Programme Area: Energy Storage and Distribution

Project: Storage & Flexibility Modelling

Title: Near Term Opportunities for energy storage

Abstract:

The report provides am assessment of the near term opportunities for energy storage over the next 5-10 years given the current market structures, with a particular focus on electricity.

Context:

This project will develop energy system modelling capability to increase understanding of the role of energy storage and system flexibility in the future energy system. The modelling capability will provide a whole systems view of the different services that could be provided and at which points in the energy system they are most appropriate. Management consultancy Baringa Partners are delivering this new project to develop the capability to improve understanding with regards the future role of energy storage and the provision of cross-vector system flexibility within the context of the overall UK energy system.

D1.2: Assessment of the near term market potential for energy storage

CLIENT: Energy Technologies Institute

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Version History

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Table 1 List of key acronyms

Acronym	Description
AAHEDC	Assistance for Areas with High Electricity Distribution Costs (charges)
ANM	Active Network Management
BEGA	Bilateral Embedded Generation Agreements
BM	Balancing Mechanism
BMU	Balancing Mechanism Unit
BSC	Balancing and Settlement Code
BSIS	Balancing Services Incentive Scheme
BSUoS	Balancing Services Use of System (charges)
CCGT	Combined Cycle Gas Turbine
CfD	Contract for Difference
CLASS	Customer Load Active System Services
CM	Capacity Market
CMSC	Capacity Market Supplier Charge
CSP	Concentrating Solar Power
CUSC	Connection and Use of System Code
DA	Day Ahead
DG	Distributed Generation
DNO	Distribution Network Operator
DSR	Demand Side Response
DTU	Demand Turn-Up
DUoS	Distribution Use of System (charges)
EBSCR	Electricity Balancing Significant Code Review
EFR	Enhanced Frequency Response
EHV	Extra High Voltage
ENA	Energy Networks Association
ERPS	Enhanced Reactive Power Service
FCDM	Frequency Control by Demand Management
FES	Future Energy Scenarios (National Grid)
FFR	Firm Frequency Response
FR	Fast Reserve
GDE	Gas Deficit Emergency
HV	High Voltage
ID	Intra-Day
LCNF	Low Carbon Network Fund
LHS	Latent Heat Storage
LLF	Line Loss Factors
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
LRMC	Long Run Marginal Cost
LRS	Long Range Storage
LV	Low Voltage
MBSS	Monthly Balancing Services Summary
NGET	National Grid Electricity Transmission

NIV	Net Imbalance Volume
OCGT	Open Cycle Gas Turbine
ORPS	Obligatory Reactive Power Service
ORR	Operational Reserve Requirements
PAR	Price Average Reference
PCM	Phase Change Material
PPA	Power Purchase Agreement
PSH	Primary Secondary High
PS	Primary Secondary
PSH	Pumped Storage Hydro
RHI	Renewable Heat Incentive
RCRC	Residual Cashflow Reallocation Cashflow
RO	Renewables Obligation
ROCOF	Rate of Change of Frequency
SBP	System Buy Price
SCR	Significant Code Review
SHS	Sensible Heat Storage
SO	System Operator
SOF	System Operability Framework
SMES	Super Conducting Magnetic Energy Storage
SRMC	Short Run Marginal Cost
SRS	Short Range Storage
SSP	System Sell Price
STOR	Short Term Operating Reserve
TES	Thermochemical Energy Storage
TNUoS	Transmission Network Use of System (charges)
ToU	Time of Use
TSO	Transmission System Operator
UKCS	United Kingdom Continental Shelf

Table 2 Glossary of key terms

Term	Description
Availability / holding volume	Positioning of plant/technology to be able to provide/withdraw energy within given response time
Embedded Benefits	Indirect benefit through avoidance of network charges by positioning at distribution/building level
Gate Closure	Point at which bilateral or exchange energy trading ceases and the system operator takes direct control
Long-run costs	Total investment and operating costs of the technology
Price arbitrage	Revenue achieved by exploiting price differentials in particular markets
Short-run costs	Operating costs (only) of the technology
Spill	Generation effectively curtailed due to constraints on network or inability to store
Utilisation volume	Action by system operator to use holding volume to provide/withdraw energy

Executive Summary

The purpose of this report is to explore the potential in Great Britain (GB) for energy storage in the next 5-10 years based on the ***current market arrangements*** focusing primarily on electricity, but also exploring the possible role of other storage options for other energy vectors in the same timeframe.

Electricity

The near-term potential for additional electricity storage is focused primarily around new grid-scale Li-Ion battery storage (alongside existing pumped storage). The GB market arrangements for electricity are highly complex and a qualitative summary of the opportunities for new electricity storage is provided below.

Market area	Opportunities for electricity storage
Firm Frequency Response (FFR)	The FFR market has good potential as a revenue stream for new storage entrants due to the fast response times of storage technologies, which allows them to compete in tenders for all FFR products. Response time and power rating are key design considerations. Providing dynamic frequency response may involve a large number of short charging and discharging periods each day
Enhanced Frequency Response (EFR)	Storage assets currently competing in the FFR markets operated by National Grid (as the Transmission System Operator) are well placed to provide the *new* Enhanced Frequency Response balancing services product in future due to their fast response times[1].
Fast Reserve (FR)	The Fast Reserve market has low potential for new storage entrants as it is saturated by existing pumped storage plant. Power rating is important as a high minimum MW threshold is applied. Frequent cycling of assets providing Fast Reserve could increase operation and maintenance costs and accelerate the degradation of the storage asset
Demand Turn Up	New service with first capacity procured for delivery in summer 2016. Although there is no mention of storage assets in the design documents for this service, the requirement to "increase" demand could in future be met by a storage operating in charging mode during periods of low demand and high supply. Therefore, if allowed by National Grid, this could be a potential revenue stream for new market entrants.

[1] This is used to provide direct Rate of Change of Frequency (RoCoF) control, which is faster acting compared to other FFR requirements and may allow National Grid to reduce the total requirement for frequency containment – i.e. 1 unit of EFR may be able to displace >1 unit of 'slightly' slower FFR products.

Market area	Opportunities for electricity storage
Short Term Operating Reserve (STOR)	The STOR market has potential as a revenue stream for new storage entrants, however there are a range of competing technologies currently participating in STOR tenders which means this is likely to be challenging. In addition, size of energy capacity is a key challenge as energy has to be delivered for up to a 2 hour continuous period. Scheduling of availability for STOR has to also account for periods ahead of the morning and afternoon STOR windows to bring the State of Charge up to an adequate level for subsequent delivery of the service if called.
Reactive Power	The current reactive power market has low potential as a revenue stream for new storage entrants as current requirements are satisfied by the obligatory (non-tendered) service. Use of storage would need to consider the interaction between provision of reactive power and provision of active power for market trading and/or Balancing Services
Black Start	The Black Start market has low potential due to incumbent providers (including pumped storage) and highly specific locational requirements. Storage must be kept with a minimum charge level at all times in order to be able to provide necessary power to start the neighbouring large generator
Balancing Mechanism (BM)	Large scale storage assets may participate in the BM (by providing bids and offers) but this has been focused on pumped storage to date, along with traditional thermal generators and STOR providers. Small scale storage assets may not directly participate in the BM (unless they have opted in via a BEGA[2] agreement) but will still be impacted by the system imbalance prices (as the price received for energy delivered for reserve Balancing Services).
Wholesale energy arbitrage	The potential for energy arbitrage revenues for new storage assets is highly dependent on prevailing market conditions (affecting available price differentials) and route to market (ability to capture these price differentials). The expectation is that wholesale revenues alone would not be sufficient and batteries would need to access other revenues to make a sufficient return. However it is not always possible to access these multiple revenue streams (e.g. with balancing services). Moving forwards this may become more challenging due to e.g. increasing levels of interconnection and DSR (competing across a range of markets and balancing services).
Embedded benefits	Embedded benefit revenue streams offer high potential to new storage entrants but are only available to distribution connected or demand (behind-the-meter) connected resources. However, these benefits are heavily dependent on the structure of the charges that they can potentially avoid. For example, careful scheduling of the storage asset is required to optimise the likelihood of receiving Triad avoidance revenues given the uncertainty surrounding when the Triad periods will occur. Ofgem have recently launched a review of embedded benefits citing a concern that these charges are becoming increasingly non-cost reflective and potentially distorting investment decisions.

[2] Bilateral Embedded Generation Agreement

Market area	Opportunities for electricity storage
Capacity Market (CM)	The CM offers an additional revenue stream for new storage entrants. However, competition has been high in the CM auctions held to date with low clearing prices and no new storage assets have been successful in receiving a CM agreement. In addition, at times of system stress, storage capacity may be required to deliver energy over an undefined period of time or face penalties for non-delivery.
Avoiding wind curtailment	Currently the direct costs of curtailment (e.g. BM constraint costs) are socialised across all market participant through the Balancing Services Use of System (BSUoS) charge (which National Grid applies to recover the balancing costs they incur in managing the system). Furthermore, the owner of the renewable asset will be indifferent in revenue terms between generating and being curtailed. Therefore there is currently no way for the owner of a storage asset to monetise the benefit provided to the system of reducing renewable curtailment at the transmission level. This is similar at the distribution level, due to most Distribution Network Operator's applying a simple 'Last In First Out' approach to curtailment of distributed generation.
Avoided network reinforcement	Current regulatory and commercial frameworks do not allow for either a) direct ownership of storage assets by the transmission or distribution network operator or b) direct compensation for new third-party owned storage assets for the avoided network reinforcement benefit they may provide to the system. This is based on the current interpretation of storage as a form of generation. However, current distribution level demonstration projects are providing evidence for the value of storage in this area and the necessary commercial arrangements may be put in place to provide an explicit route to market to help realise this value

It is acknowledged that "benefit stacking" is a key requirement to making future storage investment economic and a number of papers discuss this issue further[3]. *However, given the current market arrangements in the near term (and complexities in accessing multiple revenue streams) it is expected that the primary and secondary reserve markets (e.g. including EFR and FFR) are likely to be the key source of revenue for driving tangible deployment of new battery storage.*

It is currently only possible to contract for delivery of one balancing service in the same period with National Grid and this is not compatible with accessing wider energy arbitrage revenues. In addition, although provision of services into these reserve markets is technically compatible with receiving Capacity Market (CM) revenues, the potential for penalties and indeterminate delivery window (coupled with low CM clearing prices seen to-date) mean that it is highly unlikely that new electricity storage will be supported via this route.

Using Baringa's Balancing Services stack tool we have modelled the potential role of batteries bidding into the auctions for these PSH (Primary, Secondary and High) reserve services against competing alternatives. Batteries are very competitive in all our scenarios (combining low/central/high battery cost projections with low/central/high estimates of market size), which results in them having a very

[3] IEA: Technology Roadmap Energy Storage, 2014; Rocky Mountain Institute: The Economics of Battery Storage, 2015; Carbon Trust & Imperial College London: Can storage help reduce the costs of a future UK electricity system, 2016.

large share of the PSH products; 100% until 2020 due primarily to the EFR requirement and around ~80% to 94% to 2025 (with DSR providing some competition), as shown in Figure 1.

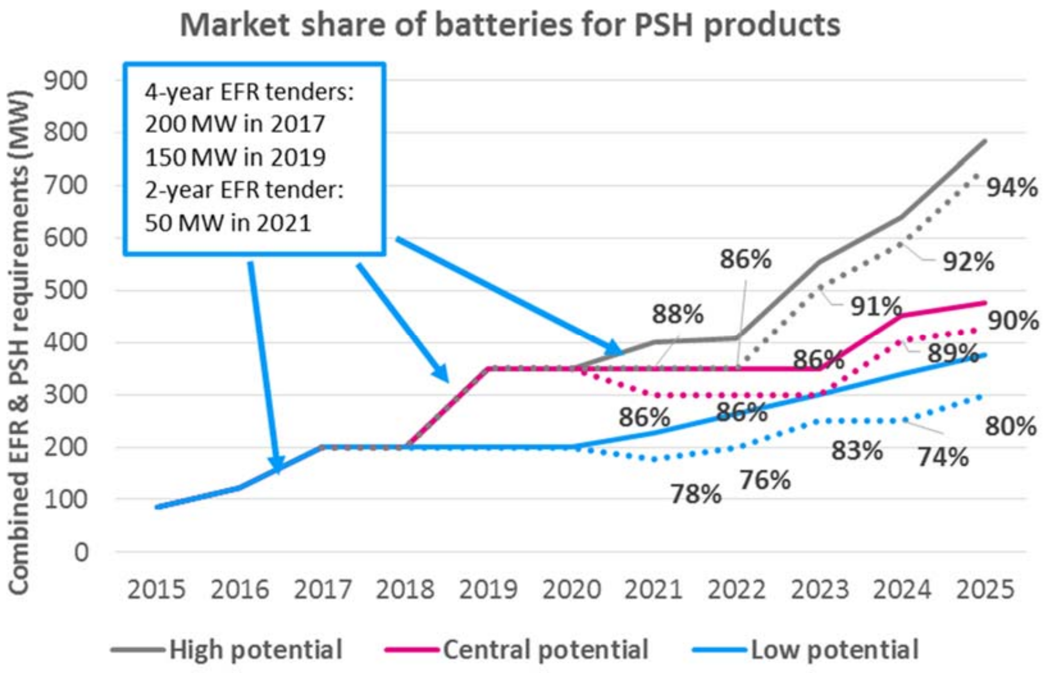
There is a good investment case, albeit for a relatively modest volume, for batteries in the near-term driven primarily by the high-value frequency service markets with fast response requirements. However, there are a number of risks associated with an early decision to investment in batteries. These include the expected rapid decline in future battery costs which means that there exists the potential for batteries deployed in early auctions (which have limited 4-year contracts) to be outcompeted in future auctions, as they are effectively undercut by newer and considerably cheaper batteries.

The battery investor would then need to look to other revenue streams to recover their remaining investment over the full life of the plant, but these are also subject to various risks:

- Other balancing services outside of frequency response, although these generally have lower clearing prices
- Wider electricity market revenues (e.g. wholesale market and BM), although these are not guaranteed and cannot be accessed simultaneously with balancing services contracts for the same period and widespread deployment of batteries may also cannibalise the potential for arbitrage by reducing the price spread across the day.
- Embedded benefits, although these may be reformed in future reducing their value
- Capacity market revenues, but with potential risks of penalties due to an undefined delivery period

High-level Baringa estimates are that wholesale arbitrage might provide revenues equivalent to ~10-50% of the long-run costs for new battery entrants built in the nearer-term, embedded benefits ~10-25% and the CM ~10-30%. Given these wide ranges and the challenges in capturing and stacking these multiple revenue streams it is clear why most developers (at least in the near term) are pursuing the higher value and more certain Balancing Services based route to market, focused around frequency response, even if these excludes the potential for other revenue streams and has limited overall market size.

Figure 1 **Market share of batteries in the selected PSH reserve auctions**



Note: Solid lines illustrate the size of the selected balancing service requirements and the dotted line the share provided by batteries.

Illustrative calculations were also undertaken to estimate the breakeven point for domestic-scale electricity battery storage in 2020, 2025. These considered low, central and high battery costs under three sets of additional assumptions:

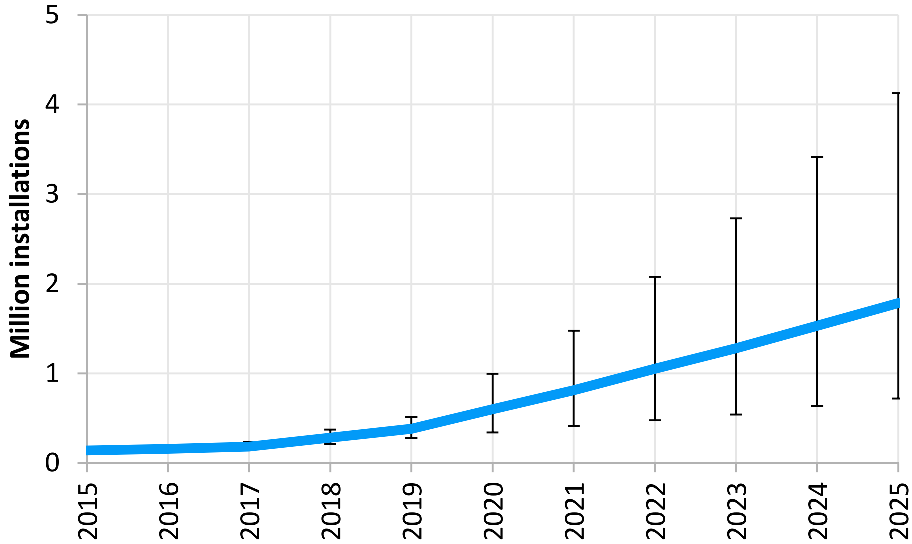
- Whether only wholesale price shape is passed through to the consumer or other forms of shaped charges (e.g. distribution network) are also passed through
- Whether the building also has heat storage or not
- Whether the building also has solar PV or not

The economic case for using a domestic battery for load shifting and management of solar output appears weak in the near term to 2025, in particular when cheaper heat storage is used to manage electrified heat load as this removes much of the arbitrage potential from the battery. In the few sensitivities where the savings are sufficient to break-even with the battery costs, this is reliant on the consumer seeing the full shaped pass through of all key tariffs, and successfully avoiding the most expensive periods under the tariff via use of the battery. However, it is unlikely to be politically acceptable to expose domestic consumers to such stringent price differentials given the potential distributional impacts on consumers who are unable to avoid the most expensive periods. With only wholesale price shape passed through the potential battery savings appear highly uneconomic in all sensitivities considered.

Heat storage

The near term potential for new building heat storage is likely to be driven indirectly by the rollout of low carbon heating systems, for which storage is required to size and operate them efficiently (with further potential benefits under ToU tariffs or in providing DSR). New heat storage installations are likely to be limited due to the modest impact of the RHI (Renewable Heat Incentive) scheme. As a proxy the estimated deployment of domestic low carbon heat installations in National Grid's Future Energy Scenarios (FES) is shown below. However, deployment is likely to be focused initially in more cost-effective off-gas grid applications, where building heat storage is more likely to exist already.

Figure 2 Estimated low carbon heat domestic installations from National Grid FES scenarios



Note: shows average and max/min from across the 4 published scenarios. Technologies covered include heat pumps and biomass

Large scale heat storage for district heat networks is generally considered an integral part of the design and hence the near-term potential is driven primarily by the underlying requirement for the network itself. Published scenarios (from e.g. National Grid and the Committee on Climate Change) show a wide range of potential increase in the scale of delivered heat of ~2-7 times by 2025, but this is an increase from a low absolute base.

Gas storage

Despite two projects completed in the last year and 11 with planning permission the economics of new build are challenging in the near term due to the reduction in price volatility and significant narrowing of seasonal price spreads. This has been compounded by a decision not to consider direct intervention for storage to provide strategic security of supply, as part of the recent (2014) Gas Security of Supply Significant Code Review. The extent of future UK shale gas is a significant uncertainty, but may further dampen the economics for storage given the US experience of significant within year flexibility in response to price changes. As a result it appears unlikely that any significant new gas storage capability will be developed in the next 5-10 years.

1 Introduction

1.1 Background

The primary objective of the *Storage Flexibility Project* is to develop the capability to improve understanding of the future role of energy storage and the provision of system flexibility within the context of the overall energy system. This aims to provide a techno-economic evaluation of energy storage across multiple energy vectors (electricity, heat, gas and hydrogen) accounting for the different services that could be provided (e.g. frequency response or avoiding wind curtailment) and at which points in energy system (transmission, distribution, building level) they are most appropriate.

Stage 1 of the project is comprised of 3 deliverables

- **D1.1 Energy Storage Mapping Report** a first principles framework for mapping the system technical services and benefits that storage (heat, hydrogen, gas and electricity) and competing flexibility options could provide
- **D1.2 Assessment of the near term market potential for energy storage** *(this report)*, over the next 5-10 years given the current market structures, with a particular focus on electricity
- **D1.3 Approach for modelling long term role of energy storage** - which defines the modelling approach to analysing the longer term role for storage and other relevant flexibility options in GB from a system operator perspective

1.2 Purpose of this report

The purpose of this report is to explore the potential in Great Britain for energy storage in the next 5-10 years based on the ***current market arrangements***[4] focusing primarily on electricity but also exploring the possible role of other storage options for other energy vectors in the same timeframe.

It includes the following:

- A description of the current market for flexibility services in electricity (e.g. reserve, back-up capacity) and a high level view of the economics of electricity storage against competing alternatives within each service segment
- A high level assessment of the potential for:
  - Gas storage including fast-cycle and seasonal storage (it is assumed that there is no meaningful role for hydrogen and hence associated storage requirements in this time frame),

[4] In comparison, the *D1.1. Storage Mapping Report* and *D1.3 Framing approach for longer term role of storage* deliverables consider the underlying technical drivers of different system services and benefits, agnostic of the market or policy arrangements to procure or incentivise providers of these services.

- Heat storage, focussing primarily on building-level storage and buffer/accumulator storage for district heat networks

1.3 Structure of the report

The structure of the report is as follows:

- Section 2 focuses on electricity storage and starts with an overview of relevant technologies.
    - Subsections 2.2 to 2.7 provide a detailed view of revenue streams currently available for both balancing services and in the wider electricity market, and then moves onto how these may evolve in future
    - Subsections 2.8 to 2.9 summarise the near term opportunities for- and barriers to- new storage deployment
    - Subsection 2.10 presents the modelling results of potential near-term electricity storage deployment
- Section 3 focuses on heat storage, it provides a summary of relevant technologies, an overview of the relevant market structure and a semi-quantitative view of near term opportunities from published literature
- Section 4 focuses on gas storage and is structured in a similar manner to the section on heat storage
- Appendix A provides an overview of the modelling methodology used in section 2.10
- Appendix B provides an illustration of the tender data required to participate in the FFR market

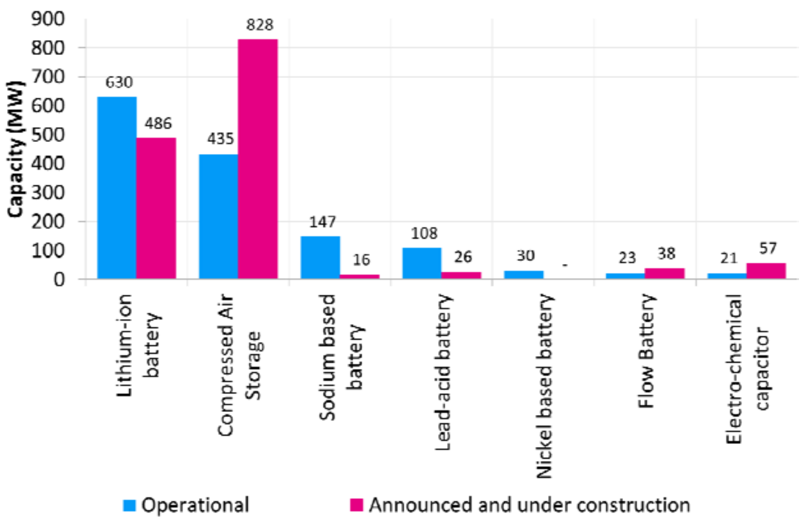
2 Electricity Storage

2.1 Electricity Storage Technologies

2.1.1 Current deployment

The U.S. Department of Energy collates information on worldwide energy storage capacity and maintains a comprehensive database of current and planned installations[5]. Figure 3 shows current and planned global deployment for a selected set of energy storage technologies. The recent deployment history of these technologies is shown in Figure 4.

Figure 3 Operational, announced and under construction capacity of selected storage technologies[6]



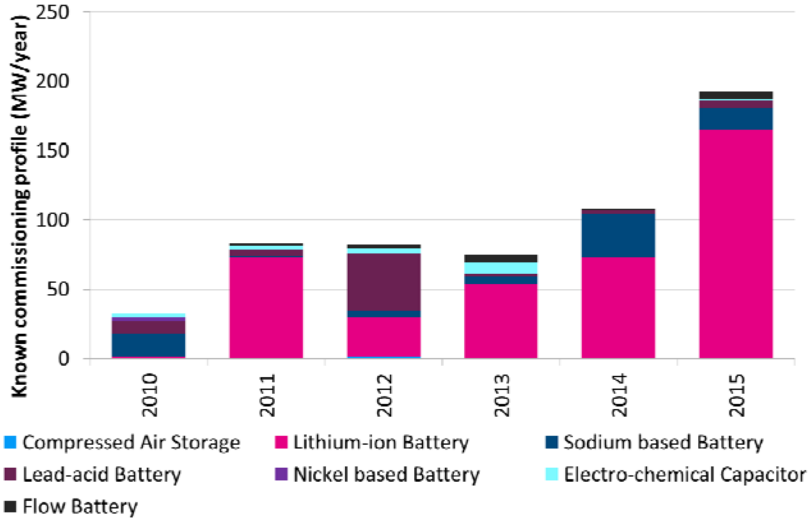
This is dwarfed, however, by existing Pumped Storage Hydro (PSH) capacity, which exceeds 127 GW globally including around 40 GW in Europe, 20 GW in each of North America and China, with the majority of the rest spread across other parts of Asia[7].

[5] http://www.energystorageexchange.org/

[6] Excludes pumped hydro storage, flywheel capacity and chilled water / ice thermal storage.

[7] NHA (2014) National Hydro Association - Pumped Storage Development Council Challenges and Opportunities For New Pumped Storage Development

Figure 4 **Recent deployment of selected storage technologies[8].**



2.1.2 Technical characteristics

There are a number of technical characteristics that are important when selecting a specific electricity storage technology for a desired application or set of applications. These are described in more detail in the separate deliverable *D1.1 Storage Mapping Report*, but include:

- **Efficiency:** The difference between the amount of energy input to the storage and the amount of energy subsequently released.
- **Energy density:** storage of energy per unit volume or mass
- **Injection/withdrawal rates:** relationship between the energy storage capacity (as defined by the energy density) and the power output of the storage determines the length of time for which the storage can operate at full power.
- **Cycle life**: The number of complete cycles a storage unit can complete before losing considerable performance.
- **Depth of discharge**: The amount of a storage's capacity that has been utilised. It is expressed as a percentage of the storage's full energy capacity.
- **Ambient conditions**: Conditions such as temperature may influence the performance of the storage asset[9].
- **Maintenance requirements**: Across the lifetime of the storage, degradation can occur, which requires ongoing maintenance and potentially the expense of replacing damaged equipment.

Of the above characteristics, most are applicable to all types of electricity storage, with the exceptions of depth of discharge and ambient conditions which may be highly relevant to battery

[8] Excludes pumped hydro storage, flywheel capacity and chilled water / ice thermal storage.
[9] In the particular case of batteries, high temperatures can lead to a more rapid loss of capacity and cold temperatures may lead to sluggish reactions:

storage[10] but less relevant for other technologies. Depth of discharge is very influential for battery storage as deeper discharge during cycles are expected to shorten the lifetime of the asset.

Differences in technical characteristics, combined with varying physical sizes, makes the different storage technologies suitable for different applications, as illustrated in Figure 5.

Figure 5 Summary of typical applications for electricity storage technologies

Storage Technology	System Location	Typical Applications	Charge/Discharge duration	Cycles
Pumped Hydro, Compressed Air	Transmission	Daily and weekly storage: Arbitrage applications.	4 – 24 hours	Up to 1 per day
Flywheels, Supercapacitors, Super Conducting Magnetic Energy Storage (SMES)	Transmission and Distribution	Within day storage: System balancing applications (frequency response).	1 min – 1 hours	20 – 40 per day
Large Scale Batteries	Transmission and Distribution	Within day storage: System balancing applications (frequency response, reserve, voltage support), network reinforcement deferral (peak shaving), renewables integration.	Minutes – hours	1 to 100 per day
Small Scale Batteries	Distribution / Building	Within day storage: Renewables integration and arbitrage applications.	Minutes – hours	Up to 1 per day

2.1.3 Storage costs

There are a number of different ways in which storage costs can be reported. These include metrics referring to power output £/kW and energy storage capacity £/kWh individually or a cumulative combination of both components. Care therefore needs to be taken when comparing costs estimates from different sources. The approach differs between available sources and this is noted in subsequent sections where relevant. Additionally conversion between currencies and monetary terms (real vs nominal) may also be required.

[10] http://www.irena.org/documentdownloads/publications/irena_battery_storage_report_2015.pdf

The availability of cost information will depend upon how developed a storage technology is. The electricity storage technologies covered in Figure 5 can be broadly categorised as follows[11]:

Research and Development: Supercapacitors, superconducting magnetic energy storage (SMES), certain forms of flywheel and flow batteries. Assessing the costs of these technologies is difficult due to a lack of reference data resulting from few (if any) commercially operating installations.

Demonstration and Deployment: Batteries (lithium-ion and sodium sulphur chemistries). Battery storage technologies are rapidly moving from demonstration projects towards deployment and commercialisation. The costs of battery storage have been widely acknowledged to be falling, driven by economies of scale and the development of manufacturing supply chains. The most dramatic cost decreases have occurred for lithium-ion batteries[12]. This has been attributed to learning achieved in other sectors as lithium-ion batteries are widely used in consumer electronics and electric vehicles.

Commercial / Near Commercial: Pumped hydro and compressed air storage technologies. The costs associated with these large scale installations are highly dependent on locational factors, such as the geography and geology of the proposed site. The underlying technology components are already mature with well-developed designs suggesting that there is limited potential for learning effects to reduce future costs[13].

Current battery costs

There are a number of components making up the fixed costs associated with a battery installation. These include:

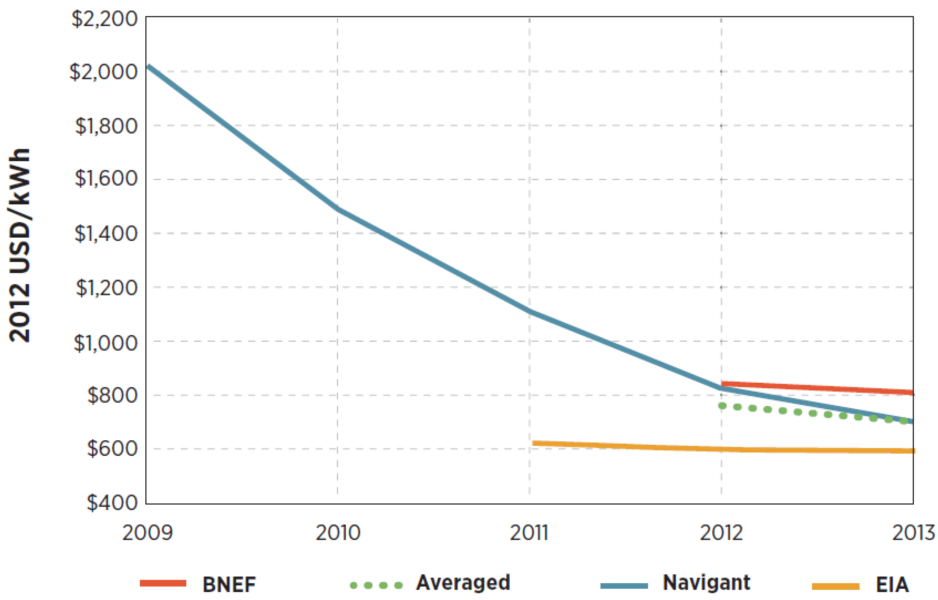
- Battery cells[14]
- Module materials
- Power conversion system
- Management and monitoring control system

In addition to these fixed costs, there will be variable costs associated with operation and maintenance. The total system cost payable by a project developer may also depend on locational and commercial factors such as equipment/labour availability and competition between vendors. Furthermore, the performance of the battery can be impacted by ambient conditions and usage patterns. This makes it difficult to compare manufacturer specifications which may have been produced under different testing conditions. Development of standardised testing, with reference duty cycles and defined ambient conditions, would be beneficial in providing cost transparency.

Recent trends for lithium-ion battery costs are shown in Figure 6 and estimates of future battery costs (for lithium-based batteries) used as part of the assessment of the near-term potential are described in section 2.10.

[11] See Figure 3 in https://www.iea.org/publications/freepublications/publication/technology-roadmap-energy-storage-.html
[12] http://www.irena.org/documentdownloads/publications/irena_battery_storage_report_2015.pdf
[13] Lazard (2015) Levelised cost of storage analysis
[14] For cell based battery technologies – flow batteries consist of external tanks filled with electrolyte.

Figure 6 Recent lithium-ion battery cost developments



Source: Irena (2015)[12]

2.2 Overview of potential revenue streams

A wide range of potential revenue streams are potentially on offer to electricity storage comprising different requirements, routes to market and value. These are broadly divided into the following categories:

- Balancing Services, including the Balancing Mechanism, which help support the operation of the electricity system in the very short-term (i.e. from Gate Closure one hour ahead through to real-time operation).
- Energy arbitrage revenues (injecting when prices are low and withdrawing when high), from trading in the Day-Ahead and Intra-Day markets (i.e. ahead of Gate Closure and the transition into the Balancing Mechanism)
- Embedded benefits - by positioning storage (and other distributed generation) within the distribution network it is possible to avoid a number of highly shaped charges (which can vary by season and time of day) associated with use of the transmission and distribution system
- Capacity Market payments to help support existing and new investment in capacity to ensure longer term security of supply

The current and future evolution of these markets is discussed in more detail in sections 2.3 to 2.6, along with potential additional revenues streams that could be made available in future with an appropriate route to market (section 2.7). For example, alleviation of network constraints (ahead of expensive actions in the Balancing Mechanism) and better integration of intermittent generation at both transmission and distribution level to avoid spill of renewables.

A high-level overview of the different potential revenue streams is provided below and a snapshot of their potential risks:

- Level of competition within each market
- Potential for new entrants for displace incumbents
- Given the two elements above the potential for significantly lower prices (and hence revenue streams) over the longer term
- Risk of revenue streams changing due to policy

It is important to note that not all revenue streams are directly comparable, having a mix of different technical requirements (to be able participate), contractual requirements (e.g. periods over which plant must be available or operate to access revenue) and contractual structures providing differing certainty over revenues (e.g. long-term multi-year contracts versus continuous auctions) and the specifics of each area of the market are discussed in more detail in subsequent sections. In addition, not all revenue streams are accessible simultaneously, given potential risks or contractual requirements and such trade-offs are discussed in section 2.8, which makes stacking revenue from multiple services / areas of the market challenging.

Figure 7 High-level overview of current potential revenue streams and risks

		Technology Types	Gross Margin (Market value)	Market Volume (MW)	Competition	New Entrant Threat	Long Term Price Risk	Policy Risk
Balancing Services	STOR	BM* CCGT/OCGT, nBM diesel & gas recips., pump storage, DSR	£15 – 35/kW (£52 - 98 m/annum)	3,000 MW Accepted	High	Med	Med	Low
Balancing Services	Fast Reserve	Pump storage & gas recips (UKPR)	£60 – 80/kW (£10 -15 m/annum)	400 MW Accepted *(With an additional bi-lateral market)*	Med	High	High	Low
Balancing Services	Firm Frequency Response	CCGTs, pump storage, nBM diesel recips, DSR	£40 – 150+ /kW (net) (£65 m/annum)	600 MW Bi-Lateral 600 MW Primary 1,000 MW Sec.	High	High	High	Low
Embedded Benefits	TRIAD Avoidance	nBM generation, storage and DSR	20 – 50 £/kW (~£2 bn/annum)	Annual peak demand net of embedded generation.	NA	NA	Low	High
Embedded Benefits	GDUoS and Other EBs		Location and connection type dependent and is updated yearly by each respective DNO in their Use of System Charging statements.		NA	NA	Low	Med
Capacity Payments		All BM and nBM parties	~£20 – 27/kW (~£1 bn)	T-4 ~ 48 GW Transition = 0.8 GW T-1 = 2.5 GW	High	High	Low	Med
Merchant Power and Balancing Mechanism			~£10-40/kW	NA	NA	NA	Med	Low

2.3 Current Electricity Balancing Services

2.3.1 Overview

In the GB power market, supply and demand balances are managed by generators and suppliers through bi-lateral OTC (Over The Counter) forward contracts, season and month-ahead exchange traded contracts (e.g. on the ICE Endex exchange) , and to an increasing extent through Day-Ahead

(DA) and Intra-Day (ID) futures contracts (via e.g. the APX or N2EX exchanges). In the first instance, flexible assets can access peak wholesale power prices in DA and ID exchanges, monetising their flexibility value. The extent to which they can achieve this via trading ahead of real-time is also affected by the degree of liquidity within each of the markets[15].

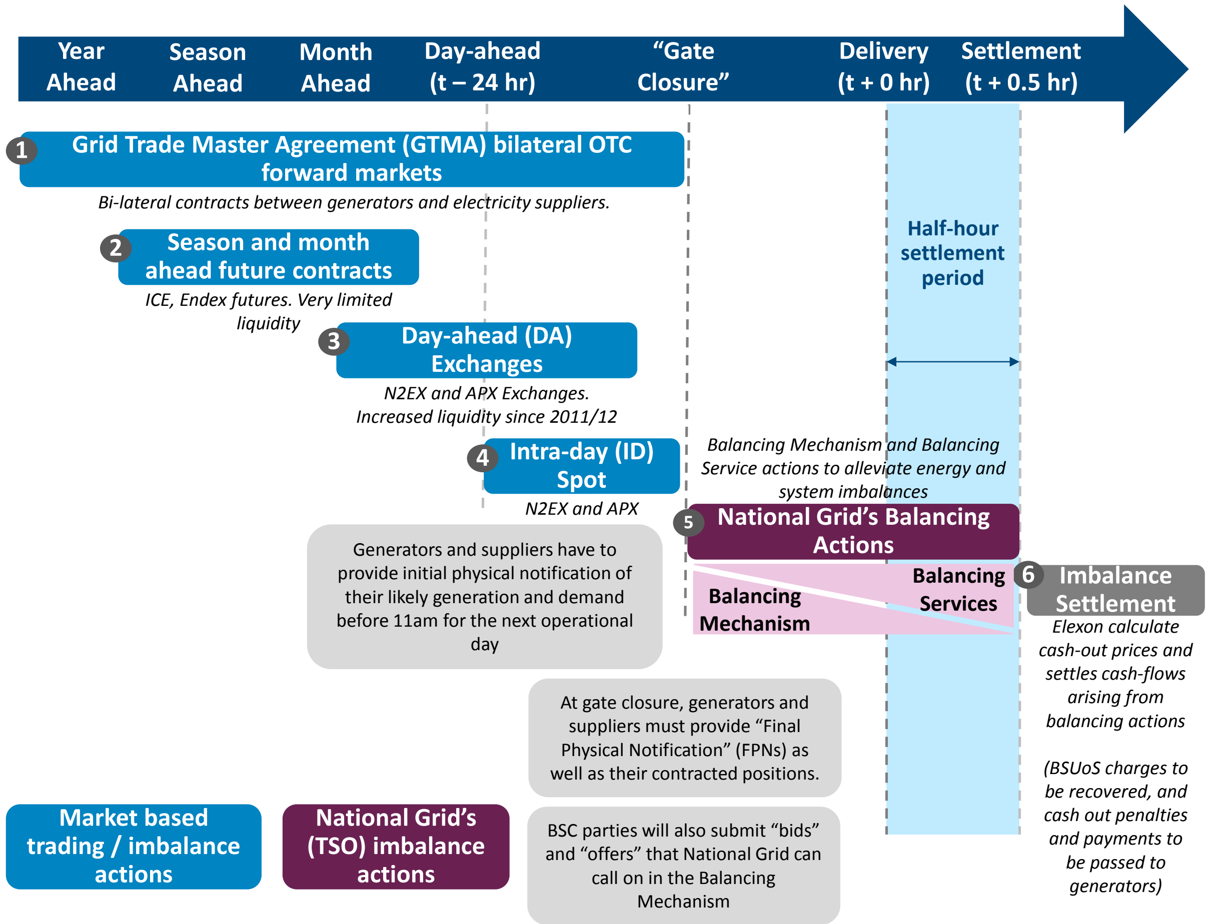
Approaching real time delivery, National Grid, as the Transmission System Operator, is obliged to manage any residual electricity supply and demand imbalances from the forward/future energy markets through what are called Balancing Actions. Balancing actions are taken through:

- The **Balancing Mechanism** (BM), which is comprised of two components
  - Imbalance Prices, which provide a financial incentive/penalty to ensure that market participants are actively trying to balance their own positions in the run up to Gate Closure (1 hour ahead of real-time) – e.g. that a generator is going to produce what their contracted position says they are going to produce, or that a retail supplier's demand is what they have contracted for
  - Obligatory offers to provide balancing actions from large generators, typically >50 MW, to help resolve any residual imbalance after Gate Closure (e.g. a plant running at 90% would provide a series of offers to turn up their generation at increasing prices) caused by very near-term fluctuations in demand, intermittent generation or plant tripping
- An additional suite of pre-contracted **Balancing Services** (multiple products including STOR, Fast Reserve, etc, that are accessible to small dispatchable generators) each with slightly different technical and operational requirements and contracting provisions. There are over twenty Balancing Services available to National Grid to use, some of which have higher capacity provisions and utilisation than others, but all are required to ensure the resilience of the system.

The role of National Grid versus wider energy market actions at different time horizons is illustrated in Figure 8.

[15] The extent to which an asset or security can be quickly bought or sold in the market without affecting the asset's price.

Figure 8 Overview of balancing actions/trading year-ahead to settlement



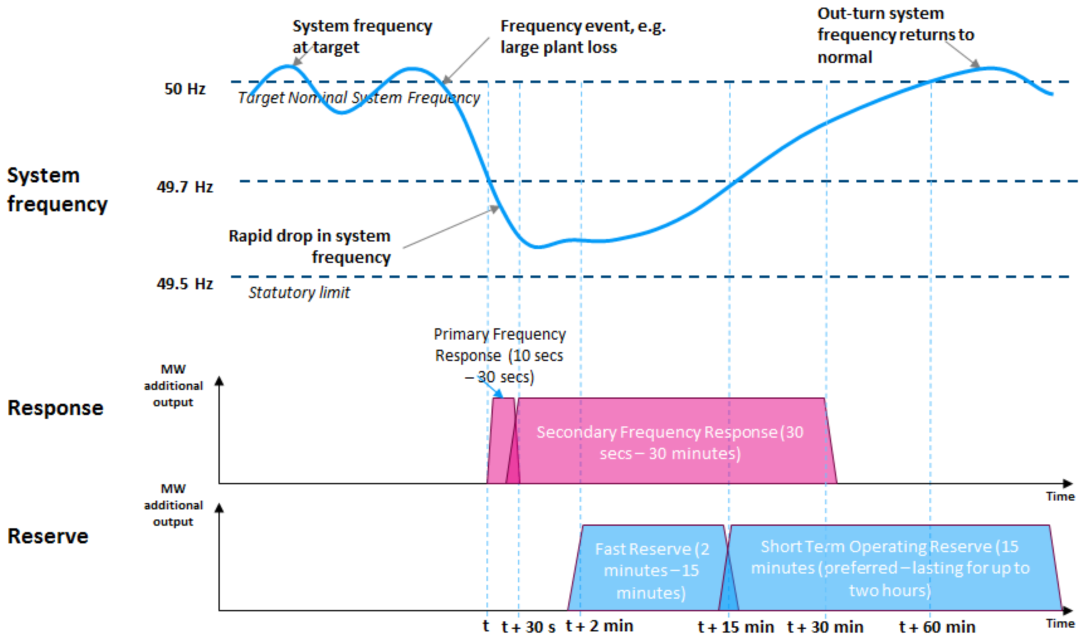
The use of both BM actions and pre-contracted balancing services actions is due to two interlinked requirements:

- Firstly, that resilient operation of the system in real-time requires actions on the part of National Grid to resolve imbalances that can be delivered with virtual 'certainty', particularly those requiring a response in the order of seconds to minutes. Pre-contracted balancing services are used to help provide this 'certainty'. National Grid procures differing volumes of capacity for each Balancing Service so as to meet set Operational Reserve Requirements (ORRs).
  - The ORRs are calculated by National Grid estimating system imbalances that may occur as a result of forecast demand deviations, intermittent generation forecasting errors and largest system in-feed loss trips (the largest generator on the system that could trip at any time).
  - National Grid requires this spectrum of Balancing Services to increase resilience across different types of imbalance event, but also to transition between differing products as the system is brought back to equilibrium (i.e. there is a cost premium paid for rapid response services that National Grid may not want to use for the full imbalance period, switching to cheaper but lower response time products that it can utilise for longer as the system equilibrium is reached as illustrated in Figure 9).

- Secondly, that overall balancing of the system is undertaken in the most economic manner. National Grid has different procurement and utilisation costs across the various Balancing Services, some of which are tendered for more competitively than others.
  - However, in many cases the requirements of wider balancing actions (where the response is required over the half-hour settlement period rather than in seconds or minutes) means that they could be provided by the wider pool of generators already operating in the energy market, as opposed to relying purely on pre-contracted balancing services. This is facilitated by the availability of larger volumes of balancing actions through the BM in addition to some of the 'slower' response balancing services such as STOR (Short Term Operating Reserve).
  - In many cases it is more cost-effective for National Grid to use energy balancing actions through the BM, but it may occasionally be more economic to use balancing services such as STOR where there is a choice (e.g. due to speculative bidding by participants in the BM).
  - National Grid is incentivised to minimise the costs of balancing the system (across both the available balancing services and BM actions) and improve the accuracy / provision of related information to industry by the Balancing Services Incentive Scheme (BSIS)[16].

A summary description of each of the specific Balancing Services discussed in the following sub-sections is shown in Table 3 Balancing Services summary. Additionally this section concludes with a more detailed description of the BM.

Figure 9 Overview of TSO balancing services as a function of response time



[16] http://www2.nationalgrid.com/UK/Industry-information/Electricity-system-operator-incentives/bsis/

Table 3 Balancing Services summary[17]

Balancing Service	Description	Technical Requirements	Contracting (current)	Opportunities for storage
Firm Frequency Response (FFR)[18]	Firm Frequency Response is the automatic provision of increased generation or demand reduction in response to a drop in system frequency. This can be further subdivided into three response levels of primary, secondary and high response, depending on the required response times and durations for different frequency losses. Frequency Response is split into Mandatory and Commercial products	***De minimis threshold*** > 10 MW de minimis (or multiple smaller assets aggregated to this scale). ***Response times*** Dispatch from 10 to 30 seconds from instruction for up to 30 minutes in duration. ***Capacity providers*** Pump-storage, hydro and some fast response DG diesel.	***Contracted capacity*** Varies by frequency response type. Primary up to 400 MW, secondary up to 400 MW and high response (tertiary) up to 200 MW (all static). Though this varies and may be higher seasonally. ***Contract types*** Tendered contracts are on rolling monthly tender basis – typically for 12 months in duration, with some 2 year contracts for PSH.	The FFR market has good potential as a revenue stream for new storage entrants due to the fast response times of storage technologies, which allows them to compete in tenders for all FFR products Response time and power rating and capacity are all key design considerations. Providing dynamic frequency response may involve a large number of short charging and discharging periods each day

[17] National Grid, respective product descriptions and design documents.
[18] Note that the new Enhanced Frequency Response (EFR) product is discussed in section 2.5.4

Balancing Service	Description	Technical Requirements	Contracting (current)	Opportunities for storage
Fast Reserve (FR)	Fast Reserve provides the rapid and reliable delivery of active power through an increased output from generation, or a reduction in consumption from demand sources. FR is split into Firm Fast Reserve (a tendered product) and Optional Fast Reserve (a bi-lateral product for which little information is available).	***De minimis threshold*** > 50 MW de minimis (or multiple smaller assets aggregated to this scale). ***Response times*** Dispatch within 2 minutes of notification for up to 15 minutes at a delivery rate in excess of 25 MW/min. ***Capacity providers*** Fast Reserve is typically provided for by pump storage and hydro units.	***Contracted capacity*** Typically a constant capacity requirement, with 400-500 MW in tendered firm FR, with additional unknown volumes in bi-lateral (optional) FR. ***Contract types*** Tendered contracts are issued in rolling monthly auctions – typically for 12 months in duration.	The Fast Reserve market has low potential for new storage entrants as market is saturated by existing pumped storage plant Power rating is important as a high minimum MW threshold is applied Frequent cycling of assets providing Fast Reserve could increase operation and maintenance costs and accelerate the degradation of the storage asset

Balancing Service	Description	Technical Requirements	Contracting (current)	Opportunities for storage
Short Term Operating Reserve (STOR)	STOR is capacity that National Grid retains on stand-by during certain hours of the day that can be called on to generate (reduce demand) within four hours of instruction (with a focus on <20min). STOR is split into a number of sub-products as well as some legacy long term fixed price STOR contracts.	***De minimis thresholds*** > 3 MW de minimis (or multiple smaller assets aggregated to this scale). ***Response times*** Dispatch within 240 minutes of notification, with strong preference to <20 min response times. ***Capacity providers*** STOR is provided by a mix of OCGTs, hydro, DSR and reciprocating engines.	***Contracted capacity*** Typically 3 GW is contracted to meet a reserve requirement of 2-2.3 GW. ***Contract types*** Contracted from 2 to 24 months ahead of delivery, for up to 24 months in duration. Generators can contract for morning and/or afternoon capacity windows, in six defined STOR seasons, for a set availability and utilisation payment.	The STOR market has potential as a revenue stream for new storage entrants, however there are a range of competing technologies currently participating in STOR tenders which mean it is likely to be challenging for storage Size of energy capacity is a key design consideration as energy has to be delivered for up to a 2 hour continuous period Scheduling of availability for STOR has to also account for periods ahead of the morning and afternoon STOR windows to bring the State of Charge up to an adequate level for subsequent delivery of the service if called
Reactive Power	The Reactive Power Service is primarily designed so that generators can produce or absorb reactive power to help to manage system voltages close to the point of their connection. Reactive power procurement is split into an Obligatory Service and a tendered Enhanced Service	***De minimis thresholds*** N/A ***Response times*** Must be able to reach target Reactive Power levels in MVAr within 2 minutes of receiving an instruction	***Contracted capacity*** No current tendered contract capacity – all provision provided by the Obligatory Service. ***Contract types*** No current tendered contract capacity.	The current reactive power market has low potential as a revenue stream for new storage entrants as current requirements are satisfied by the obligatory (non-tendered) service Use of storage would need to consider the interaction between provision of reactive power and provision of active power for market trading and/or Balancing Services

Balancing Service	Description	Technical Requirements	Contracting (current)	Opportunities for storage
		Capacity providers Mandatory for Grid Compliant BMUs		
Black Start	Black start generators are those that are capable of starting up in isolation from the grid. This capability is required for system recovery in the event of a total or partial shutdown of the transmission system.	***De minimis thresholds*** No specific capacity threshold applied – but station selection will depend on technical capability and geographic location. ***Response times*** N/A. ***Capacity providers*** Typically coal, gas, pump storage.	***Contracted capacity*** Unknown. ***Contract types*** Contract lengths are negotiated but may be up to 10 years for new providers.	The Black Start market has low potential due to incumbent providers (including pump storage) and highly specific locational requirements Storage must be kept with a minimum charge level at all times in order to be able to provide necessary power to start the neighbouring large generator

2.3.2 Firm frequency response

Technical requirements

Frequency response is used by National Grid for second by second real time control of demand and supply. Frequency response is split into two categories, mandatory and commercial services.

- **Mandatory frequency response** - Is a requirement of all Balancing Mechanism (BM) generators (large, typically greater than 50 MW) to actively change power output in response to a frequency change.
- **Commercial Firm Frequency Response (FFR)** – Open to BM and non-Balancing Mechanism (nBM) providers[19] in monthly tenders offering contracts that are typically 6 to 12 months in duration. Commercial FFR providers must be able to deliver 10 MW of response energy. This threshold can be met via aggregation of smaller units, provided they have a single control point. In the same auction, providers have the opportunity to offer different response capabilities as follows[20]:
    - **Low Frequency Response**:
        - **Primary**: An initial increase of active power, with sustained output from 10 seconds to 30 seconds following a loss of frequency.
        - **Secondary**: An increase in active power, or equivalent demand reduction, in response to frequency still being lower than target frequency, with sustained output from 30 seconds to 30 minutes.
    - **High Frequency Response**:
        - A decrease in active power, achieved 10 seconds from the time of the frequency increase and sustained thereafter (current requirement is for an indefinite response duration).
  - **Commercial FFR Bridging**: A sub-product of Commercial Firm Frequency Response that allows parties to aggregate small scale capacity from a total aggregated capacity of 1 MW as a minimum, up to 10 MW over time.
- **Commercial Frequency Control by Demand Management (FCDM)** – A sub-product of commercial Frequency Response available to load reduction only.

Of the above services, the one of most interest to storage technologies is **Commercial FFR**. FFR can further be categorised into **Dynamic Response** where the provider responds continually to frequency changes and **Static Response** where the provider responds once a trigger threshold has been passed (set as a wide band around the target frequency). Dynamic response is usually provided by "spinning" generators while static response is usually provided by idle capacity.

Market arrangements

Commercial FFR is procured by National Grid using a monthly tendering process where tendering parties submit complex bids. As well as submitting "Tendered Frames" stating their availability, they

[19] n-BM are small generators that do not participate in the balancing mechanism.
[20] For storage, the ability to offer different response capabilities in both directions at 10 MW of rate power output is therefore also a function of the storage capacity in MWh.

state the tender capacity for one or more of the response services described above for a given set of prices. FFR contracts can vary in length from 1 month to 23 months.

Figure 10 Firm Frequency Response tender data

	FFR Tender Items	Description
Main fees	**Availability Fee (£/h)**	This is paid to the provider for the hours in which a provider has tendered to make the service available, the "FFR Contracted Frame"
	Nomination Fee (£/h)	This is a holding fee for each hour utilised within FFR nominated windows
Optional fees	**Window Initiation Fee (£/window)**	National Grid will notify 'windows' during which it requires the service to be provided, for which a Window Initiation Payment will be made.
	Window Revision fee (£/hr)	National Grid notifies providers of window nominations in advance and, if the provider allows, this payment is payable if National Grid subsequently revises this nomination
	Response Energy Fee (£/MW/h)	This is based upon the actual response energy provided in the nominated window

Market size

Frequency response is the second largest of National Grid's balancing services in terms of MW. National Grid's FFR holding volume remained broadly flat over the past few years but began falling towards the end of 2014, as shown in Figure 11. Historically, the volumes of energy held for mandatory frequency response have been much greater than the volumes held for commercial frequency response (FFR and FCDM). Since the second half of 2015, Commercial FFR holding volumes have been increasing, and Mandatory FFR holding volumes correspondingly decreasing[21].

Since 2014 the total cost of commercial response has become larger in absolute terms compared than mandatory response, as illustrated in Figure 12. Note that the split of commercial frequency response between Commercial FFR and FCDM is unknown, but it is assumed that FFR makes up most of the commercial frequency response expenditure[22].

It is not straightforward to compare the cost of mandatory versus commercial frequency response. Mandatory holding fee payments alone are not directly comparable to FFR fees as National Grid also has to incur positioning fees, reserve creation fees, plus payment for any response energy that was used, as part of providing mandatory frequency response.

National Grid are, however, incentivised to minimise the total costs of balancing[23] and more recently the trend has been towards greater use of commercial frequency response. National Grid have stated that the current value of replacing Mandatory Frequency Response is around £22/MW/h, which sits in the mid-range of accepted commercial offers show in Figure 16. They also expect the level of mandatory participation to reduce over time. However, because commercial response is

[21] This is understood to be as a result of National Grid choosing to be more flexible with its holding requirements.
[22] Note that there are also additional bi-lateral contracts that are not included in these figures – for example with interconnectors.
[23] Under the Balancing Services Incentive Scheme (BSIS)

procured on a forward basis, compared to real-time procurement of mandatory response there is always likely to be a need for some volume of the latter to provide "shape" in the holding volumes at any one time.

Figure 11 FFR Holding volume (GWh/month)[24]

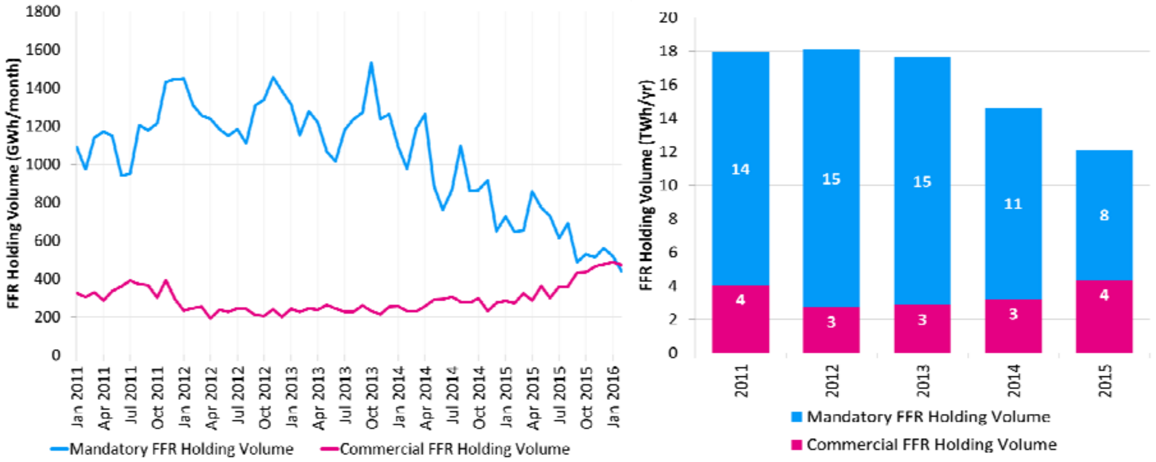
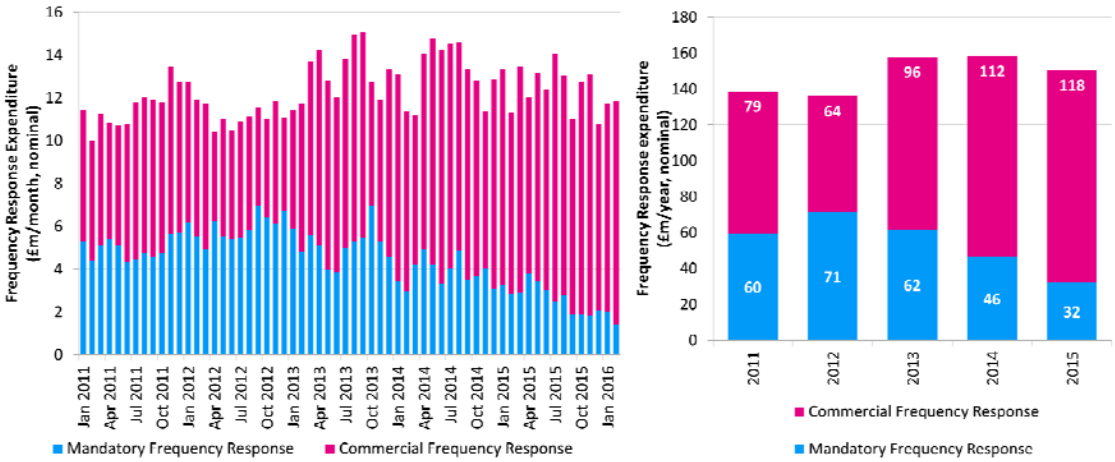


Figure 12 Frequency response expenditure[25]

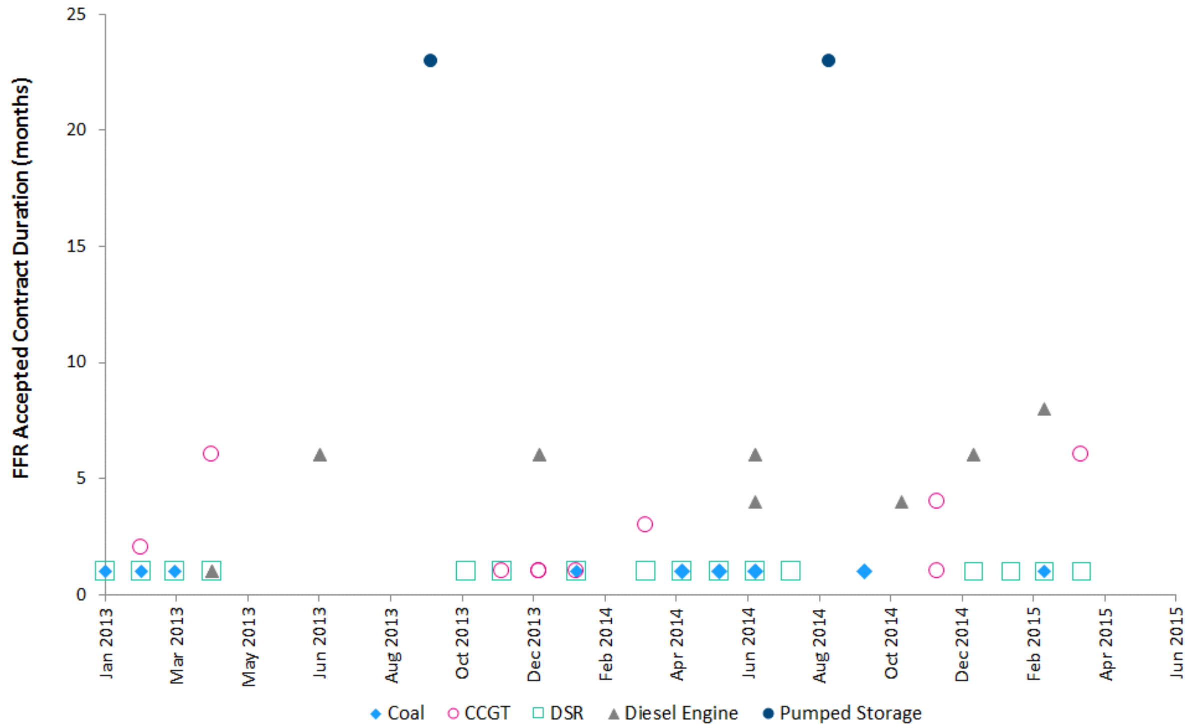


Market participants

A broad mix of units contract for FFR, with a mix of thermal (coal and CCGT), hydro, demand side response and distributed generation units all tendering for FFR contracts on a monthly basis. Historically, pump storage units have saturated the FFR market for long term contracts. Most other successful tenders tend to be for one, three or six month contracts, as illustrated in Figure 13. Accepted tenders typically offer around 700 hrs availability per month, with some units historically receiving contracts for between 250 and 500 hours a month.

[24] National Grid, MBSS reports. Baringa analysis.
[25] National Grid, MBSS reports. Baringa analysis.

Figure 13 FFR accepted contract durations (for each unit participating in FFR)[26]



While all tenders compete alongside each other in the FFR auctions, there is a clear split between capabilities of technology types, and the availability/nomination fees they can subsequently receive. The tranches of capability and current active capacity can notionally be split as follows:

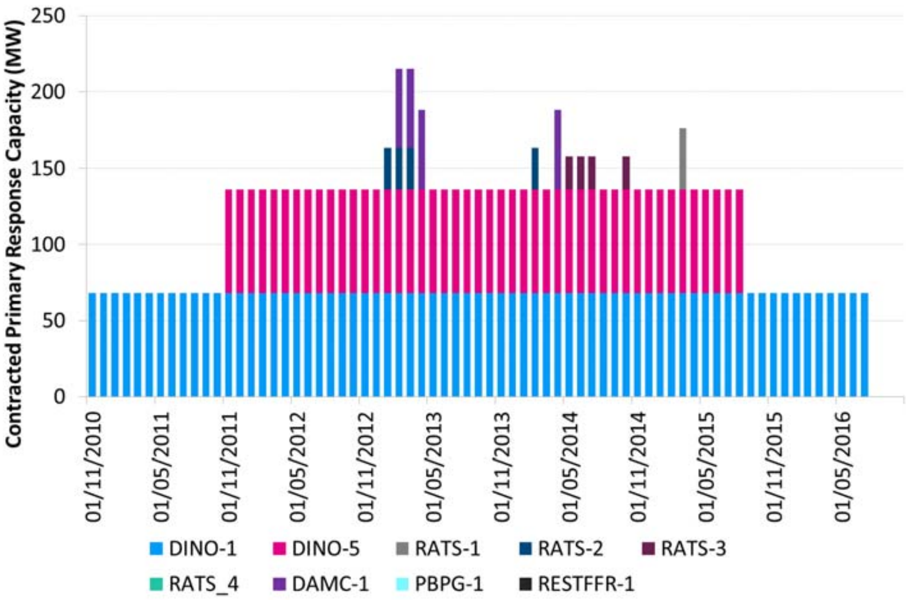
- **Tranche 1 – Spinning BM Thermals** – **"Primary, Secondary & High" (PSH) response capability** - The most valuable contracts are awarded to spinning thermal plant (CCGTs and coal), which provide dynamic low and high, primary and secondary response capability up to 24 hours a day.
- **Tranche 2** – **Pump Storage Hydro – "Primary & Secondary" (PS) response capability** - These are followed by contracts with pump storage hydro units, which part load their plant to provide dynamic low, primary and secondary response over the day time period only. These units have historically not provided High response capabilities.
- **Tranche 3 – Diesel Reciprocating Engines and DSR – "Static" response capability -** Increasing volumes of diesel engines are entering the market providing static low response within 30 seconds. DSR has historically provided a similar capability, though some DSR providers are now providing dynamic high and low, primary and secondary response at a value more akin to that offered in Tranche 1 & 2.

Even though the primary reserve market continues to be saturated with two Dinorwig pump storage units (as shown in Figure 14), tenders can be submitted for the multiple different response products, with participants having some success contracting for the premium response services. Publicly

[26] National Grid pre and post FFR tender reports, Baringa analysis.

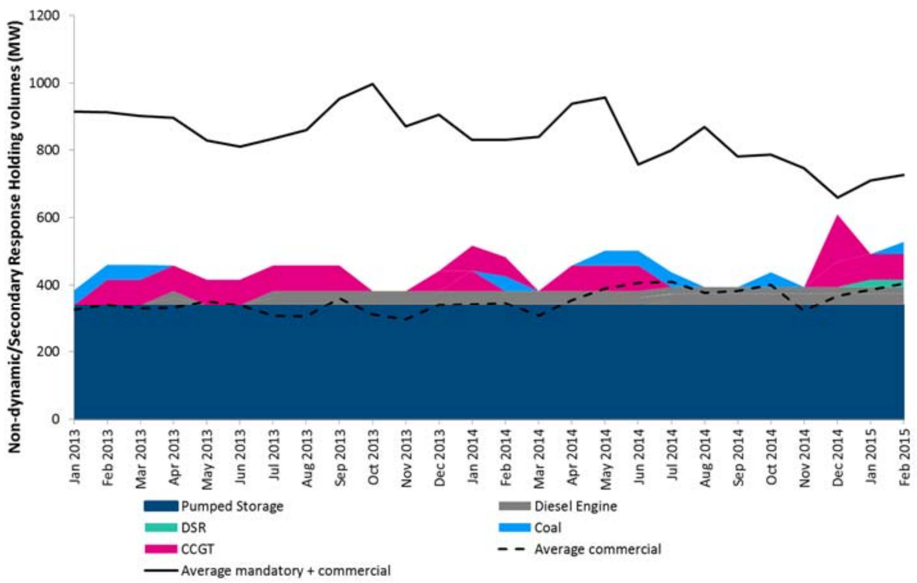
available information shows that companies with diesel engines have had some success contracting for services on a rolling 6 month contract basis.

Figure 14 Commercial contracted primary FFR response[27]



Note: Codes refer to individual Balancing Mechanism Units (BMU)[28]. DINO = pumped storage, RATS = coal, DAMC = CCGT

Figure 15 Commercial secondary FFR response[29]

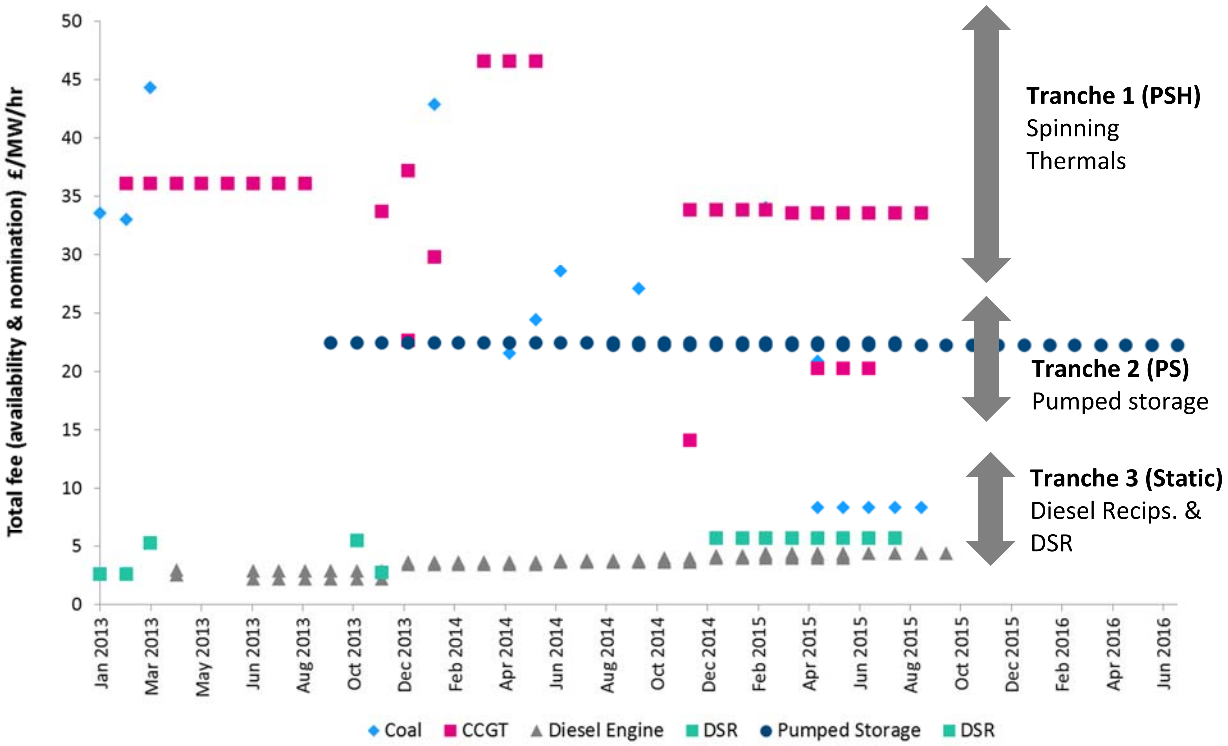


[27] National Grid, FFR pre and post tender reports, Baringa analysis.
[28] http://www.netareports.com/data/elexon/bmu.jsp?id=217
[29] National Grid, FFR pre and post tender reports, Baringa analysis.

Market revenues

There is a similar split in the value of contracts between these notional tranches of capability within FFR, with Tranche 1 historically receiving 25 – 50 £/MW/hr, Tranche 2 receiving 20 – 22 £/MW/hr and Tranche 3 receiving 8 £/MW/hr[30].

Figure 16 Historical successful commercial FFR tender availability prices



Opportunities for storage: The FFR market has good potential as a revenue stream for new storage entrants due to the fast response times of storage technologies, which allows them to compete in tenders for all FFR products.

Key design considerations: Response time and power rating as well storage capacity (influencing duration).

Key operational considerations: Providing dynamic frequency response may involve a large number of short charging and discharging periods each day.

[30] Availability hours are quoted as both availability and nomination payments, assuming bidders receive a nomination payment in each hour in which they receive and availability payment.

2.3.3 Fast reserve

Technical requirements

Fast Reserve is required to manage frequency deviations that arise from sudden changes in generation or demand, for example as a result of "TV pick-ups", unpredictable short term demand increases (e.g. weather conditions), short term frequency control or loss of operational or commercial systems[31].

Fast reserve is the fastest response time of the reserve products (as opposed to frequency products), with participants capable of commencing within 2 minutes following instruction at rates of 25 MW/min or greater, for a minimum duration of 15 mins. FR participants must be capable of providing a minimum capacity of 50 MW, possibly of aggregated units.

Fast Reserve can be further split into tendered and bi-lateral products (which are also described as Firm and Optional FR respectively). Tender data is available for the tendered FR product but there is little publicly available information on the Optional, bi-lateral Fast Reserve product[32].

Market arrangements

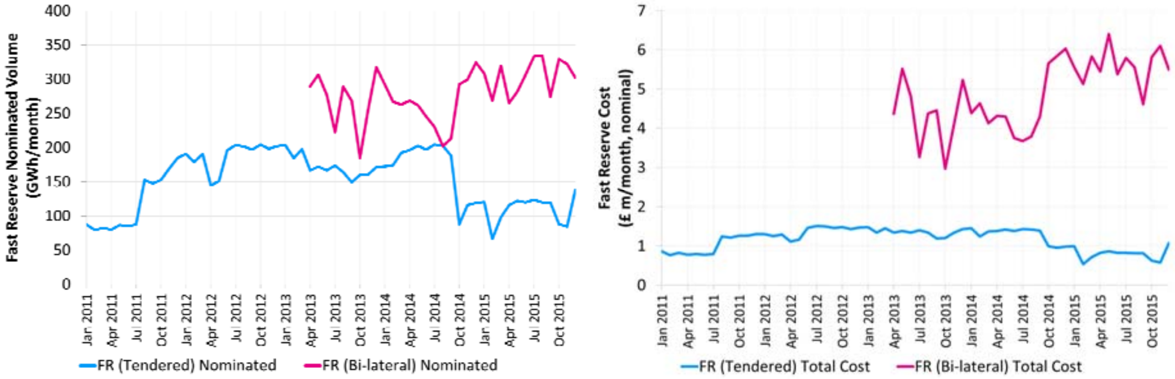
The tendered component of FR is tendered for directly with National Grid on a monthly rolling auction basis. Tendering parties submit complex bids, as illustrated in Appendix A. Details of long term tenders (i.e. for 24 months or more) are submitted alongside single and multiple month tenders.

Market size

National Grid have accepted 300-400 MW of tendered fast reserve on average since 2012, having stepped up the FR requirement from under 200 MW in years previous to that. The nominated volume has also remained constant from 2011 through to mid-2014 at 150 – 200 GWh/month, with a drop in the nominated volume in mid-2014. The nominated volume for the bi-lateral product is shown in Figure 17 for 2013 through to 2015, which was on average 60 % higher than the nominated MWhs in the tendered FR services and National Grid's expenditure on the bi-lateral FR service was over 2.5 times that for the tendered FR service in 2015[33].

[31] National Grid, Fast Reserve service description.
[32] We acknowledge that there is considerably more FR expenditure on Optional Fast Reserve than the less opaque tendered Firm Fast Reserve.
[33] There is little or no publically available information on bi-lateral FR other than the nominated volume and expenditure per month.

Figure 17 FR nominated volume and reserve cost per month[34]



Market participants

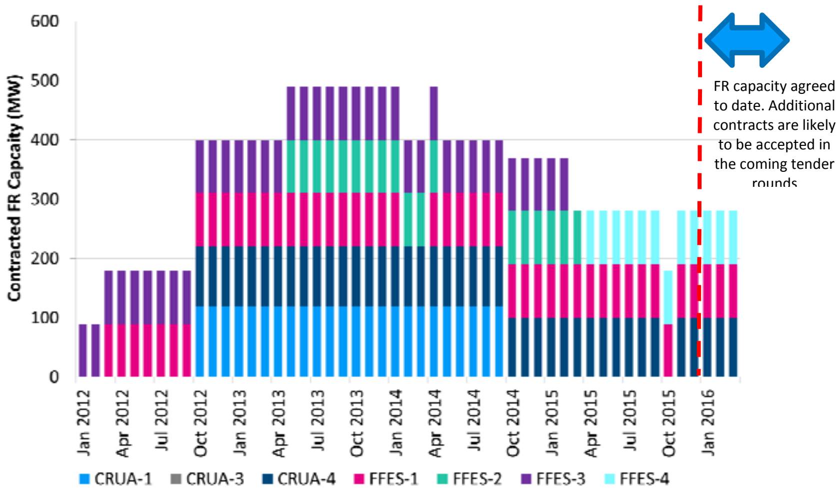
The FR market has a small number of participants at present, with only 3 units from Scottish Power Generation's Cruachan (CRUA) pump storage facility, and 4 units from First Hydro Company's Ffestiniog (FFES) pump storage facility tendering on a regular basis[35]. Historically it has only been these pumped storage units that have participated in the FR market as the service requirements strongly suit PHS technical characteristics, though in January 2016 UK Power Reserve successfully tendered 60 MW of small scale gas reciprocating engines into the market.

Historically, accepted and rejected FR tenders have been 12 months in duration, with some 8 and 6 month tenders and no clear bias between accepted and rejected tenders. There has also been conformity in the contracted tender windows, which is unsurprising considering there are only two plant participating in the market. Participants typically tender for either the full day (e.g. 8am to 11pm), or for split periods during the day (e.g. 7am to 10.30am and 4pm to 11pm), with no tenders received by the pump storage units overnight (as the units pump from their tail to head ponds). On average, across the year accepted and rejected tenders have offered 350 – 600 hrs of day time availability per month, with tenders offering less than these number of hours typically being rejected.

The Fast Reserve market has fewer participants than other Balancing Service markets, largely owing to the 50 MW de minimis threshold that limits small distributed capacity participation, as well as the opportunity cost for large thermal plant in other Balancing Services.

[34] Baringa analysis, National Grid MBSS reports.
[35] It is noted that these units are not restricted to FR, and can choose to contract for other services such as STOR, Frequency Response and the Balancing Mechanism if they wish.

Figure 18 FR (tendered) Market participants



Market revenues

Similar to the contract duration and availability windows, historic availability and utilisation prices in Firm FR have been relatively stable, again owing to there being only two units in the market. Tendered availability fees have varied from £350/hr to over £800/hr (or 3.50 £/kW/h to 4 £/kW/h[36]), but have remained relatively constant by individual parties since 2012 (i.e. 17 £/kW/year to 35 £/kW/year availability payments as shown in Figure 19. Similarly, FR utilisation prices have remained flat at approximately 140 £/MWh since late 2012, with little or no difference between tender prices of the respective FR parties as shown in Figure 20. However, the out-turn £/kW/yr utilisation revenue varies considerably amongst the different FR units, owing to their differing running hours as shown in Figure 21. On average, units have historically been dispatched in Firm FR for 450 hours/year, though running hours per unit varies considerably (including ramping periods). Firm FR is typically dispatched for short durations, potentially multiple times within the same period.

Opportunities for storage: The Fast Reserve market has low potential for new storage entrants as market is saturated by existing pumped storage plant.

Key design considerations: Power rating as high minimum MW threshold is applied.

Key operational considerations: Frequent cycling of assets providing Fast Reserve could increase operation and maintenance costs and accelerate the degradation of the storage asset.

[36] Allowing for the capacities of the units tendering.

Figure 19 FR (tendered) availability fees (nominal) for each tendering unit (per month)[37]

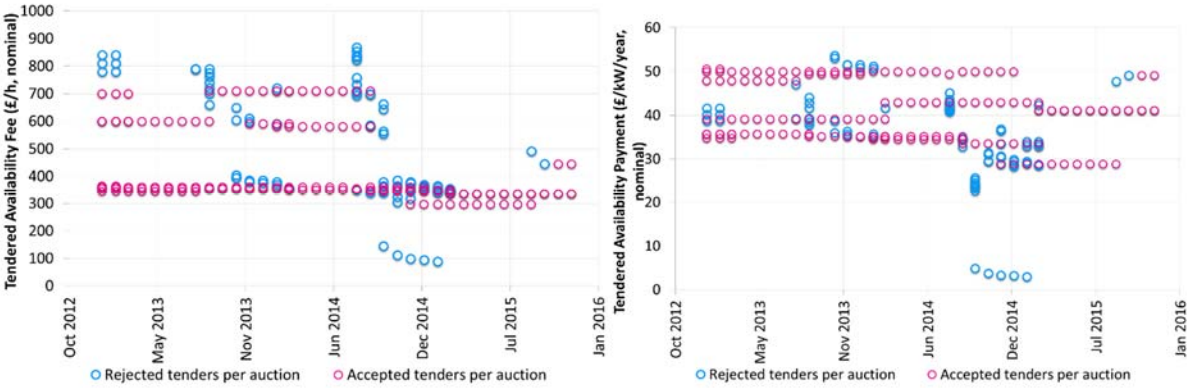


Figure 20 FR (tendered) utilisation fees (nominal) for each tendering until (per month)[38]

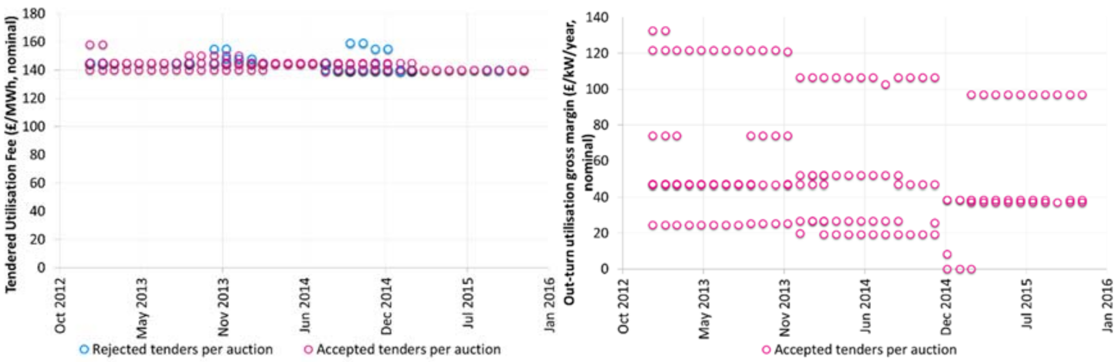
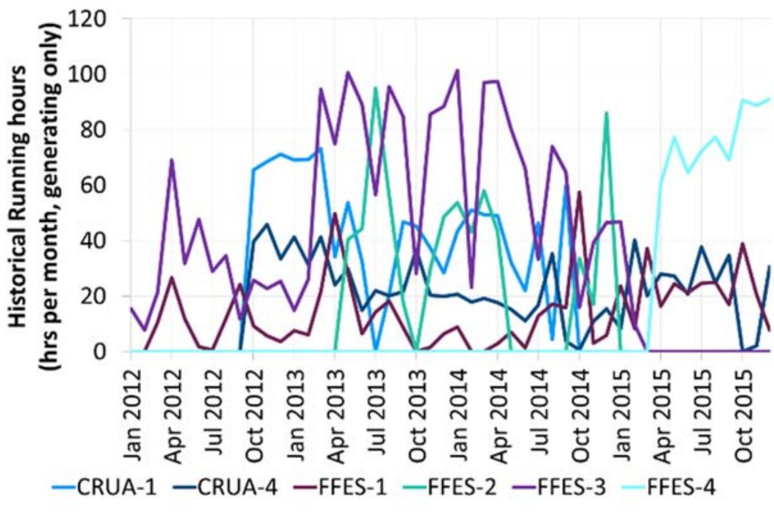


Figure 21 FR (tendered) Utilisation hours by month[39]



Note: CRUA refers to units at Cruachan Power Station, and similarly FFES for units at Ffestiniog

[37] Baringa analysis, National Grid MBSS reports.
[38] Baringa analysis, National Grid MBSS reports.
[39] Baringa analysis, Elexon SO action data.

2.3.4 STOR

Technical requirements

Short term operating reserve (STOR) is one of the key Balancing Services that National Grid use for the provision of additional active power from generation and/or demand reduction.

STOR providers, either BM or n-BM, must have a de minimis capacity of 3 MW, possibly aggregated from smaller sub 3 MW units. STOR capacity must be available within 240 minutes of receiving an instruction to generate, though National Grid strongly favour tenders with sub-20 min dispatch times or shorter. Once instructed, STOR providers must be able to generate/load reduce for a minimum of 2 hours so as to be eligible to participate in STOR.

Market arrangements

National Grid contracts STOR throughout the year in thrice yearly auctions, splitting the fiscal year into 6 STOR seasons of differing lengths. Each STOR season has a set of weekday (WD) and non-weekday (n-WD) diurnal capacity window pairs, where STOR providers must be available to produce STOR capacity if required by National Grid.

STOR providers receive an availability payment (£/MW/hr) for each of the capacity windows they tender for, typically 3,865 hrs/year, but differing slightly year on year. STOR providers also receive utilisation payments for the hours in which they are instructed to generate/load reduce by National Grid (£/MWh).

Figure 22 STOR Capacity windows, Season 2015/16[40]

		Week Day (WD)		Non-Weekday (n-WD)		Hours/Day type		
STOR Season	**Dates**	**Start Time**	**End Time**	**Start Time**	**End Time**	**WD**	**NWD**	**Total**
1	05:00 on Wednesday 1st Apr 2015 - 05:00 on Monday 27th Apr 2015	07:00	13:30	10:00	14:00	199.5	32.5	232
		19:00	22:00	19:30	22:00			
2	05:00 on Monday 27th Apr 2015 - 05:00 on Monday 24th Aug 2015	07:30	14:00	09:30	13:30	1150	133	1283
		16:00	18:00	19:30	22:30			
		19:30	22:30					
3	05:00 on Monday 24th Aug 2015 - 05:00 on Monday 21st Sep 2015	07:30	14:00	10:30	13:30	276	30	306
		16:00	21:30	19:00	22:00			
4	05:00 on Monday 21st Sep 2015 - 05:00 on Monday 26th Oct 2015	07:00	13:30	10:30	13:30	330	32.5	362.5
		16:30	21:00	17:30	21:00			
5	05:00 on Monday 26th Oct 2015 - 05:00 on Monday 1st Feb 2016	07:00	13:30	10:30	13:30	920	135	1055
		16:00	21:00	16:00	20:30			

[40] STOR Market Information Report, TR 25, Appendix 3.

		Week Day (WD)		Non-Weekday (n-WD)		Hours/Day type		
STOR Season	Dates	Start Time	End Time	Start Time	End Time	WD	NWD	Total
6	05:00 on Monday 1st Feb 2016 - 05:00 on Friday 1st Apr 2016	07:00 16:30	13:30 21:00	10:30 16:30	13:30 21:00	561	67.5	628.5
				Total Hours		**3436.5**	**430.5**	**3867**

STOR providers are not permitted by National Grid to contract for additional Balancing Services during these capacity windows losing their availability payments if they do so. That said, STOR providers can receive additional wholesale energy payments as well as any embedded benefits that are applicable during the STOR hours in which they generate (as agreed in the STOR providers offtake agreement).

The STOR product is split into 5 sub-products, each of which provides a slightly different service to National Grid:

- **Committed STOR** – Committed STOR is the primary STOR product where STOR providers tender to provide capacity during both diurnal STOR windows (morning and evening) for a full STOR season.
- **Flexible STOR** – Flexible STOR providers are given the option to opt-out of one, or both of the diurnal STOR windows, with STOR providers firming up their position a week ahead of time (available to n-BM plant only). This allows Flexible STOR providers to contract for STOR when it is most profitable for them to do so.
- **Premium Flexible STOR[41] –** This product is similar to Flexible STOR in that providers can choose which STOR windows they will be available in, with the difference being that National Grid identify "Premium Windows" which it considers to be of greater value.
- **STOR Runway[42] –** This is targeted at demand side response (DSR) providers[43]. The aim of this product is to allow DSR to tender for STOR contracts with capacity which they have not yet secured contractually. STOR Runway is procured separately to the main STOR products - subject to economic assessment, STOR Runway will look to procure between 100 – 200 MW of capacity in clip sizes ranging from 3 – 30 MW.
- **Enhanced Optional STOR (EOS)[44]** – EOS is available to n-BM providers, where participants tender for a contract for the option to make themselves available to National Grid a week ahead of time in the STOR evening windows only. Successful participants would receive no availability payment and a utilisation price set at the highest received utilisation price

[41] Introduced in January 2014.
[42] Introduced in January 2015.
[43] At present this focused on shedding or shifting of large industrial and commercial loads
[44] Introduced on a trial basis in December 2015 for the remainder of winter 2015/16.

for that season in the regular STOR tender rounds. National Grid are looking to procure up to 300 MW of EOS capacity[45].

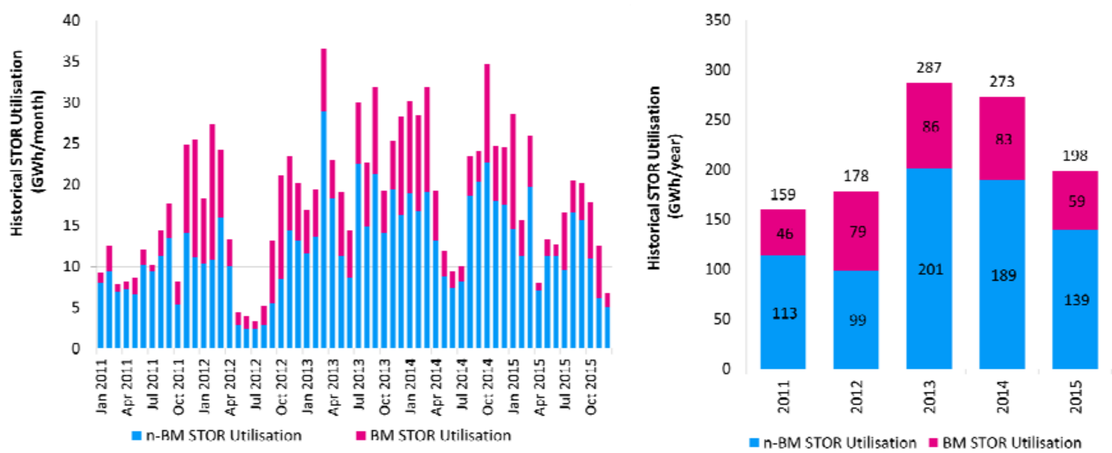
- **Long term STOR contracts** – As well as the existing STOR products, there is 338MW of capacity with long term (up to 15 year) STOR contracts, that were awarded between June 2009 and October 2010 with fixed availability and utilisation payments for the contract term[46].

STOR providers can tender directly with National Grid for upcoming STOR seasons in the 3 STOR auctions held each year. Providers can tender their capacity a minimum of 2 STOR seasons ahead of delivery, and a maximum of 12 STOR seasons ahead (i.e. 2 years).

Market size

National Grid's utilisation of STOR capacity has fluctuated over time but is broadly increasing, driven by increasing renewable penetration (5 to 12 GW of installed wind capacity), as well as the closure of large thermal plant under the LCPD emissions directive (over 9 GW of coal closures); although the relative impact of this is likely to greater in terms of increasing frequency response requirements as system inertia is a more direct driver compared to its influence on STOR. N-BM capacity made up 70 % of total utilised STOR volume in 2015 (illustrated in Figure 23), despite making up only 57 % of the contracted capacity. This is a trend that has been observed since 2010 and is in part due to the faster response times and lower utilisation prices of n-BM STOR capacity.

Figure 23 Historical monthly and annual STOR utilisation[47]



The drop in both BM and n-BM STOR utilisation volumes in 2015 is assumed to be as a result of;

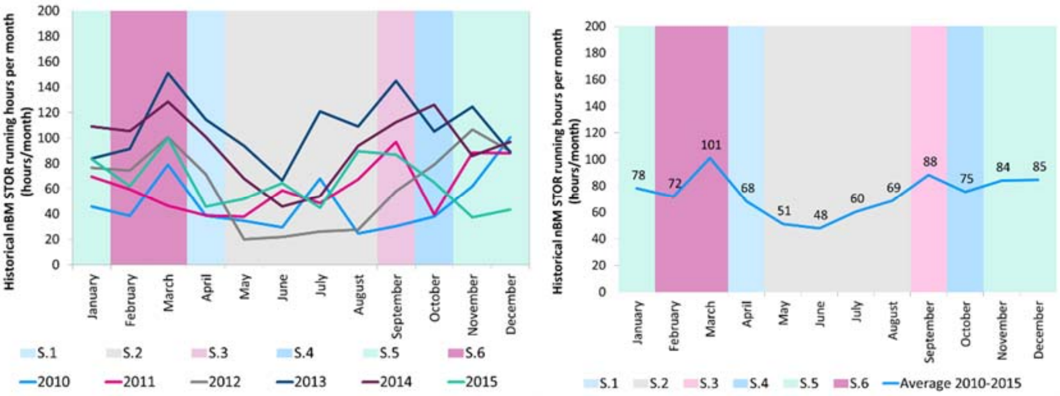
- Winter 2015/16 and winter 2014/15 have both been abnormally mild.

[45] Tender results were expected to be published in January 2016, but were not yet available at the time of writing.
[46] It is high unlikely that National Grid will again tender for long term STOR contracts, as announced in its open letter issued in September 2013 http://www2.nationalgrid.com/UK/Services/Balancing-services/Reserve-services/Short-Term-Operating-Reserve/Short-Term-Operating-Reserve-Information/
[47] Baringa analysis, National Grid MBSS reports, Elexon n-BM STOR utilisation data.

- National Grid has contracted less STOR yet still need to keep the same volume of STOR in reserve to manage the largest system loss. As such they have less STOR to use for balancing purposes.
- The sharper price signals in cash-out prices (discussed in Section 2.3.7) incentivises generators to better manage their own positions, necessitating less STOR as a balancing tool.

STOR utilisation volumes have historically been weighted to the September through to March months (STOR seasons 4, 5 & 6), with over 65 % of all STOR hours occurring over the past five years during these months. Similarly, STOR utilisation hours historically have been evenly split between the morning and evening STOR capacity windows, with 41 % of utilisation hours occurring in the STOR morning window, and 43 % in the STOR evening window[48].

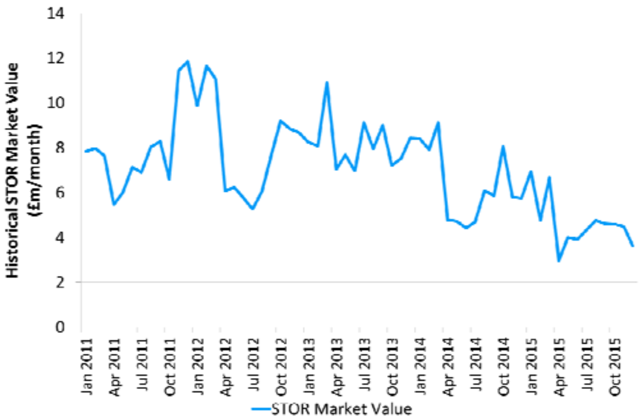
Figure 24 Historical total STOR running hours by month and STOR season[49]

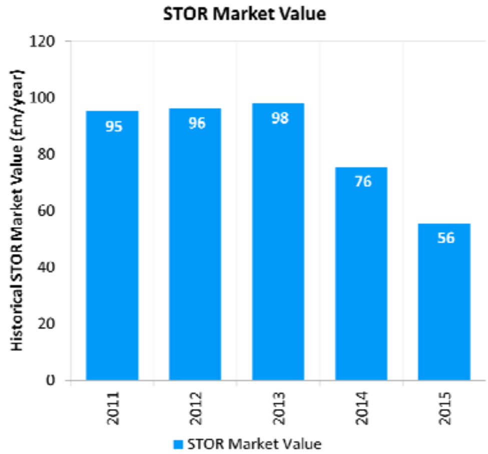


National Grid's expenditure on STOR (for availability and utilisation payments) dropped in 2014 and 2015, having been relatively constant at £95 m/year since 2010. National Grid in their 2014/15 Procurement Guidelines Report attributed this drop to a large decrease in BM unit availability prices, driven by increased competition by n-BM units making up an increased share of the market at lower prices than previous BM availability prices[50].

[48] There is also some residual STOR running hours outside of the contracted STOR windows, where National Grid ask STOR providers to generate through their existing STOR contracts.
[49] Baringa analysis, Elexon n-BM STOR utilisation data.
[50] www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=40784 (section 2.8).

Figure 25 Historical monthly and annual STOR expenditure[51] [52]

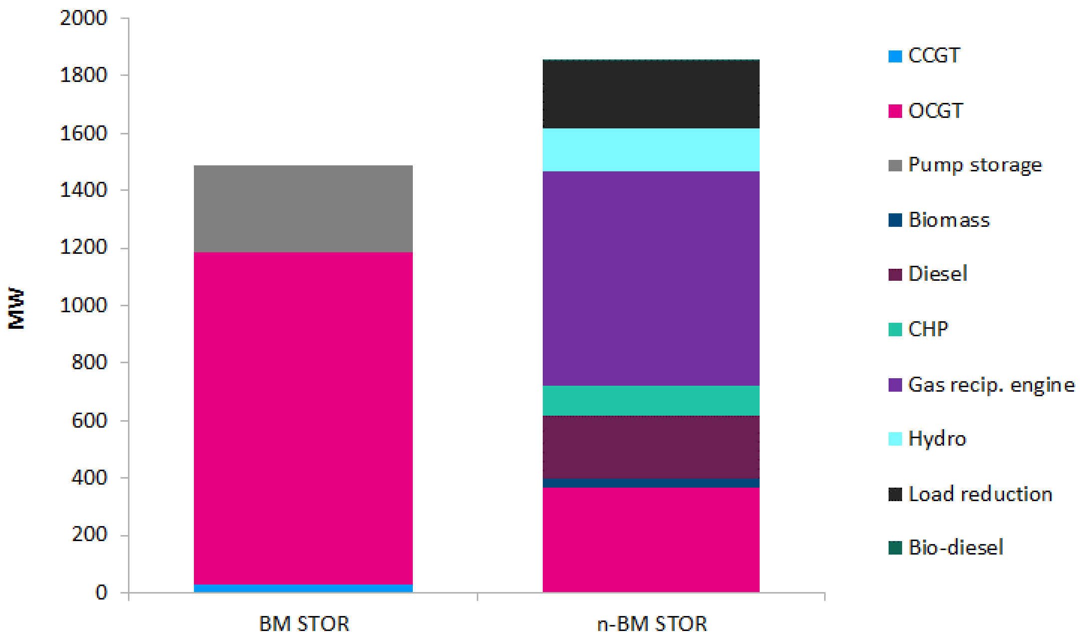




Market participants

STOR capacity has historically been provided for by a mix of BM and n-BM capacity. National Grid publish the technology types that were contracted for STOR in their fuel type summary reports, the latest of which was published for STOR season 8.5 (Jan 2015).

Figure 26 Contracted STOR capacity by technology type, January 2015[53]



[51] Baringa analysis, National Grid MBSS reports, Elexon n-BM STOR utilisation data.
[52] Note these are out-turn calendar year figures, as opposed to financial year out-turn.
[53] National Grid fuel type summary reports, Season 8.5.

The volume of BM capacity contracted for STOR decreased in 2014, falling from 1,444 MW of OCGT capacity in late 2013 to 1,156 MW of OCGT capacity at the beginning of 2015. This is understood to be one combined cycle gas turbine (CCGT) to open cycle gas turbine (OCGT) conversion either retiring, or choosing to contract for National Grid's new Supplemental Balancing Reserve (SBR) service (which precludes participants form participating in STOR). A large volume of the OCGT capacity is assumed to be auxiliary gas turbines that are located alongside large coal and gas plant (i.e. 20-50 MW start-up engines for larger thermal units). Similarly, the volume of n-BM capacity increased in 2014, with an additional 200 MW of diesel reciprocating engines, 133 MW of DSR and 40 MW of gas reciprocating engines entering the market[54].

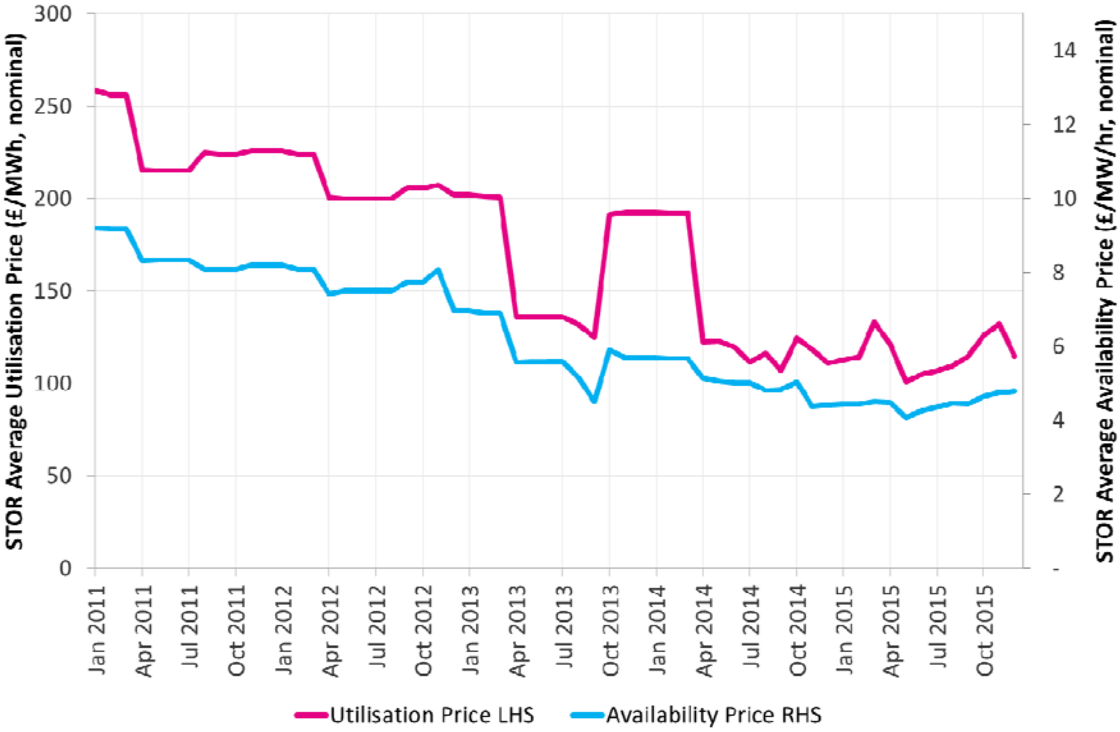
Market revenues

The average contracted STOR availability and utilisation price (monthly) has decreased steadily since 2010 (this includes all contracted capacity, including BM plant). This drop has occurred for a number of reasons, such as increased STOR market competition from low short run marginal cost (SRMC) n-BM plant, and n-BM generators increasingly contracting their utilisation price more competitively.

Tendering with lower utilisation price increases a plant's number of running hours, capturing a higher proportion of utilisation revenues on a volume weighted basis (acknowledging that STOR value has shifted from capacity to utilisation type revenues since 2010).

[54] Quoted DSR capacities can often be misleading, as a large portion of quoted DSR capacity is made up back-up diesel generators that are located "behind the meter", as opposed to load reduction. This was noted and is being considered further by the Energy Select Committee, February 2015, para. 35-44, http://www.publications.parliament.uk/pa/cm201415/cmselect/cmenergy/664/664.pdf

Figure 27 Historical average monthly STOR utilisation and availability prices[55]



It should be noted that the average monthly availability and utilisation prices shown in Figure 27 include contracts accepted 2 years ahead of delivery, and as such are inflated above present day accepted prices for future tender rounds. Similarly the average monthly prices do not show the spread of utilisation prices in the market, and the increased competitiveness at lower utilisation prices. For example, though the average out-turn utilisation price in 2014/15 was £117/MWh, a plant contracted at this price would have a materially different number of running hours, and as such a volume weighted STOR utilisation revenue, to a plant contracted at the front of the merit order curve at £90 - 100/MWh.

Opportunities for storage: The STOR market has potential as a revenue stream for new storage entrants, however there are a range of competing technologies currently participating in STOR tenders which make this challenging.

Key design considerations: Size of energy capacity as energy has to be delivered for up to a 2 hour continuous period.

Key operational considerations: Scheduling of availability for STOR has to also account for periods ahead of the morning and afternoon STOR windows to bring the State of Charge up to an adequate level for subsequent delivery of the service if called.

[55] Baringa analysis, National Grid MBSS reports, Elexon n-BM STOR utilisation data.

2.3.5 Reactive Power

Technical requirements

Levels of reactive power on the transmission system vary according to the specific equipment installed in the area; some devices absorb reactive power, while other devices produce reactive power. National Grid Electricity Transmission (NGET) looks to manage reactive power across the network as it can affect local voltage levels, and potentially cause voltage constraints.

The Reactive Power Service is primarily designed so that generators can produce or absorb reactive power to help to manage system voltages close to the point of their connection. The minimum technical requirements are shown in Figure 28.

Figure 28 Reactive power technical requirements

Product	Description
Reactive Power	▸ Supply rated power output (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the BMU terminals ▸ Have the short circuit ratio of the BMU less than 0.5. ▸ Keep the reactive power output under steady state conditions fully available with the voltage range of ±5%. ▸ Have a continuously acting automatic excitation control system to provide constant terminal voltage control of the BMU without instability over the entire operating range of the BMU ▸ Must be able to reach target Reactive Power levels in MVAr within 2 minutes of receiving an electronic instruction from NGET

Market arrangements

There are two forms of Reactive Power Service:

- The **Obligatory Reactive Power Service** (ORPS), where generators are required to provide varying Reactive Power output. At any given output the generators may be requested to produce or absorb reactive power to help manage system voltages close to its point of connection. All generators caught by the requirements of the Grid Code are required to have the capability to provide Reactive Power.
- The **Enhanced Reactive Power Service (ERPS)**, which is an optional tendered service for the provision of either:
    - Voltage support which exceeds the minimum technical requirement of Obligatory Reactive Power Service

- Reactive Power Capability from any other Plant or Apparatus which can generate or absorb Reactive Power that isn't required to provide the Obligatory Reactive Power Service.

While the Obligatory service is a Grid Code requirement for compliant BMUs, it is also possible for NGET to procure the ERPS from BMUs through its regular tendering process. NGET runs tenders for ERPS every six months. ERPS bidders must bid a minimum of 12 months, and can extend this in six month blocks (no maximum tenor is specified).

Bidders have the option of requesting one or more of the following fee categories in their tender submissions:

- An **Available Capability Price** (£/MVar/r) and/or
- A **Synchronised Capability Price** (£/MVar/hr) and/or
- A **Utilisation Price** (£/MVar/hr)

NGET assesses the economics of ERPS bids against the costs of using the Obligatory service instead, using a forecast of available BMUs that are able to provide the Obligatory service.

Market size

Since April 2015, NGET has utilised between 2,300GVArh and 2,800GVArh per month to manage reactive power on the transmission system[56]. However, all of the capability was provided through the Obligatory (non-tendered) service. Importantly, NGET has not received any EPRS market tenders since October 2011, and no BMU has provided ERPS since October 2009. The total amount of money spent on Reactive Power services was £71.2m in 2014 and £74.9m in 2015[57].

Market participants

Currently reactive power requirements are satisfied by BM units through the Obligatory service. The utilisation of each specific unit for reactive power provision is unknown.

Market revenues

There are no ERPS prices available given the absence of market bids. The Obligatory service receives a utilisation payment only, the value of which is calculated using a codified formula in the Connection and Use of System Code (CUSC) known as the "Default Payment Rate". For the Obligatory service, between April and November 2015, NGET spent £2.49/MVArh on average. This is lower than the Default Payment Rates for these months, which varied between £2.65 and £2.75/MVArh, suggesting that some units were paid a lower rate for lower performance. The Default payment rate for a fully available BMU in January 2016 is £2.68/MVArh[58].

[56] NGET, October 2015. 36th Reactive Market Report.
[57] Monthly spend values were not available for July 2015, so this has been interpolated from neighbouring months.
[58] NGET, 2015. Obligatory Reactive Power Service, Default Payment Rates.

Opportunities for storage: The current reactive power market has low potential as a revenue stream for new storage entrants as current requirements are satisfied by the obligatory (non-tendered) service.

Key design considerations: Power inverter and control system design.

Key operational considerations: The interaction between provision of reactive power and provision of active power for market trading and/or Balancing Services.

2.3.6 Black start

National Grid has an obligation under the Grid Code to ensure that the National Electricity Transmission System can be re-energised in the event of a shutdown. Black Start is the procedure to recover from this total or partial shutdown of the transmission system. Contingency arrangements must be in place to enable a timely and orderly restoration of supplies and hence Black Start capability is maintained continuously.

The Black Start process entails isolated power stations being started individually and gradually being reconnected to each other in order to form an interconnected system again. In general all power stations need an electrical supply to start up: under normal operation this supply would come from the transmission or distribution system, under emergency conditions Black Start stations receive this electrical supply from small auxiliary generating plant located on site.

Not all power stations have, or are required to have, this Black Start capability. The system Black Start requirement is met through the procurement of Black Start service capability at a number of strategically located power stations across GB. The level of Black Start capability procured is determined with regard to the balance between increased system resilience and the associated costs[59].

The two key drivers determining whether a power station will be considered for Black Start capability are geographic location and technical capability:

- **Geographic location**: Black Start stations are distributed equally across GB to enable a relatively uniform restoration of the total system. Furthermore this distribution ensures that DNOs have a balanced share of Black Start stations, ensuring that resources (people and facilities) are optimised in a Black Start situation. The main objective of a Black Start power station is to start other non-BS power stations – therefore proximity to other generators is a desirable characteristic.
- **Technical capability**: There are a number of specific technical power station characteristics that can provide greater Black Start capabilities and therefore provide more value, including:
  - Number and size of main units
  - Expected availability of the station
  - Expected reliability of the station

[59] Additional detail can be found in the National Grid Statement on its determination of required Black Start level - available from: http://www2.nationalgrid.com/uk/services/balancing-services/system-security/black-start/

- Start-up time from cold
- Number and size of auxiliary starting units
- Connectivity (voltage level and number of circuits)

The requirement to procure a Black Start service from a new Black Start station is usually triggered by the closure of an existing Black Start station. Initial exploratory discussions with potential new providers are carried out well before the new service is required. Generally National Grid expresses interest in procuring the Black Start service from new power stations during the Connection Agreement process, however National Grid state that they would consider determining the feasibility of retro-fitting black start capability to existing power stations if required.

Black Start is procured on a bilateral contract basis. The contract term would be specific to the particular Black Start station and requirements at the time. For a new build Black Start station it is likely that the contract term would be at least 10 years. Black Start providers are paid an agreed fee per settlement period for their availability and a utilisation payment both for testing purposes[60].

The total amount of money spent on Black Start services was £20.6m in 2014 and £19.6m in 2015[61]. During this time there were 15-18 stations contracted for this service. Note that the regulator has launched an investigation over the proposed National Grid request to recover >£100m on black start contracts this year (compared to the originally agreed ~£20m), with some industry participants accusing them of agreeing to highly inflated terms to keep coal generators on the system, due to concerns about very low near term capacity margins[62]. However, this increased level of spend is not expected to persist beyond the relatively near-term due to other policy measures such as the Capacity Market being used to drive increased capacity margins.

Opportunities for storage: The Black Start market has low potential due to incumbent providers (including pump storage) and highly specific locational requirements.

Key design considerations: Co-location with a larger generator.

Key operational considerations: Storage must be kept with a minimum charge level at all times in order to be able to provide necessary power to start the neighbouring large generator.

2.3.7 Balancing mechanism

Technical requirements

National Grid, as the Transmission System Operator, is obliged under primary legislation to ensure that electricity generation and demand are balanced across the GB transmission system on a minute by minute basis. Imbalances can occur for a number of reasons, which are broadly categorised as being either Energy or System imbalances:

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[60] In a Black Start situation, payments for energy provided are dealt with as set out in the Balancing and Settlements Code (BSC)

[61] Monthly spend values were not available for July 2015, so this has been interpolated from neighbouring months.

[62] http://utilityweek.co.uk/news/national-grid-spent-113m-on-black-start-contracts-with-drax-and-sse/1250662#.V2OvkKKwm_E

Energy Imbalances (national level) can result from:

- Intermittent plant (wind and solar) output deviating from their contracted generation position due to forecasting errors.
- Errors in forecasting of demand by suppliers.
- A generation plant failing (tripping) and not being able to meet its contracted position.
- Generators or suppliers systematically trying to adjust their imbalance positions ahead of gate closure to minimise their potential exposure to imbalance prices.

System Imbalances (Location specific) can result from:

- Transmission constraints owing to the restricted capacity, breakdown or maintenance of grid assets, thus preventing contracted generation being transported to where it is needed to meet demand.
- Locational transmission level constraints.

Some imbalances are managed within intra-day and day-ahead market exchanges, where price signals in the respective exchanges (owing to system shortfalls) incentivise generators to generate. To the extent that forward/futures markets leave a residual system imbalance approaching delivery, then National Grid will take Balancing Actions to meet their Electricity Supply Obligations.

Depending on the size and location of a generator (typically greater than 50 MW and transmission connected), it may be required to sign up to a Balancing and Settlement Code (BSC), with a set of mandatory balancing service provisions set out. These balancing service provisions require that generators submit "bids" and "offers" for the prices they would charge or pay for varying their generation or supply in any given settlement period[63].

These mandatory obligations on large thermal generators as part of their connection agreement are National Grid's first line of defence in known system imbalance periods. National Grid can call upon these bids and offers in the period from Gate Closure[64], when generators and suppliers make final notifications of their contracted positions, to delivery through a system called the **Balancing Mechanism (BM)**. In the BM, National Grid instructs already generating plant (or fast start up plant such as pump-storage) to increase or decrease their output for a limited period of time. In addition, National Grid, can also call upon plant contracted under STOR to resolve system imbalances.

Small scale distributed generation assets are eligible to participate in the BM (as BSC signatories), by entering into specific contracts with National Grid, such as the Bilateral Embedded Generation Agreements (BEGAs). BEGAs allow distributed generation assets to be BSC signatories and to participate in the BM, either the asset owner themselves or their off-taker.

Market arrangements

In the GB electricity system, market participants are exposed to imbalance charges for not meeting day-ahead contractual positions nominated to the System Operator at gate closure. These imbalance

[63] A "bid" is a proposal to reduce generation or increase demand, and an "offer" is a proposal to increase generation or reduce demand. There is no restriction on the prices that are submitted.
[64] Gate closure occurs 1 hour before delivery.

charges are determined by applying an imbalance price to a participant's imbalance volume, determined as the difference between nominated contracted and final physical positions.

Up until 5 November 2015, the price a participant was exposed to was dependent on the participant's imbalance position relative to the system's overall imbalance position. The effect of this dual pricing mechanism was that participants contributing to overall system imbalance were penalised by an imbalance price that represents an opportunity cost of not trading out final physical positions in the market in advance of gate closure. In contrast, participants mitigating overall system imbalance were exposed to a price equivalent to that traded in the market, so remained indifferent between an imbalance and a neutral position.

From 5 November the balancing mechanism moved to a single cash-out price as one of the Electricity Balancing Significant Code Review (EBSCR) reforms. In all cases:

- Participants with **long positions** (over generation or under consumption) receive the **System Sell Price (SSP).**
- Participants with **short positions** (under generation or over consumption) pay the **System Buy Price (SBP)**.

Note that there is single price calculation, so **SBP will equal SSP in each settlement period**. The price calculation will depend upon the overall imbalance direction:

- When the transmission system is long, the price calculation is based on actions taken by the System Operator to reduce generation or increase demand.
- When the transmission system is short, the price calculation is based on actions taken by the System Operator to increase generation or decrease demand.

The underlying rationale for shifting from dual to single prices is two-fold:

- To actively reward participants who are helping to resolve a system imbalance (e.g. generating more than their contracted position if the system is short overall), as opposed to them being indifferent
- Avoid over-penalising participants who find it inherently difficult to balance their positions (such as wind generators or small retail suppliers) even when the system conditions are relatively benign

Currently prices are based on the average of the most expensive 50MWh of actions taken (known as "PAR50"). In addition corrections to the price are made to account for certain STOR actions taken (through the Reserve Scarcity Price mechanism[65]) and for any disconnection actions[66] taken (which are currently priced at £3,000/MWh).

Market size

The overall level of system imbalance is known as the Net Imbalance Volume (NIV). NIV has historically been negative (indicating an oversupplied system) on average, as shown in Figure 29. This in part reflects the systematic long positions that many participants adopted in the dual cash-out mechanism to hedge against large thermal generator outages and to mitigate exposure to the SBP,

[65] This mechanism is intended to better attribute the allocation of pre-contracted reserve costs to the periods in which those actions are most needed and utilised.
[66] Voltage control or involuntary disconnections.

which was typically more penal than the SSP. Historic distributions of SBP and SSP are shown in Figure 30[67]. These distributions indicate that historically, SSPs have been of lower magnitude and have exhibited less variation than SBPs (as indicated by the tighter distribution).

Figure 29   Distribution of historic Net Imbalance Volumes[68]

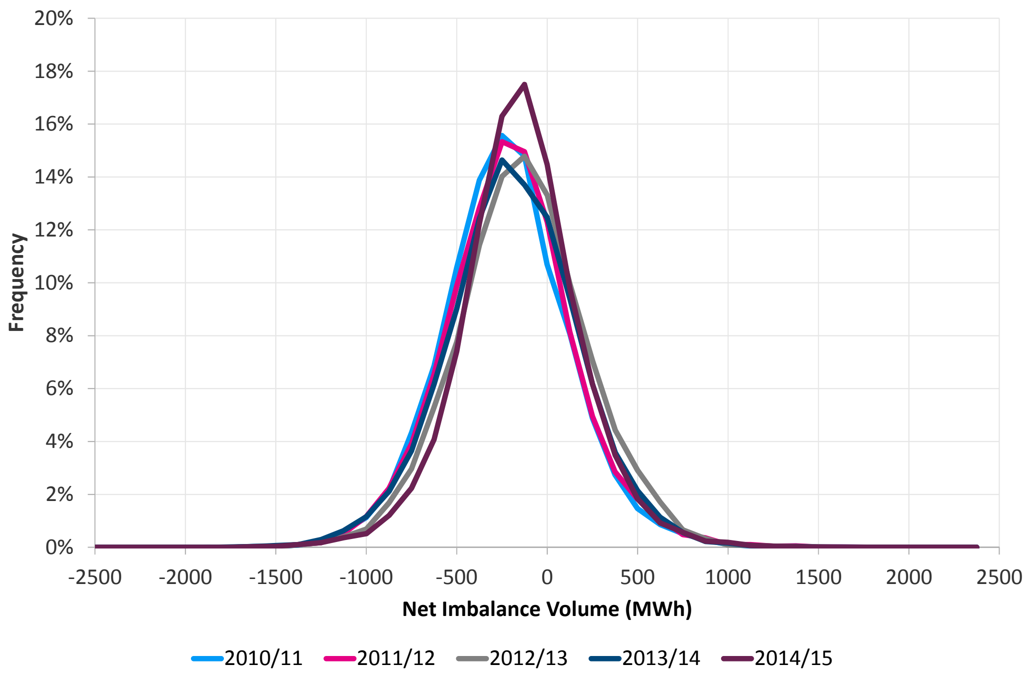
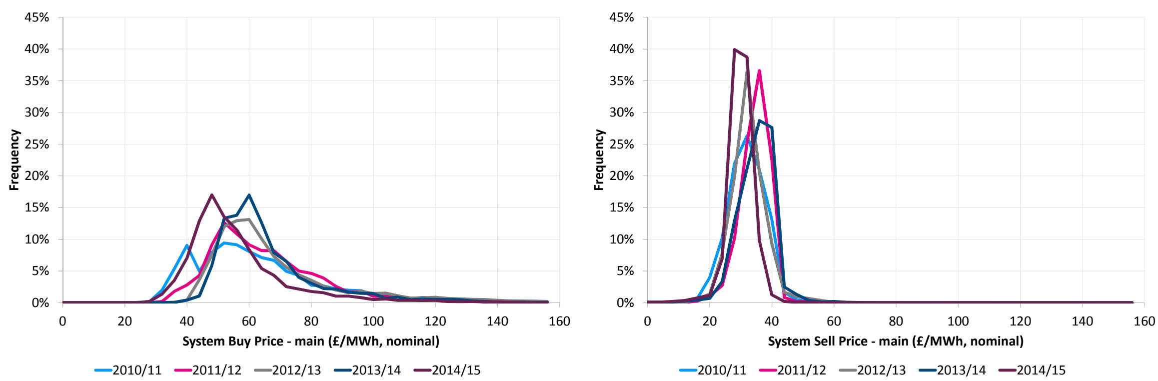


Figure 30   Distribution of historic SBPs and SSPs (Main Price only)



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[67] These distributions indicate the imbalance price as a main price under the dual pricing mechanism i.e. the prices applied when the imbalance of the participant was in the same direction as the imbalance of the system.
[68] Elexon data – Note that negative NIV indicates a long system (surplus generation); positive indicates a short system (generation deficit).

Opportunities for storage: Large scale storage assets may participate in the balancing mechanism (by providing bids and offers). Small scale storage assets may not directly participate in the balancing mechanism (unless they have opted in via a BEGA agreement) but will still be impacted by the system imbalance prices (as the price received for energy delivered for reserve Balancing Services).

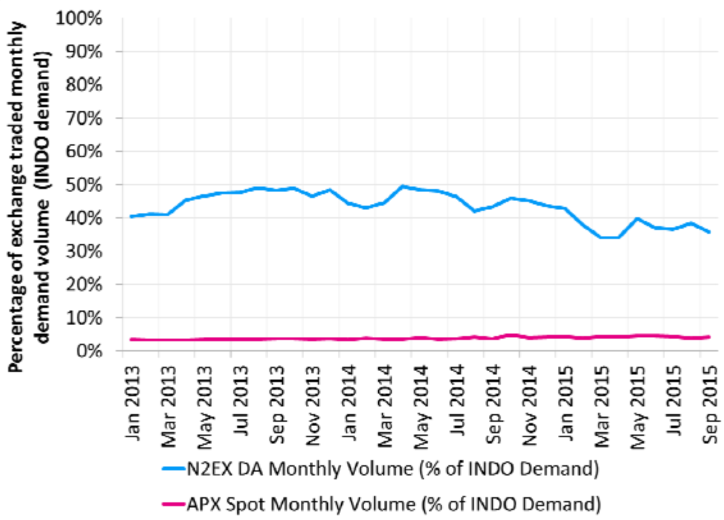
2.4 Current Wider Electricity Market Revenues

2.4.1 Energy arbitrage revenues

When generators dispatch for a balancing service they get paid for the electricity they produce in addition to the £/MWh utilisation payment from National Grid. Historically, distributed generators have been offered the system sell price by their off-takers as this was the only price off-takers could guarantee without prior warning that the asset would dispatch. In effect the offtaker would "spill", or go long into the Balancing Mechanism and take the prevailing BM sell price.

Similarly, should the generator have known it would dispatch ahead of time, be it within the day (intra-day, ID), or even a day-ahead (DA) of time, there was insufficient liquidity in both of these exchanges for off-takers to offer either of these prices. Following Ofgem's liquidity review in 2008 many of the Big-6 Vertically Integrated Utilities (VIUs) in GB decided to sell some, or all of the generation into the private day-ahead and intra-day exchanges (as opposed to the generation net of their own demand which they sold into exchanges prior to that). This resulted in an increase in DA and ID liquidity from 2011 to a point where approximately 40 % of GB generation is traded on liquid exchanges in 2015, as shown in Figure 31.

Figure 31 ID and DA historical power price volumes on N2EX and APX exchanges



Note: Initial National Demand Out-turn (INDO) is transmission level electricity demand accounting for transmission losses, but not included station transformer load, pump storage demand or interconnector demand

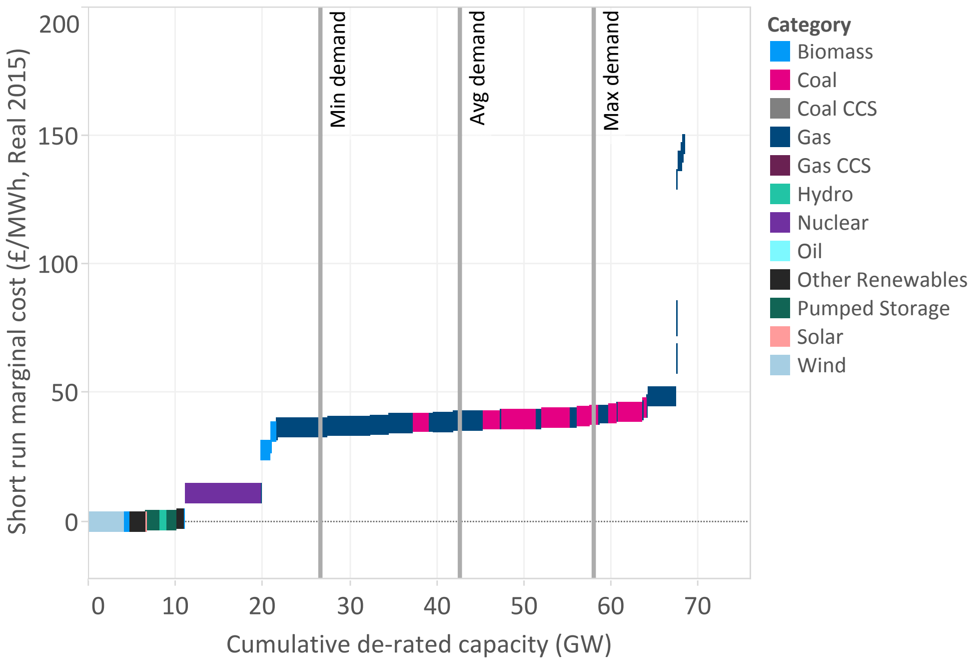
Historically, the ID and DA power prices have been less volatile than the SSP price received through the BM and offer a more reliable revenue stream to generators. Distributed asset operators can either notify their offtaker that they will generate during specific periods and the off-taker can then trade that power in DA markets. Or, operators could allow the offtaker to actively trade the asset in

ID or DA markets where the offtaker dispatches the asset when prevailing power prices make it profitable to do so.

A storage asset can arbitrage between charging at times of low prices and subsequently discharging at times of high prices. The associated revenue will depend on the power price differential achieved and the round-trip efficiency associated with charging and discharging the storage asset (see Section 2.1 for more details of storage technology efficiencies).

A typical winter merit order curve for GB is shown in Figure 32, this illustrates the Short Run Marginal Cost of operating different plants (ignoring capital costs) from cheapest to most expensive. Note that renewable capacity (onshore wind, offshore wind, hydro and solar[69]) is shown as de-rated capacity, which reflects the estimated availability of that plant to the system at peak periods considering factors such as forced outage rates and primary resource availability for variable renewable. As such there will be some periods where renewable output is much higher than shown in Figure 32. The merit order for other seasons will be similar but with some changes due to lower demand, lower commodity costs for thermal plant and reduced thermal plant availability (as large plant take planned maintenance outages).

Figure 32 SRMC supply winter 2015/16[70]



While fuel and carbon prices will impact the relative positions of coal and gas assets, there are clear tranches of capacity observable in the merit order:

- Renewable capacity with zero or near zero SRMC.
- Nuclear capacity with low SRMC.

[69] Solar PV has a derating factor of 0% - to account for the unavailability of this resource during peak demand periods which occur in winter evenings.
[70] Based on Baringa Reference Case analysis – values shown for demand indicate minimum, average and maximum values observed across a selected month.

- A large volume of coal and gas capacity with broadly similar SRMC.
- A small volume of peaking capacity with very high SRMC.

Using the example of within day storage operation then the available arbitrage revenues will depend on prevailing system conditions:

- **Low demand and high supply**: Low cost power (e.g. from high renewable and nuclear output) is available at time of minimum demand (e.g. overnight and daytime in summer) to charge the storage. Maximum demand is met by efficient thermal plant in the main tranche of capacity resulting in higher power prices. There is potential to capture significant arbitrage revenue.
- **Low demand and low supply**: In this case there is insufficient supply (e.g. due to low renewable output or nuclear plant undergoing maintenance) to drive prices down to very low levels. In this case minimum and maximum demand will likely both be satisfied by efficient thermal plant. Hence there is little price differential and little arbitrage revenue.
- **High demand and high supply**: In this case there is sufficient supply (e.g. high renewables output) to keep very expensive peaking plant off the system. In this case minimum and maximum demand will likely both be satisfied by efficient thermal plant. Hence there is little price differential and little arbitrage revenue.
- **High demand and low supply**: In this case minimum demand will be met by thermal plant in the main tranche of capacity. However due to low supply (e.g. low renewables output or the unavailability of some thermal plant), peaking capacity is required to meet maximum demand resulting in very high power prices. There is potential to capture significant arbitrage revenue.

Opportunities for storage: The potential for energy arbitrage revenues for new storage assets is highly dependent on prevailing market conditions (affecting available price differentials) and route to market (ability to capture these price differentials). The expectation is that wholesale revenues alone would not be sufficient and batteries would need to access other revenues to make a sufficient return, however it is not always possible to access these multiple revenue streams (e.g. with balancing services in the same contracted period).

Key design considerations: Size of energy capacity.

Key operational considerations: Daily cycling, with high depth of discharge, could increase storage degradation and negatively impact storage asset lifetime.

2.4.2 Embedded benefits

Embedded benefits describe multiple revenues that generation on distribution networks can receive from electricity suppliers for them being able to *avoid* the costs associated with transporting power through the transmission and distribution networks.

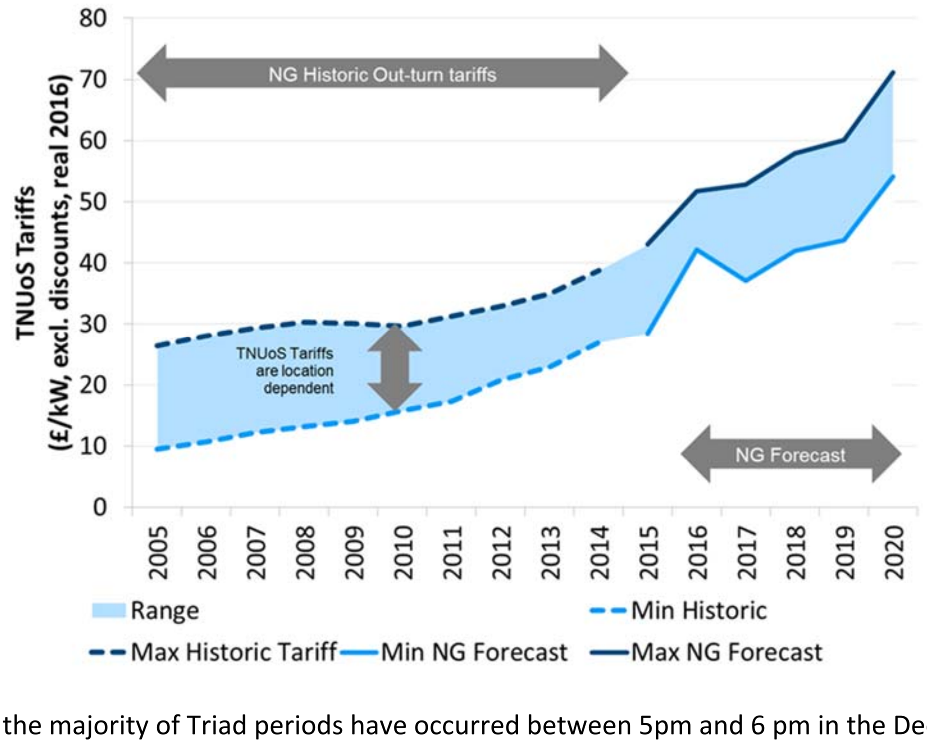
Avoided demand TNUoS charges (Triad Benefit)

In April of each year, each licensed electricity supplier is charged a fee for the peak load it imposed on the grid during three peak half hour demand periods in the previous year, what are commonly called the Triad periods[71]. These fees are National Grid's Transmission Network Use of System (TNUoS) charges, the mechanism by which they recover the costs they accrue to manage the electricity transmission network in the UK. The costs are split between generators and demand, with generators carrying 23 % of the total cost, and demand 77 % of the total cost[72]. It is this demand component of the charge that embedded generators can avoid.

Embedded generators allow electricity suppliers to offset this demand TNUoS tariff, as they are in effect seen as negative demand on the system, netting capacity off of the supplier's demand position if the embedded generator is generating/load reducing during the Triad periods. Embedded generators typically monetise this revenue through a PPA (Power Purchase Agreement), receiving the Triad value from the supplier with agreed discounts, provided that they are generating at full capacity during the Triad periods.

TNUoS tariffs vary considerably by geographic zone, with TNUoS tariffs highest in the south of the UK where demand is highest, and tariffs lowest in the north where generation is highest. Therefore the Triad benefit available to embedded generators will depend on where they are located. Historic and forecast TNUoS tariffs are shown in Figure 33.

Figure 33 National Grid's historical and forecast TNUoS tariff range (varying by zone, excluding Scotland – England and Wales only)[73]



Historically, the majority of Triad periods have occurred between 5pm and 6 pm in the December and January months. There are a number of commercial Triad warning services that generators can subscribe to. Alternatively, many companies now forecast Triad periods "in-house", or indeed

[71] Triad periods can only occur from November through to February, with Triad periods only known ex-post.
[72] Historically, the ratio was 27:73 generation to demand. However recent European legislation to cap average generation transmission charges at €2.50/MWh has resulted in this ratio shifting to 23:77.
[73] National Grid.

generate baseload during winter months from 4-7pm so as to virtually guarantee that they are generating during the lucrative Triad periods, capturing the full Triad value.

Red Band DUoS Payments

As well as helping to avoid transmission level TNUoS tariffs, distributed generators can also receive a payment from DNOs if they are connected at low voltage levels on the distribution network. Generation that is located close to demand (i.e. connected at low distribution network levels) is seen as a benefit to DNOs, in that it reduces the DNO's net demand on that network and can avoid having to reinforce the grid in that area.

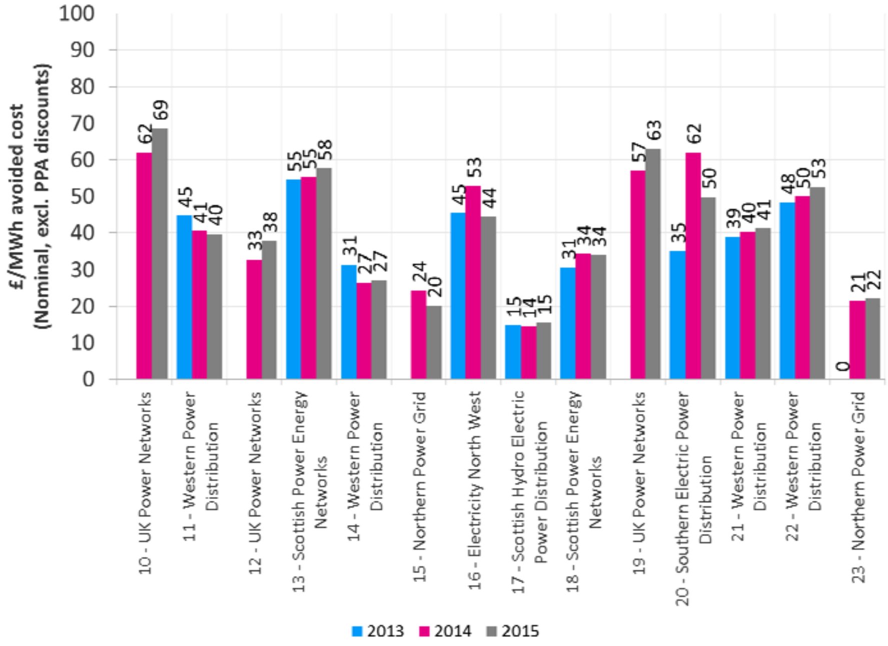
Generators are remunerated through negative tariffs (i.e. payments) in the respective DNOs' Distribution Use of System (DUoS) Charging Statements, which they update annually based on fundamental power flow analysis of their respective zones.

DUoS tariffs differentiate between voltage connection levels (LV, HV & EHV[74]), intermittent and non-intermittent generation, as well as different time periods. The afternoon tariff, called the Red-Band tariff, is the most profitable for distributed generators (in that it is the greatest of the negative tariffs). Red-band periods also differ by DNO, but are typically from 4-7pm, Monday to Friday.

If distributed generators generate through the Red-Band, then they receive a payment from their DNO, possibly through a PPA with an appropriate discount. Historical DUoS (also known as GDUoS) values are shown in Figure 34 (i.e. the negative tariffs that distributed generators were paid in Red-Band periods). DUoS tariff benefits increase if assets are connected closer to demand at lower (LV) voltage connections, and correspondingly decrease if assets are connected further from demand on Extra High Voltage (EHV) connection levels, typically >33 kV.

[74] Low Voltage, High-Voltage and Extra-High Voltage

Figure 34 HV Generation non-intermittent Red-Band tariffs[75]

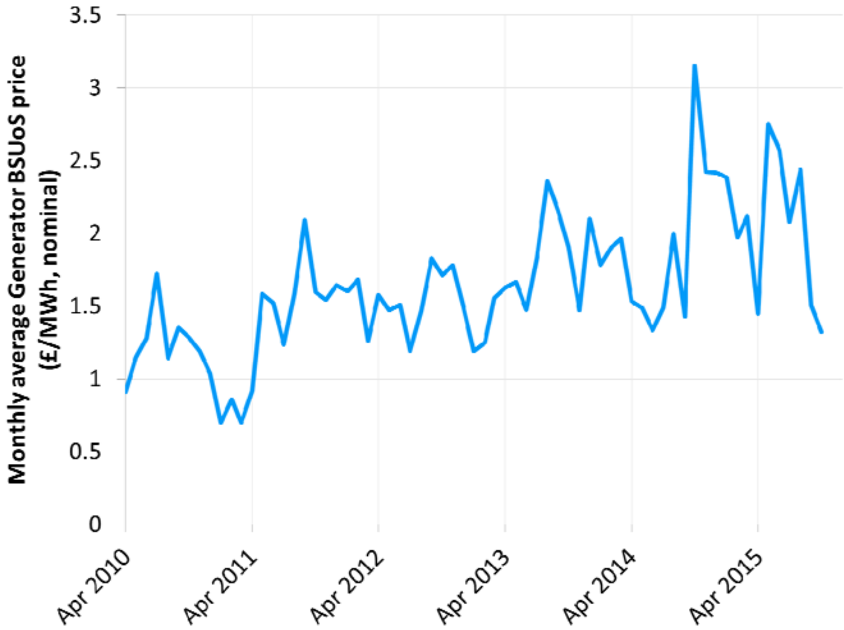


Avoided BSUoS Costs

Avoided Balancing Service use of System (BSUoS) costs are a small additional revenue of approximately £1.50 – 2/MWh (pre PPA discounts) that distributed generators receive. BSUoS costs are the charges that National Grid passes to both generators and demand to cover the balancing costs that they accrue when managing the system in real time (i.e. recovery of balancing mechanism and balancing service costs). This cost is split 50:50 between generators and demand, with distributed generator again able to help avoid the demand component of this charge (storage would therefore benefit by avoiding generation-related BSUoS, but still have to pay demand or injection related BSUoS). Historical BSUoS charges can be seen in Figure 35.

[75] Respective DNO UoS charging statements

Figure 35 Historical BSUoS Costs (monthly average, nominal)



Avoided Capacity Market Supplier Charge

The costs associated with the Capacity Market will be recovered from suppliers through a Capacity Market Supplier Charge (CMSC). The annual CMSC charge depends on the total cost of the Capacity Market in that year (see section 2.4.3 for further details) which depends on the auction clearing price, long term contracts from previous auctions (if applicable), as well as the electricity demand during the winter peak charging period.

As the design is presently stated, this charge will be calculated annually and based on a supplier's forecast market share between 4-7pm on winter weekdays, before switching to actual data once available[76] [77]. If distributed generators or storage run continuously during these winter weekday evening periods then additional revenue should be made available through avoided CMSC charges.

Additional Embedded Benefits

There are other smaller embedded benefits that distribute generators can monetise through their PPA.

- **Avoided line loss factors adjustment (Distribution line losses) -** The DNOs publish Line Loss Factors (LLFs) each year, which are used to scale up suppliers' and other off-takers' metered demand to account for losses on the distribution system. The effect of this mechanism is to make suppliers and off-takers over-procure to account for the energy lost on the system as it reaches the end-user. As embedded generation reduces the amount of

[76] Implementing Electricity Market Reform (EMR), June 2014, Section 3.4.2.1, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324176/Implementing_Electricity_Market_Reform.pdf
[77] EMR Settlement Limited, Calculation of Supplier Demand for EMR Charging, August 2015 https://emrsettlement.co.uk/documents/2015/08/calculation-supplier-demand-emr-charging.pdf

energy that off-takers have to procure from the transmission system, it nets off of the volumes that are loss-adjusted at the grid supply point and saves the offtaker from having to over-procure to cover losses.

- **Avoided Transmission Losses** - Resistance on the transmission network means that generators either need to over-produce energy to deliver a certain volume, or that suppliers need to over-procure to account for losses. National Grid Electricity accounts for losses on its transmission system by determining the lost energy as the difference between the sum of meter readings for energy imported onto the system and the sum of meter readings for energy exported from the system; and then splitting the cost of this lost energy between transmission-connected generators and suppliers based on a 45:55 ratio. This means that a transmission-connected generator will have its output scaled down at the meter, and suppliers will have their demand scaled up to achieve equalisation for the purposes of charging. Current total losses on the transmission system are approximately 1.6% of total demand, meaning that losses of approximately 0.7% are allocated to generators and 0.9% are allocated to suppliers. Total transmission losses vary from one year to the next (based on actual metered volumes), but the 45:55 ratio is constant. The loss factors are not zonal, i.e. they do not depend on the location of the generators and suppliers.
- **Avoided AAHEDC charges** - The Assistance for Areas with High Electricity Distribution Costs (AAHEDC) scheme reduces the costs of distribution to consumers in designated areas, currently Northern Scotland. The AAHEDC tariff is set annually by National Grid and collected from all authorised suppliers based on metered grid volumes. The provisional tariff for 2014/15 is approximately £0.20/MWh. Contracting with an embedded generator allows suppliers to reduce their net demand and exposure to AAHEDC charges.

Opportunities for storage: Embedded benefit revenues streams offer high potential to new storage entrants but are only available to distribution connected or demand (behind-the-meter) connected resources only. However, these are benefits are heavily dependent on the distribution of the charging structures.

Key design considerations: Size of storage energy capacity.

Key operational considerations: Careful scheduling of the storage asset is required to optimise the likelihood of receiving Triad avoidance revenues given the uncertainty surrounding when the Triad periods will occur.

2.4.3 Introduction of the Capacity Market

The Capacity Market (CM) is designed to help address the Government's concern about future security of supply. To mitigate the risks to security of supply, the Energy Bill 2013 provided new powers for the Secretary of State to introduce a CM to ensure there is enough capacity available to meet expected demand. The decision on how much capacity to procure is informed by an enduring reliability standard. No electricity system can ever be 100% reliable, and there is always some trade-off between the cost of providing additional back up capacity, and the level of reliability achieved.

The reliability standard for the GB electricity market is a Loss of Load Expectation (LOLE) of 3 hours/year[78].

The main CM auction will be held with a four year lead time, and will be supported by a secondary auction the year before delivery to fine tune the capacity requirement as levels of supply and demand are better known. This year-ahead auction is expected to be the main route to the capacity market for demand side response (DSR) and storage providers.

The Government is keen to enable the development of DSR and storage, and has therefore developed a series of "transitional" year-ahead auctions[79]. DSR and storage will be able to opt-in to these transitional arrangements owing to their different characteristics (for example their limitations from being able to supply energy for extended periods of time) and have the option of bidding for a standard agreement or alternatively a "time-banded" product (where the obligation to deliver capacity will only apply in certain hours and hence the payment received will be lower).

Eligibility to participate

The required amount includes both existing capacity and potential new build capacity. It also includes non-generation forms such as interconnectors[80], DSR and storage. However, generators receiving a Contract for Difference (CfD), or generators under the Renewables Obligation (RO) will not be eligible to participate concurrently in the CM. Capacity wishing to participate in the CM auction must meet the 2 MW de minimis threshold and go through a pre-qualification process to ensure they meet other technical and organisational requirements.

The design of the CM is technology neutral, with the aim being that the market brings forward an appropriate capacity mix. Existing capacity and DSR providers can bid for annual contracts, whereas new capacity can bid for contracts up to 15 years in duration. Existing providers planning significant refurbishment (e.g. conversion from CCGT to OCGT) can bid for contracts of up to three years.

Auction process

A capacity demand curve is published, ahead of the auction, which communicates the willingness to pay at different levels of capacity margin. The CM is a 'descending clock' auction design with multiple rounds corresponding with a price range. As the auction moves through each round with the price decreasing, eligible capacity providers can choose to withdraw their capacity by submitting an 'exit bid'. This process continues until the volume of capacity remaining in the auction matches the target capacity requirement as closely as possible.

The CM auction is for a homogeneous capacity product. Existing plant/DSR, refurbishing plant and new plant are able to bid and win capacity agreements, with all plant paid the clearing price in a given auction, but with different contract lengths (1, 3 and 15 years respectively).

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[78] For more details on how this reliability standard was arrived at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/268221/181213_2013_EMR_Delivery_Plan_FINAL.pdf

[79] In the transitional auction embedded generation capacity is permitted to bid as a DSR provider

[80] Interconnector owners, rather than foreign generators, will be the bidding party and (if successful) holders of the capacity agreement up to the level of the de-rated interconnector capacity.

Obligations and penalties

Successful bidders in the CM auction must deliver their capacity obligation[81] when a system stress occurs during the delivery period covered by their CM contract, or face penalties for non-delivery:

- The System Operator will issue a Capacity Market Warning when an inadequate system margin (less than 500 MW) is forecast.
- If 'system stress events' such as load shedding, brown outs or black outs occur, capacity providers who are not supplying energy at the level of their capacity obligation will face financial penalties as long as a Capacity Market Warning was issued (at least 4 hours ahead).
- Penalties will accrue at a rate based on the plant's CM revenues (as defined by their capacity agreement and the clearing price of the auction in which they were successful). Total penalties are capped at 200% of a provider's monthly income for a single stress event, and overall at 100% of their annual income.

This obligation and penalty model may implicitly reward flexibility from capacity providers (such as storage assets) to respond to anticipated system stress events, as plant that can ramp up quickly will have a clear advantage for responding to the tightening margins and Capacity Market Warnings that may precede a system stress event. However the current design of the CM is unfavourable to storage assets, with their finite energy capacity, as the obligation to deliver is not time bounded. As long as the capacity market warning remains in place, CM agreement holders have to continuously deliver energy or face potential penalties. A key exception is that successful CM units can still contract for Balancing Services if they are in receipt of a Capacity Market contract[82]. Under such circumstances the capacity obligation would be adjusted to take account of their balancing services delivery requirements (availability and utilisation) as instructed by National Grid[83].

Auction Results

The first four year ahead CM auction was held in December 2014 (for delivery in winter 2018/19) and cleared with a price of 19.4 £/kW (real 2012 money) and a contracted volume of 49.3 GW of de-rated capacity. The low clearing price reflects a high level of competition in the auction, with 5.9 GW of existing capacity failing to secure a contract. Although the auction attracted a great deal of interest among new plant, 95% of the contracts (46.8 GW) were awarded to existing generators. Only 2.5 GW of new plant capacity was successful in the auction. This new capacity included one large-scale CCGT project (1660 MW), 510 MW of known gas engines, 110 MW of known diesel engines and the remainder made up of a mixture of technology types, the split of which is unknown.

[81] This capacity obligation will be profiled over the year to reflect their contribution to peak demand at any one time (a 'load-following obligation').
[82] With the exception of long term STOR contracts - plant with existing long term STOR contracts may only participate in CM auctions if they irrevocably commit to terminating the STOR contract if successful in the capacity auction and ahead of the relevant delivery year.
[83] DECC, Electricity Market Reform: Capacity Market – Detailed Design Proposals, June 2013, section 54
DECC, Electricity Market Reform: Consultation on proposals for implementation. Government response, June 2014, pg. 72/73.

The second four year ahead CM auction was held in December 2015 (for delivery 2019/20) and cleared with a price of 18.0 £/kW (real 2014/15 money) and a contracted volume of 46.3 GW[84]. The low clearing price reflects a continuing high level of competition in the auction, with 5.1 GW of existing capacity failing to secure a contract. Some of these plant can still try to secure a capacity payment in the 1-year ahead auction. The older generators, however, may see this as an exit signal and decide to close sometime between 2016 and 2019. Although the auction again attracted a great deal of interest among new plant, 95% of the contracts (44.0 GW) were again awarded to existing generators. Only 1.9 GW of new plant capacity was successful in the second auction. This new capacity included one large-scale CCGT project (800 MW de-rated). The remaining 1100 MW comprises mainly small scale distributed generation (DG).

The first transitional CM auction was held in January 2016 (for delivery 2016/17) and cleared with a price of 27.5 £/kW and a contracted volume of 802.7 MW of de-rated capacity[85]. Of the agreements awarded, 315MW were to existing generation units, 13 MW to new generation units and 475 MW to unproven DSR resources. Of the non-DSR agreements, 264 MW were for CHP / autogeneration technologies, 48 MW to OCGT or reciprocating engines and 17 MW to oil fired generators. All agreements awarded in this auction are for 1 year duration.

Opportunities for storage: The capacity market offers an additional revenue stream for new storage entrants. However, competition has been high in the CM auctions held to date and no new storage assets have been successful in receiving a CM agreement.

Key design considerations: Size of storage energy capacity.

Key operational considerations: At times of system stress, storage capacity may be required to delivery energy over an undefined period of time or face penalties for non-delivery.

2.5 Future Electricity Balancing Services

2.5.1 Key market drivers

The demand for Balancing Services in GB is driven by:

- The level of intermittent generation on the system.
- Wind forecasting error.
- Demand forecasting error.
- The largest single normal in-feed loss on the system.

These factors will continue to set the level of reserves required going forward. The reserve requirement is expected to increase in future as wind penetration increases in the near to medium term and large thermal plant retire. The potential commissioning of new nuclear units in the mid-2020s would also raise the largest single in-feed loss that could occur on the system. Large scale

[84] Note some new and refurbishing plant had already been contracted for this delivery period in the previous CM auction – resulting in lower volume procured compared to the previous auction.
[85] A total of 1100MW entered the auction

deployment of solar PV could also raise the level of reserve required[86]. The wind and solar capacity assumptions associated with National Grid's Future Energy Scenarios (NG FES) are shown in Figure 36 and Figure 37, respectively.

Figure 36 National Grid FES 2015 wind installed capacity assumptions[87]

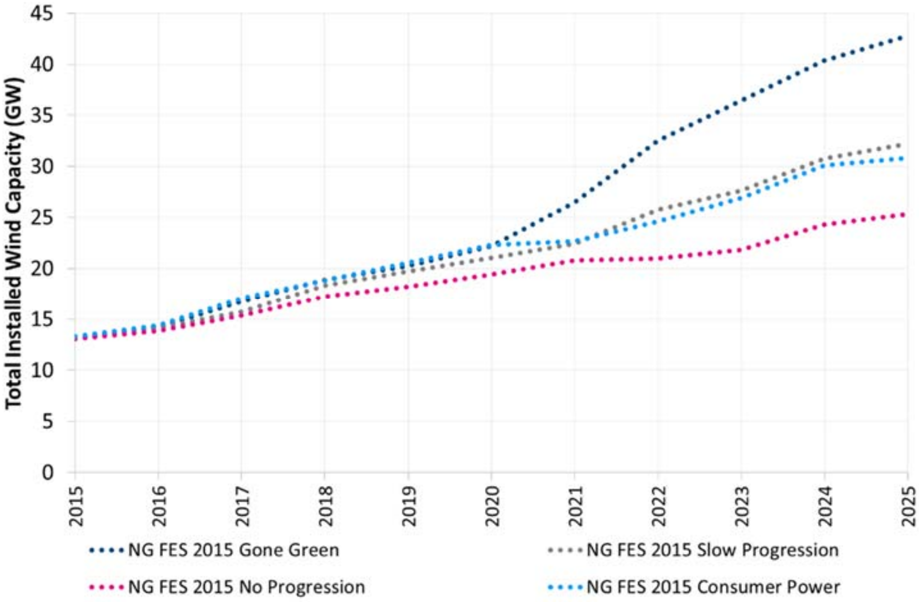

Figure 37 National Grid FES 2015 solar installed capacity assumptions[88]

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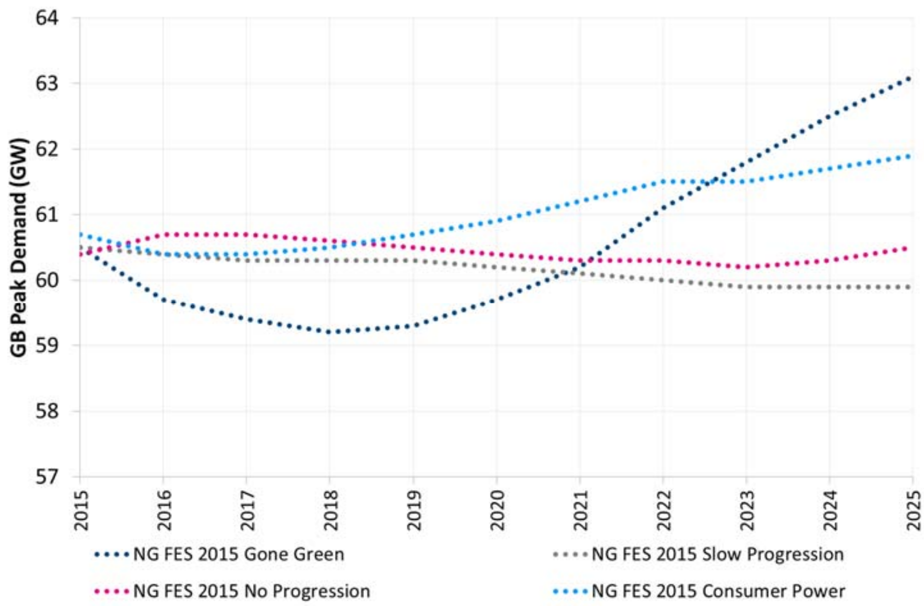
86 Solar output is also intermittent owing to cloud cover affecting forecasting confidence.
87 National Grid Future Energy Scenarios 2015.
88 National Grid Future Energy Scenarios 2015.

Peak demand is modelled to remain broadly flat until 2020 by National Grid. In the longer term there is divergence between scenarios, resulting from different assumptions for a number of peak demand drivers including heat pump deployment and load shifting (e.g. through Time-of-Use ToU tariffs).

Figure 38 National Grid FES 2015 peak electricity demand assumptions[89]



New reserve products may also be required as the characteristics of the GB power system evolve. For example, periods with low demand (e.g. overnight/weekends) and excess supply (e.g. high renewable output) may present new "downward" flexibility challenges for the system operator, in particular if the generating supply resources are embedded generators that do not participate in the Balancing Mechanism and are not controllable by National Grid.

2.5.2 Evolution of current balancing services

Firm frequency response

National Grid appears to use a formula based on the following three factors when determining the reserve requirement for frequency response at a planning level[90].

- Largest in-feed loss.
- System inertia.
- Average effectiveness of plants for response provision.

In future it is expected that primary (rather than secondary) frequency response, as defined previously, will drive the overall response requirements in GB given:

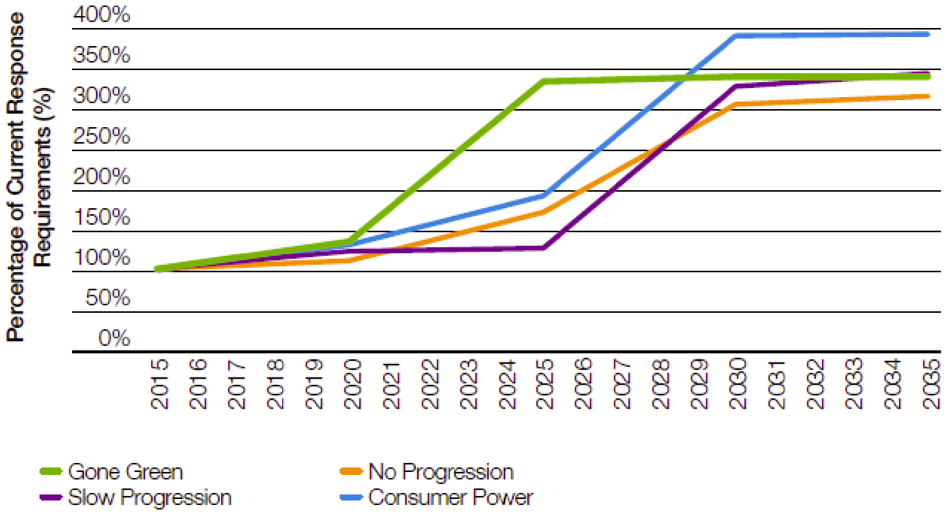
- The anticipated reduction in system inertia with less spinning plant on the system.

[89] National Grid Future Energy Scenarios 2015 – see document for demand definition applied.
[90] For day-to-day system operation a more complex representation is modelled along with the interaction across different operational reserve requirement timescales.

- The increase in the Rate of Change of Frequency (RoCoF) driven by increased penetration of intermittent generation.

The potential impact of system changes on primary response requirements have been a focus for NG throughout 2015, and culminated in the release of the System Operability Framework (SOF) in November 2015.[91] This SOF report shows a large increase in Primary Frequency Response against current requirements, as shown in Figure 39.

Figure 39 National Grid forecast of total Primary Response Requirement (summer maximum)[92]



The SOF report notes that the extra Primary Frequency Response required post-2020 would fall if new providers have 'enhanced capabilities', which are defined as capability to provide response within 1 second (intended to arrest the sharp RoCoF). The new Enhanced Frequency Response service, proposed by National Grid, is discussed in Section 2.5.4.

Due to the evolution of the GB generation mix, mandatory frequency response may become more expensive for National Grid in future:

- More expensive 'Positioning costs' for mandatory response are likely as the volume of plant that is part-loading, and able to provide 'free headroom' when response is needed the most, is decreasing.
- More expensive 'Holding costs' for mandatory response are likely as thermal plant's load factors are declining and the times when they run may feature sharper energy prices – therefore if running in response mode, they will look to recover these foregone revenues.

This reduction in expected mandatory volumes is evident in the SOF report, in which NG estimate little if any spinning plant on the system by the mid-2020s, meaning the majority of the (summer) requirement will need to be met by commercial FFR.

[91] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/
[92] National Grid, System Operability framework 2015, Figure 18.

NG also needs to hold a certain volume of Secondary Response, linked to the size of the largest in-feed loss on the system. Additional Secondary Response procurement may therefore be required if and when the Hinkley Point C plant comes online.

Implications for storage: Storage assets currently compete in the FFR markets operated by National Grid and are well placed to provide additional Frequency Response Balancing Services in future due to their fast response times. The increased volume of Frequency Response required therefore represents a key commercial opportunity for new market entrants.

Fast Reserve

Fast Reserve is used by National Grid to manage unexpected volatility in demand. Therefore, in the absence of large increases in demand levels or changes to demand profiles, it is likely that future Fast Reserve demand will be consistent with historically observed levels[93], at least in the near term. Beyond this, widespread penetration of electric heating could potentially lead to additional demand for Fast Reserve, but the scale of this may itself be tempered by e.g. the application of heat storage within buildings.

Implications for storage: Given the current market saturation by existing pumped storage assets with sunk capital costs, the Fast Reserve market provides limited opportunity for new entrants.

STOR

The level of reserve contracted for may be greater than the calculated operational reserve requirement (ORR) based upon the identified reserve drivers described above. This difference between a fundamentals-based requirement and out-turn demand for balancing services occurs for a number of reasons:

- **Difference between committed and flexible STOR availability**: Not all flexible STOR will come available at the week ahead stage.
- **The un-reliability of plant:** National Grid may choose to over procure to account for plant unavailability.
- **Locational/Seasonal requirements:** Additional reserve capacity is often procured for other purposes, for example to resolve locational constraints or account for seasonal differences in the calculated operational reserve requirement.
- **Economics**: National Grid may contract above their requirement if the economics of bids received closer to delivery date are sufficiently attractive.

[93] This focuses on the Firm (tendered) Fast Reserve product as there is insufficient information available in the public domain on the Optional (bilateral) Fast Reserve product.

Rather than explicitly contracting one balancing service for a specific reserve component (level of intermittency, wind forecast error, demand forecast error and loss of largest infeed), Balancing Services are contracted for coverage across multiple components. However, as the level of intermittency and associated wind forecasting error is projected to increase in future, it can be assumed that the level of STOR reserve will increase from present day contracted levels.

Implications for storage: The increase in future STOR requirements presents an opportunity for future market entrants. However, competition in the STOR tenders has increased in recent years with new small scale diesel and gas engine assets entering the market.

Reactive Power

While overall levels of Reactive Power utilisation have reduced in the last decade, National Grid stated in the SOF report that it considered voltage and reactive power management to be a challenge that is likely to significantly escalate in severity in the future, possibly requiring an increase in the level of reactive compensation across the system which could include voltage control from distributed generation resources, given that most of the issues are generated at the distribution level but currently resolved at the transmission level.

National Grid further describes that it has had to take increasing numbers of actions to control Reactive Power in the last year, including constraining generation onto the system overnight, when reactive power levels can be at their greatest. National Grid expects this trend to continue in all of its Future Energy Scenarios, so that Reactive Power Compensation requirements increase by a factor of two or three compared to current levels by 2025, and by a factor of 5 to 6 in 2035.

Implications for storage: The increased requirements for reactive compensation may provide a potential revenue stream for new storage assets. The value associated with this revenue stream is difficult to assess due to the current lack of a commercial market for this service. Going forward it may be that reactive power provision may be a secondary source of revenue for a storage asset that is primarily targeting a different market or Balancing Service.

Black Start

The identity of the current contracted Black Start capacity is unknown, but is believed to include coal, hydro, OCGT and CCGT sites. The current technical requirements for Black Start favour traditional large thermal generators. However the ability of these large generators to provide future Black Start capabilities may be reduced due to:

- A number of plant that have retired or plan to retire, for reasons of poor economics or environmental legislation such as the EU Industrial Emissions Directive.

- Reduced running hours for thermal plant (due to increased renewables capacity ahead in the merit order), means that generating units may be more often in a “cold” state and hence will take longer to restart after a shutdown.

National Grid is considering future alternate approaches for Black Start system restoration. Two reports, published in September 2015[94], examined these alternate approaches in detail, including the identification of which technologies may be suitable for Black Start capacity. They both conclude that a combination of renewable technologies and electricity storage installations might be technically feasible as future providers of Black Start services. However there are a number of technical factors that would need to be studied further. In addition the properties of the storage asset (energy capacity, charge/discharge rate) would need to be carefully designed to account for both the auxiliary power requirements of the renewable generator and the impact of weather intermittency on start-up processes. Battery energy storage may also play a role for current or prospective Black Start thermal generators by co-location on a generation site and replacing existing/future diesel units used as part of the start-up process.

Implications for storage: There is likely to be limited opportunity for storage assets (outside of existing pump storage) to gain revenues from Black Start provision in the near to medium term due to highly specific location requirements and the presence of incumbent providers.

2.5.3 Evolution of the balancing mechanism[95]

In September 2012 Ofgem began a review of the imbalance arrangements (Electricity Balancing Significant Code Review (EBSCR)), which resulted in a number of reforms to the balancing arrangements[96]. The first set of reforms was implemented in November 2015. Further changes to the arrangements will take place in November 2018 as follows:

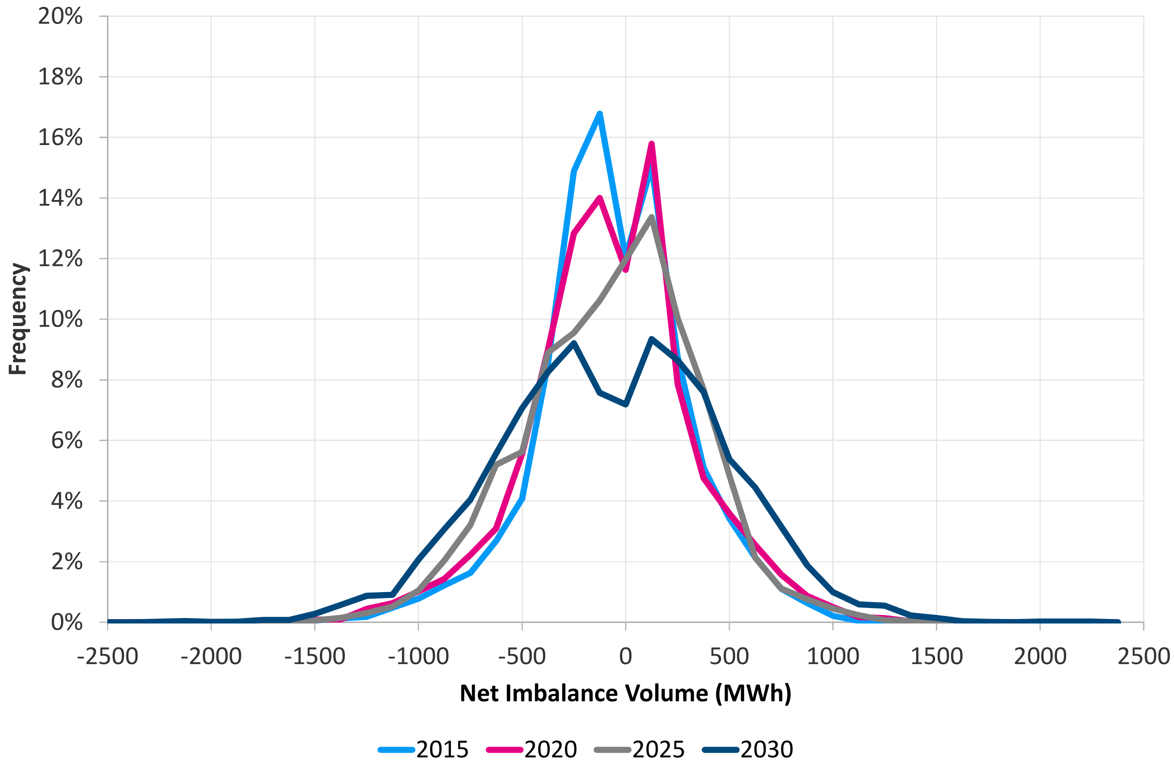
- **More marginal imbalance prices -** A principle aim of EBSCR is to sharpen incentives to provide flexibility by making prices in the Balancing Mechanism more ‘marginal’. Full marginal pricing (PAR[97] 1) will be introduced i.e. imbalance prices set at the most expensive balancing actions (compared to the present where prices are determined as the average of the most expensive 50 MWh of actions taken (PAR50)).
- **Cost of disconnections -** The full prevailing Value of Lost Load (VoLL) of £6,000/MWh will be included in the System Buy Price (SBP) compared to the present where the implied cost to consumers of using voltage control to balance the system, or for making involuntary disconnections where system balancing is set to be £3,000/MWh.
- **Reform to pricing reserves –** The Reserve Scarcity Price , used to reprice STOR actions to better reflect market conditions, is calculated for each settlement period as the product

[94] http://www.smarternetworks.org/Project.aspx?ProjectID=1653#downloads
[95] All data in this section is consistent with the modelling undertaken by Baringa for Ofgem as part of its Impact Assessment for the Electricity Balancing Significant Code Review consultation.
[96] https://www.elexon.co.uk/wp-content/uploads/2014/05/P305D-v2.0.pdf
[97] Price Average Reference (value)

of Loss of Load Probability (LOLP)[98] and the VoLL. LOLP will be dynamically calculated for each settlement period using up to date system information compared to the present where the LOLP calculation is done using static look-up tables based on historic system margins.

Changing fundamentals are expected to affect the aggregate imbalance properties of the GB power system in the future. In particular, Net Imbalance Volumes are expected to become more volatile over time in response to a growing proportion of intermittent renewable capacity with more volatile forecasting error and poor balancing properties. This will result in a greater proportion of total market trades occurring through the Balancing Mechanism. This trend is indicated in the broadening distributions of forecast Net Imbalance Volumes shown in Figure 40.

Figure 40 Forecast distribution of Net Imbalance Volumes



In addition to the impact of the EBSCR reforms, system fundamentals are also a primary driver for imbalance pricing. The impact of system fundamentals can be categorised into two groups:

- **The evolution of commodity prices** will naturally impact the underlying costs of thermal generating units in much the same way as it impacts wholesale price formation. A flow through effect into the bids and offers submitted by generators into the Balancing Mechanism will occur, with offers typically submitted as a premium to a generator's Short Run Marginal Cost (SRMC) and bids as a discount to a generator's SRMC.

98 A measure of system reliability that indicates the probability that there will be insufficient generating supply to meet the capacity requirement https://www.elexon.co.uk/wp-content/uploads/2016/02/Imbalance_Pricing_v9.0.pdf

- **The evolution of capacity mix** will determine:
  - The types of generators (e.g. coal vs CCGT vs wind) that are available to submit bids and offers into the Balancing Mechanism.
  - The imbalance properties of the system and how this equates to a need for National Grid to accept bids and offers to resolve system Net Imbalance Volumes.

The expected impact of the full EBSCR reforms, and accompanying changes to system fundamentals, is to increase the magnitude of prevailing imbalance prices for a given system NIV. In particular:

- **High SBPs**: In periods approaching system stress, The PAR1 and VoLL pricing policies will yield maximum SBPs that are far greater than those observed historically. Moreover, the RSP function, by definition, will allocate the cost of STOR contracts to periods with a tight operating margin during which STOR is utilised by National Grid.
- **Negative SSPs**: There is a growing proportion of subsidy-supported capacity in the UK generation mix. These generators are incentivised to bid at the negative level of support provided such that they are indifferent between positions of generation (receiving support level) or curtailment (paying negative support level). Where this capacity is on the margin and there is a long system imbalance event, negative SSPs will reach a magnitude corresponding to the level of support of the marginal accepted bid. Although an increase in the incidence of negative prices can therefore be expected over time, the low bids that these generators will submit necessarily means they will likely only be curtailed in periods of very low thermal unit commitment, for instance during periods of low demand and high wind.

In the GB electricity system, generators are permitted to deliver electricity without first selling it in advance through a bilateral contract or on power exchanges. This can be an appropriate strategy for generators or storage assets that are targeting a range of alternative revenue sources outside of electricity market revenues. In doing so these generators will assume a systematic long position so will be required to sell this electricity at the prevailing System Sell Price (SSP). Similarly a generator called upon to generate under a STOR contract will receive the prevailing SSP for the energy generated[99], in addition to the pre-agreed availability and utilisation revenues.

- In future, during long system imbalance periods, the SSP received will be lower than under the current rules as the PAR1 marginality will set the price at the lowest of the accepted bids. Therefore, the opportunity cost to the generator of not selling the spilled power in advance will increase.
- Conversely, the upside potential of SSPs is expected to increase significantly as the single pricing mechanism provides access to the marginal SBP for long generators when the system is short.

An alternative to selling power at SSP is to sell power in advance of gate closure either directly with a counterparty through a bilateral contract or on power exchanges. Forward trading permits generators to submit bids and offers into the Balancing Mechanism, providing an additional source of

[99] Historically, distributed generators have been offered the system sell price by their off-takers as this was the only price off-takers could guarantee without prior warning that the asset would dispatch.

potential revenue. A registered BM unit (BMU)[100] can submit offers on upward increments of its contracted position to sell additional generation at an offered price.

Offers are typically made at a premium to the market price so if accepted constitute additional revenue that would not have been achieved by selling this power in advance. Bids on the other hand are made on downward increments of a BMU's contractual position to buy back power already sold. Bids are typically made at a discount to the market price, allowing BMUs to generate revenue on the spread between the price at which it sold power on forward markets and the discounted price this power is bought back.

In any given period, National Grid will accept the range of bids and offers needed to resolve system Net Imbalance Volumes (NIVs) and any other system considerations as required. Bids and offers compete on price, so withholding capacity to submit offers into the BM comes at a risk of not being accepted. At present the BM operates as a pay-as-bid mechanism, so a BMU will trade only at the level of the accepted bid or offer not at the level of the marginal accepted bid or offer as in a pay-as-clear mechanism[101].

Total energy system imbalance costs are borne by those participants responsible for imbalance. The distribution of these costs will therefore change in accordance with the changing ownership of generation and supply portfolios. For instance, independent intermittent renewable parties and vertically integrated utilities (VIUs) with a large share of intermittent renewable capacity can be expected to face an increased imbalance exposure over time. Under the new BM arrangements participants will have greater incentive to resolve imbalance positions prior to gate closure at short notice and avoid more punitive imbalance prices. In doing so, intraday prices should reflect this increased activity, with greater volatility expected, particularly during peak periods. Flexible generators and storage assets that are able to trade at short notice are well placed to capture this increased volatility in intraday prices. Alternatively, market participants may be encouraged to directly develop flexible resources (including storage assets) as part of their generation portfolio to mitigate their potential increased exposure to high imbalance charges. See Section 2.7.2 for further discussion of the integration of storage assets with renewable capacity.

Implications for storage: The reforms to the calculation of imbalance prices in the Balancing Mechanism may result in more volatile revenue received by storage operators for energy delivered during reserve service provision. In particular, there may be upside associated with higher SBP prices received when the system is short. The volatility in imbalance prices may promote the development of storage assets by participants wishing to hedge against imbalance exposures of intermittent resources.

[100] Small scale distributed generation is eligible to participate in the Balancing Mechanism (as BSC signatories), by entering into specific contracts with National Grid, such as the Bilateral Embedded Generation Agreements (BEGAs). BEGAs allow DG assets to be BSC signatories and to participate in the BM, either as the asset owner or as its offtaker, while still receiving embedded benefits. Other than through these BEGA agreements it is uncommon for DG to participate in the BM.

[101] This could be subject to change however, as GB begins to adopt the principles of the Network Code on Electricity Balancing (NC EB) as part of EU third package target model reforms. One of these principles is indicated in Article 39 of Section 4 – General Provisions for the Procurement of Balancing Energy. It states that "the pricing methods shall be based on marginal pricing (pay-as-cleared)" which will likely prompt a change from the current pay-as-bid to a pay-as-clear mechanism in the medium term.

2.5.4 New balancing services

Enhanced Frequency Response

Enhanced Frequency Response (EFR) is a new product that National Grid is looking to procure to improve management of the system frequency and mitigate increases in the rate of change of frequency as a result of:

- Reducing system inertia (synchronous thermal plant being replaced with asynchronous renewables and embedded generation).
- An increase in the largest single in-feed loss anticipated with the arrival of new nuclear plant.

EFR is a fast reacting product[102] where;

- Providers must begin producing output within 0.5s of frequency moving outside of a +/- 0.1 Hz dead band (from the 50 Hz target system frequency).
- Providers must produce full output within 1s for system frequency deviations of +/- 0.2 Hz.
- Providers will have to sustain the service for 15 minutes for both High and Low response (covering the timescales of both the current Primary and Secondary Frequency Response services). However it is also stated that National Grid will be providing further information on what the minimum duration would be for assets with a finite energy capacity.

While EFR is technology agnostic, the sub 1 second response times strongly favour storage technologies, and electrochemical (battery) storage in particular, and the new service is predominantly aimed at these technologies.

National Grid expect to contract up to 200 MW of capacity in the first auction[103]. However, depending on the offers received as part of the tender process, the capacity procured may be more or less that the target 200MW. National Grid are considering 4 year durations for the EFR contracts with individual tenders between 1 MW and 50 MW. Contract terms are likely to be similar to those for Commercial Frequency Response, with availability and utilisation prices for available operational hours as defined by respective bidders. National Grid has published EFR's technical requirements, assessment principles and contract terms for the first tender which is planned for the 11th to the 15th of July for contracts to be awarded on the 26th of August[104]. There was a strong response to the E-FR pre-qualification that was run in late 2015, with a total of 72 separate submissions, of which 64 were successfully pre-qualified.

[102] National Grid published product FAQs: http://www2.nationalgrid.com/Enhanced-Frequency-Response.aspx
[103] This capacity is in addition to that already procured for existing mandatory and commercial frequency response requirements. In future E-FR may be merged with existing commercial frequency response requirements once the product and providers are better understood.
[104] National Grid, Enhanced Frequency Response, Timeline for Web, 3rd March 2016.

Implications for storage: This design of this product favours storage assets and as such has high potential as a revenue stream for new market entrants. The value associated with providing this E-FR service will become clearer when the results of the first tender are published later this year.

Demand Turn Up

Demand Turn-Up (DTU) is a new Balancing Service product introduced by National Grid in November 2015, with the first capacity to be procured for delivery in summer 2016[105].

The predominant drivers for the DTU service are;

- A decrease in downward margin available on the GB system outside of peak times, as less fossil fuel-fired plant is providing energy in these periods. Summer night time and weekend periods are of particular concern as transmission level demand is expected to reach sub 20 GW levels from 2016 and sub 10 GW from 2025, meaning that there is little firm thermal generation on the system that can provide downward reserve[106].
- A large increase in distribution-embedded solar PV driving a suppression in demand levels during the day.
- Significant variation in wind levels overnight and during the day.
- The increasing capacity of embedded wind, which National Grid cannot control.

Details of the DTU product are still being refined, but outline contract parameters as set out by National Grid are given below.

Figure 41 DTU Outline contract parameters[107]

Contract parameter	National Grid's stated position as of December 2015
Potential Providers	Demand side – defined as delivery of reserve via an increase in demand seen at a transmission level (embedded generation)
Delivery volume	Minimum 1 MW
Response rate	5 minutes
Minimum delivery duration	30 minutes
Delivery start	May 2016
Contracting	Initial bilateral with progression to tendered service if commercially viable. Non-delivery penalties will apply
Availability	Could accept a range of committed and flexible volume, similar to STOR
Declaration of availability	Week or month ahead availability declarations possible
Locational requirement	There may be a premium paid on central locations due to higher requirement

105 Demand Turn-Up Service Outline document, November 2015, http://www.powerresponsive.com/
106 National Grid System Operability Framework 2015, http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/
107 DTU Contract Development, Webinar Slide pack, http://www.powerresponsive.com/

Contract parameter	National Grid's stated position as of December 2015
Sundays	National grid acknowledge certain providers would not operate on Sundays
Pricing structure	**Option A** Availability and utilisation payment on a sliding scale (higher availability payment = lower utilisation payment and vice versa)
	Option B Fixed availability and utilisation pricing (different payment for peak / base and Saturday / Sunday – Friday)
	Option C Availability only pricing, potential to procure volume through CM type auction
Contract length and volumes	**Option A** Fixed MW contract of one or two years **Option B** Two year with option to grow volume across duration of contract **Option C** Longer term contracts

National Grid expect to procure 200 – 300 MW of DTU capacity in summer 2016 (May through September), with this requirement potentially increasing in subsequent summers. Through January 2016 National Grid intend to refine the product design through stakeholder meetings, publishing contract conditions and their volume procurement method in February 2016. National Grid then intend to sign contracts in April 2016 for delivery of capacity in May 2016.

Implications for storage: Although there is no mention of storage assets in the design documents for this service, the requirement to "increase" demand could in future be met by a storage operating in charging mode during periods of low demand and high supply. Therefore, if allowed by National Grid, this could be a potential revenue stream for new market entrants.

DNO Balancing Service Provision

Through the Low Carbon Network Fund (LCNF) the DNO Electricity North West (ENW) trialled their Customer Load Active System Services (CLASS) project from spring 2014, with the first stage of the trial completed in September 2015[108] . Through CLASS, ENW are exploring the potential of adjusting voltage controls in sub-stations across their network so as to achieve load reductions when instructed. This demand reduction can then be contracted for Balancing Services with National Grid, similar to demand side response (DSR).

The CLASS trials have shown the potential of Active Network management (ANM) to provide new mechanisms for frequency and voltage control provision to National Grid. ENW estimate an

[108] http://www.enwl.co.uk/class/about-class/what-is-class

achievable demand response using CLASS type services in their own ENW network of 65 - 235 MW, with a total GB potential of 1.2 – 3.3 GW[109].

Implications for storage: While there are a number of regulatory and technical challenges that balancing service provision through ANM has yet to overcome, CLASS type services could pose a threat to the value of storage assets in the future, in particular for the provision of the higher value rapid response time Balancing Services.

2.6 Future Wider Electricity Market Revenues

2.6.1 Evolution of wholesale market revenues

There are four key market trends that are effecting the current GB generation mix that are expected[110] to continue in the near to medium term.

Increasing intermittent generation

The UK is required, in common with other Member States of the EU, to deploy a significant capacity of renewables in the near term to meet defined targets for 2020. The UK has also committed to challenging long term targets for the reduction of greenhouse gases[111] which will driver further decarbonisation of the power sector in the medium to long term. To meet these targets, the existing infrastructure of large thermal plant connected to high voltage transmission networks is steadily being replaced by smaller scale intermittent wind and solar generation, connected at lower voltage levels.

Government's recent announcement postponing CfD auctions, and their stated intention to preclude onshore wind from future CfD auctions, have both served to decrease the expected growth rate of renewables in GB. However, the trend of increasing renewable penetration is expected to continue[112]. National Grid scenario projections for future wind deployment can be seen in Figure 36 in section 2.5.1. The installed solar PV capacity in GB has increased dramatically over the past 3 years, increasing from 1.7 GW of installed capacity in October 2012 to over 8.2 GW in October 2015[113] [114]. In 2014 and 2015 DECC made a series of announcements restricting subsidies for large scale solar installations (through the Renewable Obligation scheme) and reducing subsidies available for small scale solar installations (through the Feed in Tariff scheme). Similarly to wind, additional solar capacity is expected to continue to be deployed in the near term, though at a slow rate of

[109] ENW CLASS Close down report, September 2015, http://www.enwl.co.uk/docs/default-source/class-documents/class-closedown-report.pdf?sfvrsn=4
[110] Absent any major changes to GB energy policy.
[111] An 80% reduction, relative to 1990 levels, by 2050.
[112] Though the growth rate of renewables is more moderate than previously expected
[113] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/424460/Solar_photovoltaics_deployment_April_2015.xlsx
[114] Many industry commentators expect this to be an underestimate of current installed solar capacity

growth than recently observed. National Grid scenario projections for future solar deployment can be seen in Figure 37 in section 2.5.1.

Decreasing firm thermal generation

As intermittent generation increases, large volumes of coal and gas fired power plant are expected to be decommissioned. A number of coal plant are set to retire in 2016, including Eggborough (1.9 GW), Ferrybridge (1 GW), Rugeley (1 GW) and Longannet (2.3 GW). These closures are the result of multiple factors making coal plant uncompetitive including:

- Plant reaching the end of their operational life.
- The requirements of the Industrial Emissions Directive.
- A sustained period of low gas prices.
- The relatively high levels of Carbon Price Support in GB.

A number of gas-fired plant have already retired in 2015 following exit signals from the first capacity market auction. By the mid-2020s, a number of other coal and older CCGT generators, may retire as the plant move further out of merit. As firm thermal capacity decreases, it is reasonable to assume that any auxiliary gas turbines located alongside these power stations also close.

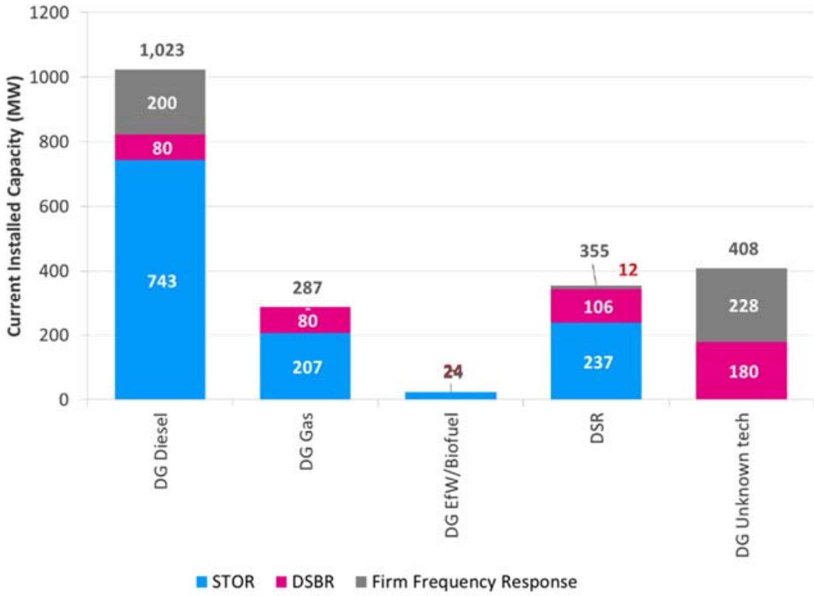
Increasing participation by distributed energy

Distributed energy describes generation assets, storage assets and demand side response participants that are small in scale (typically sub 50 MW) and connected to the low voltage electricity distribution network.

The existing capacity of distributed energy assets can be estimated by looking at non Balancing Mechanism units participating in Balancing Services[115], as illustrated in Figure 42.

[115] FFR, STOR and the DSBR (one of the contingency balancing reserves currently operated by National Grid). This may be an underestimate of existing capacity as not all distributed energy resources participate in these markets.

Figure 42 Existing Distributed Energy capacity estimate 2015[116]



The increasing participation by distributed energy resources going forward is signposted by the results of the capacity auctions held in December 2014 and 2015. In the first CM auction, the new build capacity awarded CM agreements included 670 MW of distributed gas generation and 97 MW of distributed diesel generation. In the second CM auction, the new build capacity awarded CM agreements included 217 MW of distributed gas generation, 170 MW of distributed diesel generation and a further 567 MW of distributed generation of unknown technology/fuel type. If all of this new capacity is successfully developed it will represent a significant increase in distributed generation capacity. Analysis of the rejected bids in the capacity auction also provides an indication of the potential development pipeline of distributed energy resources that may be developed in future. In the 2015 CM auction there was 1055 MW of distributed capacity that was unsuccessful in gaining a capacity agreement.

The increasing take-up of DSR will affect the wholesale market and increase competition for market share in providing Balancing Services in the future. While the current installed DSR capacity and new build potential are difficult to ascertain, there are a number of data points that can be used to reference the potential impact of DSR;

- There is 237 MW of DSR that is known to participate in the STOR market at present[117].
- In the 2014 CM auction, 174 MW of DSR capacity received a 1 year CM contract[118].
- In the 2015 auction, 476 MW of DSR capacity was successful in receiving a 1 year CM contract.

[116] STOR – National Grid, Season 8.5 Fuel Type Summary Report.
DSBR – National Grid, Tender 2 DSBR results for delivery in 2015/16 report.
Firm Frequency Report – National Grid, Baringa Analysis of FFR Post-tender reports up to January 2016.
[117] National Grid, STOR fuel type summary report, Season 8.5.
[118] Note this is both behind the meter generation assets and load reduction capabilities.

- The Transitional CM auction, held in January 2016 for delivery in winter 2016/17, awarded contracts to 803 MW of DSR[119]. A further 307 MW of DSR entered the auction but was unsuccessful in gaining agreements.

Implications for storage: While the total potential DSR resource is difficult to assess, and new entrant DSR providers may face commercial and regulatory hurdles, going forward DSR participants could present a competitive threat to new storage assets. A key test will be for new DSR participants (particularly those using new aggregation business models) to demonstrate that they can successfully provide the services they have contracted for.

Increasing interconnection with other markets

Interconnectors are an important source of flexibility in power markets. In general, greater interconnection can enable the pooling of energy, reserve and other Balancing Services between markets, thus typically leading to flatter prices.

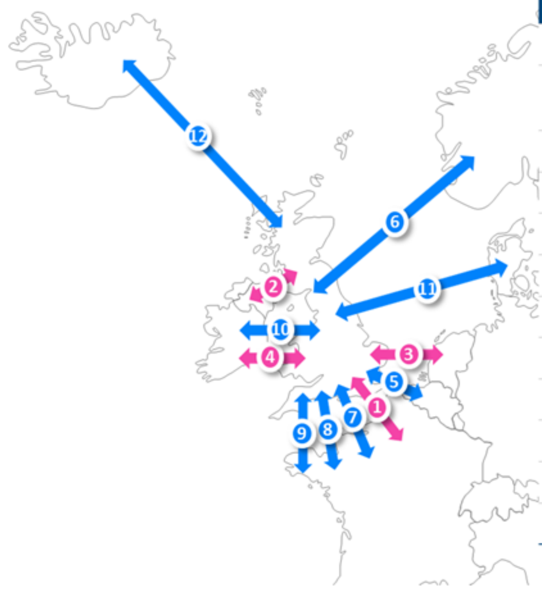
Currently GB is interconnected with France (2 GW), Ireland (1 GW)[120] and the Netherlands (1 GW). There is over 10 GW of IC capacity in various stages of planning at present (see Figure 43); the projects that are furthest developed and may commission in the near to medium term are:

- The Eleclink cable (1 GW) between England and France.
- National Grid has signed joint venture agreements with Elia and Statnett to develop NEMO to Belgium (1 GW) and NSN to Norway (1.4 GW) respectively.

Interconnectors can technically contract for Balancing Services, however the extent to which interconnector operators choose to contract for Balancing Services will be a commercial decision. With the carbon price floor in GB creating a basis difference to neighbouring markets, it is likely that gross margins in wholesale electricity arbitrage will be greater than those achievable in Balancing Services.

[119] Note this is both behind the meter generation assets and load reduction capabilities.
[120] The 500 WM Moyle interconnector to Ireland is running at half capacity as of October 2011 owing to a technical fault. This is expected to be corrected and the interconnector return to full service in 2017.

Figure 43 Current and future interconnector projects



No.	Country	Capacity (MW)	Status	Target
1	France	2000	Existing	1986
2	Northern Ireland	500	Existing	2001
3	Netherlands	1000	Existing	2012
4	Ireland	500	Existing	2012
5	Belgium	1000	Proposed	2018
6	Norway	1400	Proposed	2020
7	France	1000	Proposed	2020
8	France	1000	Building	2017
9	France	1400	Proposed	2020
10	Ireland	500	Proposed	2025
11	Denmark	1000	Proposed	2020
12	Iceland	1000	Proposed	2027

Implications for storage: There is an established regulatory framework for new interconnector projects (the “Cap and Floor” regime) that together with stated Government support[121] means a number of new projects will likely proceed through development to operation. Interconnector assets may compete with storage assets across a number of markets and Balancing Services, and hence increased interconnection may negatively impact the business case for new storage market entrants.

2.6.2 Evolution of embedded benefits

Triad Benefit

The principle risks with avoided demand TNUoS (Triad) revenues are forecasting risk and product risk. The processes associated with forecasting Triad periods, and determining optimal operating regimes to ensure generation during these periods, will likely remain similar going forward. There is however considerable product risk associated with all embedded benefits, and the avoided demand TNUoS benefit in particular.

National Grid undertook a formal consultation on the Triad charging methodology in April 2013, as directed by Ofgem under Project Transmit (a wider investigation into the transmission charging methodology), and decided not to change the Triad based charging methodology for demand TNUoS tariffs[122]. Similarly National Grid also undertook an informal review of the embedded benefits that

121 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266460/More_interconnection_-_improving_energy_security_and_lowering_bills.pdf

122 A conclusion of Transmit pertaining to demand tariffs was to remove a special discount treatment on Triad charging for Scottish generators that was introduced as part of BETTA in 2005 (BETTA was when Scotland

distributed energy resources can receive in 2014, focusing on Triad avoidance revenues in particular. In April 2014, National Grid concluded their review publishing an open letter with their conclusions and making no reference to considering embedded benefits further[123].

However the future of Triad charging arrangements remains open to change. In DECC's March 2016 Capacity Market consultation[124], DECC stated that Ofgem would review embedded benefits by summer 2016 noting that Ofgem are concerned that:

- Embedded benefits may not be fully cost reflective and may over-reward distribution connected generators.
- Current charging arrangements could be having an increasing impact on the system, including distorting investment decisions and leading to inefficient outcomes in the Capacity Market.

GB transmission network costs are expected to increase to £3.9 – 4.6bn/year by 2020[125], it is these costs that are to be recovered through the demand and generation TNUoS tariffs. As such, owing to the size of this cost recovery regime any new proposal to change the current charging methodologies would likely necessitate a lengthy and rigorous consultation process.

Red Band DUoS Payments

DUoS tariffs are power flow dependent, and as such are sensitive to the build out of generation, or indeed demand, in the area that the plant is located. These tariffs are therefore volatile year on year, and could decrease in the future, should a large volume of distributed generators locate in the same area for example.

Avoided Capacity Market Supplier Charge

There is considerable policy risk still associated with the avoided CMSC benefit, and scope for the design of the mechanism to still change. Suppliers' demand calculation for Contracts for Difference (CfD) charging is done on a gross demand basis so there is no benefit available to distributed generators or storage operators for avoiding this charge. Furthermore the current design of the CM regulations allows embedded (thermal) generation and storage assets to both receive a Capacity Market payment as well as a payment for avoiding the CMSC charge passed to suppliers to recover the cost of the CM, which appears inconsistent.

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joined the England and Wales Electricity Trading Arrangements). This removal takes effect from April 2016 (this change is subject to an industry modification to grandfather the discount for all Scottish generation connected before 2016).
Though it was decided to change the methodology for generation TNUoS tariffs, which will come into effect from April 2016.

[123] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/

[124] https://www.gov.uk/government/consultations/consultation-on-reforms-to-the-capacity-market-march-2016

[125] National Grid, EMR analytical report, December 2013.

Implications for storage: Any reduction in embedded benefit revenue could negatively impact the potential revenue available to distribution connected storage providers. New entrants will have to carefully consider the regulatory and policy risks, associated with these revenue streams, when constructing the business case for new storage assets.

2.6.3 Evolution of the capacity market

There is a defined process, administered by Ofgem, to review and update the Capacity Market rules in response to industry/participant feedback. In addition to this DECC have issued a number of consultations relating to the design of the Capacity Market (and associated Capacity Market regulations) in response to key policy changes[126] and lessons learned from the first two CM auctions. The latest consultation, published in March 2016, proposes a number of reforms:

- Buying materially more capacity in the next T-4 auction[127] to account for increased capacity delivery risks.
- Tightening delivery incentives and penalties for both non-delivery of new projects and early retirement of existing capacity.
- Allowing only demand reduction resources into the transitional auctions (i.e. excluding embedded generators) to better target support at this still developing resource.
- Holding an early T-1 capacity auction in winter 16/17 for delivery in winter 17/18[128]. All eligible plant types would be able to participate in this auction with 1 year contracts being issued to all successful bidders.

Implications for storage: An increase in capacity procured for future CM auctions may lead to higher auction clearing prices. This additional revenue could be beneficial to new entrants developing a business case for new storage assets. However, storage assets need to be confident they can deliver their CM obligations, otherwise they could face penalties (that in a worst case scenario would be equal to the total CM revenue received).

[126] For example, interconnectors were not allowed to participate in the first auction – however the rules and regulations were subsequently amended to allow their participation in the second auction.
[127] This would be both additional capacity volume (compared to the previous year) and a shift of the required capacity (for a given delivery year) out of the T-1 auction and into the T-4 auction.
[128] Note that auction would be for the full capacity volume required to meet the defined reliability standard and is intended to replace the current Contingency Balancing Reserve (CBR) (e.g., the SBR and DSBR mechanisms) schemes being operated by National Grid to ensure security of supply in the short term.

2.7 Potential Additional Electricity Market Revenue Streams

2.7.1 Alleviation of network constraints and avoidance of network reinforcements

Transmission

As discussed in Section 2.3.7 National Grid, as the Transmission System Operator, is obliged under primary legislation to ensure that electricity generation and demand are balanced across the GB transmission system on a minute by minute basis. Imbalances can occur for a number of reasons, which are broadly categorised as being either Energy or System imbalances, with the latter being location specific imbalances that can result from transmission constraints owing to the restricted capacity, breakdown or maintenance of grid assets, thus preventing contracted generation being transported to where it is needed.

Constraint management is therefore required when the electricity transmission system is unable to transmit the power supplied to the location of demand due to congestion at one or more parts of the transmission network. National Grid will take actions in the market to increase and decrease the amount of electricity at different locations on the network. The different mechanisms that National Grid use to manage constraints are:

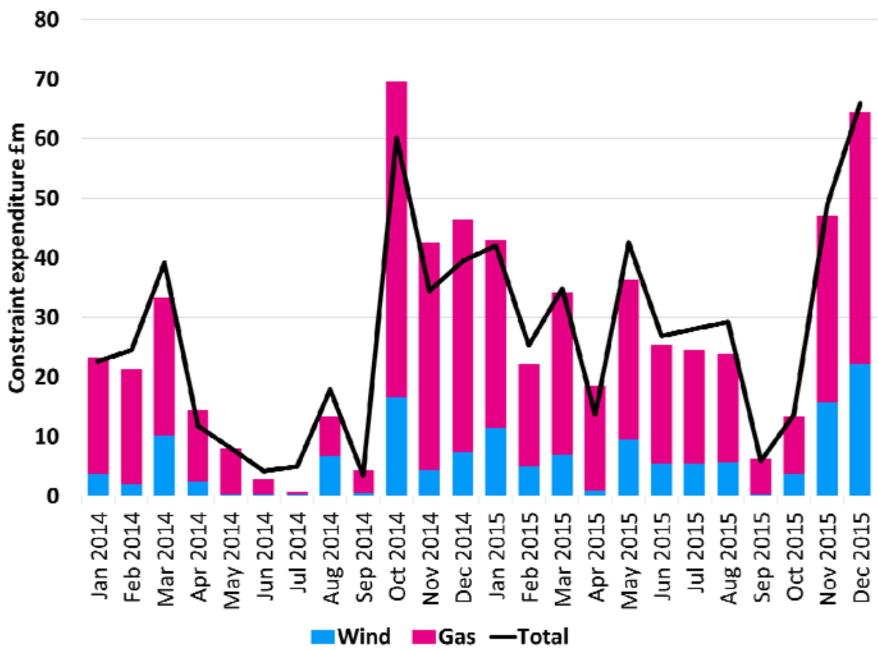
- Taking actions in the Balancing Mechanism.
- SO-SO actions over interconnectors.
- Contracted Services.

National Grid publish monthly values for their expenditure on resolving constraints. In general, the largest volume of actions and corresponding expenditure for constraint management occurs through the Balancing Mechanism[129]. An example of a typical constraint resolution action in the BM would be to reduce wind output in Scotland and correspondingly increase gas generation in England, as there is insufficient transmission capacity available between the north of GB (with high supply) and the south of GB (with high demand). National Grid also provides breakdown of the split of constraint payments/receipts categorised by fuel type. The monthly payments to gas and wind generators, together with the total expenditure, can be seen in Figure 44 for the last two years.

Implication for storage: Curtailing wind generation involves wasting renewable generation that could have been used to meet decarbonisation targets. Additionally, the curtailment of wind generation incurs high payments to wind generators in order to provide compensation for lost subsidies. Integrating storage with renewable capacity could provide a number of benefits to the GB energy system (these are discussed further in Section 2.7.2).

[129] Monthly reports from National Grid detail the expenditure on each Balancing Service and includes further breakdown of constraint expenditure: http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Report-explorer/Services-Reports/

Figure 44 Monthly transmission constraint expenditure[130] [131].



Constraint management contracts enable National Grid to agree in advance technical parameters with parties to facilitate the management of a constraint, and are considered when agreeing action in advance is expected to be more economic than BM trades. Constraint management requirements are advertised on an ad-hoc basis to match an identified specific network need. Providers who can provide the required solution[132] will either enter directly into a bilateral contract, or if there sufficient competition, compete to enter into a contract with National Grid. The structure of the payment will depend on the solution required and may be structured as one of the following: fixed fee, availability + utilisation fee, market indexed fee (e.g. indexed to fuel and power prices). In February 2016 there was zero spend reported by National Grid for constraint management contracts[133].

There is a complex, multi-stage process used by National Grid to identify and approve transmission network reinforcement projects. Broadly speaking, the cost to manage particular network constraints is compared against the cost of identified reinforcement projects that would alleviate the transmission constraint. If one or more reinforcement options are found to be economic, under a number of future energy scenarios, then detailed cost benefits analyses of these potential

[130] Monthly reports from National Grid detail the expenditure on each Balancing Service and includes further breakdown of constraint expenditure: http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Report-explorer/Services-Reports/ - Note monthly spend values were not available for July 2015, so this has been interpolated from neighbouring months.
[131] Note that contributions from other technologies such as coal and interconnectors are not shown.
[132] Which will depend on a number of factors including the nature of the flows on the transmission system, the duration of the requirement, the local level of generation output and the local level of system demand
[133] National Grid MBSS reports

reinforcements are undertaken before a final set are recommended for development[134]. Currently GB network operators are not allowed to directly own and operate storage assets due to strict unbundling regulations[135], whereas in other countries such as Italy this is not the case. Direct ownership and operation of storage by a network, prioritised to help manage constraints, would potentially change the economics and point at which other reinforcement projects were considered.

The Integrated Transmission Planning and Regulation (ITPR) reforms lead by Ofgem propose that competitive tendering should be used for certain onshore transmission assets[136]. This opens up the potential for third parties to provide solutions to network constraints. However it should be noted that none of the ITPR consultation and decision documents explicitly mention storage assets.

It can be argued that distributed energy resources, who actively look to generate during the Triad periods, are providing a valuable "avoided reinforcement" service to the System Operator as this distributed generation (or reduced load) replaces an equivalent amount of transmission level "peak" generation which the transmission network does not to be sized for. Distribution generators are compensated for this service indirectly through suppliers in terms of the reduced TNUoS charge (Triad avoidance benefit).

Implication for storage: Current regulatory and commercial frameworks do not allow for either a) direct ownership of storage assets by the transmission network operator or b) direct compensation for new third-party owned storage assets for the avoided network reinforcement benefit they may provide to the system.

Distribution

Distribution network operators (DNOs) also face the issue of having to manage network constraints and/or support network security (e.g. statutory voltage limits).

Two demonstration projects, with funding provided by the Ofgem-administered Low Carbon Network Fund[137], have investigated the potential for storage usage by DNOs for constraint management purposes.

Orkney Energy Storage Park, SSE: The scope of this project, completed in 2012, was to design commercial incentives and associated contracts, which would encourage third party energy storage

[134] For more details see the Electricity Ten Year Statement and Network Options Assessment reports published by National Grid: http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-ten-year-statement/ ; http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Network-Options-Assessment/

[135] Which are designed to allow equal access to networks and restrict the types of assets that can be owned concurrently. Storage assets do not have a separate regulatory classification and as such are often classified as both generation and supply.

[136] https://www.ofgem.gov.uk/sites/default/files/docs/2015/03/itpr_final_conclusions_decision_statement_publication_final.pdf

[137] https://www.ofgem.gov.uk/electricity/distribution-networks/network-innovation/low-carbon-networks-fund

providers to locate a storage asset on a constrained network where it would provide beneficial services to the DNO[138].

Smarter Network Storage, UK Power Networks: Typically, distribution upgrades are driven by peak demand requirements even though the number of periods in the year where demand reaches peak levels may be relatively few. Energy storage assets can be used to “shave” this peak demand as seen by the distribution network and hence reduce the required network capacity and may defer large investments in infrastructure upgrades. The ability of battery storage to provide this peak shaving service has been demonstrated by the Smarter Network Storage 6MW/10MWh battery installed in Leighton Buzzard. A 2016 report on “Successful Demonstration of Storage Value Streams”[139] details the range of trials[140] undertaken by the storage asset, including successfully fulfilling the primary purpose of the installation which was to provide peak shaving for the DNO[141].

Implication for storage: Similar to the situation for transmission network, current regulatory and commercial frameworks do not allow for either a) direct ownership of storage assets by the distribution network operators or b) direct compensation for new third-party owned storage assets for the avoided network reinforcement benefit they may provide to the system. However, the Smarter Network Storage demonstration project currently being undertaken is providing evidence for the potential benefits of storage assets located on distribution networks, and going forward the necessary commercial arrangements may be put in place to allow this benefits to be recognised as a revenue stream for the storage operator.

2.7.2 Integration with renewable generation

Transmission and Distribution

There are two main ways in which integrated solutions of intermittent renewable plus storage capacity may provide a benefit to the system:

Generation smoothing: Integrating a storage asset with intermittent renewable generation can help to “smooth” fluctuation in output which aids in system stability. Battery solutions have been applied for wind smoothing in Hawaii and solar smoothing in New Mexico[142]. These batteries smooth the volatile ramp rates associated with wind and solar resources, and demonstrates a “dispatchable” renewable resource.

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138 https://www.ofgem.gov.uk/sites/default/files/docs/2013/09/sset1007_close_down_report_final.pdf

139 http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Smarter-Network-Storage-(SNS)/Project-Documents/SDRC+9.7+Successful+Demonstrations+of+Storage+Value+Streams+LoRes+v1.pdf

140 Including frequency response, STOR, reactive power support, Triad avoidance and energy arbitrage.

141 This peak shaving requirement was driven by the need to maintain adequate security of supply standards – such that a defined amount of demand could still be met if there was a circuit failure.

142 IRENA Battery Storage for Renewables, accompanying Case Studies: http://www.irena.org/menu/index.aspx?mnu=Subcat&PriMenuID=36&CatID=141&SubcatID=495

Implication for storage: Commercial arrangements will need to be developed and implemented to allow system stability benefits through renewables smoothing to be recognised as a revenue stream for the storage operator. The development and use of storage assets to compensate for variable renewable output may be an attractive proposition for owners of renewable assets looking to hedge against potentially large imbalance cost exposures.

Reduced curtailment: Curtailing the output of renewable generators can occur for system balancing reasons (i.e. due to the presence of transmission constraints) or for energy balancing reasons (i.e. the excess supply of intermittent generation in periods of low demand[143]). Curtailing renewable generation is costly (due to compensation payments made for lost subsidy revenue) but in addition it is also an inefficient use of installed renewable capacity. The cost of decarbonising the GB energy system will increase as available renewable electricity, which could have been used to meet renewable energy targets, is wasted. Utilising storage assets to store excess generation can therefore make more efficient use of existing renewable capacity and avoid the need to build further capacity to meet targets.

Implication for storage: Currently the direct costs of curtailment (e.g. BM constraint costs) are socialised across all market participant through the BSUoS charge (which is the charge National Grid applies to recover the balancing costs they incur in managing the system in real time). Furthermore, the owner of the renewable asset will be indifferent in revenue terms between generating and being curtailed. Therefore there is no way for the owner of a storage asset to monetise the benefit provided to the system of reducing renewable curtailment.

Demand (Behind the Meter) Located

The potential benefits of small scale household storage deployment are illustrated through the case study of battery installations in households that additionally have solar PV installed. DECC are currently supporting a demonstration project deploying small scale storage in around 300 homes[144].

Solar PV deployment by households has been supported by the Feed-in-Tariff (FiT) scheme. The basic design of this support scheme is a follows:

- **Generation tariff:** Households receive from their energy supplier a set rate for each kWh of electricity generated, as measured by an installed generation meter.
- **Export tariff:** Households receive from their energy supplier an additional rate for each kWh that is exported to the grid (i.e. the excess energy generated not required for consumption). Currently, there is no requirement to have an installed export meter. Therefore, the quantity of electricity exported to the grid is estimated to be equal to 50% of the electricity generated.

[143] Noting that some non-intermittent generation will always be required to provide adequate flexibility and Balancing Services
[144] https://www.gov.uk/government/news/5-million-boost-for-energy-storage-innovation

In addition to receiving the above generation and export tariffs, the household will realise savings on their electricity bills as the total amount of electricity bought from the energy supplier is lower.

Under current market arrangements, the benefit to households for installing battery storage[145] would be the ability to store any excess electricity produced. This stored electricity could then be released at times of high demand and further reduce the amount of electricity required to be bought from the energy supplier. Note that while no generation is physically being exported to the grid, the household will still receive the export tariff. In this case, the economics of the storage system will be assessed by comparing the cost of the battery storage device to the avoided energy supplier cost (e.g. retail electricity price multiplied by additional volume saved).

Going forward there are two market developments that will greatly impact the economics of installing battery storage in combination with solar PV for households:

- **Smart meter roll-out**: DECC has set a target date for installation of smart meters in the majority of households by 2020. Smart meters can be used to correctly measure the solar PV generated electricity that is exported back to the grid. This enhanced metering will therefore impact on the revenues received through the export tariff. The economics of installing a storage system will continue to depend on the prevailing retail electricity price and additional volume saved.
- **Time of Use tariffs**: The roll out of smart meters would enable the implementation of time of use tariffs, which have varying prices for energy depending on the time when the energy is used. Time of use tariffs can have differing levels of granularity and complexity – the simplest version would be an economy-7 style two tier tariff with offpeak (low demand) and peak (high demand) pricing. The economics of installing a storage system will now also depend on the differentials between offpeak and peak pricing[146]. Greater value could be gained by storing solar power generated during the day (when prices are lower) and using this power in the evenings (to avoid paying higher peak prices).

Implication for storage: The reduction in peak electricity demand from a household, due to storage usage, may provide a valuable service to the distribution network operator. If a significant number of households adopt storage technologies then the combined result will mimic “peak shaving” and potentially avoid or delay network reinforcement projects. However, under current market and regulatory arrangements it is not possible for this benefit to be directly monetised by households. Going forward, new business models may emerge with aggregators offering services back up the network to the DNO/TSO and sharing the resulting benefits with households.

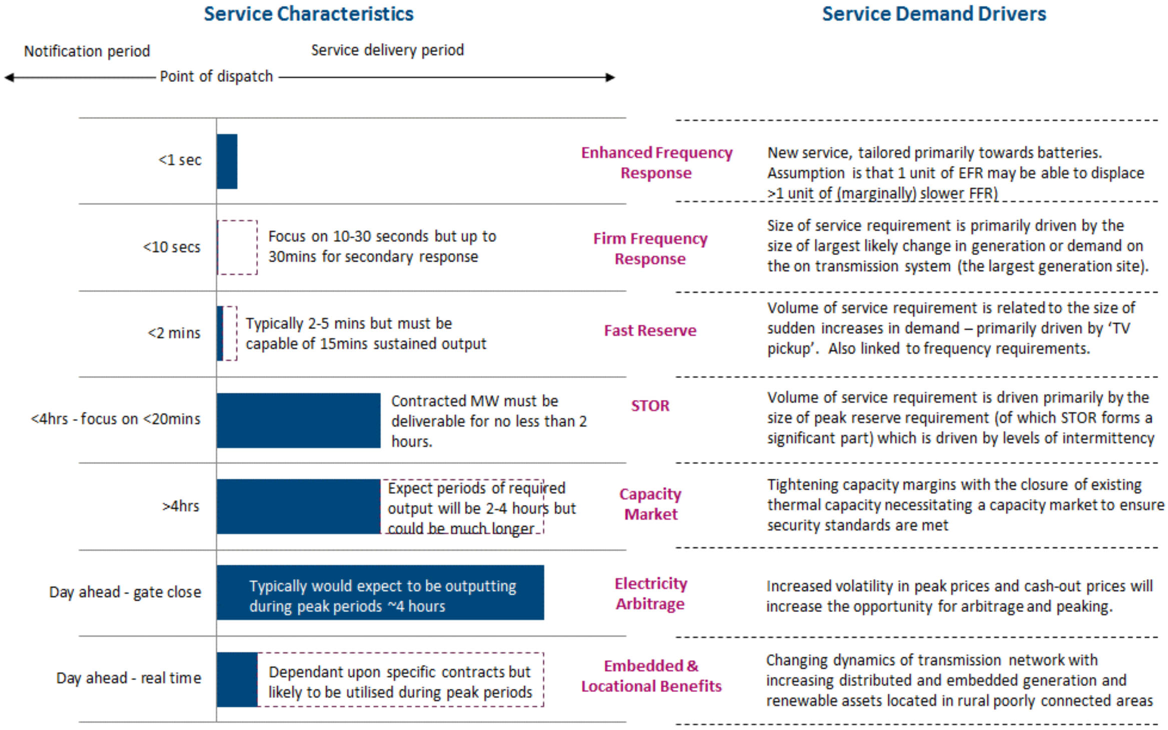
[145] Battery storage is assumed to be the appropriate technology for household scale installation due to size considerations.
[146] Essentially this would be energy arbitrage – as described in Section – on a retail scale.

2.8 Opportunities for near term storage deployment

2.8.1 Summary of available revenue streams

Storage assets have the option to contract across multiple revenue streams with different counterparties and different contracting arrangements. Determining an optimal operating regime will therefore require detailed market knowledge and forecasting capabilities. An overview of the available revenue streams, with the required service characteristics and service demand drivers, is shown in Figure 45.

Figure 45 Revenue Stream Overview



Not all revenue streams are compatible with each other, and there are a number of mutual exclusivities (i.e. services that cannot be provided simultaneously) that must be considered when the storage asset is deciding on an operating regime. Two key mutual exclusivity "rules" are:

- An asset cannot contract for multiple services with the same counter-party (i.e. different Balancing Services with National Grid).
- Balancing Services with availability payments preclude an asset from dispatching for any other services/revenues during their contracted periods.

Conversely, two key compatibilities between revenue streams are:

- An asset can contract for Capacity Payments as well as Balancing Services[147].

[147] Noting that capacity obligations are adjusted to account for Balancing Service provision. However assets would still face penalties if they did not delivery their adjusted obligation in the capacity market or if they did

- If dispatching for Balancing Services then a distribution connected asset can capture embedded benefits associated with avoided use of system charges (TNUoS, BSUoS, Red-Band DUoS) for that period, as well as receive payment (as set out in the agreed PPA terms) for the energy generated.

A summary of the commercial and operational considerations associated with the various available revenue streams, and discussion of the compatibilities between them, is shown in Figure 46.

Figure 46 Summary of key revenue streams for storage operators

Revenue Stream	Market access	Operating regime and technical limitations	Relation to other revenue streams
Capacity Market (CM)	The CM Delivery Body (National Grid) is the counterparty for capacity market payments. Revenue received for any energy generated will depend on whether the storage was scheduled to run (wholesale market revenues) or not (BM imbalance revenues).	No specific requirements or restrictions on technology type or operating regime, provided that the storage can export power when called upon during system stress periods.	Compatible with all other services.
Wholesale Energy Arbitrage Revenues	Direct participation in the Day-Ahead or Intra-Day power exchanges is possible for large scale storage assets. Smaller storage assets will likely access these prices through a Power Purchase Agreement (PPA) agreed with an energy supplier.	Price arbitrage would typically involve daily cycling with overnight charging/injection for subsequent generation in evening peak periods. High efficiency for the storage asset is key to capturing full price spread. Repeat cycling may accelerate the degradation of certain storage types (e.g. batteries).	Compatible with CM requirements and the capturing of Triad avoidance benefits (for distribution connected assets). In general, storage assets operating in energy arbitrage mode will not be able to provide Balancing Services, and may not be able to simultaneously fulfil locational constraint management contracts. Assets will face imbalance charges (directly or indirectly through the agreed PPA terms) if energy is not delivered as agreed.

not fulfil their Balancing Service obligations. In addition, plant with long-term STOR contracts are not eligible to participate in the capacity market.

Revenue Stream	Market access	Operating regime and technical limitations	Relation to other revenue streams
Balancing Mechanism (BM)	The System Operator will be the counterparty for revenues resulting from bids and offers made directly in the BM. Similarly larger generators that have not pre-contracted power ahead of time will receive the system sell price if dispatched (for balancing services or otherwise). Smaller storage assets will likely access system sells prices through an agreed PPA with an energy supplier unless a BEGA contract has been entered into to allow direct participation in the BM.	No specific requirements or restrictions on technology type or operating regimes.	Bid and offer revenue is compatible with storage assets operating in energy arbitrage mode. System sell price revenue is compatible with storage assets operating to provide Balancing Services. All balancing mechanism revenue is consistent with CM revenues.
Firm Frequency Response (FFR)	Contracted directly with National Grid through competitive tenders, payments will be as agreed per the accepted tender terms.	For dynamic FFR, the operating regime will be determined by system frequency and will involve continuous small adjustments to the state of charge of the storage. For static FFR, the operating regime will likely involve lower utilisation with discreet periods of charging and discharging required once a trigger frequency threshold is passed.	FFR provision is compatible with receiving CM revenues. Providers cannot contract with National Grid to deliver more than one Balancing Service in the same period. In general FFR provision will not be compatible with energy arbitrage revenues.
Fast Reserve (FR)	Contracted directly with National Grid through competitive tenders or through agreed bi-lateral contracts.	High de-minimis capacity threshold (50MW) and high ramp rate (25MW/min) restrict the number of applicable storage technology types.	FR provision is compatible with receiving CM revenues. Providers cannot contract with National Grid to deliver more than one Balancing Service in the same period.

Revenue Stream	Market access	Operating regime and technical limitations	Relation to other revenue streams
			FR provision will not be compatible with energy arbitrage revenues.
STOR	Contracted directly with National Grid through competitive tenders, payments will be as agreed per the accepted tender terms.	While available for STOR, assets will not be operating but must be sufficiently charged/injected so that they can generate within the agreed time frame and for the agreed duration. Operating regimes of contracted STOR assets will be determined by National Grid. The operating hours of individual asset are variable and driven by the relative levels of agreed utilisation fees.	Assets cannot provide other Balancing Services, or generate in the energy market, in periods for which they are receiving availability payments for STOR. When STOR assets are called on to generate by National Grid they will receive the prevailing SSP in the BM (either directly or through an agreed PPA). STOR provision is compatible with receiving CM revenues, with the exception of assets with long term (up to 15 year) STOR contracts.
Embedded Benefits	Applicable only for assets that are non-BM parties connected to the distribution network. Benefits will be realised through a PPA with an energy supplier or bilaterally with a large energy consumer.	Certain embedded benefit revenue streams are highly dependent on the location and voltage connection level of the asset. As Triad periods are unknown in advance, the optimal operating regime for Triad avoidance will involve continual generation through winter peak periods.	Compatible with wholesale energy market arbitrage revenues and capacity market revenues. Assets operating in winter peak periods for Triad avoidance will not practically be able to simultaneously provide Balancing Services during the same period. However the asset would be able to contract for Balancing Services in other months of the year.
Locational Benefits	Currently locational benefits are only realisable through bespoke TSO / DNO constraint management contract.	Depending on the nature of the constraint being managed, the regime may require peak shaving from the storage asset or more flexible operation to respond to intermittency / other system fluctuations.	Agreed contract would likely prioritise the constraint management above all other actions, and may further restrict the simultaneous provision of Balancing Services.

Access to multiple revenue streams has both advantages and disadvantages; while it increases the complexity of the storage business model there is value in diversification and the resultant business model will have resilience and redundancies across the various revenue streams.

It is acknowledged that "benefit stacking" is a key requirement to making future storage investment economic. A number of papers discuss this issue further[148]. *However, in the near term it is expected that the primary and secondary reserve markets (e.g. including EFR and FFR) are likely to be the key source of revenue for driving tangible deployment.* As described above, it is only possible to contract for delivery of one balancing service in the same period with National Grid and this is not be compatible with wider energy arbitrage revenues.

Although these reserve markets are technically compatible with receiving CM revenues, the potential penalties for non-delivery, an indeterminate delivery window and low CM clearing prices seen to-date) mean that it is highly unlikely that batteries will be supported via this route in the near-term.

The potential for storage, focusing on the primary and secondary reserve markets, is modelled in more detail in section 2.10.

2.9 Summary of barriers to near term storage deployment

There are a number of barrier that may impede the future role-out of electricity storage capacity in GB, a number of which have been discussed in previous section. These can be broadly categorised and summarised as follows:

- Technical
- Commercial
- Regulatory

Technical

As shown in Figure 3, the combined worldwide installed capacity of a number of electricity storage technologies is currently < 1 GW. While battery capacity is expected to grow strongly over the next few years based on announced projects, the relatively low number of current installations suggests that the technology has not yet reached full learning maturity. There are a number of areas where further deployment would provide beneficial information:

- Understanding the difference in performance (e.g. efficiency, charge/discharge times) between operating under laboratory testing conditions and the operating regimes required to capture market revenues or for the provision of Balancing Services.
- Understanding the ability to provide multiple services simultaneously (e.g. providing voltage control services concurrently with a peak shaving service) and the impact of switching between operating regimes.

[148] IEA: Technology Roadmap Energy Storage, 2014; Rocky Mountain Institute: The Economics of Battery Storage, 2015; Carbon Trust & Imperial College London: Can storage help reduce the costs of a future UK electricity system, 2016.

- Understanding the potential degradation of the asset throughout its lifetime operation, and in particular understanding the relationship between number of cycles / frequency of cycling and performance (e.g. energy capacity and efficiency).

Commercial

As discussed throughout this report, storage assets can access a number of different revenues streams. This provides a welcome diversity benefit and may increase the resilience of the asset to future market and regulatory changes. However accessing multiple revenue streams increases the complexity associated with constructing a viable business case and operating the asset. Accessing these multiple revenue streams can involve contracting directly with a number of different parties or alternatively through negotiated agreements made with an energy supplier or an aggregator. Going forward, new commercial arrangements[149] and business models may emerge to allow storage assets to monetise the full range of benefits they provide to energy system.

There are a number of alternative technologies that can compete for the various revenue streams available to storage assets including traditional large thermal generators, smaller distributed thermal generators (including gas and diesel engines) and interconnectors. These competitor technologies may have advantages over storage assets in terms of economics (i.e. capital costs), accepted business/operating models, proven development and deployment record and established routes for financing. In addition the current regulatory framework may favour traditional generation technologies over newer storage technologies.

Regulatory

Current regulations were developed when the GB electricity system consisted of mainly larger transmission connected generators. The only storage assets in operation at this time were large scale pumped storage plant. There is no distinct classification of storage in the current set of electricity regulations. Storage is therefore often treated as both a form of generation and a form of demand. This can lead to some charges being effectively double counted:

- Storage assets can potentially face network charges both when exporting energy (as a generator) and when using energy (as a consumer).
- Additionally there can also be double charging associated with government levies[150] which are placed on the electricity used to charge the storage and again on end-consumers when the same units of electricity are withdrawn from storage.

There remain key regulatory barriers to the deployment and utilisation of storage for network constraint management and investment deferral. The "Smart Power" report published by the National Infrastructure Commission in 2016[151] recommends that *"network owners should be incentivised by Ofgem to use storage (and other sources of flexibility) to improve the capacity and resilience of their networks as part of a more actively managed systems"*. Currently network operators are not allowed to directly own and operate storage assets due to strict unbundling

[149] For example, these arrangements may include development of a framework agreement with the System Operator that allows an asset to contract for a number of Balancing Service simultaneously. The System Operator would then optimise which service is provided by which asset at any given time.
[150] For example renewable levies to recover the costs of the CfD, RO and FiT support schemes.
[151] https://www.gov.uk/government/publications/smart-power-a-national-infrastructure-commission-report

regulations[152],[153]. Therefore, third parties separate from the network operator would own and operate the storage asset. Regulatory and commercial arrangements would then need to be put in place to allow appropriate remuneration to be passed to the third party operator from the network operator in recognition of the beneficial services provided. Joint working groups (including Ofgem, DECC, DNOs and Energy Networks Association) are actively exploring these issues.

Fostering increased TSO-DNO collaboration within future regulatory frameworks could facilitate the introduction of new services that have been designed with the aim of achieving the most benefit to the whole of the network and allowing participation from all assets (transmission or distribution connected) who are able to provide the service. As above, joint working groups are exploring how additional flexibility (be it from storage, DSR, etc) provided at the distribution level or behind the meter (i.e. at building level) can be coordinated to provide different DNO/TSO services. This ranges from a simple market structure whereby DNOs have priority to use this flexibility as they see fit, to a fully integrated market where the value of flexibility across the system is identified and provided where it is most cost-effective. The latter is appears unlikely to materialise in the next 5-10 years.

Storage assets, along with other market participants, face the possibility that Government and/or Ofgem may choose to reform policy and/or regulatory arrangements in future if they are found to no longer be fit for purpose nor delivering their intended aims. The Balancing Mechanism is in the midst of ongoing reforms that will be completed by 2018. Looking forward, the Capacity Market rules and regulations may face amendments as a result of the recent consultation issued by DECC and there is an open Ofgem investigation regarding network charging arrangements that may have an impact on future Triad avoidance benefits.

2.10 Modelling of near-term electricity storage potential

This section will focus on quantifying the near-term potential for electricity storage technologies to be deployed in the GB market under current arrangements.

- First, an assessment is given of the role that electricity storage technologies[154] could play in the markets for primary and secondary reserve as these are considered to be the most promising markets to support near-term storage deployment given their high value and ability to lock in multi-year contracts. This route is being pursued more actively by developers in the near term whereas a wholesale plus BM arbitrage route along with CM (if exposure to potential CM penalties for non-delivery is deemed acceptable) and embedded benefits where possible, is deemed a much riskier route and unlikely to be viable until the early 2020s. High-level Baringa estimates are that wholesale arbitrage might provide revenues equivalent to ~10-50% of the long-run costs for new battery entrants built in the nearer-term, embedded benefits ~10-25% and the CM ~10-30%.

[152] Which are designed to allow equal access to networks and restrict the types of assets that can be owned concurrently.
[153] Some exceptions such as UKPN's Leighton Buzzard battery have been allowed as part of innovation-related trials funded under the Low Carbon Network Fund
[154] The focus is currently on new grid-scale batteries, but the findings would apply to the extent that alternative technologies can meet the technical requirements of the specific balancing services and compete at the price points shown for accepted bids in the analysis.

- Three scenarios of evolution of these balancing services markets over the next ten years were modelled in order to estimate a range of possible outcomes from low to high potential.

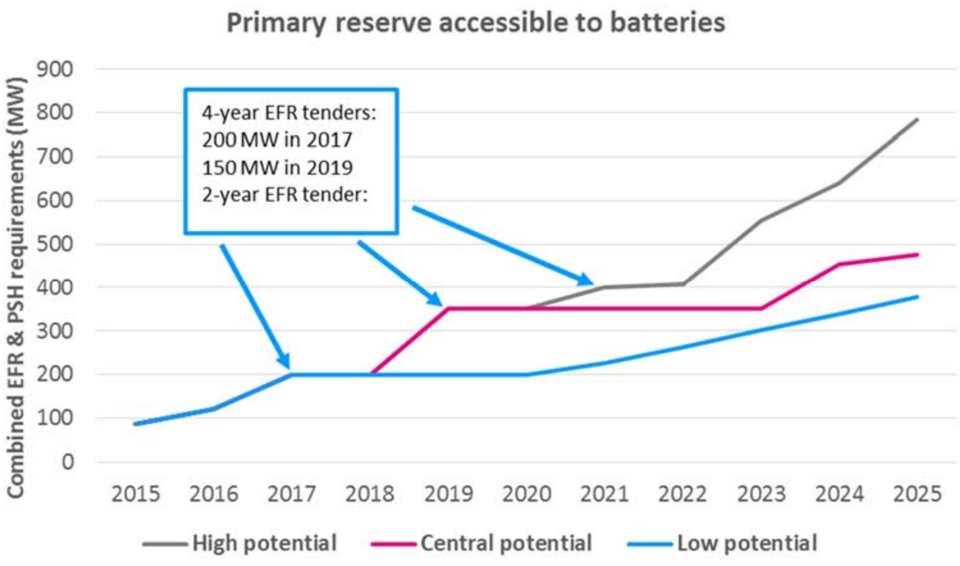
- Then, we will estimate the possible benefits of a domestic electricity storage device to take advantage of Time of Use (ToU) price signals and solar PV output.

2.10.1 Scenarios of reserve requirements

National Grid published scenarios for the evolution of minimum primary response requirements in line with their Future Energy Scenarios (FES). They were used as the basis for a High, Central and Low cases for battery deployment.

All scenarios also assume a progressive reduction of reserve volumes from mandatory frequency response in favour of a market-based system. Figure 47 below shows the volume of reserve jointly required for tendered EFR and FFR PSH products across our three scenarios. A particular focus is given to these two products as batteries can only bid for PSH in our model. The three rounds of EFR tenders for batteries have been pointed out for clarity in the high scenario. In the central and low it is assumed that National Grid only pursue two and on tender rounds, respectively.

Figure 47 Total EFR + PSH accessible to batteries

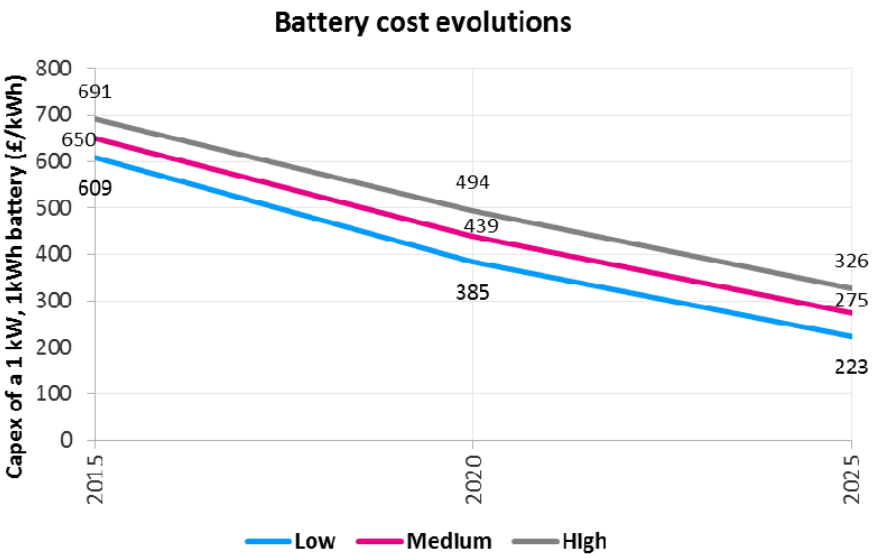


Source: Baringa estimates from National Grid FES scenario data[155] corresponding to Gone Green, Consumer Power and Slow Progression scenarios respectively.

The three scenarios of battery costs (for Li-ion grid scale batteries) chosen for this analysis are plotted in Figure 48 below. This combines Baringa's central 2015 estimate and forward projections (for a 1 kW by 1 kWh configuration including balance of plant costs), based on discussions with a range of current developers and wider literature (based on mean of available values), with the uncertainty range in the ESME v4.1 database to 2025.

[155] System Operability Framework 2015 can be found here: http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/

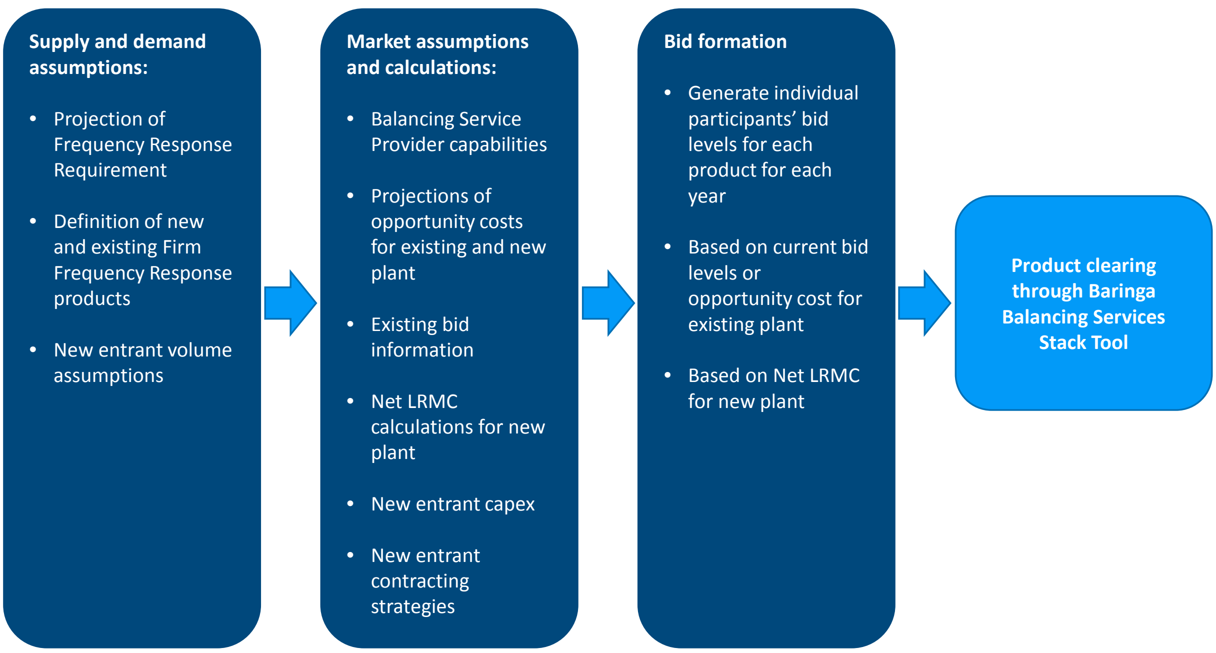
Figure 48 Reference scenario of battery capex evolution (cell and Balance of Plant costs)



2.10.2 Reserve auctioning methodology

The analysis of battery potential within the balancing services markets uses Baringa's Balancing Services Stack tool. Our methodology is focused on projecting **availability fees** for different balancing services (the working assumption is that **utilisation fees** are priced to keep plant whole, unless these are codified, mainly for BM plant in Response markets). An overview of the tool is shown in Figure 49.

Figure 49 Overview of Baringa Balancing Services Stack tool



Once reserve requirements across the considered products are determined, the model will run auctions for each of the products in order of value to the system (and speed of required frequency response) as follows:

1. Enhanced Frequency Response (EFR) Primary Secondary High (PSH): this is first modelled as tender rounds specifically designed for batteries (i.e. no other technology can participate) and from 2021 onwards is merged with the FFR PSH product.
2. Firm Frequency Response (FFR) Primary Secondary High (PSH): batteries, Dynamic Demand Side Response (DSR) and large conventional power plant (CCGT, coal) can bid into these auctions.
3. FFR Primary Secondary (PS) reserve: this product is auctioned to Dinorwig exclusively for continuity with current market practice[156].
4. FFR Secondary (S) reserve: this product suits the fast-ramping capabilities of diesel engines although DSR will also bid for it.

Table 4 below recaps the capabilities associated with each technology bidding into these reserve auctions. Batteries and dynamic DSR are allowed to bid in two different reserve markets. In this case all the available capacity will bid in the most valuable market (e.g. EFR PSH for batteries) and the unsuccessful bids would then bid again in the less valuable market (e.g. FFR PSH for batteries).

Table 4 Mapping of technologies to reserve products they are capable of bidding for

Technologies	EFR PSH	FFR PSH	FFR PS	FFR S
Batteries	Yes	Yes		
DSR dynamic		Yes		Yes
DSR static				Yes
CCGT		Yes		
Coal		Yes		
Diesel engines				Yes
Dinorwig			Yes	

Bids are constructed so that technologies would recover their annualized Long Run Marginal Cost (LRMC). The model considers the opportunity cost of revenues that existing plant could make outside of balancing services, as part of determining whether or not they would bid. For new plant bidding into EFR/ FFR PSH markets, of most relevance for batteries, it is assumed that bidding for these balancing services precludes wholesale market or other revenues as the plant must be available for the majority of the year.

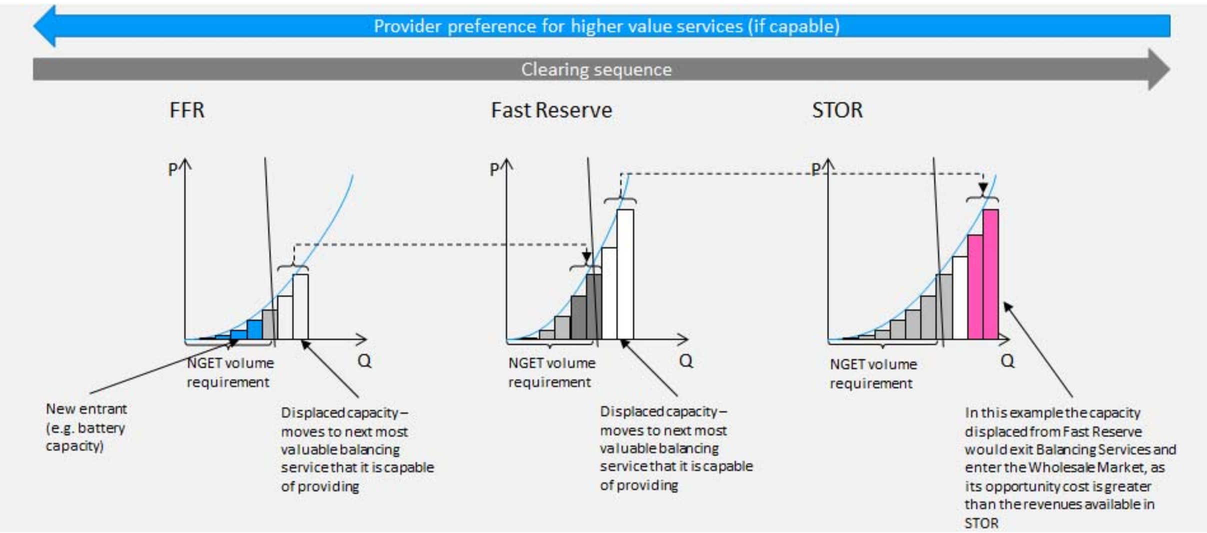
For batteries we have also assumed:

- A weighted average cost of capital (WACC) of 15%
- An economic and technical life of 10 years

An illustration of the balancing services stack tool logic is provided in Figure 50.

[156] We will discuss the implications of making this market competitive in our discussion of results.

Figure 50 Illustration of balancing services stack tool logic



It is important to note that:

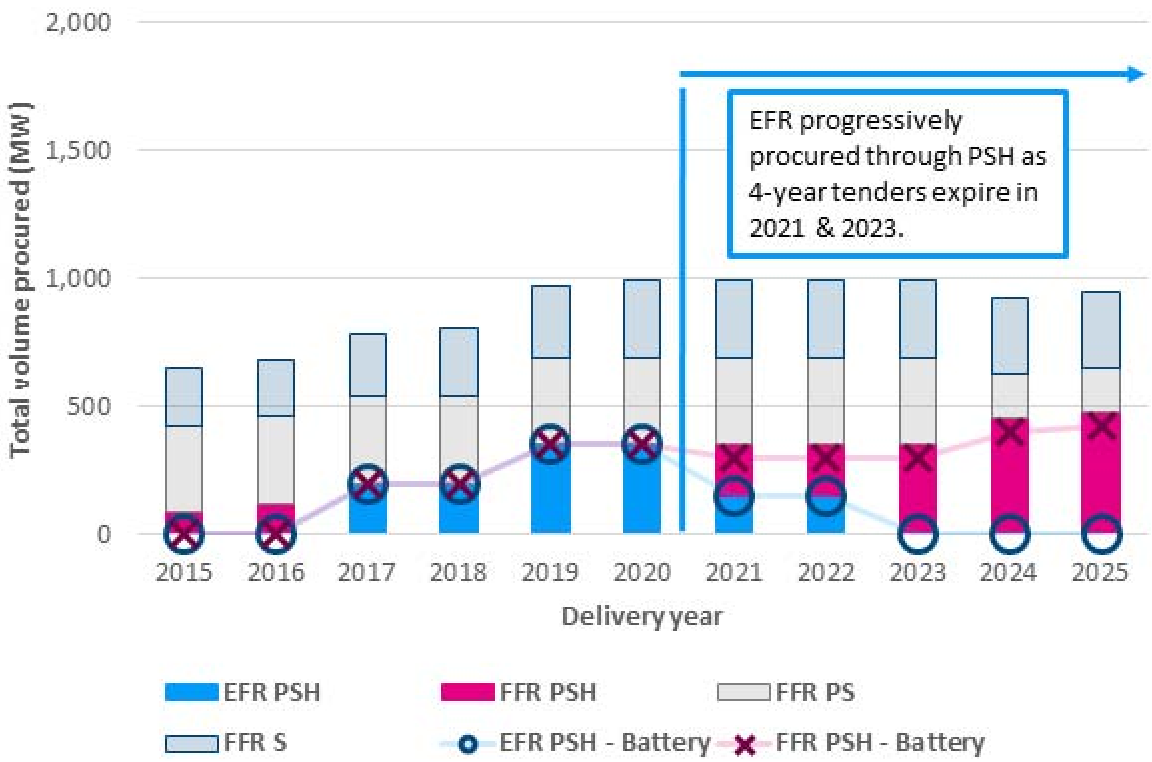
- All of the balancing services markets are pay-as-bid, so the tool provides the marginal price for a given volume that all plant in-merit could bid up against (all else being equal)
- Batteries that are selected in the EFR 4-year tender rounds are assumed to continue bidding their LRMC in the FFR PSH market after their contracts expire. In reality, they may discount their bids to be sure to receive some revenue from the reserve market instead of being displaced by newer and cheaper capacity.
- PS is assumed to be a non-competitive market as Dinorwig is the only technology allowed to participate despite the fact that batteries and DSR would have the technical capabilities to displace Dinorwig. However:
  - The volume of the PS market is reduced from 340 MW in 2015 to 170 MW by 2025 in the Low and Central potential scenarios, and
  - Dinorwig's bidding behaviour may well change to a price taker approach so as to keep receiving revenues from providing reserve.

2.10.3 Near term grid-scale storage potential for electricity reserve

Central battery potential scenario

Figure 51 presents the results from running the auctions in the Central battery potential scenario. The shaded areas represent auctions in which batteries are selected. On top of the capacity required for the EFR tenders in 2017 & 2019, 300 MW of batteries are installed from 2023 to 2025. These batteries have lower costs than the ones used to respond to the 2017 200 MW EFR tender, so that they can place lower bids for the FFR PSH product. This results in 150 MW 2017-vintage batteries being stranded in 2025.

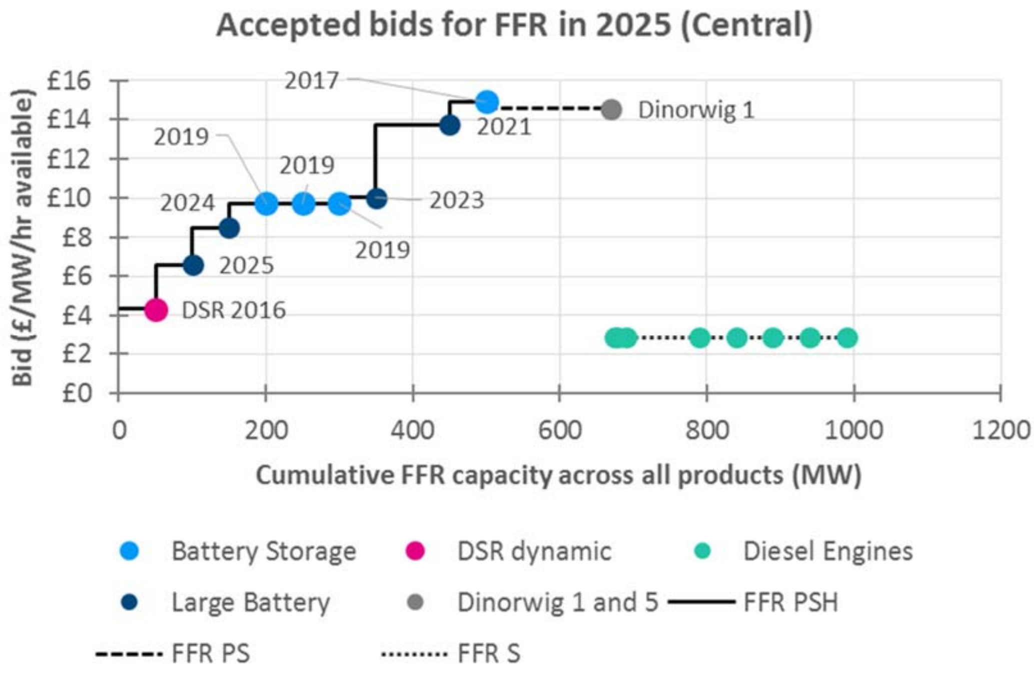
Figure 51 Reserve requirements and accepted battery storage response (Central)



Note: Markers represent battery volume *within* each market segment.

Figure 52 shows the merit order across the Firm Frequency Response products in the Central scenario in 2025. Batteries are labelled by vintage to visualize the evolution of bids as capex reduces. 2017-vintage batteries (responding to the first EFR tender) make the marginal bid for PSH, slightly higher than the one of Dinorwig for PS. In this case, we could envision some additional strategic bidding between the 150 MW of 2017-vintage batteries that were not successful in the PSH auction and the 170 MW of Dinorwig 1 that is allocated the PS reserve in our model to compete for the PS product. For the separate secondary FFR product diesel engines clearly undercut battery technologies even for the lowest cost vintages.

Figure 52 Merit order for EFR & FFR products in 2025 (Central)



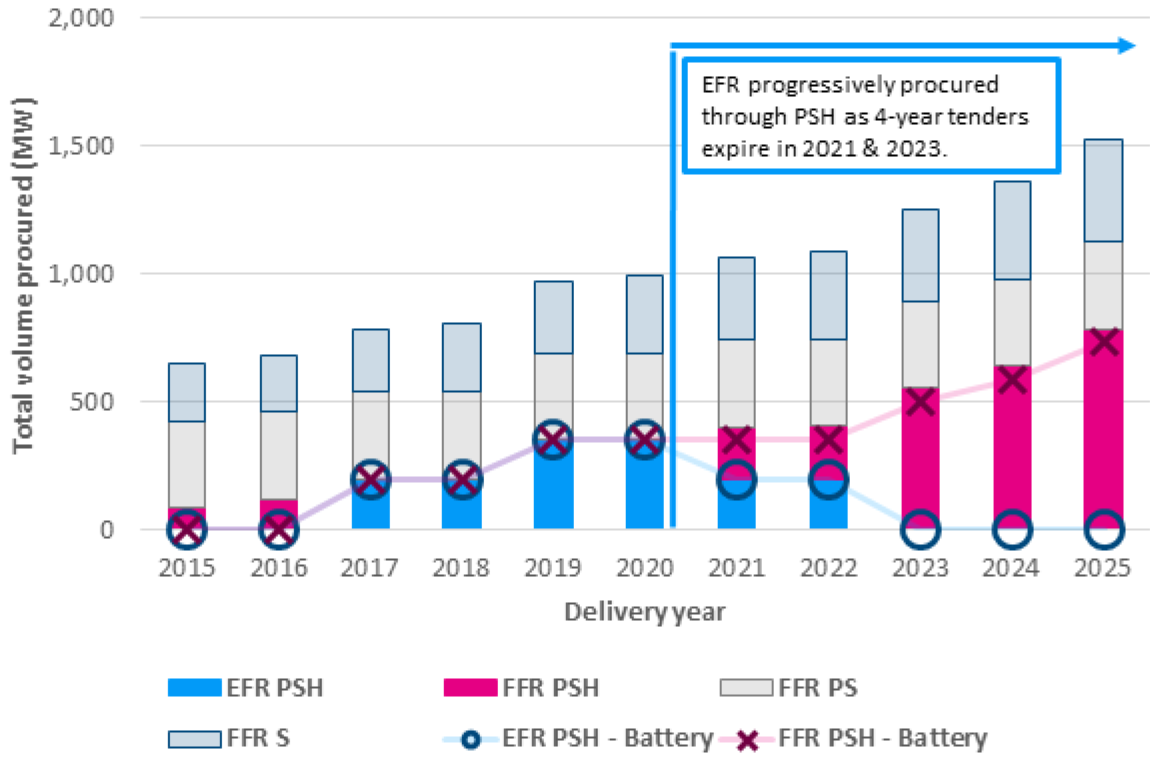
Note: Solid and (different) dashed lines reflect separate FFR products

High battery potential scenario

Figure 53 presents the results from running the auction model in the High battery potential scenario. EFR and FFR PSH products are shown as shaded where batteries place successful bids. On top of the 400 MW required for the EFR tenders in 2017, 2019 and 2021, 550 MW of batteries are installed from 2023 to 2025. Since these later batteries can outbid the earlier ones, all of the 200 MW that responded to the 2017 EFR tender end up being stranded in 2025 in our model.

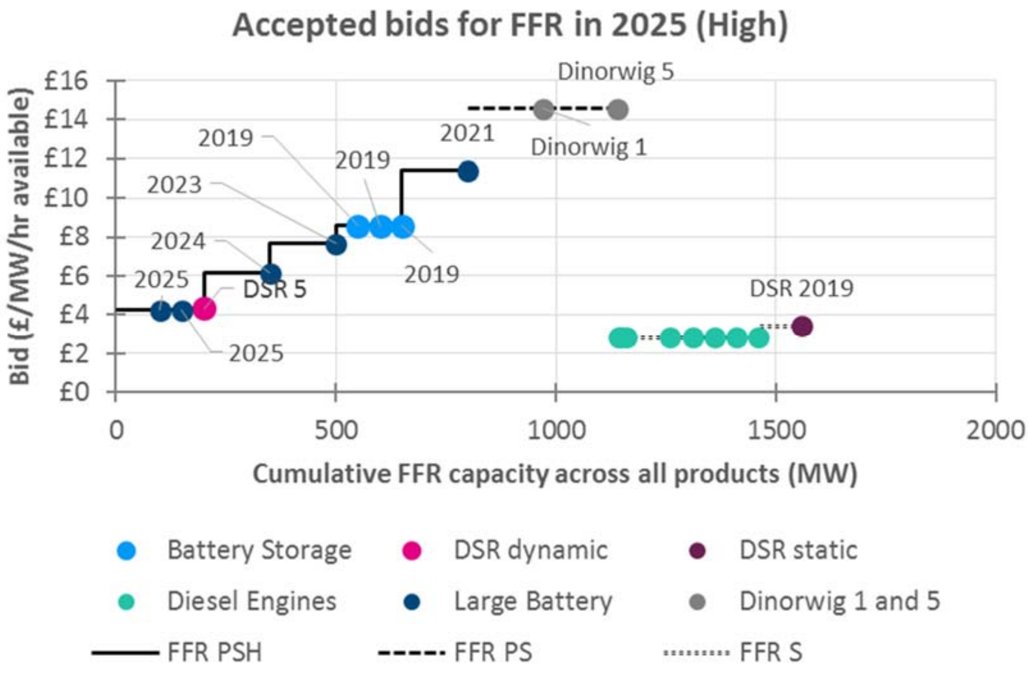
Figure 54 shows the merit order across the FFR products in the High scenario in 2025. Batteries are labelled by vintage to visualize the evolution of bids as capex reduces. In this case 2021-vintage batteries (responding to the third EFR tender as well as merchant ones) make the marginal bid for PSH, ~£1.4/MWh cheaper than the ones of Dinorwig for PS. This scenario requires 340 MW of PS reserve so the stranded 200 MW of 2017-vintage batteries could potentially outbid both Dinorwig units on cost alone if the PS reserve market is open for competition. Similarly, we could consider even more deployment of 2025-vintage batteries to meet the additional 140 MW PS requirement and completely displace Dinorwig (assuming Dinorwig does not bid as price taker to preserve its market share). For the separate secondary FFR product diesel engines still undercut battery technologies even under the more optimistic scenario of future battery cost reductions.

Figure 53 Reserve requirements and accepted battery storage response (High)



Note: Markers represent battery volume *within* each market segment.

Figure 54   Merit order for EFR & FFR products in 2025 (High)



Note: Solid and (different) dashed lines reflect separate FFR products

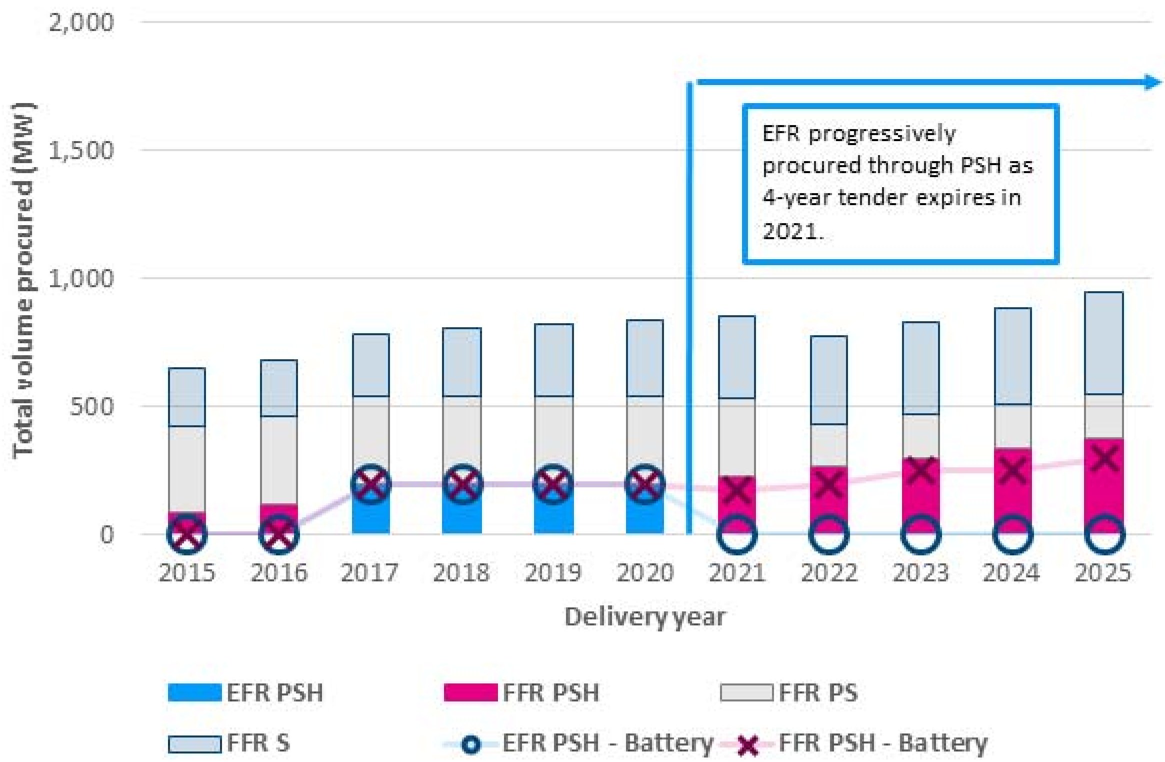
Low battery potential scenario

Figure 55 presents the results from running the reserve auctions in the Low battery potential scenario. As previously, successful battery bids for EFR & FFR PSH products are shown as shaded areas. On top of the capacity required for the 2017 EFR tender, 100 MW of batteries are installed from 2023 to 2025. In this scenario, all of the installed battery capacity is able to place successful bids in the PSH market by the end of the modelling horizon.

Figure 56 shows the merit order across the Firm Frequency Response products in the Low scenario in 2025. As before, batteries are labelled by vintage to visualize the evolution of bids as capex reduces. Here, the marginal bid for PSH is made by a CCGT (Damcreek) at a level much higher than previous bids from batteries and DSR.

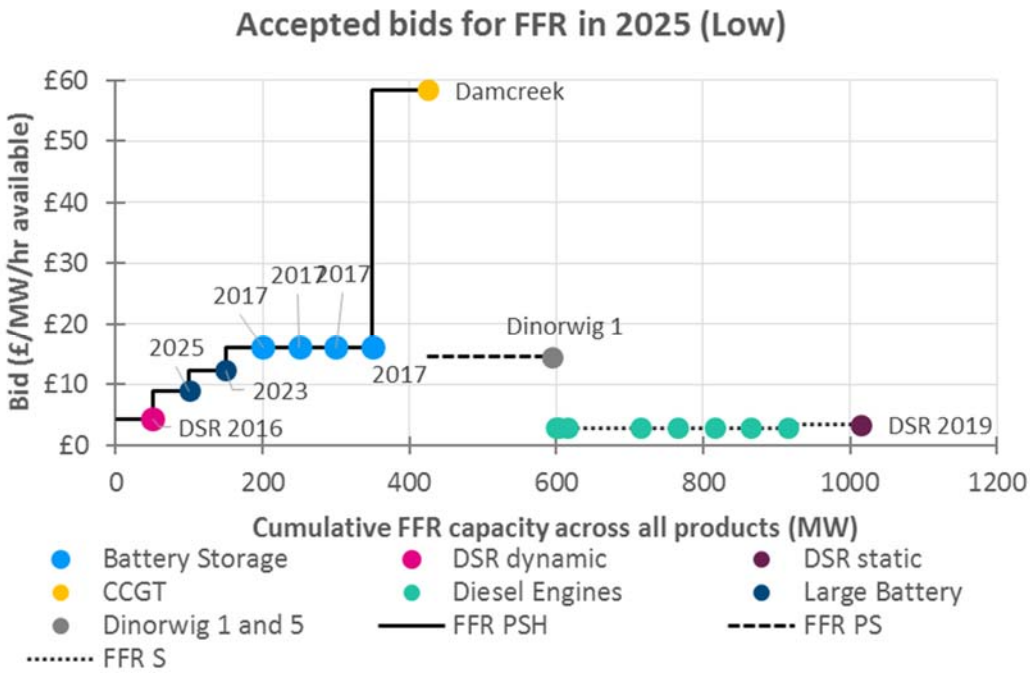
As in the other two scenarios, the PS product could be considered competitive, such that 2025-vintage batteries could displace both Damcreek and Dinorwig (~200 MW overall) because their costs (~£9/MWh) are much lower than Dinorwig's (~£14.5/MWh). In this scenario, 2017-vintage batteries are bidding ~£1.5/MWh higher than Dinorwig, so they could potentially be displaced if roll-out of later vintages increases.

Figure 55 Reserve requirements and accepted battery storage response (Low)



Note: Markers represent battery volume *within* each market segment.

Figure 56 Merit order for EFR & FFR products in 2025 (Low)

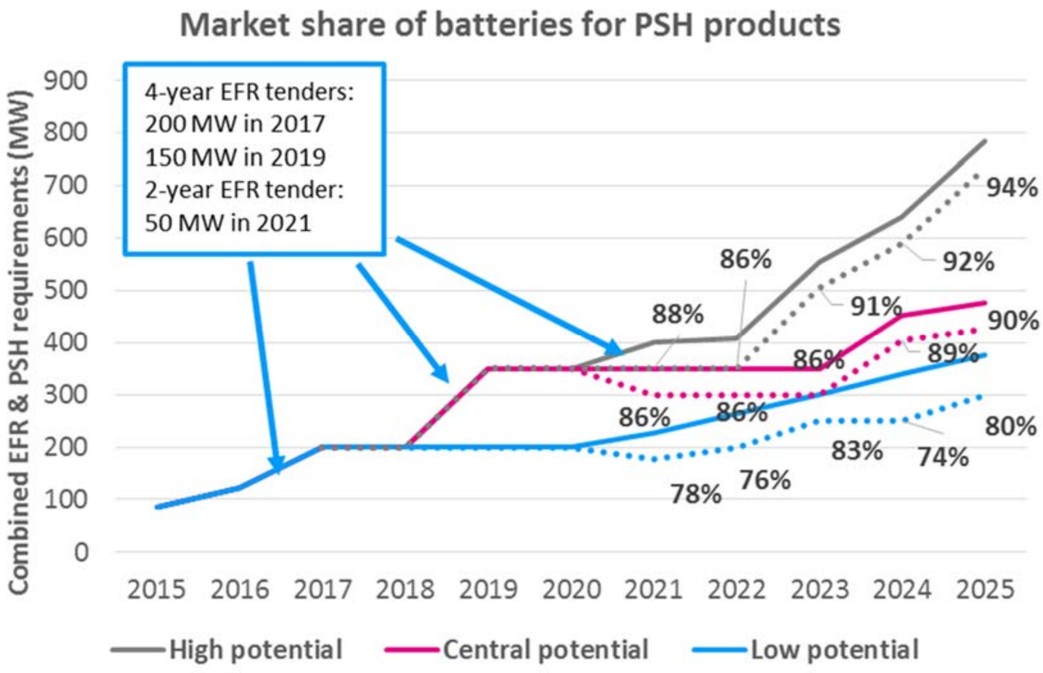


Note: Solid and (different) dashed lines reflect separate FFR products

Summary of market share for batteries in PSH auctions

As a summary of the battery potential in reserve markets, Figure 57 shows the market share of batteries in the PSH reserve auctions from 2021 to 2025 across all three scenarios considered. . Batteries are very competitive in all our scenarios (combining low/central/high battery cost projections with low/central/high estimates of market size), which results in them having a very large share of the PSH products; 100% until 2020 due primarily to the EFR requirement and around ~80% to 94% to 2025 (with DSR providing some competition). We should also note however that the auction model used had fixed deployment assumptions of 50 MW of dynamic DSR, which consistently outbids most batteries. Therefore, increasing the roll-out of dynamic DSR would directly cut into batteries' market share of PSH auctions.

Figure 57 Market share of batteries in the PSH auctions



There is a good investment case, albeit for a relatively modest volume, for batteries in the near-term driven primarily by the high-value frequency service markets with fast response requirements. However, there are a number of risks. These include the expected rapid decline in battery costs which means that there exists the potential for batteries deployed in early auctions (which have limited 4-year contracts) to become outcompeted in future auctions, as they are effectively undercut by newer, considerably cheaper batteries. The investor would then need to look to other revenue streams to recover their remaining investment over the full life of the plant, but these are also subject to various risks:

- Other balancing services, although these generally have lower clearing prices
- Wider electricity market revenues (e.g. wholesale market and BM), although these are not guaranteed and cannot be accessed simultaneously with balancing services contracts for the same period
- Embedded benefits, although these may be reformed in future reducing their value

Given the wide range in potential near term revenue from non-balancing services mentioned in section 2.10 and the challenges in capturing and stacking these multiple revenue streams it is clear why most developers (at least in the near term) are pursuing the higher value and more certain Balancing Services based route to market, focused around frequency response, even if these excludes the potential for other revenue streams and has limited overall market size.

If regulatory barriers to network ownership of storage were removed at distribution level, this is unlikely to materially affect the near term strategy of pursuing the more lucrative frequency response markets. This is because these markets require high plant availability across the year and although benefits at distribution level are indirectly accessible at the moment via embedded benefits (i.e. the avoidance of specific distribution charges), they cannot be accessed in parallel with balancing services in the same period.

At transmission level it is less clear what the impact of TNO ownership may be, but the value to the TSO would primarily be to operate the storage through the BM if it is not being used for the direct provision of pre-contracted balancing services. However, this by itself is unlikely to justify the case for new batteries in the near term given the wide of competing options available through BM and batteries would need to look for further wholesale arbitrage opportunities. As noted previously this route (wholesale and BM arbitrage plus CM plus embedded benefits) is deemed riskier in the near term compared to locking in higher value (albeit for smaller volumes of batteries) through key balancing services.

2.10.4 Illustrative economics of home-scale battery storage

In this subsection, we outline a simplified assessment of the potential value of electricity storage for domestic consumers. We will focus on an example consumer (in the North West as some charges vary by region) and estimate the possible break-even costs of electricity storage across a range of scenarios:

- Pass through of wholesale market price shape (i.e. so that the battery can be used to minimise costs) versus an assumption that with smart meters and half hourly settlement there could be full pass through of diurnally shaped tariffs (wholesale market price, Capacity Mechanism, Transmission Network Use of System charge, Distribution Use of System charge, Distribution Line Loss Factor),
- Use of a heat storage (in conjunction with electricity storage) or not
- The presence of solar panels or not.

Methodology and assumptions

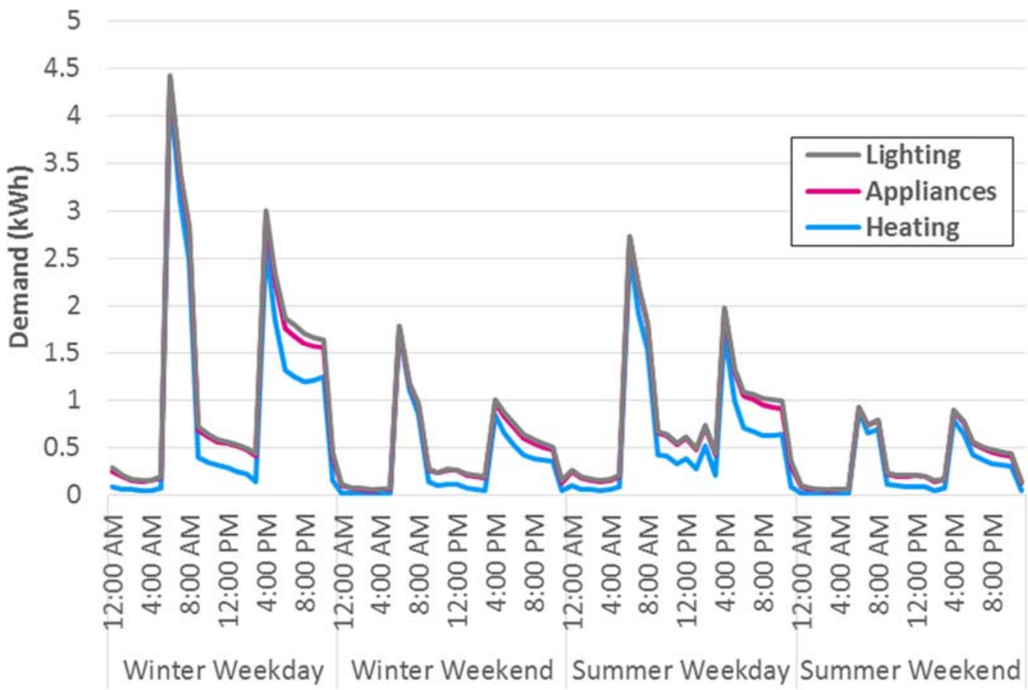
Example consumer considered

For this illustrative analysis we have assumed a domestic consumer in a 130m^2 terraced house[157] in under the coverage of Electricity North West (ENW). We further assume this consumer has electric-based heating (so that electricity storage can be used to shift heat demand) and to have 10m^2 of roof space available for solar PV installation. Finally, the consumer would have a smart meter which would enable half-hourly metering and dynamic time of use tariffs i.e. the costs from the electricity system could be passed through to the consumer as they occur.

Figure 58 shows the electricity demand broken down by use for this example consumer across four characteristic days[158] in the year. The same level of demand applies for both 2020 and 2025.

[157] The heating characteristics of the building would imply cavity wall insulation and double-glazed windows as well as some loft insulation.
[158] The four characteristic days are chosen to be able to represent the various charging patterns applying to electricity. Winter refers to November through February included.

Figure 58 Electricity demand at consumer level across uses



Wholesale and retail power prices

The retail price applying to our example consumer is formed of several components based on Baringa's in-house analysis:

- The **wholesale price** which represents the cost of the running marginal generation unit including a margin (or discount) for strategic bidding. Transmission losses (1.8%) are included in the cost of wholesale electricity for a domestic consumer.
- The **Capacity Market** (CM) auctions costs are recouped through a fee on demand during periods of high demand[159]
- The **Transmission Network Use of System** (TNUoS) charge is applied on winter weekdays, from 4PM to 7PM as this is the most likely time the Triad periods (upon which the charges are levied) would occur.
- At the distribution level, ENW levy two charges on domestic consumers:
  - **Distribution Use of System** charge (DUoS): three rates (Red, Amber or Green) apply, depending on the time of day and characteristic day, and
  - Distribution **Line Loss Factor** (LLF), which represents distribution losses and vary based on the time of day and characteristic day. These distribution losses would be used to scale the wholesale power price and TNUoS rate.
- Other price components would be levied on domestic consumers, however, these are not currently differentiated by time of day, so that they would not drive the operation and

[159] CM tariff is charged between 4PM & 7PM on winter weekdays.

benefits from domestic electricity storage devices. They are excluded from analysis for simplicity:

- To recoup the cost of supporting renewables deployment under the **Renewable Obligation** (RO) or **Contract for Difference** (CfD) schemes,
- To support various transmission network functions e.g. **Residual Cash-flow Reallocation Cash-flow** (RCRC), **Balancing Service Use of System** charge (BSUoS)
- To reduce distribution costs in Northern Scotland: **Assistance for Areas with High Electricity Distribution Costs** (AAHEDC)

Figure 59 and Figure 60 below represent the average daily profile of the GB wholesale power market price across the four characteristic days considered in 2020 and 2025 respectively.

Figure 59   GB wholesale market power price (2020)

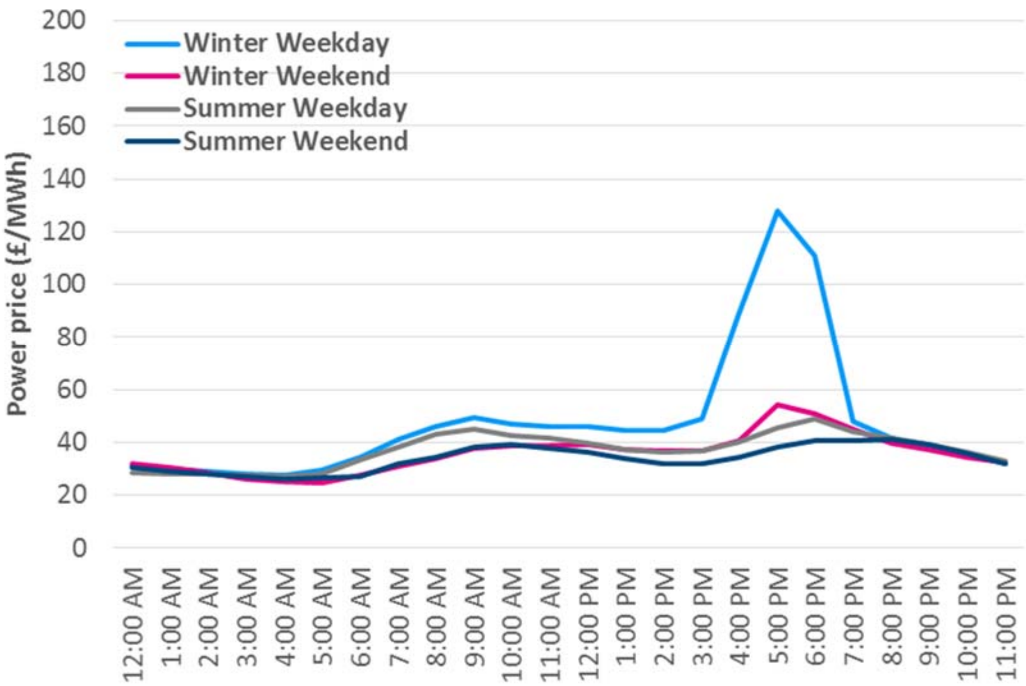


Figure 60   GB wholesale market power price (2025)

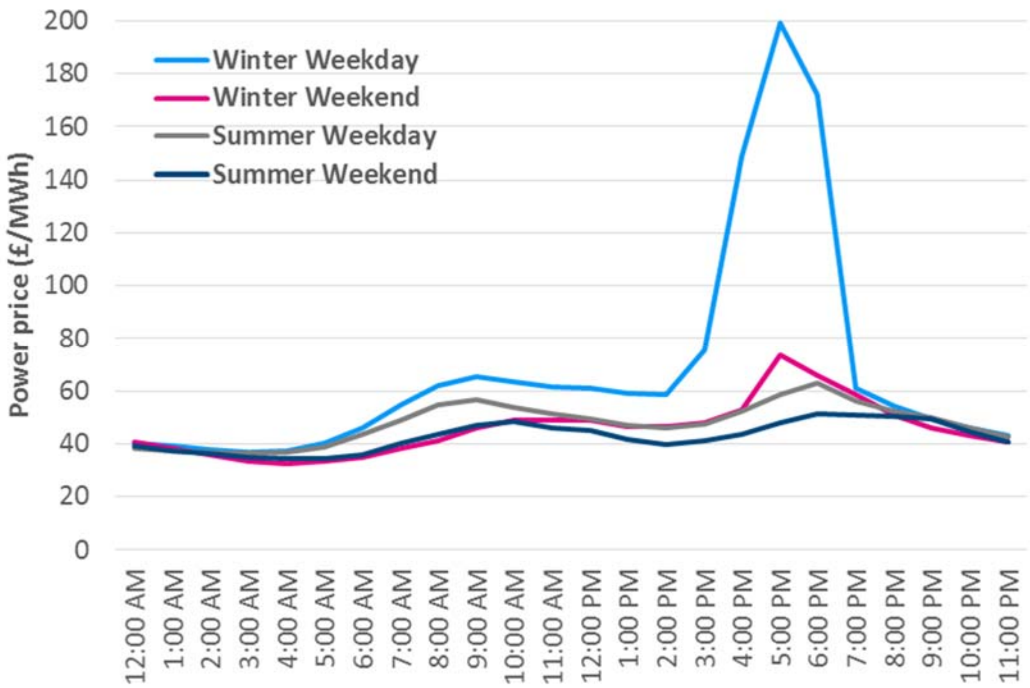


Figure 61 and Figure 62 below show the adjusted retail price i.e. after application of the considered surcharges for the four characteristic days in 2020 and 2025, respectively. The winter weekday prices during the 4PM-7PM time period are much higher due to the concentration of surcharges (DUoS, TNUoS, CM and LLF).

This would raise questions about the political acceptability of such a charging regime. We consider this full cost pass-through scenario only insofar as an optimistic case for domestic batteries deployment. Ofgem is currently reviewing the charging structure of 'embedded benefits' (as noted in section 2.6.2), which may alter the future savings that can be made by avoiding highly concentrated charges.

Figure 61 Retail electricity price in Greater Manchester (2020)

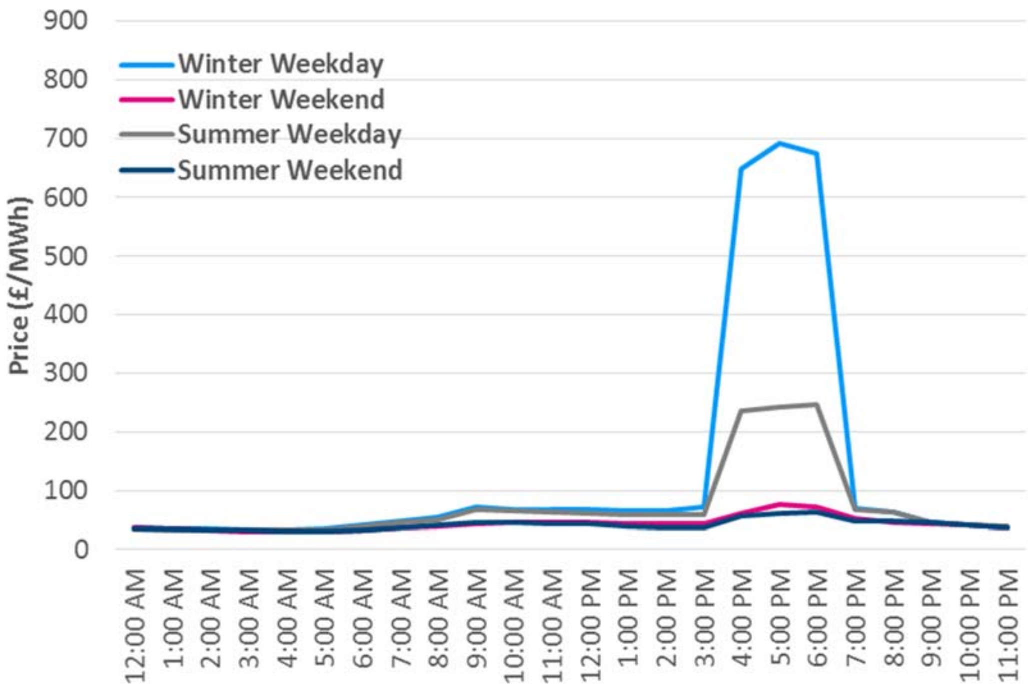
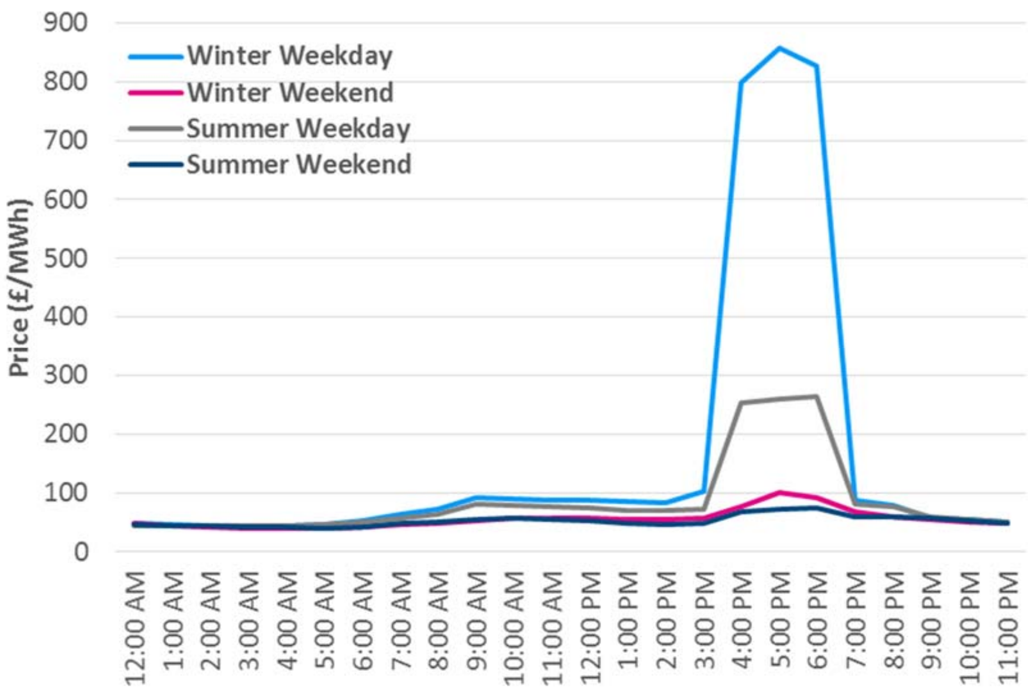


Figure 62 Retail electricity price in Greater Manchester (2025)



Domestic battery characteristics

We consider a small and a medium domestic battery modelled after the lithium-ion PowerVault[160] model. Their main technical characteristics are summarized in Table 5 below.

Table 5 Characteristics of domestic batteries considered (cell plus Balance of Plant)

Characteristic	Small battery	Medium battery
Usable storage volume	2 kWh	4 kWh
Peak power	1.6 kW	1.6 kW
Round-trip efficiency	92.5%	92.5%
Technical lifetime	15 years	15 years
Discount factor	8%	8%
Total installation costs in 2015/16[161]	~£2,000	~£2,800

Results

Simulated load shifting

Figure 63 and Figure 64 show simulated load shifting away from evening peak prices (4PM to 7PM) by charging a small or medium battery from 3AM to 6AM (when power prices are lowest) in the example terraced house. In both cases, the batteries are cycled daily to provide part of the evening peak electricity demand for heating, lighting and appliances i.e. we assume there is no heat storage. Figure 64 also shows the case when solar panels are generating electricity for auto-consumption or storage[162].

[160] Full technical documentation for the PowerVault batteries is available here: http://www.powervault.co.uk/wp-content/uploads/2016/05/Powervault_Technical-Specification_20May-2016.pdf
[161] Assumes announced costs decline in line with trend in Figure 48
[162] We assume buy-back subsidies for electricity export to the distribution grid would be low in 2020 or 2025 so as to incentivize auto-consumption or storage of locally generated electricity (current export tariffs for solar PV are around the level of off-peak prices so there is only an incentive to export if there is surplus generation across the entire day).

Figure 63 Simulated load shifting (no heat storage)

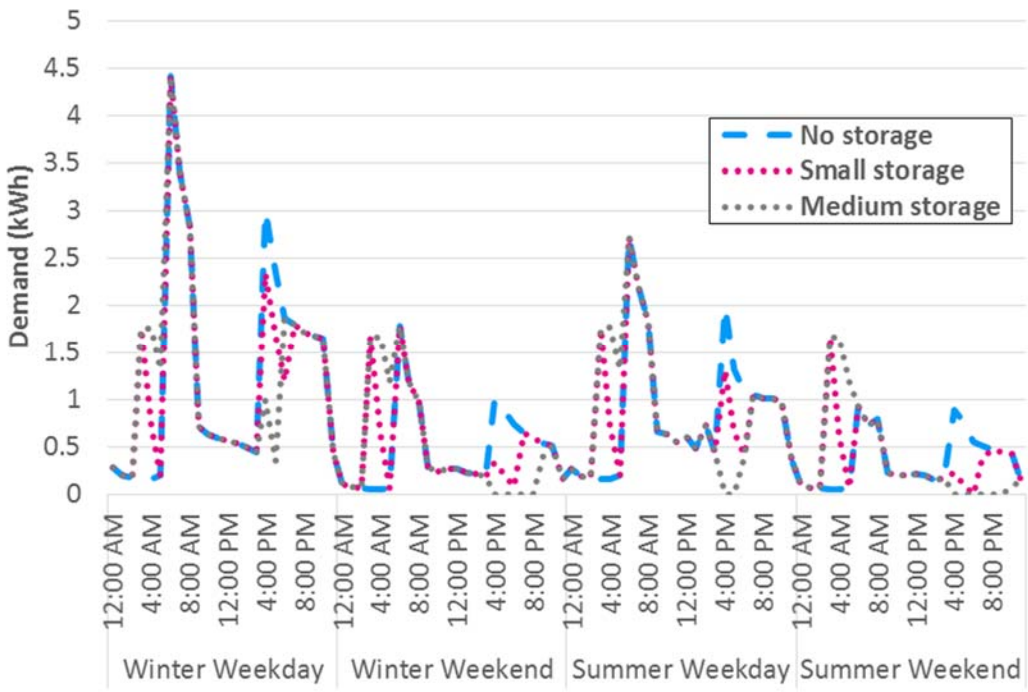


Figure 64 Simulated load shifting with solar PV (no heat storage)

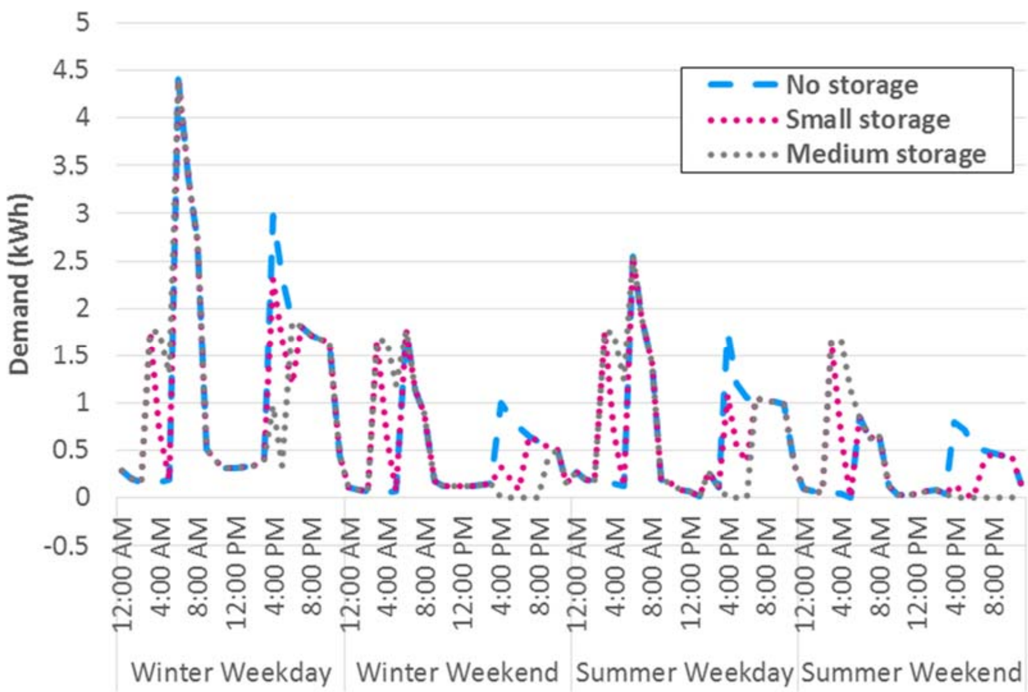


Figure 65 and Figure 66 present a simulated load shifting in the presence of heat storage i.e. the battery is only discharged to provide electricity demand for lighting and appliances. We would consider this to be the most likely case as the costs of heat storage are much lower than for batteries.

In this case, the electricity demand (and potential for load shifting) is much smaller so a small battery would be large enough to offset all the evening peak demand across all four characteristic days. As previously, Figure 66 plots the demand pattern shift with local solar PV generation. We note that in this last scenario, the summer daily demand can be provided almost in full by solar energy and a half battery charge (or less) overnight.

Figure 65 Simulated load shifting (with heat storage)

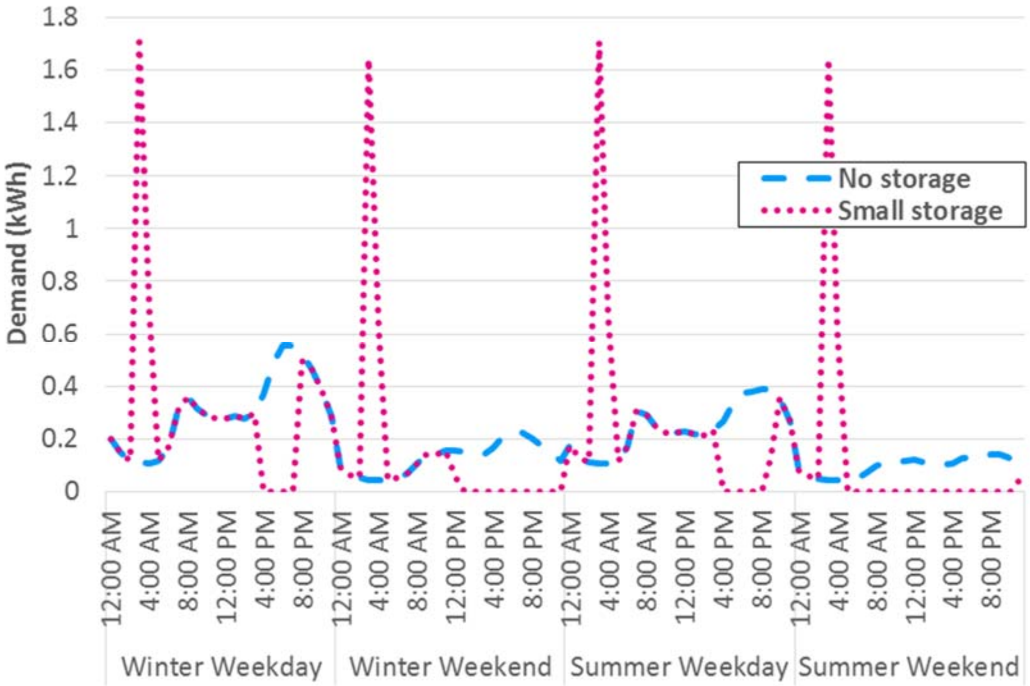
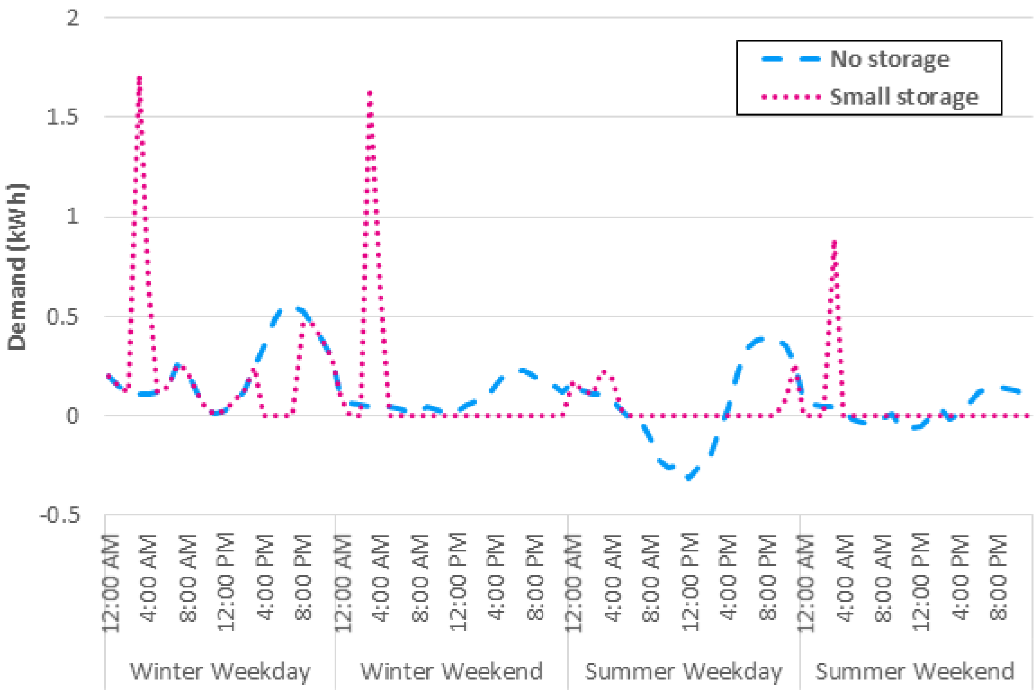


Figure 66   Simulated load shifting with solar PV (with heat storage)



Break-even costs of domestic electricity storage

As future cost estimates for domestic battery technology (including installation) are currently unclear[163], we have estimated the total ownership break-even cost for domestic batteries in all scenarios studied here which gives an illustration of how low costs have to become so that domestic electricity storage would represent a financially attractive investment for the selected customer type.

Figure 67 plots the break-even costs of domestic batteries where no heat storage is present. The tall blue and pink bars show the break-even costs when all costs are passed through, while the short grey and dark blue bars represent break-even costs when only the wholesale price is passed through to the consumers. We can observe that the impact of the 'full price pass through' (i.e. passing through shaped wholesale and retail tariffs elements, predominantly around the winter evening peak) provides a much higher degree of possible cost saving and hence lower breakeven point for the electricity storage unit (~£1,000 in 2020 and ~£1,100 in 2025) as compared with only passing the wholesale prices (~£130 in 2020 and ~£210 in 2025). An estimate of domestic battery costs is plotted in red, amber & green dots to compare with the break-even costs. This shows domestic batteries are very far 'out of the money' in both scenarios in 2020 and would make small savings in the optimistic pass-through case in 2025. Break-even costs vary very little with the addition of solar PV since price signals are rather flat in summer periods in both scenarios of prices, when the solar PV is providing the most output.

[163] Current costs are reported around £2,500 but future costs by 2020 could be as low as £1,000: see http://www.telegraph.co.uk/finance/personalfinance/energy-bills/11567977/Can-a-2500-solar-box-power-your-house-at-night.html

Figure 67 Break-even costs of domestic batteries (no heat storage)

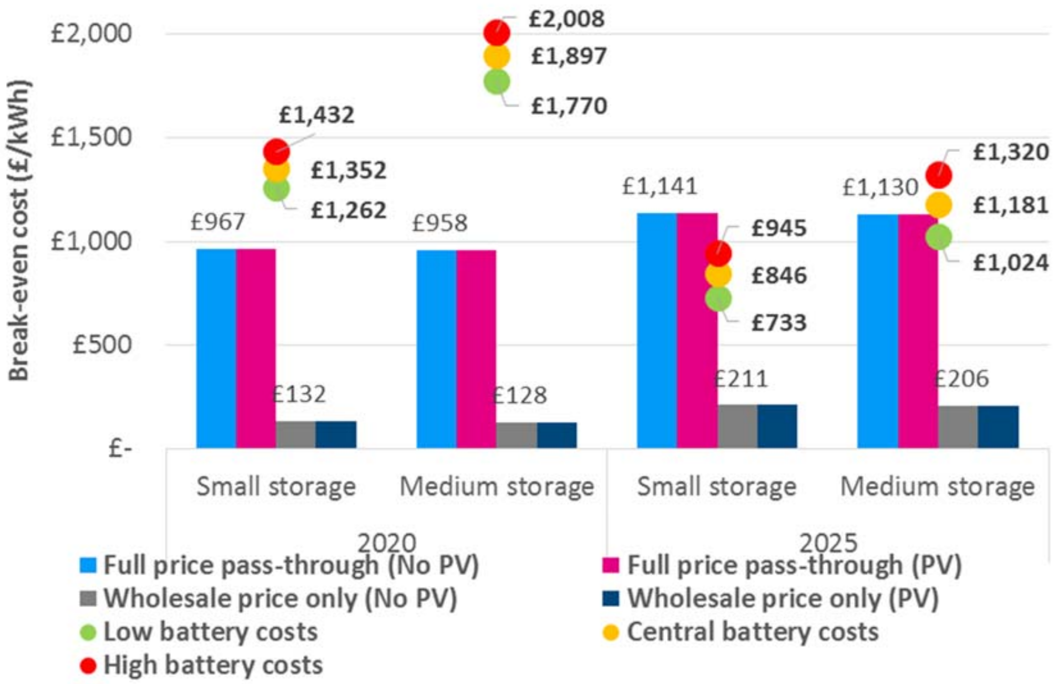
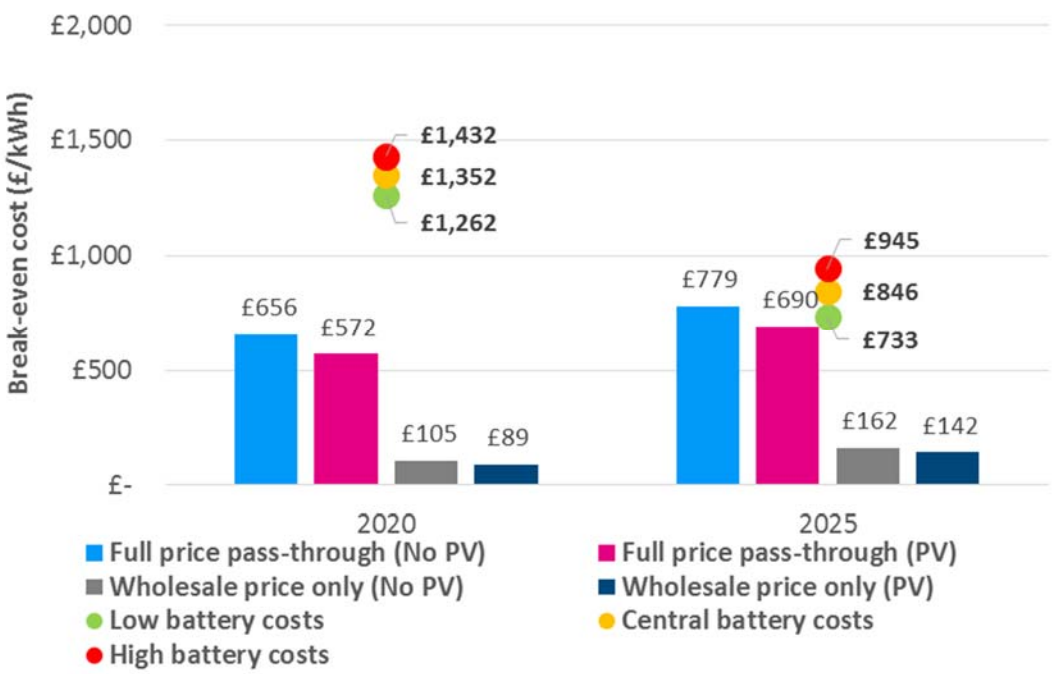


Figure 68 plots break-even costs of domestic batteries when the consumer uses heat storage (the most likely case). Financial benefits from batteries are significantly reduced in this case as the potential for load shifting decreases: break-even costs are ~£600 in 2020 and ~£700 in 2025 in the full price pass through scenarios, which is out of the money in both years. When only wholesale prices are passed through to domestic consumers, break-even costs reduce even further to ~£100 in 2020 to ~£150 in 2025.

Break-even costs with solar PV are markedly lower than in the scenario without heat storage as solar generation cuts into the load shifting potential of the battery e.g. only a half-charge (or less) is required to cover the full daily load on summer weekends.

Figure 68 Break-even costs of domestic batteries (with heat storage)



3 Heat Storage

3.1 Storage technologies

Heat storage technologies are classified into three main types:

- **Sensible Heat Storage (SHS)** – heating or cooling a liquid or solid storage medium (water, sand, molten salts)
- **Latent Heat Storage (LHS)** – using Phase Change Materials (PCM) moving from e.g. a solid to liquid state as a mechanism to store more energy in the same volume compared to sensible heat storage
- **Thermochemical Energy Storage (TES)** – using chemical reactions to store and release thermal energy

At a high level SHS systems are the most developed, with lowest costs and storage energy densities. TES are at the higher end of the spectrum, being the least developed and still primarily at the R&D stage but with the potential for the significantly higher energy densities. LHS falls in between SHS and TES systems in terms of level of development, cost and energy density. Commercial LHS systems are already available for building cooling, but further research is required for higher temperature systems. In particular, there are still challenges involved in commercialising PCM systems operating in the temperature range suitable for heat pumps (35-55°C)[164], which provide significantly greater energy density than water, that are scalable to meet several hours of space heat load and with sufficient discharge rate[165].

Table 6 Examples of storage technologies

Storage Type	Energy density (kWh/t)	Efficiency[166] (%)	Cost (€/kWh)	Examples
Sensible Heat Storage	10-50	50-90	0.1-10	– H20
Latent Heat Storage[167]	50-150	75-90	10-50	– Na-acetate Trihydrate – Paraffin – Erytritol
Thermochemical Energy Storage	120-250	75-100	8-100	– Microporous materials (Aluminophosphate) – Composite materials (Porous salt hydrates)

Source: IRENA-ETSAP (2013) Thermal Energy Storage Brief, UKERC (2014) Future role of thermal energy storage in the UK

[164] PCM systems are most effective where the wider operating system temperature is close to the phase transition temperature

[165] UKERC (2014) Future role of thermal energy storage in the UK

[166] Over "standard cycle" as SHS and LHS are time-dependent due to heat losses in containing vessel.

[167] Further examples of commercial products are provided here http://www.pcmproducts.net/Phase-Change-Material-Solutions.htm

A wider range of technologies exist under each of these categories, but for the purposes of characterising near-term storage potential it is important to distinguish between storage as a standalone technology, which can help to provide dispatch optionality to the wider system and is the focus of this analysis, versus storage which is just one part of a wider technology and it not considered explicitly here. Examples of the latter include:

- Small-scale solar thermal, seasonal heat storage and Concentrating Solar Power (CSP) where storage is integral to what is effectively a solar energy supply source for heat or electricity
- Industrial heat storage where the process itself (e.g. liquid bitumen in tanks) provides a heat store which can provide some flexibility as Demand Side Response (DSR), but which would not be developed as a standalone heat technology in its own right

As a result we have focused on:

- Building heat storage (domestic and non-domestic)
- Large thermal/buffer stores

3.2 Overview of market structure

In comparison to electricity, a market for heat related services that storage could provide (competing against other technologies) does not exist at present. The underlying drivers for heat storage in the near term are more direct and can be categorised as follows:

- ***Is a technical enabler of a supporting technology*** – e.g. building heat storage coupled to ASHPs to avoid excessive wear and tear on the pump/compressor due to continual short cycling, or, for district heat networks thermal stores to cover unplanned production outages or reduce bottlenecks within the heat distribution network.
- ***Helps to minimise operating costs*** – e.g. building heat energy storage arbitrage minimising electricity costs under ToU tariffs, or, for district heat networks using thermal stores for more efficient peak sizing and use of heat production units.
- ***Helps to maximise electricity-related revenue streams*** – e.g. for a district heat network using thermal storage to help decouple operation of a CHP plant from the heat load to maximise electricity revenues, or for electrified heat loads (building and industry) to provide Demand Side Response (DSR) services to National Grid and/or DNO.

As a result the drivers for further expansion of heat storage as a technology in the near-term are primarily indirect, in particular for:

- ***Building heat storage (domestic and non-domestic)***
  - The uptake of low carbon heating such as electric-heat pump based heating or biomass boilers[168]
  - Uptake of ToU based tariffs for domestic consumers (many non-domestic consumers are already half-hourly metered)

[168] Some modern pellet boilers can be plumbed directly into underfloor heating or radiators, but log and chip boilers require buffer tanks. However, as the use of a buffer tank can help to more cost-effectively size the boiler it is assumed that biomass, along with heat pumps and solar thermal technologies, will be used in conjunction with a hot water storage tank as far as is possible.

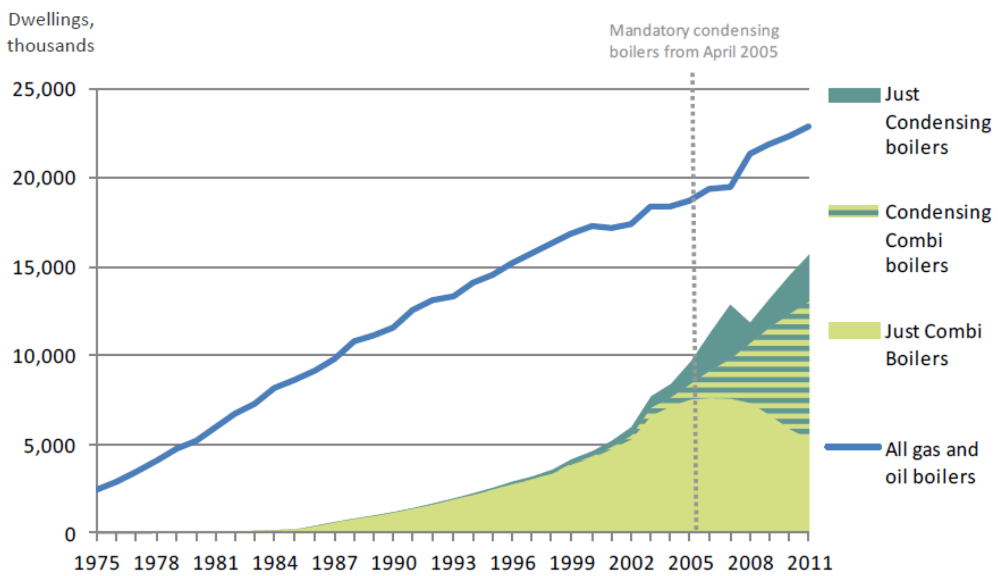
- The extension of DSR aggregation services to cover small-scale domestic and non-domestic electricity load (including electrified-heat, electric vehicles and other load such as appliances)

- ***Large thermal/buffer stores***
  - Penetration of district heat networks
  - Size of the thermal store will be driven by the detailed economics of each scheme including e.g. choice of heat source (e.g. CHP, large scale heat pumps, etc) as the underlying diversity of load[169]

Over the longer term significant advances in TES based systems may facilitate development of wider market structures where storage and transport of heat competes more directly with localised heat production for heat networks (or avoids the need for expensive transmission networks) or industry. For example, a demonstration project in Germany used TES-based truck transportation of waste heat (~3 MWh) from an incineration plant and transported this over 7km for use in an industrial drying process[170]. However, these are not assumed to have material penetration in the near term.

The potential for dedicated near-term storage building heat and buffer store technologies due to the indirect drivers is discussed further in the following section. At present, it is estimated that around two-thirds of domestic dwellings have combi-gas boilers, which do not require separate hot water storage tanks and this has increased strongly in the last 10-15 years (see Figure 69). As a result the number of households with dedicated hot water storage has been declining as people remove these to free up space.

Figure 69 Estimate of combi-boilers in UK domestic dwellings[171]



169 The latest 2015 CIBSE guidance for district heat networks references optimising the use of thermal storage as a key objective http://www.cibse.org/knowledge/cibse-other-publications/cp1-heat-networks-code-of-practice-for-the-uk

170 IEA-ETSAP and IRENA (2013) Thermal Energy Storage – Technology Brief

171 DECC domestic energy fact file 2013 https://www.gov.uk/government/collections/domestic-energy-fact-file-and-housing-surveys

It is estimated that heat networks currently supply less than 2% of building space heat demand in the UK with almost 2000 individual schemes[172],[173].

3.3 Near term opportunities

3.3.1 Building heat storage

The main policy instrument for supporting low carbon building heating technologies, which indirectly represents a proxy for the requirement for new building heat storage, is the Renewable Heat Incentive (RHI). This is analogous to a feed-in-tariff and the scheme started for non-domestic buildings at the end of 2011 and for domestic buildings in 2014.

As of April 2016 there were over 14,000 accredited non-domestic schemes[174], with the vast majority of these (~93%) biomass boilers. For the domestic scheme there were just under 22,000 accredited schemes, with around half these heat pumps, 40% biomass boilers and the remainder solar thermal.

The RHI is currently being reviewed and the Impact Assessment accompanying DECC's consultation on the proposed reforms to the RHI[175] provides estimates of deployment over the next 5 years.

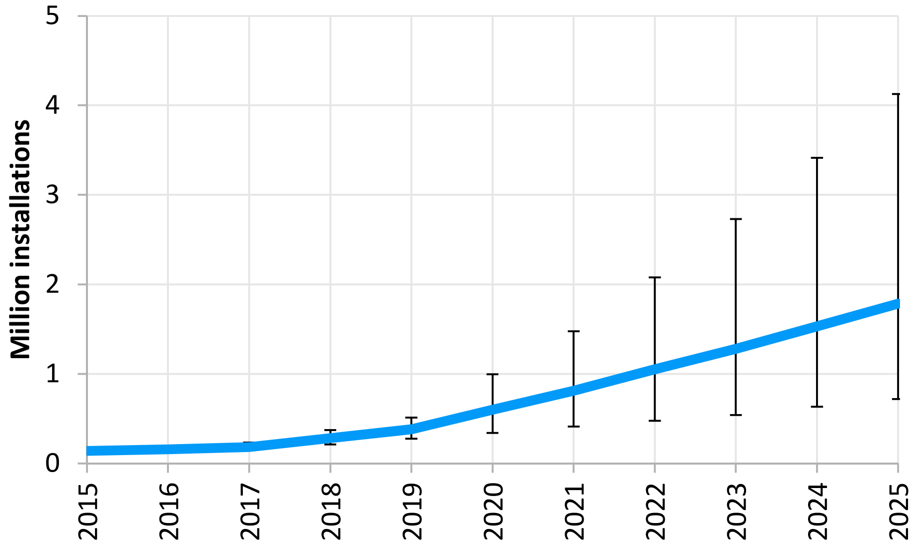
Table 7 DECC estimates of annual low carbon building heat installations to 2020/21

Type	Domestic	Non-domestic
Biomass boilers	1,000 (~20kW)	60 (~7MW)
ASHP	13,700 (~10kW)	1,000-2,000 (~40 kW)
GSHP	2,500 (~9 kW)	2,200 (~30 kW)

Assuming these trends continue to 2025, this would imply around 200,000 domestic installations with associated building heat storage and around 50,000 non-domestic installations. As a comparison, these projections put the level of uptake at the very bottom end of the National Grid's 2015 Future Energy Scenarios[176] (FES) which incorporate feedback on near-term trends from across the energy industry. The wide spectrum of uncertainty is due to the number of off-gas grid households (~4M in the UK) for whom low carbon heating may be economic compared to solid or liquid fuel, however, these buildings are more likely to have pre-existing hot water storage tanks given they have more available space and would not have been able to fit a combi-gas boiler.

172 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/212565/summary_evidence_district_heating_networks_uk.pdf
173 http://www.theade.co.uk/district-heating-installation-map_790.html
174 https://www.gov.uk/government/statistics/rhi-deployment-data-april-2016
175 https://www.gov.uk/government/consultations/the-renewable-heat-incentive-a-reformed-and-refocused-scheme
176 http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/

Figure 70 Estimated low carbon heat domestic installations from FES scenarios



Note: shows average and max/min from across the 4 published scenarios. Technologies covered include heat pumps and biomass

Although PCM for building heat storage is likely to become viable in the next few years[165], whether new storage is based on traditional hot water tanks or PCM is likely to be driven by the value of available space versus the reduced size of the storage tank. An example for a relatively large (~180m^2) detached house is shown below. PCM tanks can potentially store around 3 times the energy for the equivalent volume, but are expected to be more expensive (UKERC estimates ~4 times for an equivalent water based store).

Table 8 Estimated tank size for detached house under different building regulations from UKERC (2014)

	1980s	1990s	2010s
Water volume (l)	1543	1097	560
PCM volume (l)	514	366	187

The majority of existing hot water tanks are in the region of 100-200 litres and these may still be appropriate for smaller, well insulated buildings which have lower heat demand. Where space is at a premium (e.g. in urban areas) the value of the building space is likely to exceed the additional cost of the PCM tank (the UK average is ~£2000/m^2 rising to over £10,000/m^2 in some parts of London[177]).

However, given that the majority of low carbon heating systems are expected to be installed in off-gas grid areas in the near term, it is likely that standard hot water tanks will continue to be used given the increased availability of space at lower cost, and that it is a mature technology.

[177] Halifax

DSR and ToU tariffs

The influence of smart metering and potential for DSR on uptake of storage is likely to be indirect. It is not a core driver in and of itself for more heat storage, but will help maximise the consumer and wider system benefits of operating electrified forms of heating in conjunction with storage (e.g. responding to ToU tariffs to minimise costs or in response to DSR signals[178]) to minimise the level of reinforcement needed on the electricity system or make balancing of the system less costly.

The majority of technical barriers to implementing DSR for electrified heating via use of building heat storage concern the flow and processing of data and instructions, but many of these should be overcome through the roll out of smart metering. This will enable half hourly metering at domestic and small business locations, and allow prices to better reflect the state of the electricity system[179]. It should be noted that uncertainty exists around the programme to implement the government's ambition to roll out smart meters to nearly all homes and businesses by 2020, and the effectiveness of the scheme once implemented. The Energy and Climate Change Parliamentary Committee declared in its 2015 report[180] on the programme's progress that it did not believe the target would be met, and also highlighted risks to the expected benefits. This will allow consumers to control their charging behaviour using e.g. timers in response to tariffs with a Time of Use element.

Barriers to DSR in the commercial value chain relate primarily to the:

- Costs of managing multiple small scale DSR providers effectively, be this from electrified heating or electric vehicles, compared to the situation at present where most DSR is provided by large scale Industry and Commercial stakeholders
- Coordination in the activation of DSR across the electricity supply chain in a way that maximises benefit for the system and avoids potential conflicts, for example whether the DSR is being used primarily to solve system level TSO issues, but at the potential expenses of exacerbating local DNO-level constraints.

These issues of coordination have previously been identified and are the focus of thinking and analysis by many stakeholders in the sector including DECC, Ofgem, the Smart Grid Forum[181], the Energy Networks Association (ENA), ELEXON[182], and the DNOs as part of the Low Carbon Networks Fund innovation scheme. Ofgem has identified the need to establish an overarching market framework to enable DSR and is taking this forward through the Flexibility Project[183].

The ENA has proposed a shared-services framework setting out how (initially non-domestic) DSR resources could be shared between DNOs and the SO[184], envisaging a hierarchy of dispatch giving DNOs precedence in using DSR resources for local issues, which is of particularly relevance for heat load on the Low Voltage part of the distribution network. This, or equivalent solutions, are likely to

[178] Via direct control or further indirect price signals)
[179] Assuming associated implementation of half hourly settlement, and that time differentiation exists in underlying costs, which is not currently the case for network charges for mass market consumers.
[180] House of Commons Energy and Climate Change Committee, Smart Meters: progress or delay?
[181] The customer-focused smart grid: Next steps for regulatory policy and commercial issues in GB Report of Workstream Six of the Smart Grid Forum, 2015
[182] Maximising the value from Demand Side Response
[183] Making the electricity system more flexible and delivering the benefits for consumers, 30 September 2015
[184] ENA Demand Side Response Shared Services Working Group: Demand Side Response Shared Services Framework Concept Paper

take several years before they are implemented for day-to-day operation. Building on this are further options for increasing the role of small-scale DSR based in increasing degrees of intervention and market redesign but are like to be occur beyond the 2025 time frame. They include extending the framework to allow parties to sell the DSR service onto another party who values it more highly (e.g. DNO to TSO) and then beyond this a central market platform to match buyers and sellers of DSRs services.

Implication for storage: near term potential for new building heat storage is likely to be driven indirectly by the rollout of low carbon heating systems, for which storage is required to size and operate them efficiently (with further potential benefits under ToU tariffs or in providing DSR). New installations are likely to be limited due to the modest impact of the RHI scheme and that they are more cost-effective initially in off-gas grid applications, where building heat storage is more likely to exist already.

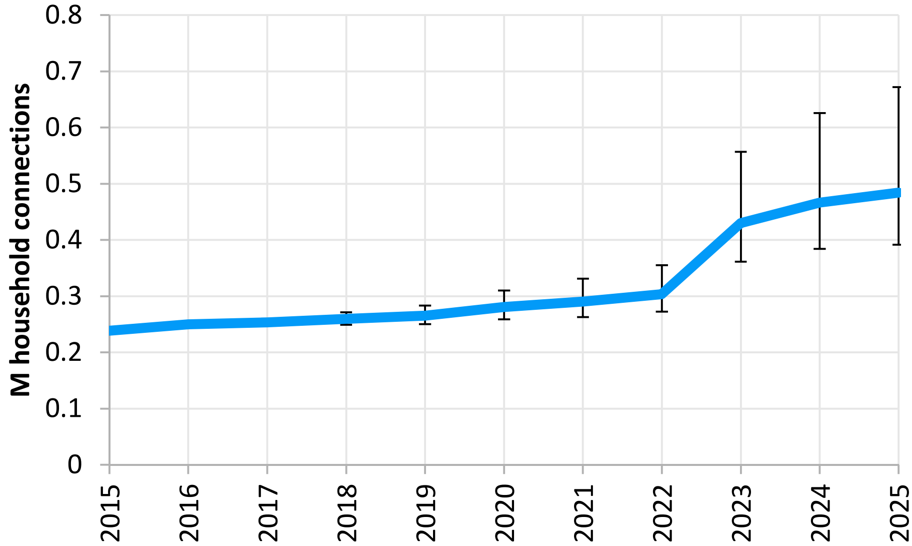
3.3.2 District heat network storage

Direct government support for heat networks is fairly limited for the network component itself, but is focused more around support through e.g. RHI, RO, CfDs for the generation of low carbon heat and electricity from the supply source[185]. The RHI reform consultation is also looking at potential changes that may help to further incentivise low carbon heat for district heating.

The future role for district heating in the next 5-10 years is highly uncertain. The published FES scenarios for domestic connections in Figure 71 shows a potential doubling or tripling in absolute terms, albeit from a very low base.

[185] https://www.gov.uk/government/publications/2010-to-2015-government-policy-low-carbon-technologies/2010-to-2015-government-policy-low-carbon-technologies

Figure 71 Estimated low carbon heat domestic installations from FES scenarios



Note: shows average and max/min from across the 4 published scenarios

By comparison, analysis for the CCC's 5th Carbon Budget[186] provides a more optimistic set of projections. In the central scenario explored, heat delivered by heat networks doubles by 2020 (equating to 171 new schemes), and increases by around five times by 2025 (with a range of increase of 3-7 times by 2025 across the scenarios considered). Each new scheme is likely to have an associated buffer heat store, the exact size will be highly dependent on the underlying configuration of the scheme, but is often equivalent ~1 day of average heat demand or ~3-4 hours of demand at peak[187].

Implication for storage: large scale heat storage for district heat networks is driven by the underlying requirement for the network itself. Published scenarios show a wide range of increase in the scale of delivered heat of ~2-7 times by 2025, but this is an increase from a low absolute base.

[186] https://documents.theccc.org.uk/wp-content/uploads/2015/11/Element-Energy-for-CCC-Research-on-district-heating-and-local-approaches-to-heat-decarbonisation.pdf
[187] https://www.theccc.org.uk/archive/aws/IA&S/Element%20Energy%20-%20Decarbonising%20heat%20to%202050%20-%20Annex.pdf

4 Gas Storage

4.1 Storage technologies

The key characteristics of a storage facility from an economic perspective are its working volume, the total volume of gas that can be stored at one time, the maximum rate at which gas can be injected into the facility, and the maximum rate at which it can be withdrawn. The main types of large scale gas storage can be categorised, from a commercial perspective, based on their typical profiles of use.

- Seasonal, or long range, storage (LRS) is primarily used to inject gas during the summer, at times of lower demand, and to withdraw in winter, when demand is higher. Such facilities typically have large working volume with relatively low injection rates, suited to filling up over the summer, and higher withdrawal rates to allow flexibility on the pattern of withdrawal across the winter.
- Fast cycle, or short range, storage (SRS) is primarily used to inject and withdraw in response to day-to-day market conditions. The pattern of injections and withdrawals for fast cycle will be likely to be volatile, and on aggregate will usually equate to multiple 'cycles' of storage over the year. Fast cycle facilities typically have higher withdrawal and injection rates relative to working volume that enables them to take advantage of shorter term market changes.

From a system perspective, storage could also be held purely for emergency purposes, termed strategic storage, or for use for system support from a network management perspective.

The two main types of geological storage are salt caverns and depleted gas reservoirs. Salt caverns are leached from geological salt strata. The relative costs of creating space versus adding injection and withdrawal capacity mean that these are typically developed as fast cycle facilities. Depleted gas reservoirs can provide significant volume, but higher relative costs of developing injection and additional withdrawal capacity mean that these are typically developed as seasonal facilities. They also typically require a high level of 'cushion gas' – the gas that must be present in the reservoir at all times to maintain the operability of the facility. Aquifers (and indeed un-depleted gas reservoirs) can in principle also be used but present higher development risks.

Dedicated LNG storage facilities (in contrast to LNG import terminals) can also be used, with the associated liquefaction and regasification to inject and withdraw. These are relatively expensive and hence, in a GB context, have historically been developed primarily for system support reasons.

Storage also exists in the form of LNG tank facilities, where LNG is stored after unloading from ships. Pressure on the transmission network is managed within a tolerance range, which also creates effective storage termed linepack.

Aside from a small amount of hydrogen production for industrial uses, there is no expectation of large scale use of hydrogen for energy in the next 5-10 years that would encourage or require tangible volumes of hydrogen storage. *Hydrogen storage is therefore not considered further in this report*, however, many of the underlying drivers of gas storage which are described in the following sections (such as exploiting seasonal arbitrage in prices or providing flexibility in supply due to more volatile demand) could apply if hydrogen reaches widespread use over the longer term (e.g.

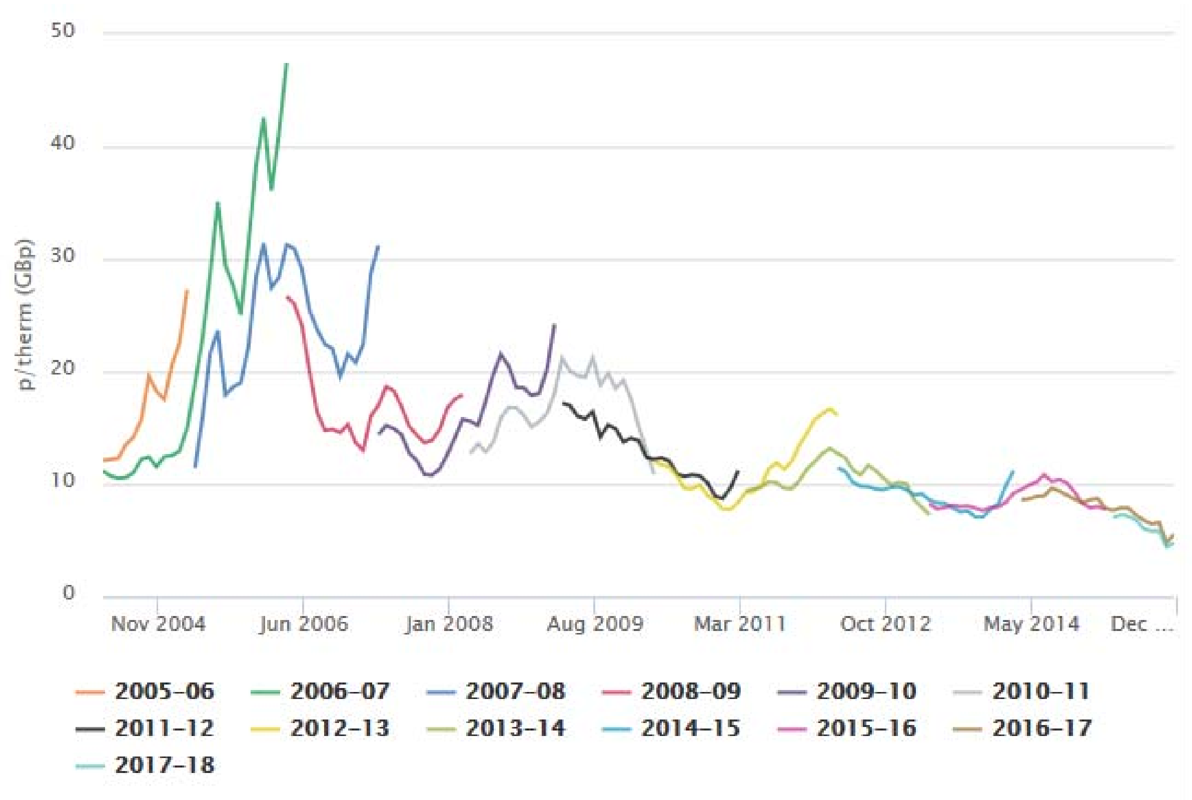
exploiting summer off-peak electrolysis from nuclear baseload plant or providing flexible supply for hydrogen peaking turbines).

At distribution network level the majority of storage in GB was provided previously by low pressure gas holders (or gasometers). These were originally constructed to store town gas and later natural gas, but by the early 1990s most local gas networks were able to function at full capacity without them. In 1999 National Grid commenced a programme to dismantle them and sell off the land, which is still ongoing. It is not anticipated that any material new storage infrastructure will be required at the distribution level in the near term. Storage facilities are generally integrated at new distribution-level biomethane-to-grid facilities, but these are part of the overall plant (e.g. Anaerobic Digestion or gasification plant) rather than standalone storage. The contribution of biomethane is also low, currently ~0.25% of annual gas supply, rising to between 0.7%-1.4% by 2025 across the range of National Grid Future Energy Scenarios. As a result, subsequent sections focus on transmission level gas storage only.

4.2 Overview of market structure

The Great Britain (GB) gas market is going through a significant transformation as its traditional domestic UK Continental Shelf (UKCS) supplies decline, and it becomes increasingly dependent on exports from Norway, gas through interconnectors from continental Europe, and imports of Liquefied Natural Gas (LNG). Alongside this, in recent years, summer-winter spreads have narrowed, with the delta in forward prices for delivery in 2017-2018 low by historic standards as illustrated in Figure 72. Price volatility has also fallen, which, taken together with significant uncertainty as to the long term role of gas within the GB energy system, has led to a difficult environment for new storage projects.

Figure 72 Gas summer-winter spreads at GB National Balancing Point



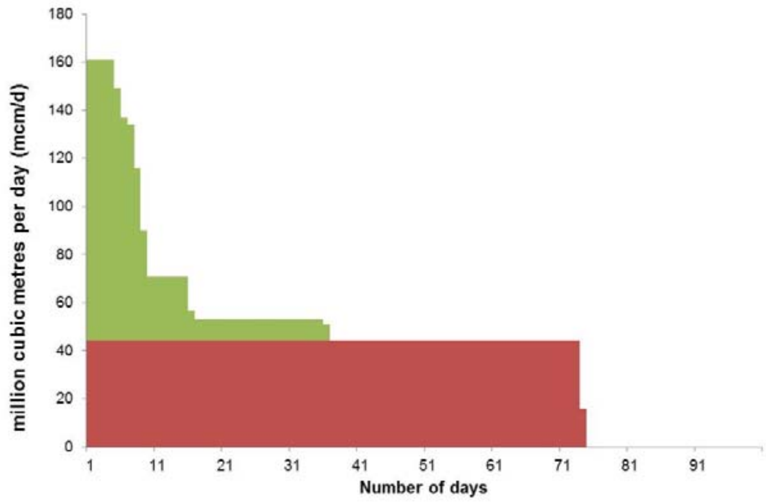
Source: Ofgem/ICIS[188]

Note: The summer-winter spread is the difference between gas prices in summer compared to the following winter price

The UK currently has around 5.1 bcm of gas storage capacity and 160 mcm/day of storage deliverability. This includes two projects completed within the last year which added around 0.5 bcm of capacity and 45 mcm/day of deliverability. This provides around ~18-25 days of daily average demand (seen across the last 5 years) and is low relative to other European markets, due primarily to the growth of the gas industry based almost entirely on domestic production, including swing (i.e. effectively storage) fields to support the variation in demand. The majority of long-range storage is contained within Rough which provides ~70% of the UK storage space but is relatively slow cycling and only provides ~25% of the deliverability (shown in red in Figure 73, with the remainder short-range storage. LNG terminal send-out rates add another ~130 mcm/day[189].

[188] https://www.ofgem.gov.uk/chart/gas-summer-winter-spreads-national-balancing-point-gb-0
[189] CEER (2014) Status Review on monitoring access to EU LNG terminals

Figure 73 UK storage capacity deliverability versus duration at maximum withdrawal



Source: National Grid – red block indicates Rough storage, green indicates all other storage.

In addition, GB has three gas interconnectors (with no plans at present to increase this capacity in the near term)

- IUK (bi-directional) interconnector to Belgium (73 mcm/day import, 56 mcm/day export)
- Balgzand to Bacton (import) Line (BBL) to the Netherlands (49 mcm/day)
- Moffat (export) from Scotland to the Republic of Ireland interconnector (31 mcm/day)

Commercial drivers of gas storage value

Historically, storage was often viewed primarily as a means of physically balancing supply and demand, and would correspondingly be used and planned within a supplier's portfolio as a means of following customer demand. Due to the increasing focus on asset optimisation, an alternative means to utilise storage is to aim to drive the greatest value through using it to buy and sell gas in the wholesale market.

The commercial value in storage comes from the ability to buy and inject gas at times of lower price, and withdraw and sell it at times of higher price. The seasonal pattern of demand (with higher demand in winter) leads to an associated seasonal price profile, enabling storage to be used to buy at lower prices in summer and sell at higher prices in winter. Seasonality in prices, and the underlying fundamental factors behind that, is thus a key value driver.

Wholesale spot gas prices also exhibit significant movements on a day-to-day basis, and indeed within-day, and hence storage can also be used on these timescales to buy when spot prices are relatively lower, and sell when they rise. The volatility of day-ahead prices is a common metric for this element of price behaviour. Volatility is a measure of the spread in the distribution of day-to-day price movements observed over a given time period. The level of volatility in the market, and the factors behind that, form the second key value driver.

The strategies deployed will in turn affect the achieved value of the facility. Considering a stand-alone asset for simplicity, value-based strategies will exhibit different levels of market risk and require different levels of trading sophistication. An example of a straightforward, low risk, strategy would be one where storage value is 'locked in' on a forward basis by buying and selling appropriate forward contracts. The expected profit from this will, however, be lower than the expected profit from a strategy involving optimal buy and sell decisions on a day-ahead basis, although this latter strategy would be more risky, with a lower potential downside outcomes. A spot-based strategy with a more sophisticated forward hedging strategy could be used to aim to capture greater upside whilst limiting downside, although this will be subject to higher transaction costs and will demand a greater level of trading capability.

Regulatory drivers of gas storage value

As well as the impact of supply and demand fundamentals, the regulatory and market frameworks for GB and its neighbouring markets will impact storage value.

This can take the form of direct regulation around the use of storage. A number of European countries have security of supply requirements that put minimum constraints on the level of gas in store at different times of the year. These are generally in the form of public service obligations (PSOs) imposed on suppliers or on transmission system operators. Other things being equal, these requirements will limit the use of storage in the market, which can effectively hold back flexibility that would otherwise be available. This would tend to be an upwards driver for GB volatility, and the removal or loosening of these regulations in the future would directionally tend to decrease it.

Other types of market arrangements can also directionally affect flexibility availability and hence volatility. Balancing arrangements vary between different markets both in the granularity by which market participants' balance positions are measured (for example, hourly or daily), and the price to which they are exposed for any imbalance. Where balancing arrangements are more 'penal' for participants, this may in turn lead to flexibility being 'held back' from the market as a risk management measure, which could drive volatility in neighbouring markets in the short run – although in the longer run this might also drive investment in further flexibility. Conversely, were these arrangements to be 'loosened' in the future, this could have a downwards impact on volatility relative to current arrangements.

Market structure, and in particular the range of participants that control flexibility, may affect the level of competition in the supply and demand of flexibility, which may also impact on volatility over time.

For GB in particular, the gas market balancing (or 'cash-out') arrangements[190] recently underwent a Gas Security of Supply Significant Code Review (SCR) which was finalised in 2014. Prior to the reforms, Ofgem had concerns that the potential price signals that would be sent to market participants during a Gas Deficit Emergency (GDE) would be insufficient to deliver supply security in an efficient manner (e.g. having an appropriate level of gas storage available or ensuring sufficient interconnector flows).

The reforms were aimed at improving the efficiency of these price signals transferring risks from consumers onto gas shippers, and included:

[190] Gas transportation licenses include a condition on shippers to balance what they are putting into and taking out of the system. Shippers pay a penalty, called the 'cash-out price', for oversupply (being 'long') or undersupply (being 'short'). These charges are designed to recoup the costs to the System Operator of entering the market and buying or selling gas to balance the grid.

- Unfreezing cash-out prices in an emergency, with no cap on prices
- Incorporating the cost of involuntary consumer interruptions into cash-out charges in a GDE. Smaller consumers such as domestic households would be priced at £14/therm (an estimate of the costs of an interruption)
- Using funds recovered from cash-out charges to make payments to consumers for the involuntary service they provide if disconnected in a GDE.
- Development of a centralised DSR mechanism with a licence obligation on National Grid to develop and manage this

Before and during the SCR review process there was extensive industry and public debate around whether direct targeted intervention to promote additional gas storage is required over and above changes to cash-out arrangements. Government's current view is that additional support is unnecessary, but they continue to monitor this via updates to a Risk Assessment on Security of Gas Supply[191].

4.3 Near term opportunities

Impact of future supply drivers

The changing supply mix will drive future storage value in two main ways. First, variation in availability or cost of different supply sources on a seasonal basis can drive seasonality in price. Second, limited flexibility in supplies, and short term variation in availability, or cost, will impact spot price volatility.

From a GB perspective, these characteristics will vary by type of supply, which is undergoing a major transition, as imports have increased since 2003-04 with a corresponding decline in the UKCS supplies. Historically, UKCS has not only provided domestic gas but also acted as a flexible source of gas through "swing fields" which can increase production during periods of high demand or reduced gas supply. These fields are now in decline and therefore the capability to ramp up production in periods of tight supply and balance demand is decreasing, although there is uncertainty over whether further significant decline can be postponed to beyond the late 2020s.

Without development of UK shale gas imports are likely to provide an increasing proportion of GB gas supply going forward, with the National Grid 2015 Future Energy Scenarios (FES)[192], showing an increase from ~55% today to between 70%-90% by 2030. This gap would potentially be made up of gas from Norway, gas through the interconnecting pipelines with the continent, Interconnector UK and the Bacton-Balgzand Line, and an increasing proportion of LNG imports. Norwegian production has significant flexibility, although this will to some extent be constrained by contractual commitments, and will also respond to the market situation both in GB and on the continent. The interconnectors provide a means for gas to respond to market situations on either side of the pipes where flows are efficient.

The non-continuous supply chain associated with LNG creates a complex dynamic from a volatility perspective. Where LNG prices are relatively low, and terminals have a high load factor, then the 'baseload' nature of the flows will mean that there is limited flexibility. At a lower average level of

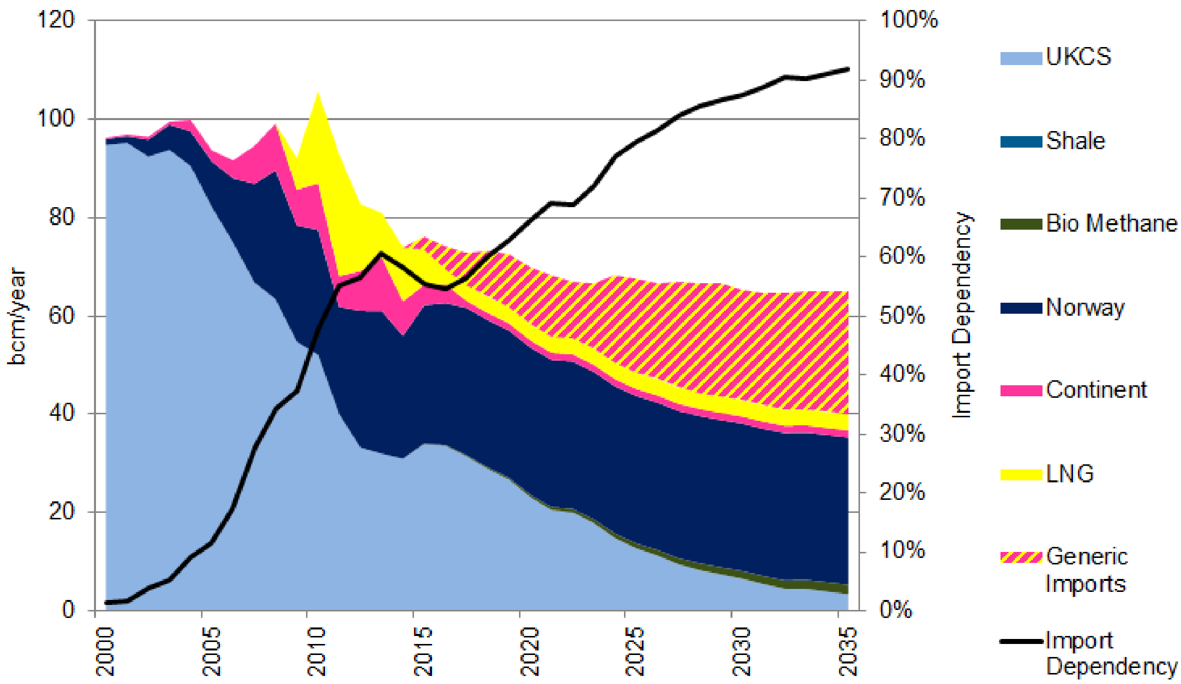
191 https://www.gov.uk/government/publications/uk-risk-assessment-on-security-of-gas-supply
192 http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/

flow, the tank storage at LNG terminal facilities can provide flexibility and could correspondingly reduce volatility. At lower levels still, with only intermittent flows, then the potential lag associated with LNG shipping and diversion decisions could be a driver for higher volatility. LNG is also likely to play a significant role in the seasonality of GB prices, as GB prices are affected by those in an increasingly interconnected global LNG market.

However, the impact of UK shale gas could provide a significant swing factor with one of the FES scenarios showing a potentially significant reduction in import dependence by 2030. In addition, experience to-date in the US has shown that many shale gas producers are highly flexible, ramping up and down production within year in response to changing prices[193], which would potentially further dampen the economics of new storage for seasonal price arbitrage.

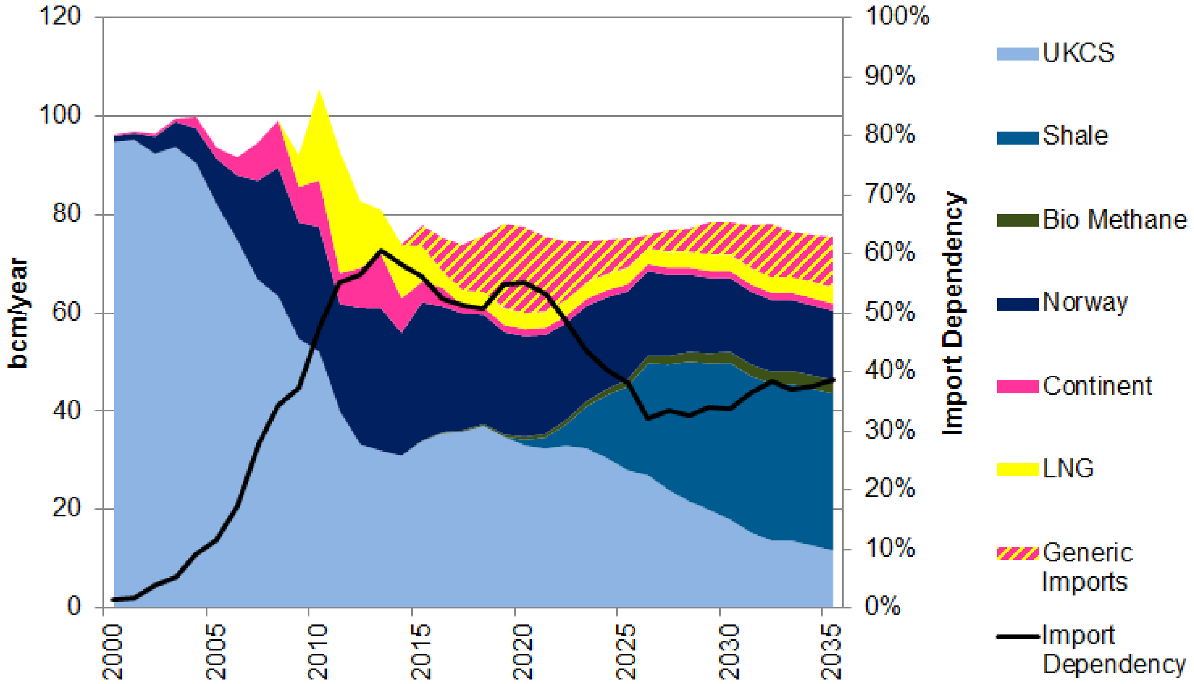
Figure 74 and Figure 75 illustrate the annual supply patterns for the two extreme ends of the spectrum in the FES (2015) scenarios for future GB import dependence.

Figure 74 Annual supply pattern National Grid FES (2015) – Slow Progression



[193] http://blogs.worldbank.org/prospects/global-weekly-flexibility-us-shale-oil-industry

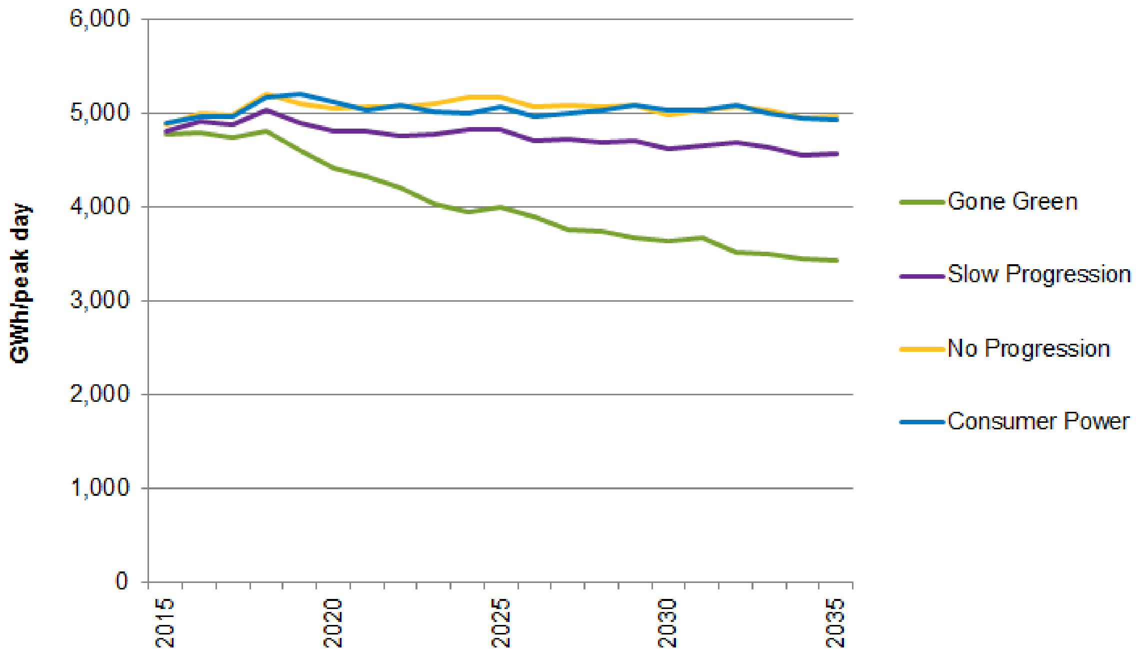
Figure 75 Annual supply pattern National Grid FES (2015) – Consumer Power



Impact of future demand drivers

On the demand-side, both the absolute and peak level of demand is expected to decline gradually, or at most remain 'broadly' flat from now to 2030. Figure 76 shows the peak day gas demand across the four FES scenarios (annual demands following a similar pattern).

Figure 76 Peak gas demand National Grid FES (2015)



Overall, a 'tighter' market might be expected to lead to higher volatility, with an increased element of 'scarcity' pricing affecting spot price dynamics. The level of demand reduction relative to the reduction in UKCS and Norwegian supplies would influence this. However, the way in which the different supply sources interact at different levels of demand, and at different relative price levels, will also be important – for example, the way in which LNG is flowing, as mentioned above.

Currently GB demand is highly seasonal, with winter demand exceeding summer demand typically by a factor of 1.7, a key driver for corresponding seasonality in prices. This is driven particularly by the seasonal nature of heating demand.

Volatility in demand on a day-to-day basis will of course be a key factor behind spot price volatility. An important driver behind this in turn will be the way in which the electricity generation mix changes, and the corresponding demand for gas in the power sector. One of the key differences is the different level of wind generation in the medium to long term which is projected to increase from ~12 GW now to between 25-50 GW by 2030 across the range of FES scenarios. The intermittent nature of wind is likely in turn to drive volatility in gas generation, as CCGTs provide the flexibility needed, which in turn would be expected to drive price volatility.

Future storage capacity

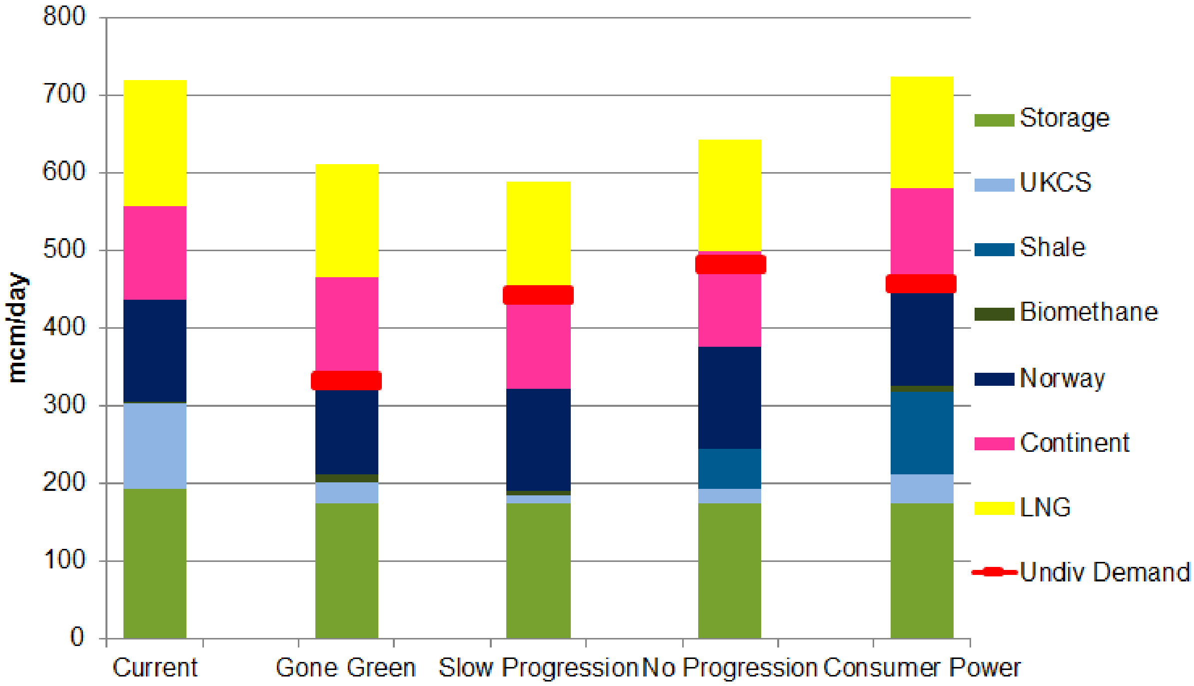
As of 2015 there were 11 gas storage projects with planning permission but where no Final Investment Decision had been taken, with a total potential of ~14 bcm[194]. It is not possible within the scope of this report to explore the feasibility of the investment cases for individual assets.

[194] DECC (2015) Delivering UK Energy Investment: Networks

However, the broad market consensus is that the economics of new capacity are highly challenging (in particular due to the price spreads between winter and summer).

This is emphasised by the National Grid FES, where *all* scenarios show a decline (in terms of peak storage deliverability) by 2035 compared to current capacity (see Figure 77).

Figure 77 Peak gas supply 2035 (National Grid Future Energy Scenarios)



Implication for storage: the economics of new build are challenging in the near term due to the reduction in price volatility and narrowing of seasonal price spreads, coupled with the lack of direct intervention for storage to provide strategic security of supply. The extent of future UK shale gas is a significant uncertainty, but may further dampen the economics for storage given the US experience of significant within year flexibility in response to price changes.

Appendix A Example of FFR tender data[195]

	FR Tender Items	Description
	Tendering Company	Company name
	Tendered Unit	Unit BM identifier
	Tendered Service Period	Duration of tender
	Tendered Service Term	Date from / to
	Tendered Window	Split Monday to Friday, Saturdays and Sunday and Bank Hols, stating hours available in each of these windows
Tendered Prices	Availability Fee (£/h)	The price in £/hr you wish to be paid for making Firm Fast Reserve available against for each hour in a Tendered Service Period where the service is available
	Positional Fee (£/h)	This parameter provides the ability should you wish to specify a Positional Fee (the cost of putting plant in a position where Firm Fast Reserve may be provided)
	Window Initiation Fee (£/window)	National Grid will notify 'windows' during which it requires the Firm Fast Reserve service to be provided, for which a Window Initiation Payment will be made.
	Capped Bid-Offer Price(s) (£/MWH) OR Firm Fast Reserve Energy Fee	Capped Bid – Offer prices are for BM participants, or the energy price in £/MWh you wish to be paid if n-BM
Utilisation Restrictions	Unit Size (MW)	Capacity to be made available for FR
	Maximum energy utilisation (MWh) in minutes	The maximum time in minutes or alternatively ticking one of the time periods for which you will allow National Grid to utilise Firm Fast Reserve in any single utilisation. (This must be a minimum of 15 minutes)
	Maximum No. of Utilisations	The maximum number of times Firm Fast Reserve can be utilised in any the appropriate time period for which Contracted MWs are being offered
	Recovery Period (Seconds)	The maximum time in whole minutes it takes to make Firm Fast Reserve available again after it has been utilised
	MW Profile	Dates of planned outages across the Tendered Service Periods.

[195] National Grid, Firm Fast Reserve Explanation and Tender Guidance.