to ensure that there will be sufficient capacity on system to meet future demand.

The Capacity Market provides successful participants with a more predictable revenue stream with the hope that it will encourage more investment in new generation. Generators bid into the "pay as cleared' auction with the lowest price at which they would be willing to supply their capacity. The clearing price is then set by the most expensive generator required to achieve the total desired capacity.

The first capacity market auction took place in December 2014 for capacity to be delivered in 2018/19, though it is as yet unclear whether it will be able to encourage the desired outcomes. The clearing price for 2018/19 was set at £19.40/kW, significantly lower than the initial bid price of £75/kW. This low clearing price prevented new plants from winning contracts: 68% of the awarded capacity went to existing infrastructure, 26% to re-furbished plants and only 5% went to new-builds. However, owing to tight margins during the period running up to the capacity delivery timelines of 2018 onwards, there has been other tools such as Supplemental Balancing Reserve (SBR) introduces to retain sufficient capacity.

7.1.5 Network charges

Transmission and distribution network operators are responsible for connecting new assets, as well as operating, maintaining and upgrading their networks. Much of this cost is passed on to network participants in the form of network charges.

New assets that wish to connect to the network must pay connection charges, which are determined by the size and location of the asset. Operational charges are then levied on consumers in the form of Use of System charges. These charges are applied at the transmission level as Transmission Network Use of System (TNUoS) charges, and for the distribution network as Distribution Use of System (DUoS) charges, which vary by time and location. Additional Balancing Services Use of System (BSUoS) charges cover day to day operation of the system.

7.1.6 Trends in the UK electricity system

The way that electricity is generated, transported and consumed in the UK is changing in fundamental ways. The three drivers of the energy trilemma – security of supply, cost and carbon emissions – each point to a system that must undergo change in the coming decades.

As an island nation, the UK must take steps to secure its energy supply. With North Sea oil and gas reserves in decline, indigenous energy sources are being developed to avoid significant reliance on imports which could otherwise increase the risk of energy price shocks. Multiple options are available, including renewable energy technologies, nuclear energy generation and exploitable domestic shale gas reserves. At the same time, further improvements in energy efficiency can reduce demand.

Under the Climate Change Act (2008), the UK is also legally obligated to reduce greenhouse gas emissions by at least 80% against the 1990 baseline by 2050, which will require significant decarbonisation of the electricity system, as well as of the transport and heating sectors. Underpinning all these considerations is the need to ensure that end consumer energy bills remain affordable.

These drivers are causing a number of trends in the UK energy system, including large scale deployment of wind power, a shift towards greater distributed generation, the closure of large scale conventional plant, and changing demand profiles due to electrification and customer behaviour. These are each discussed in turn below, followed by an assessment of the various impacts that these trends will have on the UK's electricity system.

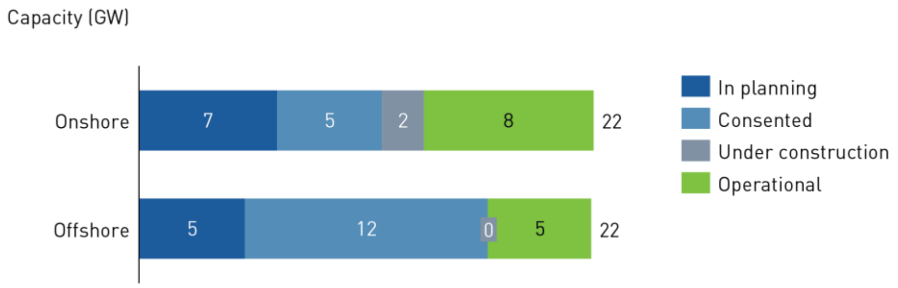
7.1.7 Large-scale deployment of wind power

In 2009 the European Union established mandatory national targets for Member States to meet the 2020 target of 20% of the EU's final energy consumption produced by renewable sources. This target was pooled among the member states, with the UK agreeing to a 15% share of energy from renewable sources by 2020 (European Parliament and of the Council, 2009) The majority of the improvements required for the UK to reach this 15% will need to come from the electricity sector.

Greater deployment of low carbon generation will be required in order to meet these targets. Wind power is expected to be an important part of a future low carbon generation portfolio because of the availability of particularly well suited UK sites. The UK currently has 8.3GW of onshore wind capacity and a further 5.1GW of offshore capacity in operation (RenewableUK, 2015). If all projects that are under construction, consented or planning become operational, the total UK installed capacity of wind power would rise to 44.6GW, evenly split between onshore and offshore (Figure 11).

However, given the significantly higher refusal rate of onshore as opposed to offshore projects – as of September 2015 8.2GW of onshore wind projects have been refused consent, compared with 0.5GW of offshore wind projects – it is likely that the total onshore deployed capacity will be smaller than this estimate. Even so, based on current plans alone the UK installed wind capacity will more than triple by 2030 (RenewableUK, 2015). Separate DECC forecasts also estimate that up to 39GW of offshore wind could be deployed by 2030 (Department of Energy and Climate Change, 2013).

Figure 11 - UK onshore and offshore wind deployment by state of development of projects in the UK Wind Energy Database (UKWED) as of September 2015 (RenewableUK, 2015)



7.1.8 Shift towards distributed generation

Growth of distributed generation has accelerated rapidly in the UK over the last few years owing to the introduction of feed-in tariffs, cost reductions of low carbon technologies, and changing attitudes towards self-generation. For example, the realisation of substantial cost reductions for solar PV has contributed to a fivefold increase of installed capacity for this technology in the UK between 2011 and 2014. It now represents more than 25% of all generation capacity connected to the distribution network (Department of Energy and Climate Change, 2015).

7.1.9 Closure of large conventional generation plant

The EU Large Combustion Plant Directive (LCPD) (European Parliament and of the Council, 2001) came into force on 27th November 2001 aiming to reduce emissions of acidifying pollutants, particles and ozone precursors from power plants. Generators were obliged to install new technologies to meet the emissions standards or opt out and close after operating for a maximum of 20,000 hours between 2008 and 2015.

The Industrial Emissions Directive (IED) (European Parliament and of the Council, 2010) superseded the LCPD at the beginning of 2016 and again gave power plants the option to implement further pollution control measures or to opt out, with a limit of 17,500 operational hours between 2016 and 2023. The IED effectively requires all coal-fired plants to install nitrogen oxide removal and flue-gas desulphurisation technology, an investment that will be too costly for many older plants.

These Directives will cause the premature closure of a number of UK coal-fired power stations and as a result the current installed coal-fired capacity in the UK has already reduced by 9GW since 2011 (Department of Energy and Climate Change, 2015). Although the closure of these coal-fired plants may not reduce the capacity margin to such an extent that there is a risk to UK security of supply, the additional closure of other large conventional generation may pose a threat if there is a lack of simultaneous investment in alternatives.

Recent influxes of cheap coal on the world market and increases in gas prices have also made it more profitable to generate electricity from coal than from gas, as evidenced by the recent decline in the gas load factor. The nationwide average load factor for combined cycle gas turbine plants has plummeted from an all-time high of 71% in 2008 to 28% in 2013 and has only just begun to recover, attaining a 30.5% load factor in 2014 (Department of Energy and Climate Change, 2015). As a result, a number of gas-fired plants have been mothballed or shut entirely and uncertainty in possible revenues for new-build gas-fired plants has made investors cautious15. Although this is likely to be a short term trend from which it is difficult to derive long term conclusions, it demonstrates the sensitivity of the energy system to changes in fuel availability and prices.

7.1.10 Changing demand profiles

Electricity generation accounted for 36% of UK carbon emissions in 2014 (Department of Energy and Climate Change, 2015). Savings must therefore be made in other polluting sectors, such as transport and buildings (heat), if the UK is to meet the target of 80% reduction of greenhouse gas emissions on 1990 levels by 2050.

Although there have been significant improvements in the fuel efficiency of both petrol and diesel cars since the introduction of the Climate Change Act, the transport sector accounted for just over a quarter of all carbon dioxide emissions in 2014, with passenger vehicles contributing the most significant share. Meanwhile, the residential sector accounted for 15% of all carbon dioxide emissions, with the main source of emissions being from the use of natural gas for heating and cooking (Department of Energy and Climate Change, 2015).

Electrification of heat and transport could significantly reduce carbon emissions if the electricity comes from low-carbon sources, and there are indications that electrification is likely to become a dominant trend. To enable and encourage electrification of both heat and transport, the UK government has implemented policy support mechanisms, including grants for Electric Vehicle purchase and the Renewable Heat Incentive.

7.1.11 Resulting system impacts

Each of these trends, among others, will result in a number of impacts within the electricity system that will need to be addressed. This section discusses the nature of these impacts, and sets the scene for discussion of available solutions in the next section. These impacts will not be the direct result of a given trend, but rather will likely occur together as a result of multiple trends.

7.1.12 Balancing supply and demand

While every generation asset faces unpredictable outages, many renewable energy sources are characterised by the partial unpredictability of their output due to the availability of natural resources such as wind or solar radiation at a given point in time. A common (and valid) criticism of many renewable energy sources is that supply may be available when there is limited demand, or there may be limited supply available at times of peak demand.

As wind power, both onshore and offshore, is likely to be the most widely deployed of the intermittent renewables in the UK, it acts as an instructive example. Grid impacts resulting from wind power have been manageable for the current low penetration, as existing back-up generators can fill the gap from forecasting errors, or as wind supply can be curtailed without significant adverse effects. It is anticipated that existing grid infrastructure could integrate up to a 20% share from wind, a level which is expected to be exceeded by around 2020 (Royal Academy of Engineering, 2014).

[15] Failure to secure capacity contracts and general fall in demand owing to several reasons are also factors that are driving mothballing and closing down of plants

7.1.13 Increased need for reserves

With greater integration of intermittent renewables in the UK network, more flexibility is required to support a stable power system, which must withstand greater variations of generation owing to forecasting errors and short-term events of over or under supply (Imperial College London; NERA Consulting, 2012). These short term variations impact the stability of the system and need to be limited immediately to keep frequency within system tolerances.

Mechanical inertia provided by large rotating masses of steam turbines and generators is critical for helping to damp these deviations and reduce frequency variation. As wind power is isolated from the grid through power electronics, its contribution to system inertia is limited, while solar PV has no contribution at all, although wind assets can be modified to contribute to inertia by utilising 'controlled inertial response' algorithms (NREL, 2012). Increased penetration of wind and solar, combined with the closure of large conventional plants under the LCPD, will have a direct impact on system inertia, which is critical to system stability and ability to respond to short term changes.

The total level of frequency response needed by the system is determined by the size of the maximum amount of generation that could potentially go offline in one go, for example, due to failure. The failure of a large generation asset would require significant reserves to come online very quickly to manage a sudden surge in frequency. After a 2011 review, the largest size of an individual generating unit or cluster was raised from 1320MW to 1800MW from 1 April 2014. While this allows larger generation units to connect to the transmission system, it also increases the additional frequency response that needs to be held in reserve by National Grid to ensure statutory frequency is maintained, which is estimated to cost an additional £160m per annum socialised across all customers (Ofgem, 2010). While the total response held is important, it is also important for the response to be delivered quickly to cope with increasing frequency change rates. For example, under its 'Gone Green' scenario, National Grid estimates that by 2024/25 it would also require a response rate of almost ten times that is currently required in order to bring frequency within safe limits (National Grid, 2014).

Beyond fast reserves, National Grid contracts a variety of operational reserves to provide real-time matching of supply and demand and to ensure overall system security. The increasing proportion of intermittent generators on the UK grid will drive greater and more variable requirement of reserves compared with current operation. Even with improved accuracy of wind forecasting and reduced variability due to dispersed sites, the increasing installed capacity of wind increases the need for frequency reserves.

While the variability of wind generation might affect reserve requirements, these are already present in the electricity system today to deal with generation downtimes and load fluctuations, so the forecasting error of solar and wind output plays a more important role in reserve provision. A further important reserve issue concerns ramp-rates, which have been an important driver of the roll-out of energy storage in California. CCGTs and coal plants cannot change output rapidly enough to keep pace with the rate of change of output of large solar (especially) and windfarms.

7.1.14 Reduced efficiency of conventional plant

Increasing penetration of solar and wind will displace conventional plants such as gas and coal and push them further down the merit order owing to marginal cost differences, with gas being affected to a greater extent than coal. This means that plants that traditionally provide baseload must endure quicker ramp ups and downs, more start-ups and greater overall cycling. This form of operation has negative consequence for these plants through higher maintenance costs, greater wear and tear, shorter lifetimes and greater environmental impact due to lower efficiency and higher emissions per unit output.

There are examples in the USA where existing installed capacity of gas is insufficient to offset wind generation and requires coal to be called in to perform more cycling, which significantly increases emissions due to the incompatibility of coal plants to such operation. While this highlights that there are negative consequences in terms of increased cost and emissions, studies generally show that renewable energy sources can more than offset this increase by avoiding fuel use (NREL, 2013).

7.1.15 Declining capacity margin

The capacity margin is a crucial element of an energy system that must ensure security of supply. It is defined as "the level by which available electricity generation capacity exceeds the maximum expected level of demand" (Ofgem, 2014). While the current capacity margin is viewed as sufficient to handle shocks, there are several factors that will adversely impact the capacity margin in the medium and long term (as discussed previously in this chapter).

The closure of large plants owing to policy directives such as LCPD and IED, a significant portion of nuclear fleet reaching the end of operational life, and the reducing profitability of conventional gas generation is expected to tighten the capacity margin to 2030. The capacity market was designed to alleviate these issues (from 2018) and is intended to provide revenue streams for capacity provision, but it is as yet unclear as to whether this mechanism will encourage construction of sufficient new generating plant.

7.1.16 Localised distribution network impacts

When distributed generation is connected to the distribution network in large volumes it can cause local network impacts. Reverse power flows and possible congestion are problematic for the distribution network, which was traditionally designed to passively distribute power from the transmission system to the end customers. Additional protection measures and a potential move to a more active network management, such as that operated at the transmission level, would be required in order to incorporate a large number of distributed generators.

Congestion in certain distribution networks may come about due to potential increases in clustered installations of distributed generators. As DNOs currently do not have widespread monitoring and control capability in their low voltage networks, constraining generation is not currently an option as a tool to alleviate network constraints.

There are also specific issues that are caused by certain low carbon technologies. For example, heat pumps experience their lowest efficiency on cold days, so require more electricity to supply the same amount of heat. The UK currently experiences its peak demand in the winter, which will be exacerbated by the use of heat pumps and could result in a significant under-utilisation of generation assets during the rest of the year. Another potential issue is due to the deployment of electric vehicles as part of ambitions to decarbonise road transport. Carefully implemented regulation and technology will be required to manage vehicle charging. If left uncoordinated, it is possible that the majority of users would recharge their vehicles simultaneously upon returning home from work, significantly adding to the evening demand peak. Alternatively, with dynamic tariffs, the charging loads can be shifted to periods of relatively lower demand and could be aligned with periods of renewable energy availability to improve the integration of electric vehicles into the electricity system.

7.1.17 Role of system level solutions

There are a number of approaches that can be used to address the system impacts discussed previously. Some of these are already widely used, for example conventional network reinforcement and flexible generation, while the relative merits, costs and applications of others, including demand side response, active network management, interconnection and energy storage, are still being considered. Many of these solutions can play overlapping roles, and so there is an element of competition between them, but similarly each could feasibly occupy a specific niche, or provide a range of services alongside the others. A flexibility solution will be selected based on its financial attractiveness and perceived benefits for a given service application.

This section discusses each of these approaches, including a description, benefits, limitations and a brief overview of their optimal role. Energy storage is discussed here at the same level of detail as the other system level solutions, and will be discussed in more detail in Chapter 3.

7.1.18 Conventional network reinforcement

Conventional network reinforcement is the 'business as usual' solution for network operators to ensure their grid infrastructure is able to cope robustly with growing demand. In the context of this report, conventional methods of reinforcement are triggered by two drivers: demand growth owing, for example, to increased electrification of heat and transport; and exceeding equipment ratings due to export from installed renewable generation capacity.

There are a number of key constraints that may trigger reinforcement (ENA, 2012), including:

- Thermal constraints, which can occur in cables or transformers if these are overloaded
- Voltage constraints, either headroom or legroom[16] depending on the direction of fluctuation, can occur across the different voltage levels i.e. low voltage (below 11kV), high voltage (11 kV) and extra high voltage (33kV or 132kV)
- Fault level constraints, which can also occur across the different voltage levels in the distribution network
- Power quality constraints: including harmonic distortions and fault current related issues

Conventional solutions that are used for addressing the constraints highlighted above include split feeders, transformer replacement, minor work for example constructing a new substation, or major works, including constructing new distribution transformers and circuits.

Benefits
Conventional reinforcement solutions have been used significantly by network operators and are seen as familiar solutions with well understood technical characteristics and economics. Aside from their perception as low risk, they are likely to remain a valuable tool to ensure the robust operation of the UK's networks. Most studies on the economics of smart grid solutions in the UK, especially for the distribution network, agree that conventional solutions will be required alongside smart solutions in the future for integrating renewables most effectively.

Limitations
While the solutions above will be present in some form alongside smart solutions, they also have many limitations that impede cost and quality of managing secure operations of the distribution

[16] Headroom and legroom refer to the difference between the line voltage at the transformer and the upper or lower statutory limit

network. With greater integration of distributed generation, deploying conventional solutions comes with costs beyond the capital expenditure of the equipment. The associated civil engineering works and disruption place both cost and inconvenience on network operators and consumers alike.

Network investments in conventional reinforcement typically have long lifetimes, and given the presence of multiple potential futures for deployment of low carbon technologies there is a real risk of creating stranded assets. If the predicted pathway does not materialise, their financial viability is at risk.

Optimal role

Conventional reinforcement will play an integral role in providing the network infrastructure to allow efficient integration of low carbon technologies into the electricity network. Greater use of smart grids, and associated technologies enabling demand flexibility, will allow for much better utilisation of existing assets thus reducing the frequency of grid upgrades. With more detailed understanding from pilot projects, standard templates for evaluating grid reinforcement will also consider smart technologies that will bring into the mainstream innovations currently in the periphery of network management and operation.

7.1.19 Flexible generation

Some conventional generators are flexible, for example CCGTs and particularly OCGTs. These generators are able to quickly adjust their output in response to system needs. While the Open Cycle uses natural gas combined with air to run a turbine to produce electricity, the CCGT additionally uses the heat from the gas turbine exhaust to produce steam to drive the steam turbine and generate additional electricity. This recycling of heat allows the CCGT to have higher levels of efficiency, for example the recent Carrington project runs at c. 57% efficiency (Parsons Brinckerhoff, 2014), higher than OCGTs which run at close to 40% efficiency (Foy, et al., 2014).

Benefits

The higher efficiency of generation makes CCGTs more efficient and less emissions intensive than OCGTs. With increased integration of intermittent renewable generation in the energy system, there has been a need for flexible and fast responding power plants to deal with load fluctuations and to contribute to grid stability and energy security.

The design of the CCGT system allows it to deal with rapid load fluctuations and respond to grid requirements quickly (in the order of minutes). Additionally, CCGTs are able to come online quickly and reliably from a period of being offline either for long or short periods of time to meet short term grid requirements, which other conventional power plants are either unable to do or are more expensive and emissions intensive to meet such operational needs. As a result of this, partially loaded CCGTs are often used to provide reserve services such as STOR. Also, since OCGTs comprise of only a gas turbine, they are able to achieve faster response times than CCGTs and therefore are utilised as peaking plants to provide back up to intermittent renewables and supply during high demand.

Also there are newer models of generators that allow them to operate at lower minimum stable generation (MSG) while also having the ability to respond quicker than the existing models installed which would be more efficient at integrating renewables than the existing models in use.

Limitations

While flexible generators offer advantages as discussed above, their place in the energy system is dependent on several market conditions such as fuel price, carbon price and prevailing structures for revenue. This dependency creates an uncertain market condition for these generators, as can be seen from the current energy scenario, and makes it difficult to integrate them into long term energy planning.

As the needs on the generator are variable and require flexible operation, there is an efficiency penalty owing to lower part-load efficiency of such assets. Beyond using more fuel to generate electricity, which has implications on carbon emissions and competitiveness, part-loading also increases emissions of particulates, pollutants and adds additional stress and maintenance requirements on the asset.

Optimal role

CCGTs will likely play some continuing role in the UK electricity system owing to their flexibility and also improvements that are made to render them even more flexible and efficient, though their future role is highly dependent on the policy structures surrounding the UK's energy market. More broadly, changing fuel prices (coal and gas), decreasing demand and depressed carbon prices are causing utilities to either mothball or prematurely close CCGT power plants in the EU (Caldecott & McDaniels, 2014).

With peaking plants historically relying on ancillary services (e.g. STOR) and reserve markets, the introduction of capacity payments is causing some changes in the UK energy market, i.e. payment for capacity beyond energy is seen to improve the economics of such generation plants. However, the results of UK's first capacity auction has not provided conclusive evidence to gain insight into the future role of CCGTs in the UK, given that many of the old CCGTs failed to secure an agreement, undermining their continued viability (Timera Energy, 2015). The new tool created, the SBR is providing an alternative revenue source through contracts as it is set up to keep operational power plants that would otherwise be closed or mothballed to improve security of supply giving a new, albeit temporary, lease of life to CCGTs.

7.1.20 Interconnection

Interconnectors are cables or overhead lines that connect different electricity grids. The GB system currently has four interconnectors providing a total of 4GW: one to France (IFA link - 2GW), another to Netherlands (BritNed - 1GW) and two to Ireland (Moyle and East-West - 1GW total). These links enable both import and export of energy to the different grids and also provide system services such as cross-border balancing and system support. There are several new interconnector proposals that are being considered at different stages including to Belgium, Norway, France, Iceland, Denmark and Sweden.

The interconnectors linking two power systems can either be High Voltage Alternating Current (HVAC) systems, usually deployed when the distance is modest, or High Voltage Direct Current (HVDC) technology for longer distances and when the systems operate at different frequencies. The UK's existing interconnectors are large sub-sea HVDC cables, which have advantages such as connecting two asynchronous grids (i.e. grids operating at different frequencies) and long distance transmission with low level of losses.

Benefits

Interconnection helps to address the intermittency of renewable generation by moving energy to other centres of demand in neighbouring grids when there is excess supply, and drawing from those grids when there is a shortfall from domestic renewable generation. In the absence of high levels of interconnectors, this intermittency impact on security of supply for the UK becomes more acute as the contribution of these sources increases to 2050. Enabling export of surplus renewable energy helps to reduce the amount of intermittent generation (mostly wind) that is constrained domestically and the associated constraint payments that are provided.

In terms of economic value, interconnectors can help to diversify the UK's energy supply. They can either reduce or raise UK electricity prices depending on whether they are a marginal cost supplier. If this is not the case then scaling up their capacity can enable substantial savings to customers. National Grid's estimates benefits up to £1 billion per year by 2020 to customers when interconnector capacity is doubled (National Grid, 2014). A highly networked grid across Europe also has implications for the cost of decarbonisation to achieve climate change targets. Studies show that more extensive interconnection in the EU could potentially reduce the cost of decarbonisation by up to €426 billion between 2020 and 2030 (E3G, 2013). However, international interconnectors may at the same time raise UK system cost as they increase the uncertainty of demand forecasts for UK generation capacity and reduce security of supply.

Limitations

As with other technologies that provide flexibility through adding capacity, the net societal benefit of interconnection is linked to several external variables. The most significant of these are the extent of renewable generation in the UK in the future, evolution of carbon and gas prices and sustained price differentials between connected markets. This uncertainly, combined with the high capital undertaking of building and commissioning an interconnector, makes planning and regulation of new projects difficult and risky.

Optimal role

While interconnectors could bring significant benefits, there are caveats to the figures as highlighted in the previous section relating to future energy scenarios and extent of convergence across EU energy markets. Analysis carried out for DECC estimates that an additional 5GW of interconnection "returned significant improvement in GB net welfare across most scenarios" and so would likely be the optimal capacity going forward to 2040 (Redpoint Energy Limited, 2013).

7.1.21 Active Network Management

Active Network Management (ANM) enables greater flexibility of network operation and more effective utilisation of existing assets. The deployment of ANM requires a combination of smart metering infrastructure, Supervisory Control and Data Acquisition (SCADA) systems and distribution and substation automation to enhance visibility and controllability of networks.

Active Network Management is sometimes also used in the context of network evolution to depict a highly controllable and fully monitored power grid that is capable of adapting to usage and is in essence "fully smart". However, here we refer to ANM as a specific technology that is being deployed to aid more cost-effective and efficient integration of renewables.

As the transmission system in the UK is considered "smarter" than the distribution system, owing to the real time visibility the system operator currently possesses, these concepts are discussed more from a distribution network perspective. However, ANM schemes are also being deployed to enhance management of the interface and aiding the Transmission Operators by providing voltage and reactive power support, as well as supporting congestion management.

Presently, there is no complete consensus on the exact collection of technologies (hardware and software) that make up an active network, so there are several variations of this concept being deployed globally. A good example of such a scheme is the one deployed on the Orkney network in the UK, which before deployment of active network management was restricted in its ability to integrate more renewable generation due to congested submarine cable circuits to the mainland. Against a conventional reinforcement cost of £30 million to install a new submarine cable, the £500,000 ANM scheme uses real-time automated controls to manage generation output while taking into account export capacity. In its review of the scheme in 2012, KEMA noted that the connection of an additional 7.7 MW of renewable energy was enabled by ANM and a further 20.2MW was contracted to be connected (KEMA, 2012).

It is also important to note that the more advanced ANM schemes have demand side response and energy storage integrated within them to ensure a robust and cost effective solution to integrating renewable energy and avoiding large capex investment from conventional reinforcement. The individual technologies present in such advanced schemes are discussed in more detail later in this section.

Benefits

The immediate benefit of ANM schemes is cost savings that can be achieved in certain constrained circuits, as the example of the Orkney project illustrates. While an average scheme might not deliver such magnitude of savings, they are still a cost effective tool compared with conventional grid upgrades. They also allow network operators to use their assets more efficiently, thereby extending their useful lives and deliver higher value for money for consumers.

Another significant benefit of ANM is the ability to connect more renewable energy sources at a lower cost and more quickly, given that large reinforcement costs are often passed on to generators and reinforcement is often time consuming. The flexibility that these systems provide also ensure a level of 'future-proofing', in that they can be adapted to future deployment of low carbon technologies such as electric vehicles without having to undertake further capacity through reinforcement. This flexibility provides an option value for network operators who are often faced with uncertain demand growth of low carbon technologies in their network areas.

Limitations

ANM is a relatively new technique in grid operation and management and is not suitable for alleviating all concerns. It requires integration of several other technologies to improve suitability and efficacy such as demand response and energy storage.

Optimal role

ANM has a critical role in ensuring the effective use of the different technologies that will better integrate renewables into the electricity system. ANM is therefore likely to play an important role as an enabler of energy storage deployments in electricity networks in the UK and in many cases will be an important pre-requisite to ensuring distributed storage assets perform efficiently.

7.1.22 Demand Side Response

Demand Side Response (DSR) is a mechanism that allows voluntary adjustment of power consumption in response to market price signals. Loads are generally spread across a range of different consumers of electricity, which are then consolidated by an aggregator. DSR can be used to reduce peak demand in electricity systems by moving customers' demand to other times of the day. DSR can be delivered by (i) reducing demand in response peak times, (ii) increasing demand to match supply surplus, and (iii) leveraging on-site generation to reduce grid power withdrawal. DSR can also be either automated and managed by a central aggregator or system operator, or left to the consumer to modify demand in response to price incentives. Storage is sometimes included as one of the possible assets to supply DSR. However, we will refer to DSR as a mechanism which does not include storage. This is because of the overall focus of this report on storage.

Benefits

In the absence of widespread storage, electricity supply must precisely follow demand, so the electricity supply of the grid must be sized to meet the peak demand, plus a safety margin. As DSR smoothens intra-day peaks, it reduces the need for additional generation and network capacity required for those peaks and thus reduces the cost associated with building such capacity. By reducing the need for additional generation capacity, it also has impact on the balancing services required to accurately meet demand and supply.

DSR also reduces operating expenditure and emissions of the energy system by avoiding expensive and emissions intensive plants that are operated to meet peak demand. In the UK, as in many countries, the plants with the highest marginal cost (and that are also more emissions intensive) are run to ensure sufficient capacity is there to meet peak demand e.g. OCGT or partially loaded flexible CCGT.

Limitations

While DSR has significant potential for rendering flexibility to the electricity system, deploying it is challenging. Estimating the true potential from diverse sources is difficult and often unreliable (especially in the domestic sector), making energy system planning around DSR complex. As DSR needs to be contracted from diverse consumer bases, the high level of segmentation adds to costs and complexity of deploying the resource (including setting up time–of-use tariffs).

Obtaining strong consumer engagement in DSR schemes is often a difficult task given wide ranging attitudes and acceptance of flexible energy use and this issue is further compounded by its dependency on other enabling technologies such as smart meters and also concerns around cyber security and data privacy.

Optimal role

The UK has a strong commitment to rolling out smart meters. This will enable the deployment of DSR and allow it to play an important role in a future energy system of the UK. However, given concerns around its reliability and the true costs of deploying large scale programmes, DSR is likely to co-evolve with energy storage as a complementary solution for providing flexibility to the energy system in the medium to long term.

Since DSR has several dependencies, especially consumer attitudes and willingness to participate, it is difficult to estimate the extent in the future, which a shortcoming of the technology. DSR from commercial and industrial consumers is likely to continue to grow and also evolve in providing different services to the grid while slower progress is expected in the domestic sector.

7.1.23 Energy storage

Energy storage enables different variable and intermittent sources of generation to be aligned to variable consumption loads. By allowing energy to be used produced and then used in the future, storage provides an important service as without which the energy generated must always equal energy consumed at every point in time. The most visible and important application to date of energy storage has been in portable electronics, however it is increasingly gaining importance in the transport sector through roll-out of hybrid and battery electric vehicles. Such has been its impact, that it is widely believed that without advanced energy storage technologies such as lithium ion batteries, the decade of smart phones, tablets and portable music players would not have been possible (Fletcher, 2011). As it has influenced the electronics and transport sector, energy storage is expected to play a vital role in the energy system by offering flexibility, improving planning and allowing effective large scale integration of zero carbon but intermittent energy sources such as wind energy.

There are several types of energy storage relevant to energy supply including strategic oil reserves, hot water tanks, and natural gas in pipelines and other reserves. While often using the more general term of 'energy storage', for reasons of scope this report focusses on "electricity storage" which is a form of energy storage that stores and outputs electrical energy using a variety of technologies from chemical batteries to pumped water storage. Pumped Hydro Storage (PHS) is one of the most widely used form of technology and one that has been in use since the 1920s originally as a centralised form of storage provision to the electricity grid.

Benefits

The current electricity system globally (barring a few countries) lacks large scale energy storage which means that electricity has to be consumed when produced and large expensive generation and network assets are built to deal with peaks that only occur several times during a year. Energy storage has several benefits across the energy system:

- Allows a reduction in expenditure on generation assets by reducing peaks and therefore only needing to meet average rather than peak demand
- Similar to above, storage can aid network reinforcement deferral by shaving demand peaks and allowing existing assets to be used more effectively
- It can help renewable generation become more "dispatchable" in the sense of helping to mediate intermittent production with variable consumption which reduces costs across the entire system
- Storage can effectively address issues caused by greater distributed generation in localised networks, such as voltage fluctuation and fault-current violations which conventionally would require reinforcement or curtailment

Limitations

Some of the key limitations of energy storage particularly for grid applications include:

- Losses associated with the round-trip conversion of electricity into storage and back to electricity can range from 10-45% across the range of technologies
- The price of storage technologies for specific applications are still relatively expensive compared with conventional generation
- The technologies are still maturing (excepting PHS) for a host of applications and some cannot be considered as commercially "ready to deploy"
- There are perceptions of high safety risks with certain battery technologies such as lithium ion and sodium sulphur

Optimal role

Energy storage is part of a portfolio of technologies that can provide flexibility to the energy system and therefore is expected to appear along with other system level solutions identified in this section. Advanced energy system modelling is required to better understand better the optimal role storage could play, this however is fraught with complexities given the uncertainty around the availability of other technologies and the generation mix of the future energy system. This report is an attempt to unpack some of the potential scenarios the UK could face and the impact storage might have in terms of cost across these scenarios.

7.1.24 Storage can supply services for a wide range of applications

There are many applications for which storage can be used at grid scale. This chapter explores a number of these applications that add value to a range of stakeholders and to the system as a whole.

7.1.25 Energy time-shifting

As fossil fuels act as chemical energy storage, the output of a fossil fuel fired power plants can be varied on demand to provide a continuous real time balance between electricity supplied and demanded. This is required to ensure a secure and high quality power supply, and as the UK transitions to a low carbon economy, with a larger portion of electricity supplied from renewable energy sources, maintaining this balance will become more difficult. Low carbon electricity generators such as wind, solar and nuclear are not dispatchable: wind and solar energy cannot be controlled by grid operators and nuclear energy is inflexible, operated instead at a constant capacity factor to provide a baseload.

The inclusion of storage within the system permits electricity to be supplied regardless of the real-time electricity demand, enabling "wrong time" electricity to be stored and used at a later time of sufficient demand.

The principle aim of energy price arbitrage is to store energy at low-demand and low-priced periods in order to discharge during periods of higher demand and price. This can benefit a renewable energy generator by shifting "wrong time" energy to a time when it is more useful and valuable. For storage to generate revenue from this application the price differential has to be sufficiently high to take into account inefficiencies within the system: no technology is 100 percent efficient hence more energy is consumed than generated in each cycle.

Storage technologies that are capable of efficiently storing large amounts of electricity are best suited as it is the amount of energy traded rather than the power rating of the system that contributes to the revenue.

7.1.26 Improving integration of renewable energy

Capacity firming. Storage can be used to mitigate fluctuations in output experienced with intermittent renewable energy, particularly solar and wind, thus maintaining the committed level of capacity. As well as improving the quality of the power supplied storage could reduce imbalance charges.

Reducing curtailment. Constrained or congested networks are one of the reasons to limit the amount of renewable generation that can be accepted on to the network and lead to the curtailment of renewable energy. For example, although a wind farm operator may be compensated for loss of revenue by curtailment payments this is an inefficiency of the system as it wastes electricity from a low-carbon source. Storage can be used to maximise the low carbon generator's output and simultaneously alleviate congestions on the network. Excess renewables is also curtailed generally (in absence of storage) when supply (minus must-run generation) is greater than demand.

7.1.27 Capacity reserve

To prevent disruption to the power supply in the event of the failure of generation, the grid operator contracts reserve capacity (or demand reduction) that is held on standby. National Grid maintains an operating reserve sufficient to replace the largest generator in the network, which is met by headroom on synchronised machines; additional actions taken through the Balancing Mechanism, and contracted reserve products such as Short Term Operating Reserve (STOR). National Grid procures a minimum of 1.8GW of STOR though aims to secure between 2.2 - 2.3GW if economic. A STOR provider must offer a minimum of 3MW, deliver the full capacity within 4 hours of instruction, though typically response time are between 10 and 30 minutes, and provide the full output for at least

2 hours. The slower response times allow a much wider range of assets to be used, thus increasing competition. The temporal requirements may be prohibitive for some storage technologies (National Grid, 2015).

7.1.28 Uninterruptible Power Supply

A number of facilities require an uninterruptible power supply (UPS) as power interruptions could cause injuries or serious business disruption, for example in hospitals or data centres. A UPS provides near instantaneous power in the event of a mains power system failure, and provides sufficient time for the auxiliary power system to become operable or for the protected equipment to be properly shut down. Storage technologies capable of fast response times are suited to this type of application.

7.1.29 Customer focused services

Increase self-consumption. Storage can be used in conjunction with on-site renewable energy generators to improve their reliability and utilisation, as well as providing reserve power in the event of grid failure. By increasing self-consumption, the consumer relies less on electricity from the grid and can reduce their electricity bills.

Avoidance of triad charges. Transmission Network Use of System (TNUoS) charges recover the cost for the installation and maintenance of network assets. For consumers with sufficiently large demand, they are half-hourly metered and TNUoS charges are billed using Triads[17]. Triads are the three half hour periods where demand in the UK is highest, these are not known in advance but typically fall during the evening peak demand in periods of cold weather, and the charges are in proportion to the electricity demanded by the consumer during these triads. Reducing the peak demand or homogenising the load profile of the consumer by installing a storage asset can avoid high TNUoS charges.

Time of use. In order to encourage a reduction in electricity demand at peak demand times, and reduce the associated stress on the network, utility companies may in future incentivise households to homogenize their load profile through time of use tariffs. Smart meters would provide energy companies with sufficient information to identify times of peak usage and charge higher rates. Similarly, customers would be charged a lower rate at off peak times, encouraging energy intensive appliances to be used when the demand on the power network is lower. Storage would reduce the disruption to a household's energy use pattern, charging when the TOU prices are low so that the household can continue to use electricity when the prices are higher without incurring the extra cost.

Across all of these potential applications, there are important considerations around impact on the overall network. It is therefore useful to consider the services in the context of evolved price signals that allow overall societal benefit while promoting customer choice. This can be achieved by ensuring that prices reflect costs and benefits of a service not only to a single market participant, but also to the overall system.

[17] Triad charges are National Grid transmission charges based on the average of three maximum demand readings across a year and are only applicable for half hourly metered sites.

7.1.30 Network upgrade investment deferral

Increased capacity requirements demand upgrades to existing transformers or power lines prior to the end of the designed service-life. New network equipment is designed to accommodate the anticipated future loading, thus uncertainty in future demand exacerbates the problem of asset underutilisation. Storage can be used to delay investments as it can reduce the peak loading on the network and extend the operational life of existing assets.

7.1.31 Isolated grid support

Isolated grids must function without connection to the power grid and its associated balancing services. Therefore all services required for a stable and reliable power supply must be provided locally. The value of balancing and back up services is higher in an isolated grid and could be provided by storage.

7.1.32 Frequency control

Frequency control is a rapid, short term service that keeps demand and supply in constant balance. In order to achieve this, National Grid tenders for assets that can provide frequency regulation (i.e. increase or reduce their supply or demand rapidly and at short notice) over various time scales. Storage is beneficial as it can provide both positive (additional generation or reduction in demand) and negative (additional demand or reduced generation) balancing power to the market.

Instantaneous reserve/spinning reserve. This is currently provided without remuneration by the inertia of large conventional plants. Storage, particularly electrochemical storage, is capable of providing "synthetic inertia" due to its fast response times and unlike conventional fossil fuel generator, it does not have to be synchronized beforehand. New wind farms in Germany are mandated to provide synthetic inertia to support integration of renewables. This approach may also be considered in the UK as wind penetration on the system increases.

Primary and secondary frequency response. Primary frequency response provides additional frequency control when the instantaneous reserve is exhausted and the frequency deviates from prescribed limits. A primary frequency reserve asset must supply the full contracted output (minimum 10MW) within 10 seconds of receiving instruction and sustain output level for 20 seconds. Secondary response then takes over from the primary reserve and must supply full output within 30 seconds of instruction and sustained for 30 seconds. Assets that provide primary and secondary frequency reserve have progressively longer response times and are capable of sustaining a certain level of power for a longer duration, hence a number of storage technologies are capable of providing frequency regulation. However, it is the fast responding technologies that are best rewarded for their service.

Voltage support. Voltages are not consistent across the grid and are affected by the local demand for active and reactive power. Voltage levels must be managed with the injection of reactive power at required locations to remain within the statutory operational limits. Electrochemical battery storages technologies require a power conversion system to convert the battery's DC energy to the AC power required by the grid, which can also provide dynamic reactive power compensation to the grid. Reactive power cannot be transmitted over long distances, hence this is an application for distributed storage.

Active and Reactive power

Components in an AC circuit supply or consume two different types of power: active (or real) power, which does useful work such as powering light bulbs, and reactive power, which represents the inaccessible energy stored within magnetic and electric fields within the circuit.

Reactive power is required to control voltage and overcome losses in the network. Too little reactive power and the voltage on the system is insufficient for active power to be supplied. Too much reactive power will reduce the amount of real power that can be transferred, as reactive power occupies a portion of the available capacity of the transmission line.

7.1.33 Peak shaving/load levelling

A power system has to be designed for the annual peak in demand, which in an inflexible system necessitates reserve generation and grid capacity that is seldom used and that has a low load factor. Load levelling or peak shaving is similar to arbitrage but aimed specifically at avoiding these peaks and flattening or homogenising the load profile. Storage can provide the additional capacity required at peak times by time shifting energy.

7.1.34 Black start

In the event of a total or partial transmission system loss of power an external source of power is required to restart larger generators and power auxiliary equipment. Once restarted these isolated power stations are then reconnected in order to restore the transmission system. The external power source is termed the black start generator and is often a diesel generator. Storage can also play this role.

7.1.35 Overview of storage technologies

Storage technologies have the ability to improve the flexibility of the network while providing efficient balancing and back-up services to intermittent renewable energy. These are expected to play a critical role in the decarbonisation of the electricity grid in the UK by improving the security of energy supply and the efficiency of the transmission and distribution networks.

7.1.36 Bulk storage

These technologies are primarily located in the transmission network to provide large scale storage and discharge of electricity according to the grid needs. The technologies covered here include:

- **Pumped hydro storage**, which is the most technologically mature of all the storage technologies considered and is also the most widely deployed by global installed capacity. Water in an upper reservoir which is pumped up from a lower reservoir to provide gravitational potential energy. This water can later be released down when required to drive a turbine in a similar fashion to a hydropower plant. The response time for pumped hydro systems are fast (or the order of seconds) and can achieve high ramp rates, but also have mechanical inertia when switching directions and hence cannot switch rapidly between charge and discharge.
- **Compressed Air Energy Storage (CAES)**, which uses electricity to compress air through a compressor and is which is then stored either in underground caverns or above ground

vessels. The stored air is then expanded through turbine-alternators to generate electricity. There are several variations to CAES from those using natural gas (diabatic) to pre-heat the compressed air, to more novel designs that utilise thermal energy storage (so-called adiabatic or isothermal CAES).

7.1.37 Distributed storage

These storage technologies tend to be smaller in nature relative to bulk storage and connect at medium- or low-voltage distribution networks. The technologies covered here include:

- Lithium ion battery, which is emerging as one of the fastest growing battery technologies for grid applications. It is a technology which relies on transfer of lithium ions from one electrode to another, with a wide range of possible lithium oxide cathode materials, and a smaller choice of anode materials. Its current market positon is also aided by the presence of large scale manufacturing of these systems contributing to cost reduction amongst other advantages including improved performance and increased safety. It has gained significant advantages from development in its use in transport applications and is presently deployed globally from small scale distributed systems (1-10 kW) to large fast-responding systems for frequency services and energy time shifting (1-50 MW).
- Sodium sulphur (NaS) battery, which is widely considered a commercial technology with several grid applications. These systems typically use molten sodium and sulphur electrodes with a ceramic separator acting as the conductive electrolyte. This battery is attractive due to its long discharge times, quick response capability and high cycle life. The combination of some safety issues and lack of diversified supply chain has somewhat slowed its global uptake.
- Vanadium redox flow battery, which is one of a class of batteries known as flow batteries, in this case with vanadium ions present in an aqueous acidic solution. This solution is pumped through a stack of cells inside which an electrochemical reaction occurs. The electrolytes are stored in external tanks and are pumped to the cell stack as needed. Vanadium flow batteries have distinct advantages such as no cross contamination of the electrolytes, minimal self-discharge, high cycle life and separation of power and energy components rendering storage capacity addition far easier and cost effective. Vanadium flow batteries have started to emerge in several grid applications.
- Liquid air storage, this system uses electricity to drive an air liquefier to produce liquid air which is then stored in insulated vessels. To regenerate power, the liquid air exposed to ambient air causing rapid expansion which can then be used to drive a turbine. This type of storage, while novel, has advantages of leveraging existing industrial processes and machinery, providing supply chain and operational reliability. This technology is driven by Highview Power in the UK where it runs a pre-commercial demonstration alongside a landfill gas generation plant.
- Pumped heat storage, Here a heat pump/engine is used to convert electrical energy to heat which is stored in gravel-filled storage insulated vessels. The system consists of two silos filled with crushed rock which are joined by pipes through which argon gas flows. This argon is compressed during the charge cycle and the heat transferred to the first gravel silo and the emergent cold gas cools the second silo. This process can be reversed for the discharge cycle with the heat engine driving the motor which now acts as a generator.

7.1.38 Fast storage

These storage technologies are categorised by their ability to provide high power for very short discharge durations of high power in the order of milliseconds to seconds, making them suitable for specific applications such as real-time voltage stabilisations:

> Flywheels are a technology class of energy storage which stores electrical energy as kinetic energy by increasing the rotational speed of a disk or rotor on its axis. The stored energy is proportional to the flywheel's mass and the square of its rotational speed. Flywheels have been used on non-grid applications alone or in hybrid systems with batteries for uninterrupted power applications (UPS) owing to their instantaneous response time. Increasingly, flywheels have been finding success in grid applications, primarily for frequency regulation displacing conventional generation mainly owing to its ability to provide up and down regulation and rapid response features.

> Supercapacitors are advanced capacitors that have higher energy storage capacity and are hence able to discharge over longer time periods than conventional capacitors. Like flywheels, they are able to respond very quickly through both charge and discharge cycles, and can be used to provide a high power output within a very short response time, which is required for frequency regulation. Supercapacitors have the ability to perform upwards of one million charge-discharge cycles in their lifetime.

7.2 Chapter 3 – Societal value of storage

This section begins with a comprehensive presentation of the methods employed in this report and proceeds to describe the results from analysis.

This report has been informed by qualitative and quantitative analysis conducted by the Carbon Trust and the Imperial College energy systems research group led by Professor Goran Strbac. This mixed methods approach was designed to ensure robust and comprehensive analysis.

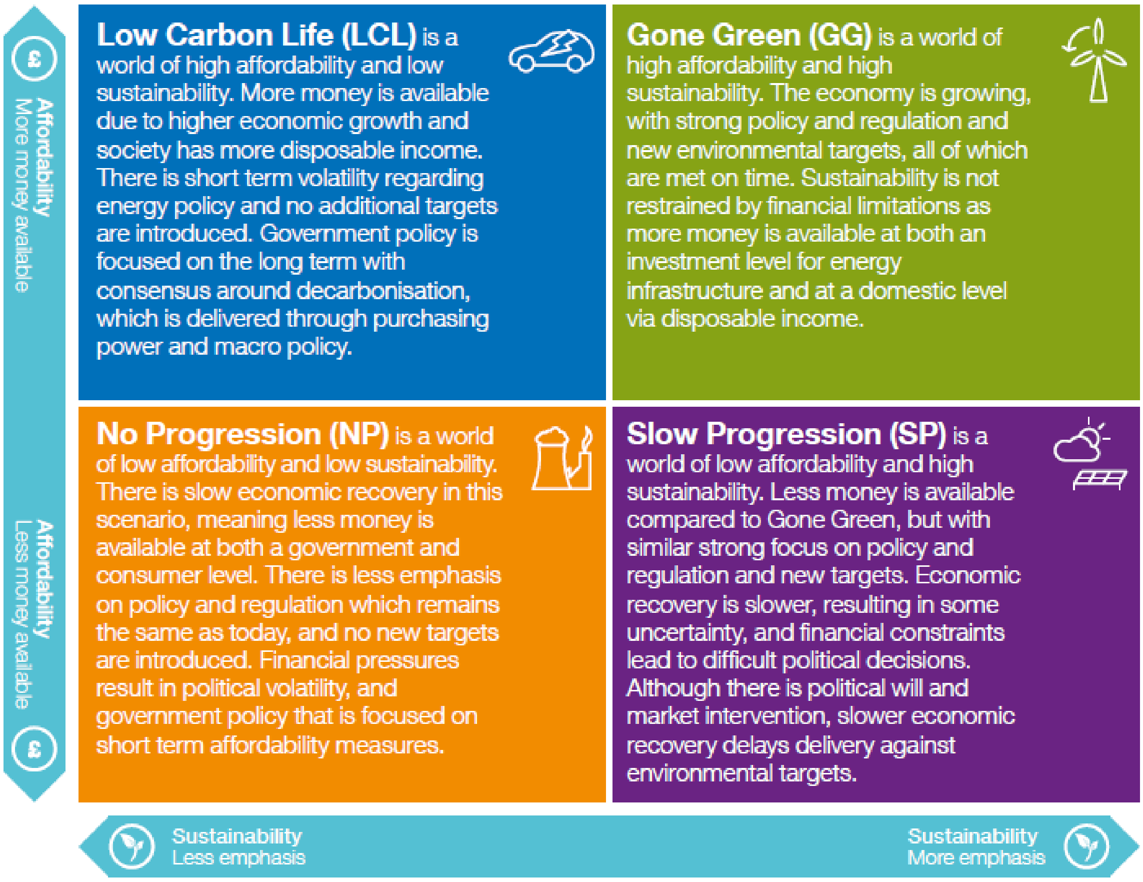
Scenarios were used to evaluate the position of energy storage across different energy futures. In addition to applying the model to three scenarios, each scenario considered three technology categories (bulk, distributed and fast) and their respective parameters across a range of parameter values. A base case was included to obtain a baseline, whereby no additional storage beyond present availability was considered. Therefore, in total, the model tested 15 cases to ensure robustness.

7.2.1 Use of scenarios

Three scenarios were used to evaluate the potential value of energy storage across different potential electricity systems. Analysis used modelling outputs based on these scenarios to provide context, but analysis did not extend to propose these as likely or desirable outcomes.

Two of these scenarios, 'Gone Green' and 'No Progression' were defined by a National Grid industry consultation exercise (National Grid, 2014). The National Grid have published four potential scenarios, outlined in Figure 12. The 'Gone Green' scenario assumes strong sustainability ambitions to meet carbon targets and significant funding available for investment in building new infrastructure. The 'No Progression' scenario assumes the opposite, with weak sustainability ambitions and limited investment. These scenarios define future expected demand and the installed generation portfolio. Considering their underlying assumptions, both scenarios were subsequently employed to develop baseline cases and provide optimistic and pessimistic boundaries when comparing the value of storage as, in reality, the true future system will likely lie along this spectrum.

Figure 12 - National Grid Future Energy Scenarios (National Grid, 2014)



The third scenario, 'Market-driven Approach', was also used in the model to forecast beyond the previous scenarios. The Market-driven Approach considers an energy future that has been fully optimised, from a whole-systems perspective, to meet carbon constraints at least cost. As such, it allows for the estimation of the value of storage that is driven by the market. This scenario reveals any additional value from acting now and further identifies actions that can be prioritised in the short-run.

Analysis used modelling outputs based on these scenarios to provide context. Analysis does not propose these as likely or desirable outcomes. Therefore, these scenarios are considered as tools in understanding the relationships between different system designs and storage, to inform improved decision making among government, industry and system operators.

7.2.2 'Gone Green' Scenario

The 'Gone Green' scenario imagines a world with sufficient funds available to invest in new infrastructure due to strong economic growth and a strong focus on sustainability. The scenario consists of the following assumptions:

- Demand will continue to grow until 2035, consistent with sustained economic growth and increasing use of electric vehicles and heat pumps.

- Grid emissions intensity in 2030 is in line with carbon targets of 50-100 g/kWh as recommended (Committee on Climate Change, 2014).
- Significant growth in both onshore and offshore wind until 2035.
- Installed capacity of coal generation falls significantly as the Large Combustion Plant Directive takes effect in 2016.
- Unabated gas continues to play a significant role by replacing lost coal capacity, alongside onshore and offshore wind, while abated gas and coal play a minor role from 2030.
- The installed nuclear energy capacity remains broadly flat and below 10GW.

Figure 13 illustrates the projected evolution, from 2013 to 2036, of the energy and grid mix under this scenario. Figure 14 illustrates the projected evolution, from 2013 to 2036, of generation capacity under this scenario.

Figure 13- Energy consumption and grid carbon intensity in the 'Gone Green' scenario (National Grid, 2014)

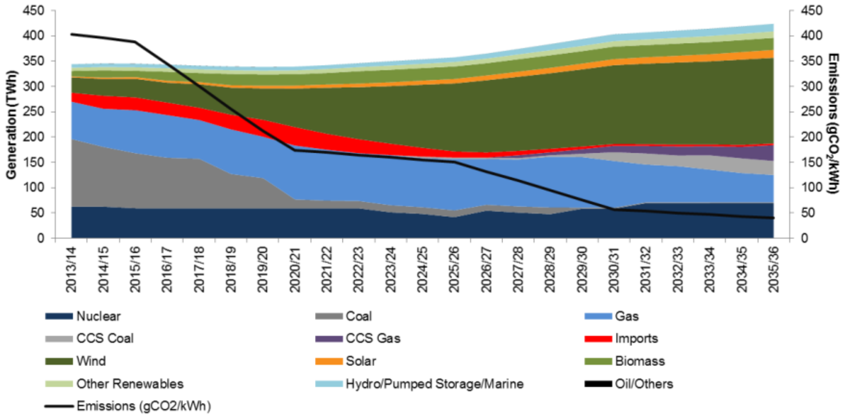
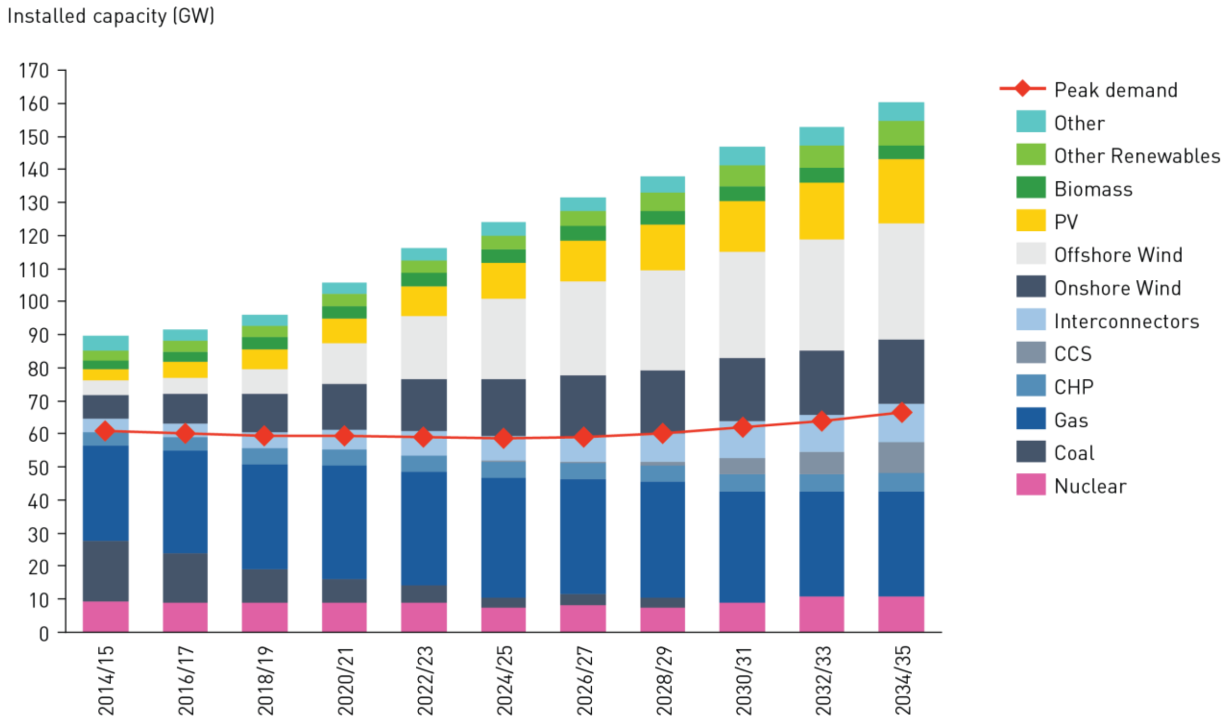


Figure 14 - Installed generation capacity in the 'Gone Green' scenario (National Grid, 2014)



7.2.3 'No Progression'

The 'No Progression' scenario imagines a world with weak economic growth and limited focus on sustainability. This scenario consists of the following assumptions:

> There is a new 'dash for gas' from 2020, which will replace most coal generation.

> There is only minimal growth from other energy sources.

> Recommended 2030 carbon targets are missed by more than 100g/kWh.

> There is greater capacity for network interconnection

> Carbon capture and storage plays no role.

Figure 15 illustrates the projected evolution, from 2013 to 2036, of the energy and grid mix under this scenario. Figure 15– Energy consumption and grid carbon intensity in the 'No Progression' scenario. Figure 16 illustrates the projected evolution, from 2013 to 2036, of generation capacity under this scenario.

Figure 15 - Energy consumption and grid carbon intensity in the 'No Progression' scenario (National Grid, 2014)

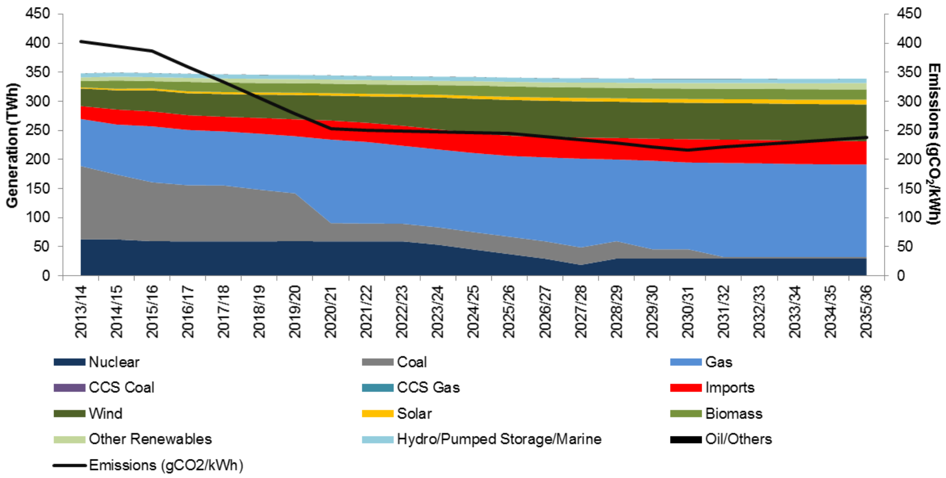
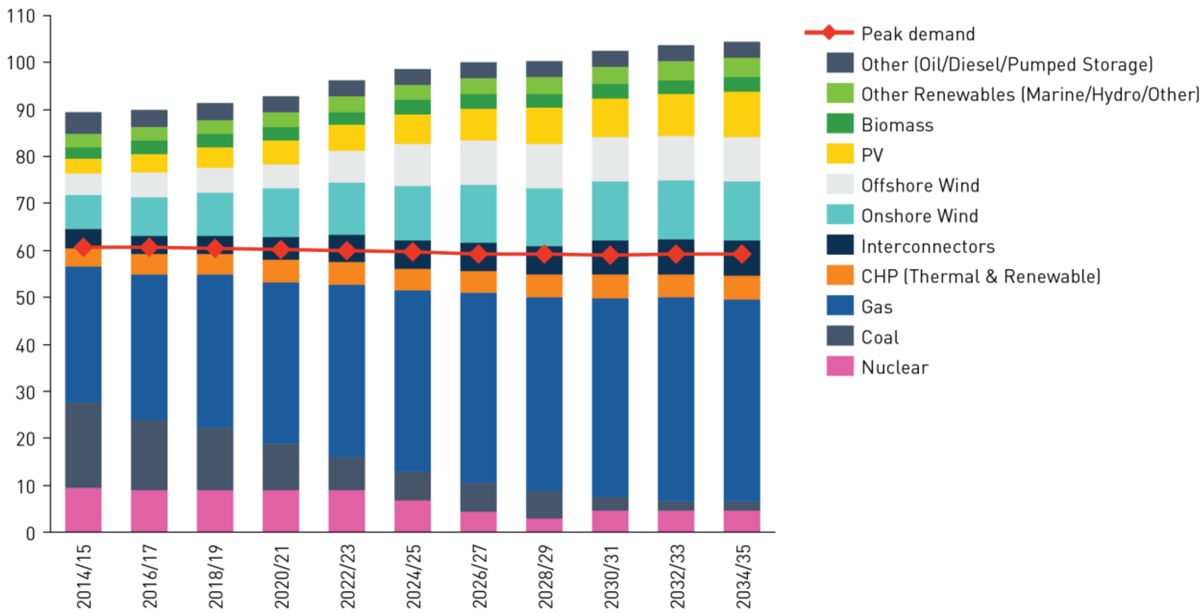


Figure 16 - Installed generation capacity in the No Progression scenario (National Grid, 2014)

Installed capacity (GW)



7.2.4 'Market-driven Approach' scenario

The 'Market driven Approach' allows the Whole-electricity System Investment Model (WeSIM) model to optimise generation assets to meet carbon targets at least costs. This scenario takes into account existing generation portfolio and also those that have been commissioning.

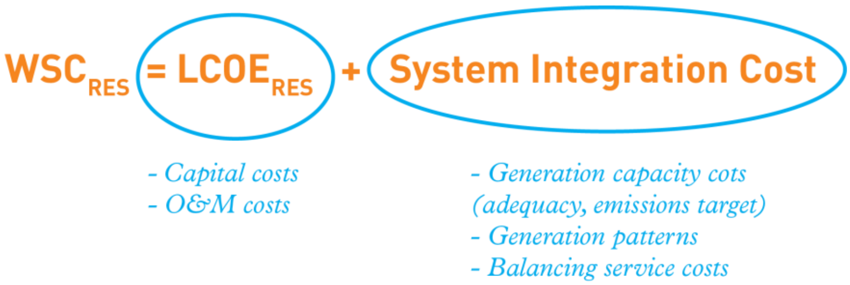
7.2.5 Whole system modelling

This analysis contained a modelling element, referred to as the Whole-electricity System Investment Model (WeSIM), which was designed by Professor Goran Strbac at Imperial College London. This was further supported by research and analysis, conducted by the Carbon Trust, to determine input assumptions and boundary conditions.

The WeSIM model takes a whole-system perspective to evaluate the Whole-System Cost (WSC) of intermittent renewable energy sources (RES).

The WSC of RES (WESRES) is calculated as the sum of Levelised Cost of Electricity (LCOE) and System Integration Cost. System Integration Cost is defined as the total additional infrastructure and/or operation costs to the system as a result of integration. LCOE considers capital and O&M costs of RES over their project life. The System Integration Cost of RES embodies costs associated with ensuring the security of generation capacity (e.g. costs associated with providing balancing services). The relationship between these variables are outlined in the following equation:

Figure 17 – Whole system cost as sum of LCOE and system integration cost (Strbac, 2014)



In this context, the model assessed the benefits that energy storage may bring in reducing system integration costs of wind and solar PV generation by reducing:

> Cost of transmission and distribution network infrastructure reinforcement

> System balancing costs

> Cost of required back-up generation capacity

> Cost of replacing curtailed renewable output with an alternative low-carbon technology to achieve the same emissions target

> Cost of transmission and distribution network infrastructure reinforcement

This approach allowed for the quantification of system benefits, the identification of cost savings enabled by storage across the system, and the identification of both the volume and value of benefits along the value chain. The latter essentially captured the savings in operation costs, the amount and value of avoided investment in generation, transmission and distribution infrastructure (all netted off against the cost of storage).

This approach is particularly relevant in the context of system-level CO_2 targets, which can be constrained by the model in a given year. Curtailment of available zero carbon output of RES or reduction in load factors of nuclear generators would be compensated by further investment in low-carbon generation capacity. In such cases, storage may also generate significant benefits in terms of reducing the cost of decarbonisation, and this was quantified in the case studies presented. The previously mentioned technology categories (bulk, distributed and fast) were used to design the modelling framework. As a result, modelling was repeated for high and low cost parameter values, and the presence of frequency response.

7.2.6 Input assumptions

Assumptions were informed by a range of sources, depending on available information. Information about the capabilities and costs of a range of storage and generation technologies, including forecast change in costs, was collected and collated to inform assumptions used in analysis. All assumptions regarding the cost of generation technologies have been published by the Department of Energy and Climate Change (Department of Energy and Climate Change, 2013). Assumptions regarding the cost reduction potential and capabilities of energy storage technologies have been gathered from reputable sources and more than 30 expert interviews across industry, government and academia.

The results of this analysis are discussed in the context of scenarios and over two categories: where energy storage is retrofitted to predetermined systems, or where the system is optimised in advance with energy storage available.

7.2.7 Storage cost assumptions in 2015

Cost estimates of various storage technologies were collected through expert interviews and reputable primary and secondary literature. The key source used for this purpose was from Pacific Northwest National Laboratory (2010). Secondary sources were minimised to maintain consistency between technologies, as this avoids adopting assumptions associated with different methodologies. Assumed storage costs are shown in Table 1.

Table 1 - Storage cost assumptions

Class	Technology	Parameter	Units	Parameter value
Bulk	Compressed Air	Efficiency	%	55
		Installed cost	£/kW	735
	Pumped Hydro	Efficiency	%	80
		Installed cost	£/kW	1144
Distributed	Lithium Ion Battery	Efficiency	%	80
		Installed cost	£/kW	556
	Sodium Sulphur Battery	Efficiency	%	75
		Installed cost	£/kW	1961
	Redox Flow Battery	Efficiency	%	75
		Installed cost	£/kW	653
	Liquid Air	Efficiency	%	60
		Installed cost	£/kW	1693
	Pumped Heat	Efficiency	%	75
		Installed cost	£/kW	523
Fast response	Flywheel	Efficiency	%	87.5
		Installed cost	£/kW	686
	Supercapacitor	Efficiency	%	85
		Installed cost	£/kW	980

7.2.8 Generation cost assumptions for projects starting in 2019

Cost estimates for generation technologies were taken from the Department of Energy and Climate Change (2013), a single, reputable source. Cost data was for projects starting in 2019. These, in addition to estimates of asset lifetime and capacity factors, are shown in Table 2.

Table 2 - Cost estimates for generation technologies for projects starting in 2019 (DECC, 2013)

Generation technology	Lifetime (years)	Capacity factor (%)	Fixed cost (£/MWh)	O&M (£/MWh)	Carbon cost (£/MWh)	Fuel cost (£/MWh)
CCGT	25	93%	9	4	24	49
OCGT	25	7%	59	23	35	74
Coal	35	93%	22	3	68	22
Coal CCS - oxy combustion	25	93%	38	28	5	36
Coal CCS - IGCC combustion	25	90%	54	36	7	36
Gas CCS	25	93%	35.7	13	4	56
Nuclear	60	91%	61	13	4	5
Onshore wind	24	28%	75	24	0	0
Offshore wind R2	20	38%	87	28	0	0
Offshore wind R3	20	39%	90	30	0	0
Solar PV	25	11%	100	23	0	0

For the assessment of societal benefits, this analysis considered the system value of storage. In order to compare technologies on a like-for-like basis, care was taken to ensure that system costs were included in the overall cost estimates (e.g., system integration costs for renewables).

As DECC cost estimates for nuclear do not include the cost of insuring against nuclear accidents, usually levied on the taxpayer, a sensitivity was run for this technology by varying the DECC number by an additional such insurance cost. Research identified €0.28/kWh as a lower bound estimate for a 50 year private sector insurance against nuclear accidents (Schweizerische Energie-Stiftung, 2013). This was validated against meta-analysis carried out in the German context by Küchler & Meyer (2012). Assuming that future nuclear projects in the UK will meet industry leading safety standards and receive public loan guarantees[18], it can be argued that the true premium levied will likely be lower for future UK plants; assumed at 20% of the quoted amount. A 20% share of the additional insurance cost adds £41.50/MWh[19], taking the total cost of nuclear to £121.50/MWh.

The DECC cost figures assume a discount rate of 10% across all technologies. This discount factor was removed to reflect the difference in investment risk between established technologies, such as

[18] Based on experience from Hinkley Point C

[19] £41.50/MWh calculated from 20% of €280/MWh using €/£ exchange rate of 1.35

coal, and emerging technologies, such as gas CCS. A specific discount rate was applied to these groups, as show in Table 3.

Table 3 - Revised discount rates (Oxera, 2010)

Generation technology	Discount rate (%)
CCGT	7.5%
OCGT	7.5%
Coal	7.5%
Coal CCS - oxy combustion	13.0%
Coal CCS - IGCC combustion	13.0%
Gas CCS	13.0%
Nuclear	9.5%
Onshore wind	7.0%
Offshore wind R2	10.5%
Offshore wind R3	10.5%
Solar PV	7.5%

7.2.9 Cost reduction potential

Generic cost curves, developed by EA Technology (2012), which "combine different factors such as volume, material cost price changes and learning curves, from both within and out of the energy sector" were applied in cost reduction estimations. This ensured that estimation occurred according to a consistent framework across storage and generation technologies. These cost curves are outlined below (EA Technology, 2012):

- **Type 1** - Rising (based on an average of the Steel and Aluminium cost curves) - 120% of original cost after 30 years
- **Type 2** - Flat (representing no change in cost) - 100% of original cost after 30 years
- **Type 3** – Shallow reduction (based on an average of offshore wind farm costs and flat line) - 75% of original cost after 30 years
- **Type 4** – Medium reduction (based on the cost curve for offshore wind farms) - 50% of original cost after 30 years
- **Type 5** – High reduction (based on the cost curve for laptops) - 20% of original cost after 30 years

Cost curves were assigned to storage and generation technologies, based on triangulation with published cost reduction estimates and expert input. The rationale behind these decisions are in Table 4. Note that cost reduction applies only to capex element of cost.

Table 4 - Allocation of generic cost curves to storage and generation technologies

Domain	Technology	Curve used	Rationale
Dispatchable generation	CCGT	Type 1	Heavy civil engineering project with limited potential for innovation - cost of materials is key driver
	OCGT	Type 1	Heavy civil engineering project with limited potential for innovation - cost of materials is key driver
	Coal	Type 1	Heavy civil engineering project with limited potential for innovation - cost of materials is key driver
	Coal CCS - CCS component	Type 3	Extrapolated from McKinsey analysis (McKinsey & Company, 2008)
	Gas CCS - CCS component	Type 3	Assumed to be the same as Coal CCS
Non-dispatchable generation	Nuclear	Type 2	Opposing drivers of increasing heavy civil engineering project costs vs. potential for cost reduction from innovation – flat cost curve assumed
	Onshore wind	Type 3	IEA Wind Energy Roadmap (2009) assumes a 17% cost reduction in onshore O&M costs by 2030, and by 23% in 2050.
	Offshore wind	Type 4	Dedicated offshore wind cost curve (EA Technology, 2012)
	PV	Type 4	IEA PV Roadmap forecasts 65% drop in price by 2050 (International Energy Agency, 2014)
Storage	Compressed air	Type 2	Improvement in efficiency is countered by increase in material costs - future costs assumed to be flat
	Pumped hydro	Type 1	Heavy civil engineering project with limited potential for innovation - cost of materials is key driver
	Lithium-ion battery	Type 4	Aggressive cost reductions from significant improvements in EV batteries
	Sodium sulphur battery	Type 3	Shallow reduction in line with 30-50% reduction, as per expert interviews

	Redox flow battery	Type 4	Shallow reduction in line with 30-50% reduction, as per expert interviews
	Liquid air battery energy storage	Type 4	New technology - high cost reduction possible due to established supply chains for NOAK installations
	Pumped heat storage	Type 4	New technology - high cost reduction possible due to established supply chains for NOAK installations
	Flywheel	Type 3	Shallow reduction in line with 30-50% reduction, as per expert interviews
	Supercapacitor	Type 3	Shallow reduction in line with 30-50% reduction, as per expert interviews

Table 5 - Generation costs in 2030 with learning effects and revised discount rates included

Generation technology	Fixed cost in 2030 (£/MWh)	Variable cost in 2030 (£/MWh)	Total in 2030 (£/MWh)
CCGT	7.8	62.7	70.5
OCGT	51.1	107.5	158.6
Coal	23.0	76.0	99.0
Coal CCS - oxy combustion	53.2	85.4	138.7
Coal CCS - IGCC combustion	53.2	97.8	151.0
Gas CCS	22.1	90.4	112.5
Nuclear	58.0	20.9	78.9
Onshore wind	52.4	18.8	71.2
Offshore wind R2	68.3	29.0	97.3
Offshore wind R3	70.6	31.0	101.7
Solar PV	61.8	18.7	80.5

Table 6 - Storage capex in 2030

Storage technology	2030 Capex (£/kW)
Li-Ion	583.7
Na S	2570.8
Redox flow	686.0
CAES	1125.0
PHS	1904.6
Liquid air	1778.6
Pumped heat	549.4
Flywheels	899.8
Supercapacitors	687.3

7.2.10 Results

This section outlines the results from this analysis.

Four charts are presented for each of the three scenarios, representing the projected system in 2030. These are:

- Installed capacity of generation assets
- Change in installed capacity of generation assets in comparison with the 'no additional storage' base case
- The change in output of generation assets on the grid in comparison with the no additional storage base case
- The cost savings resulting from the deployment of storage

In the 'Gone Green' and 'No Progression' scenarios, the WeSIM model did not consider the build or closure of generation, and was restricted to given capacities. Storage can be deployed with the intention of changing the utilisation of existing assets. However, for the 'Market-driven Approach' scenario, the model allowed for new assets to be realised and for generation assets to be shut-down, if they were already scheduled to be decommissioned. The installed generation capacity chart illustrates the impact different types of energy storage could have on the energy system in terms of generation assets.

The results shown here assume the higher nuclear cost of £121.50/MWh, to be consistent across all technologies in including societal costs. Key results from DECC stated figures, based on £80/MWh, are shown separately as sensitivity analyses.

7.2.11 Gone Green

Figure 18 - Installed generation capacity of the 'Gone Green' scenario in 2030

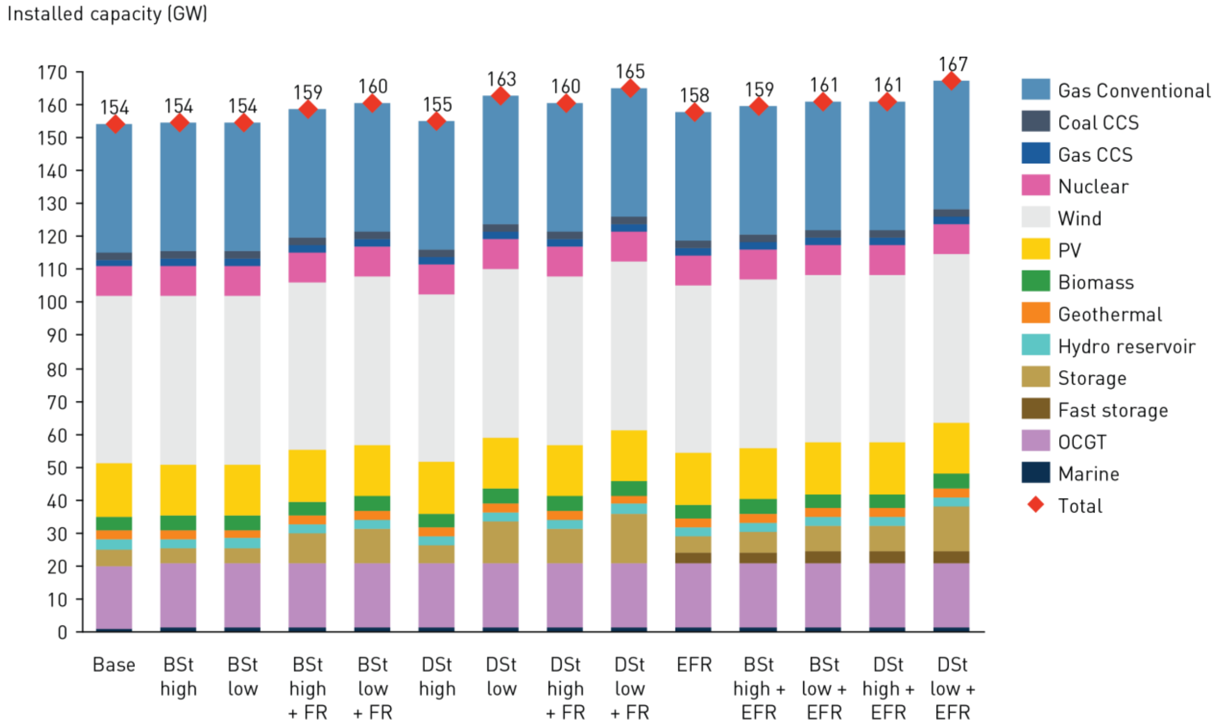


Figure 19 - Change in installed generation capacity of the 'Gone Green' scenario in 2030

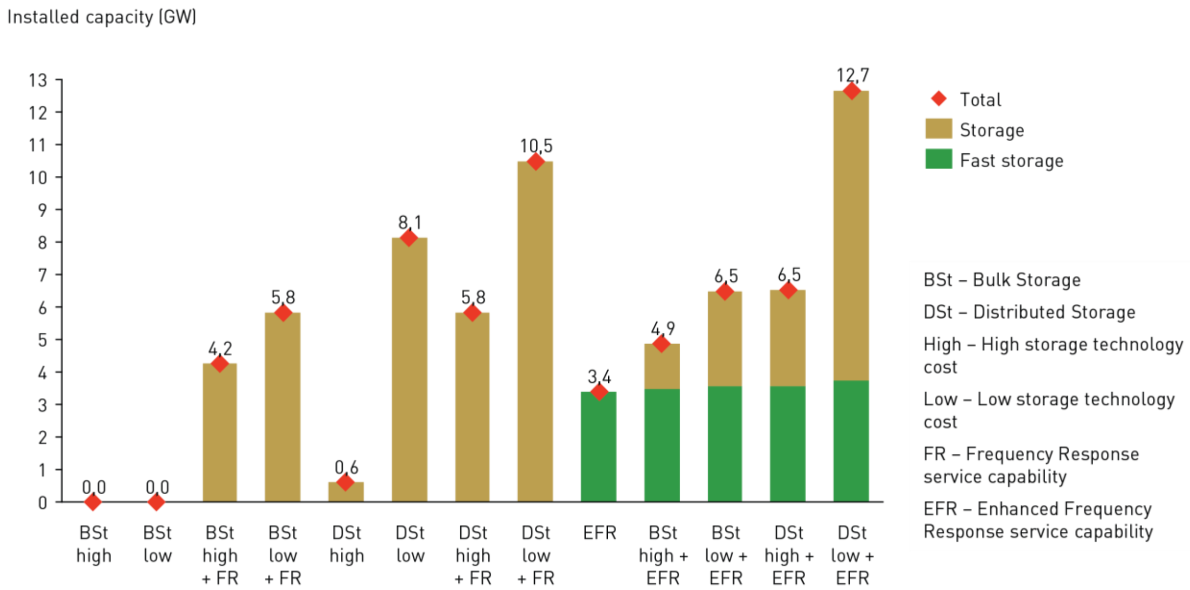


Figure 20 - Change in electricity output of generation assets in the 'Gone Green' scenario in 2030

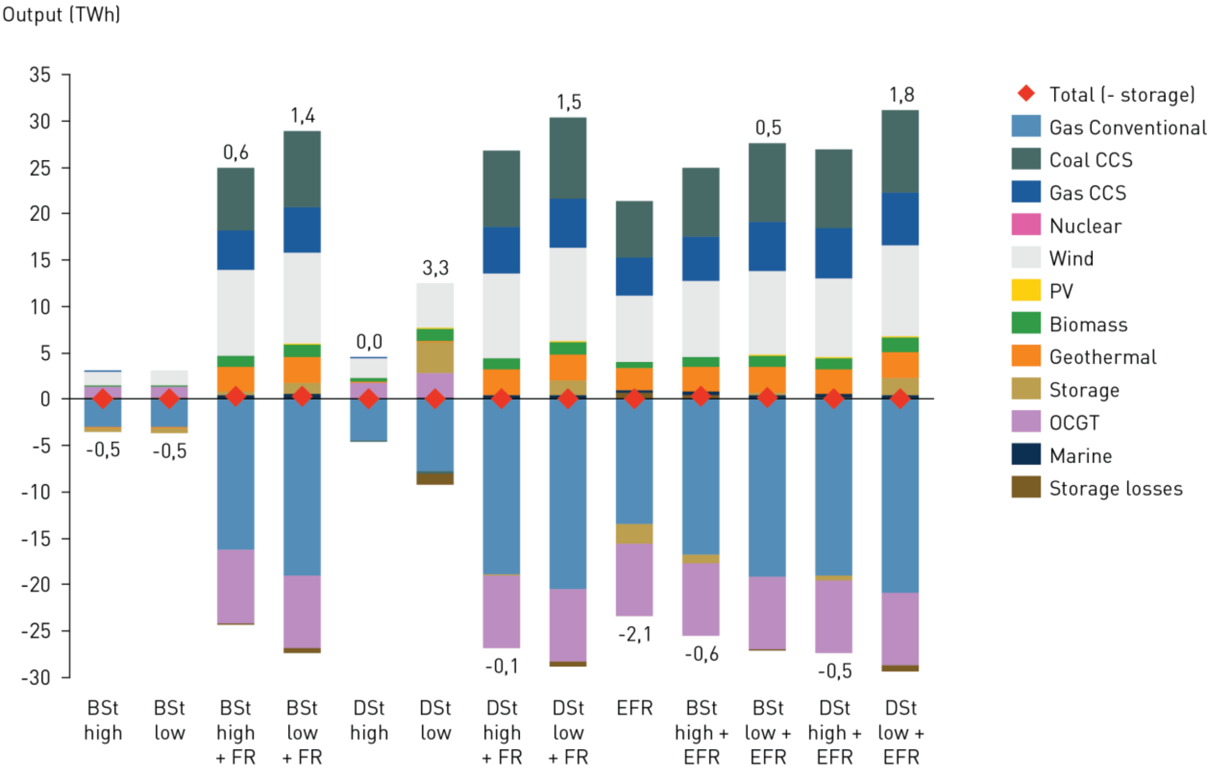
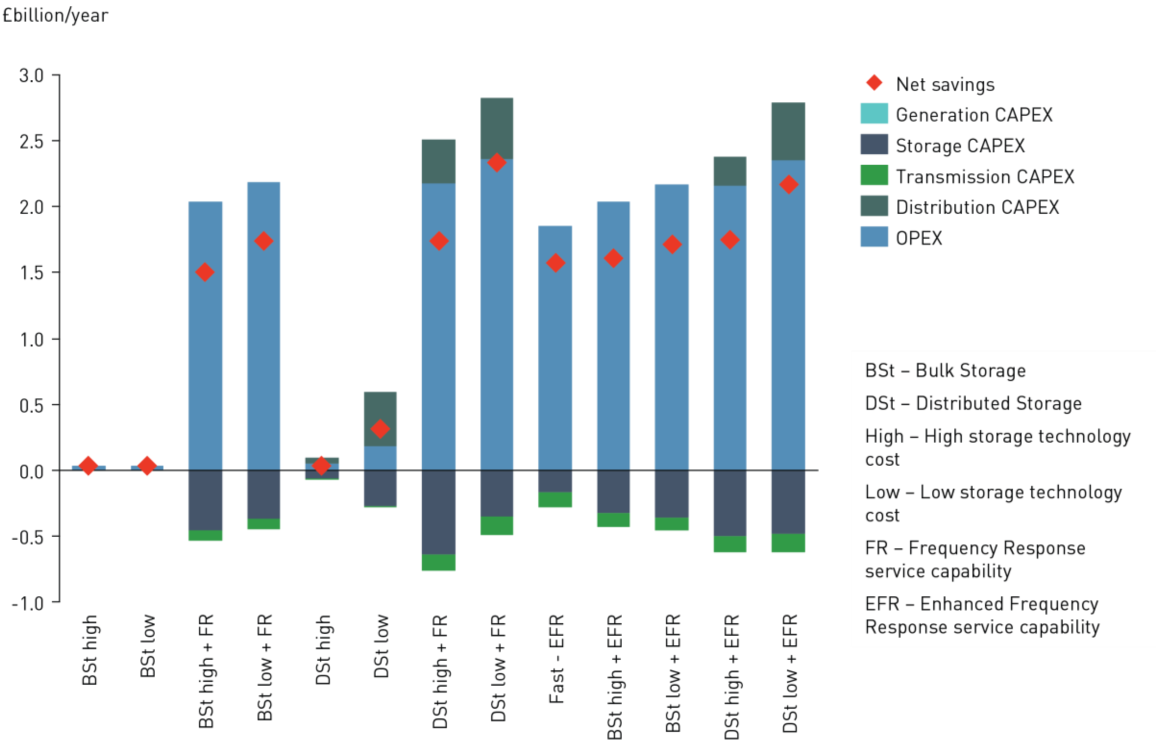


Figure 21 – Annual cost saving across whole system resulting from deploying different storage types in the 'Gone Green' scenario in 2030 against a base case of no additional storage



7.2.12 'No Progression'

Figure 22 - Installed generation capacity of the 'No Progression' system in 2030

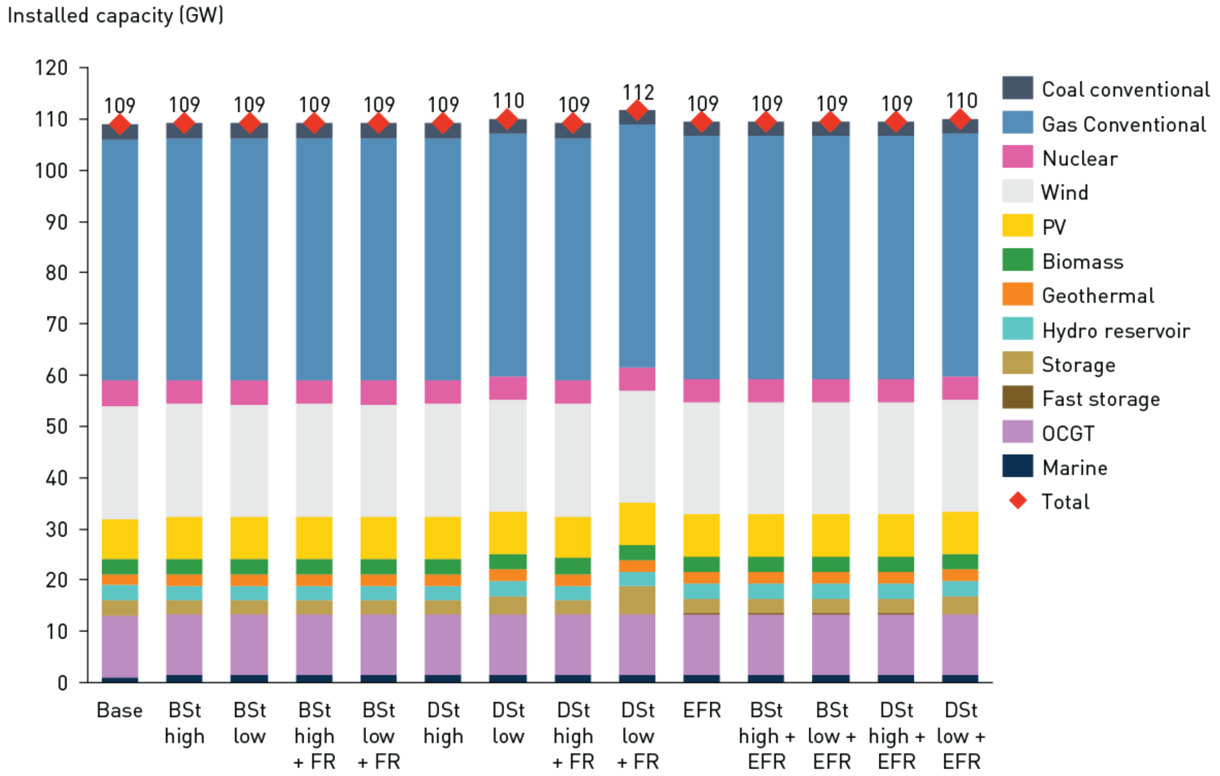


Figure 23 - Change in installed generation capacity of the 'No Progression' system in 2030

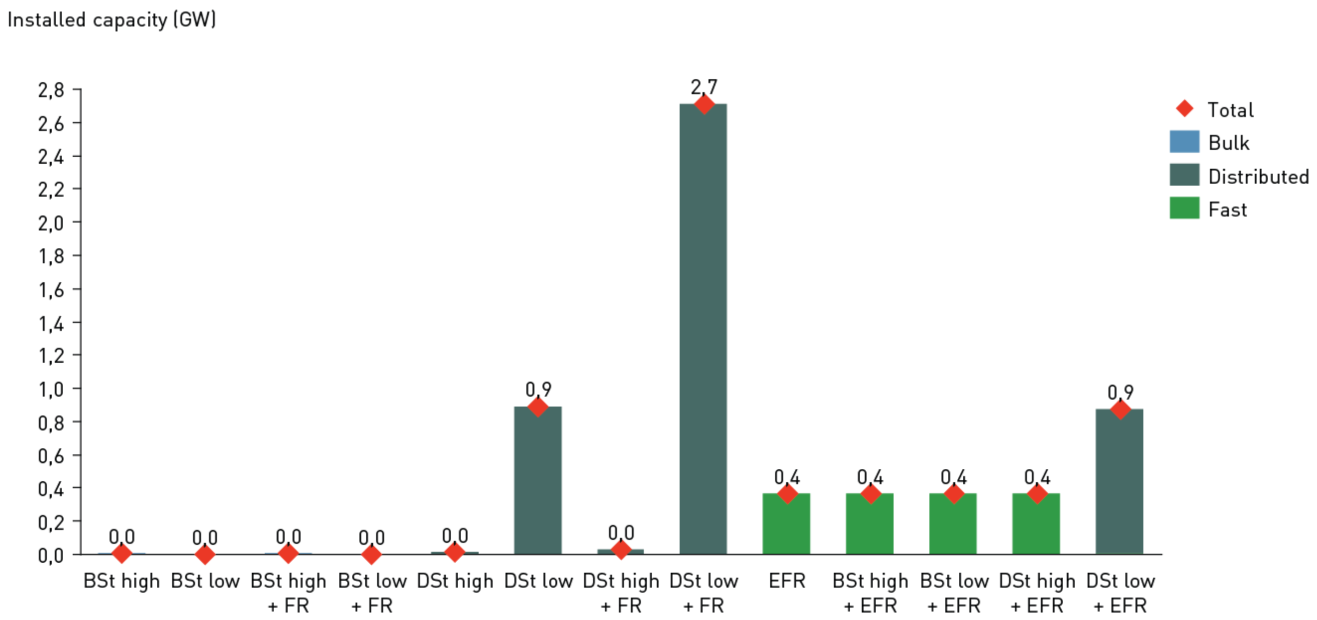


Figure 24 - Change in electricity output of generation assets in the 'No Progression' system in 2030

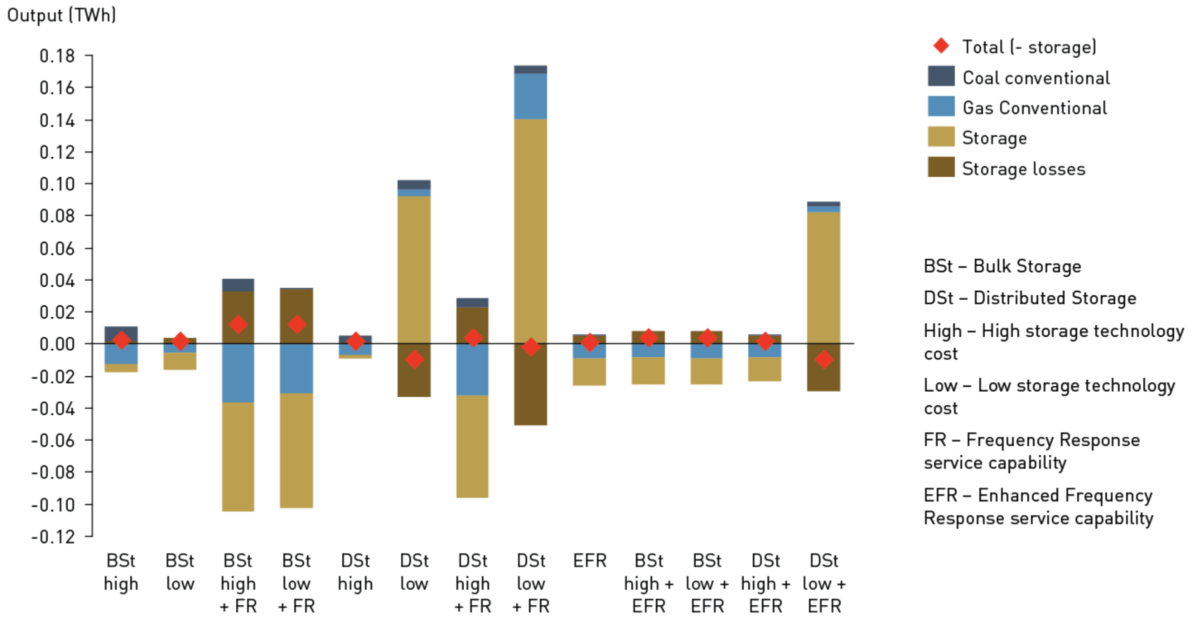
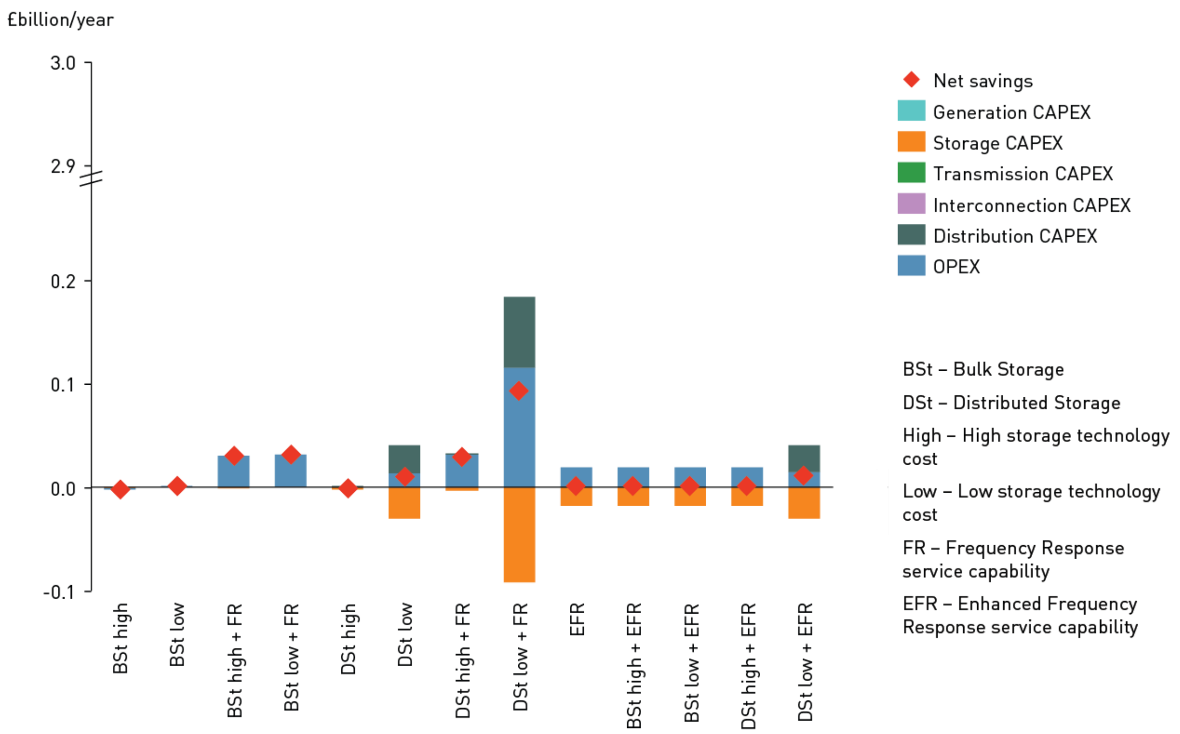


Figure 25 - Annual cost saving across whole system resulting from deploying different storage types in the 'No Progression' scenario in 2030 against a base case of no additional storage



7.2.13 'Market-driven Approach'

Figure 26 - Installed generation capacity of the 'Market-driven Approach' system in 2030

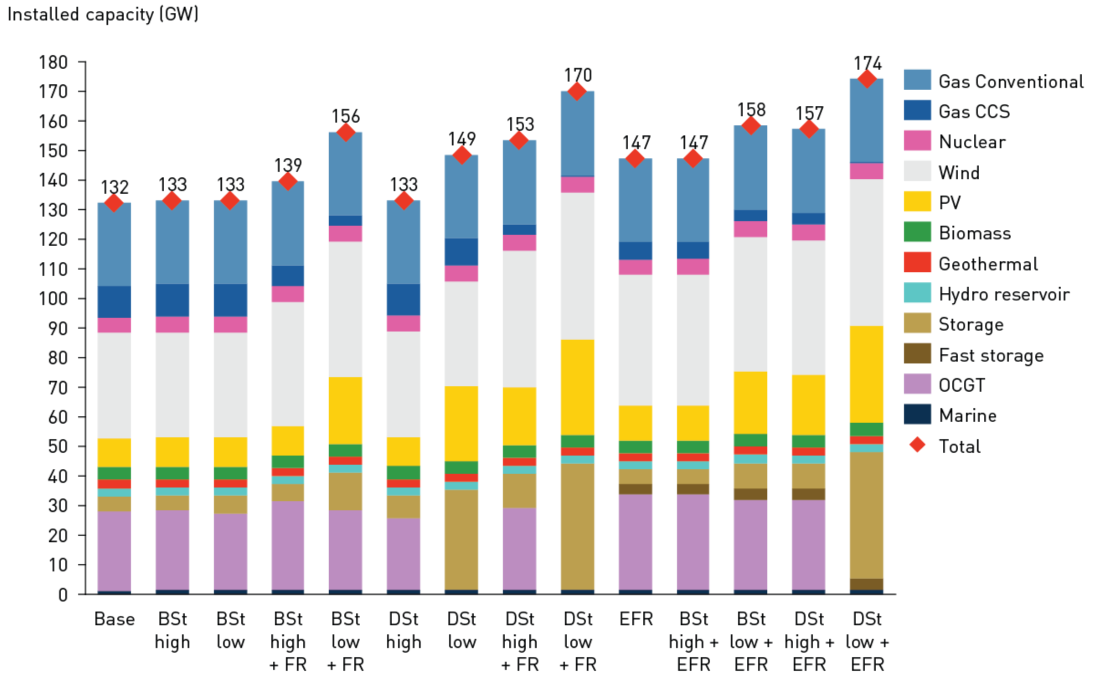


Figure 27 – Change in installed generation capacity including additional storage cases when nuclear cost is £121.50/MWh when additional storage is available

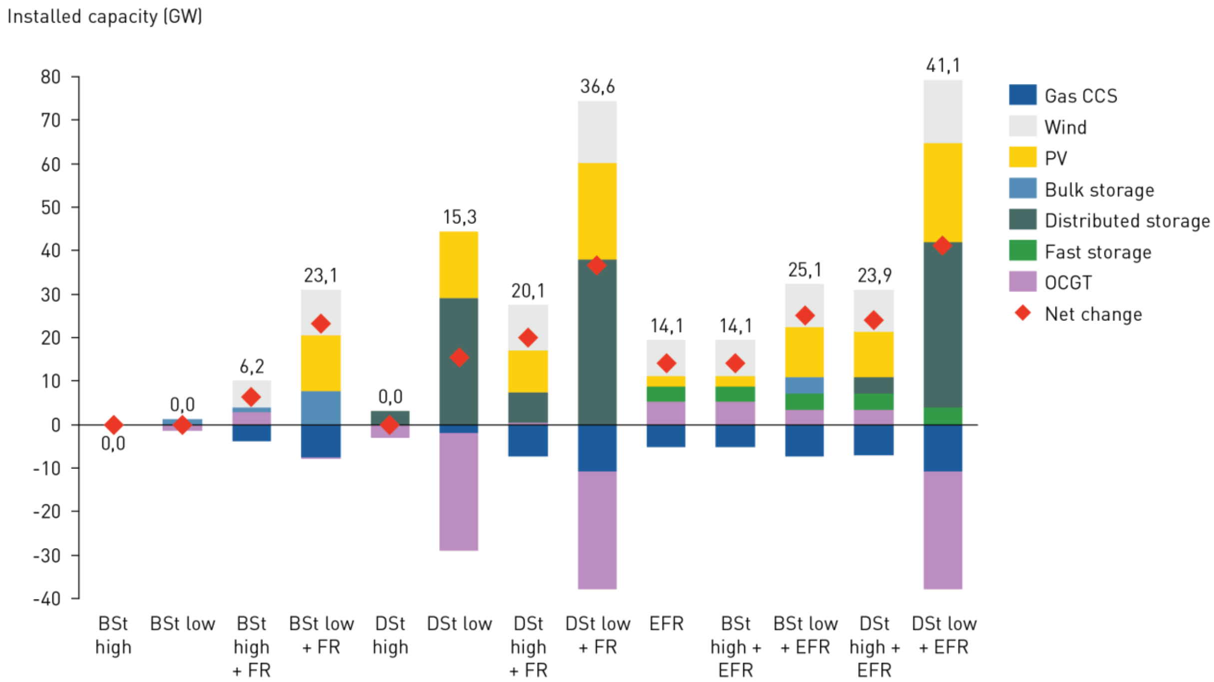


Figure 28 - Change in electricity output of generation assets in the 'Market-driven Approach' system in 2030

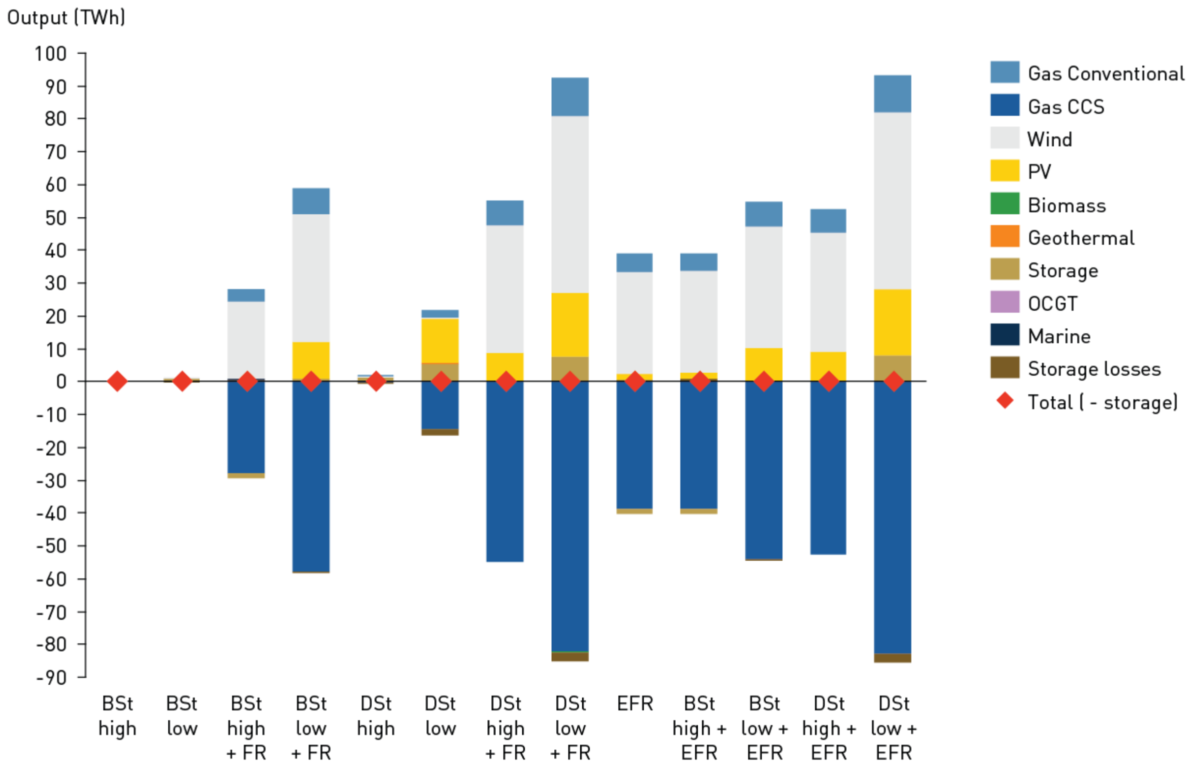
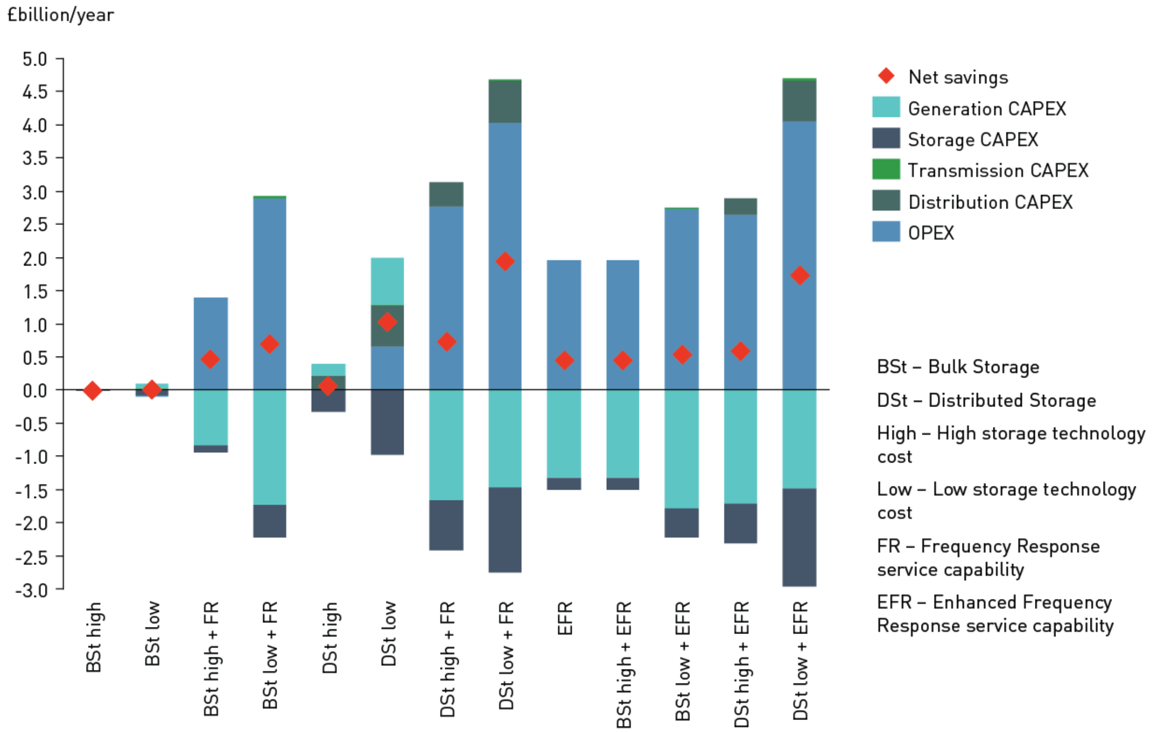


Figure 29 - Annual cost saving across whole system resulting from deploying different storage types in the 'Market Driven approach' system in 2030 against a base case of no additional storage



BSt – Bulk Storage

DSt – Distributed Storage

High – High storage technology cost

Low – Low storage technology cost

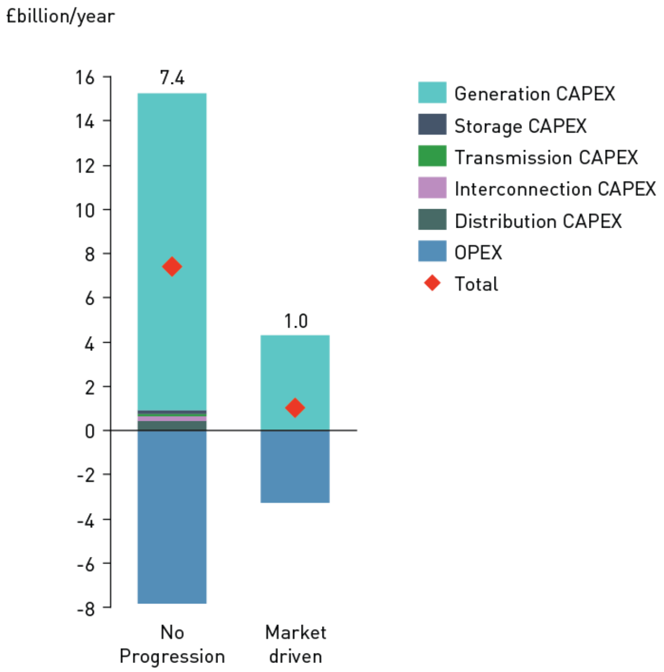
FR – Frequency Response service capability

EFR – Enhanced Frequency Response service capability

Cost savings between scenarios

Analysis showed that the cost of deploying the 'Market-driven Approach' scenario can save about £5 billion more than the 'Gone Green' scenario to meet the same carbon targets. This is predominantly the result of avoiding investment in unnecessary generation assets, as evidenced in Figure 30. Although the 'No Progression' scenario is significantly less expensive than both the 'Gone Green' and 'Market-driven Approach' scenarios, it does not meet the required carbon targets. These cost savings represent differences between the base cases of each scenario, where no additional storage has been deployed. Cost savings resulting from storage shown in previous analysis would therefore be additional to the savings shown in Figure 30.

Figure 30 - Cost savings of 'No Progression' and 'Market-driven Approach' base cases compared with Gone Green



7.2.14 Sensitivity analysis – fuel and carbon prices

The value of storage is influenced by the relative attractiveness of assets within the system that are able to provide similar services. These, in turn, are influenced by the fuel price, which drives the operational cost of most conventional generation technologies. Assumed prices are shown in Table 7. Across the analysis and the results presented through the report, the central fuel and carbon prices are utilised as inputs excepting the sensitivity analysis.

Table 7- Assumed oil, gas, coal and carbon price sensitivities – 2030 (Department of Energy and Climate Change, 2014)

	Oil		Gas		Coal		Carbon
	($/barrel)	(£/GJ)	(p/therm)	(£/GJ)	($/tonne)	(£/GJ)	(£/tonne)
Low	78.3	8.12	43.2	4.10	73.1	1.93	38.50
Central	120.6	12.50	76.4	7.24	103.3	2.72	76.99
High	170.3	17.66	107.8	10.22	139.9	3.69	115.49

In the base case, assuming no additional storage, a high fuel and carbon price compared with the central case increases the operational cost of existing gas generation assets, which favours the deployment of wind and solar PV as illustrated in Figure 31. A low fuel and carbon price compared with the central case has a small impact on the installed capacity, shifting some capacity away from gas CCS towards OCGT.

Figure 30 and Figure 34 show the effect of these fuel and carbon price sensitivities when additional storage can be deployed. If fuel and carbon prices are low, deployment of storage is limited to low cost distributed storage performing a direct replacement of the most expensive gas generation, OCGT. If fuel and carbon prices are high, there is greater incentive for a variety of storage types to displace gas generators. Note that changes in installed capacity shown in Figure 30 and Figure 34 are additional to their associated base case shown in Figure 31.

Figure 31 - Change in installed capacity in the 'Market-driven Approach' base case given change in fuel and carbon price

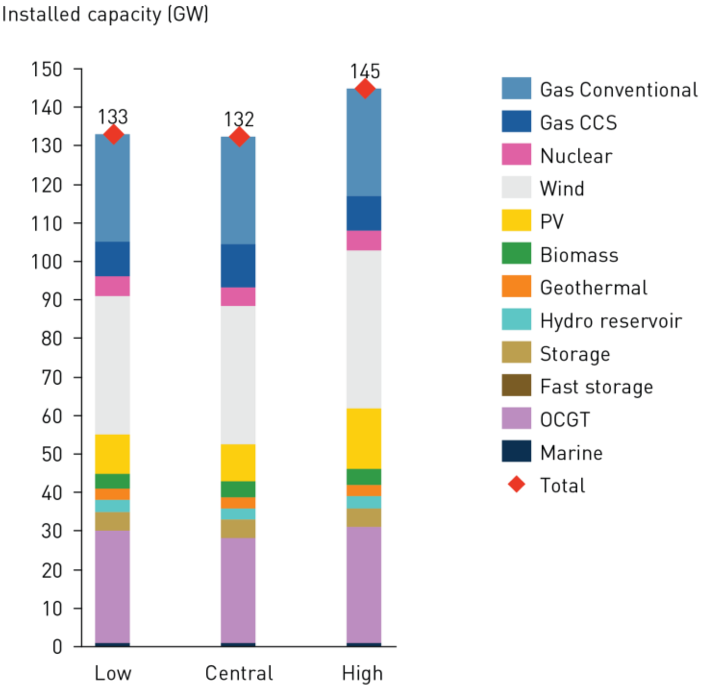


Figure 32 - Change in Installed generation capacity including additional storage cases under a low fuel and carbon price scenario

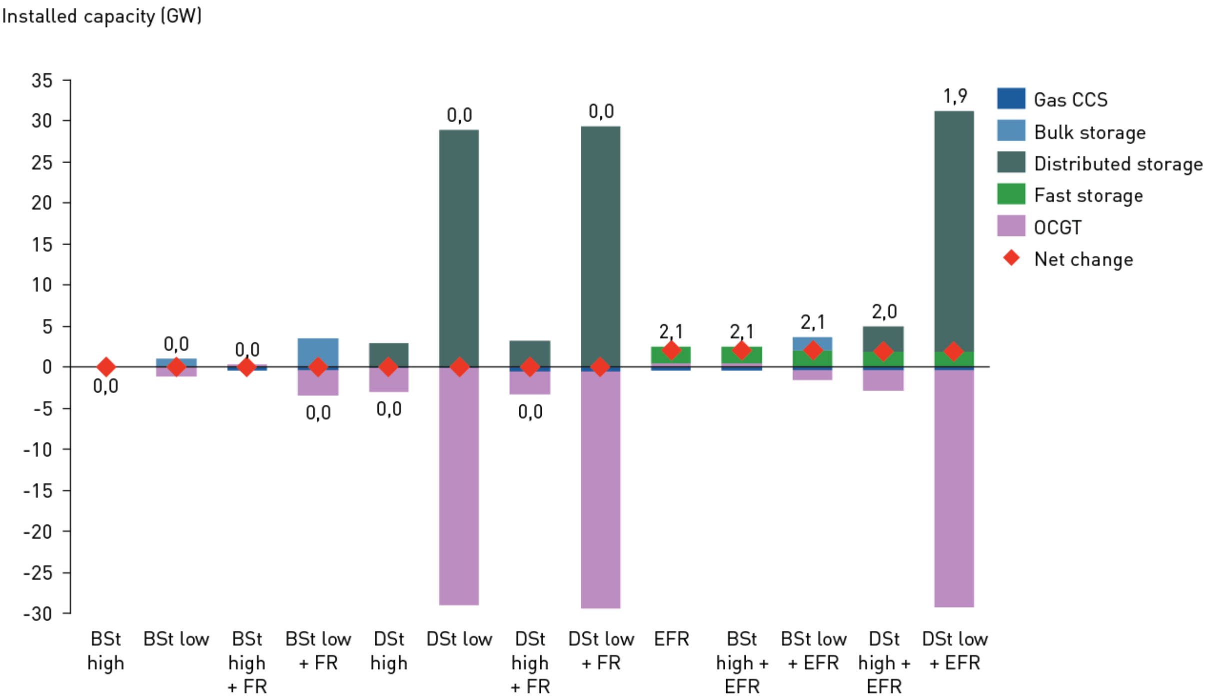


Figure 33 - Change in Installed generation capacity including additional storage cases under a central fuel and carbon price scenario

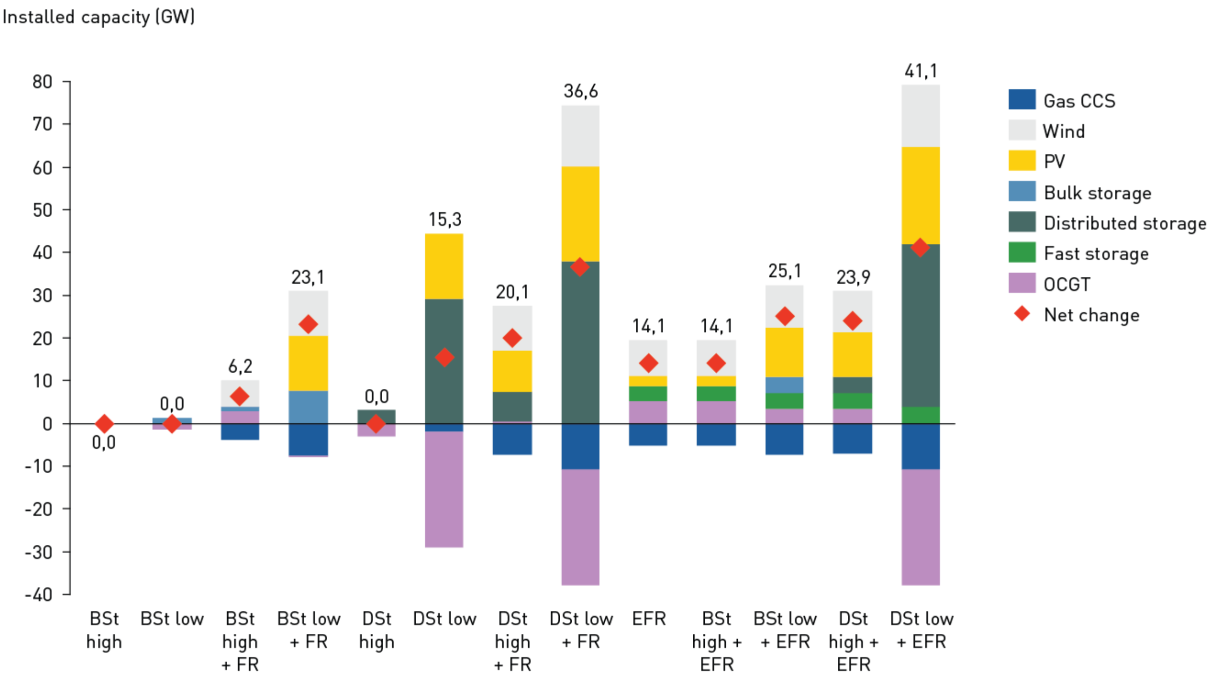
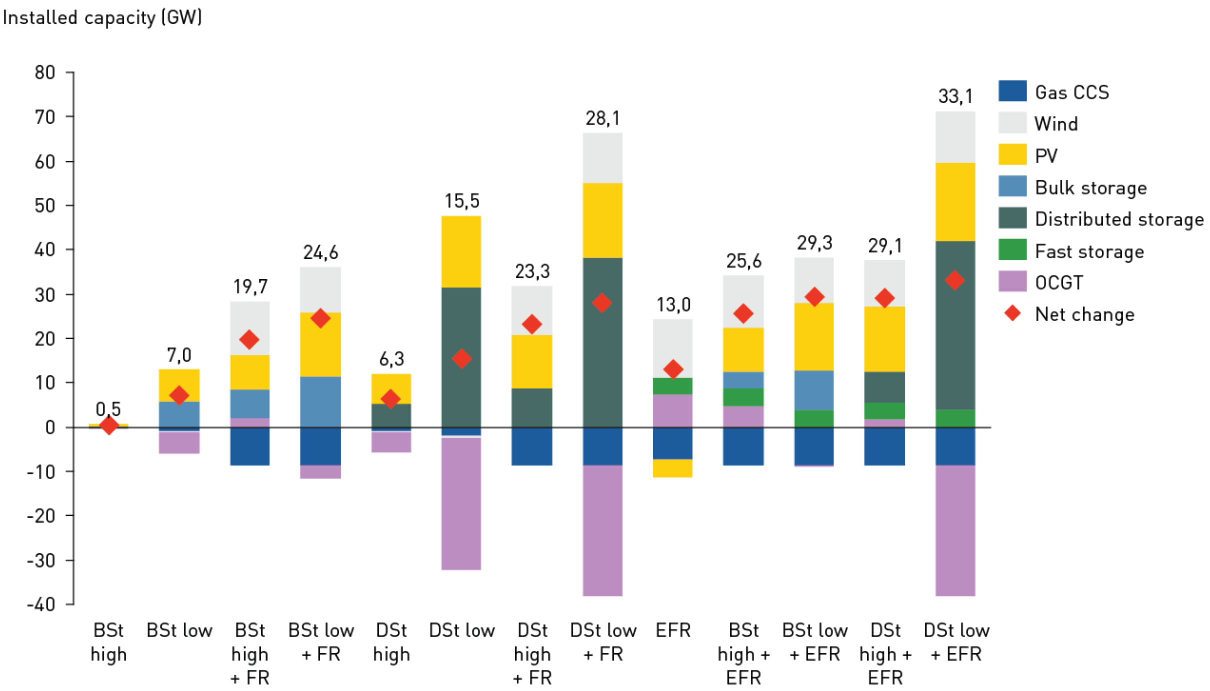


Figure 34 - Change in Installed generation capacity including additional storage cases under a high fuel and carbon price scenario



7.2.15 Sensitivity analysis – nuclear cost

In the sensitivity analysis for cost of nuclear power, three representative costs for were considered:

- **Full societal cost.** As discussed earlier in this section, a nuclear societal cost of £121.50/MWh was assumed, which includes provision of insurance against incidents. While this cost may not be borne by developers and instead by public sector guarantees, it still represents a system cost and must be included, in the same way that externalities such as carbon and system integration costs of renewables are.
- **Hinkley Point C strike price.** The Hinkley Point C strike price of £92.50/MWh was used as a reference point for the latest available project in the UK.
- **DECC published cost.** Assumed at £80/MWh. This is the estimate published by DECC and does not include insurance costs. (Department of Energy and Climate Change, 2013)

The costs mentioned throughout the central analysis and discussion refers to 'full societal cost', as it is necessary to compare the societal costs of each technology to ensure a like-for-like comparison. All nuclear cost sensitivities are carried out under the central fuel and carbon price.

The impact of these changes in the cost of nuclear power, under the no additional storage base case in the 'Market-driven Approach' scenario, are shown in Figure 35. At £121.50/MWh, gas CCS is deployed in favour of nuclear power. The only nuclear power that remains on the system is 5.4GW of legacy plant. As nuclear cost decreases it becomes more competitive against gas CCS. In this way, gas CCS and nuclear power effectively compete to supply a fixed share of available low cost baseload power.

Figure 35 - Change in installed capacity in the 'Market-driven Approach' base case given change in assumed nuclear cost

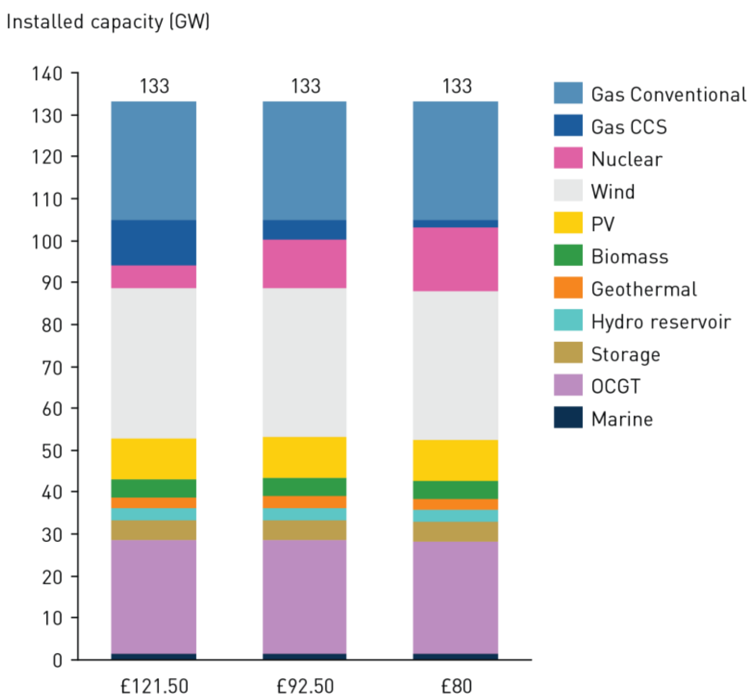


Figure 36 and Figure 37 show the impact of changing the cost of nuclear power on the deployment of storage, under each nuclear power cost assumption. At £121.50/MWh there is significant deployment of storage that enables further deployment of wind and PV, while displacing the need for gas CCS and OCGT. This effect reduces with the cost of nuclear power, where at a nuclear power cost of £80/MWh, the role of storage is reduced to replacing OCGT.

Figure 36 – Change in installed generation capacity including additional storage cases when nuclear cost is £121.50/MWh when additional storage is available

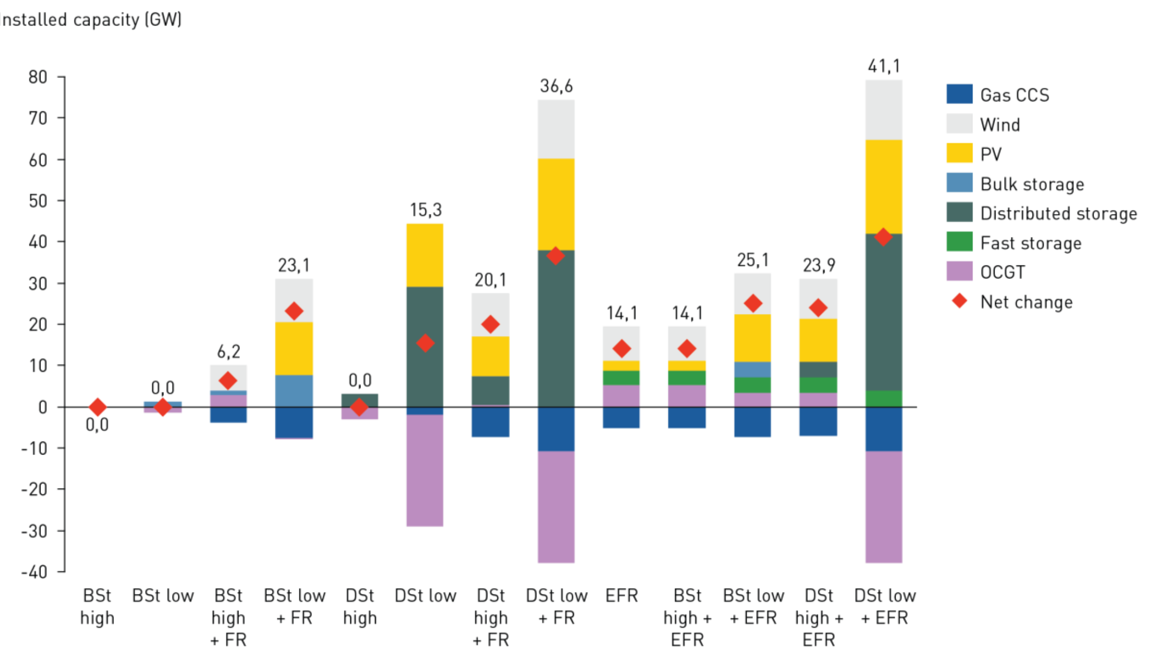
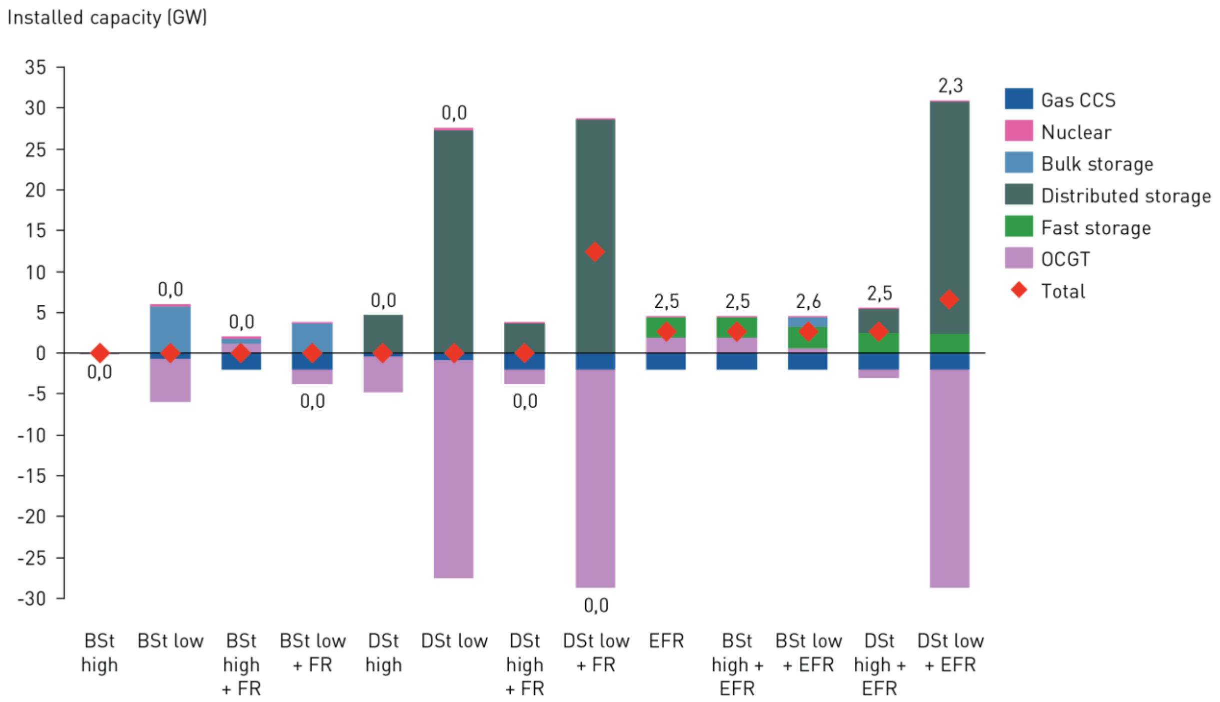


Figure 37 - Change in installed generation capacity including additional storage cases when nuclear cost is £92.50/MWh when additional storage is available

Figure 38 - Change in installed generation capacity including additional storage cases when nuclear cost is £80/MWh when additional storage is available



7.3 Chapter 4 - Business Case 1

Two business cases were designed to illustrate the outcomes of the analysis presented in this report. The first Case Study looks at the opportunities available in maximising revenue following the incorporation of energy storage. The second Case Study examines a distributed scenario of kilowatt scale storage systems in households and at community scale.

The guiding principle of business case one is that a supplier that operates wind assets is incentivised to maximise its revenues by any means available. For the purposes of this analysis, this supplier has the option to incorporate energy storage into its portfolio and seeks to understand how this can best be achieved in order to maximise revenue. It is assumed that the supplier's portfolio contains 100MW of wind that is contained within a single wind farm. A storage asset can then either be located alongside the wind farm or elsewhere in the system.

7.3.1 Cost assumptions of storage

The cost assumptions of storage for this case study are based on Li-Ion batteries considered as a representative technology and are outlined in the following table:

Size	Capital cost (£m) – full project cost including BOP	O&M cost (£/year)	Source
25MW	50	180,000	(Sandia National Laboratories, 2013)

7.3.2 Location and sizing

Results shown in Figure 39 and Figure 40 show the value of both a 5MW and 25MW storage asset when co-located with a 100MW wind farm, in the context of both a flexible and inflexible system respectively. These results show that the annualised value (per kW) of energy storage is approximately double in an inflexible system. Since matching supply and demand on a short term basis is inherently more difficult, and therefore more expensive, in an inflexible system, the prices for this service would be high.

It is likely that, even in the absence of any further energy storage deployment, some measures will need to be taken to increase system flexibility (likely some combination of the measures discussed in Chapter 2). The flexible case is modelled with the assumption that 10GW of installed storage is already on the system to provide flexibility. Therefore further storage in this case would be a price taker rather than a price setter.

Of these two possible futures, the flexible system is considered to be more realistic, and will be used as the base case for discussion of subsequent analyses. The 'true' value will lie somewhere between the two scenarios, depending on the level of flexibility of the system.

In the flexible system, illustrated in the value of energy storage is higher when the asset is co-located with the wind farm, as it is able to better utilise the energy produced by the wind farm. However, this value decreases as the size of the storage asset increases from 5MW to 25MW. When co-located, the size of the asset is independent of its value. This implies that a supplier may prefer to select a small asset to capture a large share of available value at less cost if the asset is co-located with a wind farm.

Figure 39 - Annual value of 5MW and 25MW storage assets under separate and co-located operation with a 100MW wind farm – flexible system

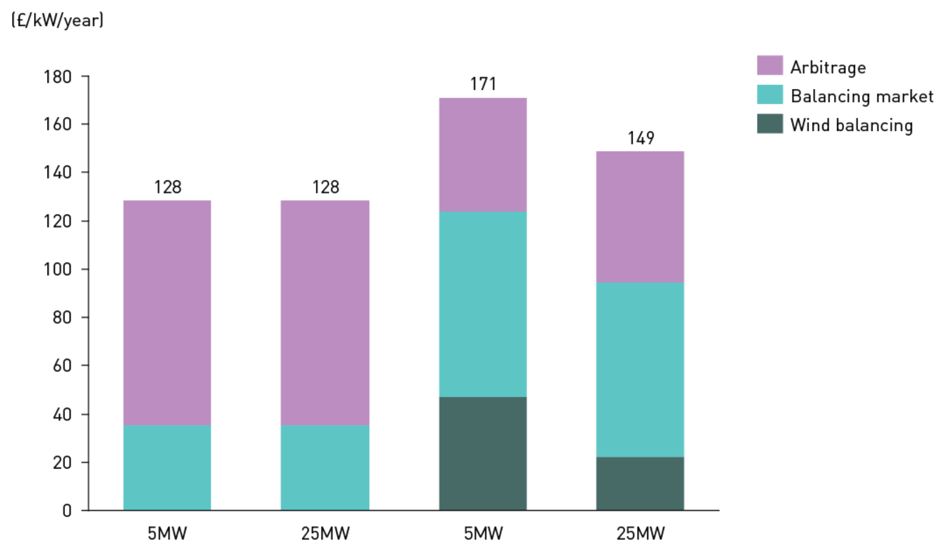
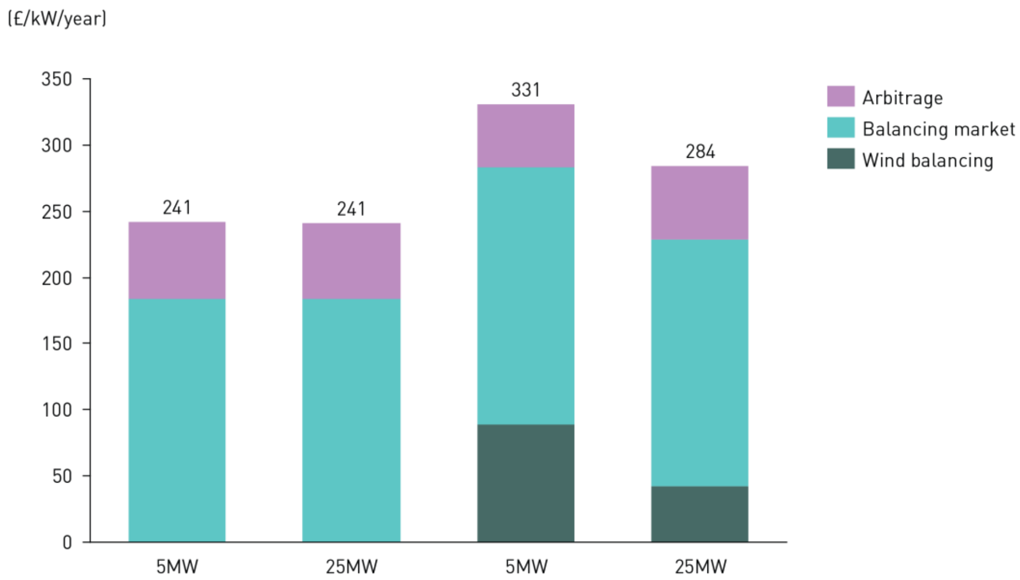


Figure 40 - Annual value of 5MW and 25MW storage assets under separate and co-located operation with a 100MW wind farm – inflexible system



7.3.3 Estimating potential revenues from multiple layered services

This analysis can also be used to estimate the potential revenues that a supplier could generate if it incorporated energy storage into a portfolio that includes 100MW of wind. These revenues are shown in Figure 40 for a 25MW storage asset across a range of different scenarios including both separated operation and co-located operation and the effect of local network constraints. While 25MW shows lower value per kW in the co-located example, we have selected a 25MW storage asset for analysis as this better illustrates the impact of storage on managing a local network constraint.

In this configuration, it is assumed that the storage asset is behind the meter of the wind farm when co-located (i.e. the wind farm and the storage asset are both equally constrained by the local network connection and the combined output of the wind farm and the storage asset cannot exceed the local network connection). The sizes of the constraint – unconstrained, 75MW and 50MW – have been selected for modelling purposes only and are not intended to be representative, however they show the role of storage in managing constraints. In separated operation, the storage asset could conceivably be anywhere on the system that is in front of the meter from the wind farm (on the system side). While there may be geographical considerations of where in the system a storage asset might be placed in this configuration, they are not included in this analysis for simplicity.

Highest revenues are available when a storage asset is co-located with a wind farm that is on an unconstrained network. The difference in revenues between a storage asset that is separated or co-located is due to a change in the distribution of services provided. When co-located the storage asset preferentially provides more services through the Balancing Market, performing less arbitrage, and it reduces curtailment of the wind farm due to the local network constraint (seen as a reduction in the negative 'Wind Balancing' bar).

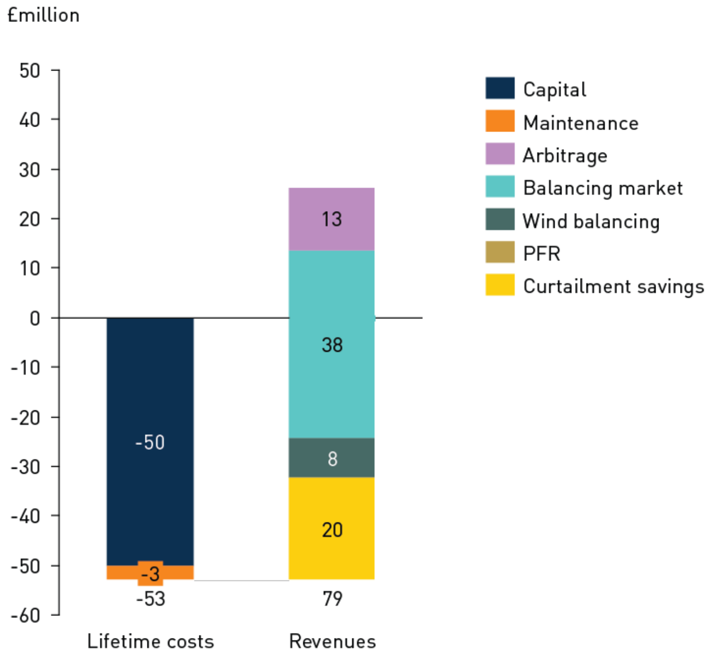
It may also be commercially advantageous for a windfarm operator to reduce imbalance charges by deploying a behind the meter storage asset rather than to rely on the National Grid's Balancing Mechanism (BM) to meet his obligations. However, from a system perspective best outcomes are achieved if all storage assets compete on an equal basis for providing balancing services at lowest cost as compared to having operators use behind the meter storage to self-balance.

The distribution of services performed is the result of the behaviour of this complex system, given that the storage asset must arrange to charge and discharge itself so as to be available to perform a service at a given time. This can be seen in the difference in behaviour of the two unconstrained scenarios in; the addition of local constraint management as a service alters the way the asset provides services through the Balancing Market or does price arbitrage, likely caused by the value available from these services at different times of the day.

The ability of the energy storage asset to manage the presence of a local network constraint can be seen clearly by comparing the 75MW and 50MW constraint conditions across separated and co-located operation. When separated, the storage asset cannot play any role in managing the network constraint faced by the wind farm, and revenues from wind energy production fall significantly as the size of the constraint increases. When co-located, the energy storage asset is able to charge up during times of network congestion and release at other times thereby saving energy that otherwise would have been curtailed.

While the annualised value of the storage system provides a sense of the scale of benefits that storage could potentially unlock, Figure 41 provides a more commercial perspective as it also looks at the respective costs involved (capital and operational). The 25MW Li-ion storage asset system pays back in fourteen years at current prices. Within the co-located scenario, there is inherently greater value in deploying storage under a network constraint (50MW network) as the additional value it gains from reducing curtailment allows it to payback by ten years. This type of usage has implications for the entire system in terms of constraint payments that are currently paid out for curtailing wind, and also for network reinforcement plants.

Figure 41 - Undiscounted lifetime (15 yrs) costs and revenues of a 25MW storage asset in a constrained network of 50MW



7.3.4 Estimating the additional value of frequency response services

In addition to providing wholesale electricity price arbitrage, balancing and better integration of wind power, a storage asset may also be able to provide frequency response services to earn additional value.

Provision of Primary Frequency Regulation (PFR) is a complex service that could be setup in a number of different ways, driven in part by existing market conditions where PFR is contracted to be available one month in advance. Figure 42 shows one approach to meeting this requirement, where a fixed proportion of the storage asset is dedicated to the provision of frequency response services. Here our analysis considers the value of a 25MW energy storage asset where 20%, 40% or 60% of the asset's capacity is dedicated to frequency response services, and is compared against a baseline case where no frequency response services are provided.

Figure 42 - Annual value of co-located energy storage with optimal frequency response – flexible system

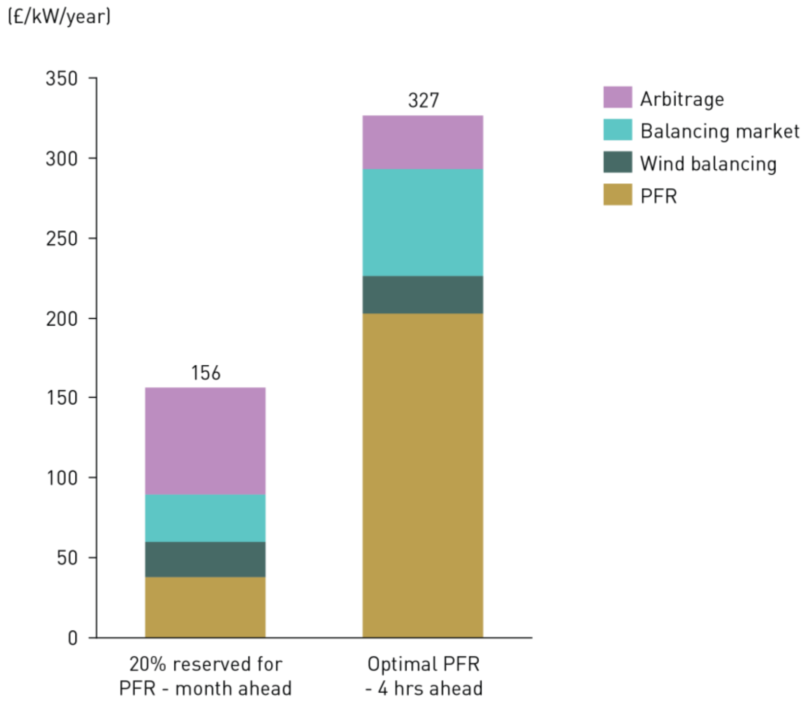
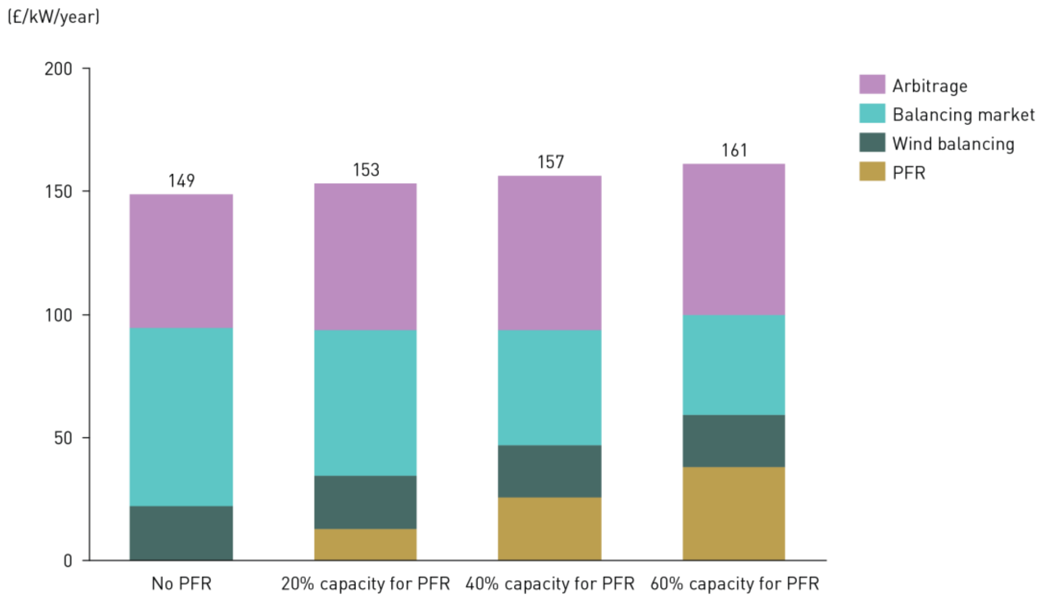


Figure 43 shows that adding the capability to provide frequency response services increases the value of a storage asset, and this value increases as more of the asset is dedicated to these services. This value depends on the flexibility of the system, which determines the price that is paid for frequency response services. In an inflexible system, this value increases significantly.

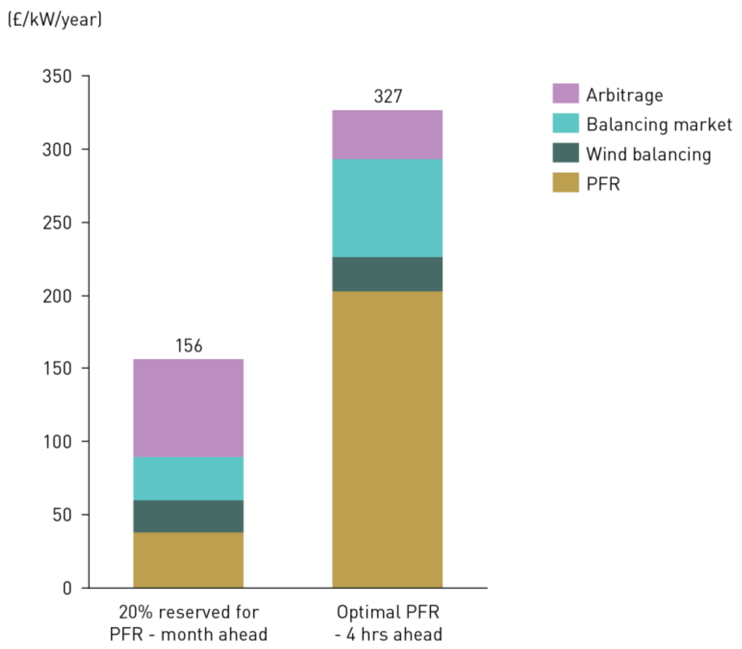
This value is also dependent on supportive market and operational structures. If the storage asset is only allowed to provide these services at certain times of the day, e.g. at peak times, then marginal value diminishes, as shown in **Figure 43.** When under this constraint, there is only a very small extra value available from providing frequency response services. This is because at peak times, there is more value available from other services such as balancing and arbitrage. The value of frequency response services come from availability, which has greater value away from peak times.

Figure 43 - Annual value of co-located energy storage with frequency response available at selected (peak) times – flexible system



The analyses in Figure 43 demonstrates the value of providing frequency response services where contracts must be entered into three months in advance. If this requirement is changed, and the storage asset can contract only four hours in advance and then optimise its services for maximum revenue, then the value more than five times compared with reserving 20% capacity, as shown in Figure 44.

Figure 44 - Annual value of co-located energy storage with optimal frequency response – flexible system



7.3.5 Commercial implication of layering PFR revenues

Layering revenues from PFR enables more attractive returns and payback as it does not require additional storage or capacity changes. This, therefore, creates significant commercial value. Any reduction in the other sources of revenue is compensated by the value generated through providing PFR services.

Figure 45 - Undiscounted costs and revenues of layered services including different types of PFR provision

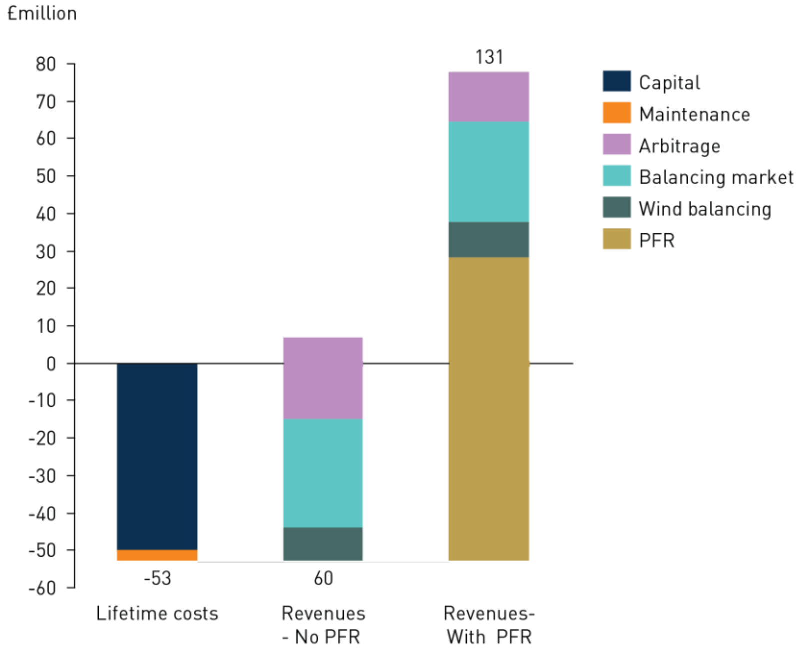


Figure 45 above, shows the increasing revenues from providing PFR services and the implications of having a mechanism moving from months ahead to 4 hour ahead, which drastically increases the value of the service for the same costs[20]. Providing PFR under the current market setup would deliver a simple payback of around thirteen years while delivering an optimised service as against reserving capacity with a 4 hour ahead call would reduce this down to around six years. Additionally, the scenarios above assume no network constraints. However, under a 75/50MW constraint, the value from reducing curtailment further improves the business case and bring the payback down to five years.

7.3.6 Layering services may increase revenue while decreasing degradation

Analysis shows that allowing a storage asset to selectively provide additional services in an optimised way may increase total project revenues while reducing costs associated with asset degradation. Figure 46 and Figure 47 show illustrative state of charge for a battery that provides one or two layered services over the course of a month.

[20] The costs include a total capex and also a lifetime OPEX costs which is termed as "maintenance"

When the storage provides a single service – in this case, electricity arbitrage – its state of charge changes depending on the demands placed upon it to provide the service. In this case, energy storage will need an appropriate state of charge, which is determined by the price signal from the wholesale electricity market.

When the storage provides two services – in this case, Electricity Arbitrage and Wind Management (imbalance reduction) – its state of charge changes significantly over time compared with the single service case. This is because the storage has a wider selection of signals to optimise its performance. Given that the model is also optimising for revenue in each case, there should be no example where the provision of additional services results in a decrease in revenue; it would not perform the additional service if it meant losing revenue.

Figure 47 shows that the amount of time spent at both 100% and 0% state of charge is less when the storage has the option of providing two services. This implies that providing multiple services can both improve project revenues while decreasing asset cycling, which has positive implications for asset lifetime.

Figure 46 - State of charge of storage that provides Electricity Arbitrage or Electricity Arbitrage alongside Wind Management (imbalance reduction) over a one month period

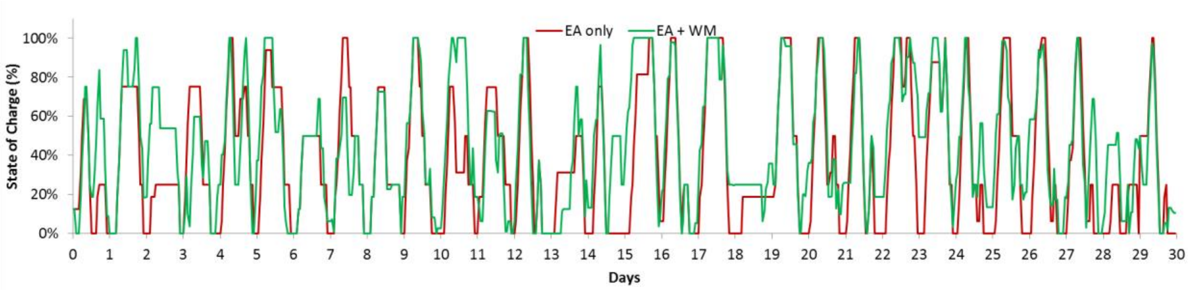
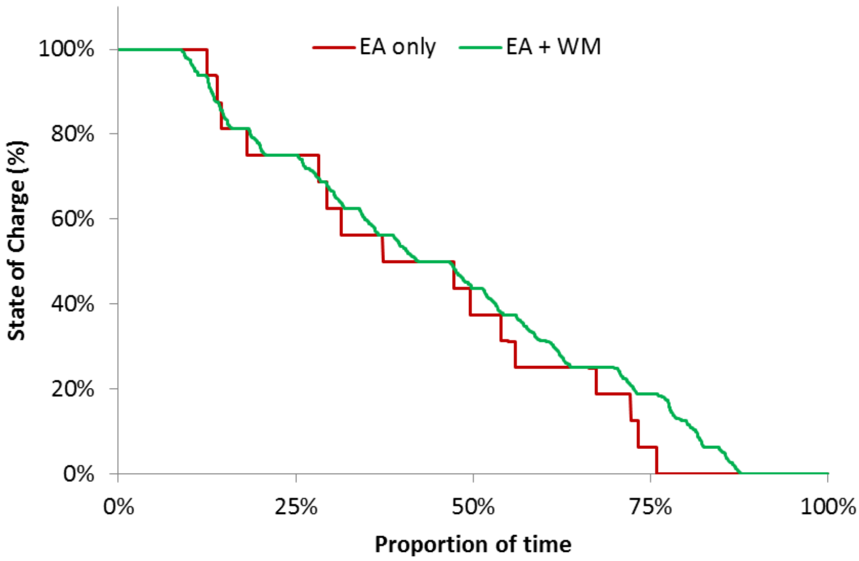


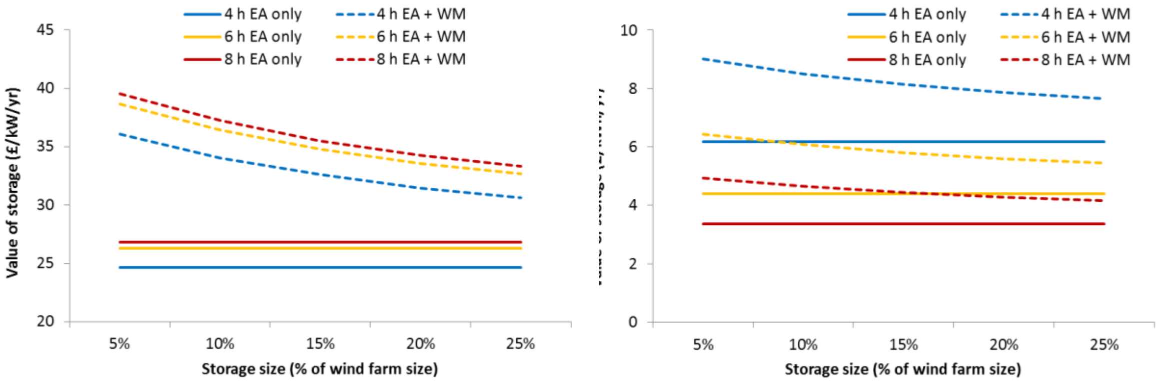
Figure 47- Proportion of time a battery spends at each state of charge with a single service or with two layered services



Analysing the impact of layering services also provides useful guidance in terms of sizing storage. Figure 48 shows the impact of varying the size of the storage asset in relation to a 100MW wind farm, both in terms of power output and energy storage capacity.

When considering Electricity Arbitrage alone, the value of storage is independent of its power output relative to the wind farm. Value of storage increases on a cost per kW per year basis with larger storage capacity (represented in terms of hours), but falls when considered on cost per kWh, which is the more appropriate metric in this case. This implies that a smaller asset, in terms of energy capacity, is more valuable on a per kWh basis. When considering both Electricity Arbitrage and Wind Management, this effect translates to sizing for power output as well, where more value is available per kW with smaller asset sizes in relation to the wind farm.

Figure 48- a) value of energy storage by size relative to 100MW wind farm (£/kW/year) (left); b) value of energy storage by size relative to 100MW wind farm (£/kWh/year) (right)



7.4 Chapter 4 - Business Case 2

The previous business case discussed the potential role of large scale storage integrated with a 100MW wind farm. This case will examine a distributed scenario of kilowatt scale storage systems in households and at community scale (tens of kilowatts). The rationale behind this case is founded by the rapid growth in solar PV installations in the UK. In 2014, the UK had installed more solar PV capacity than any other country in the European Union.

This case explores the effects across two levels. The section begins by looking at the effects on an individual household level, and how energy storage can translate into reductions in a household's energy bill. This is referred to as the individual domestic storage scenario. This section then proceeds to view the effects from a community level. This is referred to as the aggregated distributed storage scenario. In this scenario, the case is presented in a stacked service nature whereby the benefits of adding services are illustrated in a step-by-step service.

7.4.1 Storage cost assumptions

Size (kW)	Cost (£/kW) – including BOP, retailer mark up and installation	O&M cost (£/year)	Source
0.55	960	6	Tesla Powerwall 2kW model; Euractiv (2014) – Solar PV installation cost; Sandia (2014) – O&M cost

7.4.2 Individual domestic storage installation

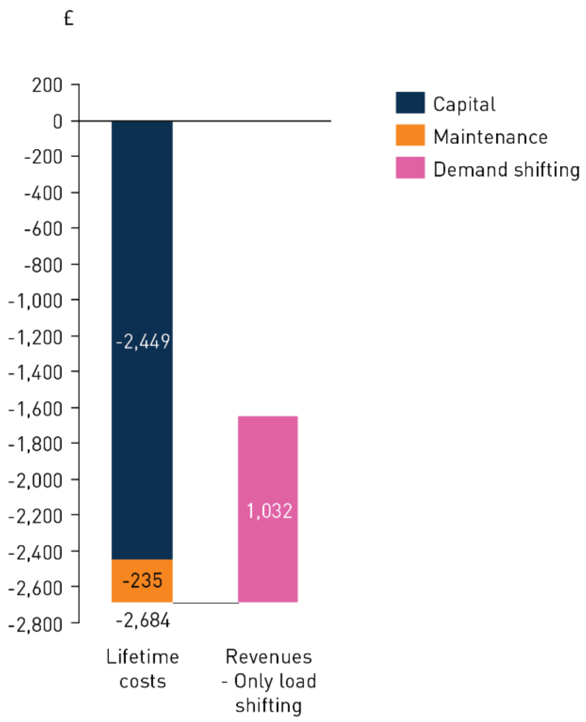
There are many services that distributed storage, coupled with solar PV, could provide. The first of these is energy time-shifting to minimise household electricity bills. Distributed solar PV currently operates without the support of storage, which means that any electricity generated by the solar system must be either consumed by coincident demand or exported to the grid at a feed-in tariff export value that is lower than the retail price. This price differential implies that if surplus solar energy can be stored and used to displace consumption at another time, then it becomes more valuable than export.

Initially, this case considers the impacts to an individual household. Consideration is made for the installation of independent storage systems, integrated with domestic rooftop PV systems, to reduce household electricity bills. Demand profiles in the UK are based on income of occupants and household size. For the purposes of this case study, the value of storage is evaluated for three main types, covering a spectrum of energy use.

This scenario considers a 2kW solar PV system with a 2kW/7kWh Li-Ion battery21, (Tesla, 2015). For comparison, the maximum diversified peak load across household types is 1.72kW with an annual energy use of 5761 kWh.

[21] This is equivalent to the original specifications of the Tesla Powerwall that is marketed for daily cycle applications

Figure 49 - Undiscounted costs and present value of a 2kW/7kWh storage system in a standalone configuration



At the current costs of storage, this business case is the least attractive proposition across the different scenarios with paybacks beyond 20 years. Comparison of undiscounted revenues against costs is shown in Figure 49. The present analysis excluded any costs associated with replacement rates, as it assumes minimal degradation effects associated with home battery systems which, therefore, confers a lifetime of 15 years. However, with paybacks beyond 20 years, it could potentially trigger a battery replacement depending on the specific usage, which will further increase the time to payback.

This case of stand-alone DG with storage under the existing network tariff regime is not socially optimal in terms of reducing overall costs to all consumers. Under the current regulation, the consumer can arbitrage between the whole sale price (export tariff) and retail price of electricity (import tariff) where the latter includes energy costs, environmental and social levies, network costs and taxes. Storage in this case allows for greater reduction in purchase of electricity at retail prices (relative to only using distributed generation). This reduces revenues required to maintain and manage the grid[22] and could lead to higher retail prices for other end users.

7.4.3 Aggregating distributed storage

The aggregated distributed storage scenario assumes the presence of a third party that can deploy a software system can coordinate and optimise across a series of small storage assets in domestic

[22] Investment into networks would be still required to cover peak demand under a worst case scenario of zero supply from distributed generation and so this is unlikely reduce in costs without energy storage and cost reflective non-static price signals that could help shave peaks and consequently defer reinforcement . Currently the cost recovery is based on a volume/kWh based tariff i.e. based on energy consumed and since storage reduces the consumption ultimately in combination with distributed PV, the cost recovery reduces.

households. Analysis has considered a community of 90 households with different demand profiles that have small scale storage installed with a 2kW solar PV system. The optimisation allows the storage unit to leverage other demand profiles; thus the installed capacity delivers greater value and renders higher utilisation compared to the individual domestic storage scenario.

However, under this scenario, storage can leverage stored surplus energy, differentials in demand, or available storage capacity to improve utilisation across the aggregated system. This additional stored energy that was previously lost can be used to offset the need to purchase electricity from the grid, translating to a reduction in household bills across the community. The roll out of smart meters and installation of Home Energy Management Systems will be crucial to aid in optimising storage use between households, given the detailed information that will be available of demand profiles. This will help accurately forecast energy use and time the operation of storage to maximise cost reduction opportunities.

While the system impact of scaling up this business case is not estimated, it is evident that there is a significant opportunity to align consumer behaviour with wider system benefits by providing appropriate price signals. These activities can be part of a wider demand side management (DSM) programme that rewards load reduction. For example, energy can also be delivered by switching to storage to run household appliances for the particular time period, rather than turning down load as is the case with conventional DSM. This would require little change in consumer behaviour in terms of energy usage as, during the time of demand reduction required, stored energy can be used to power various household activities rather than reducing outputs or deferring the activity itself.

Leveraging diverse demand profiles in a community significantly improves the revenue of the storage system. While providing the same demand shifting service as in the standalone case, the storage asset provides a better commercial case that pays back in fourteen years. Since aggregation improves the utilisation of the storage system and returns higher value per unit of installed capacity, the business case is thus better for the smaller asset (0.6kW) in the sizes of storage considered in this analysis.

Figure 50 - Undiscounted costs and value of an aggregated 0.6 kW storage system

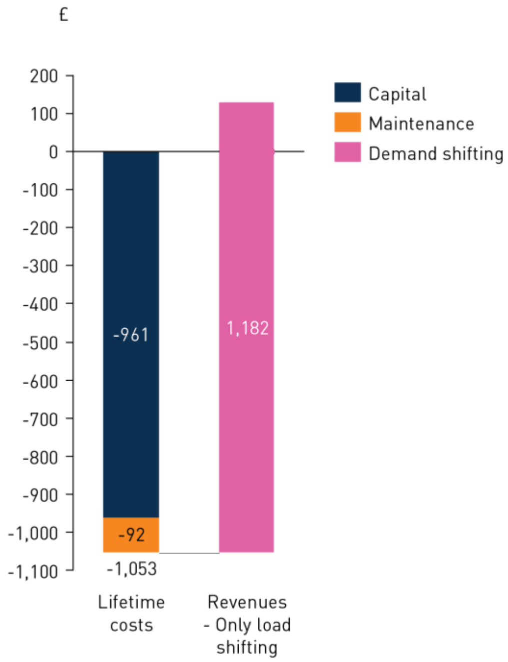


Figure 51 - Undiscounted costs and present value of an aggregated 2kW system providing demand shifting

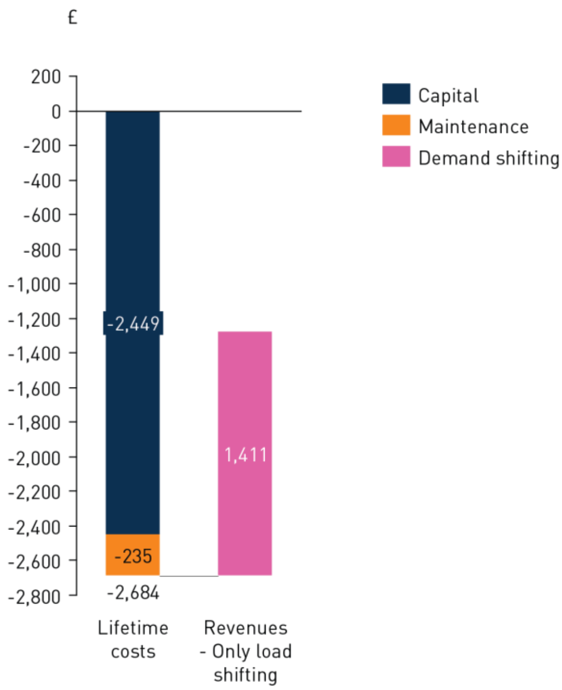


Figure 50 and Figure 51 provide a simplistic overview of different storage system sizes for providing demand shifting services. Comparing the two scenarios gives an insight into system sizing, under a scenario where small scale distributed storage is aggregated. Here, as marginal cost exceeds marginal revenue potential, the gap between costs and revenues increases for the larger asset.

The improved utilisation of storage provides an opportunity to scale down the asset and improve the specific revenue potential across its lifetime. This implies that there is an opportunity to reduce capital expenditure, which increases the attractiveness of such an investment decision.

7.4.4 Combining consumer and grid facing services

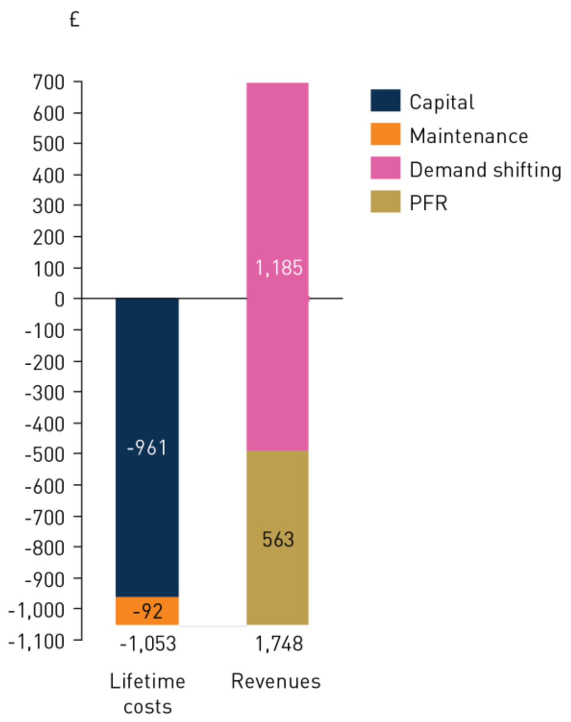
Aggregating storage provides advantages beyond better utilisation of assets. It helps unlock other potential sources of revenue beyond the household by using the aggregator to engage with different markets. This route is more cost effective as it benefits from economies of scale.

The first alternate revenue opportunity that is considered is the provision of primary frequency response (PFR) services into commercial markets procured by National Grid. As mentioned previously, frequency response is generally used by National Grid when balancing services to address unexpected imbalances between demand and supply. PFR is currently provided by generators that regulate their output and react to frequency variations within 10 seconds and adjust their output for 30 seconds. There are several ways of adjusting household load to provide PFR, from automatic load control in domestic appliances to refrigerators that can be turned off for short durations to provide similar responses. Here, it is assumed that the distributed storage systems can feed into the PFR market by providing similar load adjustments to vary with grid frequency deviations.

It is assumed that PFR is provided through existing system capacity and the aggregator's ICT system has the ability to optimise the storage unit to provide PFR when required. It is important to note that the modelling, in this case, has made simplified assumptions regarding PFR provision scheduled and overall system flexibility; overall intentions are to provide an initial estimate of the scale of opportunity rather than absolute figures.

Providing additional services using the storage asset as expected improves the economics of this business case, with the asset paying back in seven years. The additional revenue from PFR adds almost 50% to the base revenues, consisting of cost reductions from demand shifting and lowering grid electricity purchase (Figure 52).

Figure 52 - Undiscounted costs and revenues for a 0.6kW storage unit providing demand shifting and PFR



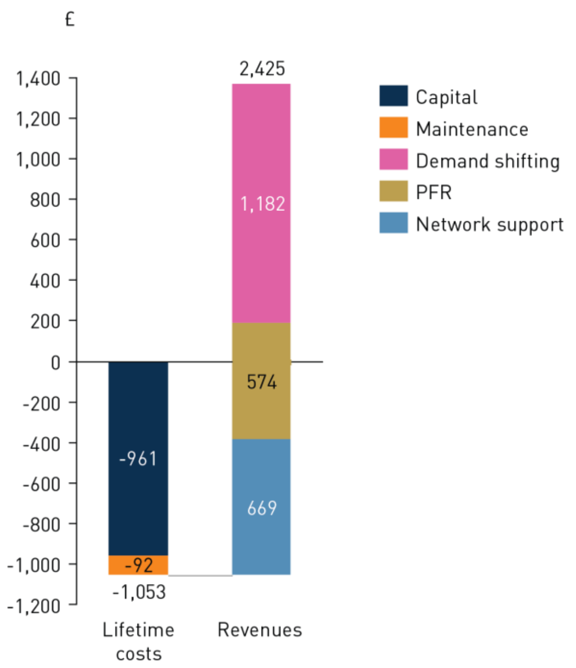
Providing PFR and gaining the additional revenues does not impede on the base cost savings from demand shifting. This highlights the potential to optimise the storage asset to provide multiple services without having to forego revenues. The trend of improved utilisation continues when performing multiple services, which has implications for asset sizing. However, while the total revenue increases with asset size, the value per kW that can be realised reduces.

7.4.5 Network constraint alleviation

Increasing penetration of distributed renewables, changing demand profiles from demographic changes, and increasing electrification of heat and transport suggests that there is a significant and ongoing need to upgrade distribution networks. Historically, these upgrades involve traditional network reinforcement (e.g. larger capacity transformers), but more advanced options are becoming available. These options are important for strategic decision making given the uncertainty in energy systems. "Smart solutions", such as energy storage, provide option value that allows planners to retain flexibility at least cost and regret, across a variety of potential energy futures that could emerge.

Providing network support increases present value by 40%, compared with a scenario where only demand shifting and PFR are provided. This highlights the additional value that storage is able to unlock, in addition to revenue at existing capacity. This revenue stacking scenario whose cost and revenues are highlighted in Figure 53 is estimated to be the most commercially attractive in the case presented here, with payback in five years after installation. A large proportion of this is due to the high revenue potential associated with this scenario.

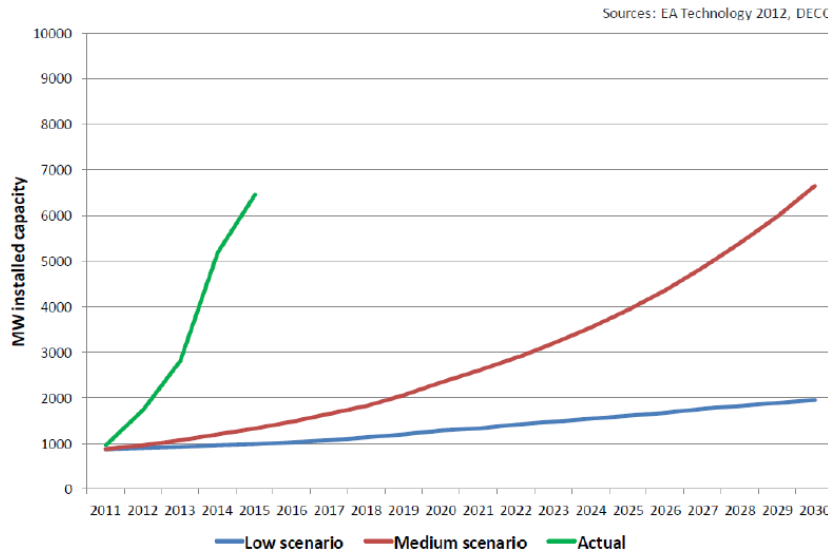
Figure 53 - Undiscounted cost and revenue for a 0.6kW asset providing multiple services



Beyond its commercial attractiveness for the household or the owner of the storage asset, this has significant implications for strategic distribution network planning, given the uncertainty around the future growth of distributed generation. Forecasting trends has been very difficult to predict, evidenced by Figure 54 below which shows that solar PV installation has far exceeded industry, policy and regulatory expectations.

Given that network constraint alleviation is an additional revenue stream beyond the other services, there is merit in considering if a scenario with distributed storage presents a flexible option for network operators for network planning. This could be to reduce risk of creating stranded network assets if a particular scenario does not materialise. In this case, a storage asset is still able to return revenue from other services and the increased cost of conventional reinforcement is avoided, directly impacting energy bills as network costs account for more than 20% of a typical dual fuel bill (Ofgem, 2015).

Figure 54 - Trend of solar PV DG installation in the UK and the challenge of forecasting (Ofgem, 2015) presented at the 2015 DG fora



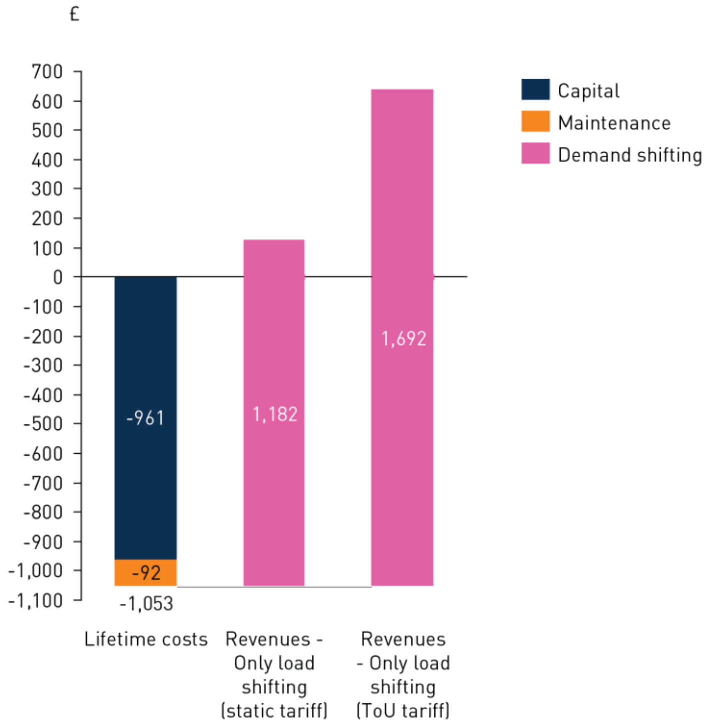
7.4.6 Time-of-Use (ToU) tariff and value of storage

While the scenarios discussed previously have assumed a flat price tariff, a representative Time-of-Use (ToU) tariff can also be used to estimate the impact on potential revenues of dynamic pricing. This scenario can be considered as a realistic future for energy pricing in the UK given the aligned intentions between Ofgem and the speech by the Secretary of State of DECC to “remove barriers to suppliers choosing half-hourly settlements for household customers” (Rudd, 2015).

The base revenues considered so far represent cost savings from leveraging storage to reduce grid purchase using solar PV. Under a ToU tariff, given that there is a presence of a peak price, the cost savings will increase. This is as storage can be used to reduce grid purchase during the times of higher price, compared to the application of a flat price tariff during non-peak times. Recent innovation projects in the UK, such as Low Carbon London (LCL), have shown the positive acceptance of such dynamic tariffs and the potential for demand reduction through their use.

Given the services that storage can provide, that have been considered in this business case, the impact of a ToU tariff only reflects the cost reduction potential of shifting demand, as the other two services are contracted in different markets independent of the profile of the domestic tariff. Examining a scenario where only demand shifting revenues are realised, it is evident from Figure 55 that revenue is significantly increased under a ToU tariff, accounting for around a 50% increase in revenues when compared to a flat price tariff. The scenario with ToU tariff also pays back in nine years compared to thirteen years under a flat electricity tariff.

Figure 55 - Comparing undiscounted revenues for a 0.6kW storage system between different tariff regimes – static and ToU



7.5 Review of existing activity

7.5.1 United Kingdom

Electricity storage is not a new concept in the UK. Since 1984, the UK has had 2.8GW of storage capacity in the form of four pumped hydro power stations. Initially they were constructed to provide flexibility to the nuclear fleet, by storing excess electricity at night and discharging it during time of peak demand; they continue to participate in energy arbitrage. The pumped hydro facilities also provide the full National Grid tendered amount of fast reserve, that is a delivery of at least 50MW active power through increased generator output within 2 minutes of instruction and sustainable for a further 15 minutes (National Grid, 2015). Dinorwig, the largest of the four facilities, is also capable of participating in the frequency response market as it can provide 1.3GW of power within 12 seconds of switching on (MacKay, 2008).

Smarter Network Storage

UK Power Network's Smarter Network Storage project received £13.2 million funding from Ofgem's LCNF to trial the efficacy of battery storage in deferring necessary reinforcement works at Leighton Buzzard by providing additional capacity at peak times. The 6MW/10MWh array of Li-Ion batteries allows for a faster provision of network capacity than traditional reinforcement and, for this particular installation, it was initially reported that it could be up to £3 million cheaper (Ofgem, 2012). This application of storage will be increasingly important with the connection of distributed generation and the electrification of heat and transport. To ensure economic viability of this solution, the battery will trial the layering of services and optimise the associated operational regime, though any additional service must be compatible with its primary purpose. Balancing services provided to the grid, such as Short Term Operating Reserve (STOR) and Fast Frequency Response (FFR), add revenue and are beneficial to the system in facilitating intermittent generation. Hence they have been identified as potentially suitable revenue streams. The storage asset was successfully enrolled into a STOR contract beginning 1 April 2015 and has demonstrated FFR functionality, though is yet to undergo prequalification with the National Grid. UKPN has also formulated first-of-a-kind contracts with third parties Kiwi Power and SmartestEnergy, to, respectively, interface with the National Grid for the provision of the balancing services and to enable suppliers to control the storage asset for a period of time, perform arbitrage and manage their imbalance risk. These contracts have furthered the potential business model and provided a more comprehensive understanding of the revenues available to a storage asset.

More storage will be required to effectively integrate a large deployment of renewable energy generators, add grid stability and energy security. Innovative use of technology has demonstrated the additional benefits that energy storage can offer and has confirmed that storage will be fundamental to the smooth operation of the electricity network in the low-carbon future. Nonetheless, in order for electricity storage to play its role in the future, current investment is required to develop and demonstrate strategies to transition the storage industry from one-off funded projects to wide scale deployment. The Low Carbon Innovation Co-ordination Group (LCICG) brings together major public-sector backed organisations that are expected to spend a combined £1 billion on low carbon innovation to maximise the impact and value of their spending. Ofgem and DECC are members of the LCICG group.

Storage has benefitted from their funding. Such projects include Ofgem's Low Carbon Network Fund and DECC's innovation competition to support energy storage technology research and development.

These have resulted in:

- The potential applications of "second-life" electric vehicle batteries to reinforce the distribution network.
- Storage to support isolated island-grids with a significant portion of wind energy
- The use of flywheel-based energy storage systems to provide services to the grid.
- The operational management of storage to allow access to ancillary service markets, thus ensuring the economic viability of storage in addressing network constraints.
- Distributed energy storage to deliver services and value to consumers and the power grid.

7.5.2 United States of America

The United States is one of the largest energy consumers and CO_2 emitters in the world. In an effort to address climate change, President Obama has set a 20% renewable energy generation target (Parnell, 2013) and pledged to cut emissions to 26-28% below 2005 levels by 2025 (Taylor & Branigan, 2014). More recently, the finalisation of the Clean Power Plan determines emissions reduction targets for individual states, based on the mix of resources available and emissions reduction potentials.

The US power grid faces many of the same challenges as the UK in efficiently providing reliable power, as an increasing proportion of the generation mix is produced from renewable resources. Concerns over the technical and economic performance of the electric power grid have motivated significant interest in energy storage technologies.

Favourable regulation in the US, outlined with the box below, has been coupled with forward-thinking grid operators to successfully encourage a number of recent grid-scale storage deployments: 61.9MW of storage was connected to the US grid in 2014, an increase from 44.2MW in 2013, and the Greentech Media *US Energy Storage Monitor* predicts that a further 220MW will be installed in 2015 (Parnell, 2015). However, the preferred method for encouraging these deployments varies across the US with two particular regions leading the way: PJM, a regional transmission organisation that coordinates the movement of wholesale electricity in 13 states in eastern US, and the state of California.

US regulation supportive of storage

FERC Order 755. (United States of America Federal Energy Regulatory Commission, 2011)
The US energy storage market was given a boost in 2011 when the US Federal Energy Regulatory Commission (FERC) introduced Order 755 - "Frequency regulation compensation in the organised wholesale power market". This mandates that grid operators must pay fast-responding frequency regulation resources based on their performance in following the frequency regulation dispatch signal and specified that separate payments must be made for capacity and actual performance.

FERC Order 784 (United States of America Federal Energy Regulatory Commission, 2013). "Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies" requires transmission providers to consider speed and accuracy when contracting frequency regulation providers. Further, it creates a reporting and accounting mechanism to track the installation, operations and maintenance costs for energy storage to ensure transparency as more projects are deployed.

FERC Order 792 (United States of America Federal Energy Regulatory Commission, 2013). "Small Generator Interconnection Agreements and Procedures" added energy storage to the category of resources eligible to interconnect with the electric grid, thus allowing energy storage to receive rates, terms and conditions for interconnection with public utilities that are just and reasonable and not unduly discriminatory.

The most significant revenue opportunity for storage operators in the US is frequency regulation, with PJM offering the most lucrative fast-response frequency regulation market. As such, PJM attracted two thirds of the 62MW of storage connected to the US grid in 2014 (Energy Storage Update, 2015). As the PJM market was the first to develop on the back on Order 755, the rush of projects has led to certain balancing issues between the different frequency regulation markets leading to an interim cap on the market which has a 2 second response time. This cap is likely to last until the PJM task force develops a better solution to manage the resources feeding into the different frequency regulation markets.

In response to the FERC order 755, PJM used knowledge gained from a number of storage pilot projects to restructure their market. Assets are now separated into those that follow a traditional, slower signal (RegA) and those that are capable of following a dynamic, fast-responding regulation signal (RegD). In addition to the capability and performance payments, high performance resources such as batteries are able to earn bonus payments, which are calculated by multiplying the performance payment by the additional amount of power that fast resources achieve compared to slower ones.

Laurel Mountain

AES Energy Storage is a technology agnostic "storage as a service" provider. Its facility at Laurel Mountain is a 98MW wind generation plant in West Virginia with a co-located 32MW/8MWh Li-ion storage facility installed in 2011. The integrated energy storage device allows the wind facility to smooth fluctuations in its minute-to-minute output and optimise renewable energy generated, as well as instantaneously follow frequency regulation commands from PJM. The facility is capable of operating better than 95% availability for the provision of emissions-free reserve capacity to help maintain grid reliability (Energy Storage Association, 2015). As a result the storage installation enables the wind farm access to additional revenue streams for services that would be impossible for a conventional wind farm to provide.

The California Public Utilities Commission issued an Energy Storage Mandate in 2013, the first of its kind in the US, partly in order to address the large scale integration of renewable energy and California's ensuing "Duck Problem", but more significantly to progress the nascent energy storage industry. The mandate stipulates that 1.325GW of energy storage must be deployed by the state's three largest investor-owned utilities (Southern California Edison, San Diego Gas & Electric and Pacific Gas & Electric) in order to support the state's power grid by the end of 2020.

The mandate was intentionally vague as to how this would be accomplished, acknowledging the considerable feat it posed and that valuable experience would be gained along the way that would better inform the additional details. However there were two significant clauses. One specified that utilities could own no more than 50% of the storage procured, thus opening the door for a variety of resource ownership models across the grid domains (transmission, distribution or customer-located storage). The other provision excluded the most mature storage technology: pumped hydro storage projects larger than 50MW. This emphasises the original purpose of the mandate, which is to enable a market transformation for newer storage technologies.

Some existing storage projects can count towards the investor-owned utility's targets, as long as the project became operational after January 1 2010 and demonstrates the ability to optimise the grid, integrate renewables or reduce greenhouse emissions (Pacific Gas and Electric Company, 2014).

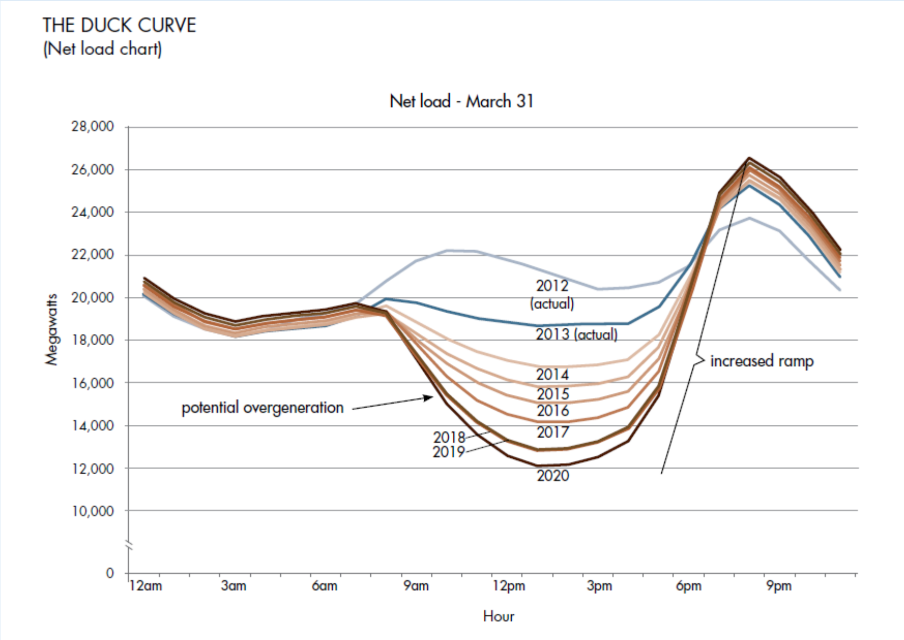
One such project is the Yerba Buena Battery Energy Storage System, a 4 MW/28MWh sodium-sulphur battery system supplied by NGK insulators. The system is located on the property of a research facility for HGST (a data storage company), at the end of a distribution feeder in order to improve power quality and reliability for customers by stabilizing voltage frequency. Further, it has the ability to island the facility and continue to supply loads downstream for up to seven hours in the event of a utility disturbance or outage.

The Yerba Buena BESS is also being used to study the performance of batteries for peak-shaving as well as participating in CAISO (California Independent System Operator) ancillary services markets. Approximately half the energy capacity of the system is planned for use for distribution support and half for CAISO market services (Electric Perspectives, 2015).

California's Duck Problem

Extensive deployment of renewable energy, in particular customer-sited solar PV, will have a large impact on the operation of the grid. The "duck curve" was created by CAISO as part of a detailed analysis of the effect of changing grid conditions on the net load (*total demand less variable generation from wind and solar)* of the California power system. A large influx of solar power at midday produces the “belly” of the duck, this is followed by the duck’s “neck” caused by reducing solar power output coinciding with rapidly increasing demand into the evening peak. The “belly” presents a problem of over-generation as conventional power plants have a minimum generation level, whereas the "neck" is problematic as it requires a significant rate of change of output in order to match demand. Although the duck curve represents the worst case scenario, it must be considered to ensure reliable and efficient operation of the grid in the future. Newer flexible capacity, along with suitable pricing incentives, will be required to “manage the duck”. (California ISO, 2013)

Figure 1- The California 'Duck Curve' (Greentech Media, 2014)



7.5.3 Japan

The Great East Japan Earthquake and ensuing Fukushima nuclear accident in March 2011 caused an abrupt redesign of Japan's generation mix. Progressively all 50 of the remaining nuclear reactors were closed or suspended for safety inspections by May 2012, amounting to a total reduction of 47.5 GW in generation capacity (World Nuclear Association, 2015). This rapid decline in self-sufficiency has aggravated a vulnerability of Japan's supply system. Prior to the earthquake Japan's primary energy self-sufficiency rate was 19.9%, but in 2012 it reached a low of 6%. To overcome this shortage Japan increased its fossil fuel imports, leading to an 88% dependency on fossil fuels as a power source in 2013, up from 62% in 2010. As well as significantly increasing Japan's greenhouse gas emissions, this also resulted in Japan's large trade deficit of 11.5 trillion yen ($9.6 billion). In response to this situation the government promoted an increased deployment of renewable energy sources by introducing a feed-in tariff and setting a renewables target of 25-35% of total power generation by 2030 (Japan Agency for Natural Resources and Energy, 2014).

However the integration of renewable energy is complicated by the fragmented power grid: there are ten different vertically integrated utilities responsible for the transmission, generation and distribution of electricity in ten different geographic zones. Additionally, the east and west of the country operate at different frequencies, within limited DC interconnection between the two. Altogether, these issues make exporting excess renewable energy from one region to another particularly problematic. Without energy storage many renewables projects are at a risk of being cancelled due to weak grid points.

Japan has a large pumped hydro storage resource, with 44 projects and total capacity of 29GW (United States Department of Energy, n.d.), and has pioneered variable-speed pumped hydro technology, allowing facilities to regulate frequency in both pumping and generating modes. The primary role of pumped hydro in Japan is to add flexibility to nuclear generation by providing peaking capacity and frequency regulation services, hence the closure of nuclear reactors has made them available for renewable energy integration. However, as nuclear generators are inevitably brought back online, additional battery capacity is required to manage intermittent renewable generation and alleviate the stress on local networks. Japan isnow pursuing large battery installations with significant funding from the government as the Ministry of Economy, Trade and Industry plans a $700 million cash injection into the energy storage market, available to investors considering storage to balance the grid (Deign, 2015).

The northern island of Hokkaido is a prime location for renewable energy generators, with a significant wind resource in the north and the availability of large areas of relatively inexpensive land suitable for mega-solar farms. However, in April 2013, Hokkaido Electric Power received four times as many applications for connection to its ultra-high-voltage transmission system than it could manage (Chang, 2013). To address this issue, a 15MW/60MWh redox flow battery is being installed, with the goal of increasing Hokkaido Electric's capacity for wind and solar by 40MW, an additional 10% of electricity (Sumitomo Electrical, 2013)

7.5.4 Germany

In 2000, the German Renewable Energy Act (2000) introduced a feed-in-tariff that provides protection for investments in renewables, giving a guaranteed connection to the grid and slightly above market price for electricity fed onto it. The digression of the feed-in tariff also promotes advances in energy efficiency and innovation in technology.

However, the investment in renewable energy generators has not been matched by investment in grid infrastructure. There is a lack of transmission capacity between north-east Germany, which has a large wind capacity, and the south of the country, where there is a large energy demand from heavy industry. Grid operators are now having to intervene increasingly frequently, often by diverting oversupply to neighbouring countries, in order to manage large influxes of wind energy and to maintain stability. This solution is a good example of the value of high levels of interconnection, and illustrates the UK's need for alternative options given the limited potential for interconnection between the UK and continental Europe.

Prior to the accident at the nuclear facility in Fukushima, Japan, nuclear generators produced nearly 20% of energy in Germany. Following revived and strengthened public sentiment against nuclear power, the government ordered the closure of eight nuclear facilities. The "Energiewende" (Energy

Transition) in 2011 then aimed to close Germany's remaining nuclear capability by 2022 and transition to 80% of energy coming from renewable sources by 2050 (or 35% by 2020) (Smedley, 2013).

Bosch Braderup

When the German power grid is congested by large volumes of wind energy, wind farms must curtail their output to prevent overloading the grid. A community-funded wind farm consisting of six 3.3MW wind turbines in Braderup installed a hybrid battery storage solution to mitigate the loss of power from curtailment. A 2MW/2MWh Li-ion battery connected alongside a 325kW/1 MWh V-flow battery produces a more efficient storage of energy by choosing the most suitable battery dependent on the strength of the wind. The hybrid system balances out the short-term fluctuations in output and allows the wind farm to participate in the frequency regulation market and perform wholesale electricity price arbitrage. Furthermore, the batteries could provide power to the community for a week if needed (Renewable Energy Industry, 2014).

Large amounts of residential solar power have created similar impacts on grid stability as well as additional challenges for low voltage distribution networks, requiring the upgrade and extension of existing infrastructure. Ultimately, this has increased the cost to the consumer.

The difference between the wholesale electricity price and the fixed renewable energy tariff is incorporated as a renewables surcharge, for which heavy industry are exempt, and account for 23% of household electricity bills. Together, these rising costs have led to German household electricity prices being some of the highest in Europe for the last five years (Thalman, 2015).

The increase in bills has brought grid parity for solar PV much closer. According to a Creara report published in February 2015, PV socket parity was reached in Munich and Berlin in 2013. However, it assumes that 100% of self-generated electricity is consumed in order for the PV LCOE to be competitive with retail electricity prices (Briano, et al., 2015).

Grid parity incentivises more households to move towards self-generation or energy independency by installing battery storage alongside solar panels. However, this reduces revenues required to maintain and manage the grid and could lead to higher retail prices for other end users In 2014, nearly one in five PV installations was sold with battery storage and nearly 70% of German PV installers now offer customers a storage option (Deign, 2015).

This trend is actively encouraged by the government as it offers more efficient use of solar power and an opportunity to reduce pressure on the local grid from peak solar power production at midday. The Federal Environment Industry in conjunction with KfW, a government-owned development bank, are offering low-interest loans and subsidies to homeowners for the purchase of new solar PV integrated with storage, or the retrofit of storage to existing PV installations. The programme aims to stimulate investment in decentralised battery storage.

Recognition of the potential for battery storage, to help stabilise the grid, has led to innovation within the German energy market. The concept of Virtual Power Plants (VPPs) have garnered increasing attention for their ability to aggregate individual decentralised power generators into a portfolio that can be operated as an easily dispatched and flexible resource. VPPs are designed to maximise profits for the individual asset owner by participating in the energy market and providing grid balancing services.

For VPPs to be successful, the software and communication between various assets is key. These issues are being addressed:

- Green energy supplier Lichtblick has developed a software platform "SchwarmDirigent" that provides electricity from a cluster by intelligently networking and managing solar panels, battery storage, combined heat and power units, electric vehicles and wind turbines.
- VHPready is an industry alliance which aims to develop the industry standard for networking of decentralized energy systems and ensure a seamless and reliable integration of all controllable components. VHPready has established a certification program designed to determine compatibility for an eventual TSO prequalification.

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