Flexibility in the GB Power System

Future needs, alternative sources and procurement

UKERC Working Paper

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1. Executive Summary

This report explores the critical role of flexibility in the ongoing transformation of the Great Britain power system toward Clean Power 2030, and the broader net zero target. Flexibility, defined as the system's ability to balance electricity supply and demand in real-time, is becoming increasingly vital as renewable energy sources replace traditional, dispatchable fossil-fuel power stations. This transition introduces significant challenges related to variability, uncertainty, and the need for system reliability, while also pursuing the decarbonisation goals mandated by government policies.

The document begins by emphasising the importance of flexibility for maintaining system security and balancing supply and demand under physical and operational constraints. Historically, fossil-fuel generators provided this flexibility, benefiting from their ability to adjust output rapidly and contribute inertia to stabilise the grid. However, the shift to renewables and decentralised energy resources necessitates novel approaches and technologies to meet the increasing demand for flexibility.

A major driver of this change is the growing reliance on variable renewable energy sources, such as wind and solar, which inherently introduce fluctuations in supply. Simultaneously, the electrification of transport and heating sectors is significantly increasing electricity demand, placing additional strain on the grid. These trends underscore the urgent need for innovative solutions to ensure system stability and cost-effectiveness while minimising environmental impact.

In addition to the mainstream energy storage technologies, such as batteries, which are crucial for providing flexibility, substantial energy storage and demand response potentials exist within different energy vectors. Namely, heat and gas/hydrogen, which can be exploited through efficient integration of these energy vectors with the power systems. This report focuses on the flexibility that can be provided by the other energy vectors to the power system. For instance, the gas network offers substantial short-term storage capacity through its within-pipe storage capability known as 'linepack', while hydrogen infrastructure and electrolysis present opportunities to integrate excess renewable electricity. Similarly, the heat sector, leveraging thermal storage and thermal inertia in buildings supplied by heat pumps, could play a pivotal role in demand-side management. Data centres are also emerging as contributors to ancillary services, particularly through load shifting and optimisation.

In addition to identifying these alternative sources of flexibility, the report outlines three primary routes to achieving low-carbon flexibility for the power system. Transitioning natural gas infrastructure to low-carbon alternatives, such as hydrogen, represents one pathway. Another option involves retrofitting carbon capture and storage (CCS) technology at existing power plants. Finally, a comprehensive focus on demand-side management and distributed energy resources can unlock significant flexibility, allowing for more efficient integration of renewable energy.

The document highlights the policy and regulatory landscape required to support these transitions. Current market mechanisms, such as the Contracts for Difference (CfD) scheme and Capacity Market, need to be revised to incorporate incentives for flexibility and long-duration energy storage solutions. The implementation of digitalised platforms and enhanced consumer participation are critical to aligning market structures with technical and operational needs.

The report underscores the urgency of addressing the GB power system's growing flexibility requirements. As the country advances toward its Clean Power 2030 and net-zero targets, system operators, policymakers, and industry stakeholders must collaborate to deploy scalable and sustainable solutions. The integration of novel flexibility sources, coupled with a supportive policy framework, is essential for ensuring a secure, reliable, and cost-effective transition to a decarbonised energy system.

2. Introduction

2.1 Definition of power system flexibility

In the context of electricity system operation, the term flexibility generally refers to the ability of the system to balance electricity supply and demand at all times in response to any changes in the expected generation and consumption. Various definitions are given by the International Smart Grid Action Network [1] and summarised as, “Flexibility relates to the ability of the power system to manage changes.” The continuous balancing of supply and demand can be achieved by modifying the electricity production and/or consumption. The changes in electricity demand and supply could happen at different speeds and timescales (seconds, minutes, hours, days, weeks, months), therefore power system operators define a range of specific flexibility services that are required to address the needs of the power system (See the Appendix for descriptions of selected flexibility services procured in the Great Britain).

Regarding the short-term operation of electricity systems (i.e. within a day), key system needs are:

- To address unprecedented faults and outages of any generation and transmission assets. This requires instantaneous response to reduce and mitigate the impacts. System inertia and fast-responding frequency services are keys for addressing supply-demand balancing at such very short time resolutions.
- To compensate for variations of renewable generation and ramp up/down of demand.
- To shift peak electricity demand and maximise the use of renewable generation within a day.

At longer time resolution of multiple days to a week, the ability to store energy and/or shift demand to address periods of low renewable generation and high demand become increasingly critical.

‘Efficient’ scheduling of production and consumption has normally been expected to be determined or incentivised through energy markets with adjustments through balancing mechanisms. Spare power capacity – ‘headroom’ or ‘footroom’ to allow responses to variations in system frequency or voltage – has been procured by system operators as ancillary services.

Present day GB wholesale market arrangements do provide opportunities for flexibility of energy production and use. Portfolio operators of generation can schedule thermal plant within their portfolio to complement the availability of, in particular, variable renewable generation in meeting their forward bilateral contracts and power exchange trades. In respect of those contracts, parties might also trade with each other, making use of resources outside their portfolio, to provide an overall best fit with the availability of zero marginal cost generation and obligations to provide specific volumes of energy in particular periods. Most remaining imbalances in the last 60-90 minutes before physical delivery are corrected by the System Operator's acceptance of offers of, or bids for, energy in the Balancing Mechanism, the rest being dealt with through frequency regulation or containment ancillary services. However, it might be argued that a more efficient overall scheduling and utilisation of resources – and, thus, lower overall cost of electrical energy and electricity system related infrastructure – could be achieved through centralised scheduling and dispatch arrangements.

2.2 Scope

The growing need for operational flexibility in power systems occurs as a result of the large-scale integration of variable renewable sources of electricity generation such as wind and solar, as well as the uptake of new demands for electricity in the transport and heat sectors. The provision of the required flexibility via conventional fossil-based thermal power plants is not compliant with emission reduction targets. The heavy reliance on battery energy storage to meet the growing need for flexibility also may not be cost-effective and has associated life cycle environmental impacts.

Substantial energy storage and demand/supply response potentials exist within different energy vectors such as heat, gas/hydrogen which can be exploited to support the operation of low-carbon power systems. To achieve this, efficient integration and coordinated operation of electricity and other energy vectors across different scales is required.

This report provides an overview of the GB power system's growing need for flexibility, the technical potential of alternative sources of flexibility from across the energy system, and their economic and policy assessments.

3. System needs for flexibility

Historically, flexibility on the British power system was provided by fossil-fuel generators – coal or oil, and, since the 1990s, gas power stations. Such ‘thermal’ power plants are able easily and quickly to alter their output in response to system conditions, and the electromagnetic coupling of steam turbines with the power grid provides necessary inertia to resist perturbations across the network due to, for example, other power stations unexpectedly disconnecting from the network.

This has meant that the power system has been highly secure and operable, with few significant large-scale disturbances since the National Grid was first energised. There has never been a national-scale blackout in the history of the National Grid. However, maintaining this level of security and reliability in the face of a changing system is a significant engineering and regulatory challenge, and may entail significant additional costs to be passed through to consumers.

The pledge to achieve net zero within the next three decades is driving radical changes in the ways that energy is produced and consumed in most countries. Although, the best pathway for decarbonising the energy sector is highly dependent on the countries' specific circumstances and potentials, the large-scale integration of renewable sources of energy such as wind and solar as well as the electrification of heat and transport sectors are considered as key solutions to meet the emission and renewable targets in many European countries including UK [2]. These will result in variability and uncertainty in electricity supply as well as substantially higher peaks for electricity demand. If these issues are to be addressed through a ‘predict and provide’ approach, high costs will be incurred for building additional capacity for back-up generation, power transmission and distribution assets. These costs can be reduced by employing flexibility options (e.g. energy storage and demand side response), enabling peak shaving and supporting demand and supply balancing in the presence of variable and uncertain renewable electricity generation. A study for the UK Government estimates that deploying flexibility technologies (electricity storage, electricity demand response, flexible power station and interconnectors) in the Great British power system can save up to £40bn of the power system costs to 2050 [3].

Flexibility in the operation of power systems is needed to address variability and uncertainty in the electricity supply and demand. In a conventional power system, the flexibility needed to address the variability (and to a lesser degree) uncertainty in the electricity demand, as well as to deal with uncertainty of supply outages, primarily comes from large dispatchable power plants. In a power system with a large penetration of wind and solar resources, the variability of demand will coincide with variability from wind and solar generation. Additionally, power outputs from wind and solar are not fully predictable, therefore the uncertainty of power generation will be added to the uncertainty of plant outages.

Historical data of wind and solar energy curtailed for several countries are evaluated by Yasuda et al. [4], which shows a clear correlation between the rate of penetration of variable renewable generation capacity and the amount of renewable energy curtailments for UK, Germany, Denmark and Spain (see Figure 1).

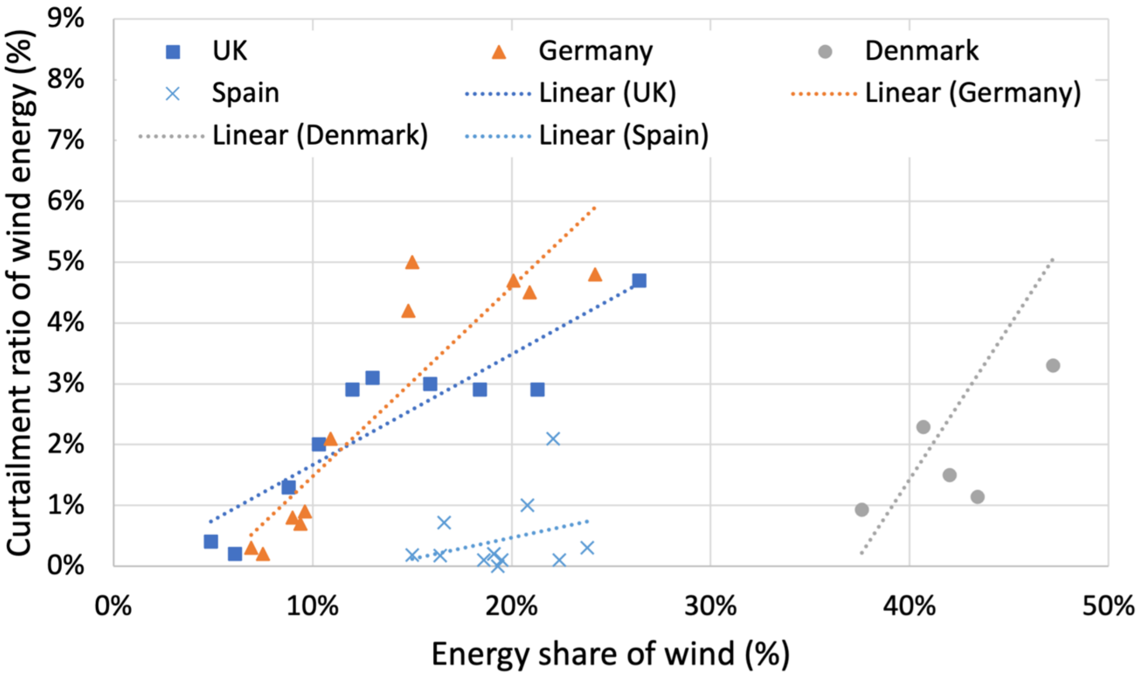

Figure 1. The trend of wind energy curtailment in selected countries in the last decade.

3.1 Drivers of system change

The decarbonisation of the British power system requires substantial change at all levels. Figure 2 summarises some of these key aspects which will impact the future needs for flexibility.

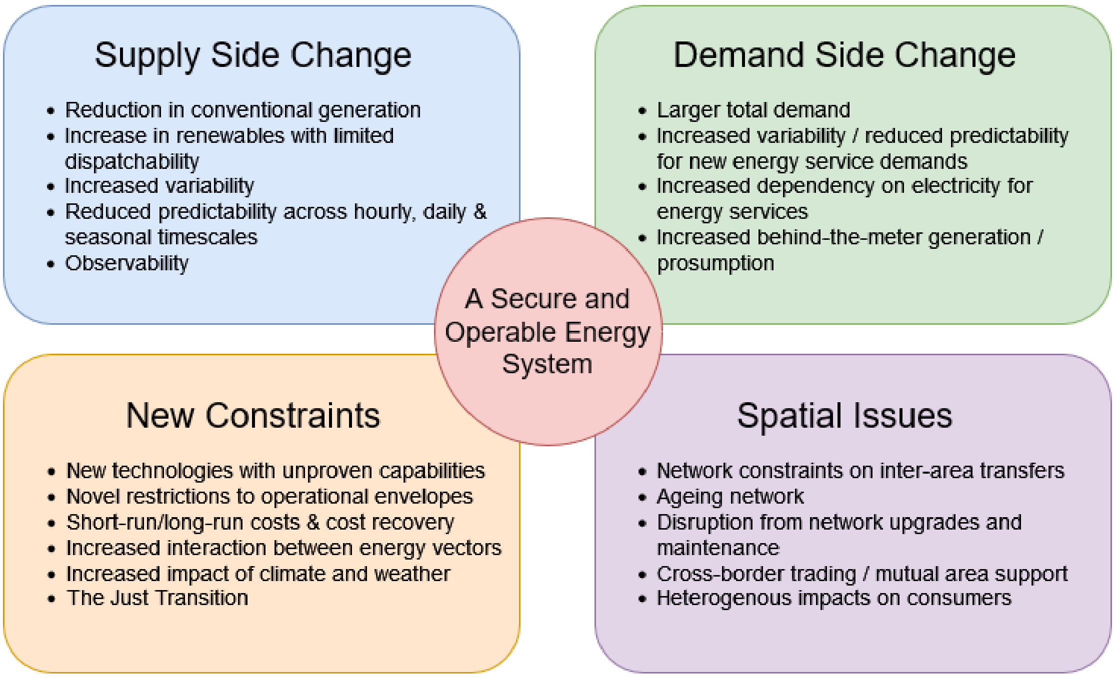

Figure 2. Summary of system changes and issues affecting the need for sources of flexibility

On the supply side, conventional thermal power stations are being decommissioned under environmental targets – the last coal power station in the UK, Ratcliffe-on-Soar, closed in September 2024. Gas generation was a key source of electricity in Britain, supplying 26% of electricity in 2024 [5] but remains a major source of GHG emissions. In order to meet the target of Clean Power 2030 (NESO, 2024b) and fully decarbonise the power system by 2035, this source of power will either need to be largely displaced by other sources of generation, or transitioned to either zero carbon gases such as hydrogen, or fitted with carbon capture and storage.

As the fossil fuel plant is increasingly displaced by renewable energythe level of flexibility and control available to the system operator will reduce unless there is recourse to other sources, as the output of such generators is tied to complex climate and weather variability. This is particularly the case for smaller-scale and decentralised power sources, such as the 13GW of solar panels installed on domestic and commercial properties over which the system operator has no direct visibility or control.

On the demand side, many energy services which were previously directly supplied by carbon-intensive fossil fuels are increasingly undergoing electrification. For example, the uptake of electric vehicles for transport and electric heat pumps and air conditioning for buildings are creating substantial new demand for electricity, and if adopted universally, may result in the total demand doubling, or even tripling, by 2050 [7].

Increasing the number of energy services dependent on the supply of electricity also means that any disruption to supply will have an increased impact on end consumers. This, in turn, increases the social and economic cost of interruptions, increasing the desired reliability and resilience of the power system.

The imbalances that will exist on the system will also vary widely in space and time. Under certain weather conditions, the location of electricity production might be focussed on particular areas of the network far from centres of demand, such as far offshore wind farms in the North Sea, and this may rapidly change with great variance over different short and long timescales. The ability to overcome this variance might be constrained by network capacity, with local flexibility options acting as an alternative to bulk investment in network assets.

In total, the future power system will need to supply more energy, more reliably, using less visible and dispatchable resources, in a planned manner that provides sufficient certainty to attract adequate investment, all within the timescales implied by national GHG emissions targets.

The key dimensions of power system design which further specify the nature of required flexibility are summarised in the remainder of this section.

3.2 Maintaining system security

In order to provide flexibility, an energy system participant must have three key characteristics [8]:

- Agility: the ability to adjust production or consumption quickly and at short notice;
- Predictability: the extent to which the resource can be scheduled, with confidence, to produce or consume power at any given time on a given day up to a few weeks in the future;
- Persistence: a particular level of production or consumption can be sustained for a period of time, i.e. energy not just power can be relied on.

Each of these may vary across different spatial and temporal scales, and individual technologies may have a different role to play in meeting the various requirements of system security. Figure 3 summarises some of these key aspects, and each of these is described in turn below.

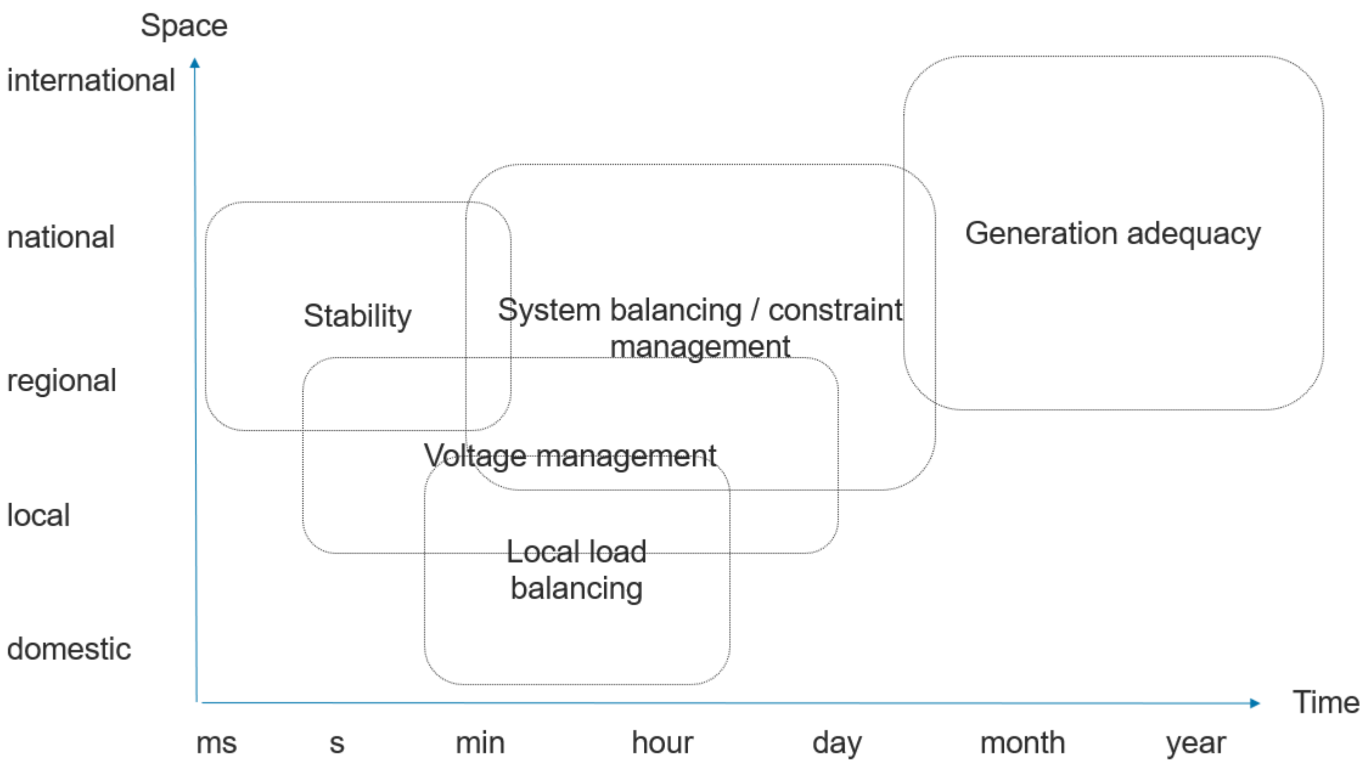

Figure 3. Spatial and temporal dimensions of system security

3.2.1 General adequacy

At the simplest level, adequacy is the question of whether there is enough generation capacity on a system to reliably meet peak demand. This comparison is usually made to inform investment decisions at long timescales to determine the need for new generation capacity. ‘Scarcity pricing’ – where a shortfall in generation capacity leads to higher energy prices – can act as a market signal to investors and encourage adequacy to be met without intervention.

Historically, flexibility on the GB system has been largely provided by fossil-fuelled generators such as Combined Cycle Gas Turbines (CCGTs) and coal plant. Low efficiency peaking plant such as Open Cycle Gas Turbines (OCGTs) have provided additional capacity margin. Forms of low carbon generation, such as nuclear power stations and natural gas with carbon capture and storage (CCS), can theoretically play a part, but neither are typically expected to provide flexibility due to the need to maximise the utilisation of costly assets. These and other inflexible sources of generation increase the surplus of low carbon energy available during windy periods and have limited ability to ramp up and down to match demand during wind droughts.

However, peak demand can be met via other means than generators. Energy stores can be discharged, electricity can be imported across interconnectors, and demand can be time shifted or reduced.

3.2.1 System balancing and constraint management

At a system-wide level, the amount of electricity generation entering the electricity grid must (after losses) be equal to the demand for electricity for the system to be in balance. Deviations from this will cause the frequency of the system to move away from 50Hz, and if this deviation is large enough, will cause disconnection of generators, leading to a further drop in frequency and, after a certain point, a cascade of disconnections and the possibility of grid collapse. To prevent this, the System Operator must take actions to ensure that the volume of generation on the system is continuously meeting demand, within the constraints of different forms of generation. This involves taking actions at a variety of timescales (days ahead to real-time) to increase/decrease generation and demand, and ideally doing so at the least cost – i.e. using the cheapest balancing actions procured through competitive markets.

Secondly, the System Operator must also ensure that the resulting flow of electricity between generators and consumers does not breach the limits of any network assets, such as from the flow of power through an overhead transmission cable exceeding the thermal limits of that line and causing faults. In order to respect such limits, further balancing actions are required, such as by reducing the output of a generator at one end of a transmission line and increasing the output of a generator at the other end by the same amount, with the net effect that the overall balance of energy on the system is the same, but the flow across that particular network asset is reduced.

3.2.1 Local load balancing

The above system-wide requirements on balancing and network constraints also apply at a local level to distribution networks which transport energy from the main electricity grid to individual consumers through lower and lower voltage levels of the system. This has additional complexity as generally at lower voltages (i.e. more localised areas of the network) far fewer network assets are actively metered, and the real-time state of network components may be unknown. In addition, an increasing volume of decentralised generation (e.g. small-scale renewables such as solar photovoltaics) is connected into local distribution networks, meaning that there is a growing requirement for the operators of those networks to actively manage their systems in the same manner as the System Operator does for the wider system.

As historically distribution networks have been passively managed (i.e. network assets installed and left to operate without intervention – so-called 'fit and forget') this increasing use of active balancing and control of generation, storage and demand at a localised level has necessitated the movement towards 'Distribution System Operators' (DSOs), replicating the tasks described above at a local level.

3.2.1 Stability

As with System Balancing, the system must be kept in balance at all timescales – including on those (second and millisecond level) where human intervention is not possible. This means that the system must be capable of automatically responding to unexpected deviations. For example, if a single large source of power (such as a nuclear power station or interconnector) goes offline, with a resulting rapid drop in frequency, other sources must be capable of either increasing generation or decreasing demand to rapidly rebalance the system and curtail that drop in frequency. Historically this has been provided by traditional synchronous generation – i.e. large fossil-fuelled power stations which are grid-coupled and can automatically regulate their output against any change in frequency.

Similarly, the existence of large thermal power stations has also bestowed the system with a high degree of 'inertia' – that is, the property of resisting changes in frequency – principally engendered by the mass of rotating turbines electromagnetically coupled to the grid. Hence any movement away from traditional thermal power generation means a loss of inertia on the system and a greater potential for any disturbances to have a larger impact on the wider system.

3.2.1 Voltage management

A feature of alternating current (AC) systems is that as well as active power (the component of electrical energy which can usefully do work such as powering light bulbs or turning motors) there exists 'reactive power' – an additional component which arises due to the exchange of energy between charging and discharging electric fields, and which provides no net gain or loss in power. As different components of the electricity system also consume or generate this reactive power, this must also be managed by the system operator, and manifests as the voltage found in different parts of the network. As with system frequency, voltages must be managed – via the control of reactive power injection and consumption – to remain within operational limits to prevent damage to electrical components. However, unlike frequency, voltage will vary across the system and must be managed locally.

At a system level, the voltage across large-scale assets such as transmission power lines is managed via specialised equipment such as shunt capacitors, reactors and synchronous compensators. As the system transitions in the type of generation connected this will have further implications for reactive power and voltage management, potentially increasing the need for such assets. Similarly, at a local level, the introduction of new forms of demand (such as heat pumps or EV chargers) will affect local voltages and require additional management.

3.3 The scale of the challenge

3.3.1 Ancillary service needs

The transition away from fossil fuels, and towards increasing use of variable renewable energy sources such as wind and solar, fundamentally changes the future requirement for 'ancillary services' – the additional tasks which must be undertaken in parallel to the delivery of volumes of energy to keep the system stable, reliable and operable. This includes:

- The need to replace large-scale sources of inertia (i.e. traditional thermal generation with steam turbines) with either low-carbon forms of thermal generation, or to procure 'synthetic inertia' via novel power electronics;
- Reserve and response services, traditionally provided by large synchronous thermal generation, which must be capable of responding on millisecond to second timescales to deviations in system frequency;
- Dispatchable forms of generation and demand which can be actively managed by the System Operator in order to enact balancing and constraint management across a variety of timescales.

One key aspect of future system development is that historically the above requirements have been met principally from large-scale generation, whereas there is a growing potential for many such needs to also be met from the demand side – e.g. through the aggregate dispatchable control of multiple energy consumers across forms of demand which may result in minimal disturbance to actual energy service use.

3.3.2 Relationship to system design parameters

The volumes of services required in the future also have a close relationship to key system parameters which are expected to evolve along the transition to low carbon electricity:

- Loss of load expectation (LOLE): as a measure of system adequacy, the expected proportion of time that generation will be insufficient to meet demand. As firm dispatchable generation is removed from the system and replaced by less dependable sources of generation (either variable renewables, or interconnectors whose availability depends on the state of the system at the other end of the cables), the LOLE will increase for a given capacity of electricity generation on the system. This, in turn, creates a requirement for more controllable forms of generation and demand which can be utilised during periods of system stress.

- Maximum in-feed loss: the largest infeed of power which may credibly be expected to disappear from the system without warning, and which the system must be capable of containing without undue frequency deviation. This is a function of the largest single sources of power on the system, typically either a nuclear power station or interconnector. For example, once Hinkley Point C is commissioned, this will represent a larger single point of failure (1.6GW of infeed) on the system than is currently (1.32GW) protected against, meaning that a larger minimum amount of reserve services must be continuously procured to protect against that possible failure.
- Capacity margin: the System Operator seeks, at any given time, to have an excess of generation that allows redundancy in the case of generator outages – and ahead of each winter period, the ESO assesses the 'de-rated margin' - defined as the excess generation capacity available during peak demand in cold weather. Additional flexibility in the system can reduce the required level of capacity margin, by creating alternative options for managing outages, such as by reducing electricity demand during periods of system stress.

3.3.3 Impact of weather and climate variability

Flexibility in an electricity system based largely on variable renewables are extremely important. Wind droughts – periods with low wind speeds and wind fleet capacity factors of less than around 10% – and the potential for them to occur at times of high demand and last for a number of days are a key challenge for the design of electricity sector commercial and regulatory arrangements. Long wind droughts give rise to a need for, on a GB-wide scale, tens of TWh of energy during such conditions from somewhere other than wind production.

This adds a further challenge in assessing the correct timescales and variability in weather that should be considered – e.g. whether the volume of flexibility services procured should ensure security against conditions expected in a typical year, once across a decade, or on longer timescales. The impact of climate change is not well understood in terms of impacts on weather trends, and care has to be taken not to assume that past weather data is sufficient when planning for future events.

Winter storms (such as those experienced under Storm Arwen in 2021) can also significantly impact network assets and disrupt energy supply. This adds a further dimension to understanding the volume of flexibility services that might help to mitigate the impact of such events, as the ability to procure alternative sources of generation, or to reduce demand in hard-hit areas of the network, is a key element of managing and containing such events.

3.3.4 Network delivery and constraints

A particular constraint on system evolution is the timescale required for the delivery of new network infrastructure. Due to planning constraints, new transmission infrastructure can take 12-14 years to plan, consent, construct and commission [9].

This creates a specific challenge for decarbonising the power system in the near term, as it may already be too late to commission new network within the desired timescales of a zero carbon power system. Flexibility can act to mitigate this issue in the short-to-medium term, by allowing network constraints to be managed by rebalancing flows of energy across the network, pending those longer-term upgrades taking place. Commissioning of new network may also require existing assets to be briefly taken out of service, and so flexibility may also be used as a measure to seek temporary alternatives to the use of existing system assets.

Although one of the benefits of flexibility is to delay and reduce the need for reinforcing network capacity, network capacity has the potential to provide access to resources in different places that are able to change generation or consumption and contribute to whole system balancing, i.e. to facilitate flexibility.

This means that there is a need to coordinate the procurement of future flexibility services along with other plans for transitioning both the supply and demand-side to low-carbon sources of electricity. For example, there is a need to avoid over-procurement of flexibility services from demand-side management where the availability of these services might be constrained by the capacity of local networks. This can also be managed by implementing low carbon ‘ready’ technologies that avoid hardwiring current system design constraints into the future networks, such as by ensuring that all new demand-side technologies have the capability to connect into existing smart grid systems.

4. Novel Sources of Flexibility

As the share of variable renewable generation is increasing in the power system, more efforts and resources are required by the system operator to maintain the operability of the power system. This includes, for instance, procuring a larger capacity for providing flexibility, proposing new flexibility services, and amending market rules to allow the procurement of flexibility in a more cost-effective manner. Meeting the growing need for flexibility via a *business as usual* approach has proved to incur a significant increase in the cost of balancing the power system. Figure 4 shows the annual cost of balancing services by the GB electricity transmission system operator. The total balancing cost has increased three-fold over five years, and is expected to continue increasing. Three main categories presented in the figure are i) *Response* that covers services related to providing frequency support to the power system, ii) *Reserve* that encompasses various types of reserve services including Short Term Operating Reserve (STOR), Negative Reserve, Fast Reserve, and iii) *Constraints* that accounts for services to support reactive power and voltage, as well as transmission congestion management.

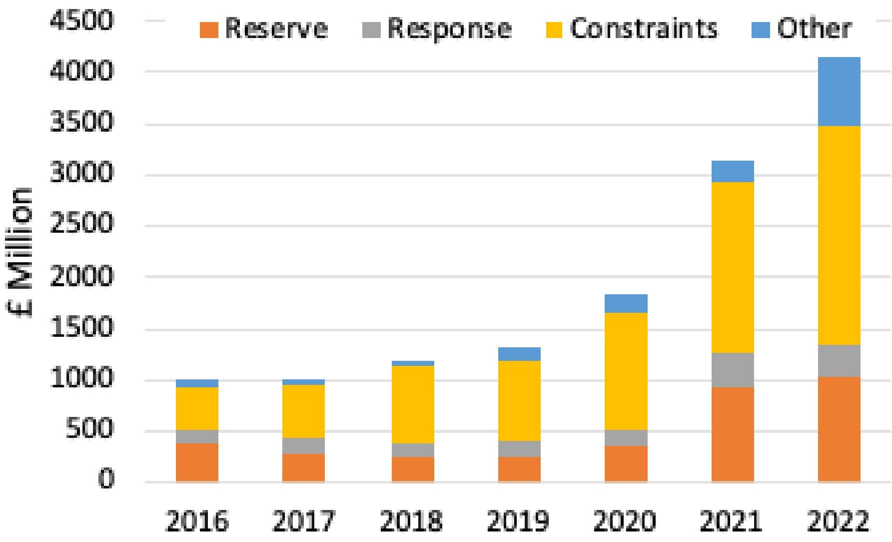

Figure 4. Cost of balancing services *[10]* **For each year the cost covers period of April to March in the following year, e.g. annual cost of balancing services in 2016 covers the period April 2016 to March 2017**

Although employing flexibility ensures the secure operation of the power system at a lower cost compared to the cost of building new generators and network capacity, the cost of balancing the power system is still growing fast proportional to the share of variable renewable generation. Therefore, the quest for cost-effective alternative sources of flexibility is underway. In addition to the flexibility options in power systems, there are substantial energy storage and demand response potentials within heat and gas systems which can be exploited to support a cost-effective transition to a low carbon energy system. To achieve this, efficient integration of electricity, heat and gas systems across different scales is required. For example, the correct integration of the electricity and heating sectors through optimal operation of “power-to-heat” technologies and large thermal storage (in the form of hot water tanks, and also as thermal storage using the thermal inertia of district heating networks and buildings) enables a shift in electricity demand required for heating.

4.1 Flexibility from gas network

Large networks of natural gas pipelines operating at high pressure have the ability to decouple the total amounts of gas inflow and outflow at each time step. The physical links between gas and electricity systems provide multiple opportunities for using the storage capability of the high-pressure gas networks to provide flexibility to the power systems. Currently, the key physical links between gas and electricity systems are gas-fired power stations, and electric-driven compressors. As of 2023 there are more than 30 GW of gas-fired power plants, and more than 200 MW of electric-driven compressor units linking the electricity and the gas transmission network. The electricity generation and consumption of the coupling components can be adjusted in response to a signal from the electricity system to support balancing the supply and demand of electricity. The subsequent changes to the gas system are absorbed via linepack and other forms of diurnal and seasonal storage available in the gas network.

Whilst the future of the natural gas infrastructure is uncertain in a net zero future, it is expected that hydrogen can play a role in decarbonising the industrial clusters, heavy goods vehicles (HGV), and marine and aviation sectors. Either new hydrogen supply networks will be developed or the existing natural gas infrastructure will be repurposed to accommodate hydrogen, and so it is likely that any future hydrogen infrastructure will continue to provide flexibility to the power systems. Under this scenario, the nature of the interactions between hydrogen infrastructure and the electricity system could change, with additional links between them established via hydrogen electrolysers.

4.1.1 Linepack as a short-term energy storage medium

Unlike electricity, gas takes time to travel from sources of supply to demand centres. Linepack is the amount of pressurised gas within pipelines of the gas network and is used as a form of diurnal gas storage to deal with rapid changes in the gas demand and supply. Injecting more gas into a pipe than is withdrawn at downstream nodes results in the accumulation of gas within the pipe and consequently increases the amount of gas in the pipe and hence the average pressure. Vice versa, withdrawing more gas at downstream nodes than is injected into the pipe depletes the gas within the pipe and lowers the pressure (unpacks the line).

The primary use of linepack is to compensate for short term imbalances of gas supply and demand. Such energy storage can be exploited to support the operation of the electricity system by mobilising the linepack through technologies that physically link the two networks such as gas-fired power stations, electric-driven compressors and hydrogen electrolysers. Linepack can provide a buffer for these technologies to deviate from their expected operation, and therefore adjust their electricity generation and consumption in a way preferred by the electricity system.

The growing variability of gas demand for power generation, caused by wind power intermittency, has already increased the variations in within-day linepack. Operational data from National Grid shows that the maximum within-day linepack swing (i.e. the difference between maximum and minimum linepack in each day) of the GB high-pressure gas transmission network in 2018 was 42 mcm, whilst this value in 2002 was 20 mcm[i].

The increase in the variation of linepack was due primarily to the increased capacity of wind generation and also partly as a result of the closure of gas holders in the gas distribution networks. The closure of gas holders in the distribution networks reduced the gas storage capability of these networks, and required more linepack in the high-pressure networks to support hourly balancing of gas supply and demand.

[i] https://www.nationalgas.com/sites/default/files/documents/Final%20Print%20Version%20GFOP.pdf

The linepack within the national transmission system (NTS) and local transmission system (LTS) can be used to dampen the impacts of the hourly fluctuations in the gas demand on the upstream gas supply from gas terminals and large gas storage facilities. Therefore, the gas network operator needs to ensure that there is enough linepack within the network when an abrupt increase in gas demand is expected. Currently, National Gas balances the linepack every 24 hours and ensures that the linepack at the end of a gas day (a gas day in GB starts at 5:00am and ends by 5:00am of the following day) is almost equal to the linepack at the start of the gas day. The expected increase in the fluctuation of gas demand which consequently affects linepack may necessitate more dynamic (e.g. within-day) linepack balancing.

The level of usable linepack is restricted by the maximum and minimum operating pressure of the pipeline system. Other fast cycle and distributed gas storage facilities can also contribute to system balancing when linepack is inadequate.

Figure 5 shows how the aggregate linepack in the high-pressure gas transmission network changed on November 25 2018: a typical winter day. The changes in the regional linepack and its level could be different from each other and from the aggregate pattern, due to different gas supply and demand profiles, as well as pressure level and size (volume inside the pipes) of the network in the region. Figure 6 shows the linepack profiles for different regions in the high-pressure gas transmission network for the same day for which Figure 5 illustrates the aggregate national linepack.

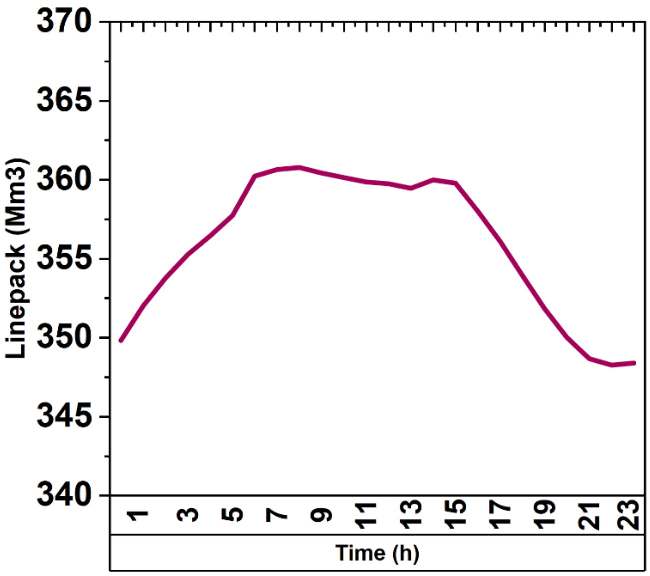

Figure 5. Aggregate linepack in the gas transmission system on a typical winter day

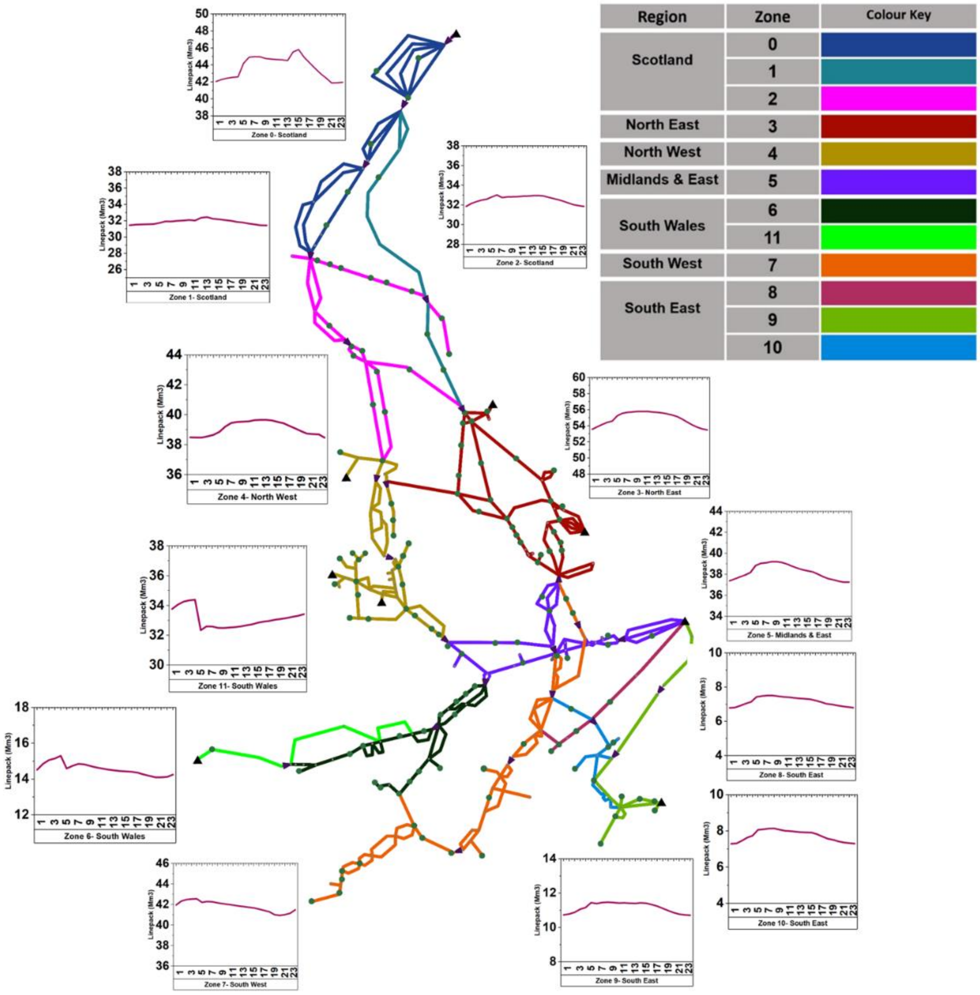

Figure 6. Regional linepack in the gas transmission system in a typical winter day

4.1.2 Electric-driven compressors

Gas compressor stations located across high-pressure transmission networks lift the pressure of gas and maintain gas flow from supply terminals to demand centres. By lifting the gas pressure, gas compressors contribute to increasing the network linepack and therefore play an important role in addressing the variability in gas demand.

The high-pressure gas transmission system includes 24 compressor stations that have 73 compressor units in total. There is a high degree of redundancy within compressor stations with some of them, such as St. Fergus compressor station, having 10 compressor units. Seven of the compressor stations have electric-driven compressors complementing gas-driven compressors. The existing electric-driven compressor units, totalling 200 MW capacity, have the potential to provide flexibility to the electricity systems by directly adjusting their electricity consumption, and also through managing the linepack so that gas is available to power stations when needed – see the illustrative case in Figure 7.

A compressor station with both electric-driven and gas-driven compressors can adjust its electricity consumption by either using linepack as a buffer, and shift their electricity consumption in time, or through fuel switching between electric-driven and gas-driven compressors.

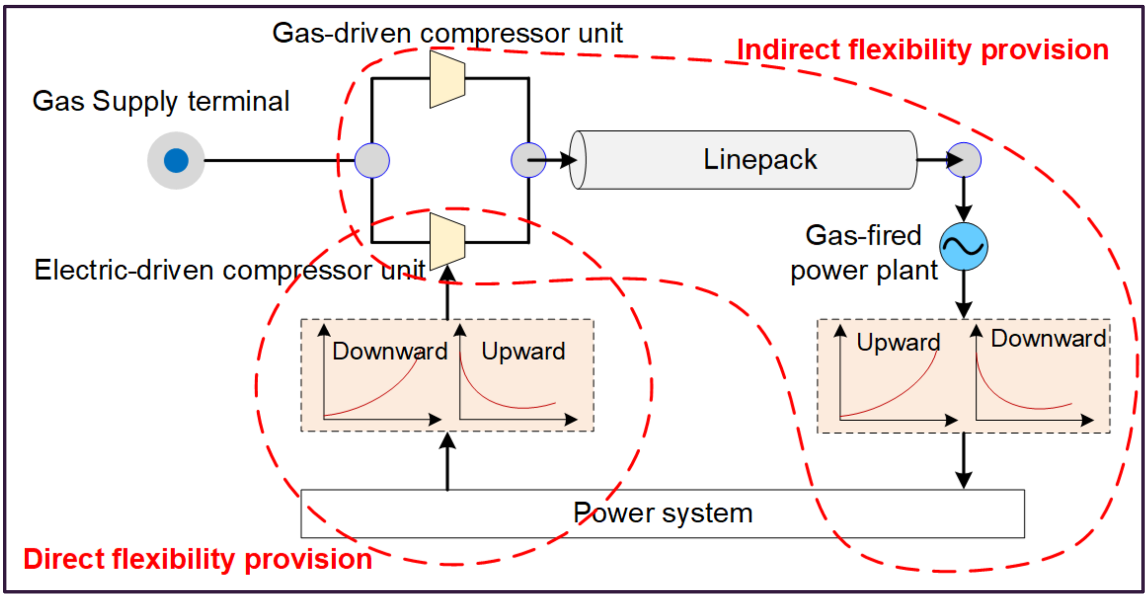

Figure 7. Flexibility provision from electric-driven compressors to the power system*[11]*

To comply with legislation such as the Industrial Emission Directives (IED) and the Medium Combustion Plant Directive (MCPD), the role of electric-driven compressors has become more critical in operating the GB high-pressure gas transmission network. This could enhance the provision of flexibility to the low carbon electricity system.

4.1.3 Power-to-gas and hydrogen storage

Using excess electricity from renewable sources to produce hydrogen or methane by methanation of CO_2 has been the focal point of activities in recent years attempting to decarbonise gas networks. The green gases produced via electricity can either be injected into the existing gas grid or stored and used locally.

The injection of green gases into the gas network provides access to large scale storage capacity available for diurnal and seasonal storage. Additionally, exploiting the transport capacity of pipelines in the gas network to bypass congestion in electricity networks helps to avoid curtailing renewable electricity when the generation is high but not much demand exists in the region. In the next decade as the high-pressure natural gas network still plays a role in meeting energy demand, the injection of hydrogen produced by electricity from wind farms to the high-pressure natural gas network could significantly reduce the wind curtailment whilst it only is a small volumetric fraction of the gas in the network which is not expected to have major impacts on the performance of the gas network and the end-use technologies.

The local storage of green gases and reusing them to produce electricity when needed (depending on the purpose of individual sites, whether it is maximising selfconsumption or maximising revenue by selling electricity to the grid when the prices are high) offers lower overall efficiency when compared to battery storage, e.g. 50% to 90% over a 24 hour period. However, the storage duration of the hydrogen system could be much longer.

The integrated systems of electrolyser, hydrogen storage and fuel cell can provide quick responses to low and high frequency events. The hydrogen storage provides a buffer for the electrolyser to absorb excess electricity from the grid and contributes to addressing high frequency events. On the other hand, the rapid response capability of PEM fuel cells becomes valuable when there is a sudden drop in the system frequency which requires more electricity to be supplied to the grid to match the demand.

The growing interests in using hydrogen as an energy vector has led to significant investment in projects for green hydrogen production. The increase in the role of hydrogen in future energy systems can to some extent compensate for the support that the natural gas network used to and still provides to the electricity system. The provision of short-term operational flexibility from regenerative fuel cell systems, as well as long-term seasonal storage that hydrogen are valuable complements to the highly electrified future energy system.

Long-duration storage is a critical feature that underground storage of hydrogen can offer to clean power systems to address the strong seasonality in the renewable generation production (mainly from PVs) and electricity demand (mainly driven by space heating). Key options for long-duration hydrogen storage are salt caverns, depleted oil and gas reservoirs, and saline aquifers (see

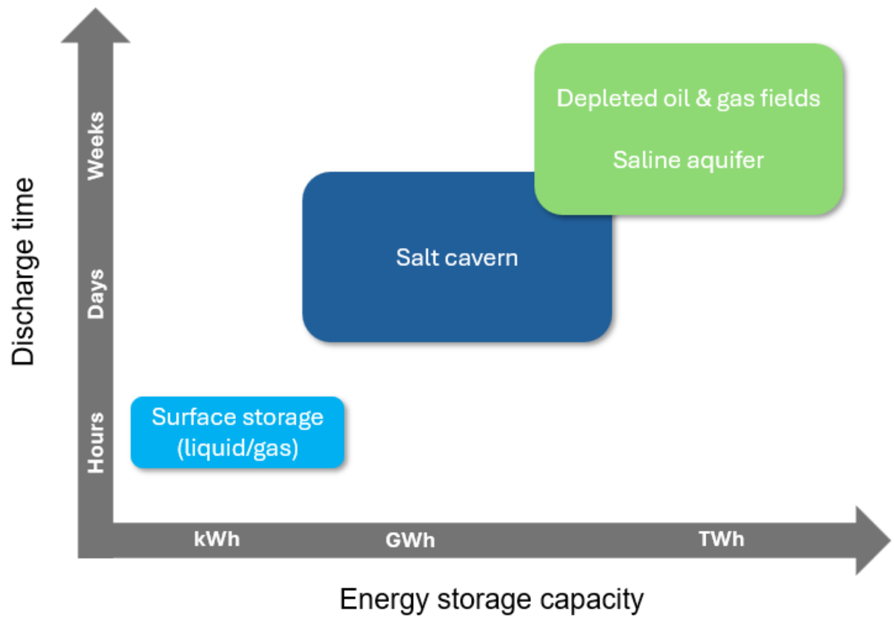

Figure 8).

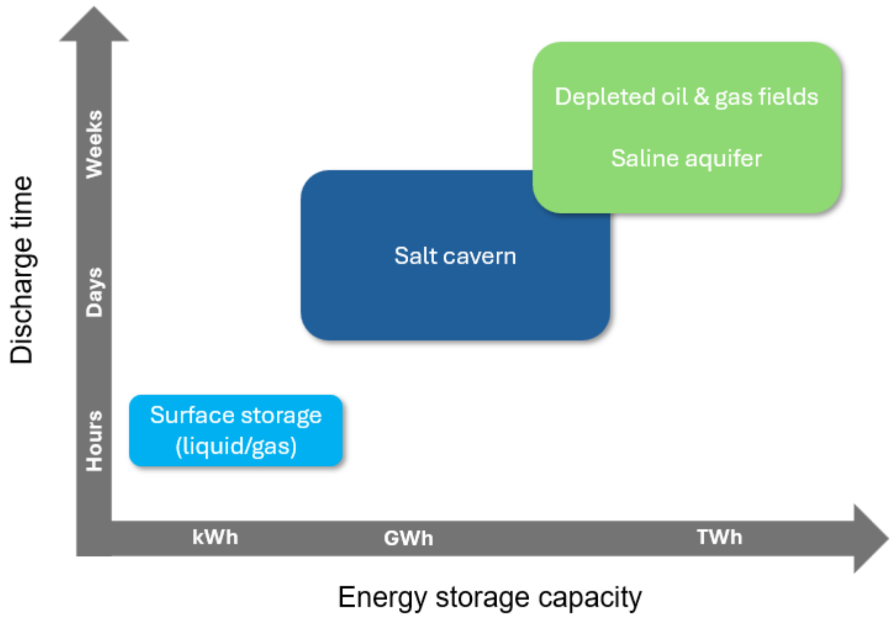

Figure 8. Hydrogen storage options. Adopted from *[12]*

Salt caverns are artificial cavities which are created in geological salt deposits. They offer excellent containment properties due to low permeability and high mechanical stability. The salt caverns allow for multiple cycles of hydrogen injection and withdrawal with minimal leakage, making them ideal for energy storage. Depleted oil and gas reservoirs provide significant storage potential due to existing infrastructure. However, they require detailed assessments of residual hydrocarbons and microbial activity, which may affect hydrogen purity and storage efficiency. Saline aquifers are porous rock formations filled with saltwater. They offer vast potential hydrogen storage capacity but involve complex interactions between hydrogen and surrounding geological materials.

The UK has significant potential for underground hydrogen storage, for instance in salt cavern located in regions such as Cheshire and Teesside. Additionally, the North Sea holds promise for repurposing depleted oil and gas reservoirs for hydrogen storage, leveraging existing offshore infrastructure.

4.2 Flexibility from the heat sector

The electrification of the residential heat sector is a promising option to decarbonise the heat sector in the United Kingdom. Therefore, different types of thermal energy storage technologies from inherent thermal inertia of buildings, to explicit thermal storage (e.g. hot water tanks and phase change materials (PCM)) to underground thermal storage via boreholes and aquifers have great potential to provide flexibility at the short- and long-term. This section discusses the use of thermal inertia of buildings and underground thermal storage.

4.2.1 Thermal inertia of buildings

The inherent flexibility available in the residential heat sector, in the form of the thermal inertia of buildings, could potentially play an important role in supporting the critical task of short-term balancing of electricity supply and demand. The average thermal capacity and thermal loss of different building forms in the existing housing stock of England and Wales are shown in Figure 9. Using the analogy of heat storage, the thermal mass of a building contributes to its heat storage capacity, and the thermal loss is equivalent to the self-discharge (or efficiency) of the heat storage. Buildings with high thermal mass and low thermal loss could provide significant heat storage capability.

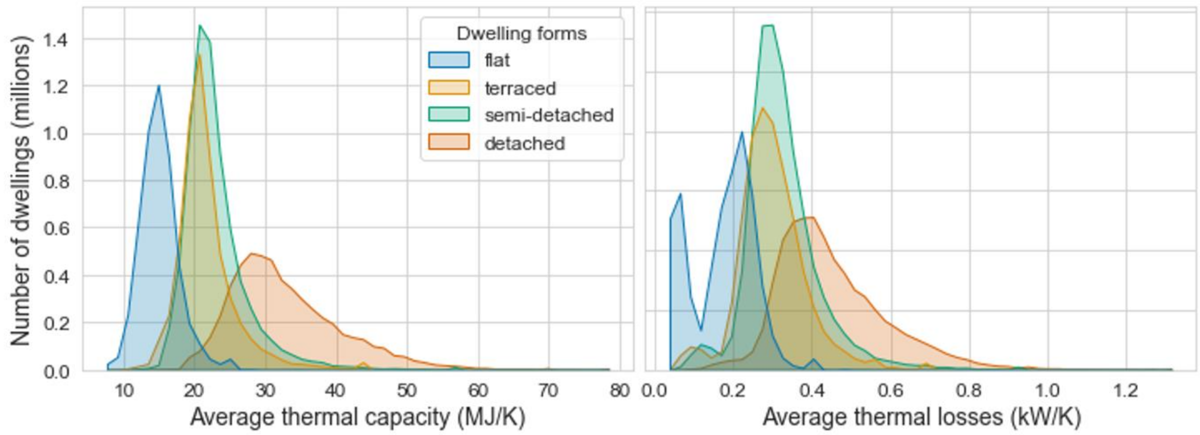

Figure 9. Distribution of the thermal characteristics of four dwelling forms in England and Wales. The average thermal capacity is based on a medium thermal capacity level. The figures were smoothed for visualization purposes by grouping the values into 50 bins.

Benefiting from thermal mass of the buildings, and allowing the indoor temperature of the buildings to vary between a minimum and maximum threshold that reflect the temperature range within which the occupiers perceive comfort, the operation of a heat pump can be controlled to adjust its electricity consumption in response to the needs of the electricity grid.

Recent research conducted by UKERC (Canet and Qadrdan, 2023) attempts to quantify the technically available flexibility from an electrified residential heat sector in England and Wales. This section summarises key findings from this research.

Assuming minimum and maximum allowable indoor temperatures of 18°C and 24°C, respectively, Figure 10 shows the simulated magnitude and duration of the positive and negative flexibility[ii] for the housing stock in England and Wales, assuming a future scenario in which all residential buildings are equipped with air-source heat pumps (ASHP). The aggregate flexibility from ASHP was estimated for four outdoor

[ii] Here, positive flexibility means the capability of heat pumps to increase their electricity demand, and negative flexibility means the capability of heat pumps to decrease their electricity demand.

air temperatures of -5°C, 0°C, 5°C and 10°C, assuming the initial indoor air temperature is the same for all the dwellings at 19°C.

The orange lines (circle marker) show the range of flexibility from ASHP for an outdoor air temperature of 0°C. The positive flexibility (i.e. increase in electricity consumption of heat pumps) can be provided for an “unlimited” duration as even if the outputs of the heat pumps increase to their maximum, the maximum indoor temperature of 24°C will never be reached. This is because the size of the heat pump was selected to compensate for heat losses of the buildings for a temperature gradient of almost 24°C. The negative flexibility (i.e. demand reduction) can be sustained for less than two hours before the indoor air temperature of the dwellings reaches the minimum indoor temperature of 18°C.

At an outdoor temperature of -5°C, the heating systems in all the dwellings are working at almost maximum capacity to meet the set indoor air temperature of 19°C. Hence, close to 100% (ca. 87 GW – considering COP of 2) of the capacity installed is available to provide negative flexibility, however, such magnitude of flexibility can only be sustained for a short period of time, otherwise the indoor temperature falls below the minimum limit of 18°C.

The magnitude of positive flexibility increases with the outdoor air temperature but the duration for which it can be provided decreases. This is explained because at a higher outdoor temperature, heat pumps operate at reduced capacity to maintain the desired indoor temperature. This means larger spare capacity is available to ramp up. At a higher outdoor temperature, running the heating systems at maximum capacity makes the indoor temperature reach the maximum set limit faster. The opposite is observed with the magnitude and duration of negative flexibility that can be provided at different outdoor air temperatures.

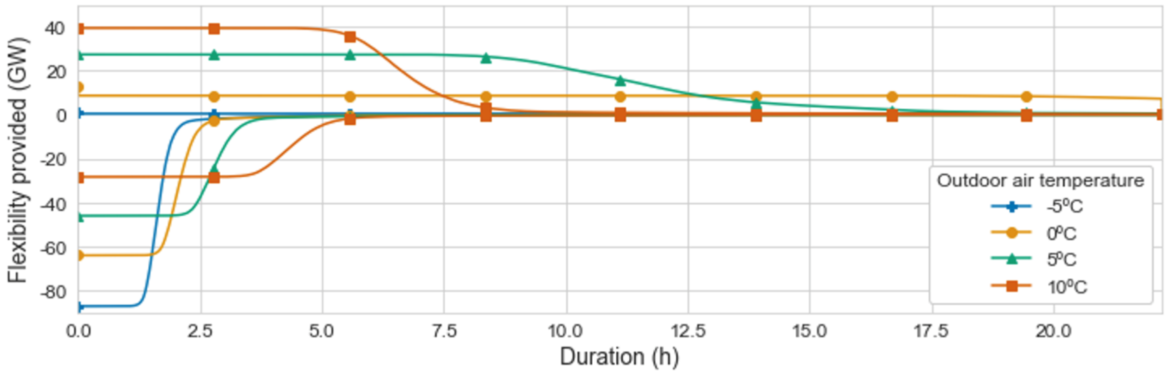

Figure 10. Estimated magnitude and duration of flexibility services provided when the initial indoor air temperature in dwellings is 20°C.

4.2.2 Underground thermal storage in boreholes and aquifers

Seasonal thermal energy storage in the ground using boreholes and aquifers is an approach to balancing heating and cooling demand across seasons by capturing excess heat during the warmer months and storing it underground for later use during colder periods.

Significant amounts of heat can be stored in ground materials like soils, rocks, and pore water due to their high volumetric heat capacity. An array of vertical boreholes can be drilled in the ground to form a borehole field. The appropriate depth and number of boreholes need to be determined based on factors such as heating and cooling demands, geological conditions, etc. (typical depth of boreholes usually is between 30m to 100m). Boreholes are installed with a U-tube pipe or casing pipes mostly made from synthetic materials, and are filled by grout materials with high thermal conductivities. Water, which can be mixed with an antifreeze solution, circulates in pipes as a heat carrier. Heat predominantly transfers by conduction between the borehole fields and the surrounding ground. Ground source heat pumps are used to transfer the heat between the boreholes and consumers buildings either directly or via district heating and cooling networks.

As depicted in Figure 11, the ground at different depth has different thermal characteristics (e.g. thermal capacity and thermal conductivity) which affect the overall storage performance of the boreholes.

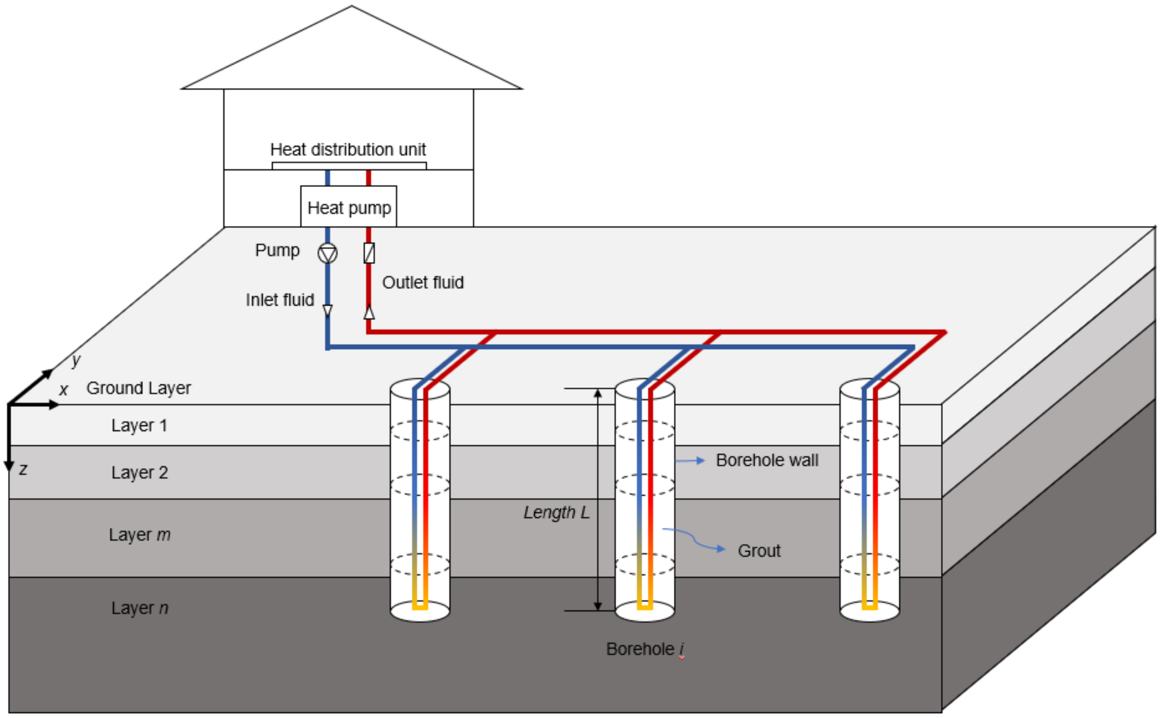

Figure 11. Borehole thermal storage. Adopted from *[13]*

Aquifer thermal energy storage systems utilise natural aquifers, which are water-bearing geological formations, to store and retrieve heat. Warm water is injected into the aquifer during summer and extracted during winter for heating purposes. Aquifer thermal energy storage systems are highly efficient in areas with suitable hydrogeological conditions, including sufficient permeability and stable groundwater flow. Their large-scale potential makes them particularly attractive for district heating networks.

4.3 Flexibility from datacentres

In response to the growing use of cloud computing and digitalisation, the capacity of data centres has been growing and is expected to continue to grow in the next decade. The exponential growth in demand for DCs is causing a significant rise in the amount of energy consumed by these facilities. In 2022, global data centre electricity consumption was estimated to be between 240 TWh and 340 TWh, constituting 1%-1.3% of the world's final electricity demand [14]. This figure excludes cryptocurrency mining, which accounted for approximately 110 TWh in 2022, equivalent to 0.4% of the annual global electricity demand [14].

Owing to their flexible operation and the growing trend of integrating distributed electricity generating and storage units, data centres are increasingly seen as a source of flexibility to the power system.

Shifting the IT workload is a strategy for providing flexibility by data centres. Data centres can shift their IT workloads in time (by postponing their non-critical workload) and space (by migrating IT workload from a data centre to another geographically distant data centre).

Data centres are equipped with Uninterruptible Power Supply (UPS) units to ensure the resilient operation of the facility during power outages. Their fast response characteristics make them useful in providing certain types of flexibility services to the electricity grid. It is estimated that a substantial fraction, ranging from 10% to 50%, of the Uninterruptible Power Supply (UPS) capacity within data centres is excess and potentially can be used as a source of flexibility to the electricity grid [15].

Backup generators are essential components in data centres, providing energy to maintain operations during long-term power outages. These generators can be used to reduce peak demands on the energy system and local networks, optimise energy usage, and minimise energy costs. However, the generators in the field are currently predominantly diesel-based, and therefore, using them directly as a source of flexibility may not be a preferable solution, given the current emphasis on transitioning from traditional diesel-based systems to zero carbon alternatives.

Thermal Energy Storage has been adopted in the cooling system of data centres in the case of any emergencies to meet the cooling demand of DC. The thermal energy storage can be used to reshape the profile of electricity consumption for cooling by discharging energy during peak times and charging during off-peak periods or in response to any other grid demands, facilitated by an energy management algorithm. In addition to the thermal energy storage, the cooling systems of data centres have significant thermal inertia that can be exploited to adjust the electricity consumption of the cooling system by overcooling the data centre for example when the electricity price is low and then temporary shutdown of electric chillers at a later time, yet ensuring the recommended temperature range for safe and efficient of IT devices are met. In this way, data centres can contribute to balancing the overall energy load and mitigating stress on the grid when it is needed.

4.4 Flexibility aggregation

Whilst the trend of moving from conventional large power plants to small-scale distributed resources for providing flexibility to the power system offers new opportunities to diversify the sources of flexibility, it poses new challenges too. Accessing the market is a key challenge for small-scale flexibility providers due to the requirements of the existing flexibility products (e.g. a minimum required size) as well as the lack of technology and expertise. This will make the aggregation of distributed flexibility critical.

A Virtual Energy Storage System (VESS) is a concept for aggregating distributed flexibility sources. VESS is created by aggregating various electricity generation, storage and end-use technologies that can modify their electricity exchange with the grid. The VESS aims to offer flexibility to electric power systems by coordinating the operation of such distributed flexibility resources so that they collectively behave similarly to a large electricity storage system. This can be achieved by receiving electricity from the grid (increasing the consumption of flexible end-use technologies, decreasing the generation of flexible distributed generation technologies, and charging different types of energy storage) which represents the charging of the VESS, and sending electricity to the grid (decreasing the consumption of flexible end-use technologies, increasing the generation of flexible distributed generation technologies, and discharging different types of energy storage) which represents discharging the VESS. As presented in Figure 12, VESS could include battery storage, flexible demand such as electric vehicles, refrigerators and heat pumps, as well as distributed generation technologies.

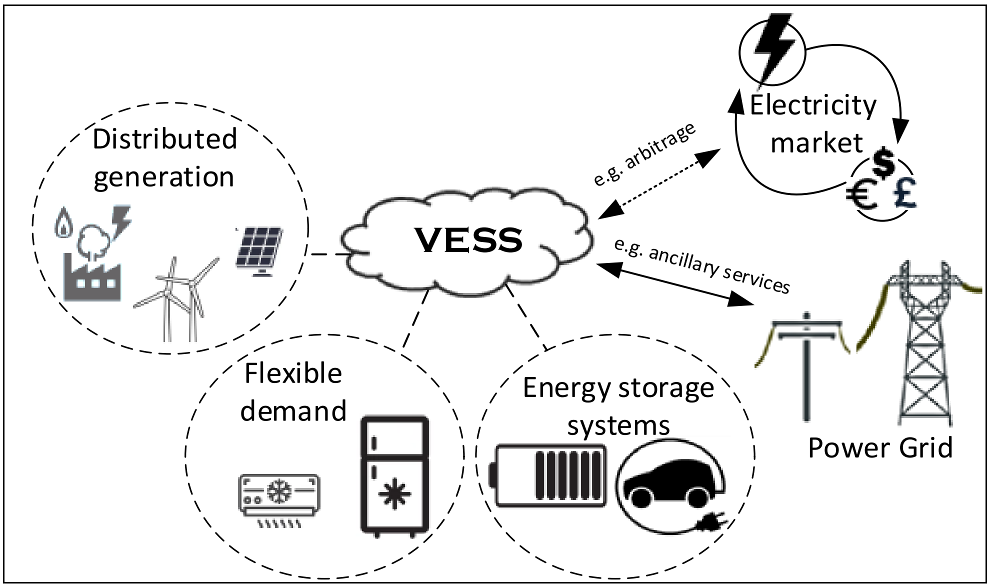

Figure 12. The concept of a Virtual Energy Storage System (VESS) in a smart grid, where a VESS can provide various services within several markets and for different parties.

Different sources of flexibility can be characterised using their flexibility envelopes that consider three metrics: magnitude, response rate and duration. In a conventional battery energy storage system, the power rating serves as a measure of magnitude, while the State of Charge (SoC) reflects the duration of the charging/discharging power at a specified magnitude. Adopting the concept of VESS can combine the complementary advantages of different flexibility sources and develop a dynamic flexibility envelope by optimal scheduling of the technologies in the VESS portfolio.

For example, aggregating two sources of flexibility as shown in Figure 13 enables a new flexibility envelope that offers new characteristics that can meet the required specifications of certain flexibility products which neither of the flexibility sources can meet individually. Therefore, the aggregation of flexibility sources with complementing characteristics could maximise the benefits that can be exploited from revenue stacking in the flexibility market.

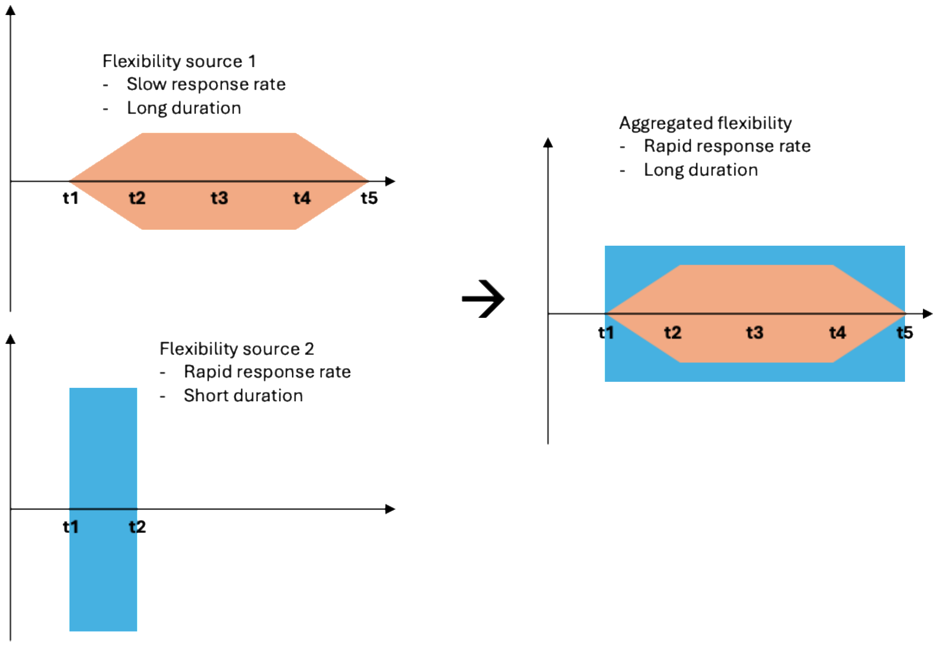

Figure 13. An example schematic of the flexibility envelope achieved through aggregating different sources of flexibility.

5. Routes to a Flexible Low Carbon System

5.1 Options for transitioning system flexibility

In this section we bring together the preceding analysis to look at three distinct visions of how flexibility provision might evolve in the GB system, with a particular focus on the next 10 years towards Clean Power 2030 and net zero power system by 2035.

Figure 14 below illustrates the main options available to transitioning a system currently dependent on natural gas-fired power generators for flexibility to low carbon operation. Broadly there are three routes to maintaining flexibility on a pathway to meeting emissions targets:

- Transitioning upstream supply of natural gas to low carbon gases. This could be through the conversion of natural gas to hydrogen with carbon capture implemented at the point of gas reformation, or via a shift to gases such as ‘green’ hydrogen or biofuels where the downstream carbon emitted is balanced by the same volume of gas being absorbed from the atmosphere by growing biomass.
- Implementing carbon capture and storage at the point of power generation. This could allow the use of fossil fuels such as natural gas to continue in power generation, continuing the use of existing power stations. Or, if coupled with the use of upstream biofuels, could permit electricity generation to be associated with net negative emissions – where effectively carbon is absorbed from the atmosphere by growing biomass, and post-combustion is stored in deep carbon sinks such as cavern storage.
- Developing new flexibility potential from the use of demand-side management, as discussed in the previous section. This would unlock the ability to decommission existing fossil fuel generation and increase the proportion of energy sourced from zero carbon renewables.

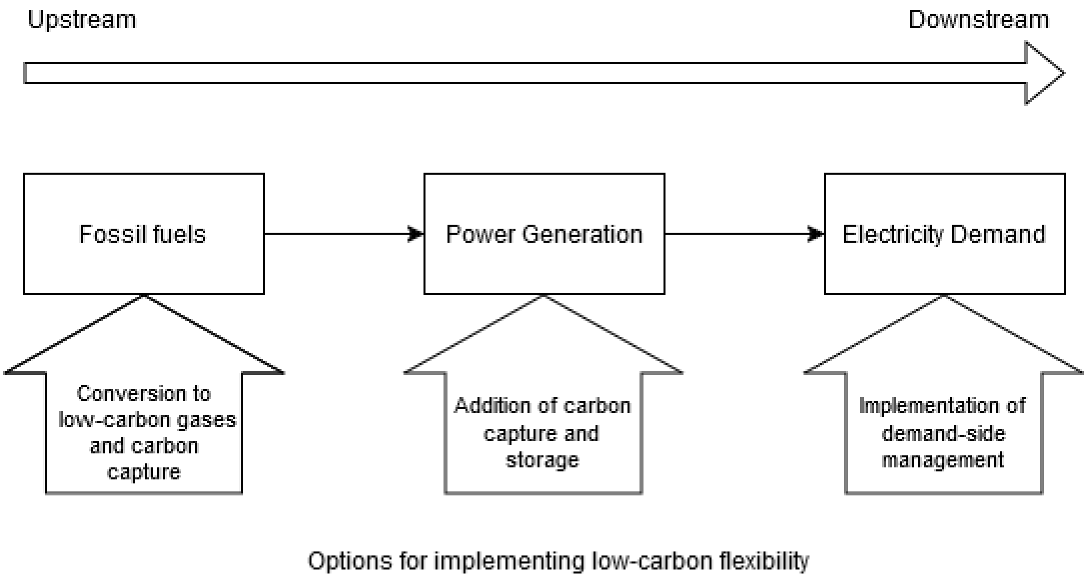

Figure 14 - The 3 points of intervention for creating low-carbon sources of flexibility in today’s power system

All these interventions require the large-scale deployment of relatively novel technologies. In particular, hydrogen and CCS infrastructure are unproven at scale, and only have been demonstrated at a number of projects in recent years. The pathways to GW-scale utilisation of these technologies are still relatively unknown and the resulting additional costs are highly uncertain. Interventions which rely on biomass might provide an attractive route to negative emissions from electricity – making a significant contribution to net zero – but there are significant land constraints to domestic biofuel production, and imported biomass will create environmental issues in the countries from which they are sourced, as well as having significant transport-associated emissions.

Further novel sources of flexibility are summarised in Table 1. This highlights that different sources will be able to provide services at different timescales, and to maintain a functioning and secure power system will require a diverse mix of flexibility providers.

Table 1. Further novel sources of flexibility

Alternative sources of flexibility	Power system flexibility needs
Hydrogen electrolysers	Rapid response to changes in electricity supply and demand
Demand response by heat pumps benefiting from thermal inertia of buildings and other types of thermal energy storage	Peak shifting and hourly balancing of supply and demand
Demand response by data centres	Rapid response to changes in electricity supply and demand (using spare capacity of UPS and batteries) Peak shifting and hourly balancing of supply and demand (using thermal inertia of DC and shifting IT workload)
Demand response by electric-driven gas compressors	Peak shifting
Underground hydrogen storage Borehole thermal energy storage	Seasonal balancing of supply and demand

A further potential source of flexibility may be available from future generations of nuclear reactors. French nuclear plants have the capability to vary their output between 20% and 100% output within 30 minutes [16] and future reactor designs may increase this capability. However, this may be at a high cost as the economics of nuclear plants strongly incentivises their use as near-constant-output ‘baseload’ plant. Similarly, in a British future with a high level of new nuclear build, this may create additional motivation to source other forms of flexibility, in order to avoid reducing output from nuclear plants during periods of high renewable output – such as by using the excess energy to generate hydrogen from electrolysis.

Considering the techno-economic maturity of the flexibility options, as well as the challenges and opportunities associated with them which discussed above, determining the optimal mix of flexibility options and timing for their implementation are critical.

5.2 Policy and implementation

The policy and regulatory challenges created by the need to increase energy system flexibility span timescales from the present day to a decade or more into the future. In 2019, Ofgem set out a ‘Flexibility Platform’ to facilitate greater volumes of flexibility provision [17], and system arrangements are already being revised to procure flexibility services more efficiently, with the first stages of the new Open Balancing Platform going live in late 2023 (with the initial stage intended to *"support the bulk dispatch of battery storage and small Balancing Mechanism Units"*). Other developments include the proposed introduction of a 'Balancing Reserve' service that will allow regulating reserve services to be purchased on a day-ahead basis [18], [19].

Over longer timescales, the need for hugely increased levels of flexibility in GB's energy system over the next two to three decades is clear. What is also clear is that the scale of the challenge in respect of the wide-ranging changes required in both policy and regulation is, in principle, recognised. The UK Government's 'Smart Systems and Flexibility Plan', which suggested that a total of around 30GW of low carbon flexible capacity will be required by 2030 and around 60GW by 2050 [20], set out the policy and regulatory areas that need to be addressed, which included:

- Barriers facing electricity storage and interconnection
- Flexibility markets
- Changes to the existing Contract for Difference (CfD) and Capacity Market mechanisms
- Digitalisation of the energy system
- Consumer participation
- Allocation of network costs

Proponents of wholesale energy market reform believe that signals in today's largely decentralised British wholesale market are insufficient to provide enough offering of flexible energy production or use in the right locations, or to 'efficiently' utilise the flexibility that is on the system.

These policy and regulatory areas address the problem from two sides – a 'top-down' approach that covers what types of flexible generation and storage capacity assets need to be deployed, and how those assets are incentivised to operate in a manner that achieves the overarching goals of energy security, carbon emission reductions, and economic efficiency. This is complemented by a 'bottom-up' approach that involves engaging consumers to facilitate their participation in a flexible system.

With regard to the delivery of long-duration energy storage, the complexity and range of the policy options are emphasised in work by the Long Duration Energy Storage Council [21], which groups these policy options under three categories, as shown in Table 2.

Table 2. Policy options to support large scale deployment of flexibility

Direct support and enabling measures	**Revenue mechanisms**	**Long-term market signals**
Grants and incentives Targeted tenders Technology standards Market rules	Cap and floor Capacity market Contract for difference Hourly attribute certificates	Carbon pricing and GHG reduction targets Grid planning

Investment de-risk mechanisms Sandboxes (pilots)	Long-term contracts for balancing/ancillary services Nodal and locational pricing Regulated asset base 24/7 clean PPA	Phase out of fossil fuel subsidies Procurement targets Renewable energy targets Storage capacity targets

The LDES analysis goes on to develop market archetypes to illustrate how policy packages might work, but these are not intended to be concrete recommendations, all of which serves to reinforce the point that selecting and implementing the right policy mix is a complex challenge. The BEIS 2021 Smart Systems and Flexibility Plan was followed by a consultation that sought to address at least some of these issues, including the relatively high capital costs and long lead times, lack of operational experience, revenue uncertainty and lack of effective market signals that flexibility and storage assets face [22]. The key concerns for investors relating to the uncertainty and duration of revenue streams and the maturity of the technology are also highlighted in work led by the Carbon Trust [23].

Analysis by National Grid in 2022 focused on the role of domestic demand flexibility and hydrogen production and use. This concluded that there was a need for new tariff structures and offerings, and better information for consumers to facilitate domestic demand flexibility. To bring forward hydrogen production and use, the key requirement identified was for a clear decision on the future role of hydrogen and a roadmap for how to get there [24]. The most recent Future Energy Scenarios analysis [25] also emphasises the need for immediate action, but this is a formidable challenge for policy to give the very wide range of plausible futures described in both the 2024, and earlier National Grid, analyses.

This call for action is echoed in work from the National Infrastructure Commission [26], which advocates for a business model that incentivises large-scale hydrogen and gas with CCS generation to cover extended periods of low output from variable renewable electricity generators. The point is made clear that active decisions need to be taken and that 'transformational change to planning, regulation, and governance of both the transmission and distribution networks' is required. Of particular note is the observation that *"core networks of infrastructure to transmit and store hydrogen and carbon are essential by 2035"* – due to the lead time needed for deploying such infrastructure, it is unlikely they can contribute to the Clean Power 2030. Since this is only just over a decade from now, and bearing in mind the observations concerning technology deployment timescales this has very significant (and essentially immediate) implications for policymakers.

The Climate Change Committee (CCC) have also emphasised the need for a clear, long-term strategy [27], although the fact that this was just one of a total of 25 recommendations does reinforce the scale and complexity of the policy challenge. One statistic serves to illustrate the issue of scale – the report's central scenario sees around 3,800km (approaching two and a half thousand miles) of pipeline being required to transport hydrogen by 2035. The underpinning analysis for the CCC report [28] observes that building out the hydrogen transmission and storage capacity envisaged in the UK Hydrogen Strategy [29] requires that project development work should start by next year. It should be noted here that the 2021 Hydrogen Strategy says that hydrogen will meet 20-35% of UK final energy consumption by 2050 (based on the ‘central range’ analysis).

More recent analysis and consultation activities [30], [31] emphasise that the challenges of the lack of revenue certainty, high capital costs and long build times are a particular barrier for prospective long-duration energy storage. This consultation proposed a cap and floor policy scheme that is similar to that currently used to support investment in electricity interconnectors. In recognition of the additional uncertainty and market barriers facing long-duration energy storage, the proposal is that prices would be administratively set rather than through the market. The need to ‘urgently progress work to remove existing barriers to market access’ for distributed flexibility is also highlighted by Energy UK [32].

There are some interesting points to note about this DESNZ consultation and supporting analysis. Firstly, there is no specific level of ambition in respect of storage capacity, albeit a figure of 3GW by 2035 is suggested. This may be a reflection of the wide range of scenarios run by the analysis, and to avoid being too prescriptive in the light of this range of possible futures. Secondly, the definition of ‘long duration’ appears to be relatively short, with a minimum duration of 6 hours and is clearly not focussed on interseasonal storage. Arguably this reflects the more immediate need (which is not for interseasonal storage), but it does draw attention to the question of how such storage might be incentivised. Thirdly, the consultation proposes that policy is to be differentiated by technology readiness levels (TRLs), with policy differentiated between the most mature technologies (TRL 9, to include pumped hydro and liquid air storage) and the next level down in terms of maturity (TRL 8 to include compressed air storage and flow batteries, and liquid air storage which appears in both TRL 9 and TRL 8 classification in the consultation document).

A key question then is how can the required sources of flexibility be selected, financed, and deployed at the scale and with the degree of urgency envisaged? Although there has been significant attention to this question of late, it remains the case that it has not generally been addressed in as much detail as the technological characterisation and energy system modelling aspects. The policy challenge that this poses is exacerbated because (as the technical analyses make clear) there is a very wide range of possible outcomes with different technological solutions, coupled with the fact that some of these new flexibility assets may, depending on renewable resource availability and system characteristics, turn out to be very infrequently used.

Nevertheless, a clear message which emerges from the policy analyses described above is that the scale and speed of energy system flexibility deployment that is required to support decarbonisation is unlikely and/or implausible without strong and directed policy intervention. The establishment of National Energy System Operator (NESO) that will take a whole system approach to planning and operating the energy sector has been an important action by the UK Government to pave the way for more coordinated delivery of flexibility required.

It should also be recognised that the physical and environmental impacts of different technology options may not be equally shared, and these (and the possible trade-offs and social impacts) are often not well discussed and characterised. The need to consider these trade-offs may manifest through future planning controversy and debate over how best to weigh localised concerns against wider societal objectives. The challenges posed by the future energy system flexibility requirements is very much not business as usual. Arguably, policymakers are in the uncomfortable position that we are beyond the ‘keeping options open phase’. The evidence suggests that decisions need to be made and decisive actions taken, even at the risk that they turn out to be sub-optimal.

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7. Appendix: Flexibility factsheets

In order to address different system's needs, National Grid Electricity System Operator (NGESO) procures a range of different flexibility services. Some of the key flexibility services procured by NGESO are summarised in Table 3.

Table 3. Summary of key flexibility services

Category	Service name	Time to delivery	Delivery duration	Minimum capacity	Comment
Frequency response	**Dynamic containment**	1 second	15 minutes	1 MW	Aggregation is allowed
	Dynamic moderation	1 second	30 minutes	1 MW	Aggregation is allowed
	Dynamic regulation	10 seconds	60 minutes	1 MW	Aggregation is allowed
Reserve	**Fast Reserve**	2 minutes	15 minutes	25 MW	Aggregation is allowed
	Short term Operating Reserve	20 minutes	120 minutes	3 MW	Aggregation is allowed
Demand Flexibility	**Demand Flexibility**	30 minutes	30 minutes	1 MW	Aggregation is allowed

Key characteristics of the above flexibility services are described below in the form of factsheets.

7.1 Dynamic Containment

Dynamic Containment (DC) are fast-acting post-fault services. DC services are designed to support containing the power system's frequency within the statutory range of +/-0.5 Hz in the event of a sudden generation or demand loss[iii]. To address over and under frequency events, DC includes Dynamic Containment High (DCH) and Dynamic Containment Low (DCL) services. DCL and DCH were launched in October 2020 and November 2021 [iii].

7.1.1 Technical requirement

The service providers are required to meet the specific technical requirements described in Table 4. Due to the expected response speeds, DC currently is mainly

[iii] NGESO, New Dynamic Response Services (2024), https://www.nationalgrideso.com/document/276606/download

provided by batteries, although it is not exclusively for batteries and more diversity in the future needs to be found[iv].

Table 4. Technical requirements to provide DC service[v]

Service specification	Details
Max initiation time	0.5 s
Max time to full delivery	1 s
Ramp time upper bound	0.5 s
Delivery duration	15 min
Minimum response capacity	1 MW
Maximum response capacity	100 MW
Aggregation	Allowed at Grid Supply Point (GSP)

DC service providers are expected to automatically react to changes in the frequency and deliver energy proportionally to the change in the frequency. DC providers begin the delivery of the service when the frequency deviation exceeds +/- 0.2 Hz, and reach 100% of their contracted capacity when the frequency deviates by +/- 0.5 Hz from 50 Hz. The DC providers are required to follow the 'response curve' shown in Figure 15.

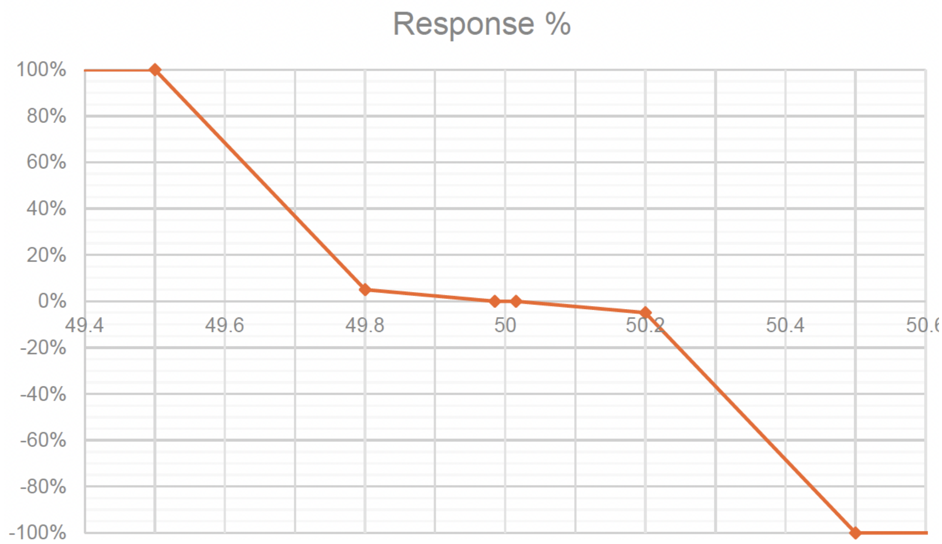

Figure 15. Dynamic Containment response curve [v]

[iv] NGESO, Markets Roadmap (2024), https://www.nationalgrideso.com/document/304131/download

[v] NGESO, New Response Services (2023), https://www.nationalgrideso.com/document/276401/download

7.1.2 Market information and payments

DC services are procured on a day-ahead basis, for 6 four-hourly blocks called EFA Blocks (Electricity Forward Agreement blocks). Each EFA block consists of 8 half-hourly settlement periods. NGESO pays service providers an availability payment based on the contracted capacity at each settlement period (MW), market clearing price for the settlement period (£/MW/h). The service providers are expected to have an availability of greater than 99.9% during the settlement period, otherwise they receive no payment. In addition, the settlement value may be adjusted if there is a difference between the expected response and the actual delivery. The formulae used to calculate the settlement value for each EFA block is shown by **Error! Reference source not found.**.

$$S = \left(\sum_j Round\left(P_j \times V_j \times 0.5\right) \times F_j \right) \times K$$

Equation 16

Where, S is the settlement value for an EFA block; the index j indicates the settlement period, and for each settlement period: Pj is the market clearing price (£/MW/h); Vj is the contracted quantity (MW); Fj is zero if the response unit has unavailability of 0.1% or greater, and is 1 otherwise; K is the factor to adjust the settlement value considering the performance of the service delivery.

The performance of the service delivery is assessed using a pair of time series (referred to as 'performance bound') that enclose possible valid service delivery profiles – this accounts for acceptable lag times and ramp rates. The performance monitoring error is zero if the metered response is between the upper and lower performance bounds and is otherwise the difference between the metered response and the closer of the performance bounds. Table 5 shows the K factor corresponding to various performance monitoring errors.

Table 5. K factor corresponding to the performance monitoring error (Dynamic Containment and Dynamic Moderation)

K **factor**	**Error value**	**Comment**
1	Error <= 3%	The response error up to and including where no performance payment penalties are applied.
with linear interpolation of error	3% < Error < 7%	The response error between 3% and 7% where k factor applied with linear interpolation of penalties.
0	Error >= 7%	The response error at and above which performance payment penalties are 100%.

7.1.3 Market size and price

Table 6. Parameters related DCH and DCL over 2022 [vi]

Parameter	DCH	DCL
Number of active market participants	28	31
Procured volume (MW)	1 M	1 M
Market revenue (£M)	19	110
Average clearing price (£/MW/h)	4.05	19.21

7.1.4 Historical evolution

The DC Service replaced the Enhanced Frequency Response (EFR) service due to limitations in EFR's speed and accuracy in responding to sudden changes in frequency. The DC Service has a higher ramp rate and can deploy up to 95% of its power within a narrow frequency range of only 0.3 Hz, making it a faster and more effective tool for managing the frequency of the grid. In addition, the DC service uses a distributed control system that allows for more precise and accurate responses to changes in frequency on the grid.

7.2 Dynamic Moderation

Dynamic moderation (DM) are fast acting pre-fault services that include DM high frequency (DMH) and DM low frequency (DML). DM services are designed to contain frequency within operational limits +/- 0.2 Hz [iii].

7.2.1 Technical requirement

DM service providers are required to meet the specific technical requirements described in

[vi] NGESO, Dynamic Containment, Regulation and Moderation auction results, https://data.nationalgrideso.com/ancillary-services/dynamic-containment-data (accessed on 08/07/2024)

Table ***7***. Due to the expected response speed, DM currently is mainly provided by batteries, although it is not exclusively for batteries and more diversity in the future needs to be found [iv].

Table 7. Technical requirements for providing DM [v]

Service specification	Details
Max initiation time	0.5 s
Max time to full delivery	1 s
Ramp time upper bound	0.5 s
Delivery duration	30 min
Minimum response capacity	1 MW
Maximum response capacity	100 MW
Aggregation	Allowed at GSP

DM service providers are expected to automatically react to changes in the frequency, and deliver energy proportionally to the change in the frequency. DM providers begin the delivery of the service when the frequency deviation exceeds +/- 0.1 Hz, and reach 100% of their contracted capacity when the frequency deviates by +/- 0.2 Hz from 50 Hz. The DM providers are required to follow the 'response curve' shown in Figure 17.

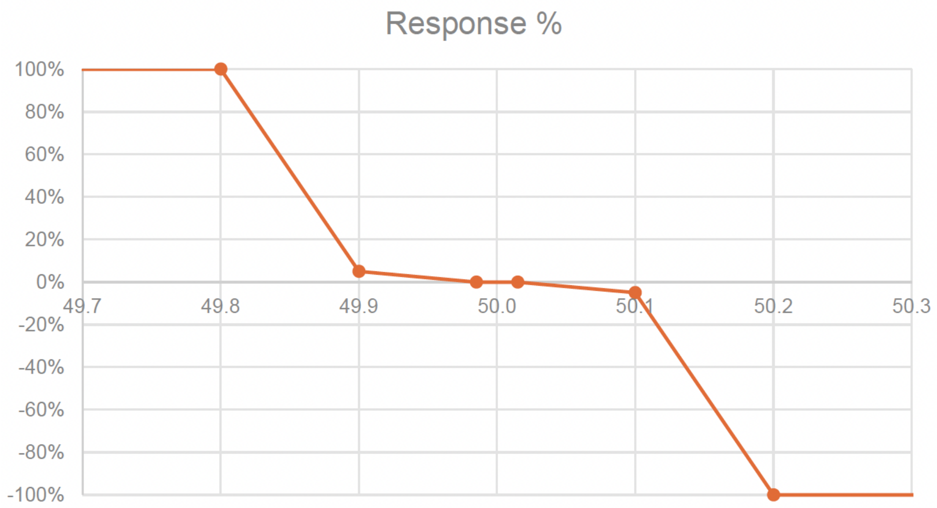

Figure 17. Dynamic Moderation response curve [v]

7.2.2 Market information and payment

DM services are procured on a day-ahead basis, for 6 four-hourly blocks called EFA Blocks (Electricity Forward Agreement blocks). Each EFA block consists of 8 half-hourly settlement periods. NGESO pays service providers an availability payment based on the contracted capacity at each settlement period (MW), market clearing price for the settlement period (£/MW/h). The service providers are expected to have an availability of greater than 99.9% during the settlement period, otherwise they receive no payment.

In addition, the settlement value may be adjusted if there is a difference between the expected response and the actual delivery. The formulae used to calculate the settlement value for each EFA block is shown by **Error! Reference source not found.**.

The performance of the service delivery is assessed using a pair of time series (referred to as ‘performance bound’) that enclose possible valid service delivery profiles – this accounts for acceptable lag times and ramp rates. The performance monitoring error is zero if the metered response is between the upper and lower performance bounds and is otherwise the difference between the metered response and the closer of the performance bounds. Table 5 shows the K factor (see **Error! Reference source not found.**) corresponding to various performance monitoring errors.

7.2.3 Market size and price

Table 8. Parameters related DMH and DML over 2022 [vi]

Parameter	DMH	DML
Number of active market participants	10	10
Procured volume (MW)	20 k	9.7 k
Market revenue (£M)	0.573	0.171
Average clearing price (£/MW/h)	7.24	4.38

7.2.4 Historical evolution

The NGESO launched the DM service in May 2022 and increased its requirement by March 2023 to transition from the faster-response Dynamic Firm Frequency Response (DFFR). DM manages large, sudden frequency imbalance’s pre-fault with a 1-second response and 30-minute operation, while DFFR, a faster legacy service, was traditionally used for frequency maintenance.

7.3 Dynamic Regulation

Dynamic regulation (DR) is a pre-fault service, intended to contain the frequency within the operational limits +/- 0.2 Hz from the target frequency of 50 Hz. It includes DR high frequency (DRH) and DR low frequency (DRL) to address over and under frequency, respectively.

7.3.1 Technical requirement

The service providers are required to meet the specific technical requirements described in

Table 9. Due to the expected response speed, DR currently is mainly provided by batteries, although it is not exclusively for batteries and more diversity in the future needs to be found[iv].

Table 9. Technical requirements to provide DR service [v]

Service specification	Details
Max initiation time	2 s
Max time to full delivery	10 s
Ramp time upper bound	8 s
Delivery duration	60 min
Minimum response capacity	1 MW
Maximum response capacity	50 MW
Aggregation	Allowed at GSP

Dynamic Regulation service providers are expected to automatically react to changes in the frequency, and deliver energy proportionally to the change in frequency when the frequency deviation is between +/- 0.015 Hz (Deadband) and +/- 0.2 Hz, reaching full delivery at the +/- 0.2 Hz frequency deviation. The DR providers are required to follow the 'response curve' shown in Figure 18.

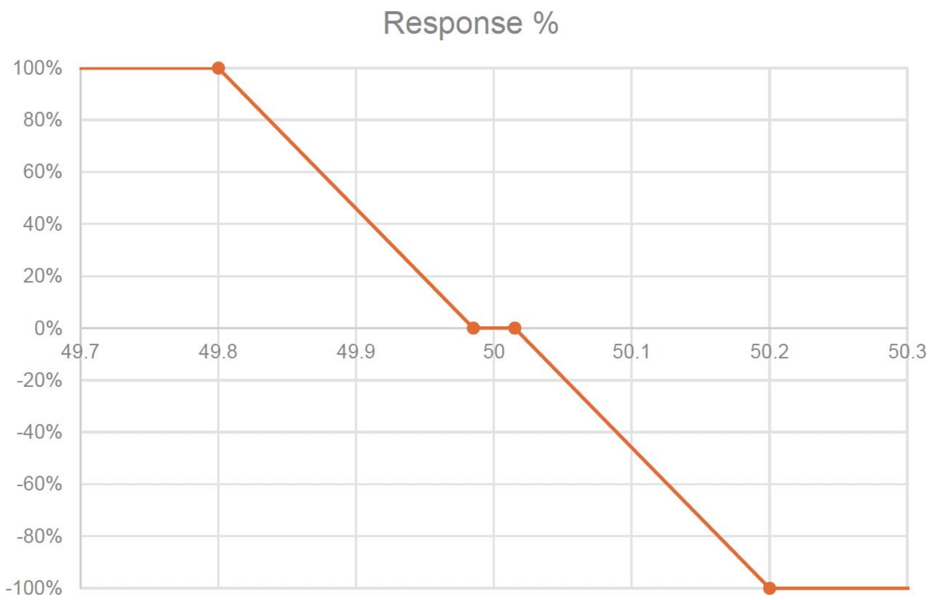

Figure 18. Dynamic Regulation response curve [v]

7.3.2 Market information and payment

DR services are procured on a day-ahead basis, for 6 four-hourly blocks called EFA Blocks (Electricity Forward Agreement blocks). Each EFA block consists of 8 half-hourly settlement periods. NGESO pays service providers an availability payment based on the contracted capacity at each settlement period (MW), market clearing price for the settlement period (£/MW/h). The service providers are expected to have an availability of greater than 99.9% during the settlement period, otherwise they receive no payment. In addition, the settlement value may be adjusted if there is a difference between the expected response and the actual delivery. The formulae used to calculate the settlement value for each EFA block is shown by **Error! Reference source not found.**.

The performance of the service delivery is assessed using a pair of time series (referred to as 'performance bound') that enclose possible valid service delivery profiles – this accounts for acceptable lag times and ramp rates. The performance monitoring error is zero if the metered response is between the upper and lower performance bounds and is otherwise the difference between the metered response and the closer of the performance bounds. Table 10 shows the K factor (see **Error! Reference source not found.**) corresponding to various performance monitoring errors.

Table 10. K factor corresponding to the performance monitoring error (Dynamic Regulation)

K factor	Error value	Description
1	Error <= 5%	The response error up to and including where no performance payment penalties are applied.
with linear interpolation of penalties	5% < Error < 25%	The response error between 5% and 25% where k factor applied with linear interpolation of penalties.
0	Error >= 25%	The response error at and above which performance payment penalties are 100%.

7.3.3 Market size and price

Table 11. Parameters related DRH over 2022 [vi]

Parameter	DRH	DRL
Number of active market participants	11	11
Procured volume (MW)	82 k	27 k
Market revenue (£M)	4	2
Average clearing price (£/MW/h)	12.16	21.73

7.3.4 Historical evolution

The NGESO launched the DR service in April 2022 and increased its requirement by March 2023 to transition from the faster-response Dynamic Firm Frequency Response (DFFR). Unlike DFFR, DR manages small, continuous frequency deviations with a slower 10-second response beyond a specified 'deadband' region.

7.4 Fast Reserve

Fast reserve provides rapid delivery of active power through increasing output from a generation or reducing electricity consumption. It is used to control frequency changes that might arise from sudden, and sometimes unpredictable, changes in generation or demand.

7.4.1 Technical requirements

The fast reserve service is open to the generators and consumers connected to the electricity transmission network (Balancing Mechanism Units - BMU) and electricity distribution networks (non-BMU) who can meet the technical requirements. This might include generators connected to the transmission and distribution networks, storage providers and aggregated demand-side response.

Table 12. Technical requirements to provide Fast reserve [vii]

Service specifications	Details
Minimum delivery magnitude	25 MW
Maximum response time to dispatch/cease instruction	2 min
Minimum duration of continuous delivery	15 min
Minimum delivery rate	25 MW/min
Whether aggregation is allowed	Yes

When National Grid ESO (NGESO) instructs a service provider to provide fast reserve, the service provider is expected to confirm receipt within 2 minutes of receipt. The service provider should start providing optional fast reserve within the response time, until the expiry of the maximum utilisation period or the commencement of a settlement period in respect of which the optional fast reserve is not available by the service provider.

7.4.2 Market information and payment[vii]

Fast Reserve is procured on a within-day basis through the Optional Fast Reserve service. Providers are paid an availability fee (£/hour) if called upon to provide the service, and a utilisation payment (£/MWh) if dispatched, based on the actual level of energy delivered in response to a given instruction.

The payments for BMUs and non-BMUs are different. While the former receive the Enhanced Rates Availability Payment, the latter receive Optional Availability Payment and the Optional Energy Payment (utilisation payment).

If the BM participating service provider fails to comply in any respect with the Bid-Offer Acceptance, then National Grid shall have the right to withhold payment of the Enhanced Rates Availability Payment.

If the non-BM participating service provider fails to comply in any respect with the instruction, then National Grid shall have the right to withhold payment of the Optional Energy Payment.

[vii] NGESO, Fast Reserve Tender Rules and Standard Contract Terms (2019), https://www.nationalgrideso.com/document/134361/download

7.4.3 Market size and cost

Table 13. Overall volumes and costs of fast reserve

Parameter	2019	2020	2021	2022
Utilisation volume (GWh)	4,401	3,087	3,247	2,868
Cost: BM participating (£ million)	79	79	99	96
Cost: not-BM participating (£ million)	17	25	111	113

7.4.4 Historical evolution

The fast reserve service was delivered as either the Firm Service (subject to a tender process) or the Optional Service. NGESO stopped procurement of firm fast reserve in July 2020, while the optional fast reserve service was continued [viii]. NGESO is planning to replace optional fast reserve with new product (Quick/Slow Reserve) [iv].

7.5 Short Term Operating Reserve

The short term operating reserve (STOR) is a post-fault service that involves increasing generation or reducing demand to help balancing the power system when demand on the system is greater than forecast or in the case of unforeseen generation unavailability. The STOR service is procured through daily auctions.

7.5.1 Technical Requirement

The service is open to Balancing Mechanism (BM) and non-BM participants (any technology) with a connection to either the electricity transmission or distribution network with the ability to increase generation or reduce demand by at least 3MW. Currently STOR service is mainly provided by open-cycle and combine cycle gas turbines, gas reciprocating engines, diesel generators, and non-pump storage hydro [iv]. The service providers are required to meet the technical requirements described in

Table *14*.

[viii] NGESO, Update on STOR and Fast Reserve tenders (2020) https://www.nationalgrideso.com/document/173101/download

Table 14. Technical requirements to provide STOR service [ix]

Service specifications	Details
Minimum delivery magnitude	3MW
Maximum time to full delivery	20 min
Minimum duration of continuous delivery	120 min
Maximum recovery time before responding again	1200 min
Whether aggregation is allowed	Yes

STOR service can be provided during the committed windows (a morning window and an evening peak window, pre-defined by NGESO) and optional windows (any periods outside the committed windows). When National Grid ESO (NGESO) issues a dispatch instruction to a STOR service provider, the service provider is expected to deliver a certain amount of STOR continuously until NGESO issues a cease instruction, or the maximum utilisation period of the service provider (the longest time for NGESO to use this STOR unit, pre-defined by each service provider during registration) expires, or the end of the committed window is reached (whichever comes the earliest).

7.5.2 Market information[x]

STOR is procured through a daily pay-as-clear auction process for contracts lasting one day. The auction for each STOR service day will open on a rolling 8-day ahead basis. Prior to the auction, providers submit their STOR bid that specifies the applicable STOR service day, availability prices (as an integer value, in £/MW/h), the contracted volume (as an integer value, in MW) and whether the bid is curtailable. The auction closes at 5.00 AM on the day that precedes the relevant service day for which STOR bids have been assessed, and NGESO notifies each STOR participants regarding the acceptance or rejection of submitted bids no later than 6.00 AM on the same day, with the auction result published online at 10.00 AM. Both balancing mechanism-participating (BM) and non-balancing mechanism participating (non-BM) providers could provide STOR during committed windows, while optional windows are open to non-BM providers only.

For balancing mechanism-participating (BM) providers, they can only provide STOR during committed windows, and they will be paid with availability payments (for being available to provide the service within the Committed Windows), and the utilisation payment (if NGESO issues dispatch instruction and the providers deliver the service). The BM providers submit bid-offer pairs via BM (including the utilisation price) before the gate closure of the settlement period for the BM providers' pre-

[ix] NGESO, Short Term Operating Reserve Participation Guidance Document (2021) https://www.nationalgrideso.com/document/189926/download

[x] NGESO, Short Term Operating Reserve Auction Rules (2021) https://www.nationalgrideso.com/document/189891/download

instruction window (around 1.5 hour before each committed window). The service dispatch order is issued by the way of bid-offer acceptance.

Non-BM providers can provide STOR during both committed windows and optional windows. They will be paid with availability payments and the utilisation payment for the STOR contract during committed windows. But for STOR dispatched during optional windows, they will be paid with optional utilisation payments for the energy delivered, without availability payments. The non-BM providers participate the STOR service market via the Ancillary Platform.

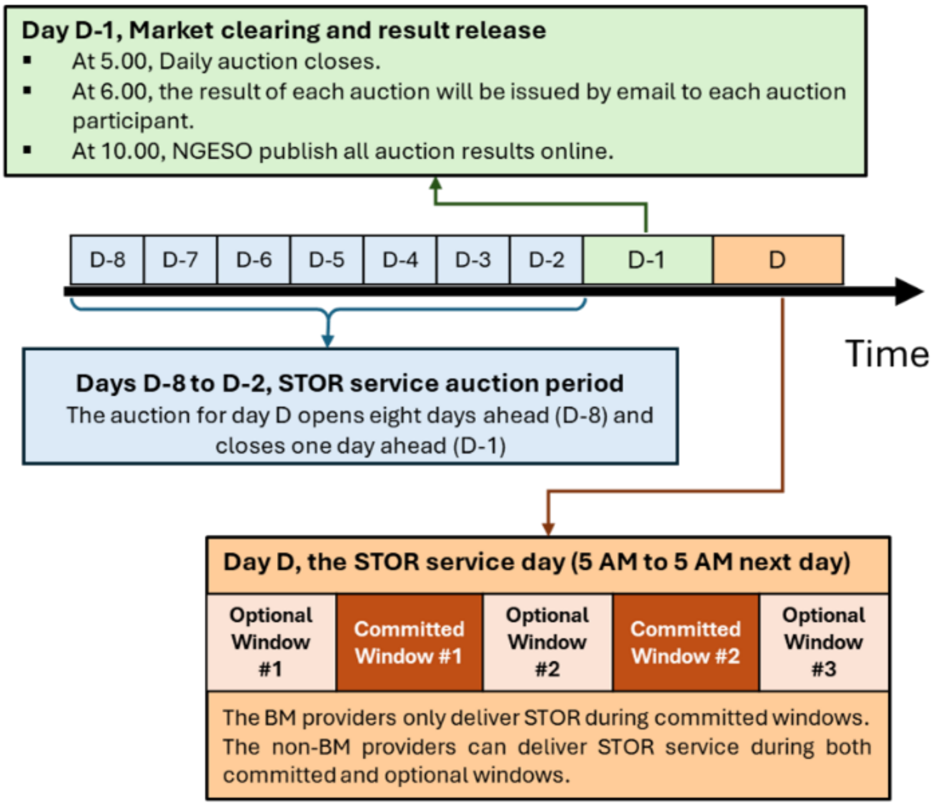

Figure 19. Timeline for the STOR service day D

The service providers are expected to deliver a minimum of 95% of the offered MW throughout the instructed period. Failure to deliver will trigger an Event of Default and will forfeit Availability payments for most or all of the relevant committed window.

Service stacking is not allowed for STOR providers with STOR contracts for Committed windows. However, it is possible to provide other services in the Optional Windows as long as STOR delivery is not impacted.

7.5.3 Market size and price

The clearing price of STOR has been very volatile. The price hit spikes in January 2022 and December 2022. The average clearing price for 2022 was £11.95/MW/hour compared with £3.90/MW/hour for the nine months April – December in 2021 following the launch of day-ahead procurement.

Table 15. STOR utilisation volumes and cost [xi]

Parameter	2019	2020	2021	2022
Utilisation volume (GWh)	217	81	60	38
Cost (million £)	55	44	54	112

7.5.4 Historical evolution

STOR procurement has been set to day-ahead procurement since April 2021. The minimum response time used to be longer (within 240 min) and was later set to within 20 min.

7.6 Demand Flexibility Service

The Demand Flexibility Service (DFS) has been developed to allow the NGESO to access additional flexibility when national demand is at its highest – during peak winter days. This service will allow residential consumers, as well as some industrial and commercial users (through suppliers/aggregators), to be incentivised for voluntarily flexing their demand by shifting energy-intensive activities to off-peak times. DFS was launched as an 'enhanced market action', so is not used explicitly as a commercial tool, but instead activated once all appropriate market actions have been taken or if available actions at day-ahead are deemed to be insufficient for balancing supply and demand.

7.6.1 Technical requirement

DFS providers would require half-hourly metering and must provide relevant half-hourly metering and baselining data to demonstrate delivery of demand reduction. In addition, the providers must meet the requirements specified in

Table ***16***.

Table 16. Technical requirements to provide DFS [xii]

Service specification	Details
Minimum delivery duration	30 min
Minimum magnitude (there is no minimum asset size)	1 MW
Maximum magnitude	100 MW
Aggregation	Allowed on a national basis

[xi] NGESO, Short Term Operating Reserve Participation Guidance Document (2021), https://www.nationalgrideso.com/document/189926/download (Accessed on 08/07/2024)

[xii] NGESO, Demand Flexibility Service, https://www.nationalgrideso.com/industry-information/balancing-services/demand-flexibility-service-dfs (Accessed on 08/07/2024)

Minimum response time	30 min

Assets that are dispatchable via the Balancing Mechanism, or participate in Ancillary services, DNO services and Capacity Market are excluded from providing DFS.

7.6.2 Market information and payment

Electricity System Operator (ESO) issues a Service Requirement to market at either day ahead, within day morning, or within day midday for a specific delivery period. DFS is procured through a DFS tender, once bids from participants (i.e. aggregators and suppliers) are accepted, they will ask their costumers to voluntarily reduce their demand at times specified and receive payment following delivery. Tender submissions are Pay as Bid.

To ensure that there are rewards in place for participating households and businesses, even if the service is not needed to manage the electricity system in real-time (Live events), the ESO run 12 tests between the start of November and end of March (Test events). The first six of these tests will pay registered DFS providers (such as energy suppliers, aggregators, and third parties) a guaranteed minimum price of £3/kWh (for 2023/2024), which they will pass onto their customers.

If for any reason, the participants (e.g. households) are unable to reduce their electricity consumption during a DFS event, there are no penalties.

7.6.3 Market size and price

DFS began on 1 November 2022 and the first round ran until end of March 2023. In 2022/23, DFS was procured over 5 half-hourly time slots, i.e. 17:00 to 18:00 on 23rd of January 2023, and 16:30 to 18:00 on 24th of January 2023. Over 1.6 million households and businesses participated (through a total of 33 aggregators/suppliers) in the delivery of DFS.

Table 17. Procured volumes and costs of DFS in 2022/23 [xiii]

Parameter		DFS procured in 2022/23
Live events	DFS procured (average over 5 half hour live events)	318 MW
	DFS Provider Bids Accepted Total Cost (£)	~£3.5 m
Test events	DFS procured (average over 40 half hour test events)	123 MW

[xiii] NGESO, Demand Flexibility Service – Live Events, https://data.nationalgrideso.com/dfs/demand-flexibility-service-live-events (Accessed on 08/07/2024)

	DFS Provider Bids Accepted Total Cost (£)	~£7.3 m