Electricity System Operator

Markets Roadmap

March 2023

ESO

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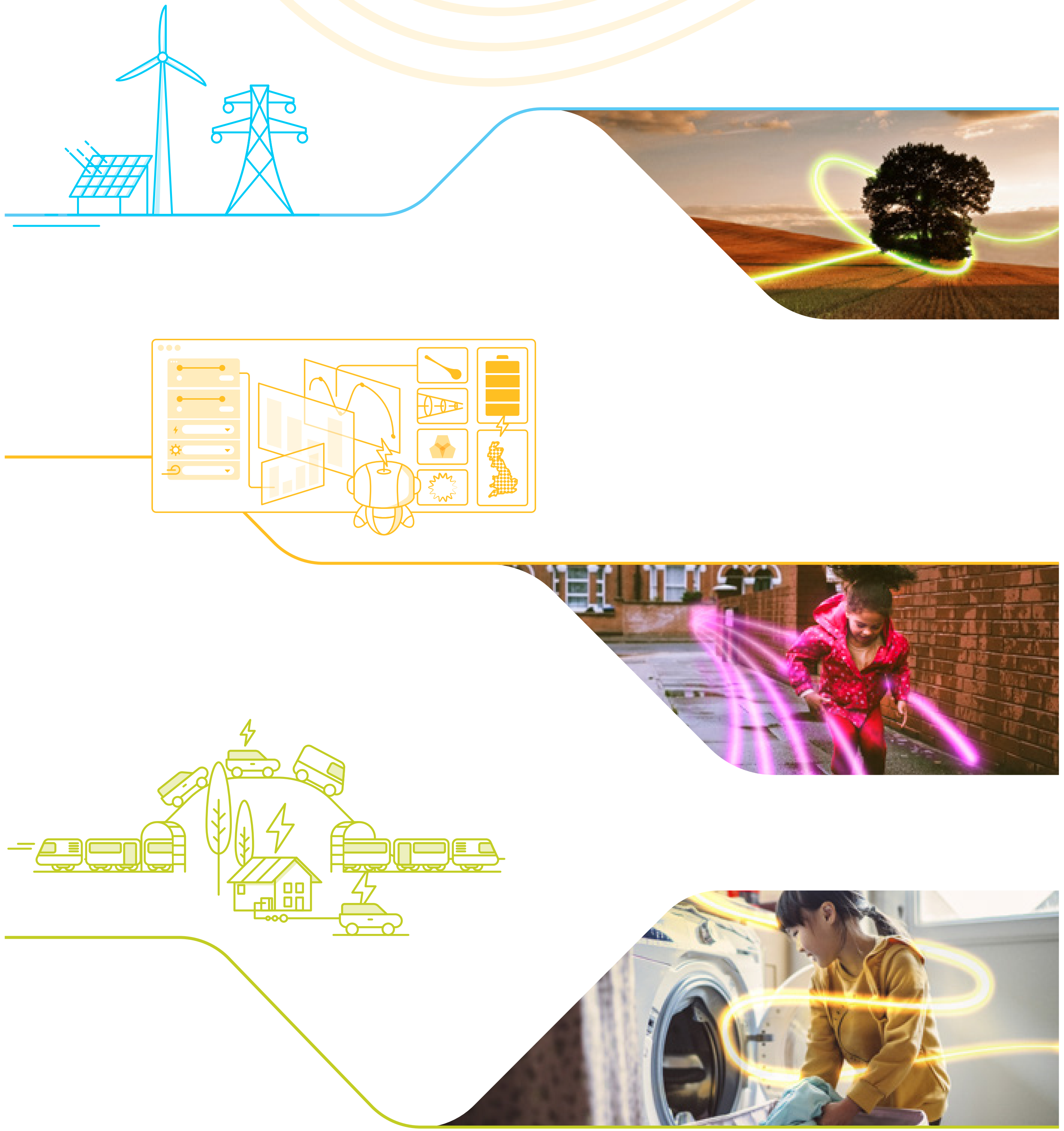


Executive summary

What is the purpose of the Markets Roadmap?

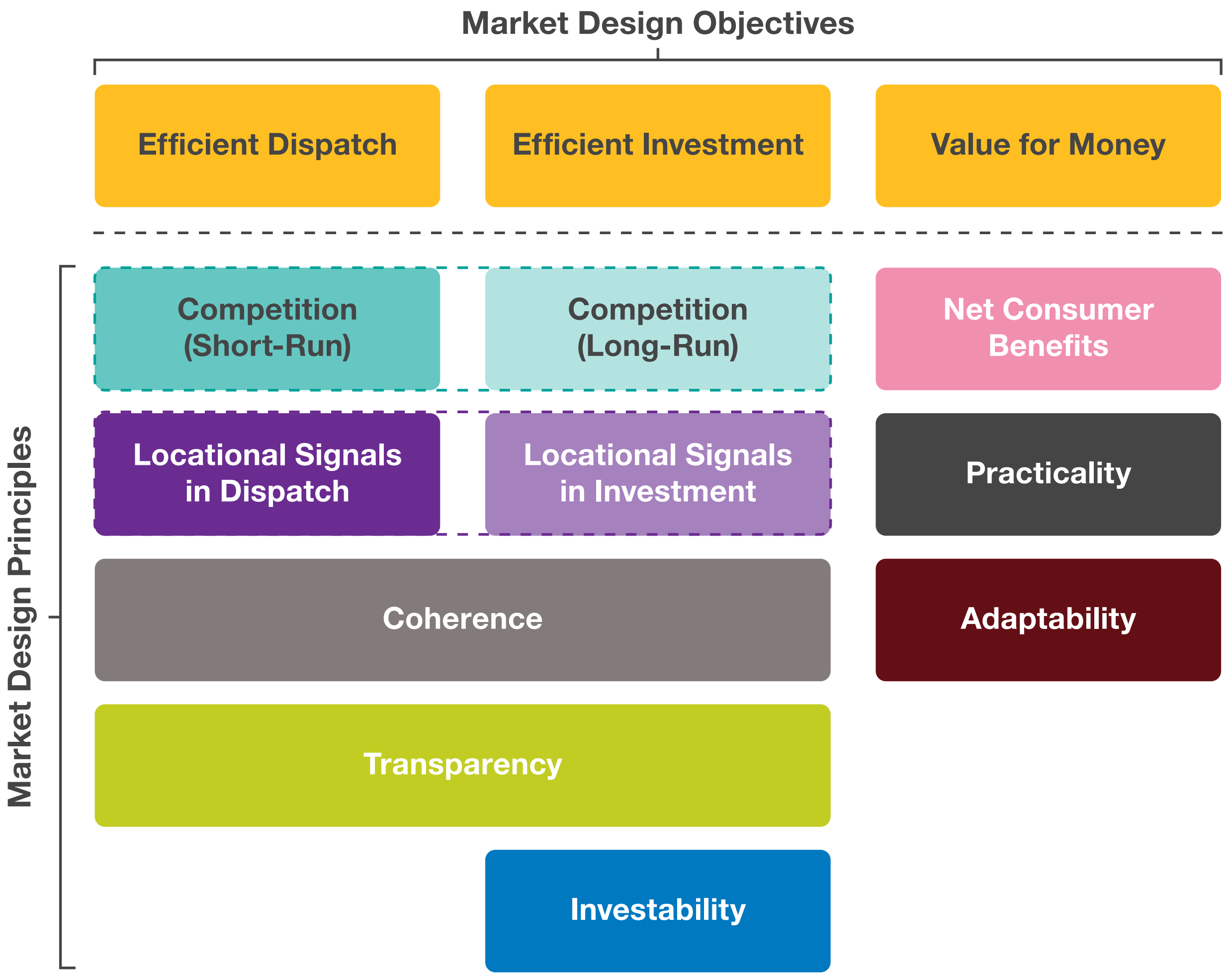
Reform of ESO's ancillary service and balancing markets is crucial if we are to ensure that we can operate a zero carbon electricity system by 2025, and fully decarbonise by 2035. These reforms will also help to lower costs to end-consumers as they are designed to make our markets more efficient, accessible and liquid. We also understand that our ancillary services and balancing markets are an increasingly important revenue stream for market participants. It's therefore imperative that we provide a clear view of how we see these markets developing. This is the aim of the ESO Markets Roadmap. Here, we outline what we are doing to reform ESO markets and why we are doing it; to give the market the ability to build investment cases and all stakeholders the confidence that we are making the right design decisions.

Last year, we introduced our Market Design Framework, which we use to underpin all our market reform decisions. It is also helps to analyse the efficiency of our existing and newly introduced markets and we can use it to drive continuous improvement and identify new opportunities for reform.

In 2022, we focused in particular on the 'coherence' principle of our framework; how our market design and procurement strategies align with each other as well as with wider markets, especially the wholesale market. We commissioned LCP-Delta to undertake a qualitative assessment of all of our markets and planned reforms against this framework, which we have published alongside this report.

Market Design Framework

To ensure that our market designs achieve these objectives, we must test whether the design satisfies 10 Market Design Principles:



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Executive summary

Objective

Efficient Dispatch

Alignment with the trilemma challenges

- **Security of Supply:** ensures that our current system requirements are met in real time.
- **Lowest cost for consumers:** ensures that we select solutions with the lowest cost to society in real time (i.e., the cost to both producers and consumers).
- **Enabling the transition to net zero:** ensures that we optimise our procurement of balancing services in real time to meet system requirements, which will become increasingly important as the system decarbonises.

Objective

Efficient Investment

Alignment with the trilemma challenges

- **Security of Supply:** ensures that our future system requirements are met.
- **Lowest cost for consumers:** ensures that we meet our system requirements using the solution with the lowest cost to society in the long run (i.e. the cost to both producers and consumers).
- **Enabling the transition to net zero:** ensures that we are incentivising sufficient investment to meet the increasing requirements for balancing services as the system decarbonises.

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Executive summary

Objective	Alignment with the trilemma challenges
Value for Money	• **Security of Supply:** ensures our procurement is flexible to changing requirements such that the system remains secure. • **Lowest cost for consumers:** considers the overall financial impact to consumers and assesses value based on the extent to which consumers benefit from any cost reductions resulting from improved efficiency. • **Enabling the transition to net zero:** ensures that our procurement is flexible to and compatible with changes in the technology mix required to facilitate decarbonisation.

Principle	Definition
Competition (Short Run)	The procurement method creates a market in which multiple current or potential participants seek to offer better terms (prices and quantities) than those offered by other participants, which is open to all providers technically capable of providing the service. That is, the market does not discriminate between technologies or providers. Short-run competition considers only existing assets.

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Executive summary

Principle	Definition
Competition (Long Run)	The procurement method creates a market in which multiple current or potential participants seek to offer better terms (prices and quantities) than those offered by other participants, which is open to all providers technically capable of providing the service. That is, the market does not discriminate between technologies or providers. Long-run competition considers the assets expected to exist in future, given expected new build and retirement decisions.

Principle	Definition
Net Consumer Benefits	The costs to consumers do not outweigh the benefits conferred by the procurement method.

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Principle	Definition
Locational Signals in Dispatch	The procurement method ensures that services are delivered in the right places.

Principle	Definition
Locational Signals in Investment	The procurement method ensures that capacity is constructed in the right places.

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Executive summary

Principle	Definition
Practicality	The procurement method is practical to implement, transition to and operate.

Principle	Definition
Coherence	Across all of ESO's markets, the procurement methods enable market participants to make decisions about where to bid, which are efficient for both the market participants and the system. The procurement decisions are aligned with the evolution of government policy and other markets.

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Principle	Definition
Adaptability	The procurement method is flexible to changes in balancing service requirements and the technology mix.

Principle	Definition
Transparency	Information is provided to market participants and procurement decisions are made in a clear and predictable way to minimise information asymmetries and uncertainty around ESO's decision making.

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Principle	Definition
Investability	The procurement method provides investment signals which market participants and investors can respond to and rely on.

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Executive summary

The bigger picture

Since we published the last Markets Roadmap, Russia's invasion of Ukraine has seen gas prices soar, stoking a cost of living crisis and feeding high inflation. These high prices, coupled with tight system margins, translated into record balancing costs, with 2022 seeing ESO spend £4.3bn on operating the system. This drove us to intervene in several ways to address inefficiencies in the wider market frameworks.

At the same time, we can see that there are many investors looking for opportunities in the global energy and renewable sector, and the UK is competing internationally for this investment, especially with the recently announced Inflation Reduction Act in the USA.

Against this backdrop of energy security and opportunity, 2022 saw the launch of Department for Energy Security & Net Zero (DESNZ) Review of Electricity Market Arrangements, a once-in-a-generation opportunity for GB to reform its market and policy framework for net zero. This strategic, holistic approach to reform is welcomed as part of the energy transition. We know that the current market framework is not fit for a fully decarbonised electricity system and we need a more strategic approach to market reform, if we are to minimise costs for consumers and avoid locking in inefficiencies and distortions. The plans within this report are an important step along the way to the market needed for a net zero future.

What have we achieved in 2022?

We have delivered on our commitments, driving down costs for consumers through more efficient procurement and management of risk, as well as launching new markets.

- We launched two new frequency response products, Dynamic Regulation and Dynamic Moderation and drove efficiencies across all our frequency response markets. Total volumes procured were significantly higher but total costs remained static, with unit prices for our dynamic products dropping 80% over the course of the year.
- We concluded our third stability pathfinder and contracted £1.3bn of capacity that will provide inertia and short circuit level, delivering £14.9bn of consumer savings between 2025 and 2035.
- We launched our second constraint management intertrip scheme tenders for 2024-25 delivery, contracting with 1.6GW intertrip capacity from wind units. In our first intertrip scheme, 764MW came online early and since April 2022 has delivered over £80m benefits to consumers, as well as facilitating a new wind generation record in December.

We rapidly responded to the energy price crisis and tight winter margins, intervening in the market to ensure security of supply and manage increasing balancing costs.

- We negotiated winter contingency contracts with three companies, securing access to five units and over 2GW of capacity to use as an emergency action if necessary throughout the winter, i.e. an out-of-the-market service.
- We created a new route to market for demand flexibility, also acting as an emergency service. This was developed in less than six months, and delivered over the winter of 22/23 over 2GWh of demand reduction via over 30 providers, through the participation of over 1 million homes and businesses across the country.

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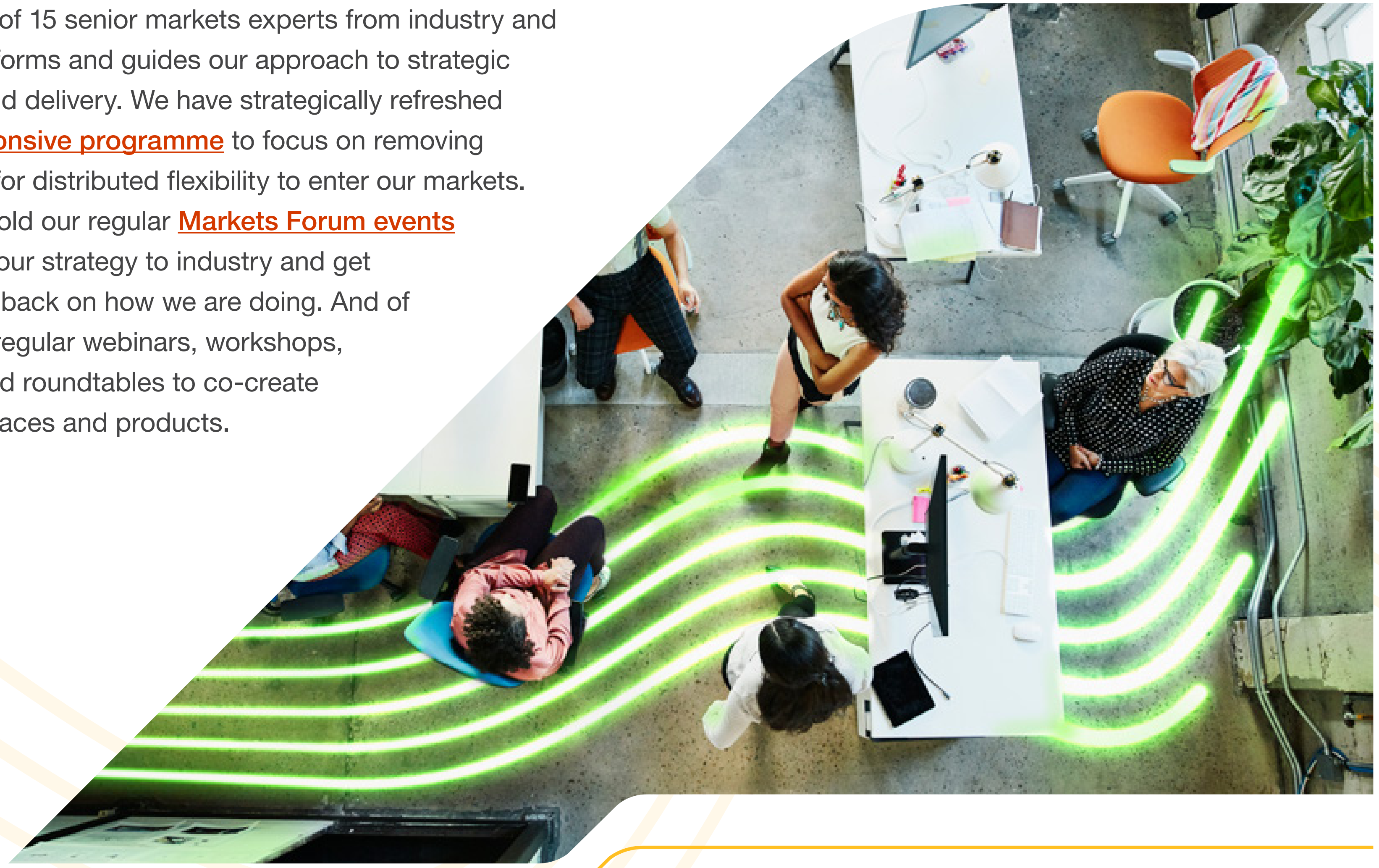
- Significant progress has been made in a short space of time preparing our systems and processes to launch Balancing Reserve. This product will help reduce operating reserve costs by enabling us to procure firm reserve capacity at day-ahead. Our analysis suggests it will save consumers £900m over 2 years.

To deliver these additional initiatives, **we deferred delivery** of our new quick and slow reserve products, as well as slowing the development of our reactive power market design, as the prioritised new markets delivered more value to consumers. The quick and slow reserve products are now scheduled to be introduced in autumn 2023.

We have maintained our **strategic focus on assessing and reforming markets**. Looking at the BM specifically, we commissioned a consortium of expert consultants to conduct a review of high-cost days. We also continued to develop dedicated markets for stability and we signed partners to deliver our Local Constraints Market and Enduring Auction Capability platforms (Piclo and N-Side respectively).

We have also introduced a much more **comprehensive approach to stakeholder engagement**. This March we celebrated one year since the launch of our Markets Advisory Council, a panel of 15 senior markets experts from industry and academia that informs and guides our approach to strategic market design and delivery. We have strategically refreshed our Power Responsive programme to focus on removing barriers to entry for distributed flexibility to enter our markets. We continue to hold our regular Markets Forum events to communicate our strategy to industry and get face-to-face feedback on how we are doing. And of course, we hold regular webinars, workshops, expert groups and roundtables to co-create specific marketplaces and products.



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What to expect in 2023

This summer we will deliver a holistic strategy for electricity markets, setting out our long-term net zero vision for GB markets and policy (NZMR), and achievable pathways to getting there. We will set out our vision for reform of the wholesale market and how it is scheduled, as well as broader investment policy. This will knit our ESO Markets Roadmap with our NZMR programme, ensuring that all reforms we undertake are moving us in the direction of an efficient, holistic, net zero market design. This will give our stakeholders a much clearer view of the longer-term direction of travel.

As we move closer to becoming the Future System Operator, this year we will expand our thinking to whole energy markets – considering the synergies an efficiencies across different vectors, markets and policies.

We will build on 2022's Balancing Mechanism Review, undertaking a more fundamental assessment of the market. This will both support the wider Review of Electricity Markets Arrangements (REMA) analysis into balancing, as well as consider what reforms are worthwhile ahead of any longer-term, more fundamental reforms to the wholesale and balancing market.

We will continue to engage with our stakeholders to ensure that our markets are designed not only to meet our operability needs but are accessible whilst also delivering the best value for consumers.

In terms of new ESO markets, 2023 will see the launch of:

- The local constraints market (LCM) at the Scottish/English boundary to facilitate access to flexible DER at the day-ahead and within-day timescales.
- Our Enduring Auction Capability in autumn 2023, which is working towards optimising all markets for day-ahead response and reserve, but will begin by co-optimising response products only.
- A new mid-term (Year-1) market for stability, offering 1-year contracts for assets to provide high-availability inertia.
- Quick and slow reserve products in autumn 2023, which are designed to operate post-fault to help secure the largest loss.
- The new Balancing Reserve product by the end of the year.

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Executive summary

	Before	Now / imminent	2025 - 2030
Frequency: Response & Reserve	Over 20 different products. Longer term tenders. Pay as bid. Procured through the BM.	New, simplified response products. Day ahead pay-as-clear auctions.	Intraday markets for response/ reserve. Co-optimisation of ESO response and reserve markets.
Stability	Provided by synchronous machines as a by-product of producing electricity. ROCOF managed by reducing size of largest loss.	Long-term tenders (pathfinders) for new investment to meet shortfall in 'baseload' requirement. BM redispatch for short-term needs.	Short-, medium- and long-term procurement.
Voltage	Build new network assets. Synchronise through the BM.	New Service Procurement (pathfinders) to secure shortfall in residual requirement. BM redispatch for short-term needs.	Short-, medium- and long term procurement.
Thermal	Build new network assets. Turn assets up and down in the BM.	Network build. Constraint Management Intertrip Scheme.	Significant network build to meet NOA7 and holistic network design outcomes. Continued tactical commercial interventions.
Balancing Mechanism (BM)	Designed to be a largely residual energy balancing market.	Increased actions to manage energy and system requirements and procurement of new stability products. Short term strategy of moving actions out of BM to mitigate high balancing costs.	Higher level of automation will allow much smaller units to be dispatched in BM. Co-optimisation of ancillary services.
Restoration	Restoration from small number of large fossil-fuel generators.	Opening tenders up to DER and renewables.	DER and renewables contracted to provide restoration services. Distribution Restart Zones introduced by 2028.

2030 and beyond

The longer-term future of our ancillary and balancing services depends heavily on several key questions being tackled by DESNZ's Review of Electricity Market Arrangements (REMA):

- Will the wholesale market remain one single national price, or will it be locational?
- Will we continue with self-dispatch, or will it be scheduled more centrally?
- Depending on dispatch, can ancillary services be co-optimised with the wholesale market?
- Will we see reform to the duration of settlement periods or gate closure?
- How will the capacity market and contracts for difference be reformed?

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Executive summary

Drivers for frequency: response & reserve (Before):

- Rising costs
- Falling system inertia
- Increasing size of largest loss
- Low diversity in market participant types

Drivers for frequency: response & reserve (Now / imminent):

- Need to further optimise procurement across markets
- Continuing to lower barriers to entry

Coming soon for frequency: response & reserve:

- Balancing reserve
- Quick and slow reserve
- New static frequency response products

Drivers for stability (Before):

- Rising costs
- Increasing requirement to meet minimum system inertia
- Need to send investment signals for new-build assets

Drivers for stability (Now / imminent):

- Need to balance efficient investment and efficient dispatch
- Reduce inefficient re-dispatch in the BM

Coming soon for stability:

- Mid-term market (Y-1)

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Executive summary

Drivers for voltage (Before):

- Not enough service providers
- Inefficient utilisation of capacity
- Greater changing power flows

Drivers for voltage (Now / imminent):

- Need to balance efficient investment and efficient dispatch
- Reduce inefficient re-dispatch in the BM

Coming soon for voltage:

- New-build tender under Network Services Procurement

Drivers for thermal (Before):

- Rising constraint costs

Drivers for thermal (Now / imminent):

- Rising constraint costs

Coming soon for thermal:

- Holistic Network Design
- Centralised Strategic Network Plan
- Local Constraint Market
- MW Dispatch Service

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Executive summary

Drivers for balancing mechanism (Before):

- Increased number of balancing actions needed
- High costs
- Barriers to entry for small energy resources

Coming soon for balancing mechanism:

- ESO's Open Balancing Platform, with capability to dispatch multiple providers

Drivers for restoration (Before):

- More renewable generation
- Retiring fossil fuel plant
- ESRS obligations
- Barriers to entry for new technologies

Drivers for restoration (Now / imminent):

- More renewable generation
- Retiring fossil fuel plant
- ESRS obligations

Coming soon for restoration:

- DER awarded restoration contracts
- Launch of first DRZ

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Introduction

Markets as part of the bigger picture

As the UK progresses towards net zero, there will be many changes to the technological, economic and political landscape of our electricity system. Both ESO and non-ESO markets will be evolving during this transition, as well as how they interact between one another. We recognise our customers' need for a coherent set of market principles across our networks, as outlined in our Markets Design Framework. The illustration on the right shows how we work with many different sources and stakeholders to ensure that our markets meet our customers' expectations need for coherency.

Products	Overview
Operability Strategy Report (OSR)	The OSR explains the challenges we face in operating a rapidly changing electricity system to enable a zero carbon electricity system in 2035. There is a close interaction between the OSR and the Markets Roadmap, both documents complement one another with the OSR defining our operational requirements and future system needs, while the Markets Roadmap explains how our markets are evolving to meet these future needs in the most efficient way.
CSNP	We are transitioning to our CSNP in 2024, which will be a framework encompassing and coordinating various processes including the ETYS and the NOA. This framework will help us communicate to industry our system requirements and how they can help solve these.
5-point network plan	We have developed a five-point plan to speed up network connections to help deploy the low carbon generation required for GB to reach net zero. This includes the introduction of a two-step connection offer.

Find out more

Find out more

Find out more

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Markets as part of the bigger picture

Products	Overview
Operational balancing platform	As the technical landscape evolves, so too must our control room features. The centrepiece of this is our new Open Balancing Platform, part of our Balancing Programme. The Platform has been designed from the ground up to be secure, scalable and flexible to underpin the benefits of the business Plan. It will reduce the heavy workload in the control room, while enabling new services, many more units, faster development and greater transparency. The transformation will be ongoing between 2023 and 2027.
Single Markets Platform	Our SMP is being introduced to improve the user experience for providers of ancillary services, thereby helping ESO become a better buyer. Reducing the resources required to enter several ESO markets (e.g., pre-qualification and registration via single portal, pre-qualification for a single asset but access to multiple markets) will allow customers to access several ESO markets through a single platform.
Frequency Risk and Control Report (FRCR)	Large sudden changes in supply and demand can cause the frequency of the GB electricity system to change. Our annual FRCR assesses how likely, how long and how large those frequency changes might be and the associated cost impacts. This informs the risks which we will secure operationally in line with Security and Quality of Supply Standard (SQSS) using our suite of ancillary services products.
Service Provider Capability Mapping	We are undertaking an innovation project to enhance the ESO's understanding of the technical capabilities and commercial decision-making (investment and operation) of existing and future flexibility providers located across the network. This greater understanding will enable ESO to reform markets in ways that unlock the potential of future flex providers, enabling them to maximise their value to the whole electricity system.

Find out more
Find out more
Find out more
Find out more

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Markets as part of the bigger picture

Products	Overview
Open Networks	The Open Networks programme brings together the nine electricity grid operators in the UK and Ireland working to standardise customer experiences and making connecting to the grid as easy as possible. This focuses on ensuring open and transparent, accessible and efficient markets that are coordinated between DSOs and the ESO.
Distributed Flexibility Strategy	We are investigating the challenges of current market arrangements for Distributed Flexibility providers to understand reforms required to deliver power sector decarbonisation by 2035.

Find out more

Find out more

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Markets as part of the bigger picture

Products	Overview
REMA	The Review of Electricity Market Arrangements (RMEA) represents the most far-reaching review of energy market arrangements since privatisation. The ESO response was informed by our Net Zero Market Reform (NZMR) analysis.
NZMR	ESO's Net Zero Market Reform programme was established in early 2021 to examine holistically the changes to current GB electricity market design and investment policy that will be required to achieve net zero.

Find out more
Find out more

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Markets as part of the bigger picture

Products	Overview
Future Energy Scenarios (FES)	FES represents a range of credible pathways out to 2050 and our net zero target. FES has an important role to play in helping to shape the energy system of the future as it used to inform network planning and investment decisions. It helps develop our understanding of what could be happening with markets for the wider energy system.

Find out more

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Markets Engagement

Stakeholder Engagement

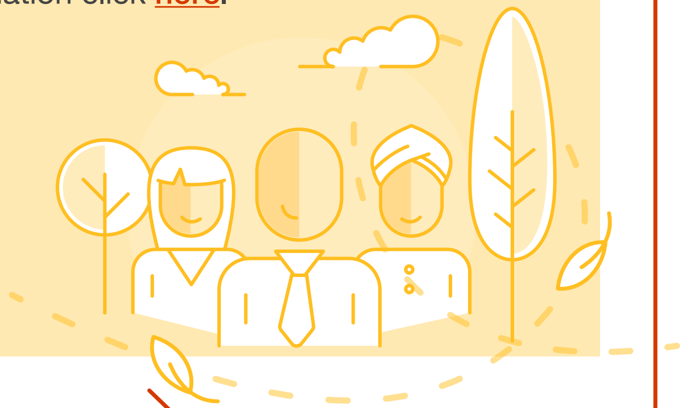
Talking to our stakeholders to understand their perspectives, needs and the products they can offer us, is a really important part of developing well-designed, cost-effective market solutions.

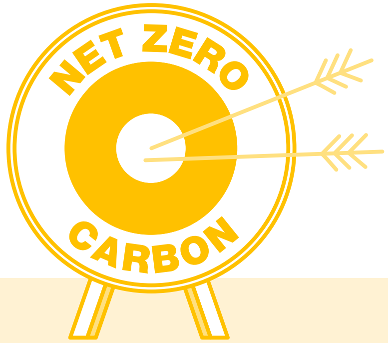
Markets Advisory Council

One of our key stakeholder groups is the Markets Advisory Council (MAC). The MAC has recently been established to inform our approach to strategic market design and delivery.

The group is made up of experts from all parts of the electricity value chain including networks, generators, flexibility providers and academia.

For more information click here.





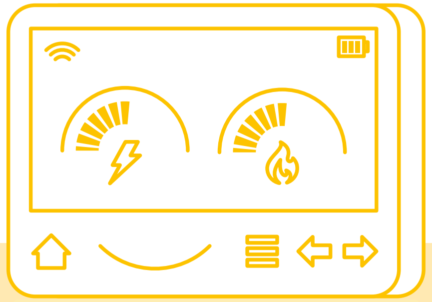
Markets Forum

We regularly hold the markets forum to help attendees learn about how the ESO is developing new and existing markets to enable the transition to net zero, as well as provide a view of electricity market change.

Markets Forum aims to:

- Communicate our strategy for developing new and existing markets as we transition to net zero.
- Allow market participants the chance to discuss any blockers or opportunities with the ESO.
- Show market participants how ESO is co-creating with industry in how we develop, design and implement our market solutions.

More information can be found here



Power Responsive

Power Responsive is a stakeholder-led programme, facilitated by ESO, to stimulate increased participation in the different forms of Demand Side Flexibility (DSF).

Its strategic goals are to:

- Help to inform the development of inclusive markets for flexibility through the removal of barriers to entry.
- Promote the participation of DSF equitably in all markets, with a focus on ESO markets.
- Enable the perspective of customers and DSF providers to be heard.

More information can be found here

Market-specific engagement

In addition, we engage with stakeholders in smaller, more focussed, forums when needed when developing new markets. An example is the stability market expert group, which has been providing vital feedback and insight to our market design process.

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Market Areas

Frequency Response

Context

To maintain a stable system frequency of around 50Hz, (set by the Security and Quality of Supply Standard), we procure a range of response services. These services are able to automatically react to changes in system frequency (increases or decreases, triggered by changes in generation or demand), which can happen in both normal operational scenarios and in post-fault situations. As we transition to net zero and a greater proportion of renewable generation capacity, we will have to manage more frequent and faster frequency fluctuations, and we will need to procure services from zero carbon technologies.

Link to frequency response webpages

How do we procure response services?

- Dynamic products
- Firm Frequency Response
- Mandatory Frequency Response
- How our future products will be used

Dynamic products

Dynamic Containment (high/low)

- Response provided within 1 second, duration of 15 minutes
- In EFA blocks (6 x 4hr blocks per day)
- Post-fault
- Bought a day-ahead of need
- Prevents frequency deviations outside -0.8Hz / +0.5Hz following large losses

Dynamic Regulation (high/low)

- Response provided within 10 seconds, duration of 60 minutes
- In EFA blocks (6 x 4hr blocks per day)
- Pre-fault
- Bought a day-ahead of need
- Assists in keeping frequency near to 50Hz during normal conditions

Dynamic Moderation (high/low)

- Response provided within 1 second, duration of 30 minutes
- In EFA blocks (6 x 4hr blocks per day)
- Pre-fault
- Bought a day-ahead of need
- Assists in keeping frequency within 0.2Hz, especially during more volatile conditions.

Frequency Response

Context

To maintain a stable system frequency of around 50Hz, (set by the Security and Quality of Supply Standard), we procure a range of response services. These services are able to automatically react to changes in system frequency (increases or decreases, triggered by changes in generation or demand), which can happen in both normal operational scenarios and in post-fault situations. As we transition to net zero and a greater proportion of renewable generation capacity, we will have to manage more frequent and faster frequency fluctuations, and we will need to procure services from zero carbon technologies.

Link to frequency response webpages

How do we procure response services?

- Dynamic products
- Firm Frequency Response
- Mandatory Frequency Response
- How our future products will be used

Firm Frequency Response

Static FFR:

- Response provided within 30 seconds, duration of 30 minutes
- Post-fault
- Contract duration of a single EFA block
- Monthly procurement (daily as of 31st March 2023)

Dynamic FFR (primary, secondary, high):

- Response within 2 – 30 seconds, duration of 20 seconds up to indefinite
- Pre- and Post-fault
- Monthly procurement

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Frequency Response

Context

To maintain a stable system frequency of around 50Hz, (set by the Security and Quality of Supply Standard), we procure a range of response services. These services are able to automatically react to changes in system frequency (increases or decreases, triggered by changes in generation or demand), which can happen in both normal operational scenarios and in post-fault situations. As we transition to net zero and a greater proportion of renewable generation capacity, we will have to manage more frequent and faster frequency fluctuations, and we will need to procure services from zero carbon technologies.

Link to frequency response webpages

How do we procure response services?

Dynamic products

Firm Frequency Response

Mandatory Frequency Response

How our future products will be used

Mandatory Frequency Response

- Response within 10 – 30 seconds, duration of 20 seconds up to indefinite
- Post-fault
- Real-time, procured through the balancing mechanism (BM).

Mandatory Frequency Response (MFR) is one of the original response services, which is procured through the balancing mechanism.

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Frequency Response

Context

To maintain a stable system frequency of around 50Hz, (set by the Security and Quality of Supply Standard), we procure a range of response services. These services are able to automatically react to changes in system frequency (increases or decreases, triggered by changes in generation or demand), which can happen in both normal operational scenarios and in post-fault situations. As we transition to net zero and a greater proportion of renewable generation capacity, we will have to manage more frequent and faster frequency fluctuations, and we will need to procure services from zero carbon technologies.

Link to frequency response webpages

How do we procure response services?

Dynamic products

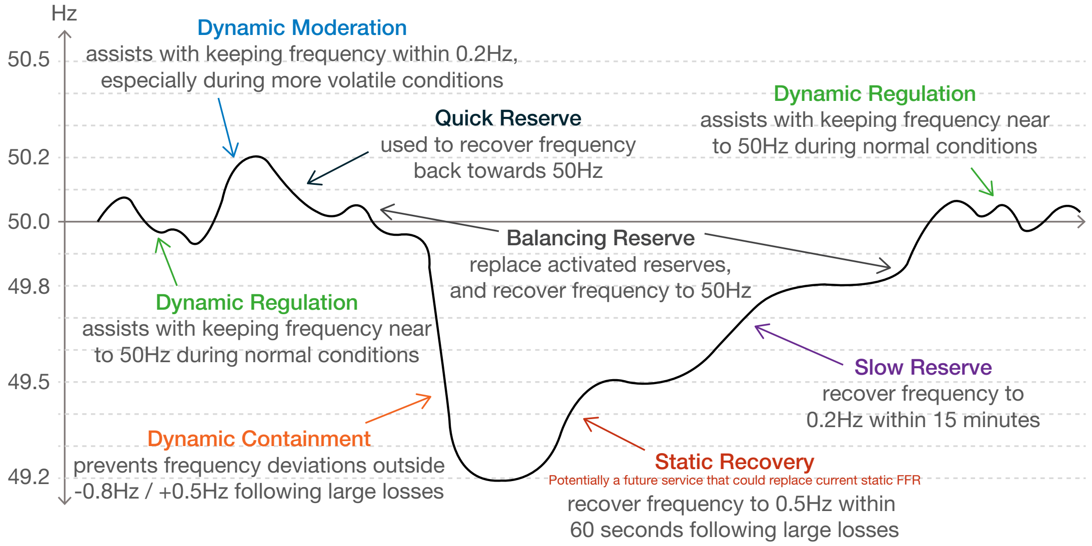
Firm Frequency Response

Mandatory Frequency Response

How our future products will be used

How our future products will be used

- Quick and slow reserve will be introduced later this year, balancing reserve is a potential future product.



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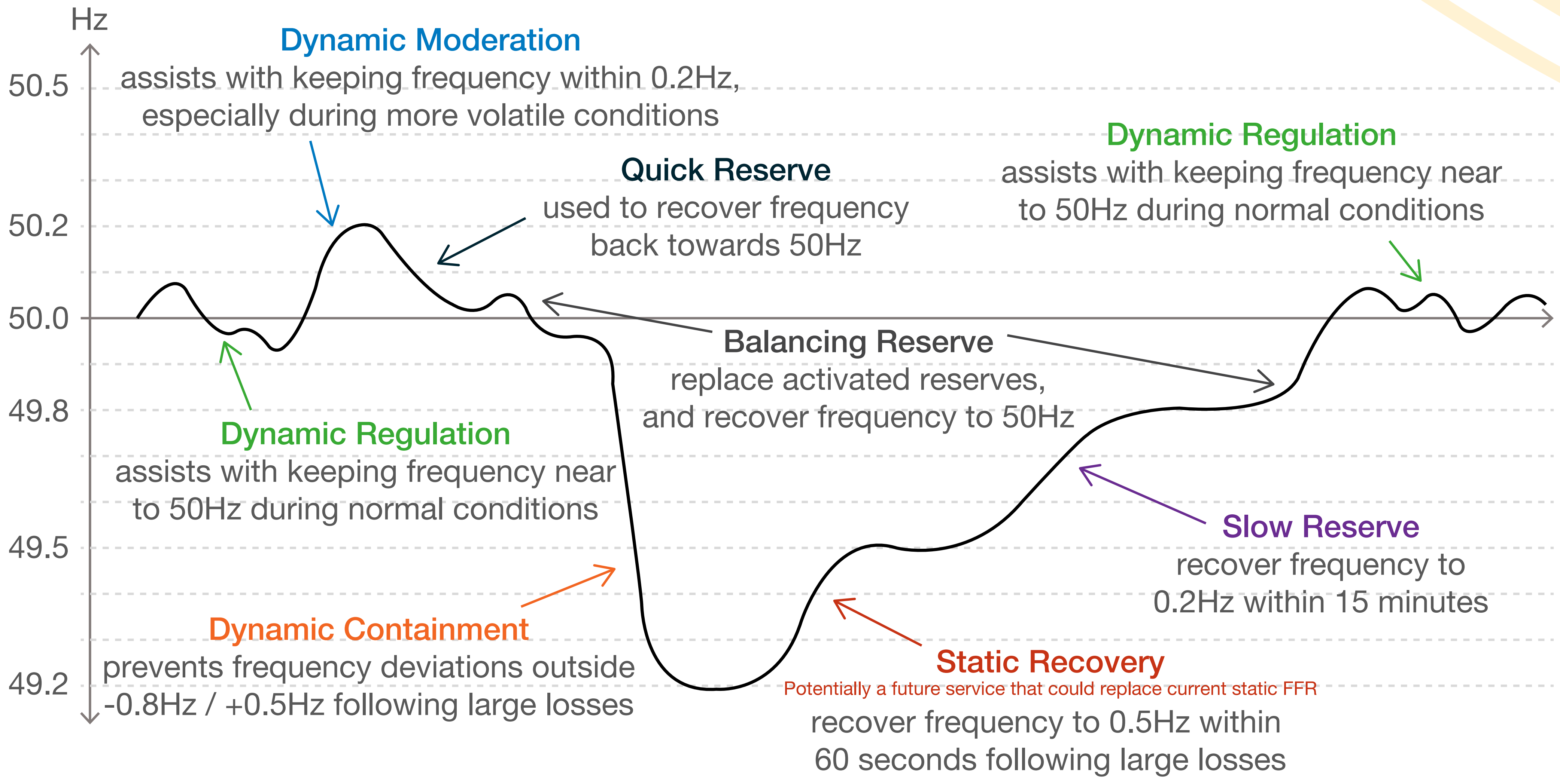
Frequency Response



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Frequency Response - Summary of the chapter

How is the landscape changing? Increasing levels of renewable generation replacing synchronous plant mean that the levels of inertia on the system are dropping. In addition, the largest potential supply or demand loss risk to the system is increasing as our interconnections grow and with the future connection of Hinkley Point C. These two factors are changing the way we need to operate the system.

How have costs and volumes evolved in the last year? Overall response volumes have increased as our requirements increased but costs have fallen by 5%. The split between the different products has shifted markedly, with much more procured via our day ahead markets, reducing MFR volumes procured in the BM. This has really driven down cost per unit volume as we have been less exposed to high intraday costs.

What is driving the need for reform? With the changing landscape, we need response products which better serve the new system requirements, from a wide range of providers. This means phasing out the legacy products and finding ways to enable more market liquidity, to reduce cost and to provide clear and coherent signals to providers about our requirements.

How are we implementing market reform? After launching DM and DR in 2022, our aim is to now drive more efficiency in procurement, primarily through co-optimisation across our products and expanding the range of technologies able to participate. We are looking to remove barriers to entry for smaller providers and new types of technologies.

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Frequency Response - Market Insights: Volumes

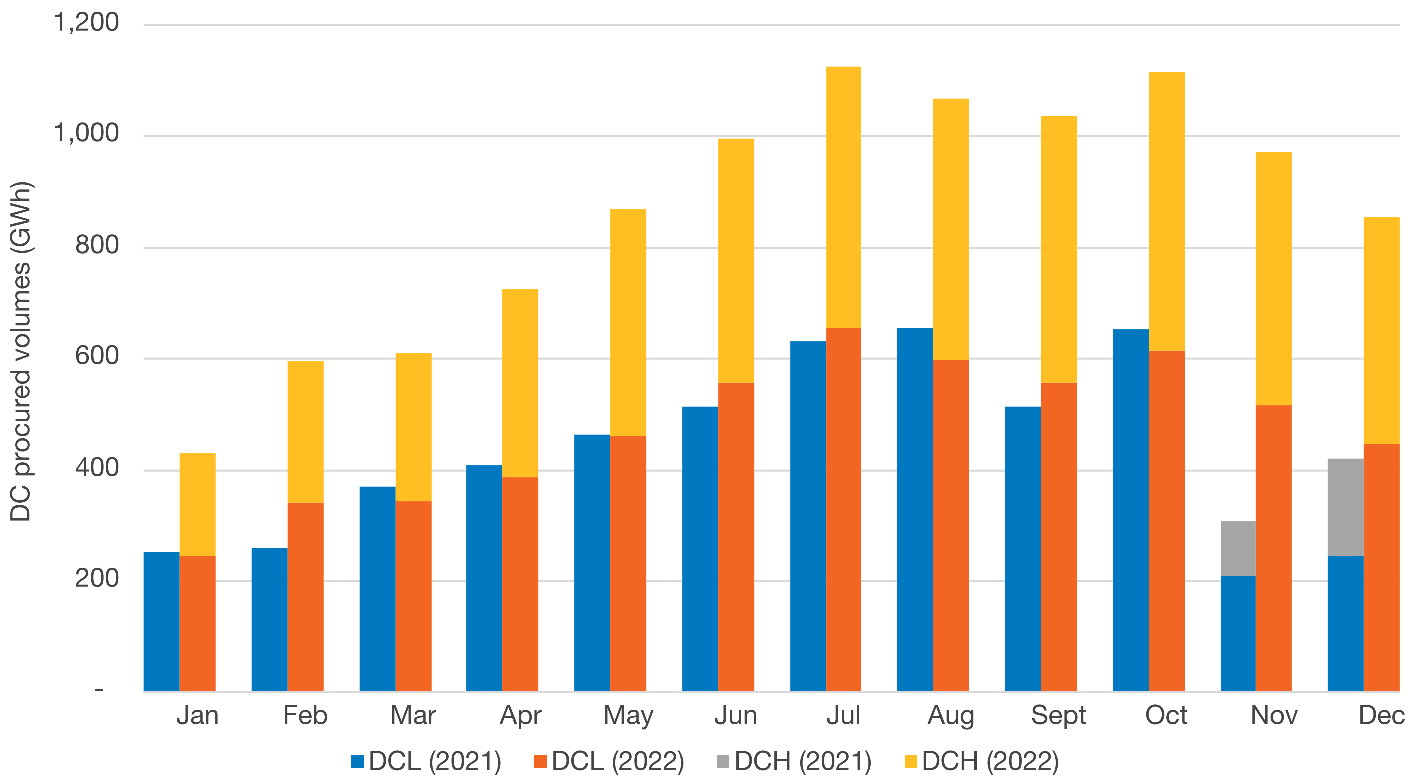
Overall frequency response volumes grew

Overall frequency response volumes grew significantly in 2022 due to changes in our approach to help us meet our requirements more cost-effectively. Our frequency control policy changed and we revised our procurement strategy for DC so it can help secure against our largest loss risk (for more information, please see our Frequency Risk and Control report). During 2021, as DC volumes were growing in an immature market, we dynamically assessed our requirements for all response services to maximise value and minimise operational risk during periods of insufficient market liquidity. This led to an 80% increase in FFR procurement, a doubling of DC procurement, and a corresponding decrease of over 20% in MFR procurement, demonstrating our success in moving procured volume to competitive markets.

Dynamic Containment

- Overall volumes of DC (high and low) increased by 100% to around 11,000 GWh in 2022 (Figure 1), largely due to the fact that DC high was launched in November 2021.
- Where DC low frequency mitigates against large generation losses, the DC high product responds to large demand losses. There has been strong growth in participation since we launched the DC market and by December last year we were fulfilling 97% of our requirements through DC. This growth is in part due to the change in our frequency control policy to securing our largest loss meaning DC could be used to help manage this risk.
- Monthly DC low volumes in 2022 were broadly similar to 2021, apart from Nov and Dec which were higher. This is down to higher levels of inertia on the system in 2021 in comparison to 2022.
- 31 market participants were active in the DC market over 2022, compared to 20 at the end of 2021.

RP Figure 1: Dynamic Containment volumes: Jan 2021 - Dec 2022



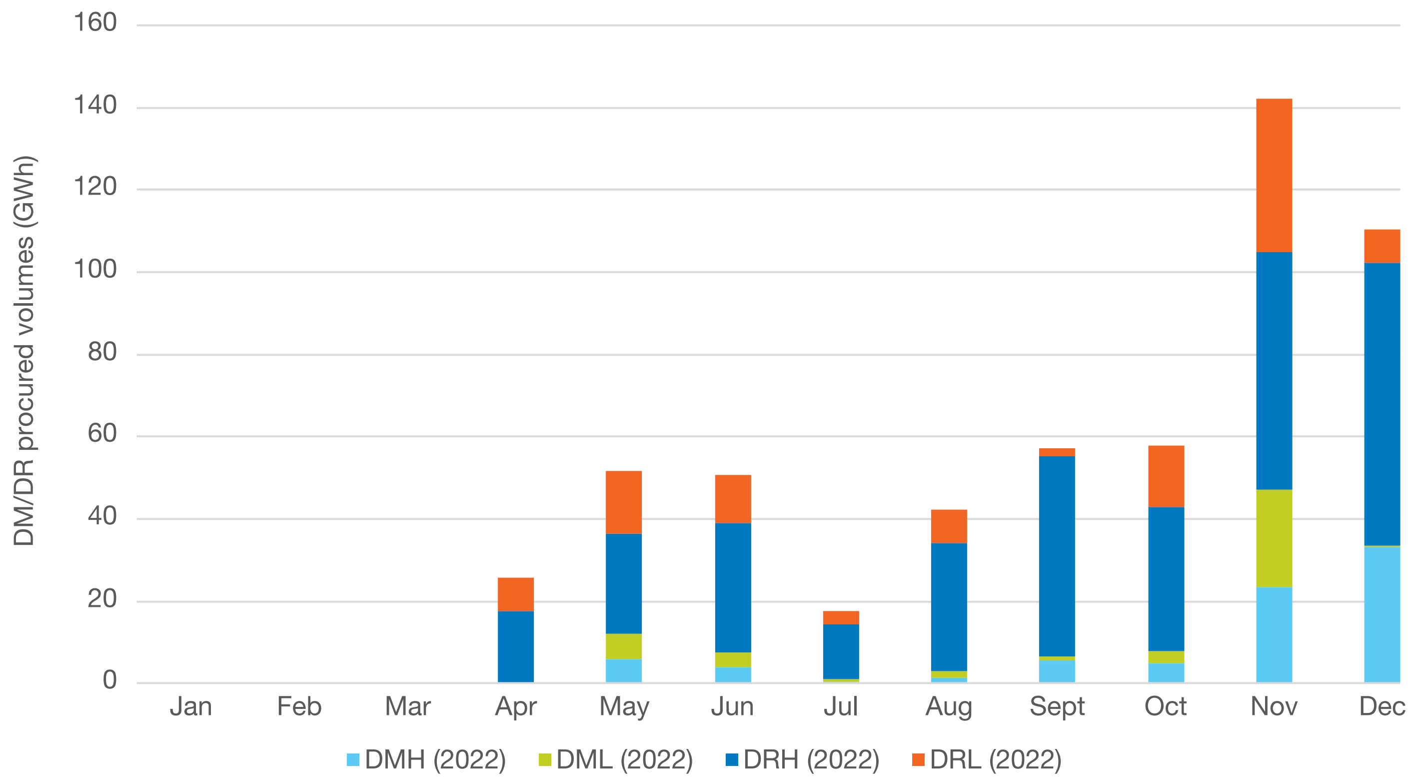
Markets Roadmap / Market Areas / Frequency Response 33

Frequency Response - Market Insights: Volumes

Dynamic Moderation and Regulation

- We launched DR in April and DM in May 2022 (Figure 2) with 100MW cap on each service.
- DM and DR procurement depends on what is happening in the DC market. For example, if DC requirements are forecast to be high or there are liquidity concerns, we reduce our DM/DR requirements. In November and December 2022, our requirements for DC fell as there was more inertia on the system, so we were able to procure more DM/DR to meet our requirements.
- The volume caps for both DM and DR will be reviewed as ESO IT system improvements are delivered and the markets develop, with the cap for DR already increased to 200 MW in March 2023.

RP Figure 2: Dynamic Regulation and Moderation volumes: 2022



Markets Roadmap / Market Areas / Frequency Response 34

Frequency Response - Market Insights: Volumes

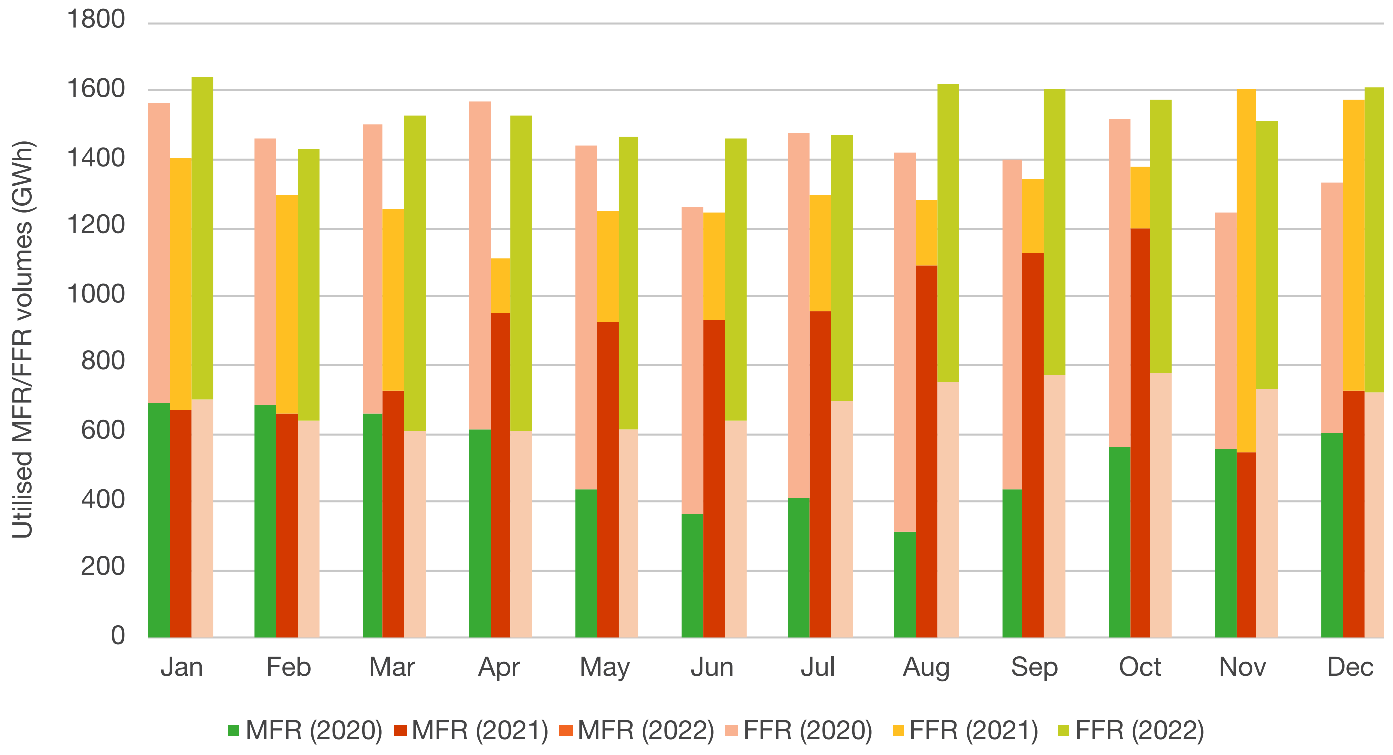
Overall frequency response volumes grew

MFR and FFR

For these two legacy products, approximately 55% of the volumes were FFR (whereas in 2021 it was only 35%). Static FFR (up 85% YoY to 10,200 GWh) was procured for secondary response, which helped reduce procurement of the more expensive MFR (volumes were down 22% YoY to 8170 GWh).

The volume of sFFR procured in 2022 increased significantly, as a result of the change in our response holding procurement policy in November 2021. The change was needed to address the shortage of market participants for dFFR, as many had chosen to enter the DC market instead, which was more lucrative.

RP Figure 3: FFR and MFR volumes: 2020 - 2022



Markets Roadmap / Market Areas / Frequency Response 35

Frequency Response - Market Insights: Costs

Overall

Overall response costs in 2022 were slightly down (-5%) compared to 2021. The split of costs however was very different. This is because we have been using frequency response as a means to reduce largest loss risks, which meant procuring more DC instead of making direct trades or issuing BOAs to manage ROCOF in the BM. An almost halving of MFR costs to ~£79m was offset by a 45% increase in DC costs to ~£129m and an almost doubling of FFR costs to £58m. However, the wider context is a significant reduction in costs of BOAs, trades and inertia as a result of using DC instead.

In 2022, monthly response costs peaked at ~£38m in June, driven largely by high volumes of DC. These costs fell dramatically from July to December as a result of ESO actions to improve market liquidity and drive more efficient procurement (see the following 2022 frequency case study).

Markets Roadmap / Market Areas / Frequency Response 36

Frequency Response - Market Insights: Costs

Cost of legacy products moved in line with changes in volume procured

As discussed in the volumes section, the change in response holding procurement policy saw FFR volumes increase and MFR volumes decrease. These movements saw a reflective movement in costs; monthly spend peaked at £25m in October 21, but after the change, costs fell to less than £11m per month throughout 2022. EFR costs fell by 60% to ~£8m in 2022 as the product was discontinued in August 2022 to give space to the new and much faster dynamic products.

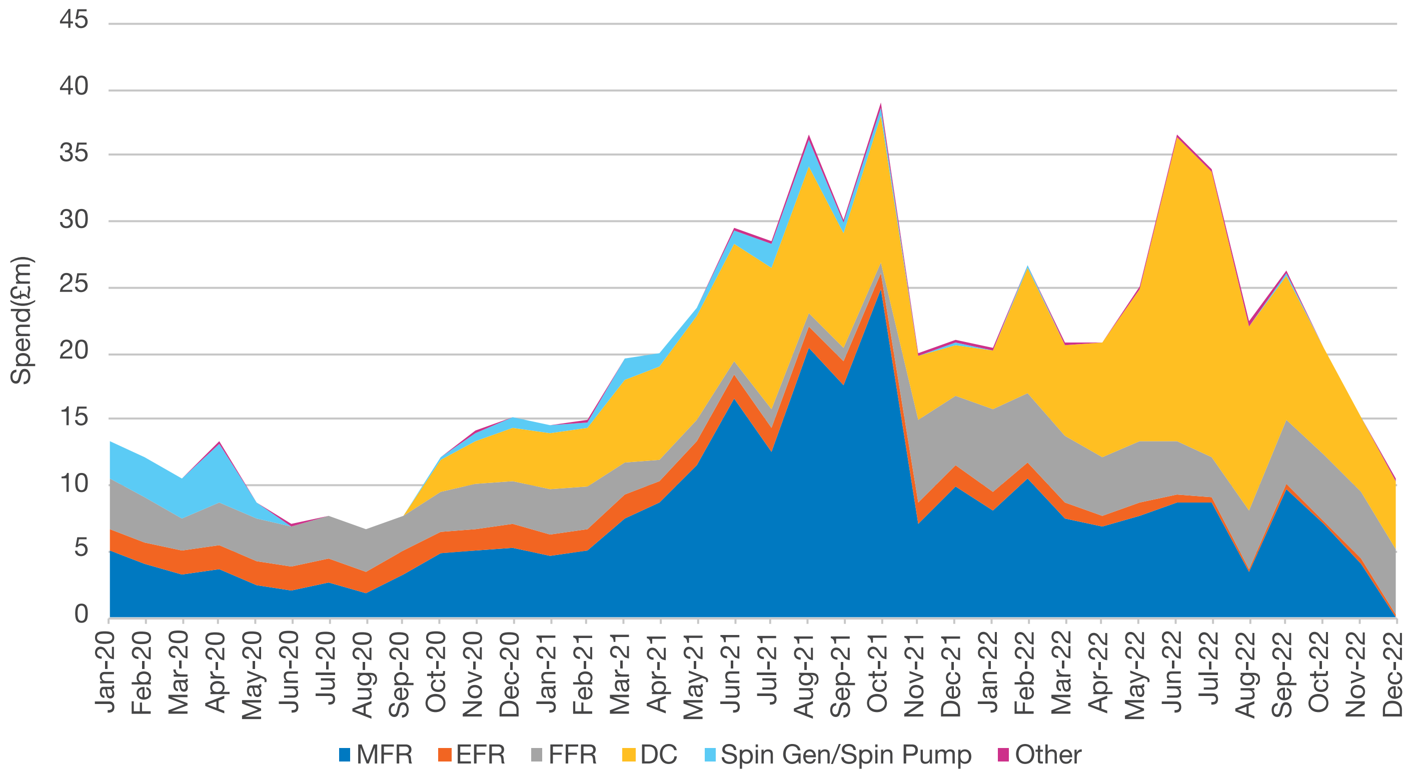
Large increase in dynamic product costs, driven by DC

The 45% increase in DC costs YoY was a lot lower than the increase in volumes (which were up 100%). However, given the significantly higher wholesale costs on average over 2022, these numbers actually mask a lot of activity by ESO over the year to drive down the per unit cost of DC. Since June 22, there has been a significant price reduction for dynamic products, from £24/MWh to £4.5/MWh, whilst procured volume remains the same.

The increase in DC volumes and costs reflects the fact that we are using it now to help secure losses in place of taking other actions, while our largest loss risks are also increasing. Additionally, the number of participants in DC markets have increased, in part due to a change in procurement from 24-hour contracts to EFA-block granularity as well as the market maturing, so it's been possible to purchase more. Further, DCH was not available for the whole of 2021, so inevitably volumes and costs were greater in 2022.

Note 1 - Figure 4 doesn't have the MFR costs for December 2022 due to a technical issue.

RP Figure 4: Response costs: 2020-2022



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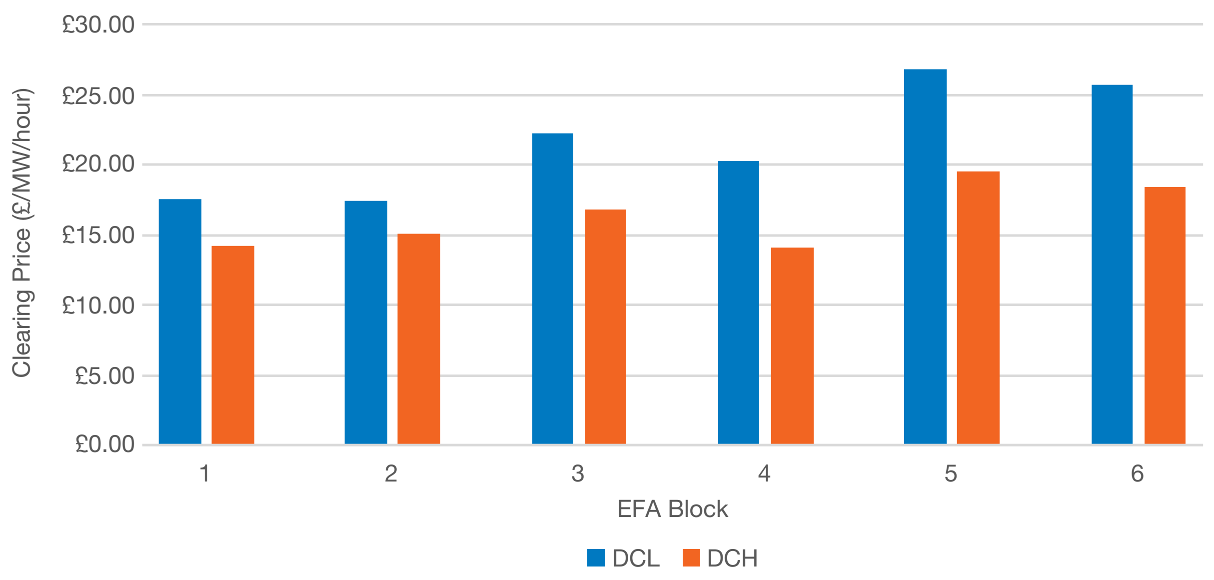
Frequency Response - Market Insights: Costs

Price variations tell the story of an evolving market

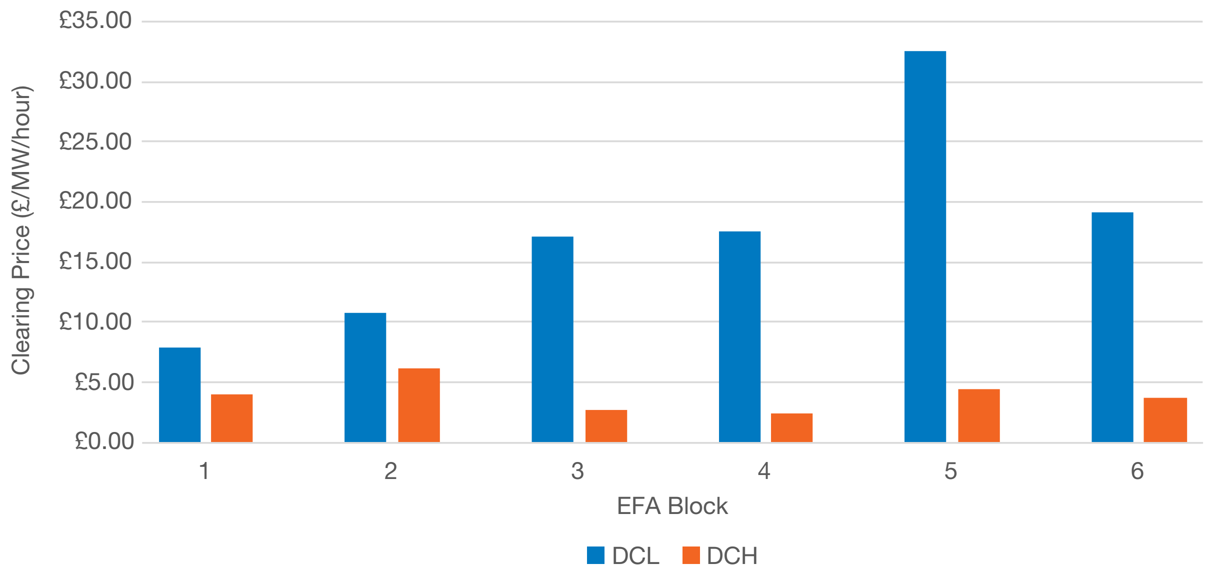
Prices for the dynamic products started with little variation when they were first launched (see Figure 5). However, they have evolved over time. For example, for all of the low frequency products, the prices now peak in EFA block 5, which is the evening peak, when there is generally more demand for the product.

The charts show the average EFA block prices over 2022 for dynamic products. For both high and low products, there is wide price range, with some prices peaking at over £100/MW/hr for EFA blocks 3 and 5. The lowest prices were £0/MW/h for both DM and DR products. We have been able to procure dynamic high products at no cost to us on some occasions because whilst the provider is not being paid to provide the service, energy-limited assets are able to restore state of charge more cost effectively.

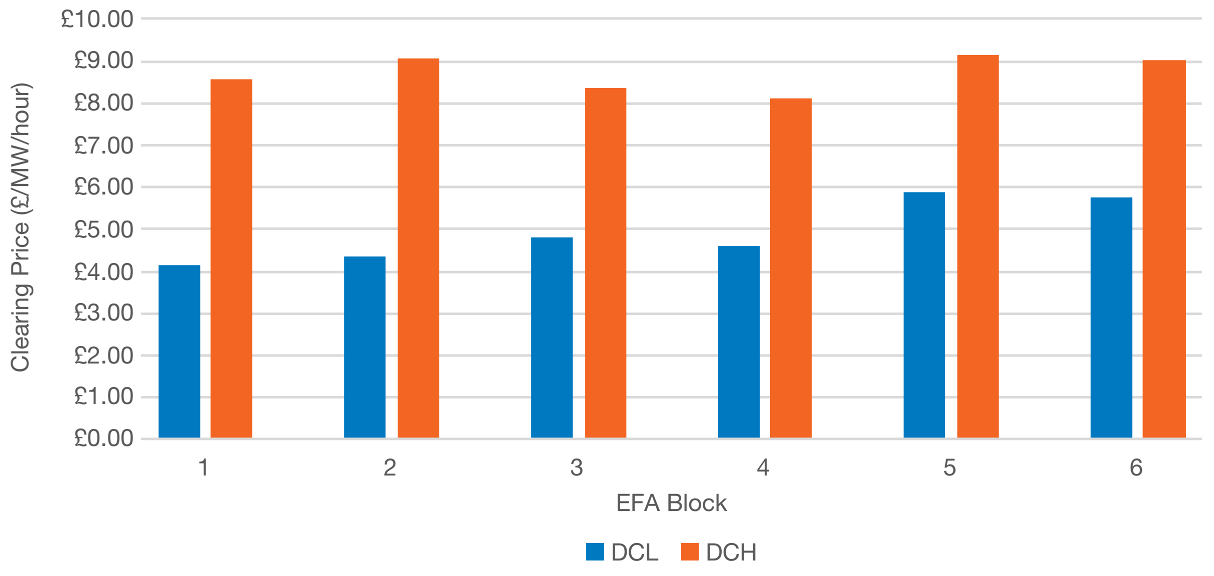
RP Figure 5b: Average DRL & DRH clearing price 2022



RP Figure 5a: Average DCL & DCH clearing price 2022



RP Figure 5c: Average DML & DMH clearing price 2022



Markets Roadmap / Market Areas / Frequency Response 38

Frequency Response - Market insights: Frequency Response Providers

Market Information: **Frequency response providers**

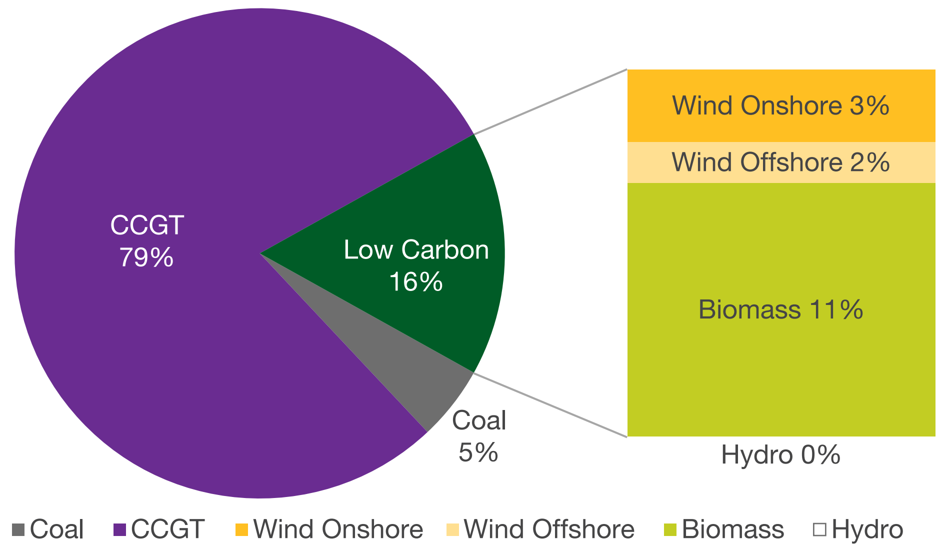
The providers for our frequency products cover a range of technologies and providers, including demand side response from large energy consumers, fossil fuel plant, renewables and batteries.

Flexible gas-fired plant provide the majority of MFR, reflective of the wider makeup of the BM where it is procured (Figure 6). The proportion from low carbon sources (including wind and biomass) doubled in 2022 in comparison to 2021.

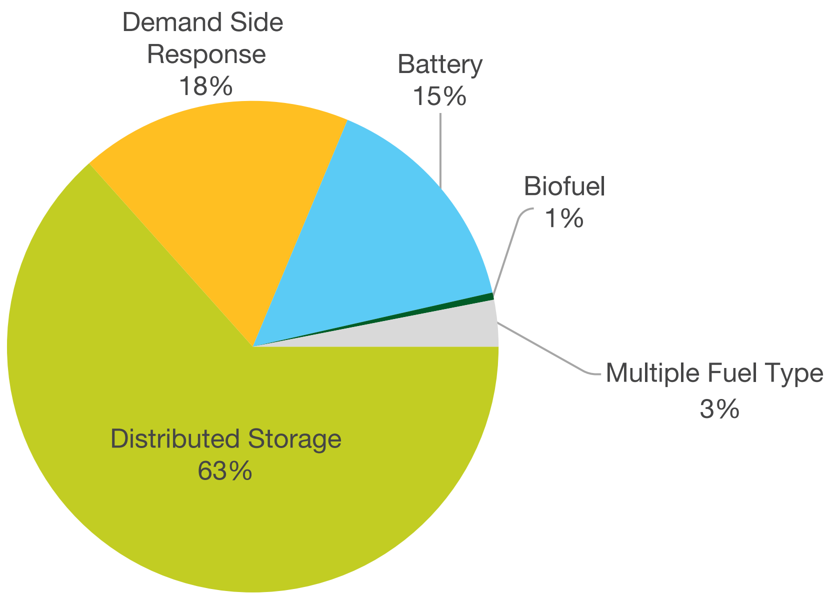
FFR has both demand-side and supply-side response providers, which include distributed storage, larger battery installations, demand turn up and turn down of major energy users as well as diesel and biofuel plant (Figure 7). These high carbon sources fell from 5% in 2021 to 3% in 2022; by 2025 they need to be at zero to enable us meeting our zero carbon operation target.

All of our dynamic products are currently provided by batteries, although it is not exclusively for batteries and we'd like to see more diversity in future. (Figure 8).

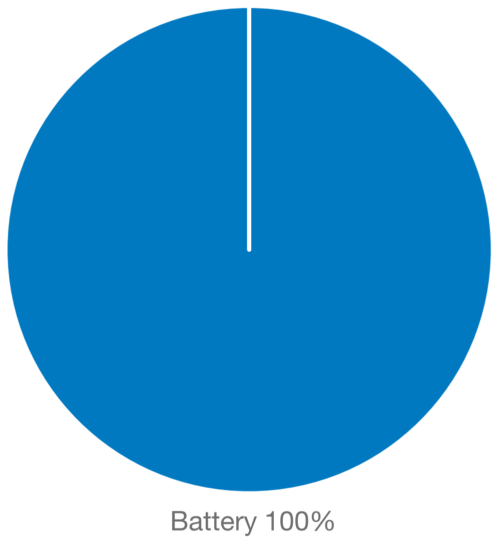
RP Figure 6: MFR by technology



RP Figure 7: Monthly tendered FFR by technology



RP Figure 8: Dynamic services by technology



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Case Study: 2022 – a year of driving costs down through liquid markets and sophisticated procurement

2021 was a year defined by establishing new products and markets – we carefully grew our new DC market to minimise risk to ESO and to stimulate confidence from market participants. In 2022, our key objectives were:

1. To grow liquidity in our DC market

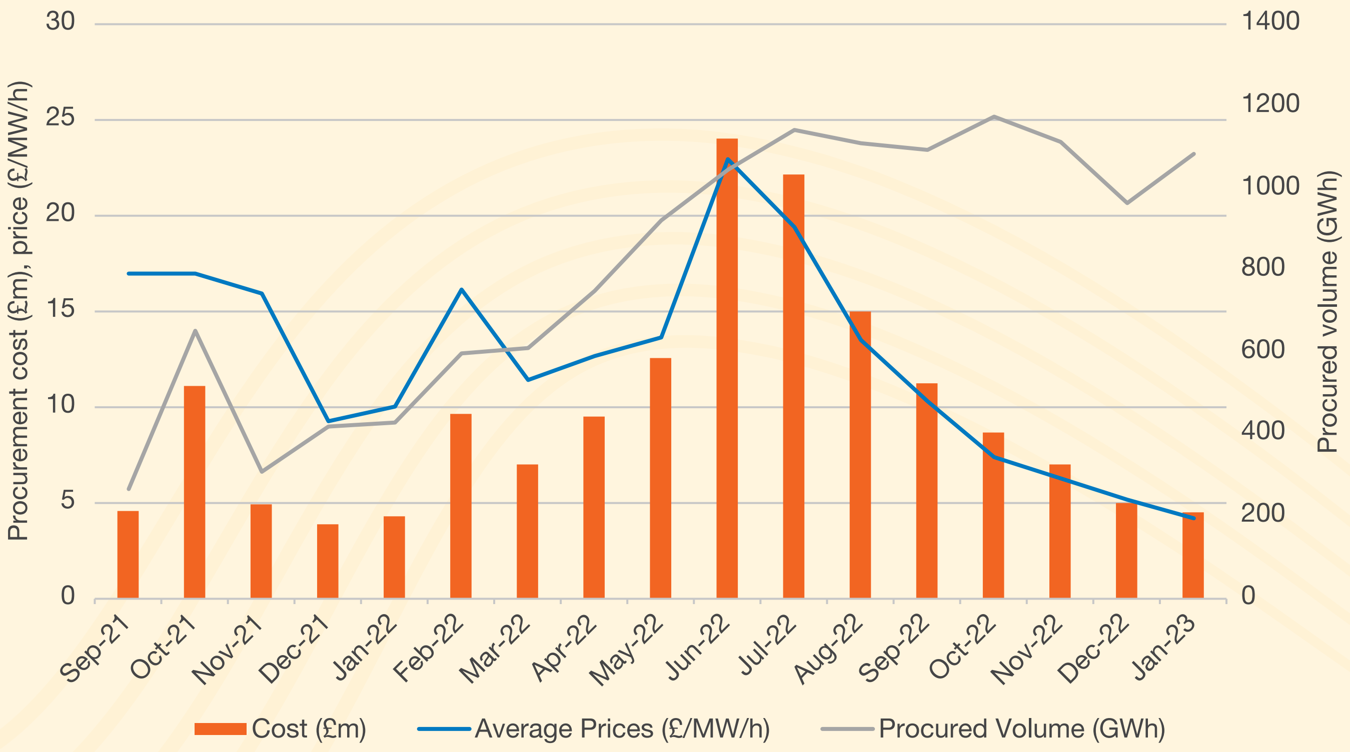
2. To increase the sophistication of our procurement strategy

3. To launch our new DR and DM products

As can be seen in Figure 9, procured monthly volumes until January 2022 were generally below 430GWh. Over the course of 2022, we have increased procured volumes to an average of ~950GWh over May through December. This was primarily in response to changes to our frequency control policy meaning that we no longer needed to restrict large loss risks to prevent consequential ROCOF losses. We also started to provide a 4-day rolling forecast of our needs, which helped to improve transparency for providers, enabling them to understand our needs better and bid in more markets. This increased liquidity allowed us to be able to buy more of the products we needed in the dynamic markets.

We significantly improved the sophistication of our procurement of DC in 2022. In September 2021, when we launched DC-high and introduced the EFA blocks, our buy curve[1] was static and predictable to attract new participants and grow the market. Market liquidity was low, with the market only presenting ~900MW against our requirement of 1.1GW. As a result, clearing prices were very close to our buy curve until Oct 2021. In Nov 2021, DC markets started to reach saturation for certain periods and clearing prices started to become competitive. However, the use of the static buy curve was creating opportunities for "hockey stick" bidding strategies. This is when the provider puts in a bid for most of its volume at a low price but includes some bids at a high price, which is just below the price cap and which they knew would very likely be accepted as well. This behaviour was driving up the clearing prices for 10% - 50% of the DC auctions per month.

RP Figure 9: Dynamic response markets 2021-23



1 The buy curve is the profile of the ESO's demand and defines how much we want to buy and the maximum price we are willing to pay.

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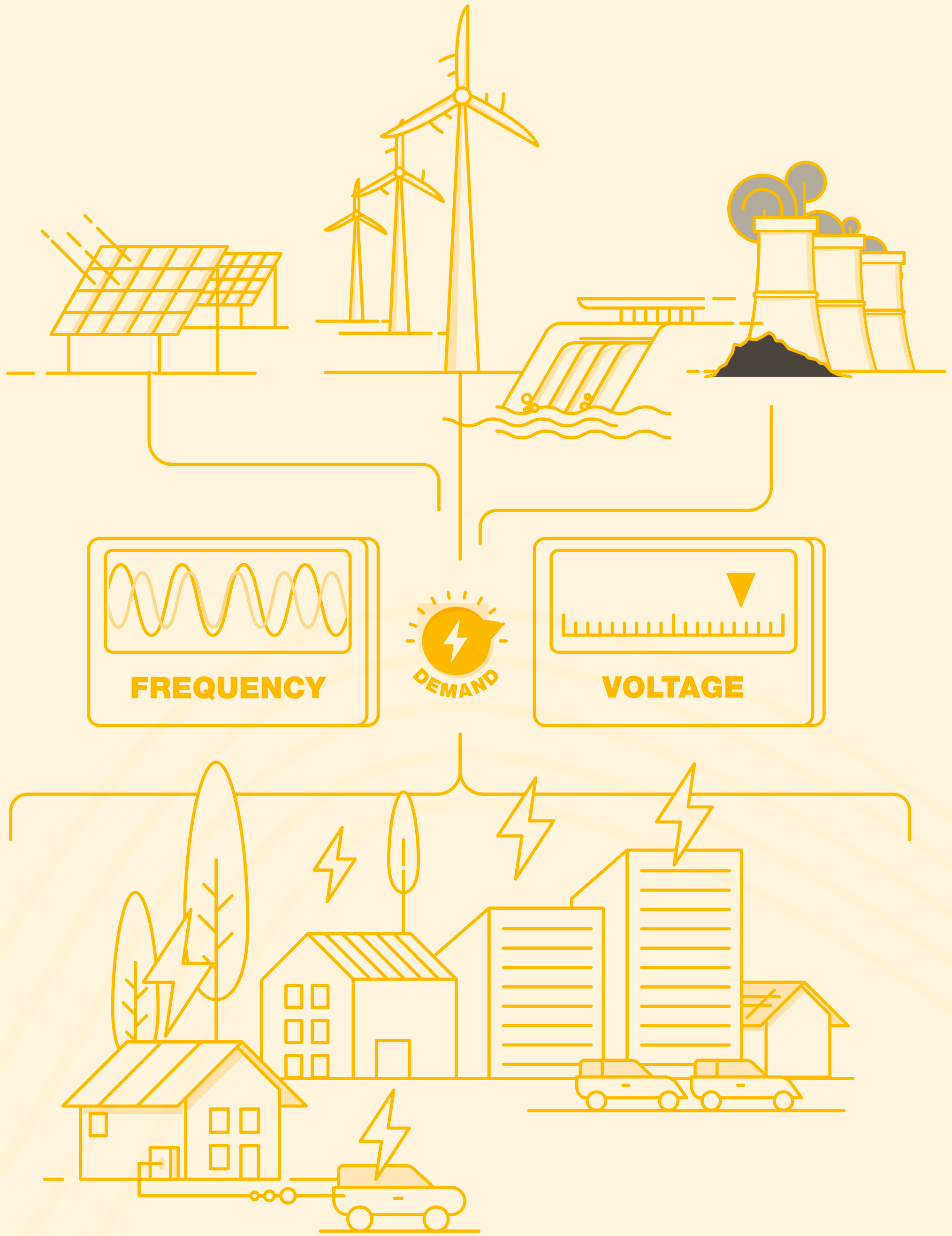
To combat this, we implemented a new dynamic buy order, effective from 1st Apr 2022. The new dynamic buy order meant we were able to meet our requirements more cost effectively by establishing multiple thresholds, based on our willingness to pay for capacity. This reduced hockey stick bidding and drove clearing prices down. From Apr 2022, it has saved us at least £1.5m per month. This new type of buy order was automatically been applied to DM and DR when they were launched in April and May 2022.

Additional costs were also being incurred by merit order constraints being applied by the auction clearing algorithm. The constraints had been in place as a trial since 2019 to test the hypothesis that the design would encourage a level playing field among all auction participants. Simulation studies showed that the removal of merit order constraints could reduce costs by 12% and so it was decided that these constraints were no longer appropriate and should be removed. The constraints were removed in March 2022, which led to a marked decrease in rejected volumes and ultimately to lower clearing prices and procurement costs.



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1 The buy curve is the profile of the ESO's demand and defines how much we want to buy and the maximum price we are willing to pay.

Frequency Response - Drivers for Reforms

Clear, coherent market signals are needed

Providers need to choose between markets, impacting liquidity and price

Barriers to entry are limiting competition

Clear, coherent market signals are needed

The existing legacy products no longer adequately meet the needs of how the system operates and won't be fit for purpose for a fully decarbonised electricity system. In future, we need coherent products with optimised approaches to help give market participants the certainty and transparency they need. This will result in a well-functioning and liquid market, which will help us keep costs down for consumers.

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Frequency Response - Drivers for Reforms

Clear, coherent market signals are needed

Providers need to choose between markets, impacting liquidity and price

Barriers to entry are limiting competition

Providers need to choose between markets, impacting liquidity and price

As our DM and DR markets grow, response providers will need to choose which dynamic products they should bid into. Currently, choosing one market necessarily means not bidding into the other two markets. This lowers overall liquidity across all markets, which will have a detrimental impact on costs for consumers and can potentially leave some units stranded and not able to participate. This is also an issue between response and reserve markets, and indeed between these markets and the wider wholesale market.

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Frequency Response - Drivers for Reforms

Clear, coherent market signals are needed

Providers need to choose between markets, impacting liquidity and price

Barriers to entry are limiting competition

Barriers to entry are limiting competition

Our dynamic response markets are suitable for technologies other than grid-scale batteries, such as aggregated EVs and domestic batteries, demand-side response and renewable technologies, all of which would help increase liquidity in the markets. However, there are barriers to entry for these technologies, including the timescales for procurement (day ahead as opposed to intraday), baselines, ramp rates and the rules for aggregation of services.

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Frequency Response - Market Reforms

Annual Development Cycle

We are introducing an annual service development cycle for frequency response, which if effective, will be rolled out to other markets. The aim of introducing an annual cycle gives all stakeholders a repeatable, reliable plan which takes into account the fixed timelines for the formal Electricity Balancing Review (EBR) consultation, and provides sufficient timelines for engagement, onboarding and systems development. Thorough engagement activities will be held ahead of consultation, ensuring all voices are heard, and importantly, most changes are developed by the ESO ahead of the consultation launch. This will help ensure that barriers to entry can be addressed and we are able to respond to stakeholders' needs in a timely manner.

1. Diagnose
- Roadshows & individual meetings
- Review product backlog
- Impact assess and prioritise potential changes covering service design, contracts and IT

2. Design
- Amend contractual terms
- Define IT requirements
- Host webinar
- Launch EBR consultation (duration: 1 calendar month)

3. Develop
- Amend contractual terms (based on EBR feedback)
- Amend IT requirements (where applicable)
- Respond to EBR consultation and submit to Ofgem (duration: 2 calendar months)

4. Implement
- Receive Ofgem decision
- IT testing and delivery
- Provider unit testing and onboarding (where applicable)

Clear investment signals

Market liquidity

Barrier removal

Phasing out FFR

We have steps in place to begin offsetting dynamic FFR volumes with Dynamic Regulation and Dynamic Moderation, however this will be a steady process, and we expect to continue to procure dynamic FFR into 2023-24. This is subject to the increase of the DR and DM volume caps as well, with the volume cap for DR already being increased in March 23 to 200MW.

We are making changes to static FFR, including moving to day ahead procurement at the end of March 23 and pay-as-clear, as well as the requirement to submit independent bids for each EFA block. Additionally, we are working on a new service called Static Recovery, which could replace current static FFR following large losses.

Frequency Measurement Standard to help minimise risks

The purpose of FMS is to set up a minimum requirement for monitoring system frequency and service response to help minimise system risks caused by measurement errors. This means improving our own systems within the control room, so that we can manage inertia levels better, allowing smaller providers to participate and ultimately help us to lift the volume cap on some markets. We are currently reviewing past performance data to understand all potential system risks, with the aim of introducing a cost-effective standard that can be met by service providers.

Markets Roadmap / Market Areas / Frequency Response 45

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Clear investment signals

Market liquidity

Barrier removal

Co-optimisation of response products will lower costs and improve dispatch efficiency

We are introducing our Enduring Auction Capability in Autumn 2023, which is working towards optimising all markets for day-ahead response initially, followed by reserve products soon after. Through a market simulation exercise held in 2022, we found that co-optimisation leads to a lower clearing price, a higher cleared volume and lower risks of stranded capacity. We also believe that it will result in more efficient markets as the process delivers clearer price signals, higher revenue certainty for providers, easier access to multiple markets and greater diversity in bidding strategies. In terms of future development, we are committed to improving the procurement of ancillary services by introducing enhanced automation and more sophisticated mechanisms to facilitate a move to closer to real time, intraday markets.

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Frequency Response - Market Reforms

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Clear investment signals

Market liquidity

Barrier removal

Introduction of GSP group aggregation level

We are continuing to explore ways of reducing the barriers to entry for a range of demand-side flexibility providers, without introducing gameable flaws or reducing the Control Centre team's capacity to forward plan. One example is changing the aggregation rules from GSP to GSP Group for frequency response services. Both DM and DR have been launched with this capability and it will be available for DC as of 1st April 2023.

Assessment of the impact of ramp rates as a barrier to entry

Currently we have ramp rates requirements for our services but they can present a barrier to some market participants and so we are continuing to investigate options for reducing the impact of this. The ESO's internal review concluded that increasing the 5% ramp rate requirement would impact system stability. A way to mitigate this risk is by overholding response and reserve services, however this would require an increased capacity to consistently be available and would incur additional balancing costs. We will complete a full assessment and continue to review market changes alongside the financial impact assessments in preparation for future updates to the service.

Change requirements to enable assets without dedicated meters to participate

Baselining prevents some providers without dedicated meters from participating. We have undertaken significant work this year with stakeholders to investigate the use of non-standard baselines. We are actively working with industry participants to agree the details of how this can be achieved and to quantify the market benefits. Once we have completed these two actions, we will assess the priority of these changes against the other backlog items when considering topics for the next release over the first half of 2023.

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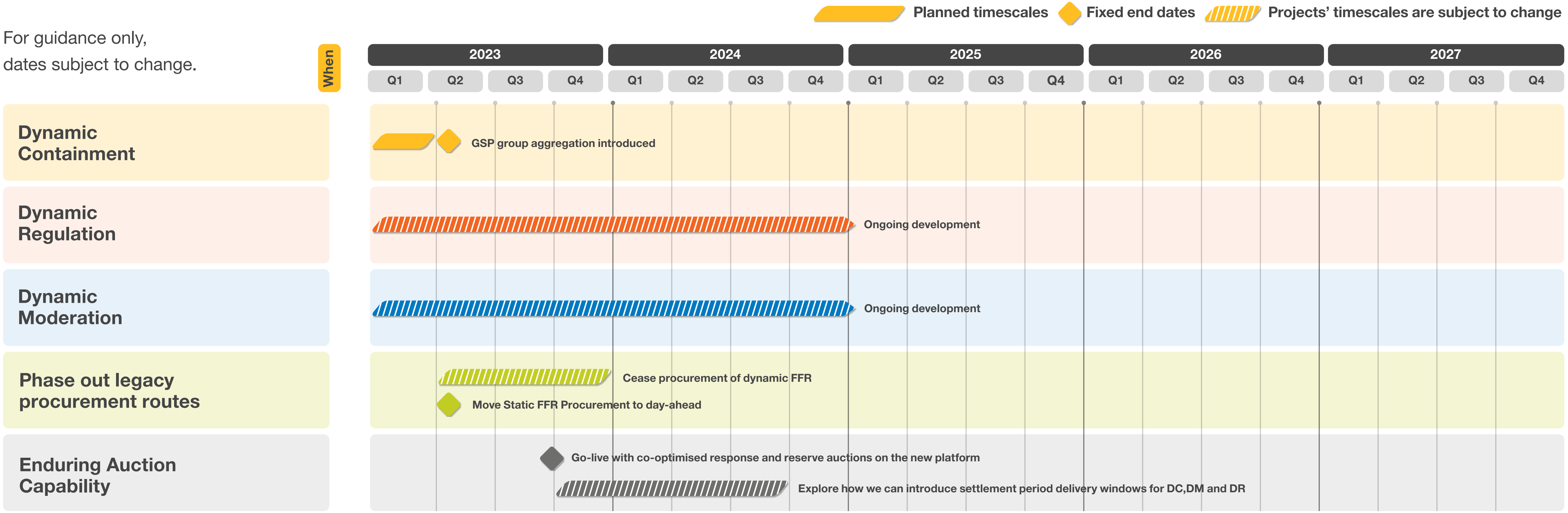
Frequency Response - Delivery Plan

For guidance only,
dates subject to change.



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Frequency Response - Delivery Plan

Dynamic Containment

What?

Dynamic Containment (DC) is a fast-acting post-fault service to contain frequency within the statutory range of +/-0.5Hz in the event of a sudden demand or generation loss. This service started in October 2020.

Dynamic Regulation

What?

Dynamic Regulation, has been designed to slowly correct small continuous deviations in frequency. The aim is to continually regulate frequency around the target of 50Hz.

Dynamic Moderation

What?

Dynamic Moderation, is designed to assist frequency management following large imbalances. The aim is to contain frequency within operational limits +/- 0.2 Hz.

Dynamic Moderation was launched in May 2022.

Phase out legacy procurement routes

What?

We are phasing out some of our legacy procurement routes including the FFR monthly tenders and moving some volumes to our dynamic product suite.

Enduring Auction Capability

What?

In accordance with our RIIO-2 plans we are developing enhanced auction capability to clear our new response (and reserve) markets.

Markets Roadmap / Market Areas / Frequency Response 49

Reserve

Context

The heightened risk to security of supply throughout winter 2022 and the associated cost impacts of balancing the system highlight the importance of reserve products. Not only do they help to manage imbalances between supply and demand, but they also secure losses on the network at the lowest cost to the consumer. We have therefore fast-tracked the development of a new reserve product – Balancing Reserve. This service will provide firm access to operating reserve in our control room. Significant progress has also been made on two new core services - Quick Reserve and Slow Reserve.

What is Reserve?

Reserve is the capability to deliver upward or downward energy within a given timescale. This is to manage pre-fault imbalances between supply and demand, and to ensure we can maintain a secure system post- fault, typically when a large demand or generation source trips. Reserve products often follow the activation of automatic, fast-acting frequency response and deliver additional energy until a plant can return to service or more economic actions can be taken to replace them.

We procure firm capacity through day-ahead markets to provide assurance that units are available to deliver flexibility as and when we need it. Dispatch decisions are then made in real-time, and units are paid a utilisation price when manually instructed by ESO. We also use the Balancing Mechanism and trading opportunities for reserve where required.

Link to reserve webpages

How our future products will be used

Balancing Mechanism

Short Term Operating Reserve (STOR)

Optional Fast Reserve

Legacy/Bespoke arrangements

Balancing Mechanism

- Speed and duration of response - as per dynamic parameters
- Use case - pre-fault and post-fault
- Timing of procurement - real-time
- Length of contract - N/A

Accepting bids and offers in the BM allows our control room engineers to reposition BMUs after gate closure. This is mainly for operating reserve where suitable units are selected in merit order.

Markets Roadmap / Market Areas / Reserve 50

Reserve

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How our future products will be used

Balancing Mechanism

Short Term Operating Reserve (STOR)

Optional Fast Reserve

Legacy/Bespoke arrangements

Short Term Operating Reserve (STOR)

- Speed of response - no greater than 20 minutes
- Duration of response - a minimum of 120 minutes
- Use case - post-fault
- Timing of procurement - 05:00 day-ahead
- Contract length - STOR service window (e.g., 3.5 - 7.5 hours)

STOR is a positive reserve service requiring an injection of MW or reduction in demand. Providers must reach their full output in 20 minutes following a dispatch instruction. We procure STOR day-ahead of delivery via a day-ahead availability auction and dispatch in real-time where units are paid a utilisation payment.

Markets Roadmap / Market Areas / Reserve 51

Reserve

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Link to reserve webpages

How our future products will be used

Balancing Mechanism

Short Term Operating Reserve (STOR)

Optional Fast Reserve

Legacy/Bespoke arrangements

Optional Fast Reserve

Optional fast reserve is procured at intra-day timescales where providers are paid an arming fee to place assets into rapid delivery mode for both pre- and post-fault activation. BM Fast Reserve reaches full delivery within 2 minutes of instruction, NBM Fast Reserve requires delivery to start within 2 minutes of instruction.

Markets Roadmap / Market Areas / Reserve 52

Reserve

Context

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Link to reserve webpages

How our future products will be used

Balancing Mechanism

Short Term Operating Reserve (STOR)

Optional Fast Reserve

Legacy/Bespoke arrangements

Legacy/Bespoke arrangements

These are bespoke BM services which offer enhanced capabilities for reserve compared to standard BOAs. Services include: Spin Gen/ Spin Pump, BM Start-up (warming), Super SEL and Max Gen. They are procured in real-time and have different costs depending on the bilateral agreement.

Markets Roadmap / Market Areas / Reserve 53

Reserve - Summary of the chapter

How is the landscape changing? The size of the largest loss is increasing (up to 1800MW from 2025), both on the demand and generation side. In a lower inertia system, with a higher Rate of Change of Frequency (RoCoF), there is a need to have more effective products to secure these losses and restore frequency more effectively. Simultaneously, the technological landscape continues to evolve and new asset types could be accessed to provide reserve services.

How have costs and volumes evolved in the last year? We continue to procure reserve via our existing markets while our new suite of products is in development. In the last 12 months, total reserve utilisation has decreased by 11%, whilst reserve costs have increased by 17%. The increase in cost is most notably for operating reserve. This is predominantly driven by higher fuel costs and greater opportunity costs for synchronous units providing operating reserve. Post-fault products, such as Short Term Operating Reserve (STOR), have also seen a smooth uptick in clearing prices at day-ahead for similar reasons, with peaks during periods of scarcity.

What is driving the need for reform? We have significant potential to access flexibility from low carbon technologies (e.g., renewables) and demand-side participants to help secure the system at lower cost.

How are we implementing market reform?
In response to rising balancing costs, we are developing a new firm operating reserve product (Balancing Reserve) to procure capacity at day-ahead, while continuing our progress to reform our suite of pre- and post-fault reserve services. Our new products will address specific needs to recover and restore frequency as per our SQSS obligations more effectively than our existing products.

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Reserve - Market Insight: Reserve Volumes

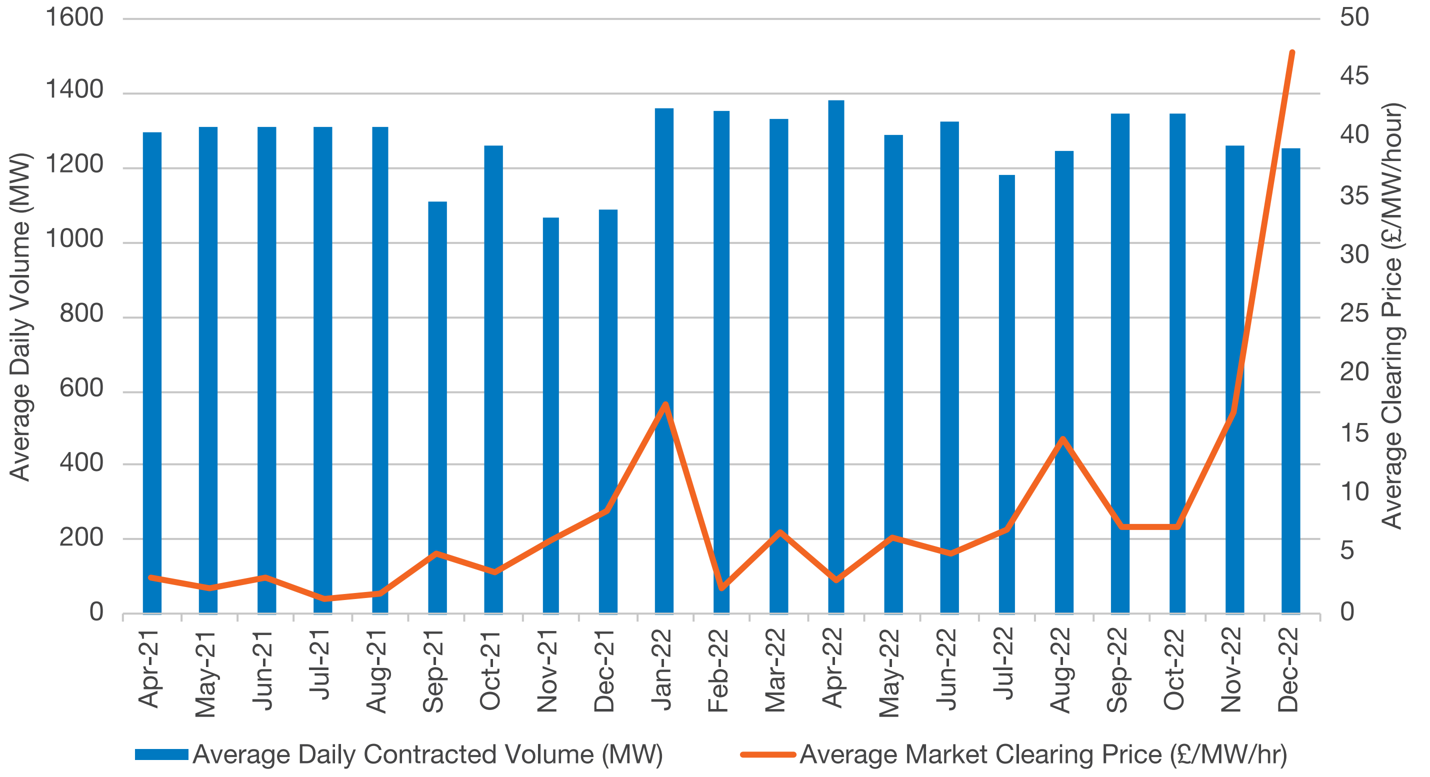
In summary, the utilisation of reserves in the last 12 months has decreased in comparison with 2021, whilst firm procurement of STOR capacity has increased relatively to the period April – December 2021, when day-ahead procurement was launched.

DA STOR Availability – Jan 22 – Dec 22

Firm availability for STOR is procured via a day-ahead auction to ensure we have access to reserve capacity in the following operational day. Figure 1 shows a consistent trend, on average, in STOR availability procurement by month throughout 2022. This is in line with our expectations for securing a consistent largest generation loss for each hour of the year. Winter 2021/22 was the first winter we operated a day-ahead STOR market and we saw several occasions whereby the ESO buy order was not dynamic enough to capture the requirement for STOR during anticipated tight margin conditions. Throughout 2022, we met >85% of our total STOR requirement for ~90% of the year, including on over 80% of days in November and December. This demonstrates the value of improvements made to the ESO buy order which ensures the market is still attractive to participants during days of scarcity.

Figure 2 illustrates the proportion of technology types which were contracted for STOR in 2022. As in 2021, the service is dominated by Open Cycle Gas Turbines (OCGT) and gas reciprocating engines. This is typically because long service windows and the minimum requirement to be able to deliver an instruction for 120 minutes are best suited to dispatchable fossil fuel plant.

RV Figure 1: STOR availability volumes and clearing prices: Jan 2020 - Dec 2022



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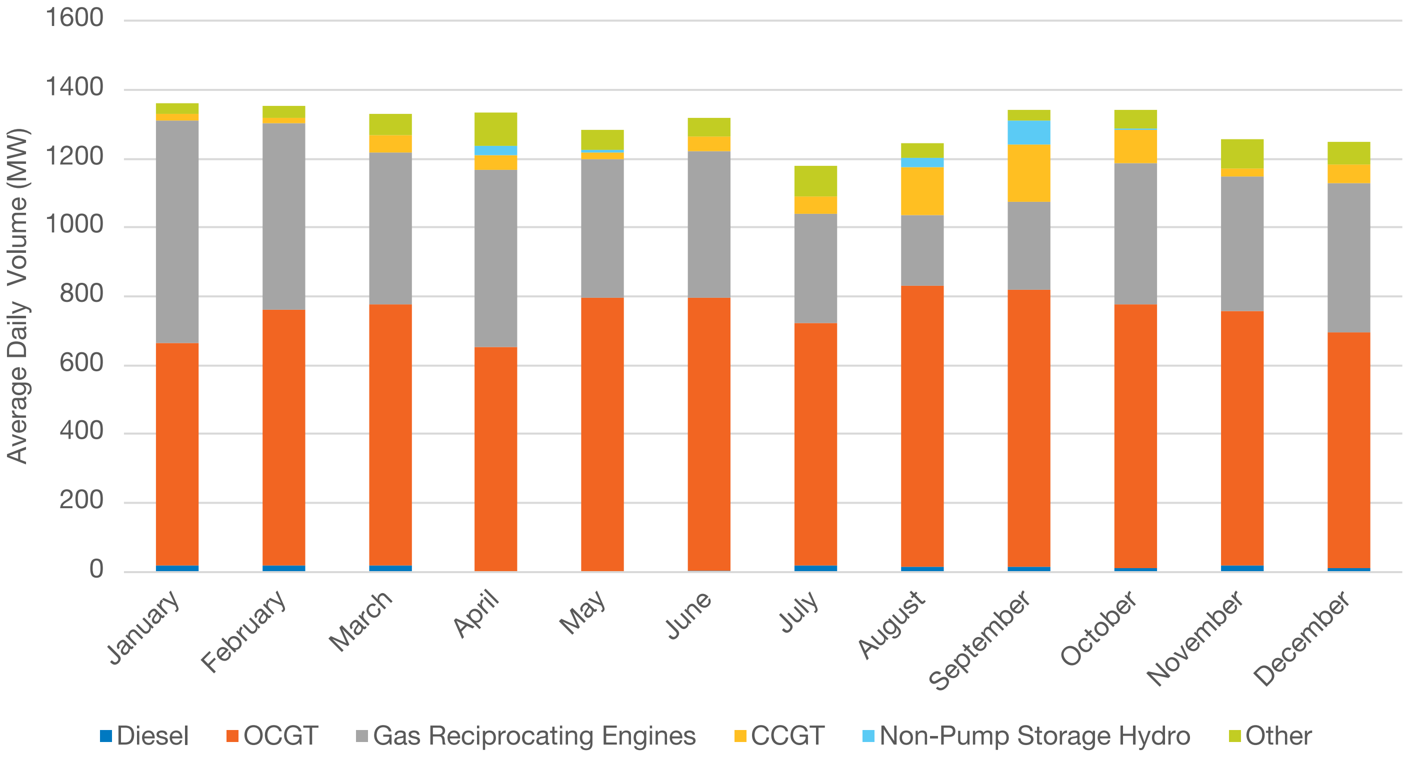
Reserve - Market Insight: Reserve Volumes

RV Figure 2: Contracted STOR Volumes by Technology Type Jan-22 – Dec-22



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Reserve - Market Insight: Reserve Volumes

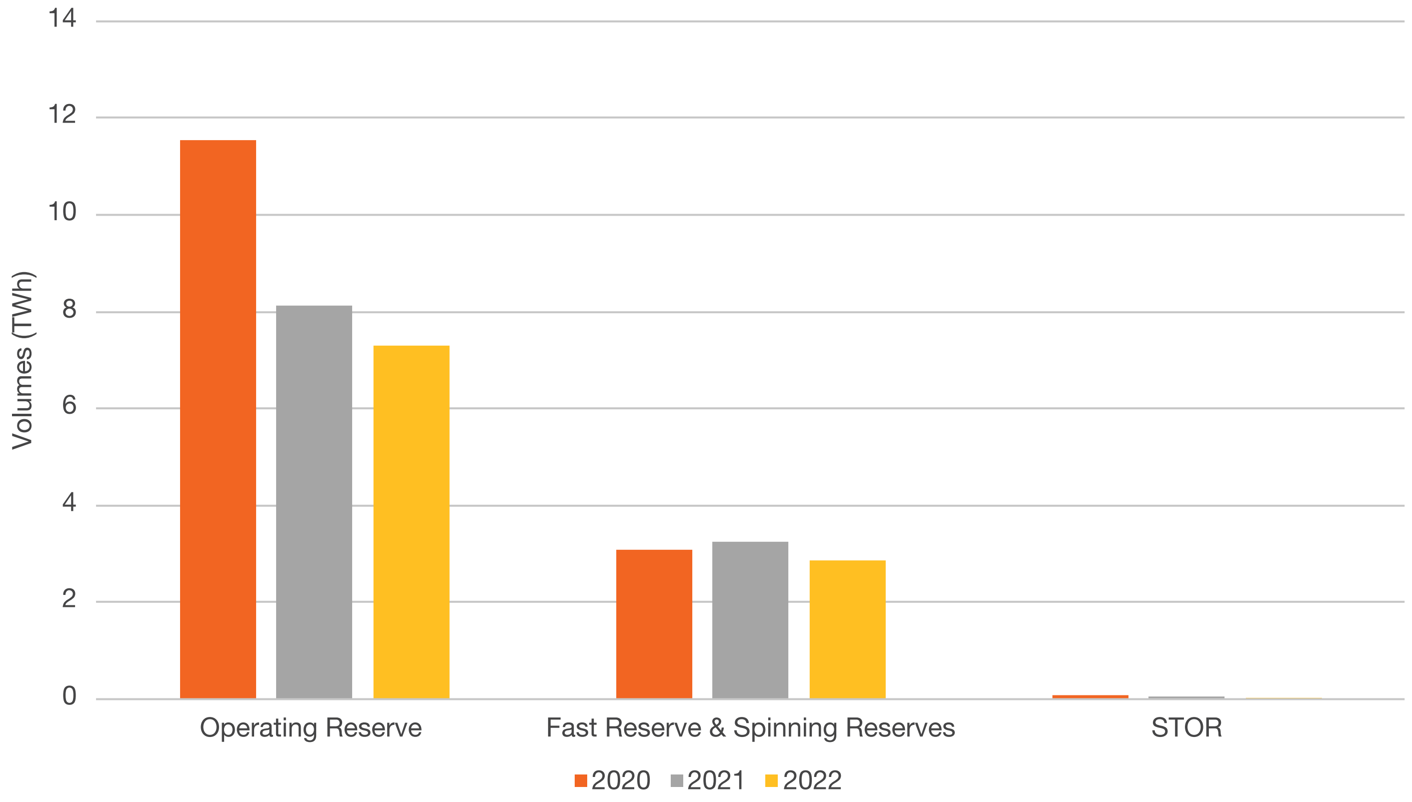
Reserve Utilisation

Total reserve utilisation volumes have decreased by 11% in 2022 (10.2TWh) in comparison with 2021 (11.4TWh). Figure 3 demonstrates an ~800GWh reduction in total operating reserve volumes in the last 12 months, predominantly actions which are taken on BMUs. These reflections are in part driven by a more stable system as the uncertainty in demand driven by COVID-19 lockdowns diminished.

Trading and SO-SO actions increased by two thirds, especially during summer periods where interconnector flows were frequently reversed to ensure we had enough positive margin.

STOR utilisation volumes have continued to decline in 2022 (38GWh) in comparison with 2021 (60GWh) and 2020 (81GWh). This is due to the infrequency of significant trips on the system and better faster-acting products which recover frequency to within operational limits sooner.

RV Figure 3: Reserve volumes: Jan 2020 - Dec 2022



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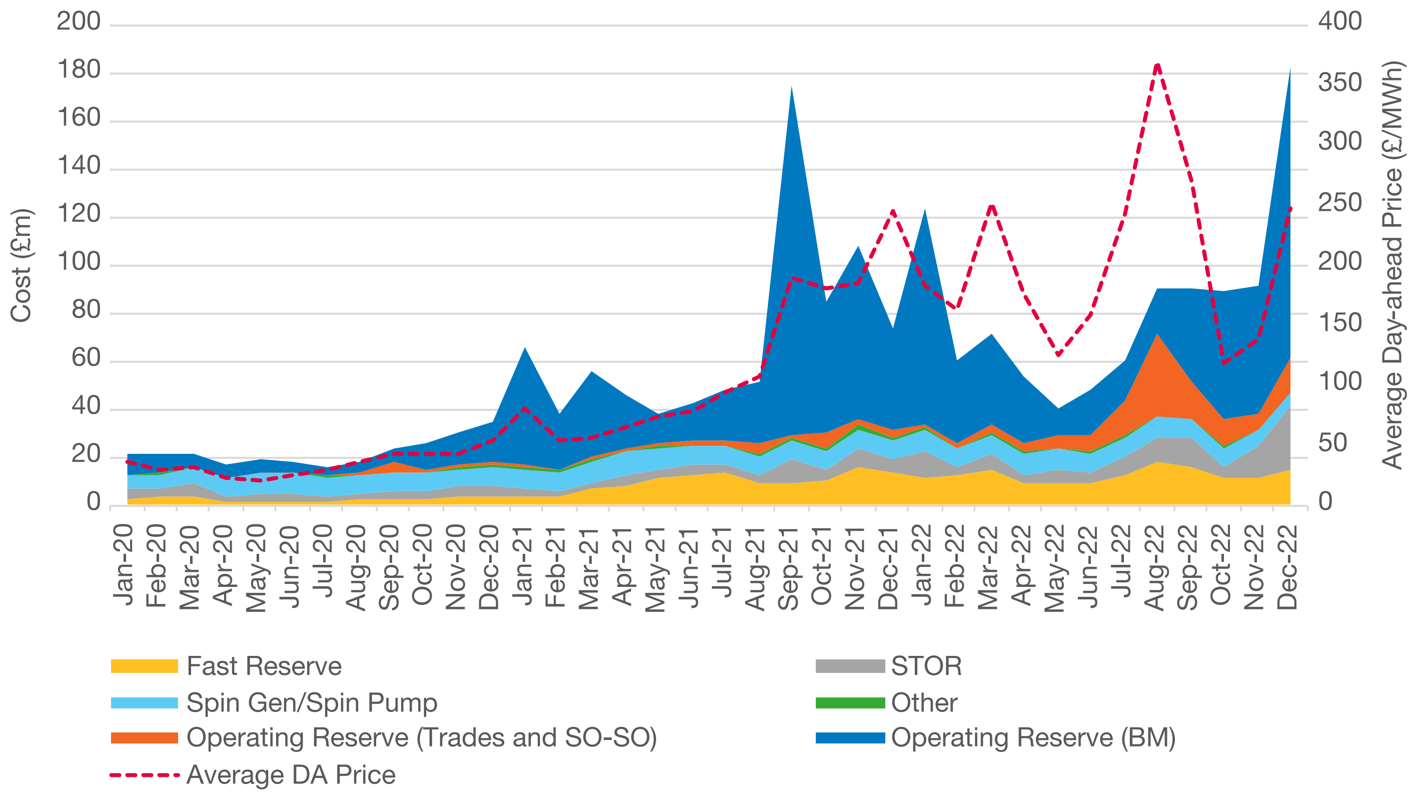
Reserve - Market Insight: Reserve Costs

Overall, reserve costs have increased by 17% in 2022 (£1bn) in comparison to 2021 (£828m) and by 291% in comparison to pre-COVID levels.

STOR Availability Costs Jan 22 – Dec 22

On the previous page, RV Figure 1 demonstrated a consistent volume of procurement of STOR availability, but it also shows an uptick in clearing prices for the most part of 2022, with significant price spikes in January 2022 and December 2022. The average clearing price for 2022 was £11.95/MW/hour compared with £3.90/MW/hour for the nine months April – December in 2021 following the launch of day-ahead procurement. Availability prices peaked on 12th December 2022 at £175/MW/hour and there were two examples earlier in January where prices exceeded £150/MW/hour. The key driver on these days (12/12/23, 24/01/23 and 14/01/23), as with peaks in July and August 2022, was especially tight margins which correlated with higher costs in the day-ahead power markets, as reflected in Figure 1. This often meant greater opportunity cost for units securing firm capacity via STOR which is therefore reflected in their bid price. It also demonstrates ESO's flexible willingness to pay under these conditions.

RV Figure 4: Reserve costs: Jan 2020 - Dec 2022



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Reserve - Market Insight: Reserve Costs

Reserve Costs

The significant increase in operating reserve costs observed from Autumn 2021 onwards has continued throughout 2022 with total operating reserve costs exceeding £500m for the second consecutive year. The dominant drivers are higher fuel costs from units providing Reserve plus greater opportunity costs related to other markets, such as wholesale and interconnector auctions.

December 2022 was the most expensive month (~£135m) with May (£16m), June (£25m) and July (£30m) the least expensive months. Nevertheless, several of the highest cost days for Reserve trading activity were observed in August 2022 driven by interconnector trades activated for positive reserve. 19th August and 24th August were particularly expensive days for Reserve due to the cost of reversing interconnectors which planned to export to Europe at high prices – driven by French nuclear outages, tight margins in Europe and volatile gas prices – and lower wind in GB. On this occasion, the LE1 constraint was also biting which meant that more, higher-priced trading actions were required overall. Please refer to the thermal chapter for more information.

Optional Fast Reserve and spinning reserve services also saw a general increase in costs in 2022 linked to higher fuel and market prices.

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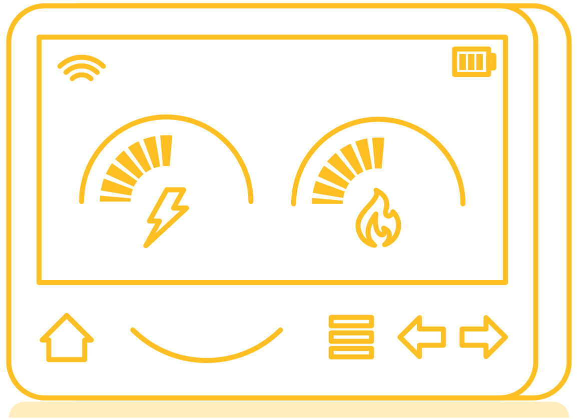
Reserve - Drivers for Reforms

We are required to secure the power system in line with SQSS so that frequency remains within statutory limits. As articulated in other chapters within this document, the generation technology mix is transforming, which presents different operability needs. To meet these needs, we require more specific, more streamlined products which provide appropriate investment signals and incentives to new technologies but can be procured at the lowest cost. We have identified several key drivers which are influencing our Reserve product design most significantly.



Drive down cost in light of high fuel prices

Lower inertia system leading to Increasing Rate of Change of Frequency (RoCoF)

A need to secure larger demand losses

Lack of diversity in market participation leading to high costs

Drive down cost in light of high fuel prices

Operating Reserve costs have increased significantly since the start of 2021 because of high fuel prices and scarcity opportunities for flexible, mid-merit plant either through other GB markets or via interconnectors to Europe. In these circumstances where GB capacity has been sold on interconnectors and there is insufficient reserve available, we often have to reverse interconnector flows through trading arrangements which increases costs further. We have identified an opportunity to provide the appropriate signal to generators to offer regulating reserve in a day-ahead market to provide firm availability with a further utilisation payment if dispatched. In addition, we recognise the value in co-optimising energy products, including frequency response and reserve and how they interact with the wholesale markets. Co-optimisation will be first implemented for response products via the Enduring Auction Capability platform.

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Reserve - Drivers for Reforms

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Lack of diversity in market participation leading to high costs

Lower inertia system leading to Increasing Rate of Change of Frequency (RoCoF)

In GB, the average annual inertia has declined by 40% in the last decade due to some synchronous plant being decommissioned and continued growth in non-synchronous inverter-based resources. The inherent characteristics of non-synchronous generators means that inertia is not naturally provided as a by-product of energy. Inertia influences how quickly grid frequency changes. Therefore, a system with less inertia typically leads to a higher RoCoF, which means that frequency could move outside of operational limits quicker without intervention. Our current reserve products will not be fit for purpose in the future for recovering and restoring frequency in tandem with our new frequency response products. Consequently, we need to develop new, faster-acting, more specific products to maintain the system in line with our obligations.

Reserve - Drivers for Reforms

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Drive down cost in light of high fuel prices

Lower inertia system leading to Increasing Rate of Change of Frequency (RoCoF)

A need to secure larger demand losses

Lack of diversity in market participation leading to high costs

A need to secure larger demand losses

The growth of interconnector capacity in the UK is important in achieving our net zero ambitions. Great Britain became a net exporter of power for the first time in 2022, exporting a total of 5.5TWh electricity to continental Europe in Q2 alone. Interconnectors also played a vital role when importing power to ensure security of supply in tight conditions throughout winter 2022. However, there are additional operability challenges which come as a trade-off. Our post-fault reserve requirements (e.g., STOR) are driven by the size of the largest loss on the network. Interconnectors, when at or near full capacity, are often the largest source of demand or generation loss and hence influence our reserve requirements. Currently, we secure demand losses through maintaining footroom in the BM and not via a specific ancillary service product. To secure outfeed losses when interconnectors are exporting to neighbouring countries and the continent, we believe more specific products are required to secure the system, improve transparency, and reduce cost. Furthermore, as interconnector flows can fluctuate significantly across a day, we need more flexible reserve products which can be procured more granularly to allow us to fine tune our procurement and reduce periods of overholding.

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Reserve - Drivers for Reforms

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Drive down cost in light of high fuel prices

Lower inertia system leading to Increasing Rate of Change of Frequency (RoCoF)

A need to secure larger demand losses

Lack of diversity in market participation leading to high costs

Lack of diversity in market participation leading to high costs

Traditionally, reserve has been provided by dispatchable generation such as reciprocating engines and open-cycle gas turbine (OCGT) units. However, there is significant untapped potential from renewable generators, such as solar, wind and battery storage. This is due to a combination of poor incentives for assets in receipt of subsidies to offer reserve capability, and the technical design of existing flexibility products. For example, STOR is currently bought in a series of defined firm service windows, which range from 3.5 to 7.5 hours in length and are not mutually exclusive. Providers have cited that shorter, more flexible service windows will help to optimise the capacity which can be offered into ancillary services markets from intermittent generation sources. We also recognise several benefits for ESO; for example, opportunities to revise MW requirements to accommodate changing demand / generation forecasts and interconnector positions across the day. We need to design new markets to remove barriers to entry and encourage greater participation from variable generation sources.

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Reserve - Market Reforms

We are developing a range of new Reserve products, which are more specific, faster acting and more accessible, so that we can regulate and restore frequency both pre- and post-fault. Our new Balancing Reserve product was identified as a high priority to deliver value for money for consumers by rapidly address soaring balancing costs during 2022; hence, this was prioritised over the delivery of Quick and Slow Reserve. Despite being deprioritised, significant progress has been made in the development of our new Quick and Slow Reserve products and we have established a plan for implementation which is shared later in this chapter.

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Reserve - Market Reforms

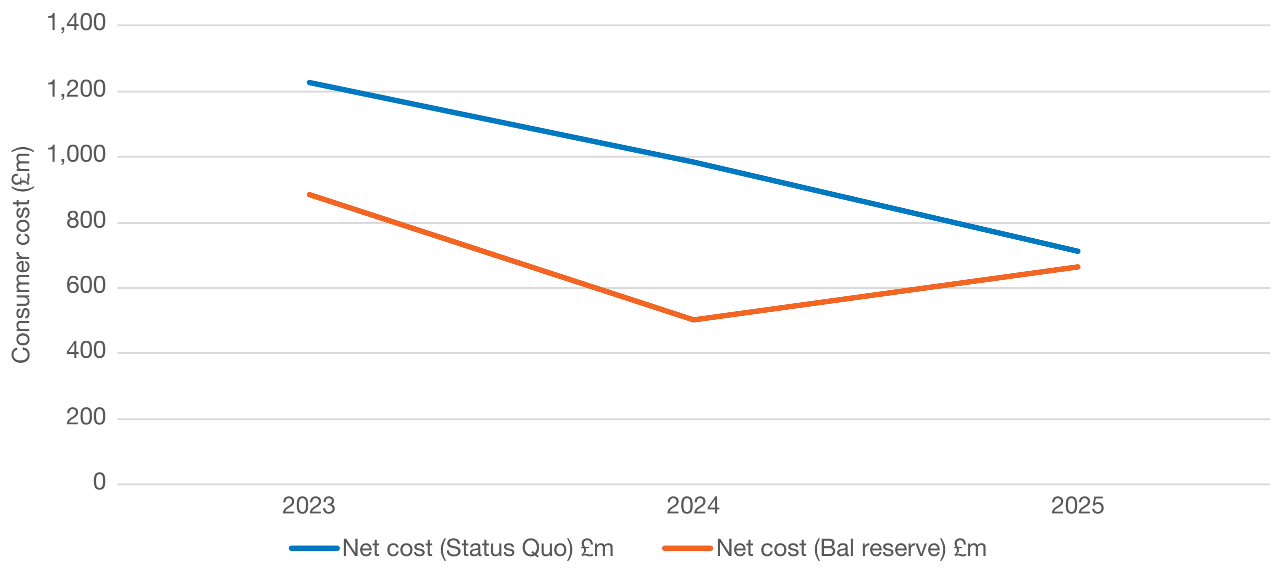
Balancing Reserve

In the second half of 2022, in response to a significant increase in operating reserve costs, ESO committed to developing a new product with the ability to procure firm reserve capacity at day-ahead. This is designed to provide a new market opportunity for eligible providers to offer reserve capacity to ESO ahead of selling it into other markets (e.g., interconnectors); for example, transactions which are scheduled on interconnectors are frequently reversed by the ESO within day via trading actions to maintain operating reserve levels. Currently, for positive reserve, units are often synchronised to Stable Export Limit and the headroom to Maximum Export Limit is maintained as reserve capacity. By valuing plant availability in advance with a day-ahead payment, Balancing Reserve aims to reduce unintended market signals in real-time (e.g., warming / synchronising high-cost units) which may misrepresent levels of scarcity.

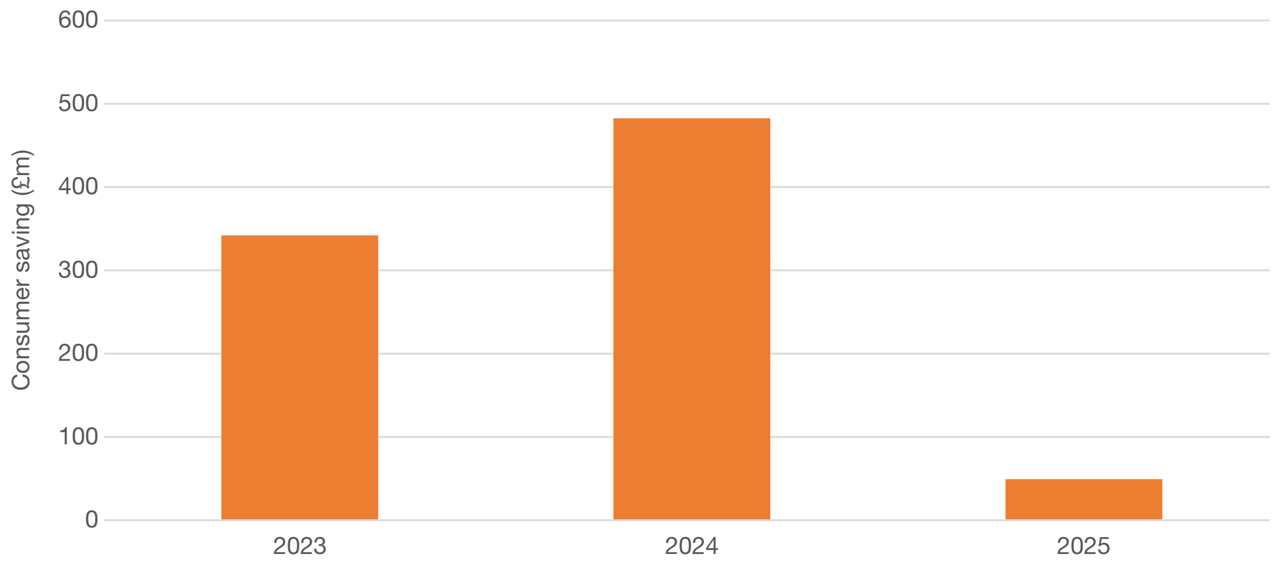
The benefits case for Balancing Reserve is well-established and will deliver value for consumers. Our base case Cost Benefit Analysis (CBA) shows that Balancing Reserve could deliver net consumer benefits of £873m between 2023 and 2025, including having factored in any corresponding impacts on wholesale market prices.

Significant progress has been made in a short space of time preparing our systems and processes to launch Balancing Reserve. An initial launch was planned for March 2023 to begin realising benefits at the earliest opportunity; however, Ofgem recently published their decision to reject the initial product design in light of barriers to entry for small flexible providers and an insufficient deterrent to prevent non-delivery. Consequently, the launch of Balancing Reserve is delayed whilst we develop the additional functionality to schedule and dispatch a larger volume of units. We remain committed to delivering the significant benefits that we think Balancing Reserve can achieve. The ESO Balancing Programme is working to develop the necessary tools so that we can enable maximum participation from the outset and realise maximum benefits for consumers. An updated delivery plan is shared on the next page which will be accompanied by further industry engagement.

RV Figure 5a: Consumer costs under the two scenarios



RV Figure 5b: Consumer saving under Balancing Reserve



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Reserve - Market Reforms

Quick and Slow Reserve

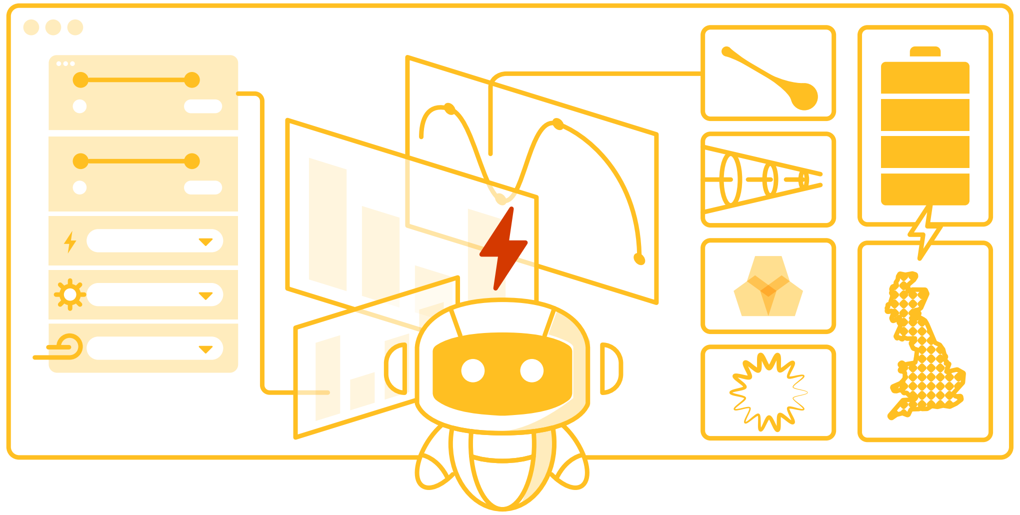
While Balancing Reserve has been a top priority, Quick and Slow Reserve remain key deliverables in our business plan. Designed to operate post-fault to secure the largest loss, Slow Reserve will aim to unlock new capacity (e.g., low carbon renewables) via shorter, more flexible service windows which are intended to maximise the available capacity tendered by providers. For the initial launch, this is anticipated to form one 8-hour overnight block which reduces risk for the ESO during higher risk periods with eight x 2-hour blocks to follow to enable wider participation from more technologies. We are keen to gather further information about asset capabilities through our Service Provider Capability Mapping Network Innovation Allowance project.

Our progress over the last 12 months on Quick Reserve also demonstrates some important trade-offs when designing optimum products for with both the market and system security in mind. For example, we have demonstrated that a 60-second ‘time to full output’ parameter for Quick Reserve will promote efficient dispatch and reduce the need for additional slower, longer-duration reserve instructions. A longer ‘time to full output’ (e.g., two minutes or greater) might enable participation from more assets but overall, would fail to restore frequency within operational limits as effectively. Nevertheless, we have revised some of the arduous ramping-down parameters from Quick Reserve following industry feedback.

Positive Slow Reserve will replace our current STOR service in securing large generation losses and Negative Slow Reserve will be a new product to mitigate the inverse impact of demand losses (e.g., high frequency event during an interconnector trip whilst flows are exporting from GB). All services are anticipated to launch during the 2023/24 financial year, as illustrated in the Delivery Plan below.

Co-optimisation of ancillary services

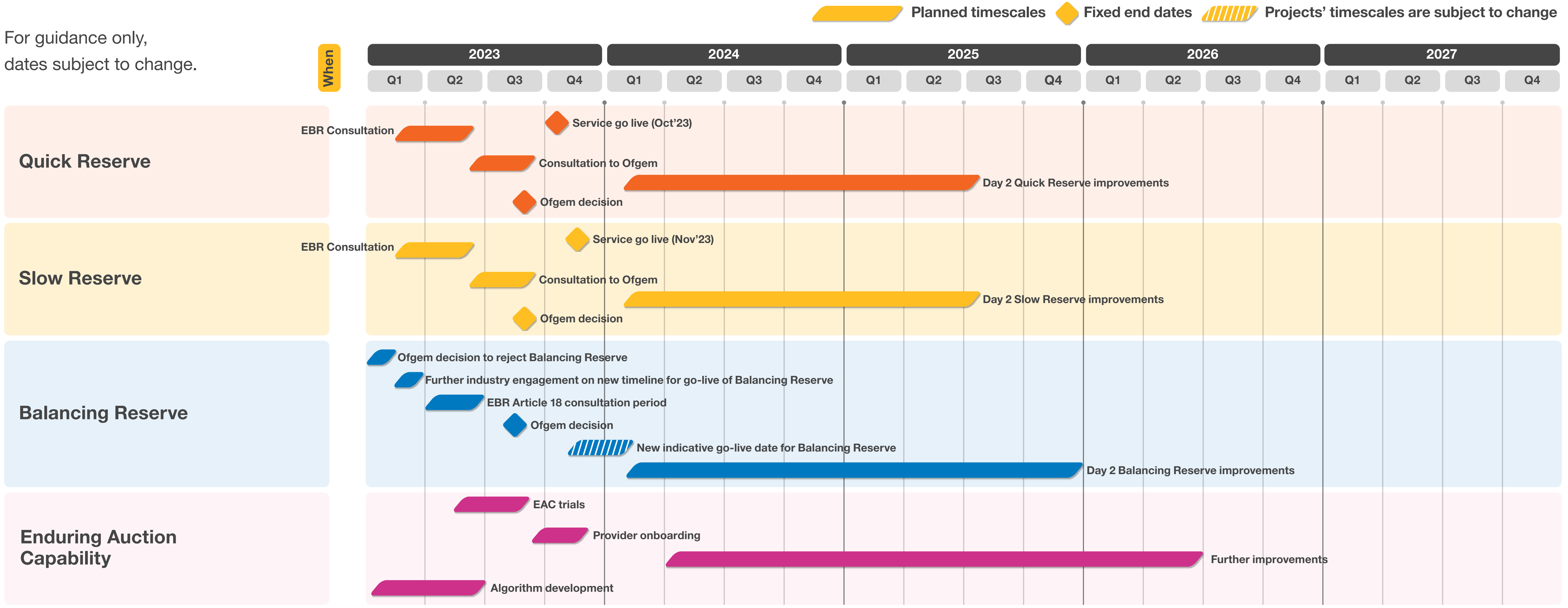
Furthermore, we are ensuring that our service design and Enduring Auction Capability are developed in tandem to facilitate stacking and co-optimisation of reserve products, where applicable, to deliver extra benefit to market participants and consumers. Co-optimisation will first commence with frequency response products - Dynamic Containment, Dynamic Moderation and Dynamic Regulation. More information can be found on this in the Response chapter. Similarly, we will also be exploring further opportunities for co-optimisation of reserve, response and energy products, such as the wholesale market. This theme is being explored by our Net Zero Market Reform programme.



Markets Roadmap / Market Areas / Reserve 66

Reserve - Delivery Plan

For guidance only,
dates subject to change.



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Reserve - Delivery Plan

Quick Reserve

What?

Quick Reserve, separated into Negative Quick Reserve (NQR) and Positive Quick Reserve (PQR), is a fast-acting reserve product designed primarily to react to pre-fault disturbances to restore energy imbalance quickly and return frequency close to 50.0 Hz.

Slow Reserve

What?

Slow Reserve, separated into Negative Slow Reserve (NSR) and Positive Slow Reserve (PSR), is designed to operate post-fault and aims to provide ESO with access to firm, bi-directional energy to displace large losses on the system and recover frequency to ± 0.2Hz within 15 minutes.

Balancing Reserve

What?

Balancing Reserve is NGESO's newest Reserve product which will procure regulating reserve on a firm basis at day ahead. This process will help reduce balancing costs and improve system security as positive and negative margin is guaranteed for the Control Room to access when needed.

By procuring via an availability auction, operating reserve volume is locked in ahead of the day-ahead energy market and therefore energy is not available to be sold into other markets.

Enduring Auction Capability

What?

The Enduring Auction Capability (EAC) is being designed to deliver co-optimised procurement for our day-ahead Frequency Response and Reserve products. It is envisioned that this method of procurement will allow us to meet our needs in the most efficient way while enabling providers to participate in multiple markets. This solution would also be scalable and extendable to any future services and products.

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Case Study: Demand Flexibility Service (DFS)

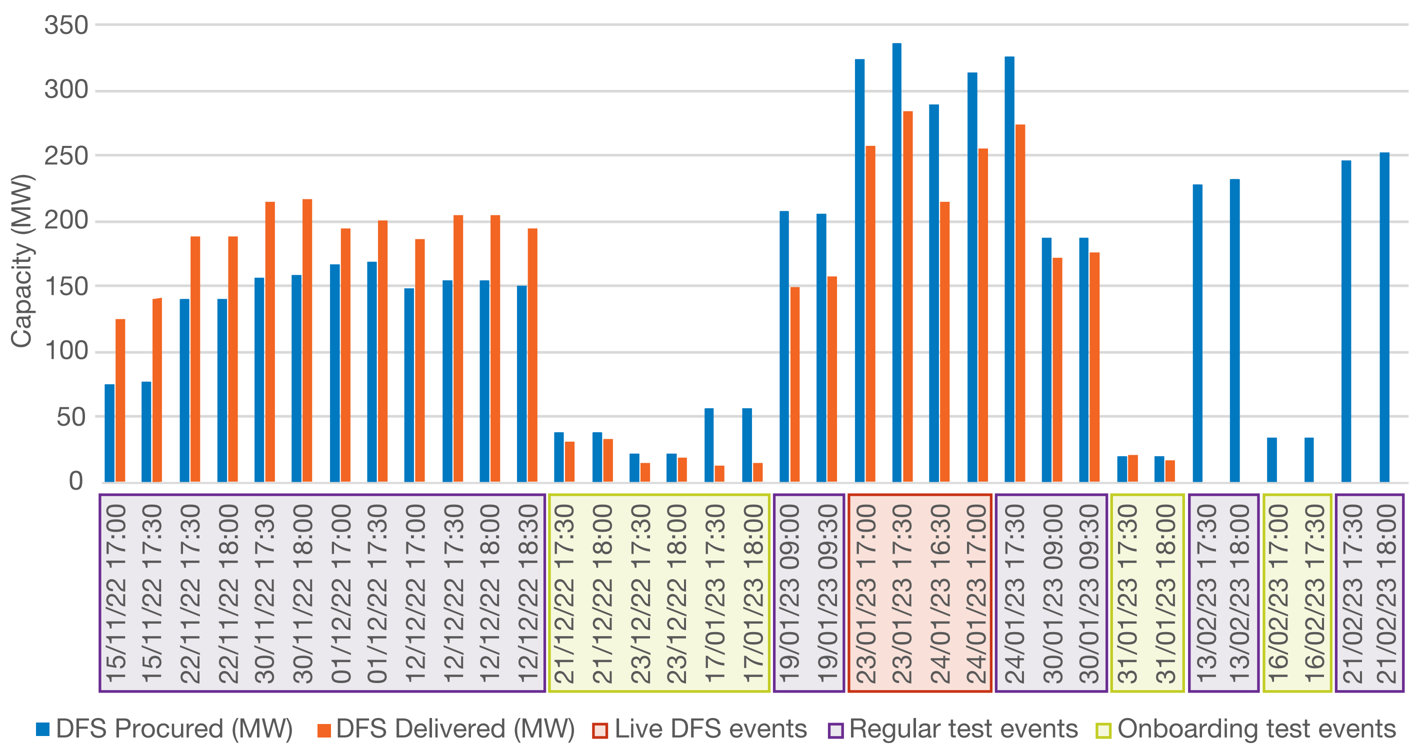
As articulated throughout this roadmap, a series of unprecedented circumstances led to us taking several key measures to ensuring security of supply in winter 2022. This included the launch of a world-leading Demand Flexibility Service (DFS). DFS was launched as an 'enhanced market action', so is not used explicitly as a commercial tool, but instead activated once all appropriate market actions have been taken or if available actions at day-ahead are deemed to be insufficient for balancing supply and demand.

Drivers for Reform

The previous dominant driver for launching DFS was a backdrop of supply scarcity linked to the war in Ukraine. Reduced exports from Russia and more competition for supply led to gas shortages in Europe. Coupled with generator outages on the continent and additional uncertainty around interconnector import availability, there was greater risk for tighter margins in comparison with previous years, especially if cold weather was to coincide with low wind conditions.

The successful Domestic Reserve Scarcity Trial demonstrated the capability to shift demand away from peak periods. DFS built on this and expanded participation to much wider range of energy suppliers over the winter of 22/23. Ultimately the aim is to develop more demand side flexibility and encourage shifts in consumer behaviour, which will help provide more options to the ESO for managing times of peak demand and supply. This would require stronger price signals for end consumers, via a combination of charging regimes and wholesale markets.

Demand Flexibility Service (DFS) Live and Test Events: Nov 22 - Mar 23



Markets Roadmap / Market Areas / Case Study: Demand Flexibility Service 69

Demand Flexibility Service (DFS)

What are the key criteria for Demand Flexibility Service?

Half-hourly smart metering	A minimum response time of 30 minutes
A minimum unit size of 1MW, maximum of 100MW with an ability to aggregate on a national basis	Ability to respond to signals issued at day-ahead via email
Settlement calculated by the supplier using historical baselining of household usage	12 tests between 1st November and 31st March with a Guaranteed Acceptance Price (GAP) of £3000/MWh

What next for the Demand Flexibility Service?

At the time of publication over 30 providers had registered as Approved Providers. This amounts to over 2GWh flexibility during Winter 2022/23 from 1.6m households and businesses.

Building on the success of the Demand Flexibility Service, the ESO is considering 'what next'. The DFS has created momentum for participation from consumer demand in flexibility markets. Initially the next steps are looking towards next winter and what may be needed including examining what changes could be accommodated to the current service design in collaboration with industry. In parallel the ESO is considering what the enduring solutions for keeping the momentum on demand flexibility are, such as looking at removing barriers to entry in the ESO's other markets and the impact of wider market changes, such as wider adoption of half-hourly settlement.

Markets Roadmap / Market Areas / Case Study: Demand Flexibility Service 70

Thermal

Thermal constraint management amounted to £1.38bn in 2022[1], more than double the previous year. Over the past 12 months, cost increases have been mitigated through significant progress in network build, as well as through new commercial solutions launched by ESO.

Going forward, addressing thermal constraints will require significantly more network build, given the sizeable increase in low-carbon generation needed to meet our decarbonisation ambitions, which will often connect at the edges of the system. At the same time, we need to develop markets, access and charging arrangements, and commercial solutions that send appropriate investment and dispatch signals to assets so that they connect, generate, and consume electricity in the most efficient locations and at the most efficient time for the whole system.

Link to thermal webpages

What is thermal constraint management?

Transmission constraint groups are geographical areas of the network where the system is unable to transmit power due to congestion at one or more parts of the network. There are several types of constraints but one of the most common on the network are thermal constraints.

Thermal constraints refer to an area of the network where the power is congested due to the thermal capability of the equipment. At times, to ensure system security, the ESO must reduce generation/increase demand behind a constraint and increase generation/ decrease demand in front of the constraint to ensure generation and demand remain in balance.

Constraint Management Intertrip Services (CMIS)[2]:

- Post fault
- Instantaneous response (150ms)
- Yearly contracts
- 23/24 units will receive an arming fee (£/Settlement period) and a tripping fee (£/trip)
- 24/25 units will receive an arming fee (£/MWh) and a tripping fee (£/trip)

The CMIS secures a pre-determined volume of generation capacity which can be reduced to 0MWs almost instantaneously in the event of a fault. Our control room, knowing that there is a pre-defined volume of generation that can be instantaneously removed from the system, can transfer greater volumes of generation across the network boundary. The CMIS is currently operational at the B6 boundary (Anglo-Scottish). We have signaled our intent to run this scheme in the EC5 boundary (East-Anglia) and we are consulting on the EC5 CMIS.

Trades:

Local Constraint Markets (LCM):

Balancing Mechanism (BM):

MW Dispatch Service:

Network Build:

1 This figure represents the costs of addressing thermal constraints only, and does not include the reducing the largest loss cost, inertia costs and voltage constraint costs.
2 Previously known as the NOA B6 Constraint Management Pathfinder.

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Constraint Management Intertrip Services (CMIS)[2]:

Trades:

Local Constraint Markets (LCM):

Balancing Mechanism (BM):

MW Dispatch Service:

Network Build:

- Pre-fault
- Ahead of gate closure
- Service provision length bespoke to ESO requirements

We can buy or sell electricity in advance of the BM where we foresee an opportunity to alleviate a constraint in a more cost-efficient way. These are bilateral agreements between the ESO and a counterparty, in which we call upon a party to increase/decrease their generation/demand by a specific volume at an agreed price and time.

1 This figure represents the costs of addressing thermal constraints only, and does not include the reducing the largest loss cost, inertia costs and voltage constraint costs.
2 Previously known as the NOA B6 Constraint Management Pathfinder.

Markets Roadmap / Market Areas / Thermal 72

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Constraint Management Intertrip Services (CMIS)[2]:

Trades:

Local Constraint Markets (LCM):

- Pre-fault
- Day ahead and intraday
- 30 minute service duration
- Pay as bid
- Utilisation payment (£/MW/h)

We are developing the LCM, helping to ease constraints at, and above the Scottish/English boundary (B6 and B4) to facilitate the provision on thermal constraint services from DER units. This will provide the ESO with a competitive alternative to the Balancing Mechanism. We expect this service to complete trials in Q2 and for this marketplace to be fully launched in Q3 of 2023.

Balancing Mechanism (BM):

MW Dispatch Service:

Network Build:

1 This figure represents the costs of addressing thermal constraints only, and does not include the reducing the largest loss cost, inertia costs and voltage constraint costs.
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Markets Roadmap / Market Areas / Thermal 73

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Thermal constraints refer to an area of the network where the power is congested due to the thermal capability of the equipment. At times, to ensure system security, the ESO must reduce generation/increase demand behind a constraint and increase generation/ decrease demand in front of the constraint to ensure generation and demand remain in balance.

Constraint Management Intertrip Services (CMIS)[2]:

Trades:

Local Constraint Markets (LCM):

Balancing Mechanism (BM):

MW Dispatch Service:

Network Build:

- Pre-fault
- Post gate closure
- 30 minute service duration
- Prices and volumes determined by BoA

We use bids and offers as both a pre- and post-fault mechanism to instruct Balancing Mechanism Unit's (BMU) to reduce or increase generation and demand at specific locations on our network.

1 This figure represents the costs of addressing thermal constraints only, and does not include the reducing the largest loss cost, inertia costs and voltage constraint costs.
2 Previously known as the NOA B6 Constraint Management Pathfinder.

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Thermal

Thermal constraint management amounted to £1.38bn in 2022[1], more than double the previous year. Over the past 12 months, cost increases have been mitigated through significant progress in network build, as well as through new commercial solutions launched by ESO.

Going forward, addressing thermal constraints will require significantly more network build, given the sizeable increase in low-carbon generation needed to meet our decarbonisation ambitions, which will often connect at the edges of the system. At the same time, we need to develop markets, access and charging arrangements, and commercial solutions that send appropriate investment and dispatch signals to assets so that they connect, generate, and consume electricity in the most efficient locations and at the most efficient time for the whole system.

Link to thermal webpages

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Constraint Management Intertrip Services (CMIS)[2]:

Trades:

Local Constraint Markets (LCM):

Balancing Mechanism (BM):

MW Dispatch Service:

Network Build:

- Pre-fault
- 2 minute response
- Service duration bespoke to need
- Pay as bid
- Utilisation payment (£/MW/h)

We are developing an enduring market which can facilitate DER to provide real time services including thermal constraint management. The MW Dispatch Service is set to go live in the Southwest DNO (NGED) region in late Summer 2023 and within the South Coast (UKPN's SPN Licence Area GSPs) region by end of the 2023/24 financial year. By the end of 2023 we are expecting up to 1.3GW of providers in the southwest and 700MW in the southeast.

1 This figure represents the costs of addressing thermal constraints only, and does not include the reducing the largest loss cost, inertia costs and voltage constraint costs.
2 Previously known as the NOA B6 Constraint Management Pathfinder.

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Constraint Management Intertrip Services (CMIS)[2]:

Trades:

Local Constraint Markets (LCM):

Balancing Mechanism (BM):

MW Dispatch Service:

Network Build:

Our Network Options Assessment (NOA) and Holistic Network Design (HND) identify the most effective means to address a thermal constraint, be that through Network Build options and/or commercial options.

1 This figure represents the costs of addressing thermal constraints only, and does not include the reducing the largest loss cost, inertia costs and voltage constraint costs.
2 Previously known as the NOA B6 Constraint Management Pathfinder.

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Thermal - Summary of the chapter

How is the landscape changing? We continue to connect new generation at the edge of the network, far from demand centres. Our 2022 Future Energy Scenarios forecasts over 51GW of offshore wind on our networks by 2030. Looking forward, new sources of demand will also connect to the network, with 40GW of electrolysers in 2050, offering new ways of managing thermal constraints.

How have costs and volumes evolved over the last year? Volumes and costs continue to increase year on year (YoY). Compared to 2021[3], volumes of thermal constraint actions more than doubled from 3.3TWh to 7.8TWh and costs doubled from £637m to £1.38bn.

What is driving the need for reform? As well as needing significantly more network build, we need to use this network more efficiently by developing and reforming markets to send efficient signals to generation and demand by location and time.

How are we implementing market reform? In addition to the continued build out and reinforcement of the transmission system, our new Constraint Management Intertrip Service (CMIS) first tendered for an October 23/24 start has delivered results earlier than anticipated, saving consumers £80m in 2022. We have also made significant progress on our Local Constraint Market (LCM) and the MW Dispatch Service which we expect to go live in Q2 & Q3 2023. Our Net Zero Market Reform programme is investigating how to fundamentally reform GB markets and policy to deliver more efficient signals through the wholesale market, by location and time, which would dramatically reduce the cost to consumers of managing thermal constraints on the system.

3 It is worth noting that 2021 was an unusual year owing to the impact that Covid-19 had on GB's demand. For more details on the implications of Covid-19 on our networks, please see our 2022 publication of the Markets Roadmap.

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Thermal - Market Insight: Thermal Constraint Management Volumes

Thermal constraint management volumes in the BM and Trades

The volume of export constraints in 2022 reached 6.3TWh, an increase of 12% vs 2020 (2021 was an anomaly year). This is illustrated in Figure 1.

Breaking down export constraint volumes by technology (Figure 1) we see that wind and gas units continue to dominate, as both are turned down behind constraints while gas units are typically turned up in front of constraints to ensure sufficient margin. Gas actions increased 260% in 2022, compared to 2021. This was due to the commissioning of an offshore windfarm near to a large CCGT unit behind a Scottish constraint. When the network was constrained, a CCGT unit would be turned down before a wind farm as the cheaper option.

The volume of import constraints in 2022 reached 1.5TWh, an increase of almost 300% vs 2020 (2021 was an anomaly year). 88% of 2022's import volume was from interconnectors. This case study explains this increase.

The volume of export constraints

An export constraint is active on the network when the generation within a constraint group exceeds the maximum rated capacity of the network to transport energy out of the group. When this occurs, the ESO instructs generating units behind the constraint (i.e., within the original constraint group) to turn down, and generating units in front of the constraint to turn up. This ensures energy margins remain adequate throughout the system, while remaining within network constraint limits. Both actions are tagged as export constraints in the balancing mechanism.

Import constraints

An import constraint is active on the network when there is not enough generation within the constraint group to supply the demand, and it is not possible to transfer the required power into the group. When this occurs, the ESO instructs generating units in front of the constraint (i.e., outside the original constraint group) to turn down, and generating units behind (i.e., within) the constraint to turn up. Both actions are tagged as import constraints in the balancing mechanism.

Case study: Import constraints

Russia's invasion of Ukraine led to significant rises in European gas prices on the continent, while GB's LNG infrastructure allowed for a greater injection of gas reserves and lower relative prices. Meanwhile, tight capacity margins on the continent drove high prices when compared to GB over the summer of 2022. Arbitrage opportunities between the two markets led to GB becoming a net exporter of power for the first time in 2022, exporting a total of 5.5TWh electricity to continental Europe in Q2 alone.

Due to this shift to net export, an existing thermal import constraint around London (LE1) become significantly more active in the summer of 2022. National GB margins were sufficient, but due to net exports in the South East, the LE1 constraint meant that more generation and interconnector imports were required in the South East to meet London's demand. Meeting this need required the reversal of interconnector flows. Figure 2 illustrates the significant increase in import constraint volumes, which peaked in July. For context, over 430GWh of interconnector buy instructions were issued in July 2022 alone, greater than the volumes procured in either 2019 or 2020 as illustrated in Figure 3.

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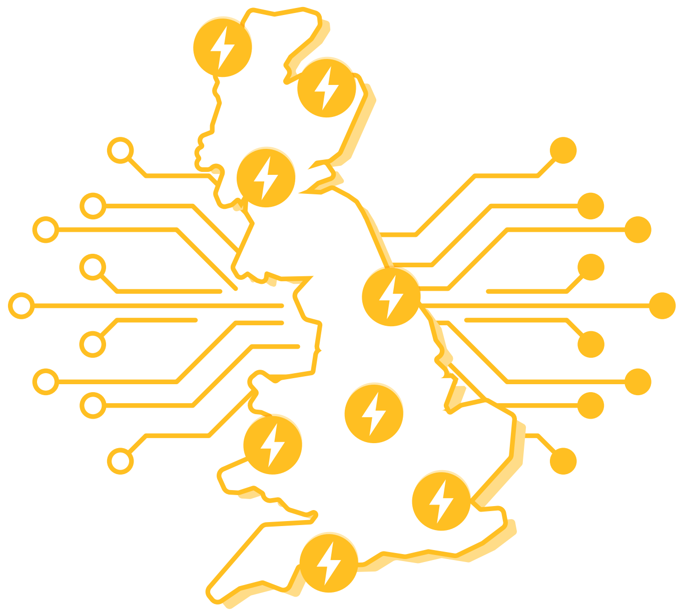
Thermal - Market Insight: Thermal Constraint Management Volumes

Constraint Management Intertrip Scheme

The ESO has awarded CMIS contracts for two tenders to help manage the B6 (SCOTEX) constraints, tendering 1,700MW of intertrip capacity in 23-24 and 1,600MW in 24-25. These will be live from October 2023 to September 2024 and October 2024 to September 2025 respectively. This case study explains the CMIS in more detail.



Case study: The CMIS

Of the ten successful units for the 23-24 tender, nine of these are wind farm units with the tenth being a 50MW battery storage unit. Six of these units have been delivering since April '22 represent 764MW of intertrip capacity. From April 2022 to January 2023, these six contracts have enabled almost 32GWh of extra renewable energy to be generated that would otherwise have been curtailed and replaced by gas-fuelled generation. This scheme is already significantly aiding the ESO's ambition of being able to operate a zero-carbon transmission system by 2025. The additional flow of wind generation across our network brought forward by the CMIS contributed to GB setting a new wind record on the 10th January 2023. We estimate that this scheme has saved ~140k tonnes of carbon between April and January. Furthermore, these six operational units saved consumers an estimated £80m that would have otherwise been spent on constraint payments across the same timescale. Looking forward, we expect this service to delivery annual savings worth tens of millions.

Of the 11 successful units for the 24-25 tender, these are all wind farm units.

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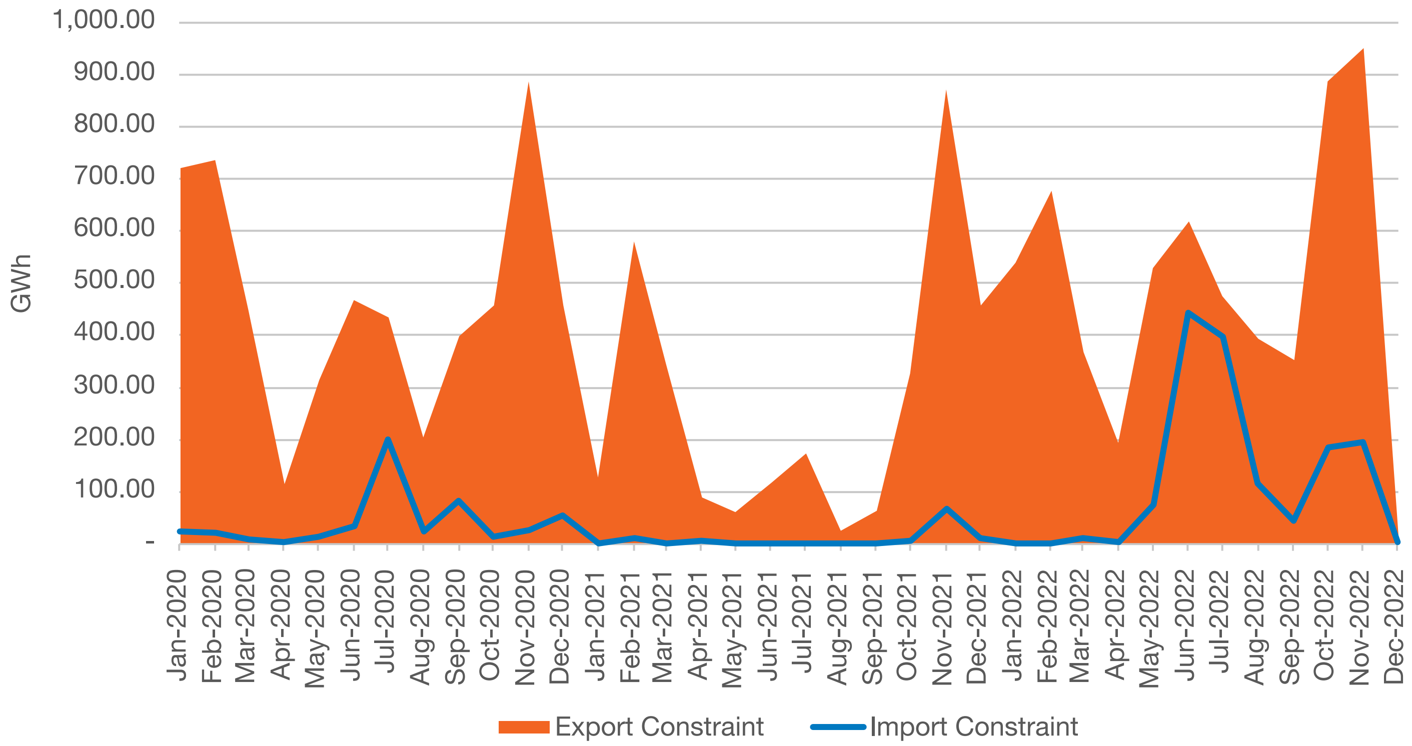
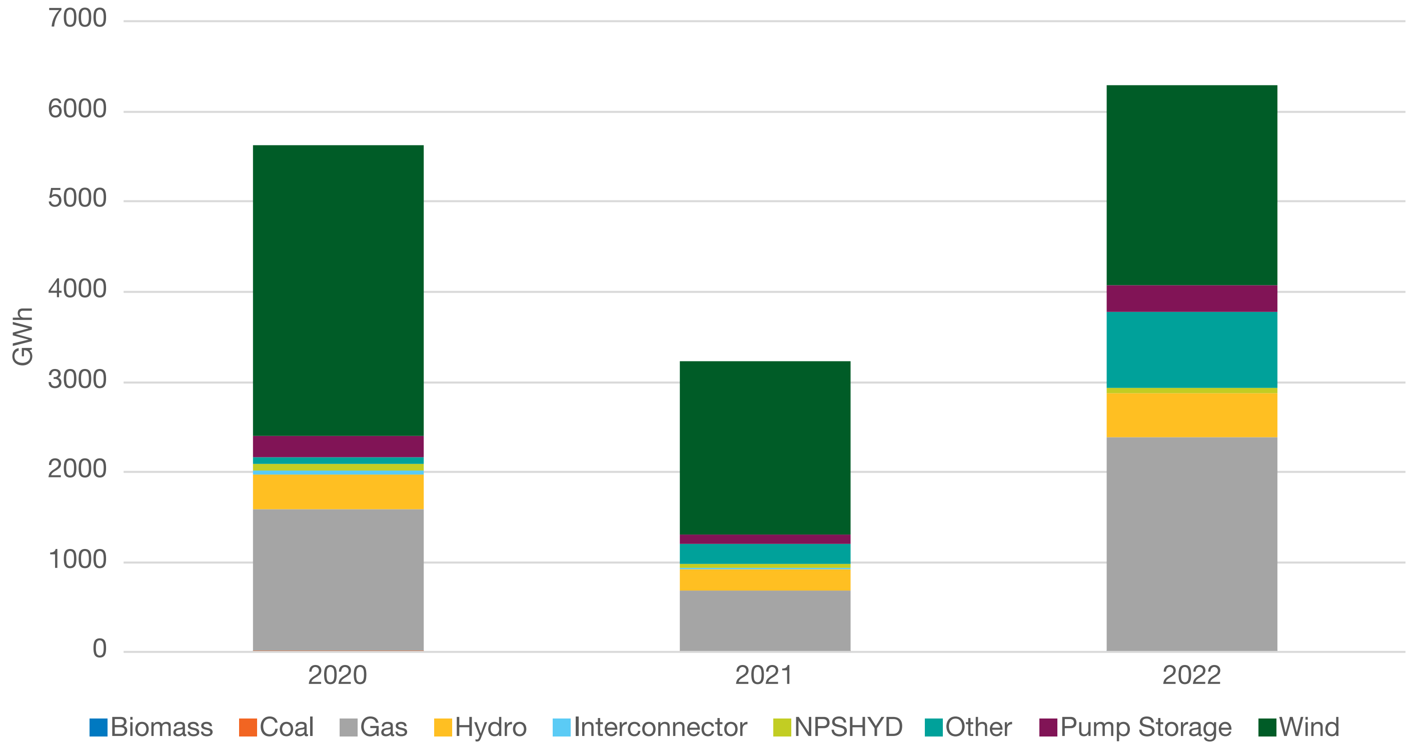
Thermal - Market Insight: Thermal Constraint Management Volumes

TH Figure 1: Thermal constraint volumes: 2020-2022



Thermal constraint volume across January 2020 – December 2022 split into import and export constraints.

TH Figure 2a: Export constraint volumes (GWh)



These charts shows the total technology types which were utilised to address a thermal export or import constraint by volume.

'Other' includes all fuel types not reported separately and includes hydro, open-cycle gas turbine (OCGT), demand side suppliers, and nuclear.

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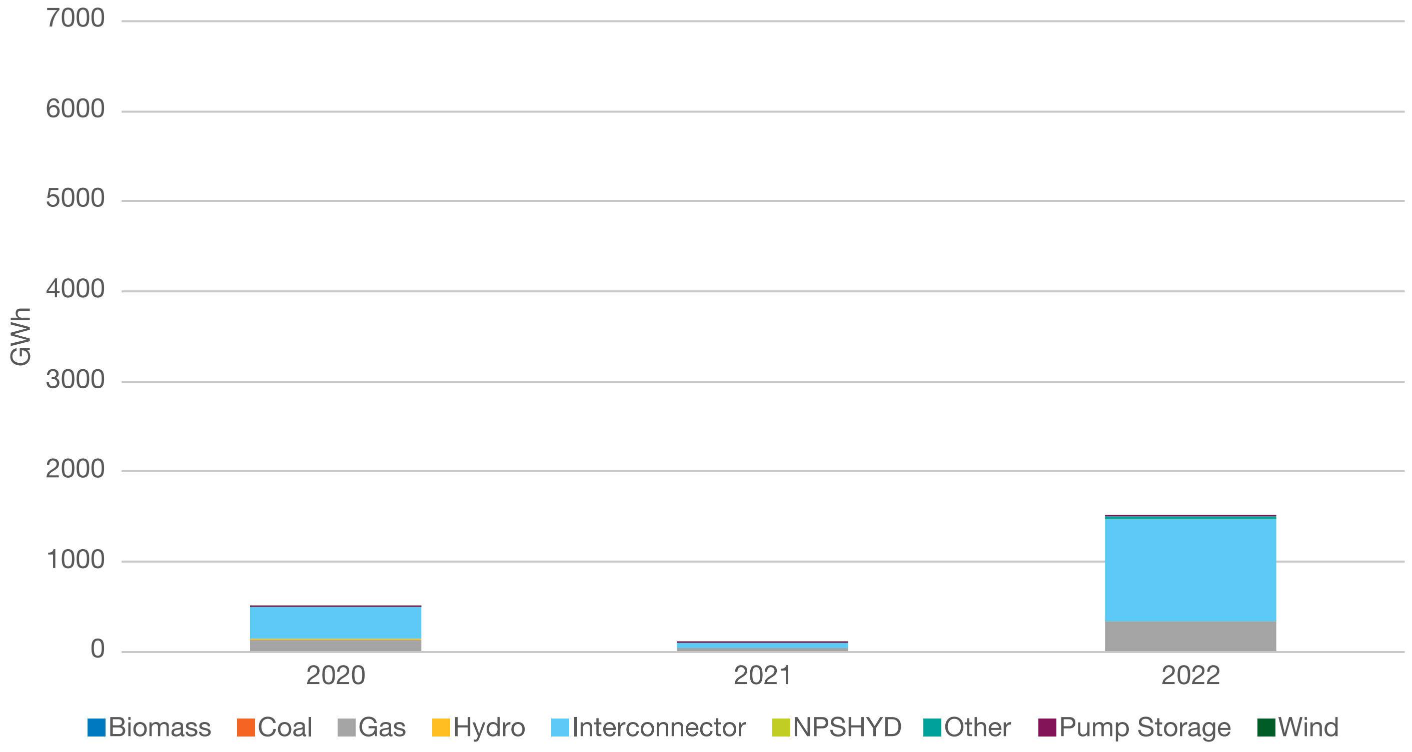
Thermal - Market Insight: Thermal Constraint Management Volumes

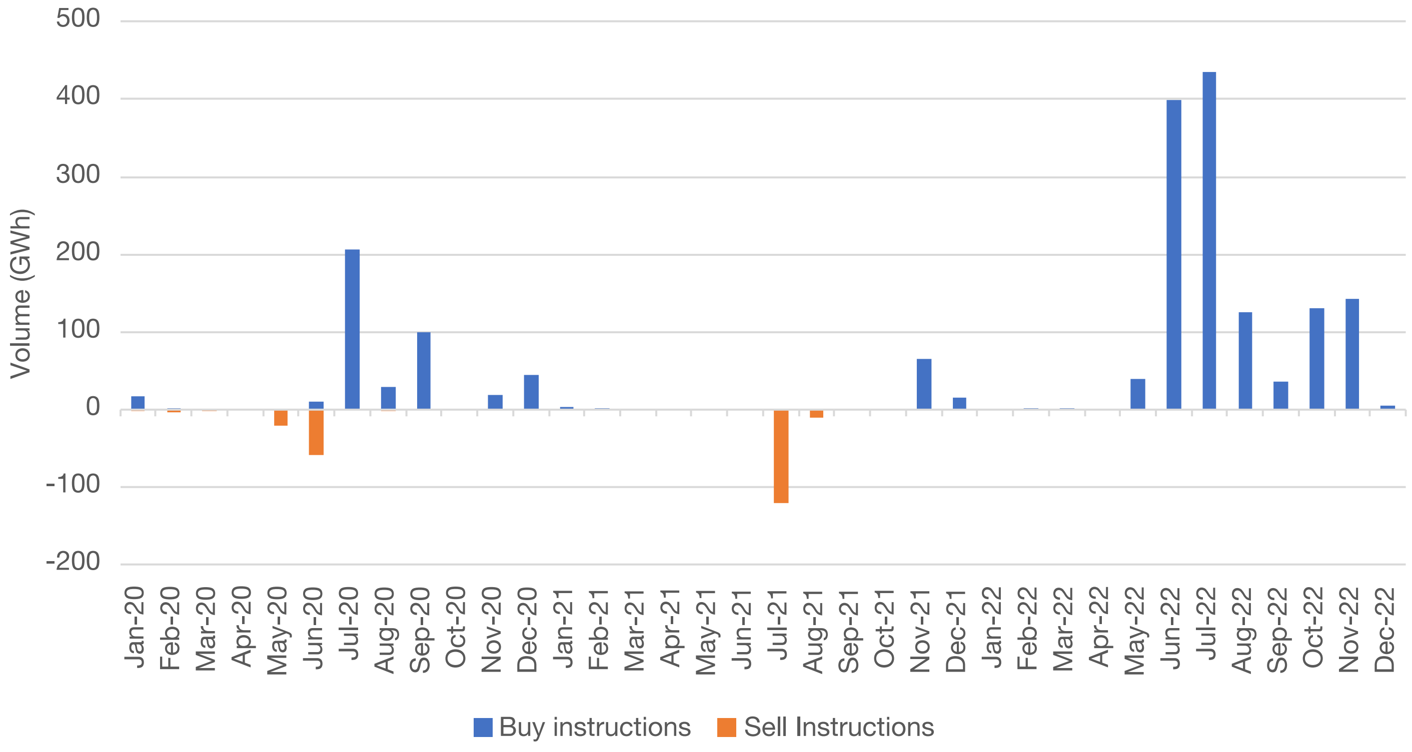
TH Figure 2b: Import constraint volumes (GWh)



These charts shows the total technology types which were utilised to address a thermal export or import constraint by volume.

'Other' includes all fuel types not reported separately and includes hydro, open-cycle gas turbine (OCGT), demand side suppliers, and nuclear.

TH Figure 3: ESO instructed Interconnector trades to address thermal constraints (GWh)



Volumes of ESO instructed interconnector trades to address thermal constraints

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Thermal - Market Insight: Thermal Constraint Management Costs

Thermal constraint management volumes in the BM and Trades

Costs of actions taken to address both export and import thermal constraints via the BM and trades significantly increased in 2022, rising from £637m to £1.38bn. This is illustrated in Figure 4.

With the volume of actions taken to address export constraints almost doubled compared to 2021, so too did the costs, increasing from £631m to £1.16bn. This price increase was dominated by gas units, which increased by 267%, reflecting the higher cost of gas throughout 2022 (Figure 5).

The costs of addressing thermal import constraints rose from £6m in 2021 to £216m in 2022. Over 90% of these costs can be attributed to interconnector trades, primarily within the summer months to address the South East import constraint. More detail on this is provided in this case study.

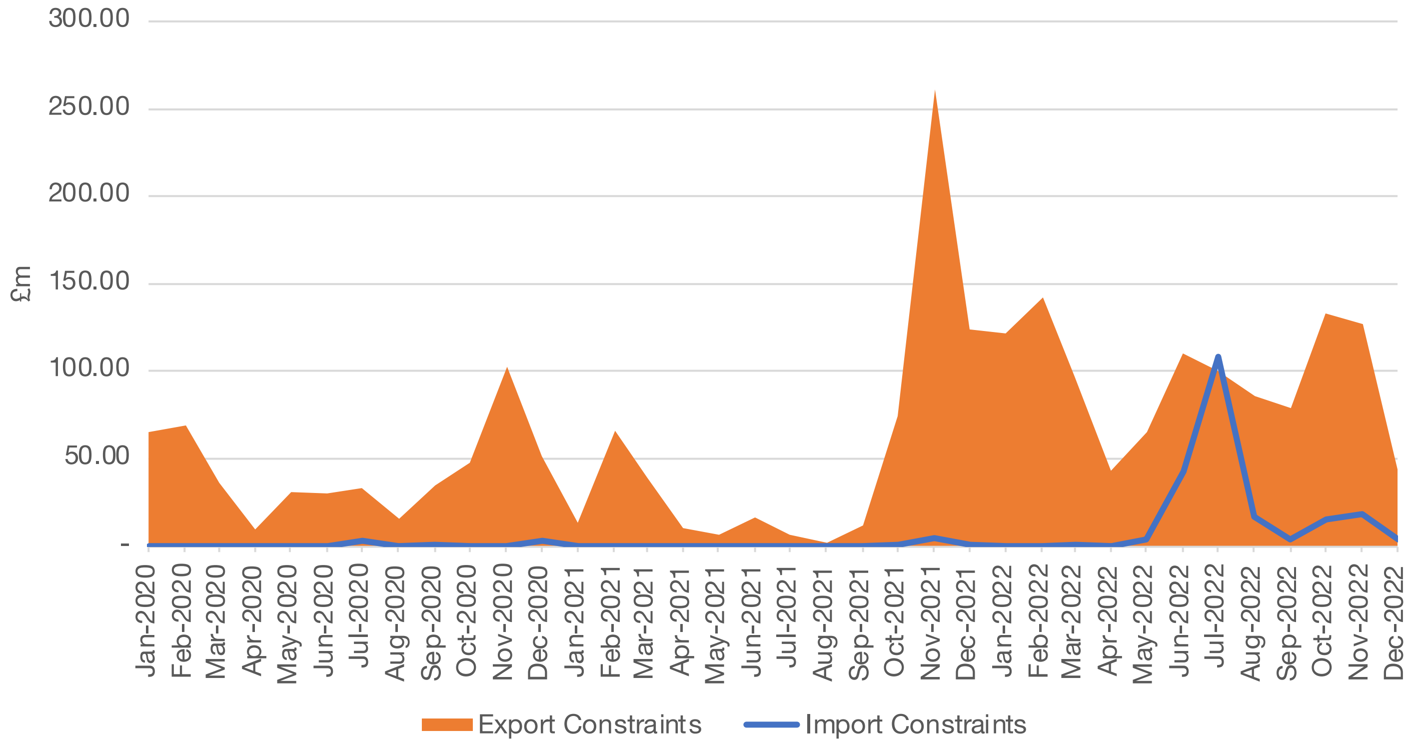
Case study: Import constraint costs

The cost of trading on interconnectors to address thermal constraints reached a historic yearly high of £193m, as illustrated by Figure 6. Almost half of these costs occurred in July (£107m), which saw record breaking ESO instructions and reaching £9,500/MWh. For context, the total combined cost of instructing interconnectors to address thermal constraints across both 2020 and 2021 was just under £14m.

Constraint Management Intertrip Scheme:

Our 23/24 tender product provides successful units with an arming fee (£/Settlement period) and a tripping fee (£/trip). Units are only paid their arming fee for the settlement periods in which they are armed. The tripping fee is only paid in the unlikely event that a fault occurs on the network which trips off an armed unit. We publish these costs as part of our tender results.

TH Figure 4: Thermal constraint costs: 2020-2022



Thermal constraint costs across January 2020 – December 2022 split into import and export constraints.

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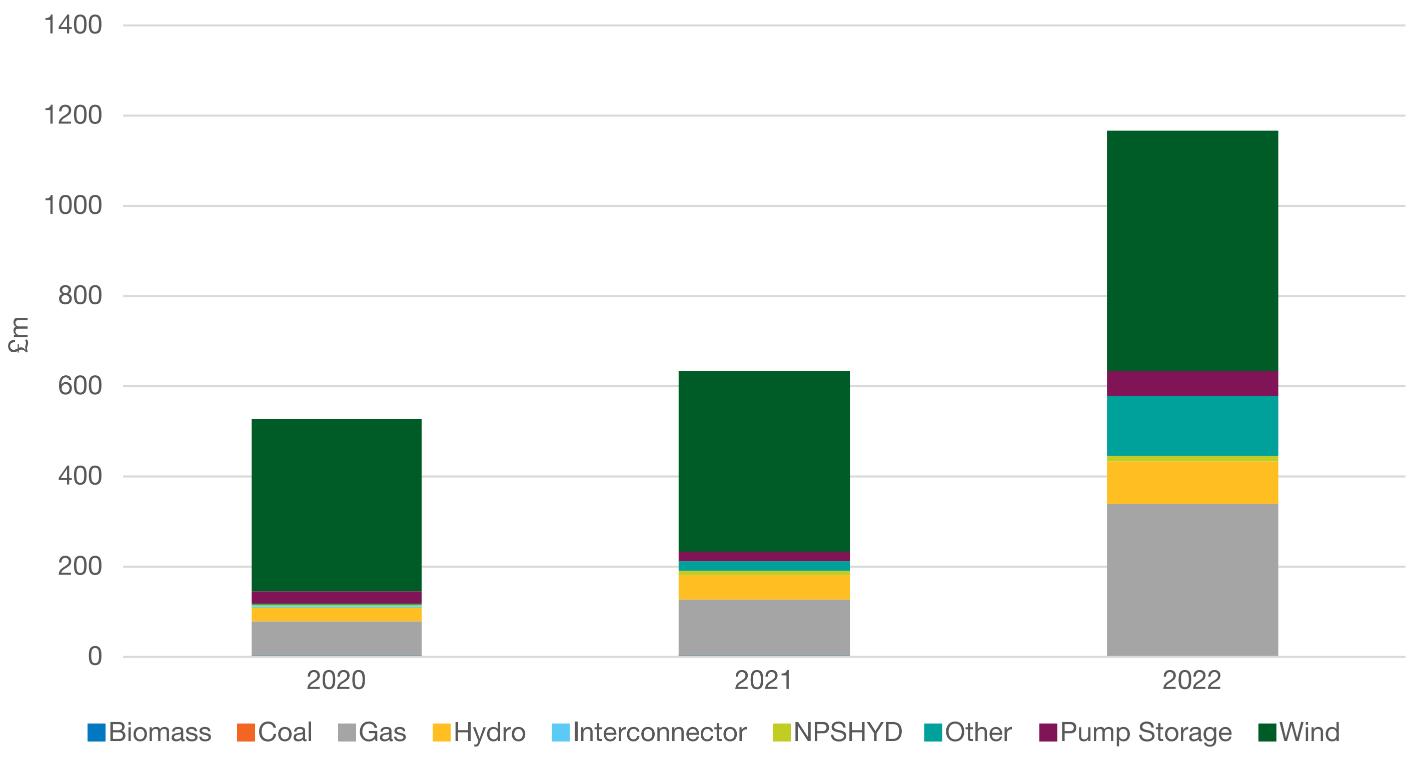
Thermal - Market Insight: Thermal Constraint Management Costs

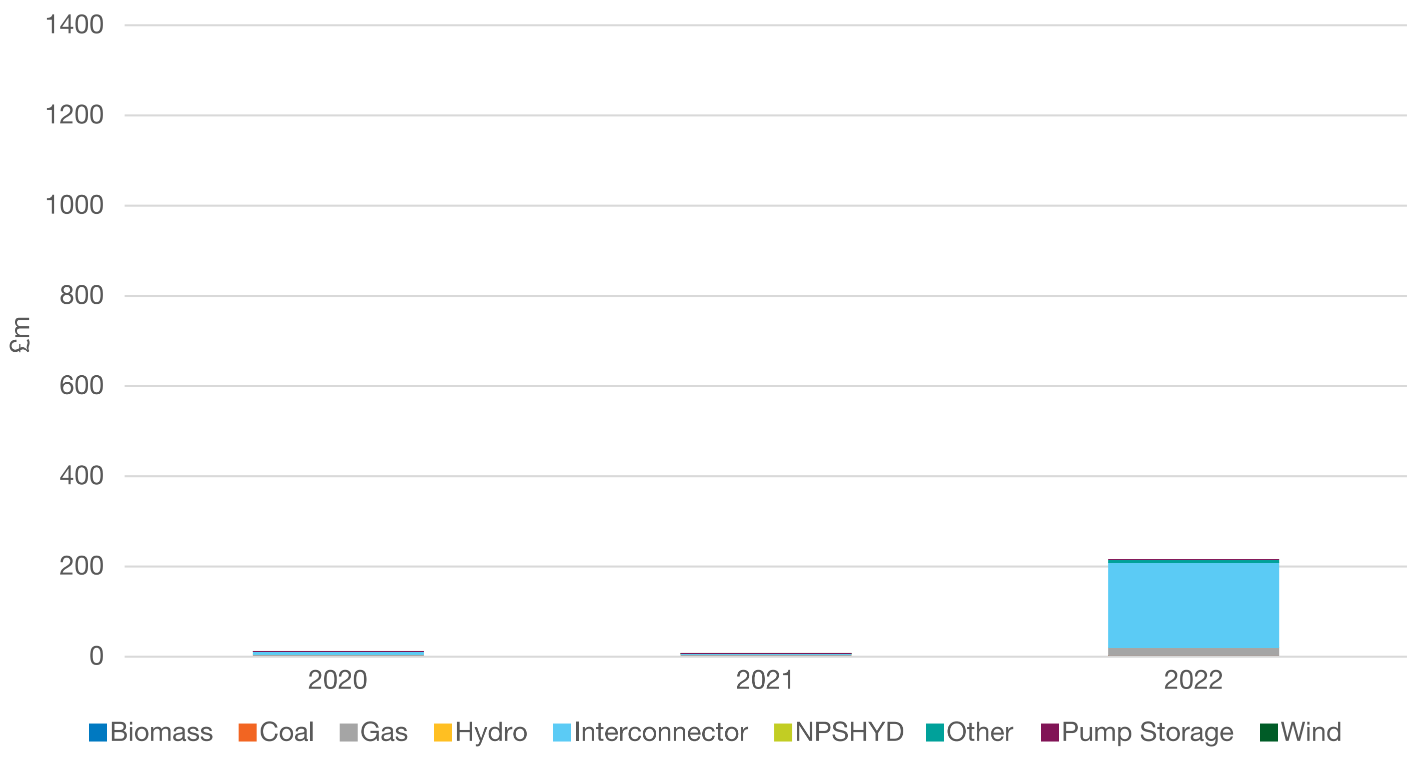
TH Figure 5a: Export constraint costs (£m)



These chart shows the total technology types which were utilised to address a thermal export or import constraint by cost.

'Other' includes all fuel types not reported separately and includes hydro, open-cycle gas turbine (OCGT), demand side suppliers, and nuclear.

TH Figure 5b: Import constraint costs (£m)



These chart shows the total technology types which were utilised to address a thermal export or import constraint by cost.

'Other' includes all fuel types not reported separately and includes hydro, open-cycle gas turbine (OCGT), demand side suppliers, and nuclear.

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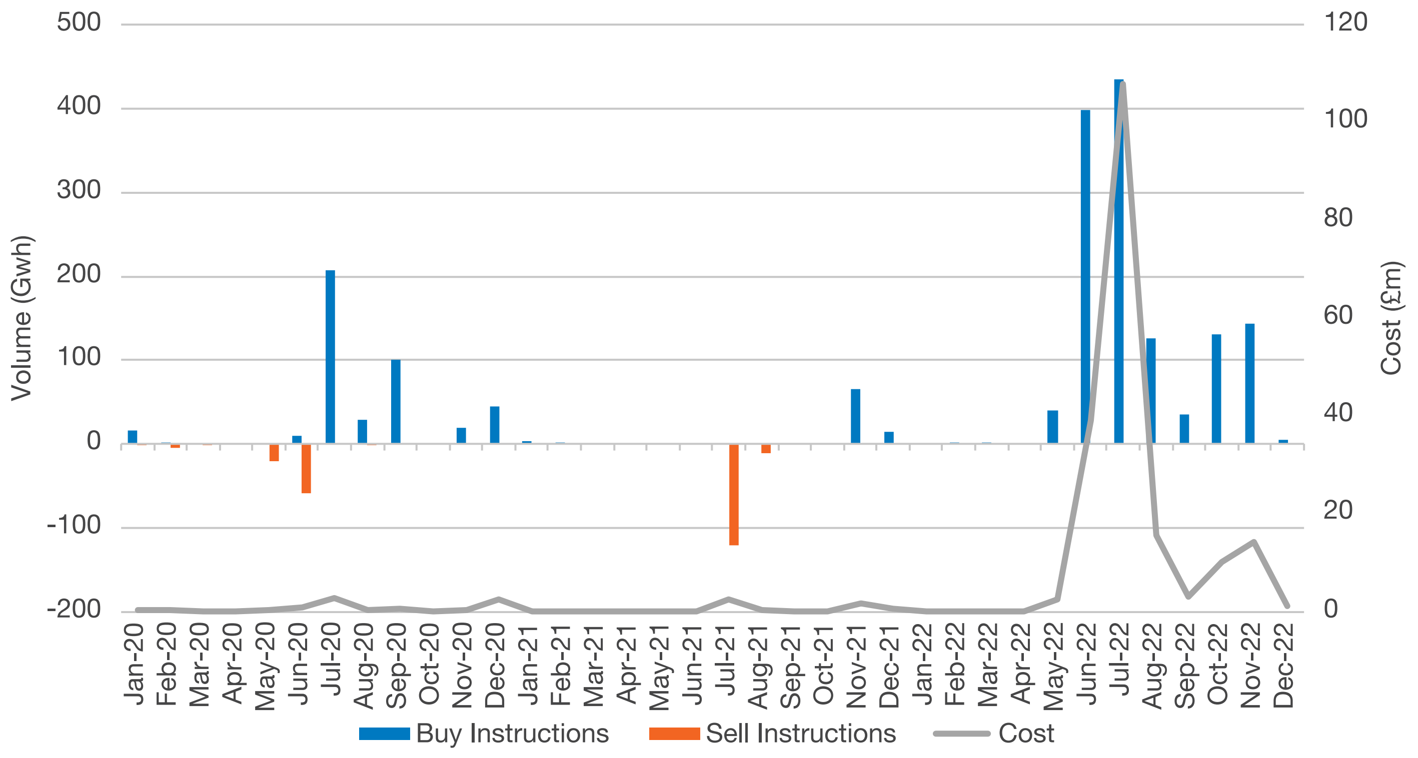
Thermal - Market Insight: Thermal Constraint Management Costs

TH Figure 6: ESO instructed interconnector trades to address thermal constraints (£m and GWh)



The volumes and costs of ESO instructed interconnector trades to address thermal constraints.

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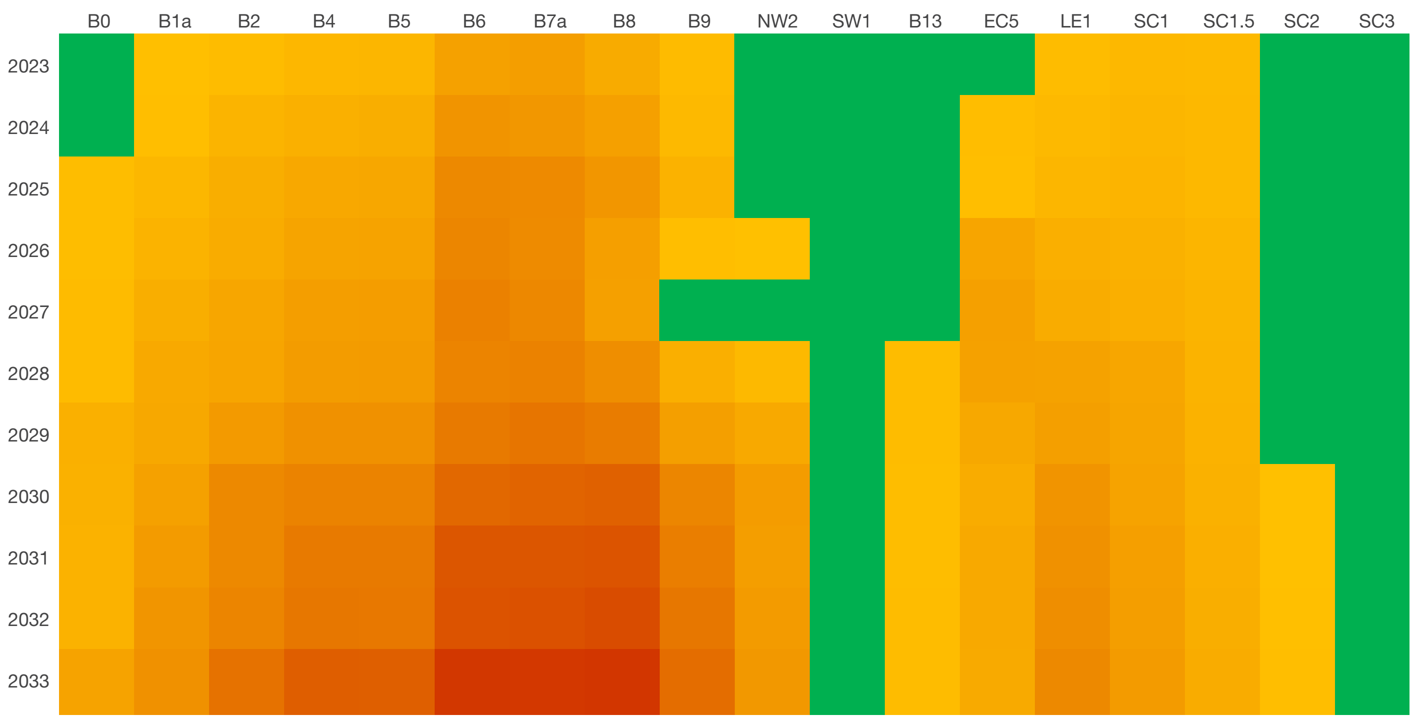
Thermal - Drivers for Reforms

The evolving generation and demand mix presents increasing thermal constraint challenges. To address these, we require a complimentary approach consisting of continued strategic network build alongside market solutions. We have identified several key drivers which are influencing how we are reforming our market solutions for thermal constraints.

Constraint volumes will continue to increase, so we need to drive down the cost of managing them

Across all our FES scenarios, by 2030 we forecast at least 31GW of offshore wind connected, with 51GWs under the Leading the Way scenario. Even with planned network build, our Electricity Ten Year Statement (EYTS) forecasts an increase in the volume of constraints across several boundaries as shown by the heat map (Figure 7), while our NOA modelling forecasts see increased costs across all of our FES scenarios (Figure 8). We need to develop new market solutions, and reform existing market design, to drive down these costs. Furthermore, our FES scenarios all forecast GB as a net exporter of electricity by 2030, we must consider how to address locational thermal constraints in regions with interconnector capacity to identify a more cost-effective means to securing against high-cost events.

TH Figure 7a: Excess flows beyond boundary capability if no action is taken to reinforce the system



This heat map illustrates the impact of network reinforcement options recommended in our NOA Refresh 2021/22 which includes the optimal network reinforcements identified by the Holistic Network Design.

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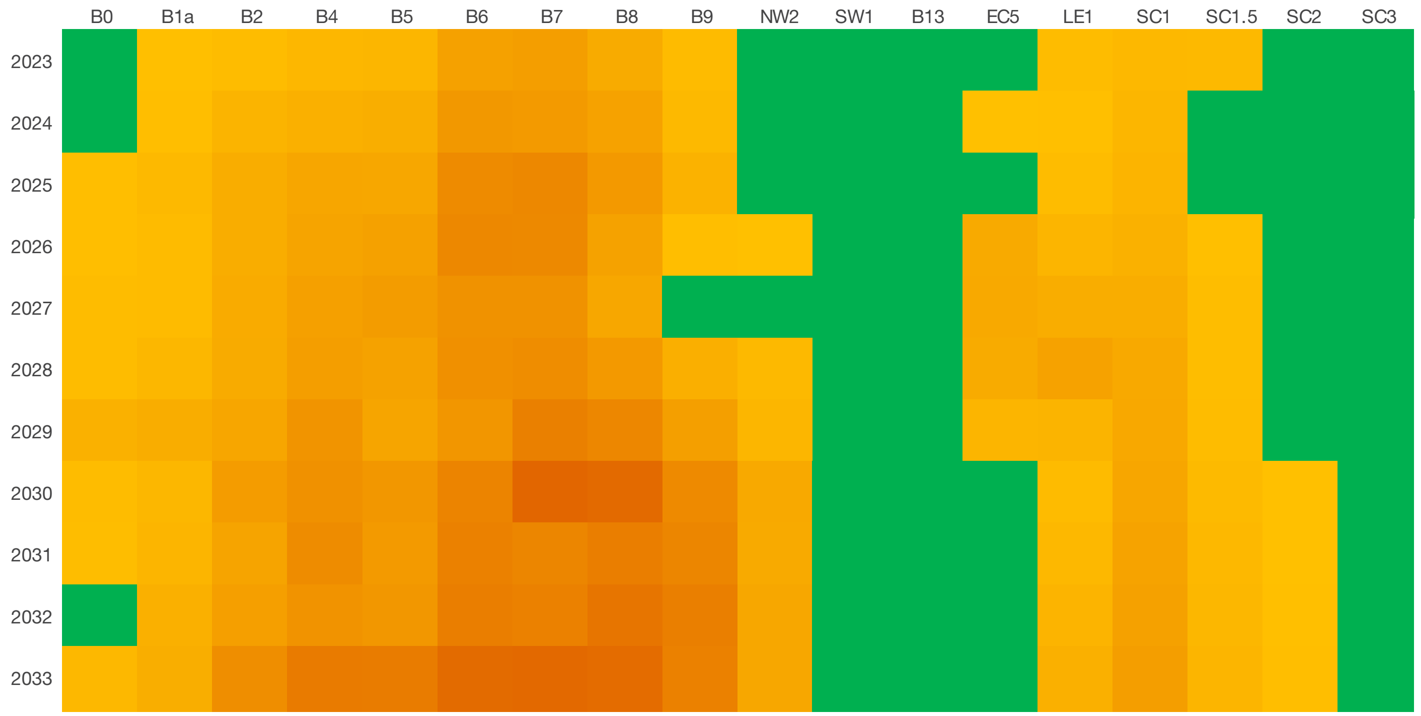
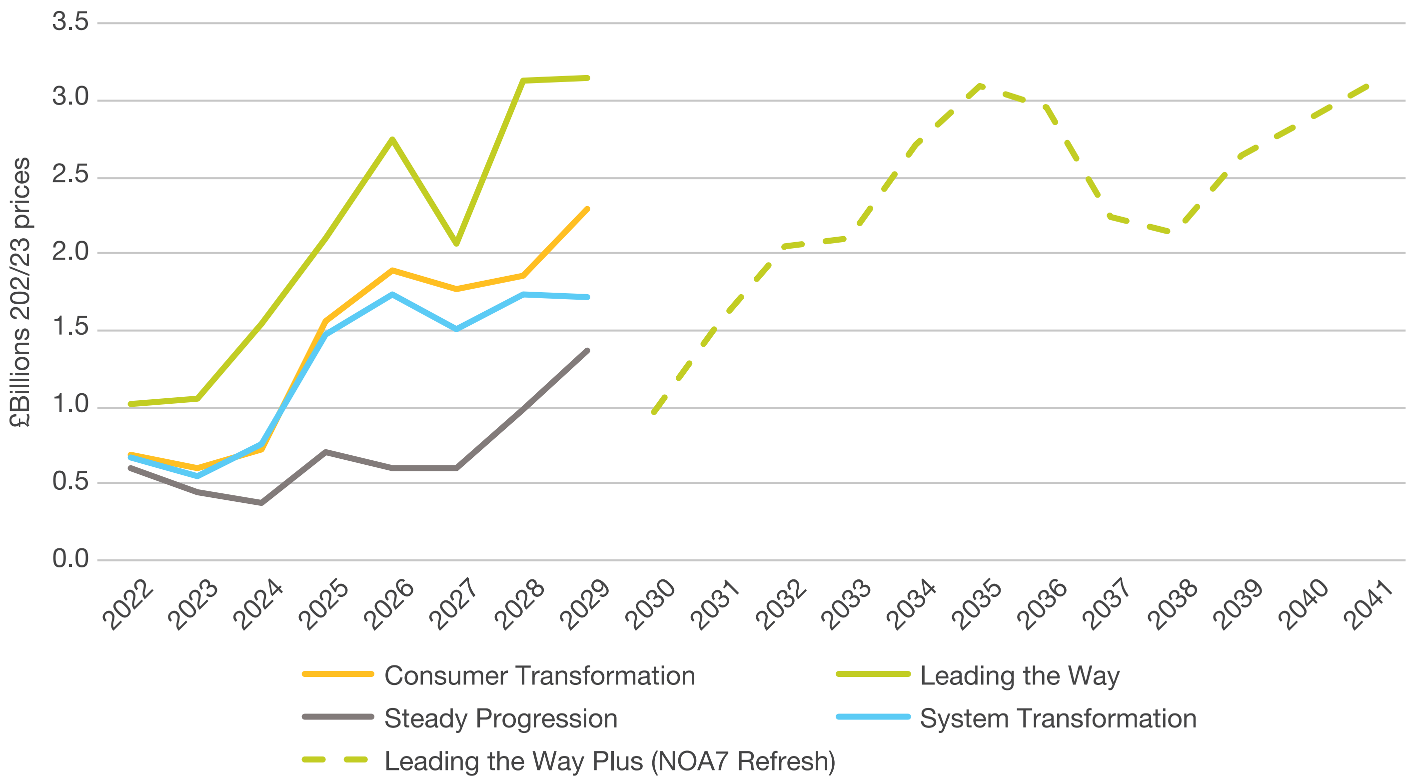
Thermal - Drivers for Reforms

TH Figure 7b: Excess flows beyond boundary capability with NOA 2021 Refresh recommended options applied



This heat map illustrates the impact of network reinforcement options recommended in our NOA Refresh 2021/22 which includes the optimal network reinforcements identified by the Holistic Network Design.

TH Figure 8: Modelled constraint costs after NOA7 / NOA7 Refresh optimal reinforcements



Modelled constraint costs after the NOA 2021/22 Refresh optimal reinforcements. The combined effort of a new offshore transmission system and the acceleration of onshore reinforcement projects causes a significant drop in constraint costs in 2030 to around £1bn per year.

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Thermal - Drivers for Reforms

A need for greater locational signals for dispatch and investment

Even under optimal network build, there will still be congestion on our network. Reducing the cost of managing thermal constraints requires greater locational signals for both the investment and dispatching of assets. We recognise the role we play in sending these signals, both through our markets and through our planning processes. However, the overwhelming majority of generation and consumption is driven by signals from the wholesale and retail markets, which currently do not send any kind of locational signal. If we are to meaningfully address the significant cost to consumers of managing locational constraint costs, more granular locational signals need to be introduced into the wholesale market in operational timeframes. For our latest thinking on what an appropriate market design looks like, please visit our Net Zero Market Reform homepage.

Enhancing our control room's options for addressing thermal constraints

The BM and trades have been the ESO's primary tools for managing thermal constraints. There is an opportunity for us to capitalise on the growth of emerging flexible technologies. The operational characteristics of many of these potential service providers will differ from conventional units, in terms of size, location on the network and visibility to the ESO. We need to:

a) Understand the technical capabilities and commercial business models of these new players better. We are undertaken several products to enhance our understanding in this area, include the Service Provider Capability Mapping and the Hydrogen Production for Thermal Electricity Constraints Management project.

b) Remove barriers to entry from our existing markets and processes, and develop new more appropriate markets where necessary

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Thermal - Market Reforms

Alongside recommending strategic network build, we are developing and reforming our markets to reflect the diversity of service providers operating on our networks and enhance the visibility of decentralised assets. However, in the longer-term, there is a need for the wholesale market to send much stronger locational signals.

Driving down costs via increased market participation and optimal procurement strategy

The CMIS provides the control room with the confidence to allow greater flows over congested network boundaries. As discussed, the six operational units from the 23/24 tender have already delivered £80m of value for consumers over a 9-month period and is expected to save tens of millions on an annual basis. We have developed a volume cap model for our 24/25 CMIS tender, in which each month all successful units will re-compete to be selected and therefore paid an arming and tripping fee. This competition will further drive down the cost for our end consumers. The CMIS scheme is only for transmission connected units at the B6 boundary. The growth of Distributed Energy Resources (DER) can also mitigate the rise in thermal constraints, however, as most DER units are not registered balancing mechanism units (BMUs) we are unable to instruct them via the BM. We are developing a Local Constraint Market (LCM) on the B6 and B4 boundary and the MW Dispatch Service to allow the ESO to instruct specified DER units. Both the LCM and the MW Dispatch Service will complement the BM, offering additional operability options and a competitive alternative. The LCM allows the control room to take actions up to 48 hours ahead of gate closure, with the MW Dispatch Service determining prices at the day ahead stage before a within day / real time utilisation.

Local Constraint Market (LCM)

The LCM is a time-limited tactical solution, developed to provide a predictable alternative to the balancing mechanism at the B6 and B4 boundary. The service design reflects a simple construct informed by our Optional Downward Flexibility Management (ODFM)[3] to reduce barriers to DER units with less sophisticated monitoring systems; a one-hour response time, a simple instruction to turn generation down to zero / demand up and two instruction windows to allow closer to real time submissions to accommodate providers who are unable to submit actions at the day ahead timescales. More information on the service design can be found here. We expect this service to go live in Q3 of 2023.

MW Dispatch Service

The MW dispatch service is an enduring product to manage transmission constraints in real time across multiple geographic regions. This service also requires turn down to zero real power output. However, compared to the LCM, the MW Dispatch Service requires control equipment to provide visibility and commercial control, a 2-minute response time and a sustained output until the ESO instructs otherwise. Developed collaborative with the DNOs, this service will deliver the first implementation of primacy rules in GB to ensure coordinated dispatch of DER. The MW Dispatch Service is set to go live in the Southwest DNO (NGED) region in late Summer 2023 and within the South Coast (UKPN's SPN Licence Area GSPs) region by end of the 2023/24 financial year.

3 ODFM facilitated access to new sources of flexibility to answer low-demand conditions experienced during the Covid-19 pandemic lockdowns.

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Thermal - Market Reforms

Reforming markets, policy, frameworks and processes to send more efficient locational signals for investment and dispatch

ESO's market reforms are driving efficiencies in how we run the network slightly harder (with CMIS) and how we redispatch the market to resolve thermal constraints (BM, LCM, MW Dispatch). However, the major inefficiencies that are driving these large volumes of constraints in the first place, other than insufficient network capacity, are the lack of efficient locational signals for investment and dispatch.

For dispatch, we strongly believe that these signals need to be sent through the wholesale market, and our NZMR programme is assessing the best way to achieve this, to support DESNZ's Review of Electricity Market Arrangements (REMA). For investment signals, the solution is less clear, should it be through reformed Transmission Network Use of System charges, complementing granular locational wholesale pricing? Or through reforms to access arrangements, or locational investment policy (e.g., CfDs or the CM)? What is clear is the need for a holistic approach across networks and markets, and we are working with our colleagues at DESNZ and Ofgem to understand the possible solutions. For investment in assets that can provide constraint management solutions, our Centralised Strategic Network Plan (to be published in 2024) will indicate where on the network we will see the most need for these services.

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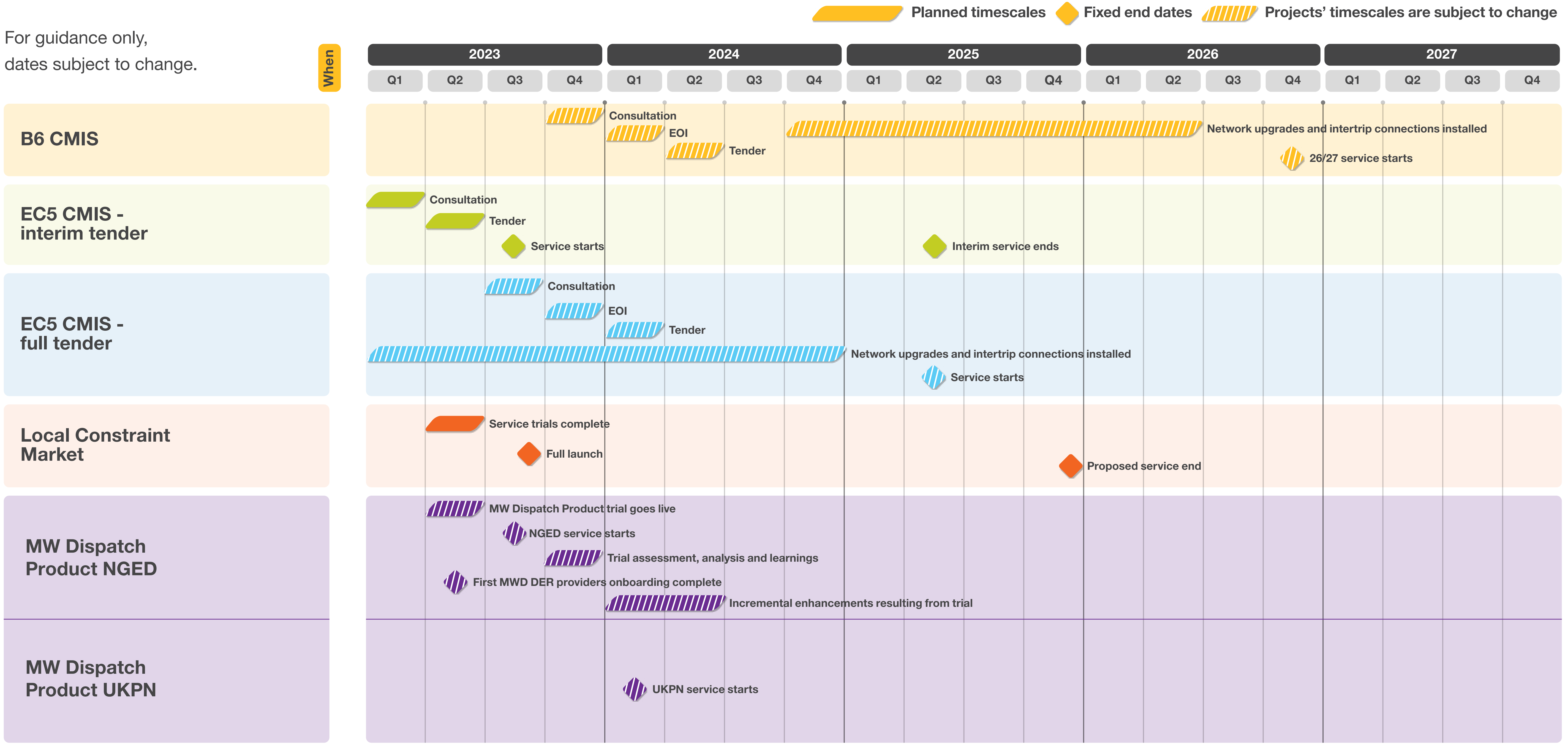
Thermal - Delivery Plan

For guidance only,
dates subject to change.



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Thermal - Delivery Plan

B6 CMIS

What?

The CMIS procures transmission connected generation above the Scottish/English boundary (B6 and B4) for the intertrip scheme. As part of the Constraint Management 5-Point Plan we have launched an interim service solution on B6 for parties already connected to the intertrip scheme until October 2023, when the CMP service commences.

EC5 CMIS - interim tender

What?

We are currently in the design phase of the tender and have identified that there is a value opportunity to begin the service early (i.e. set up 'interim' contracts). An industry consultation on the rationale and contract terms and conditions for this 'interim' service will be released on Monday 6th March 2023. Please find the associated documents when they are available here.

EC5 CMIS - full tender

What?

The EC5 CMIS will take lessons learnt from the B6 CMIS and the 'interim' EC5 CMIS scheme and apply these to the East-Anglia boundary.

Local Constraint Market

What?

The Local Constraint Management (LCM) service is a workstream launched as part of the Constraint Management 5-Point Plan, the LCM is intended to be a short term strategic solution utilising flexibility from DER to reduce constraint costs on the B6 Anglo-Scottish boundary. This workstream is accelerating market delivery to access distribution connected assets in Scotland. The market is intended to offer a competitive alternative to the Balancing Mechanism when resolving Anglo-Scottish boundary constraints via generation turndown / demand turn-up.

MW Dispatch Product NGED
MW Dispatch Product UKPN

What?

As part of our Regional Development Programmes, the ESO alongside project partners National Grid Electricity Distribution (formerly Western Power Distribution) and UK Power Networks, are working with distributed energy resources (DERs) to help develop a new market solution. This new constraints management service will complement existing market routes, like the Balancing Mechanism and Wider Access Markets.

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Restoration

As the system transforms and becomes more reliant on intermittent energy sources, it is critical that we continue to develop the restoration market to meet these changing needs.

In future, system restoration will need to be delivered by a range of technologies at both transmission and distribution level. The Distributed ReStart project has proven that it is possible to restart the system from distribution level up and this year we have started to implement this in our restoration tenders. As we move forward, this approach will be rolled out more widely.

What is restoration?

Restoration services ensure that, in the unlikely event of a partial or full national power outage, we have a robust plan to restore power as quickly as possible to meet our System and Quality of Supply Standards (SQSS).

[Link to restoration webpages]

How do we procure restoration services?

We continue to procure restoration services through competitive Electricity System Restoration Events (tenders) where providers are awarded contracts for 3 years or more. In 2022 we launched 3 tenders: Southeast; Northern; and the first national wind-only tender for full restoration service provision at transmission level. The Southeast and Northern tenders will be the first time we procure from distributed energy resources (DER).

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Restoration - Summary of the chapter

How is the landscape changing?
We are becoming more reliant on intermittent, renewable energy as we decarbonise our power supplies, for both generation and restoration. Traditional sources of restoration, such as gas power stations and diesel generators, are in decline and we need find zero carbon alternatives to meet our net zero target.

How have costs and providers evolved in the last year? Costs have remained relatively consistent compared to previous years with the elimination of warming costs for restoration in 2022. Expressions of interest for the tenders in 2022 show the potential for the participation of new technology types (battery, wind, biomass, solar, synchronous condensers, rotating stabilisers).

What is driving the need for reform?
We must evolve the way in which we procure and deliver restoration to be fit for a system dominated by renewables and DER. Additionally, we have to achieve an efficient level of procurement in line with Electricity System Restoration Standard (ESRS) obligations. Currently there are areas of the UK that are struggling to meet these standards due to a lack of available technologies and so we must reform our market to ensure we can restore the system from technologies that are available.

How are we implementing the reform?
Following the successful tests and trials in the Distributed ReStart Project, we are now incorporating these learnings into Business As Usual (BAU). The three new tenders launched in 2022 will go through ESO and Distribution Network Operator (DNO) feasibility assessments in 2023, before we award contracts to a new and diverse range of technologies including renewables and DER.

ESRS

This new Electricity System Restoration Standard (ESRS) requires the ESO to have sufficient capability and arrangements in place to restore 100% of Great Britain's electricity demand within 5 days. This should also be implemented regionally, with an interim target of 60% of regional demand to be restored within 24hrs.

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Restoration - Market Insight: Restoration Providers

Traditionally we rely on transmission connected and largely fossil fuel generators for restoration services, but the new tenders launched in 2022 show the strong potential for the introduction of different technology types.

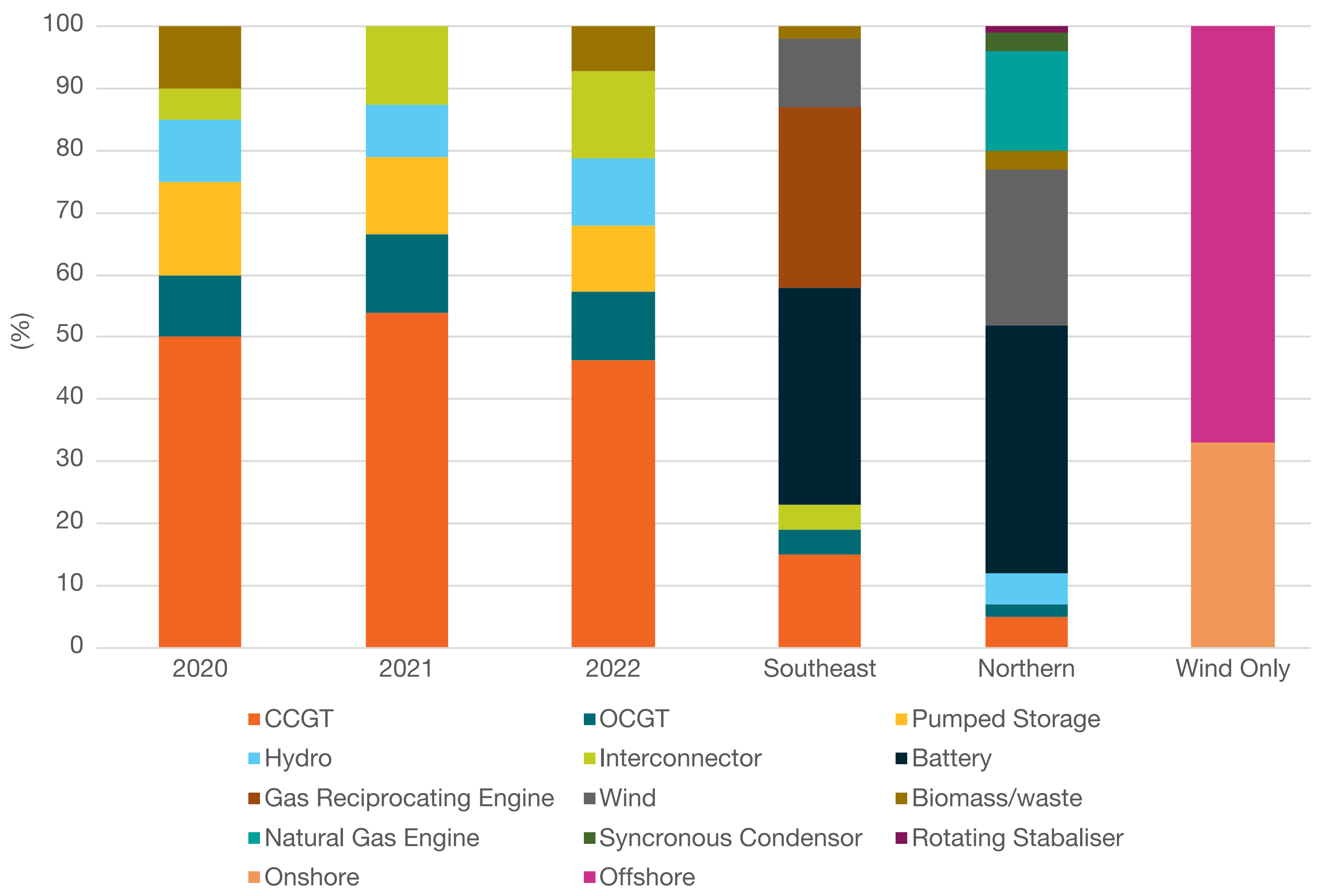
The graph shows the technology break down of providers coming into the market in 2020, 2021, 2022 and the breakdown of Expression of Interest bids from tenders launched in 2022 by technology type.

The providers who have entered the market in 2020, 2021 and 2022 have remained relatively consistent, with the introduction of new interconnectors in 2021 and biomass providing a second set of services in 2022.

As can be seen by Figure 1, the Expression of Interest stage of the tenders launched in 2022 show a much more diverse portfolio mix and a significant reduction in CCGT. We can see potential for the introduction of several new technologies, with batteries being one of the most significant bidders in both the Southeast and Northern tenders.

It is important to note that those who have expressed interest are not guaranteed to be contracted and will be required to go through two rounds of feasibility testing to ensure they can meet the technical requirements to provide restoration services.

RT Figure 1: Restoration Providers (2020-2022)



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Restoration - Market Insight: Restoration Costs

The Figure shows costs associated with restoration over the last three years (2020-2022). There are two key elements:

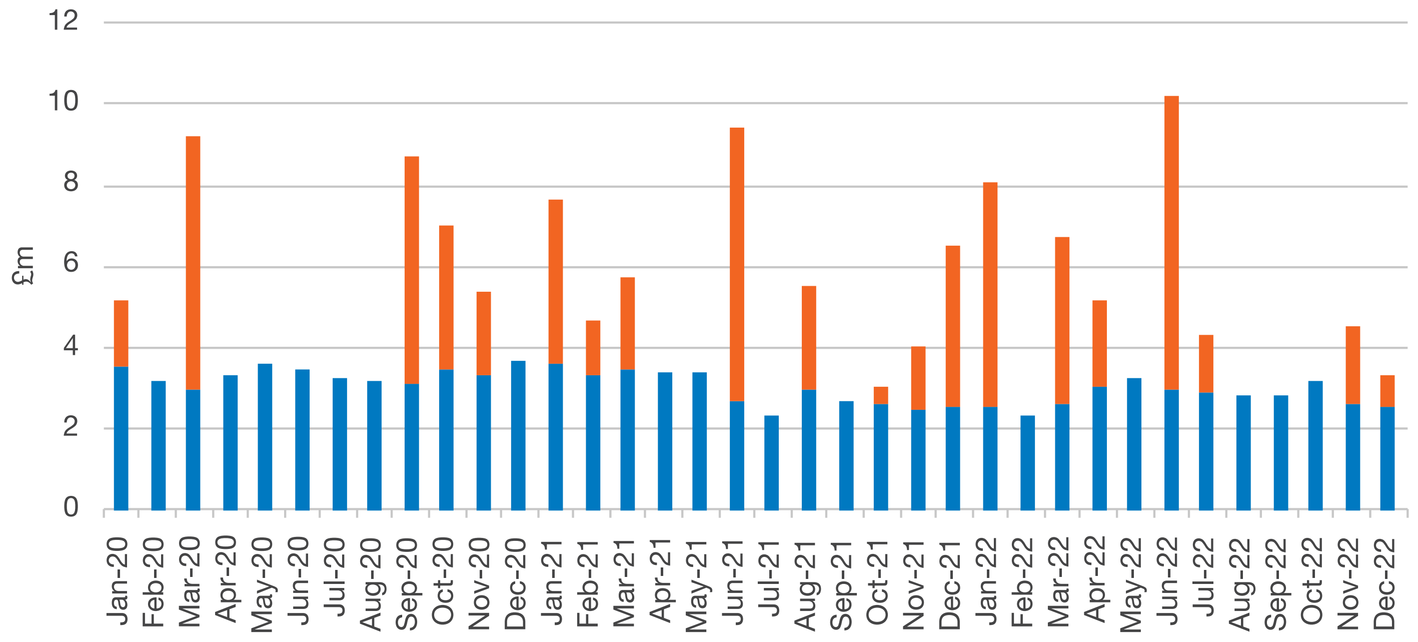
1. **Availability Payments:** We agree a fixed annual price with providers, which is converted to a £/settlement period payment, paid monthly. Providers are only paid for settlement periods they have declared their availability for.

2. **Capital Contributions:** New restoration services are likely to require significant capital investment. Each contract will include a breakdown of costs including, where necessary, a milestone payment schedule. These costs are therefore quite ad-hoc.

There are a number of other much smaller payments, including feasibility studies and testing. We have not paid warming requirements since 2021, this is because fossil fuels are being utilised for services other than restoration and therefore the machinery is warmed.

It can be said that restoration costs have remained fairly consistent when compared to previous years, but as we introduce new DER technologies these costs are likely to increase, due to the large upfront Capital Contribution payments to ensure they are equipped to provide restoration services. For more information on costs associated with restoration and the relevant calculations, click here.

RT Figure 2: Restoration Costs



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Restoration - Drivers for Reforms

We need to decarbonise the restoration fleet

As we become more reliant on renewable energy for generation in order to meet decarbonisation targets, we must also reform the restoration market to ensure that it is also on track to meet these targets. As we are still reliant on ageing fossil fuel plants for restoration services, we must evaluate how we can reduce reliance on these plants to meet the 2035 decarbonised power system target.

Retiring fossil fuel plants will result in increased restoration costs

Restoration costs are expected to increase in the short term, due to the older generation of plants that currently have restoration capabilities nearing end of life so there is a big cost in 'upgrading' intermittent technologies, to ensure as many of them require collocated batteries to meet technical requirements.

A lack of available traditional technologies will make it challenging to meet ESRS obligations in certain areas

The introduction of the ESRS has been a key driver in ensuring all areas of the UK are equipped to meet these restoration requirements. This standard requires the ability to restore 60% of GB's electricity demand in 24 hours and 100% in five days and our evaluation has shown that there are certain areas that may be at risk, due to a reliance on a limited number of generators or retiring fossil fuel generators.

Lowering barriers to entry for new technologies

Feedback from previous tenders told us that some of the technical requirements were hard to meet and that the time between tendering processes was too short.

Technical and operational challenges faced by DNOs to make Distributed Restart Zones (DRZ)

In the transition to BAU, it will be necessary for all DRZ participants to tackle the technical challenges identified in the Distributed ReStart project analysis and live trials. These will vary depending on whether they can offer Anchor DER[1] or Top-up services.[2] The key technical issues to be considered by DNOs, which may require investment on the network to allow it to form part of a DRZ, include: 33kV network earthing, network protection and switchgear capability. For more information click here.

1 Each DRZ requires an "anchor" DER, a key requisite is having grid-forming capability.
2 To supplement the technical capability of the anchor generator, stabilise or grow (connect more demand or network to) the DRZ, additional DER resources may be required. The requirements are defined in terms of "top-up services" (such as fast MW control, short circuit level) and in themselves are technology agnostic.

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Restoration - Market Reforms

Diversifying technologies to meet decarbonisation targets and reduce long term restoration costs

In 2022, through launching a one-off wind only tender and introducing DER in the Northern and South-eastern tenders we see strong potential for a more diverse portfolio of technologies that can offer restoration services. This will reduce our reliance on volatile fossil fuels.

Diversifying the technology mix for restoration aids us in ensuring security of supply. This helps to ensure that there are as many options as possible available to us. Increased diversification of providers will also reduce long term restoration costs due to increased competition.

Reducing barriers to entry for DER

We need to reduce barriers to entry for smaller units. Based on stakeholder feedback, we reduced availability requirements from 90% to 80%, block loading size from 20MW to 15MW and we increased time between tenders by 50%, tenders used to run for around 15 months and now run for 2 years. Grid Code reforms should also continue to reduce barriers to entry, as currently small generators are paying large Connection and Use of System Code (CUSC) fees, which can limit their participation in this and other markets. Distributed ReStart has also reduced the barriers to entry by providing a route to market for even smaller players at distribution level.

Targeting specific areas of the country to ensure we are on track to meet ESRS obligations

Tenders are a cyclical process and so the Southeast and Northern were due to be renewed, it is however opportune that these were next as they are key areas deemed at risk of not meeting ESRS obligations by 2026 due to reliance on one technology type and aging fossil fuel plants. They will be the first to launch DER as BAU in the tendering process and this will continue in future tenders across all of GB. The next tenders expected to launch in the Southwest and Midlands in 2024 and the next round for the Southeast is planned for 2026.

Reforms at DNO level to ensure that they are equipped to create DRZs

DRZs will be implemented through the process of the ESO tendering for services and prompting a collaborative process of DNOs and DERs working through feasibility studies and design of potential solutions. Technical modifications to networks will vary dependent upon the specifics of the DNO area that will be used to form a DRZ. More detailed information can be found by downloading our Final Findings Report.

Given the technical and operational challenges associated with establishing, growing and maintaining a DRZ, and the limited human resources which may be available at the time of a black start, it is anticipated that some level of automation will be required.

Grid Code reforms

There are two key reforms taking place to help facilitate the introduction of DER in providing restoration services,
GC0156 & GC0148.

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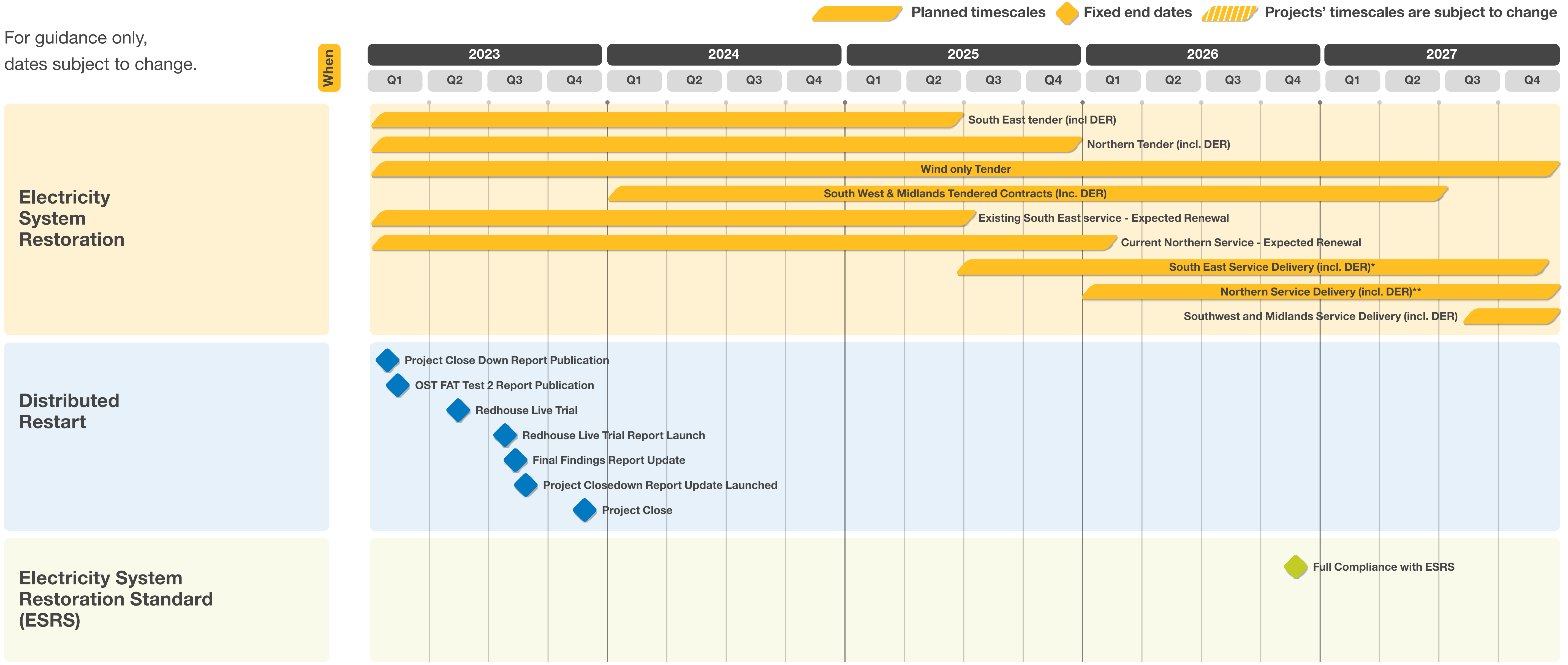
Restoration - Delivery Plan

For guidance only,
dates subject to change.



* End date Q3 2028
** End date Q4 2028

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Restoration - Delivery Plan

Electricity System Restoration

What?

Electricity Restoration (ESR) is a market mechanism to competitively procure restoration services from a wide pool of providers.

The procurement principles for ESR have been developed in line with the overall EOS principles and ambitions. These principles are outlines in the Black Start Strategy and Procurement Methodology 2022/2023 and explains how our procurement process will enable a fairer market. Currently the ESO has tendered for two regional Electricity System Restoration events: South East and Northern as well as the national Wind tender.

Distributed Restart

What?

Distributed Restart Project is a collaboration between ESO, Scottish Power Energy Networks (SPEN) and TNEI (a specialist energy consultancy). This world-first initiative has been designed to re-energise the system in the event of a partial or national power outage from the bottom up through DER. This project seeks to remove our dependence on carbon intense generators, and instead explore how technologies such as wind, solar & hydro can be used to restore power to the transmission in the unlikely event of a partial or national power outage.

The project is now in its final stages and over the next few years, the project will look to resolve challenges such as, organisational coordination, commercial and regulatory frameworks, and power engineering solutions.

Electricity System Restoration Standard (ESRS)

What?

From December 2026 a GB Electricity System Restoration Standard (ESRS), and associated frameworks and implementation methods will align the ESO Restoration Strategy and a GB Restoration Standard to fulfil obligations on the ESO and the wider sector.

The implementation of a GB ESRS will result in a power grid that restores power faster and more consistently across regions. Further, the upgraded capabilities by the ESO and other industry partners will align to the Government net zero targets. This is being led by the Department for Energy Security and Net Zero (DESNZ). The implementation of a GB ESRS (which started on 19th October 2021) will result in a power grid that restores power faster and more consistently across regions. Further, the upgraded capabilities by the ESO and other industry partners will align to the Government net zero targets.

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Stability

Stability services have traditionally been provided by synchronous generation, which can contribute inertia and Short Circuit Level (SCL) when supplying the grid with electricity, as well as dedicated network assets. Some forms of low-carbon generation do not automatically provide the same level of stability as they are non-synchronous. Therefore, we need to procure additional stability services to ensure the system can be operated with the same stability in a low-carbon world. To date, we have procured a series of stability pathfinders, which have incentivised the new build of stability-capable assets. However, our stability needs continue to evolve and are becoming more variable. Our Stability Market Design innovation project is investigating the optimal approach to meeting these needs in the future and is recommending the launch of a Y-1 mid-term market.

What is stability?

Stability is the inherent ability of the system to quickly return to acceptable operation following a disturbance. The term is used to describe a broad range of topics, including inertia, short circuit level and dynamic voltage. If the system becomes unstable it could lead to a partial or total system shut down leading to the disconnection of consumers. To keep the power system stable, we need to maintain sufficient amounts of inertia, SCL and dynamic voltage support. Various projects, such as the Accelerated Loss of Mains Change Programme (ALoMCP)[1] and our new faster-acting frequency services, like Dynamic Containment (DC), will also help us maintain system stability.

Link to stability webpages

How do we procure stability services?

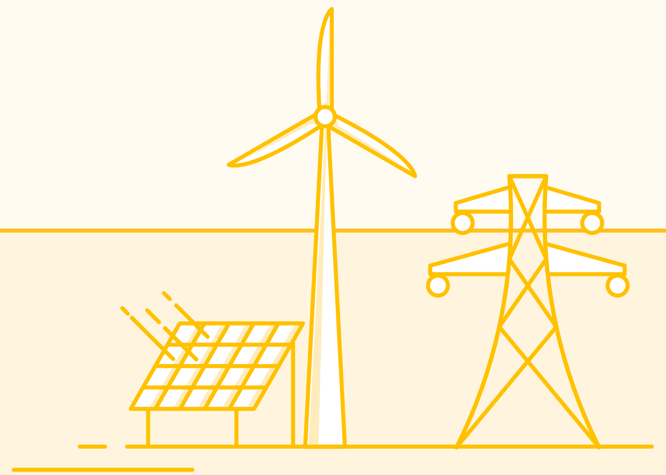
Stability pathfinders

Balancing mechanism

Trading

Stability pathfinders

Through our stability pathfinder initiatives, we have procured a total of 36GW.s of inertia and sufficient SCL to resolve local system strength issues across GB transmission network. We have completed three long-term pathfinder tenders for stability services and published our results for Phases 2 and 3 in April and November 2022 respectively. You can find out more from our stability pathfinder webpages.



1 The Accelerated Loss of Mains Change Programme (ALoMCP) offered funding to distribution-connected generators to upgrade their hardware to improve network resilience and prevent nuisance tripping of generation with more sensitive Rate of Change of Frequency (RoCoF) protection equipment.

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Link to stability webpages

How do we procure stability services?

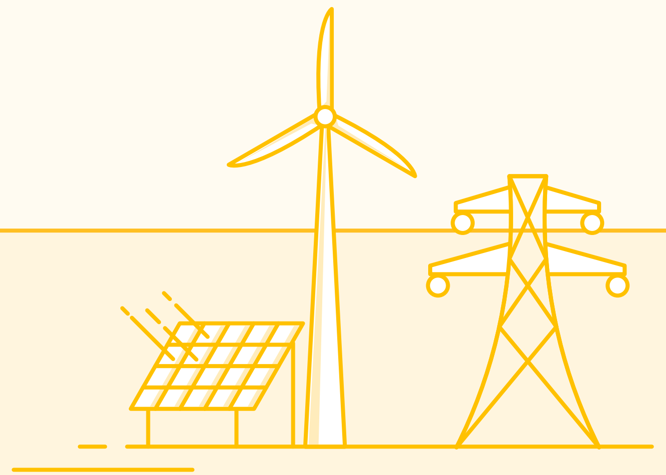
Stability pathfinders

Balancing mechanism

Trading

Balancing mechanism

We use the balancing mechanism to schedule and dispatch units to meet minimum inertia levels and maintain compliance with our SQSS obligations. These actions offer close to real-time intervention but can be expensive and are often at the expense of cheaper generation on the system at the time, which are bid off to make room for synchronous machines.



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Link to stability webpages

How do we procure stability services?

Stability pathfinders

Balancing mechanism

Trading

Trading

We use trading options to reduce the size of losses and occasionally increase system inertia to manage Rate of Change of Frequency. This is often on larger units, such as interconnectors.

1 The Accelerated Loss of Mains Change Programme (ALoMCP) offered funding to distribution-connected generators to upgrade their hardware to improve network resilience and prevent nuisance tripping of generation with more sensitive Rate of Change of Frequency (RoCoF) protection equipment.

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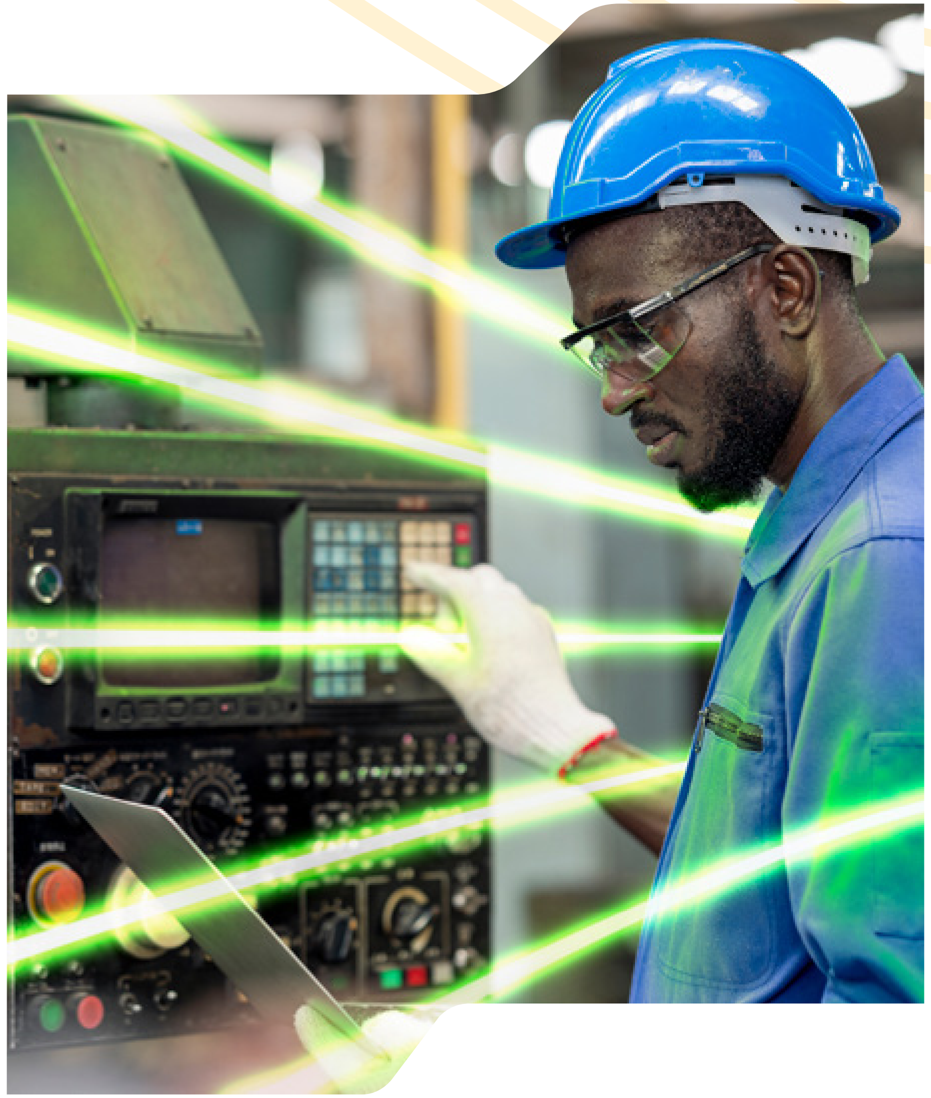
Stability - Summary of the chapter

How is the landscape changing? As more non-synchronous generation connects to the network and displaces synchronous generation, we recognise the need for additional stability throughout this decade especially during low demand, high renewable periods. Our inertia requirements are becoming more dynamic as they fluctuate according to wind and demand. There is a need to address this more cost effectively. We will continue to monitor the impact of locational stability such as short circuit levels and dynamic voltage.

How have costs and volumes evolved in the last year? We concluded two more stability pathfinders in the last 12 months, providing 24GW.s (gigawatt seconds) new inertia capacity and sufficient SCL to resolve local system strength issues across the GB transmission network. Stability pathfinder phase 3 will deliver a benefit to consumers of £14.9bn between 2025 and 2035. Volumes and costs of actions taken via the Balancing Mechanism / trades to reduce the largest loss have decreased drastically; however, both volumes and costs for increasing inertia have increased significantly.

What is driving the need for reform? We have an economic need to procure inertia for the foreseeable future, emphasised by costs incurred during 2022 because of global gas prices. New technologies (e.g., grid-forming technology and zero-MW capable synchronous plant) present a significant opportunity to diversify our technology mix and to explore the potential to procure inertia as a specific product, as opposed to it being bundled with energy.

How are we implementing market reform? Our Stability Market Design project is considering eligibility rules, contract structure and procurement approach for a range of stability markets across short-, medium- and long-term timescales. This will enable us to signal a requirement for new capacity more effectively when we need it, but more immediately provide a route to market for assets capable of delivering stability services in the present, and those which could do so in the future with additional investment. The first mid-term (Y-1) stability market will be initiated in 2023.



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Stability - Market Insight: Stability Volumes

Stability pathfinders

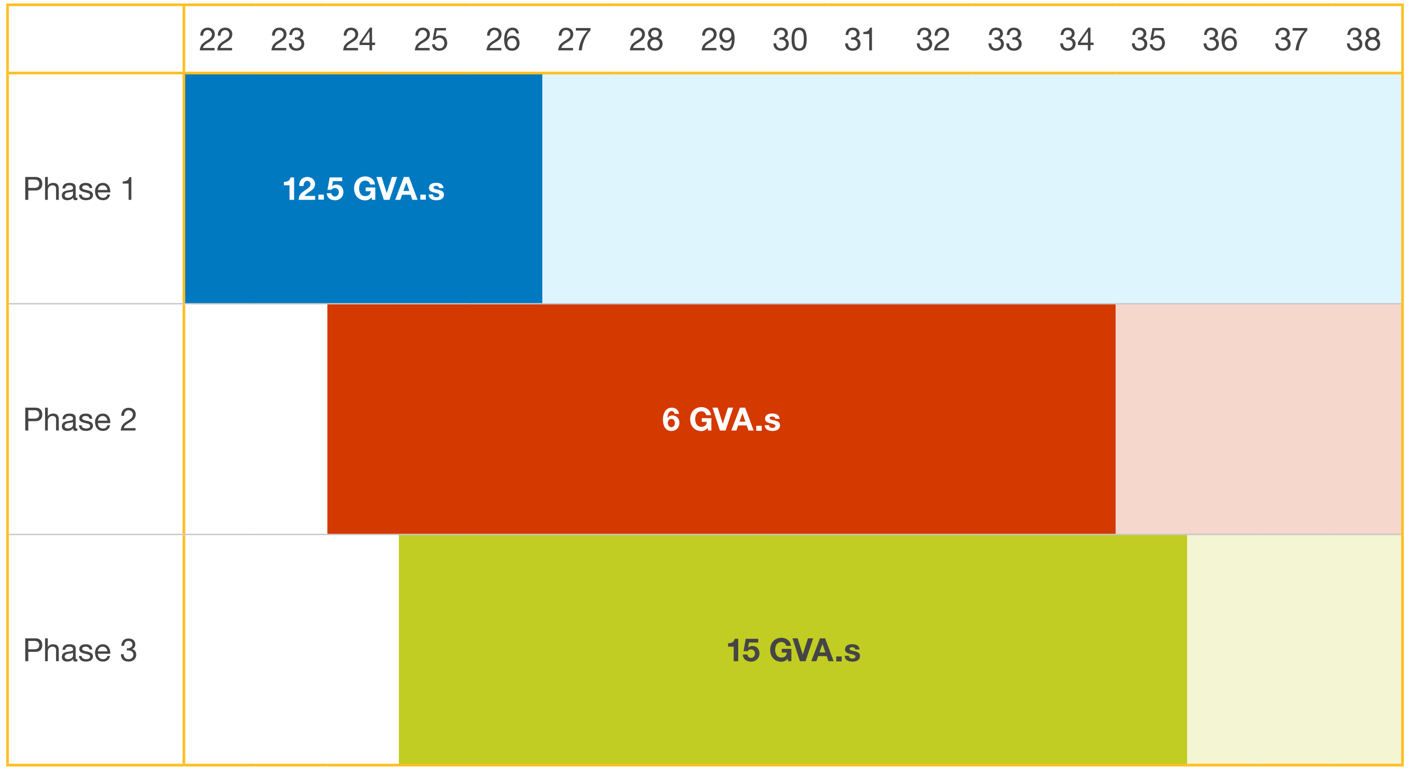
We have procured >36GW.s inertia and SCL through stability pathfinders to date. This represents our 'learn-by-doing' approach to competitive procurement of new-build units capable of delivering stability services.

In the last 12 months, we have announced the results of our Phases 2 and 3 stability pathfinders.

- **Phase 2 –** We published the outcome for stability pathfinder phase 2 in April 2022. This procured 11.55GVA effective Short Circuit Level across Scotland, plus an additional ~6.8GW.s inertia. 5 of the 10 successful solutions were battery storage with grid-forming capability, as well as five synchronous condenser solutions.
- **Phase 3 –** This concluded in November 2022 and is our largest to date both in terms of volume and cost. In total, 12.7GVA effective SCL and 17.3GW.s inertia was procured out to 2035. 29 contracts, all synchronous compensators, have been awarded to six companies.

Furthermore, assets from our first stability pathfinder, which concluded in 2020, have now commissioned and are delivering valuable inertia to support the electricity system. Synchronous compensators at Lister Drive, Rassau, Killingholme, Cruachan, Keith, Connah's Quay and Grain are contributing 12.5GW.s inertia across Great Britain.

ST Figure 1: Total volume of contracted inertia (GVA.s) through stability pathfinder 1, 2 and 3.



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Stability - Market Insight: Stability Volumes

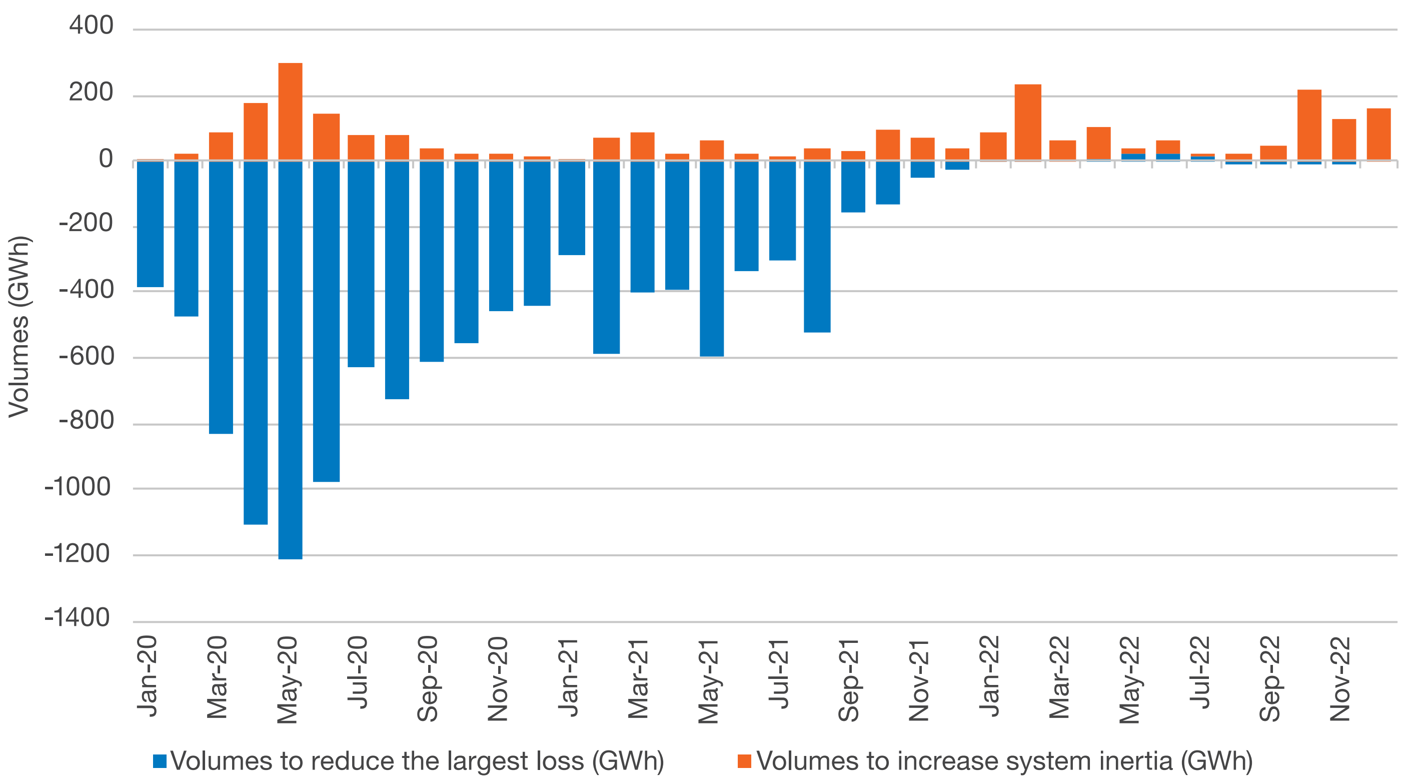
Balancing Mechanism and Trades

In the last 12 months, actions taken in the BM to reduce the size of the largest loss have reduced significantly. The average monthly volume in 2021 (269GWh) dwarfs the annual total for the whole of 2022 (47GWh). This is driven explicitly by a revised approach to how we secure losses, implemented through the Frequency Risk and Control Report (FRCR) and the launch of our Dynamic Containment (DC) products. These developments allow us to secure losses (e.g., large BMUs, interconnectors) more effectively in line with our SQSS obligations and substitutes the need for reducing the size of the largest loss.

BM actions taken to increase system inertia are system-tagged with best endeavours noting that one BM action can be taken for a combination of reasons. The volume of these actions has doubled in 2022 (1,121GWh) comparison to 2021 (554GWh), and a slight increase compared with 2020 (972GWh). Many of these actions are concentrated in February, October, November and December 2022. This is driven predominantly by actions taken on thermal, synchronous machines to increase inertia above our current 140GVA.s threshold, often during long spells of high wind, low demand periods. February, October, and November had the highest total wind output in 2022.

We expect that these volumes will reduce following the successful commissioning of all remaining stability pathfinder Phase 1 units, and our operating inertia threshold reduces, as signposted in FRCR 2023, as we move towards our ambition of 102GVA.s by 2025.

ST Figure 2: Inertia management volumes: Jan 2020 - Dec 2022



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Stability - Market Insight: Stability Costs

Stability pathfinders

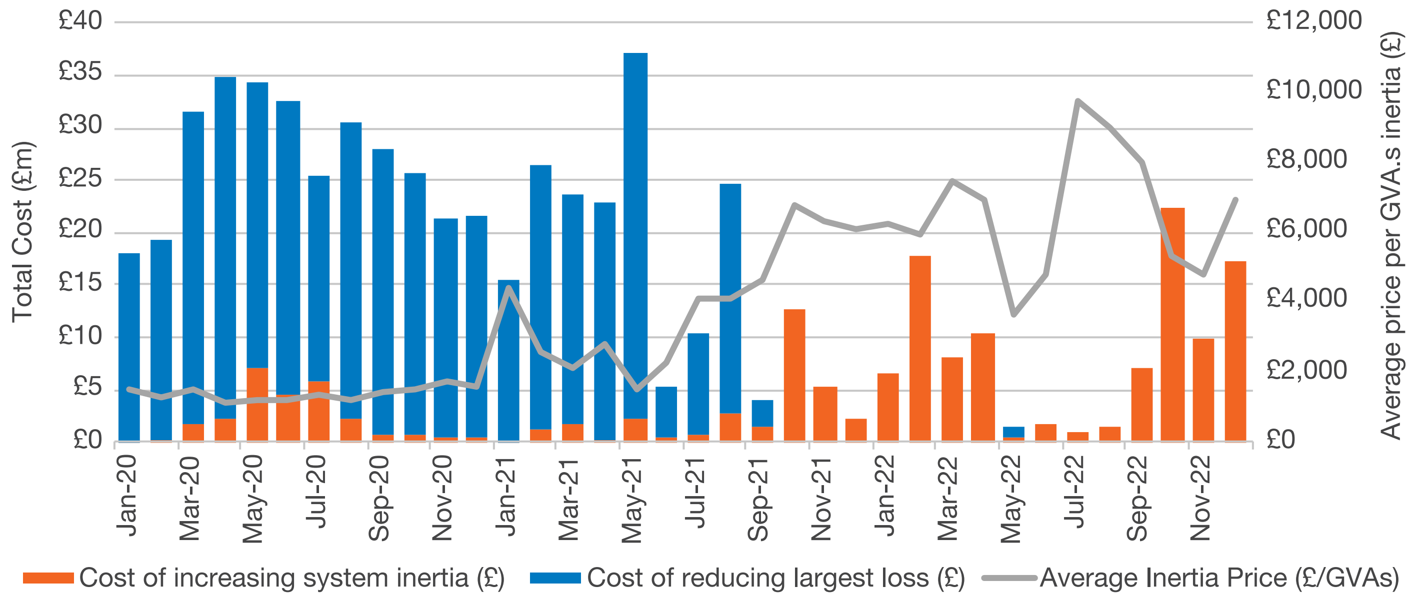
The stability phase 2 pathfinder assessed over 1,500 solutions for increasing system inertia and Short Circuit Level in Scotland. All successful solutions were provided by commercial market providers at a total cost of £322m.

Stability phase 3 satisfied our need for SCL in five regions across England and Wales. The total cost is £133m per annum between 2025 and 2035 and will deliver £14.9bn benefit versus the counterfactual options currently available to ESO.

Cumulatively, total spend across stability pathfinders to date is over £1.6bn. This represents a significant saving versus our alternative option for procuring these services through the Balancing Mechanism.

As illustrated in the chart analysing inertia management costs, this counterfactual cost has increased significantly in 2022, reaching a daily average peak in excess of £13,000/GVA.s in August 2022. Additional stability pathfinder units, contracted under phases 2 and 3, are commissioning in the next few years and will provide competition with existing solutions and drive down costs associated with managing stability.

ST Figure 3: Inertia management costs: Jan 2020 - Dec 2022



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Stability - Market Insight: Stability Costs

Balancing Mechanism and Trades

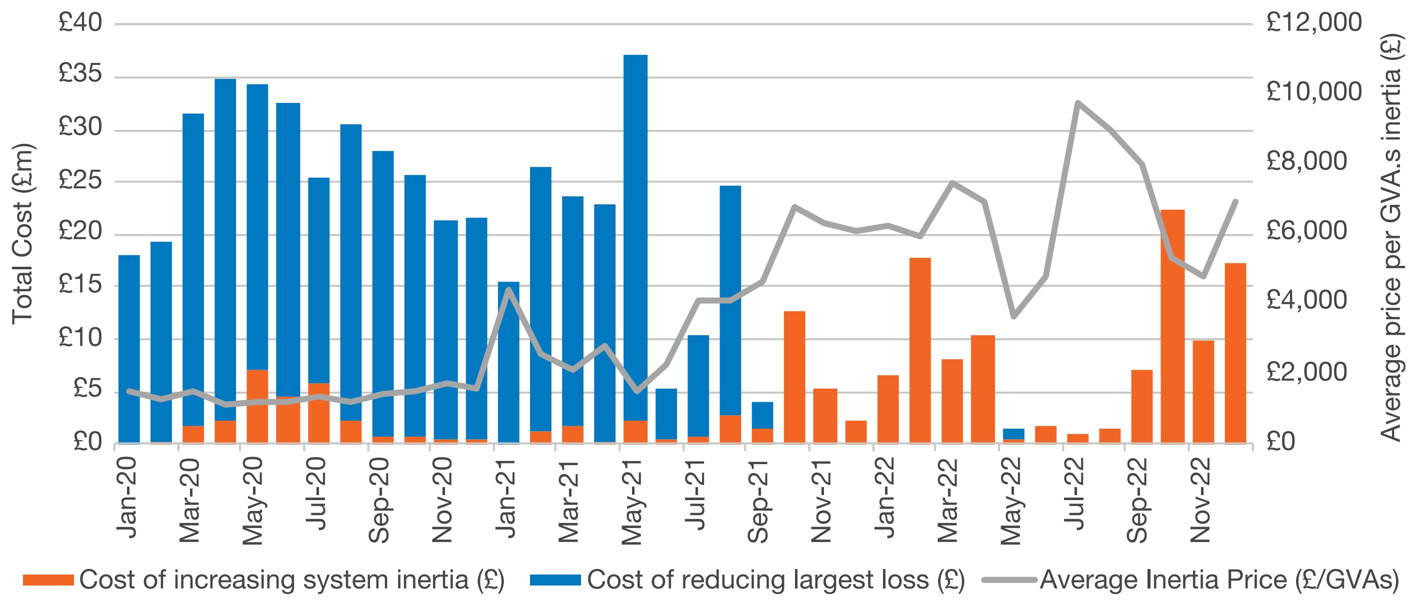
As per the decrease in volumes for reducing the largest loss, costs have also decreased sharply – totalling £5.7m in 2022 in comparison to £180m in 2021. This highlights the value driven by FRCR and Dynamic Containment products in 2022.

The declining costs of reducing the largest loss are a stark contrast with the increased costs associated with increasing system inertia, which have trebled in 2022 (£104m) compared with 2021 (£30m). This is partly a result of the increased volume of actions in 2022 (102% increase compared with 2021), but also a relative increase in the average price paid per GVA.s inertia instructed via the Balancing Mechanism. The average cost of inertia increased from £3,981/GVA.s in 2021 to £6,575/GVA.s in 2022.

The core driver of this is higher fuel costs for synchronous units taken in the BM. Almost half of our annual costs are concentrated in October – December during particularly high renewable, low demand periods. The average cost of inertia during this period was slightly lower than the annual average at £5,702/GVA.s but these months equated for 45% of all actions taken to increase system inertia in 2022.

To reiterate, we expect that reducing our inertia threshold from 140GVA.s will alleviate some of these costs, alongside a reduction in fuel supply costs for synchronous plant. Nevertheless, it also highlights the need for more economic inertia procurement.

ST Figure 3: Inertia management costs: Jan 2020 - Dec 2022



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Stability - Drivers for Reforms

Reduce cost of actions taken to manage system inertia

Increased variability of inertia requirements

More certainty needed for investors

Encourage participation from new technology types

Reduce cost of actions taken to manage system inertia

As articulated in our 2023 Operability Strategy Report, our latest modelling indicates short circuit level requirements are met sufficiently until 2029. However, the increased costs of managing system inertia outlined in the previous section, plus our latest modelling of future inertia needs, indicate there is merit in exploring ways to procure inertia more efficiently.

Stability Pathfinders have been an excellent pilot for procuring new-build capacity on a competitive basis where a need has emerged. However, these contracts are time-bound; for example,12.5GW.s inertia contracts in Stability Pathfinder Phase 1 elapse in the middle of this decade. Our latest stability modelling indicates that we have a requirement for additional inertia beyond 2027 for a high proportion of the year. While there is sufficient generation available via the Balancing Mechanism to satisfy our minimum inertia operating threshold, we acknowledge this may not be the most cost-effective solution for managing future stability needs on a daily basis. Therefore, in advance of balancing timescales, we think that there is merit in contracting a proportion of high-availability inertia to provide certainty to the ESO in meeting our needs cost-effectively, and to provide price certainty for service providers. This compliments our approach to managing stability in short-term timescales, as described later in the chapter.

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Stability - Drivers for Reforms

Reduce cost of actions taken to manage system inertia

Increased variability of inertia requirements

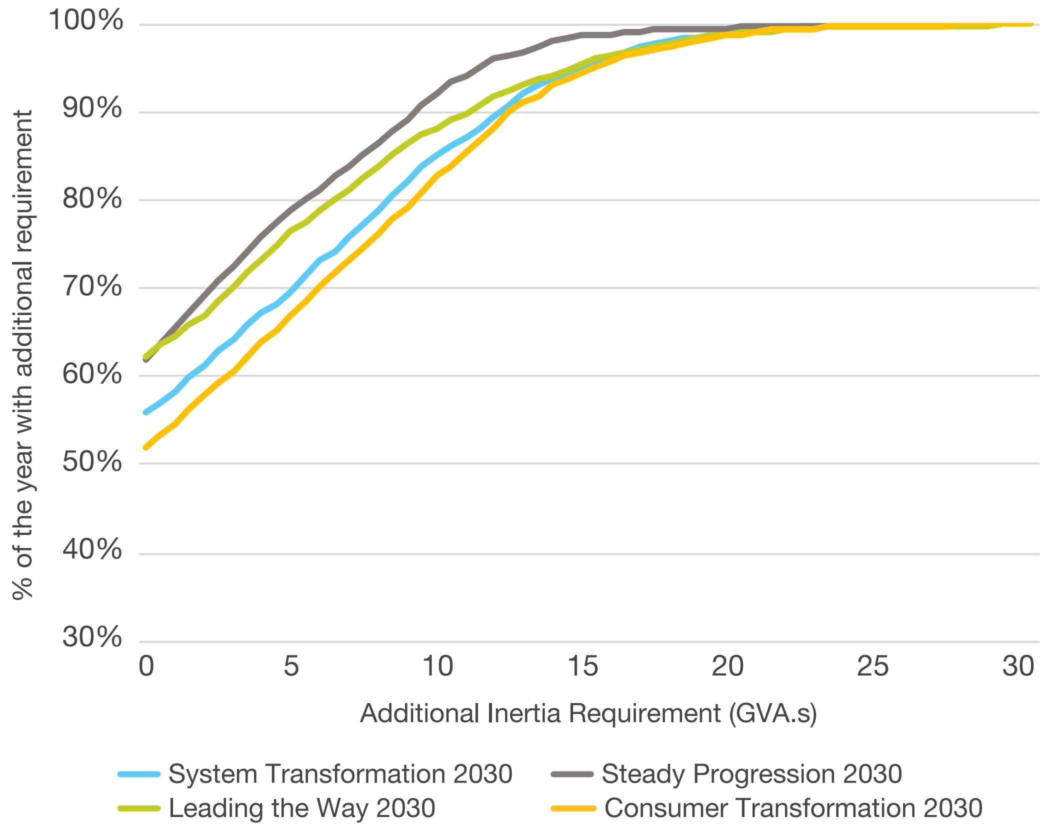
More certainty needed for investors

Encourage participation from new technology types

Increased variability of inertia requirements

Our residual inertia requirement predominantly occurs overnight where demand is lower and thus, fewer synchronous machines are typically running and providing inertia. Furthermore, wind generation continues to set new records and is expected to further displace inertia provided by the energy market in the power stack. The inherent intermittency of renewable generation, coupled with the continued evolution of demand flexibility linked to dynamic price signals and increased electrification of heat and transport, will continue to influence how much inertia is naturally provided by the market. Consequently, this means that our residual inertia requirements will become more variable (dynamic) across the year. Therefore, to complement a high-availability service, there are opportunities to procure inertia effectively in the short-term at low cost, during periods of increased variability, where our requirement isn't met through pathfinders or naturally by the energy market.

ST Figure 4: Distribution of additional inertia requirement (2030)



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Stability - Drivers for Reforms

Reduce cost of actions taken to manage system inertia

Increased variability of inertia requirements

More certainty needed for investors

Encourage participation from new technology types

More certainty needed for investors

Looking beyond Stability Pathfinders, we recognise the benefits of a more regular framework to signal a need for accessing new capability. The Centralised Strategic Network Plan (CSNP) will align the modelling of thermal, stability and voltage requirements. We envisage that a regular procurement process running in parallel with this will provide greater confidence to the market when making strategic investments.

A key enabler for grid-forming technology was also approved by Ofgem in 2022 - Grid Code Modification GC0137[2] - which will facilitate participation in stability services from many new assets. The advantages of better foresight and more standardised processes are anticipated to reduce risk both for market participants and ESO by reducing tendering costs for existing parties and the cost of entry for prospective market participants.

2 GC0137: Minimum Specification Required for Provision of GB Grid Forming (GBGF) Capability (formerly Virtual Synchronous Machine/VSM Capability) - https://www.nationalgrideso.com/industry-information/codes/grid-code-old/modifications/gc0137-minimum-specification-required

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Stability - Drivers for Reforms

Reduce cost of actions taken to manage system inertia

Increased variability of inertia requirements

More certainty needed for investors

Encourage participation from new technology types

Encourage participation from new technology types

We want to remove barriers to entry and encourage participation from different technologies to ensure we are procuring the solutions which best meet our needs at the lowest overall cost. For example, units which are not wholly dedicated to providing Stability services, such as renewables and storage, aren't able to meet the (high) availability criteria specified in long-term tenders to date; however, with the introduction of grid-forming technology, we recognise that they may be able to offer their capacity with more certainty closer to real time. Finding out more about the wide range of technologies capable of offering stability services is an important feature of our Service Provider Capability Mapping project.

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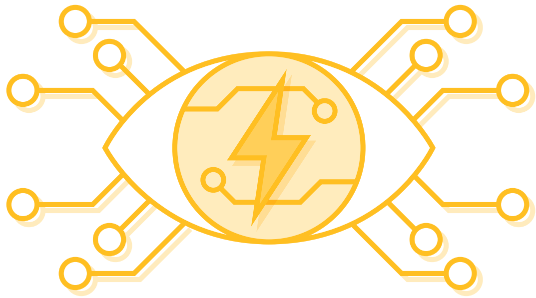
Stability - Market Reforms

Stability Market Design

In last year's Markets Roadmap, we highlighted the benefits of procuring stability via a blend of long and short-term procurement. This provides long-term certainty for both the ESO and investors, but also an avenue for fine-tuning procurement closer to real-time when there is a clearer view of the residual requirement. In the last 12 months, the Stability Market Design NIA project has developed these options further, looking at key design questions on eligibility, contract length and granularity, procurement strategy and more.

We recognise the trade-offs in securing too much or too little capacity and how over procurement in the long-term market could overburden consumers with unjustifiable cost where a requirement may not materialise. Similarly, under procurement in the long-term places additional risk on the ESO and potential exposure to high costs to meet those needs in the short term. Therefore, we are proposing to procure stability services across several timescales with an initial focus on procuring inertia services.



Short-term (Day-ahead) Stability Market

Mid-term (Year-ahead) Stability Market

Long-term (Four years ahead) Stability Market

Short-term (Day-ahead) Stability Market

A short-term market will help meet our more dynamic need for stability. The most common solution currently used to improve system stability close to real-time – other than utilising stability pathfinder units – is to synchronise additional units via the Balancing Mechanism. During high renewable periods where additional energy is not desired, system-flagged actions to increase inertia are often at the expense of lower cost, renewable generation which is bid off to make room. To mitigate this, the short-term stability market will operate at the day-ahead stage once better information on generation and demand forecasts is available. Through the introduction of grid-forming, there is an additional opportunity to harness stability from non-synchronous generators which could be tendered in at low cost. Given our inertia requirement is often greatest where there is an excess of supply (e.g., low demand, high renewable periods), this could be provided most effectively by units able to operate at 0MW export (e.g., grid-forming units, synchronous generators equipped with a clutch); however, more work is required to determine whether restricting eligibility in this way is in the best interests of consumers. The short-term market will pay providers to be available on an EFA block basis and will be paid to deliver stability within the contracted service window. More information can be found on our Stability Market Design webpage and in the delivery plan on the next page.

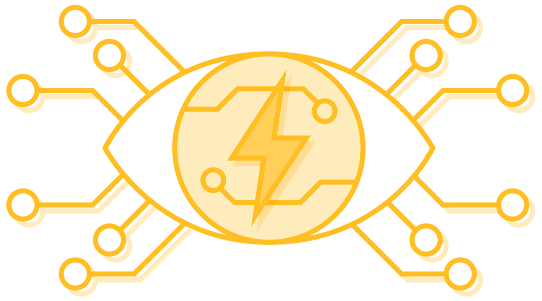
Markets Roadmap / Market Areas / Stability 112

Stability - Market Reforms

Stability Market Design

In last year's Markets Roadmap, we highlighted the benefits of procuring stability via a blend of long and short-term procurement. This provides long-term certainty for both the ESO and investors, but also an avenue for fine-tuning procurement closer to real-time when there is a clearer view of the residual requirement. In the last 12 months, the Stability Market Design NIA project has developed these options further, looking at key design questions on eligibility, contract length and granularity, procurement strategy and more.

We recognise the trade-offs in securing too much or too little capacity and how over procurement in the long-term market could overburden consumers with unjustifiable cost where a requirement may not materialise. Similarly, under procurement in the long-term places additional risk on the ESO and potential exposure to high costs to meet those needs in the short term. Therefore, we are proposing to procure stability services across several timescales with an initial focus on procuring inertia services.



Short-term (Day-ahead) Stability Market

Mid-term (Year-ahead) Stability Market

Long-term (Four years ahead) Stability Market

Mid-term (Year-ahead) Stability Market:

We recognise that short-term should not be the only market where we buy stability services, especially where we have a need which exists for longer periods in a given year. Where a requirement exists, we could meet this need using existing tools, such as the Balancing Mechanism; however, we value the benefit of longer-term contracts to reduce cost exposure for ESO closer to real-time and to provide greater certainty to dedicated assets who seek to offer their capacity for stability services on a high-availability basis. Hence, we are preparing to initiate a mid-term stability market in 2023 which will conclude one year ahead of delivery (Y-1), offering a one-year contract duration for successful parties. A high-level plan to launch this is illustrated in our delivery plan and more information around eligibility for this market, plus further industry engagement, will be published shortly after this publication.

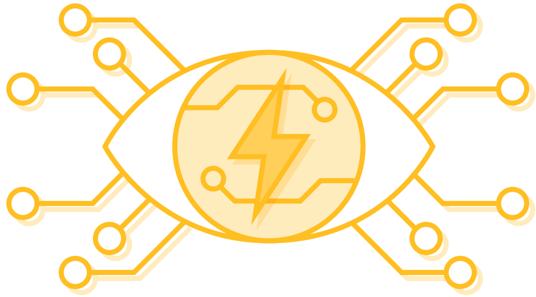
Markets Roadmap / Market Areas / Stability 113

Stability - Market Reforms

Stability Market Design

In last year's Markets Roadmap, we highlighted the benefits of procuring stability via a blend of long and short-term procurement. This provides long-term certainty for both the ESO and investors, but also an avenue for fine-tuning procurement closer to real-time when there is a clearer view of the residual requirement. In the last 12 months, the Stability Market Design NIA project has developed these options further, looking at key design questions on eligibility, contract length and granularity, procurement strategy and more.

We recognise the trade-offs in securing too much or too little capacity and how over procurement in the long-term market could overburden consumers with unjustifiable cost where a requirement may not materialise. Similarly, under procurement in the long-term places additional risk on the ESO and potential exposure to high costs to meet those needs in the short term. Therefore, we are proposing to procure stability services across several timescales with an initial focus on procuring inertia services.



Short-term (Day-ahead) Stability Market

Mid-term (Year-ahead) Stability Market

Long-term (Four years ahead) Stability Market

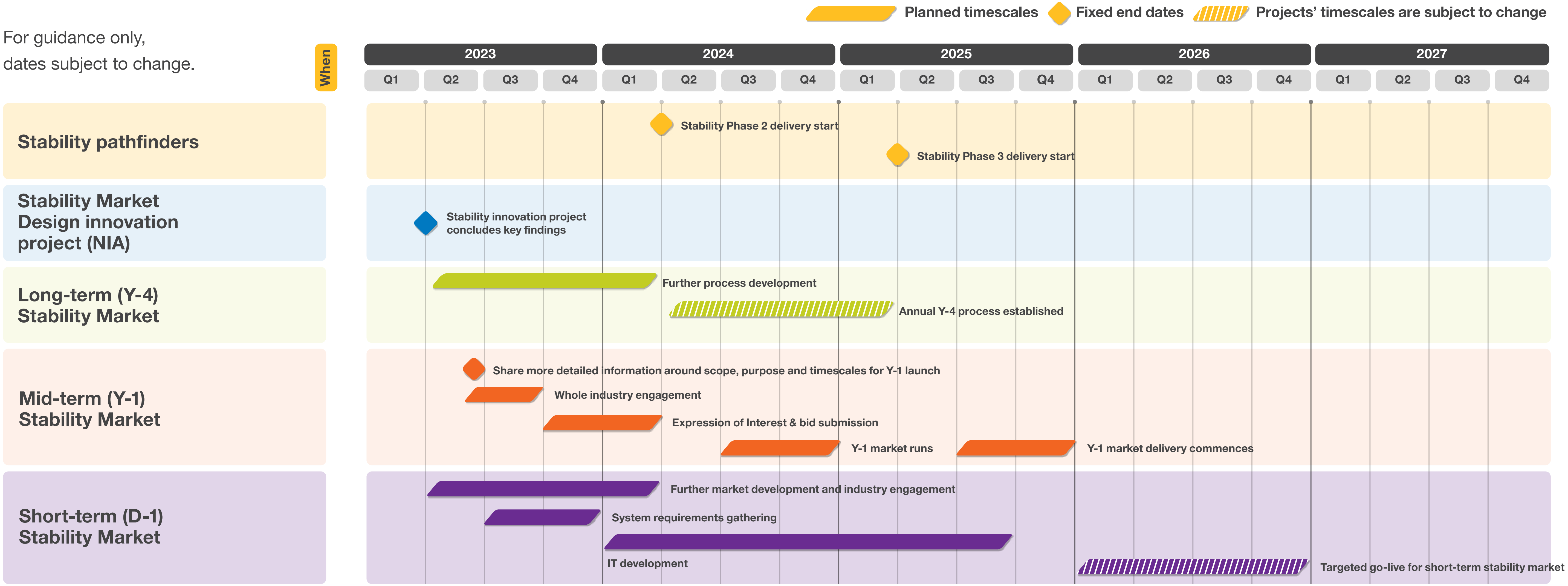
Long-term (Four years ahead) Stability Market

We are also committed to enhancing our mechanisms for long-term procurement. NOA pathfinder, soon to be rebranded as Network Services Procurement, will evolve into the long-term stability and reactive markets. Our latest stability modelling, coupled with the planned Y-1 market, means we do not foresee an immediate need for new long-term procurement. Nevertheless, we recognise the benefits of making the long-term process more streamlined. Therefore, any new, long-term stability procurement will align with CSNP, which is co-ordinated across thermal, voltage and stability, to provide regular opportunities to signal new investment. Furthermore, we will continue to explore key issues such as how a level-playing field can be maintained between commercial providers and Transmission Owners (TO's) to promote fairness whilst delivering value for consumers. More information on this will be published on our Stability Market Design webpages.

Markets Roadmap / Market Areas / Stability 114

Stability - Delivery Plan

For guidance only,
dates subject to change.



Markets Roadmap / Market Areas / Stability 115

Stability - Delivery Plan

Stability Pathfinders

What?

Stability Pathfinder Phases 2 and 3 both concluded and published results in 2022. They will fulfil specific needs for both inertia and short circuit level across Scotland, England and Wales from 2024 onwards.

Stability Market Design innovation project (NIA)

What?

The stability market design innovation project is investigating the enduring market design for stability procurement.

Long-term (Y-4) Stability Market

What?

Procurement of new-build assets to deliver SCL and inertia has been facilitated by Stability Pathfinders to date. The Stability Market Design project recommends that the learn-by-doing approach, demonstrated via Stability Pathfinders, should transition into an enduring long-term (Y-4) stability market. Although we haven't identified an immediate need for procuring volume through this market right now, we will be developing and establishing the processes for this Y-4 market to run in parallel with annual network planning, coordinated by CSNP. We will use this market to signal further new-build capacity, should we identify a need to procure it in the future.

Mid-term (Y-1) Stability Market

What?

Whilst we have demonstrated the success of procuring new assets via Stability Pathfinders, we recognise that there is also existing capacity which can offer stability services reliably at low cost. Therefore, we are planning to launch a mid-term Y-1 stability market in 2023 which will conclude one-year ahead of delivery and offer one-year contracts to successful parties. More detailed information will be shared shortly on our Stability Market Design webpages to provide further details on the technical specification and timelines.

Short-term (D-1) Stability Market

What?

Our stability needs are becoming more dynamic, and we propose to mitigate this by introducing a short-term (D-1) stability market to meet any remaining shortfall closer to real-time. A day-ahead market will supplement the volumes procured via long and mid-term stability markets and focus primarily on buying inertia in the first instance. A day-ahead market will unlock stability provision from lots of new technologies and allow ESO to fine-tune procurement closer to real-time.

Markets Roadmap / Market Areas / Stability 116

Voltage

Our voltage requirements are increasing, whilst our traditional routes to accessing these services are reducing. By 2025, the ESO will require an additional 2,225MVAr of residual reactive power capability to maintain a compliant network. However, synchronised generation is being displaced by embedded generation which does not provide reactive services to the ESO. Transmission connected non-synchronous sources such as wind, which can provide reactive services, aren't always readily available to dispatch in the BM and are often located further away from areas of need. We will continue to use TO assets first as they are zero cost at point of use, and TO's will otherwise build where they identify a need. We then use operational actions and dispatch reactive power on an economic basis, and we recognise there are greater efficiencies to be made through developing our markets.

We therefore need to develop markets that signal new investment to be built in the right locations, and signal existing assets to operate efficiently. Over the last year, we have progressed our enduring market design for the procurement of voltage services alongside identifying how to increase the reactive power services provided by assets already operating on our networks.

Link to voltage webpages

What is Voltage?

Voltage is the 'push' that causes electrons to move in an electrical conductor, measured in volts. Voltage must be kept within set limits across the transmission system to maintain safe and efficient operation. We manage the voltage of the network through absorbing, or injecting, reactive power onto the network. By absorbing reactive power, the voltage reduces in the surrounding network area, whereas injecting will increase the voltage in the surrounding networks. We often refer to absorbing as a 'lead' action, and the injection as a 'lag'. Synchronised generators may provide either a lead or lag action through adjusting their active power output.

Residual reactive power capability

Our residual requirement is our forecasted need still to be met once all other actions have been utilised, such as market dispatch and existing TO assets.

Voltage

How do we procure voltage services?[1]

Grid Code provisions

Network Services Procurement (NSP)

Short Term Tenders

Grid Code provisions

The Grid Code requires all transmission-connected generators to have the capability to both absorb and inject reactive power. For power generating modules, such as wind, solar and battery storage, the grid code only mandates reactive capability when the asset is generating at >20% of the asset's rated MW. Where reactive power is needed, and there are no suitable providers already generating, we will synchronise units through offers in the BM, or proactively via pre-gate closure trading. Assets dispatched are paid via the Obligatory Reactive Power Services (ORPS).

1 The ESO can also instruct non-market solutions to secure reactive power services, such as switching out circuits and from TO network assets reduces our need for reactive power services but could reduce our level of redundancy. There are many TO assets on the transmission network which can be used to manage voltage levels. TOs submit plans to build new assets with reactive capability in their business plans for each price control via their Regulated Asset Build (RAB). We can also trigger investment in reactive assets through an SO-TO Code (STC) planning request.

Markets Roadmap / Market Areas / Voltage 118

Voltage

How do we procure voltage services?[1]

Grid Code provisions

Network Services Procurement (NSP)

Short Term Tenders

Network Services Procurement (NSP)

To meet our increasing requirement, we are launching a third long-term voltage pathfinder tender. Previous tenders (Mersey and the Pennines) have contracted 440MVAr, with 240MVAr already operational. Both of these provide an availability fee (£/SP) for the effective MVar they provide during the contract length (April 2022-31). Following the success and learnings of previous Pathfinders, we intend this competitive approach to become "business as usual". Going forward these tenders that would have previously been known as 'Pathfinders' will be collectively known as Network Services Procurement (NSP). Please look out for more information about this voltage NSP tender by monitoring the ESO website.

1 The ESO can also instruct non-market solutions to secure reactive power services, such as switching out circuits and from TO network assets reduces our need for reactive power services but could reduce our level of redundancy. There are many TO assets on the transmission network which can be used to manage voltage levels. TOs submit plans to build new assets with reactive capability in their business plans for each price control via their Regulated Asset Build (RAB). We can also trigger investment in reactive assets through an SO-TO Code (STC) planning request.

Markets Roadmap / Market Areas / Voltage 119

Voltage

How do we procure voltage services?[1]

Grid Code provisions

Network Services Procurement (NSP)

Short Term Tenders

Short Term Tenders

The ESO also runs short-term tenders when we identify a voltage requirement that is temporary e.g., caused by planned outages, asset availability, forecast system conditions and providing a service until pathfinder units go live.

1 The ESO can also instruct non-market solutions to secure reactive power services, such as switching out circuits and from TO network assets reduces our need for reactive power services but could reduce our level of redundancy. There are many TO assets on the transmission network which can be used to manage voltage levels. TOs submit plans to build new assets with reactive capability in their business plans for each price control via their Regulated Asset Build (RAB). We can also trigger investment in reactive assets through an SO-TO Code (STC) planning request.

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Voltage - Summary of the chapter

How is the landscape changing?
The volume of new reactive capability needed to economically maintain a compliant network in 2025 has increased. In 2021, we forecasted an additional 1,600MVAr requirement in 2025, this forecast has now increased in 2022 to 2,225MVAr.[2] This rise is driven by the continued decline in reactive power absorption capability on the transmission network and the distribution network is increasingly producing reactive power, rather than absorbing it as it has done historically. We expect TO assets to provide most of this requirement. Requirements are locational: London's residual requirement is 500MVAr, whereas the Southwest of England is 125MVAr.

How have costs and volumes evolved over the last year? There are two aspects of reactive payments, a MW payment to make the unit available (the synchronisation cost) and then the MVAr payment as well (the utilisation cost). Synchronisation and utilisation costs increased by 43% and 240% respectively compared to 2021, whereas utilisation volumes increased by ~8%.The main driver of costs is the impact of wholesale gas prices on the default price paid to reactive power providers.

What is driving the need for reform?
Meeting our short-term needs via existing procurement methods is expected to become increasingly costly for our consumers.

How are we implementing market reform?
We progressed our enduring market design for the procurement of reactive services via our Reactive Market Design project. Our minded-to position is to utilise a nodal procurement strategy to provide appropriate locational signals alongside procurement on three distinct timescales to incentivise efficient investment and dispatch. In the short term, we are introducing a Commercial Service Agreement to procure greater reactive service provisions from existing units.

Why do our reactive requirements differ by region?

Reactive Power generation and absorption requirements for voltage control are regional and vary significantly across the electricity system. System Requirements are driven by many factors including demand, generation, and system conditions. Our Operability Strategy Report goes into more details on this.

The synchronisation cost

Synchronisation costs are payments for an asset altering their active energy output which provides reactive services (Lead/Lag) as a by-product of this MW instruction.

The utilisation cost

Utilisation costs are payments that we make for the reactive services then provided as the by-product of the change in active power. Payment rates are determined by the ORPS methodology which is indexed linked to the wholesale market.

Default price paid

We provide a default payment price to units that provide us reactive power services under Obligatory Reactive Power Services (ORPS). The default payment rate is the price that we pay all service providers for their utilisation in £/MVArh. The default payment price is indexed linked to the price of electricity within the wholesale market. When the wholesale price of electricity rises, so too does the default payment price and vice versa.

2 We identify and regions with voltage issues to be addressed via our annual voltage screening reports, the Electricity Ten Year Statement, and the Network Options Assessment. Our screening process helps identify and prioritise the region(s) which should be further explored through a detailed power system and cost-benefit analysis. For voltage management, this process analyses the potential cost saving achieved by investing in a proposed solution compared to using existing services such as Obligatory Reactive Power Services (ORPS). To estimate this saving, the ESO forecasts the constraint and utilisation costs they will pay for accessing and using the ORPS via the BM.

Markets Roadmap / Market Areas / Voltage 121

Voltage - Market Insight: Reactive Power Volumes

Utilisation volume

Over the past year, the total volume utilised under ORPS rose 9%, primarily driven by the need for the absorption of reactive power as shown by the chart on the right (Figure 1). By breaking down the total into lead and lag requirements, we can see that lead volumes rose 8% to 28,830GVArh, whereas lag volumes rose by 11% to 3,890GVArh.

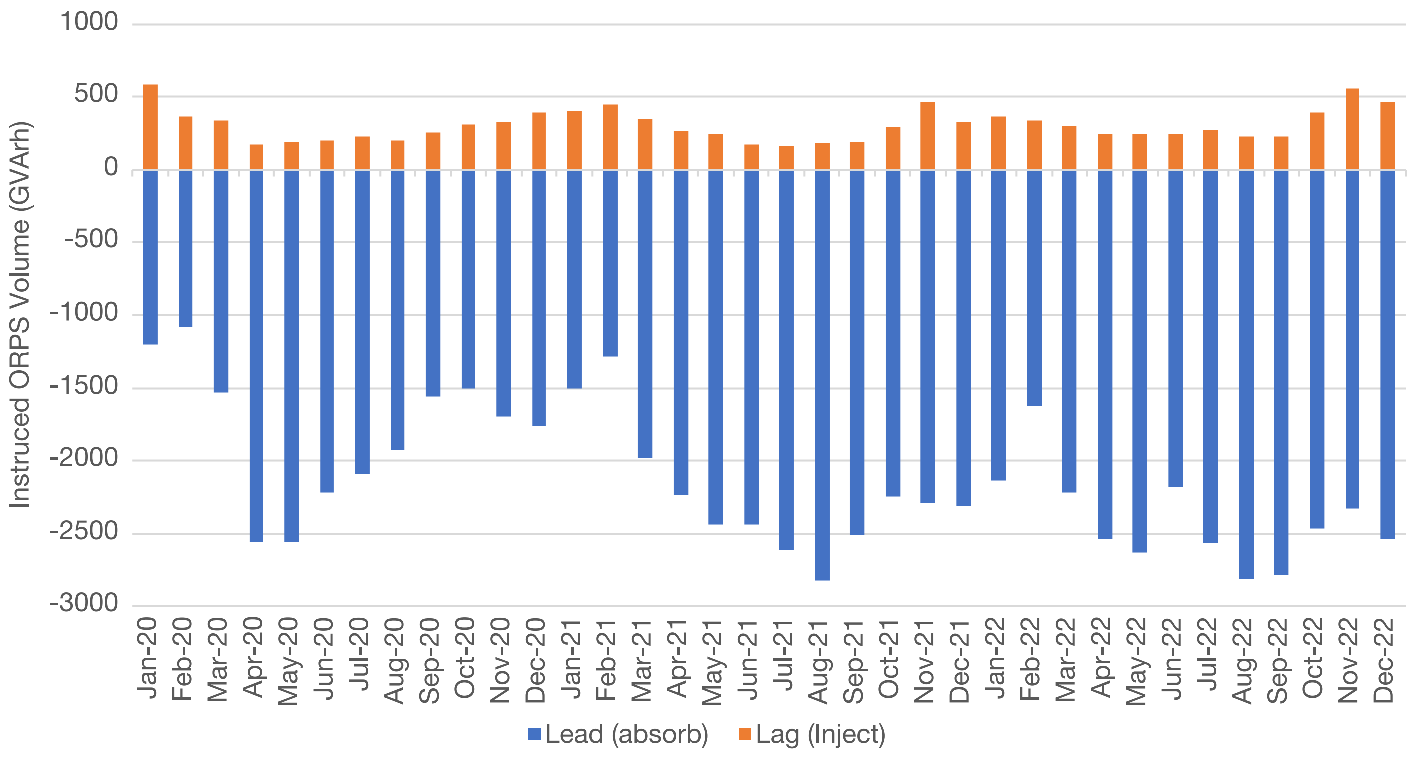
We continued to see a seasonal need for reactive services, with higher absorption volumes over the summer months owing to a more lightly loaded network and higher injection in the winter months due to higher power flows.

Figure 2 illustrates the technologies which contributed to meeting our reactive requirements by region between 2020-2022. Due to the locationality of reactive power provision, it is unsurprising that regions with high levels of zero carbon generation, such as Scotland, met 97% of their lead requirements from these technologies.

Network Services Procurement

The successful units from the Mersey long term NSP, a battery facility and a reactor, are now operational. This represents 240MVAr of reactive volume within the North region. This has reduced our reliance on a CCGT units in this region. The successful units from the Pennines long term NSP, a mix of TO assets and the Dogger Bank offshore wind farm, are expected to be operational in 2024. This will provide 700MVar of effective reactive volume to the North region. All NSP units contracted have been zero carbon, supporting our 2025 zero carbon operability ambition.

VT Figure 1: Total lag and lead volumes by ORPS between 2020-2022

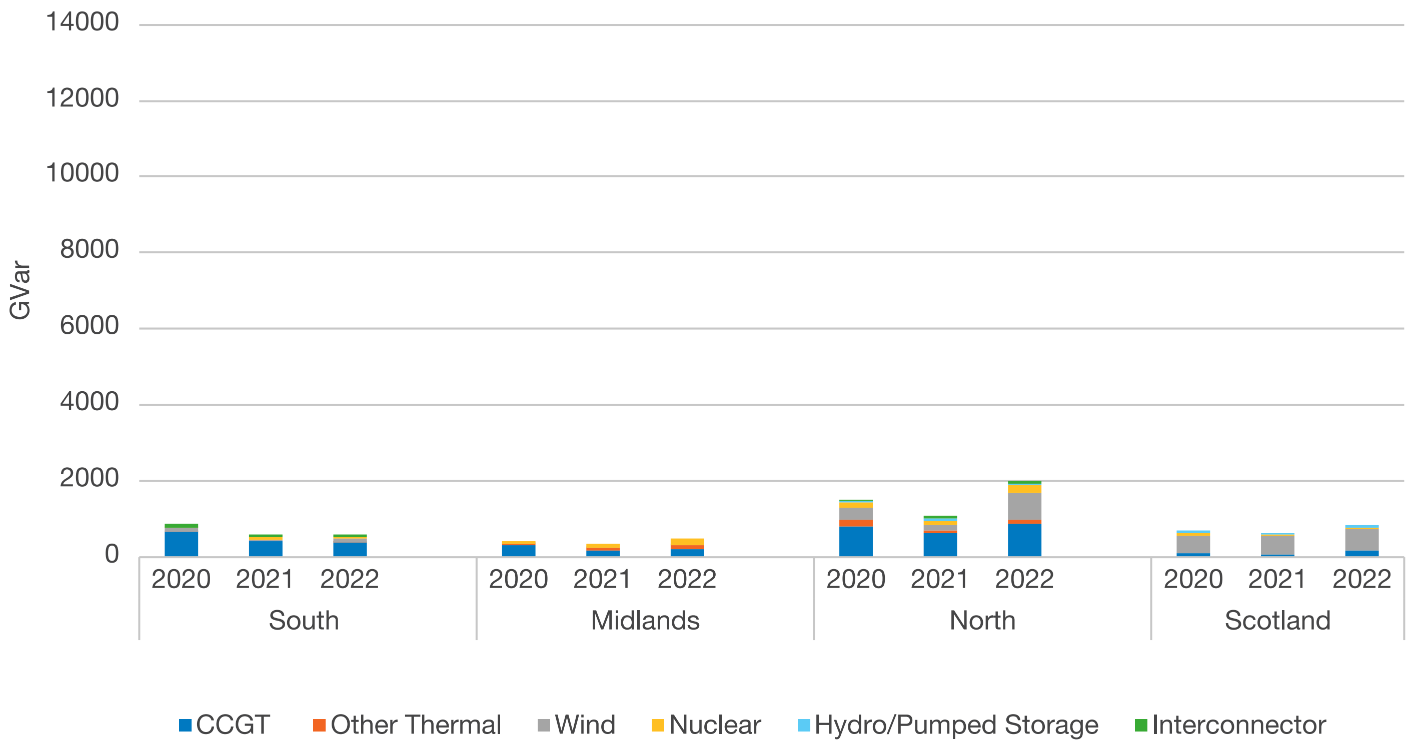


Lead volumes (absorption of reactive power) are included as negative values whilst lag volumes (injections of reactive power) are positive.

Markets Roadmap / Market Areas / Voltage 122

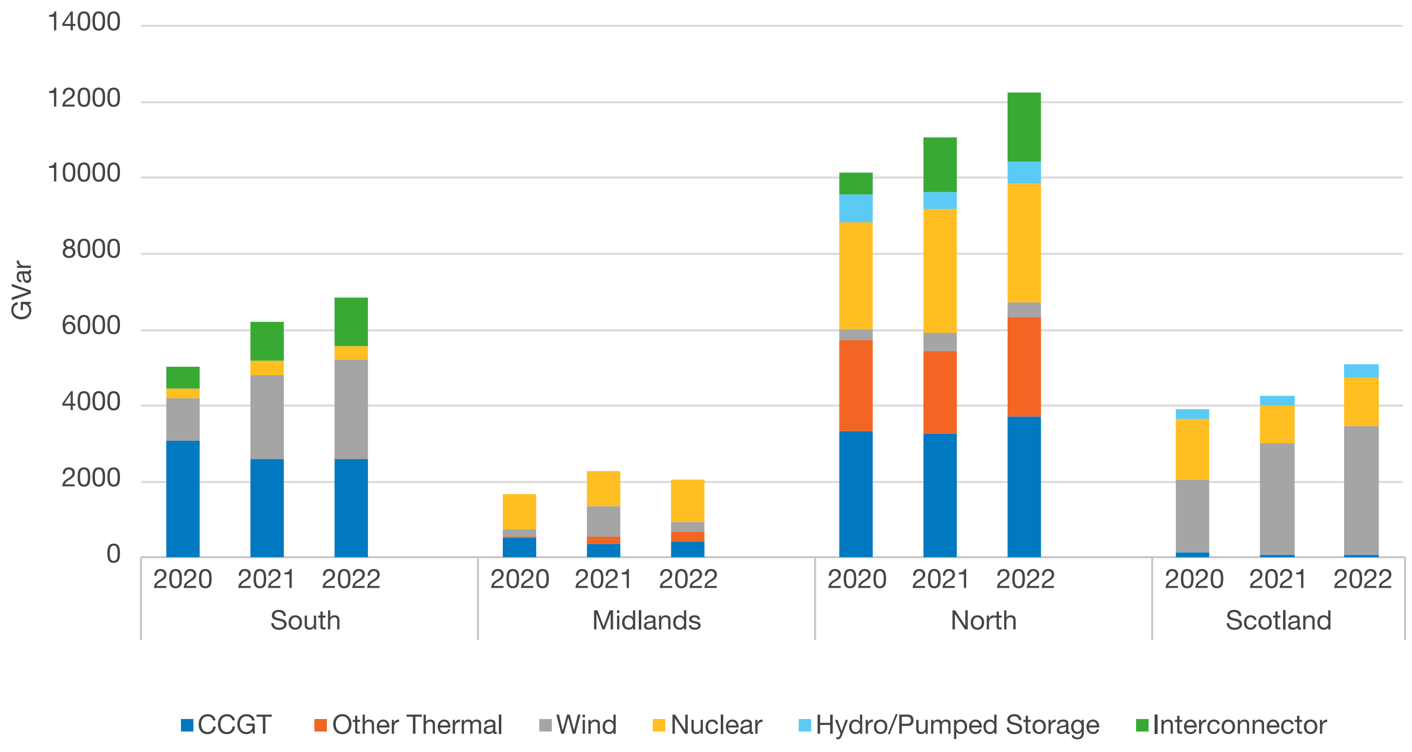
Voltage - Market Insight: Reactive Power Volumes

VT Figure 2a: Lag providers by technology and region between 2020-2022



The lag/lead providers by technology and split by regions from 2020-2022. Note that across all regions Lead requirements have even remained stable or increased. Volumes provided by network assets are not included and pathfinder volumes are shown as effective MVARs.

VT Figure 2b: Lead providers by technology and region between 2020-2022



The lag/lead providers by technology and split by regions from 2020-2022. Note that across all regions Lead requirements have even remained stable or increased. Volumes provided by network assets are not included and pathfinder volumes are shown as effective MVARs.

Markets Roadmap / Market Areas / Voltage 123

Voltage - Market Insight: Reactive Power Costs

Synchronisation and utilisation costs

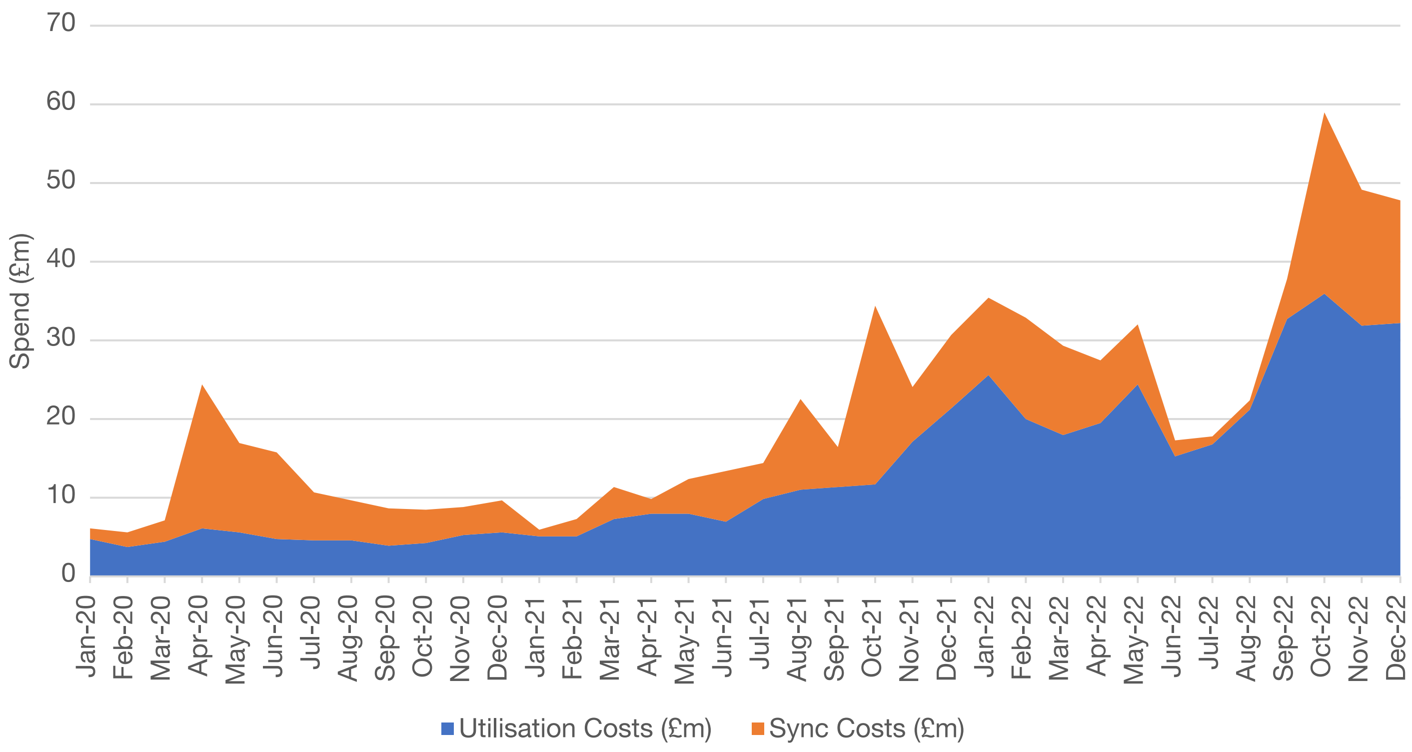
The cost of reactive services doubled in 2022 compared to the previous year with a total cost of £408m. Synchronisation costs rose by 43% compared to 2021, with a cost of just under £115m whilst utilisation costs over doubled to £293m. Geopolitical events leading to higher gas wholesale prices are the primary driver behind the rise in both synchronisation and utilisation costs. Synchronisation costs, i.e., dispatch instructions from the balancing mechanism, increased as we typically utilise thermal assets to secure reactive services as a by-product of their assets power output. Utilisation costs, i.e., the wholesale indexed default payment price paid under ORPS, increased from ~£3MVArh at the start of 2021, to ~£17/MVArh at the end of 2022. As gas prices begin to fall from the beginning of 2023, we are also seeing a reduction in the ORPS default payment rate.

Rising synchronisation costs in 2022 were somewhat offset by a higher rate of conventional unit self-dispatch during the summer months, driven by higher wholesale prices on the continent. As a result, we did not need to pay them their synchronisation costs, only a utilisation payment to receive their reactive power services. We can see this trend clearly in the summer months within Figure 3 where sync costs are almost negligible.

Network Services Procurement

Across 2021/22, the Mersey voltage pathfinder has saved £12.6m, and is estimated to save £25.3m across 2022/23. These savings stem from securing our reactive needs at a fixed price, reducing our reliance on CCGT units in this region and therefore providing value for money for our consumer against potential volatile energy prices. As these units are zero carbon, there is also an environmental benefit as we do not need to utilise a gas-fired plant in that region.

VT Figure 3: The utilisation and synchronisation costs between 2020-2022

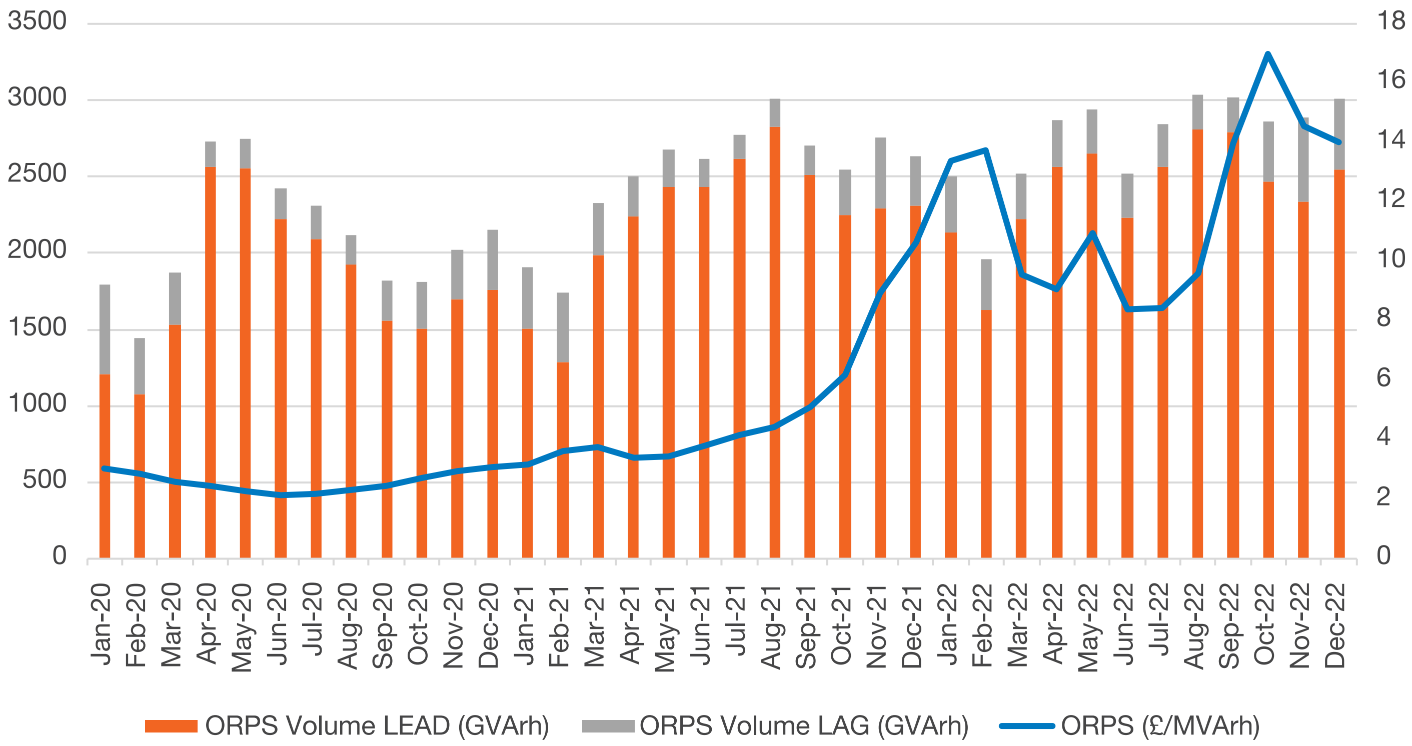


Note: revenue recovered by the Transmission Owners related to their reactive compensation equipment cannot be identified within their overall Regulated Asset Base (RAB). The above chart, therefore, does not represent the full cost to consumers of voltage management in 2022.

Markets Roadmap / Market Areas / Voltage 124

Voltage - Market Insight: Reactive Power Costs

VT Figure 4: Lead and lag (GVArh) and the ORPS default payment price (£/MVArh)



Lead and lag (GVArh) compared to the ORPS default payment price. This clearly illustrates an incremental rise in Lead and Lag volumes, but a significant increase in the ORPS default payment price.

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Voltage - Drivers for Reforms

We have identified several key drivers which are influencing our reactive product design most significantly.

Increasing requirements require new location-specific investment as well as efficient dispatch of existing assets

Need for more efficient utilisation of existing capacity

Potentially large interconnector swings will cause challenges

Increasing requirements require new location-specific investment as well as efficient dispatch of existing assets

Traditional synchronous units are being displaced by:

- Non-synchronous sources that can provide reactive services but aren't always readily available to dispatch in the BM. Renewable units are typically located further away from areas of reactive requirement, reducing their effectiveness.
- Embedded generation which does not currently provide reactive services to ESO.

Traditional sources can be instructed to synchronise and provide their reactive services, but this may incur a high cost. We need to develop other means of securing our reactive services to minimise cost to consumers.

Furthermore, owing to the locational requirements of reactive service provisions, we must ensure that we develop products which signal to industry where on the network to deploy technically capable assets, a signal that is not effectively delivered by BM instructions or ORPS payments. This means developing an enduring market which provides locational investment decisions, whilst also promoting competitive dispatch of assets closer to real-time.

3 These figures should be caveated that this volume has been declared by the provider with no studies carried out to confirm the reactive range of these assets nor its effectiveness on the network so the total volume capability will certainly reduce.
4 New interconnectors have obligations to provide dynamic reactive capability which will help to manage some of this uncertainty.

Markets Roadmap / Market Areas / Voltage 126

Voltage - Drivers for Reforms

We have identified several key drivers which are influencing our reactive product design most significantly.

Increasing requirements require new location-specific investment as well as efficient dispatch of existing assets

Need for more efficient utilisation of existing capacity

Potentially large interconnector swings will cause challenges

Need for more efficient utilisation of existing capacity

In 2022, we identified a significant volume of additional reactive power which could be provided from units already operating on our network. Accessing this capacity can help us meet our growing reactive requirements between 2023-26. Responses to the Request for Information (RFI) which we published in May 2022 shows that there will be around 1.8Gvar and 1.6GVar on the transmission and distribution networks respectively.[3] In securing this additional capability from units that are already operational, we avoid high investment costs.

3 These figures should be caveated that this volume has been declared by the provider with no studies carried out to confirm the reactive range of these assets nor its effectiveness on the network so the total volume capability will certainly reduce.

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Voltage - Drivers for Reforms

We have identified several key drivers which are influencing our reactive product design most significantly.

Increasing requirements require new location-specific investment as well as efficient dispatch of existing assets

Need for more efficient utilisation of existing capacity

Potentially large interconnector swings will cause challenges

Potentially large interconnector swings will cause challenges

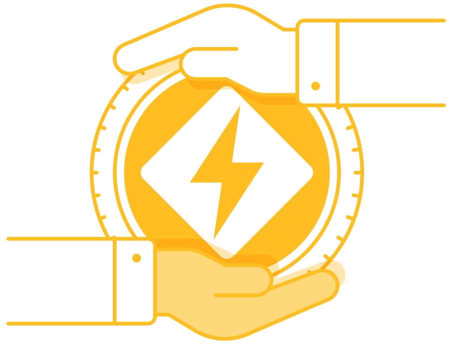
All FES 2022 scenarios suggest that GB will be a net exporter of electricity by 2030, with an installed capacity of at least 13GW. As price differentials between GB and the continent become more volatile, we expect much greater swings in interconnector flows (up to 26GW swing by 2030), impacting power flows and voltage levels across the network.[4]

Markets Roadmap / Market Areas / Voltage 128

4 New interconnectors have obligations to provide dynamic reactive capability which will help to manage some of this uncertainty.

Voltage - Market Reforms

In last year's Markets Roadmap, we highlighted the benefits of procuring voltage services via a blend of long- and short-term procurement based upon a nodal market. We have progressed our thinking on this. In the short term, we are introducing a Commercial Service Agreement (CSA) to increase our reactive service provision from assets already on the network, and intend to run a Network Services Procurement tender, with more information to be presented to industry shortly.



Introducing the Commercial Service Agreement

The CSA formalises our ability to access reactive capability which exists but is not mandated by grid code or the Connection and Use of System Code (CUSC). This will help offset the loss of reactive power services from traditional units. The CSA is a relatively easy and quick to implement, requiring no changes to the MSA nor any impact to the testing, dispatch and settlement process. Whilst the CSA's implementation is a great opportunity for the ESO, we must recognise that there are challenges with this approach. Primarily, that this is not an enduring solution as we are only able to secure reactive services from existing units. Units will be paid via ORPS which is not competitively determined. Our enduring market design will address these concerns.

Markets Roadmap / Market Areas / Voltage 129

Voltage - Market Reforms

Enduring market design

In April 2022, we presented our minded position on the future reactive market design. These include the procurement of services across three timescales, the payment structures for each market and procurement based on a nodal design.[5] We are now optimising the details and assessing the feasibility of introducing the market design from an implementation perspective.[6] We present here a summary of the complimentary aspects which stem from this procurement methodology.

We are designing this enduring voltage market design and the stability market design NIA project in tandem, sharing lessons across both of the projects to bring forward learnings to help provide a more efficient enduring electricity market design.

Short term market (day ahead)

Medium term market (1-year contract)

Long term market (4-year contract)

Short term market (day ahead):

To meet a more dynamic need for voltage service procurement which ensures that we can meet our locational reactive needs on a closer to real time basis, we are considering the merits of designing a short-term market for voltage. Our minded-to position is to hold this auction at the day-ahead stage with 4-hour EFA blocks to align with other ancillary services procurement. Closer to real time markets based upon nodal pricing will promote the effective dispatch of assets via competitive procurements mechanisms with an availability and utilisation price to reflect the types of techs that are to bid in as we recognise there may be an opportunity cost for them in providing reactive costs considering other market alternatives. This will signal to industry where we require reactive power services and procure these based on competitive tender. Reactive market reform work will continue to assess and validate whether a new short-term market will add values and bring the benefits of widening market access to bring the reactive cost down.

5 The design has been proposed by our project partners, AFRY. Further research is required to analyse the potential merits of procuring across these three timescales and any subsequent market design details. To be keep updated, please sign up to our Future of Balancing Services newsletter.

6 Please note that our new Balancing Reserve product was identified as a high priority to deliver value for money for consumers by rapidly address soaring balancing costs during 2022; hence, this was prioritised over the delivery of the enduring market design.

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Voltage - Market Reforms

Enduring market design

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Short term market (day ahead)

Medium term market (1-year contract)

Long term market (4-year contract)

Medium term market (1-year contract)

We recognise that the short-term market must be complemented with longer term markets, especially when we identify a need which exists for the majority of the year. Meeting a continual need could be met by our existing products, however, we value the benefit of longer-term contracts to reduce risk for the ESO and provide greater certainty to dedicated assets, which seek to operate on a high-availability basis. Hence, we are considering the launch of a medium-term voltage market, which will conclude one year ahead of delivery (T-1) and offer a one-year contract duration for successful parties who would be paid an availability payment (£.MVAr/SP).

5 The design has been proposed by our project partners, AFRY. Further research is required to analyse the potential merits of procuring across these three timescales and any subsequent market design details. To be keep updated, please sign up to our Future of Balancing Services newsletter.

6 Please note that our new Balancing Reserve product was identified as a high priority to deliver value for money for consumers by rapidly address soaring balancing costs during 2022; hence, this was prioritised over the delivery of the enduring market design.

Markets Roadmap / Market Areas / Voltage 131

Voltage - Market Reforms

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Short term market (day ahead)

Medium term market (1-year contract)

Long term market (4-year contract)

Long term market (4-year contract)

There is value to both the ESO and customers in offering longer-term reactive power contracts. These contracts would provide greater investment certainty for new units with the capability to provide reactive services, whilst reducing the ESO's exposure to potentially fluctuating prices. We also recognise that over procurement in the long-term market could burden consumers with unjustifiable costs when a requirement may not materialise. This is where the long term and short term market will compliment each other.

We are taking lessons from our 'pathfinders', when designing this service.

5 The design has been proposed by our project partners, AFRY. Further research is required to analyse the potential merits of procuring across these three timescales and any subsequent market design details. To be keep updated, please sign up to our Future of Balancing Services newsletter.

6 Please note that our new Balancing Reserve product was identified as a high priority to deliver value for money for consumers by rapidly address soaring balancing costs during 2022; hence, this was prioritised over the delivery of the enduring market design.

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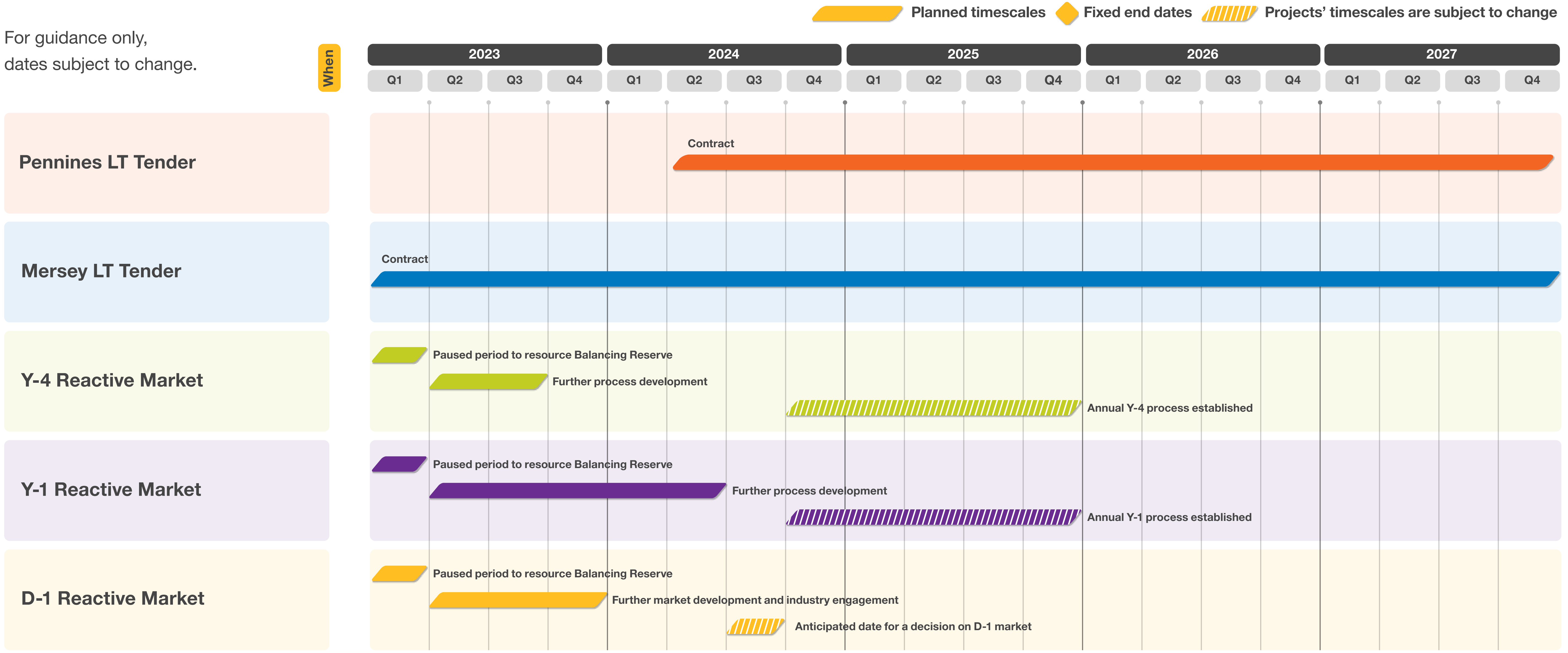
Voltage - Delivery Plan



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Voltage - Delivery Plan

Pennines LT Tender

What?

The voltage pathfinders are a world first, offering long-term contracts to providers who can help address high voltage issues. Our second high voltage pathfinder is looking for long term voltage support in the North of England and Pennines region.

Mersey LT Tender

What?

The voltage pathfinders are a world first, offering long-term contracts to providers who can help address high voltage issues. Our first high voltage pathfinder is looking for long term voltage support in the Mersey region.

Y-4 Reactive Market

What?

Taking lessons from our voltage pathfinders, we recognise the value of offering longer-term reactive power contracts. Our current minded-to position will be to procure these contracts on an annual procurement cycle. This will promote investment whilst reducing exposure to potentially fluctuating prices. Please visit our Reactive Reform homepage for more details.

Y-1 Reactive Market

What?

Whilst we have demonstrated the success of procuring new assets via voltage pathfinders, we recognise that there is also existing capacity on our network which can offer reactive power services reliably at low cost. Therefore, we are planning to launch a mid-term Y-1 reactive market which provides an opportunity for providers with firm availability to monetise capacity from existing units. Please visit our Reactive Reform homepage for more details.

D-1 Reactive Market

What?

Our reactive power needs are becoming more dynamic, and our minded-to position is to implement a short-term market (D-1) to meet any shortfall closer to real-time. A day-ahead market will supplement the volumes procured via the Y-4 and Y-1 markets. Please visit our Reactive Reform homepage for more details.

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Balancing Mechanism

Context

The BM is a critical tool for managing system security. BM providers submit their intended physical schedules for each unit and the price they are willing to vary from these plans, alongside asset technical parameters. We dispatch assets in the BM as flexibility needs cannot always be predicted and continuously change. Procuring in the BM can therefore be at times more efficient than trying to contract specific services ahead of gate closure.

Description of the Balancing Mechanism (BM)

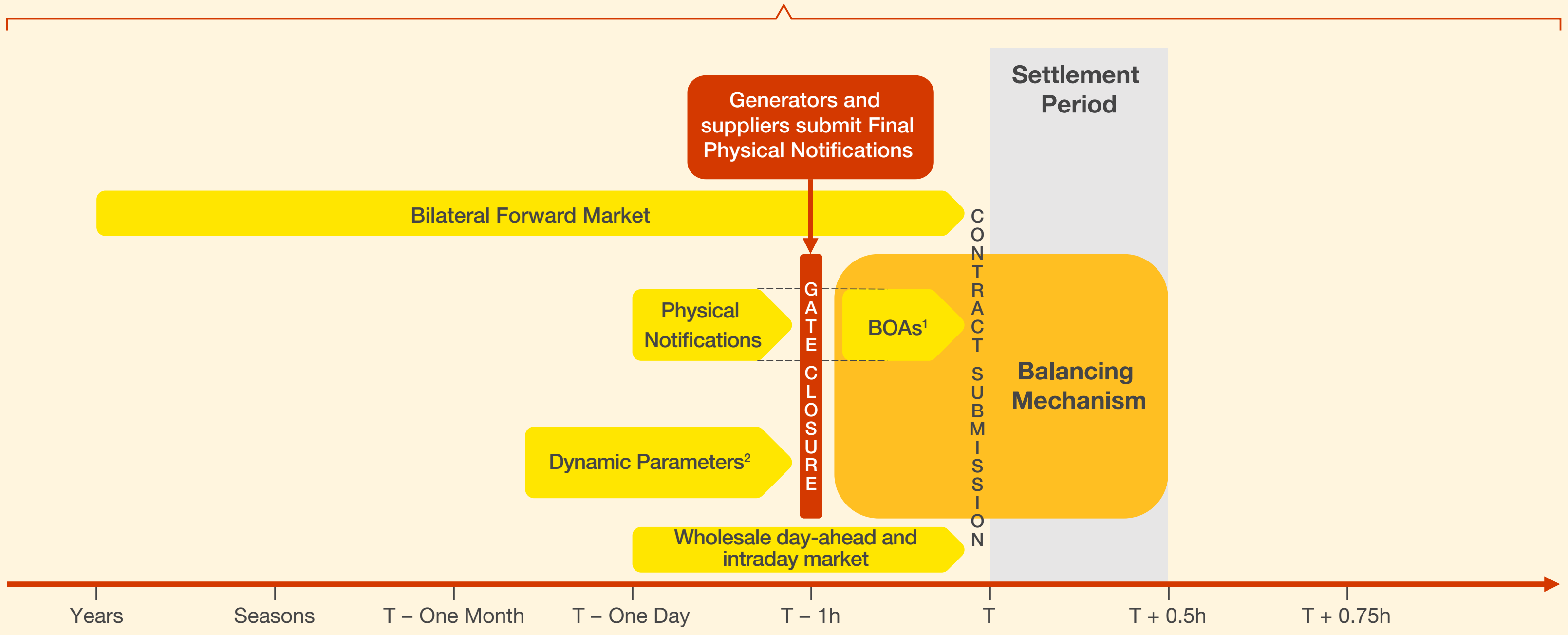
The BM is the final market ESO runs before real time dispatch. Following the end of wholesale market trading, ESO uses the BM to balance supply and demand for each settlement period. As residual electricity system balancer for GB, ESO is responsible for ensuring electricity generation and demand are balanced on a second-by-second basis. To do this, ESO instructs flexible generation close to real time through the Balancing Mechanism and contracts ahead of time for balancing services where we have a firm requirement. For more information on BM trading, please refer to the 2022 Markets Roadmap.

What services do we procure in real-time via BM?

BM actions fall into two broad categories: 'Energy' tagged actions are where ESO manages supply and demand imbalances. Energy actions also include managing reserve and response requirements.[1] 'System' tagged actions include management of system constraints, products we use to manage constraints include: stability, voltage and thermal constraints.

When dispatching in the BM, our objective is to select the most economical plant and contract services in a non-discriminatory manner. When selecting resources we consider their ability to provide multiple services including frequency response, system management (thermal, voltage or stability constraints), and frequency control.

GB Trading Arrangements



[1] Bid Offer Acceptances, using Final Physical Notification as a basis [2] Dynamic parameters may be submitted to ESO several days in advance of the Delivery Day ('T'), except interconnectors which are required to submit data each day by 11:00 day-ahead. Dynamic parameter data can be modified up to gate closure.

1 For example, ESO may issue an 'energy' instruction for margin in reaction to forecasting errors for demand or renewable plants such as wind. Similarly, it could be an action to manage a network constraint if generation exceeds the rated output of that line or if an additional unit needs to be synchronised to provide inertia.

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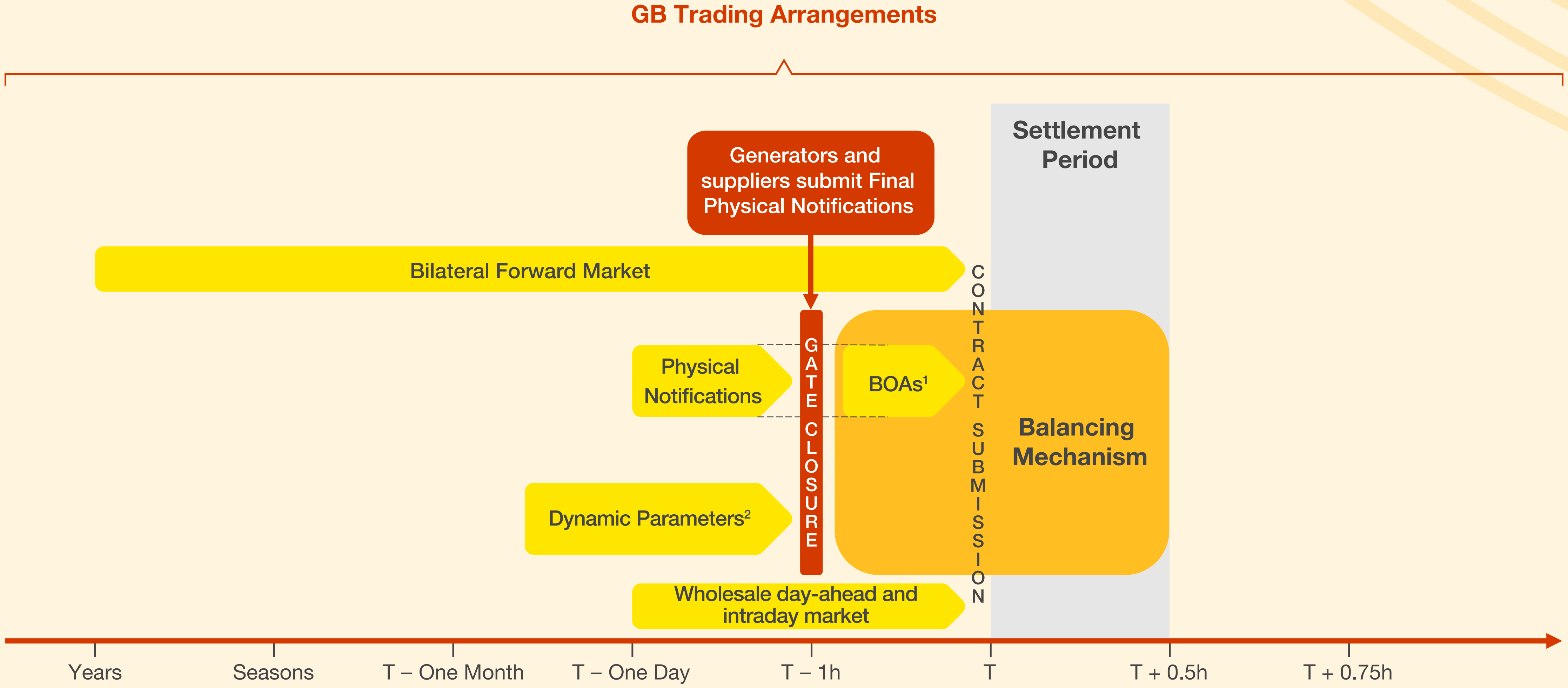
Balancing Mechanism



[1] Bid Offer Acceptances, using Final Physical Notification as a basis [2] Dynamic parameters may be submitted to ESO several days in advance of the Delivery Day (‘T’), except interconnectors which are required to submit data each day by 11:00 day-ahead. Dynamic parameter data can be modified up to gate closure.

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Balancing Mechanism - Summary of the chapter

How is the landscape changing? Over the last two years, energy markets have been increasingly volatile due to the pandemic, global gas crisis, tight system conditions, and higher levels of intermittent generation. This volatility has manifested itself in high prices in the BM.

How have costs and volumes evolved in the last year? We have seen a steady increase in the actions to manage both energy balancing and thermal and stability constraints. The costs of these actions have increased significantly due to high gas prices. Another key driver for energy balancing was procurement of reserves to maintain adequate margins. Since implementing the Frequency Risk and Control Report (FRCR) in 2021 and our new, fast-acting Dynamic Containment products in 2020/21, the volume of actions taken by ESO via trades to reduce the size of the largest loss has decreased significantly.

What is driving the need for reform? The number of dispatch actions in the BM is increasing, and as one action can resolve multiple requirements, it is increasingly complex for market participants to assess the underlying drivers of BM actions, potentially resulting in barriers to entry and inefficient pricing amongst other issues. There is a need to update our internal systems and processes to manage the new asset types coming onto the system. Finally, the BM is particularly sensitive to other markets (e.g wholesale markets, ESO markets and the Capacity Mechanism) – their inefficiencies and any changes to their design.

How are we implementing market reform? We are introducing new markets that provide transparency of ESO requirements which are currently procured in the BM. For example, we plan to introduce a new balance reserve product (subject to Ofgem approval), a Local Constraint Market and dedicated Stability/Reactive markets (building on Pathfinders). We are increasing the volume of providers that can provide us with energy and system services through updates to our balancing platform and operational metering requirements. We are also undertaking a holistic review of the BM design, considering the impacts of incremental and more fundamental market reforms on security of supply, consumer costs and coherency with the long-term direction of travel (REMA). We will engage with industry on these reforms and signpost future engagement activities.

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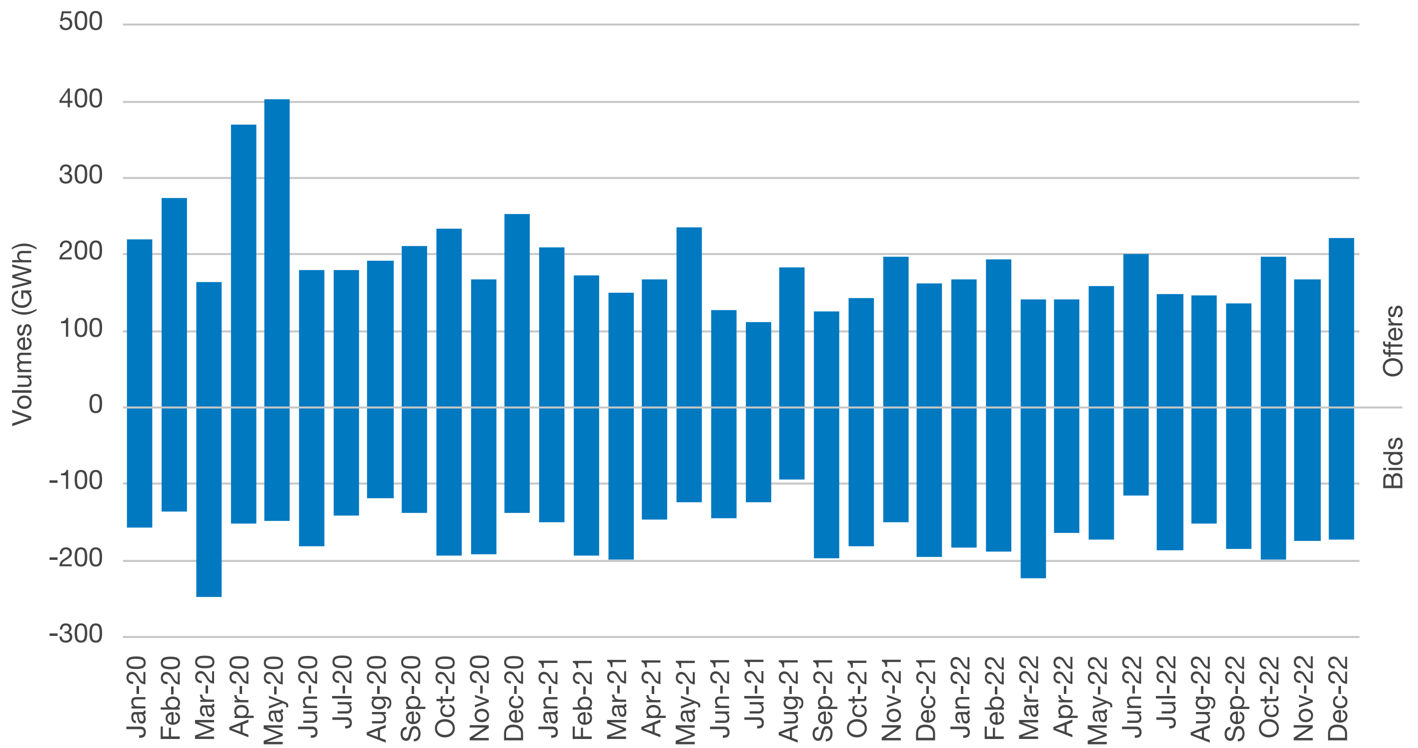
Balancing Mechanism - Market Insight: BM Volumes

Energy imbalance volumes continue to grow steadily, driven in part by forecast uncertainty of intermittent renewables

ESO actions taken to balance supply and demand have steadily increased with bid volumes increasing by 11% from 2021 to 2022 and offer volumes increasing by 2% in the same timeframe. Certain quarters saw higher increases than others over the same period in 2021. For example, Q3 2022 volumes of energy imbalance bids increased by 26% vs Q3 2021, and volumes to manage energy imbalance offer in Q4 2022 increased by 17% vs Q4 2021. Imbalance volumes occur when generators or suppliers deviate from their contracted positions submitted at gate closure (1 hour before real-time delivery). Imbalance volumes are driven by ESO and supplier forecasting errors, unplanned outages or maintenance.[2] We anticipate imbalance volumes will continue to rise steadily as more weather-driven renewable generation connects, although ESO is taking steps to improve its forecasting capabilities.[3]

BM Figure 1: Energy Imbalance Volumes (2020-2022)



2 For example, bids are accepted to turn down energy resources when they provide more than their contracted positions or outturn demand is less forecast demand. Offers are accepted to turn up energy resources when they provide generate less than their contracted positions or when outturn demand is greater than forecast demand.

3 Our strategic Platform for Energy Forecasting (PEF) Roadmap sets out how we will deliver value to consumers through the development and implementation of new ESO forecasting tools. We encourage market participants to work with us as we look to improve forecasting capabilities, please email us at: box.NC.Customer@nationalgrideso.com

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Balancing Mechanism - Market Insight: BM Volumes

System and energy balancing volumes continue to be dominated by management of reserve and thermal constraints

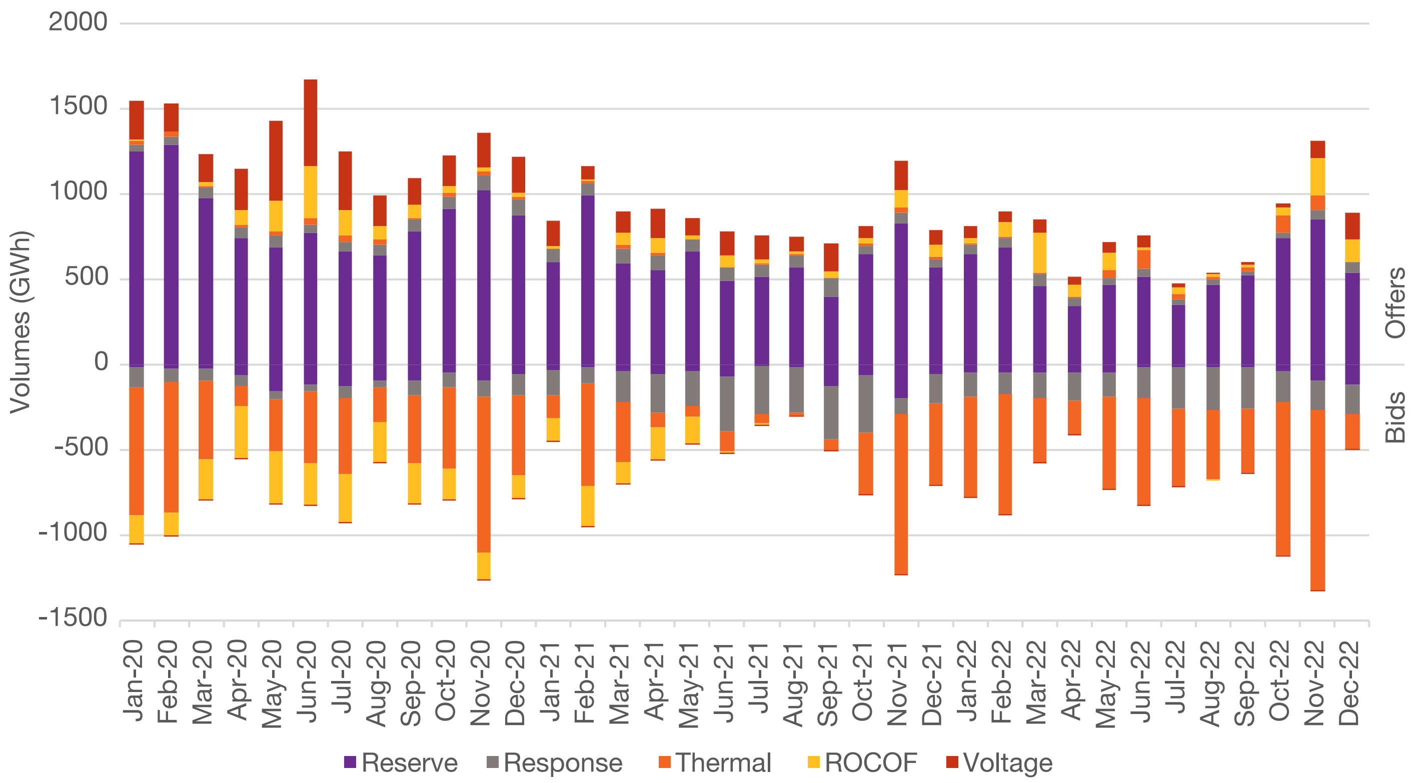
The main driver of BM energy offer volumes in 2022 was the management of reserve (~26%) to maintain adequate margins. Reserve offer volumes decreased slightly across 2021 and 2022 due to tight system conditions, down 11% vs 2021, however, have remained relatively high driven by tight margins largely due to plant closures and higher exports to the continent. Reserve holdings are also driven by output uncertainty associated with intermittent generation.

Export constraint[4] management was the predominant driver of bid volumes which nearly doubled since 2021 due to higher wind generation and network maintenance. For more information on BM and trades used for constraint management, refer to the Thermal chapter.

Since implementing the Frequency Risk and Control Report (FRCR) in 2021, we are no longer managing Stability by reducing the largest loss. The result is a decrease of Stability bids by 100% from 2021 to 2022. Actions to increase system inertia increased as a result of more a-synchronous generation on the system, higher wind and lower demand on the system. For more information, refer to the Stability chapter.

Volume of offers to manage voltage decreased by 46%, while the volume of bids to manage voltage decreased by 56%, driven by higher levels of generators self dispatching to take advantage of higher prices in continental Europe. For more information, refer to the Voltage chapter.

BM Figure 2: System and Energy Balancing Volumes (2020-2022)



4 Export constraints occur when net generation exceeds capacity of network in area.

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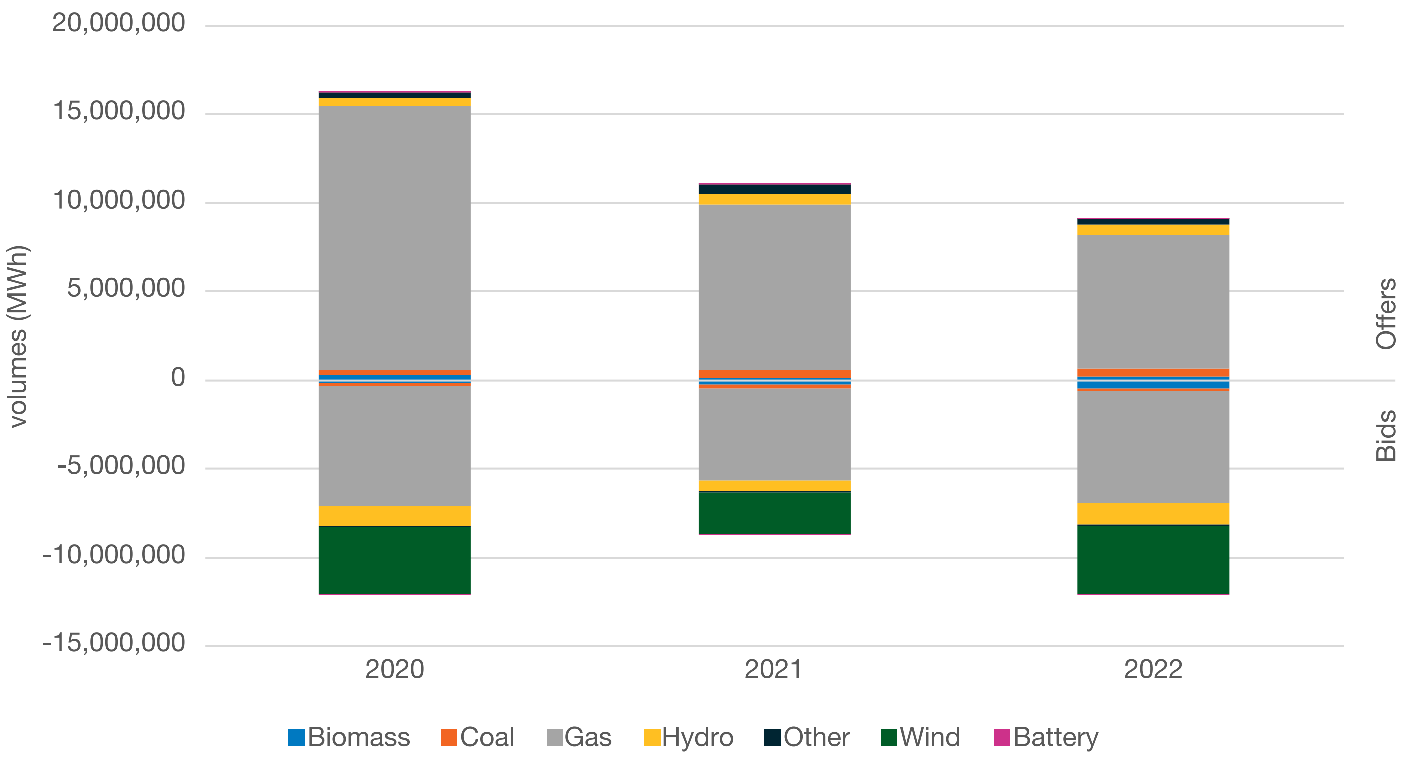
Balancing Mechanism - Market Insight: BM Volumes

The BM is dominated by gas plant

The chart on the bottom right compares bid-offer acceptance volumes in the BM by technology[5] over the last three years. The technology mix in the BM is largely unchanged and still dominated by gas plant. We discuss this trend in more detail under our drivers for reform below.

BM Figure 3: BM Bid and Offer Volumes by Technology (2020-2022)



5 ENAPSYS data

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Balancing Mechanism - Market Insight: BM Costs

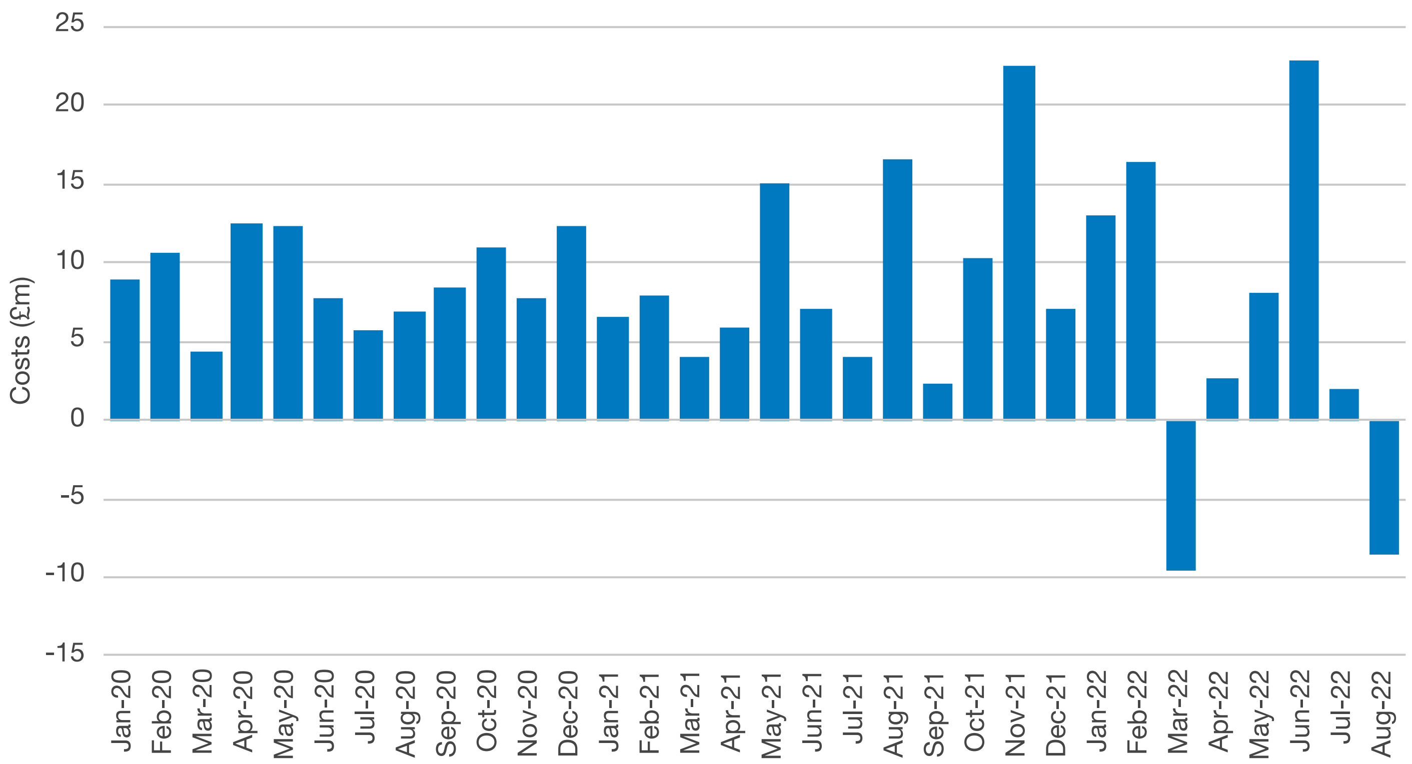
High wholesale gas prices and system tightness led to more frequent scarcity conditions and high reserve costs

Energy imbalance costs in 2022 were volatile, driven by volatility in gas prices. Figure 4[6] shows costs for bids to manage energy imbalances increased by 158% from January to August 2021 to January to August 2022 and offers increased by 132% in the same time period.

The combination of ongoing outages in the French nuclear fleet, low hydro levels in Norway & EU have contributed to tight system conditions. Gas prices were persistently high over the summer resulting in high BM costs as gas is typically the marginal plant. Reserve costs totalled c£63m over the summer[7], this is a slight decrease since 2021 (1% decrease).[8] High reserve costs were due to high interconnector exports and tight system conditions as GB gas prices were substantially lower than Europe, GB was a net exporter across all summer.[9]

Towards the end of 2022, demand levels were lower due to warmer temperatures in November and although temperatures were historically colder than normal in December, we continued to see a reduction in demand and higher levels of embedded generation. Costs to manage reserves over the Q4 period totalled c£246m, this is a 38% increase since Q4 2021.[10] Reserve volumes are lower in 2022 relative to 2021 but remain high due to tight system conditions, while price drivers relating to gas prices are largely the same as 2021. For further information, refer to Reserve chapter.

BM Figure 4: Energy Imbalance Costs (Jan 2020-Aug 2022)



6 Energy imbalance cost chart excludes data after August 2022 due to data inconsistencies.
7 June to August.
8 This figures do not include trades.
9 ESO Data Portal Monthly Balancing Services Summary.
10 ESO Data Portal Monthly Balancing Services Summary.

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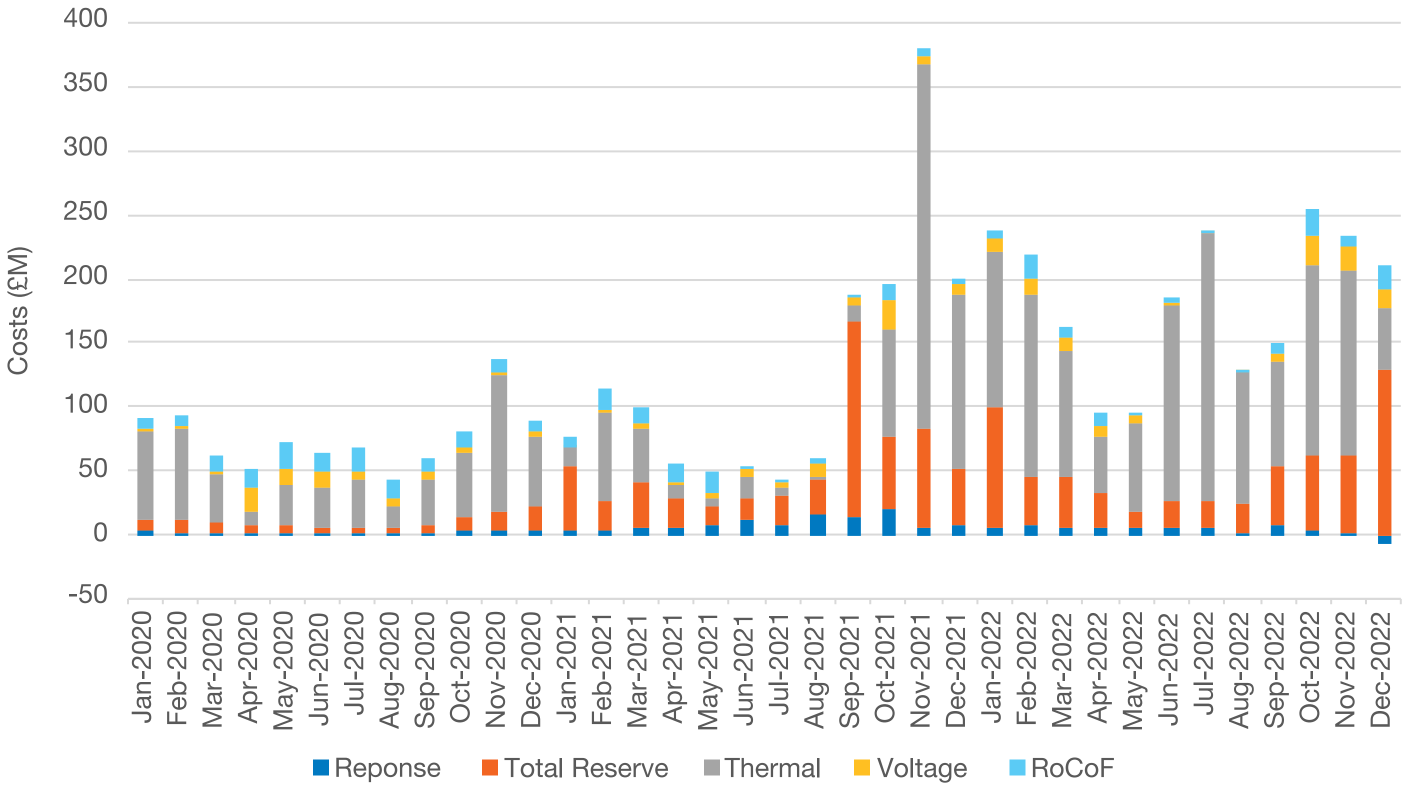
Balancing Mechanism - Market Insight: BM Costs

BM Figure 5: System and Energy Balancing Costs (2020-2022)



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Balancing Mechanism - Market Insight: BM Costs

Generator bidding behaviour accounted for some exceptionally high-cost days

Winter 2021 saw several very high-cost days in the BM. January 2022, we commissioned a Review of the BM and worked closely with Ofgem to understand underlying cost drivers to ensure there were no breaches of market rules. The Review indicated that the top 10 high-cost days selected for the review were driven by system tightness combined with rapid changes to contracted positions at gate closure and inflexibility of dynamic parameters on some units led to a very high prices to secure capacity to meet operational margin requirements. We continued to observe similar trading behaviour in 2022 however with reduced frequency. Our market monitoring team is working closely with Ofgem to ensure competitive outcomes.

Costs to manage system inertia and thermal constraints remain high

The cost of managing thermal constraints doubled to £1.36bn compared to 2021, roughly in line with increased congestion volumes. For further information, please refer to the Thermal chapter.

Lower than seasonal normal demand coupled with high levels of non-synchronous generation meant that high volumes of actions were required to increase system inertia. Costs to manage stability totalled c£104m, a slight increase from 2021 where costs totalled c£98m, largely due to increased gas prices across 2022. For further information, please refer to the Stability chapter.

Generator bidding behaviour accounted for some exceptionally high-cost days:

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Our highest cost day in 2022 was Monday 24th January where the daily spend was c£40m. A key cost driver was margin management across the darkness peak period (17:00-18:00).

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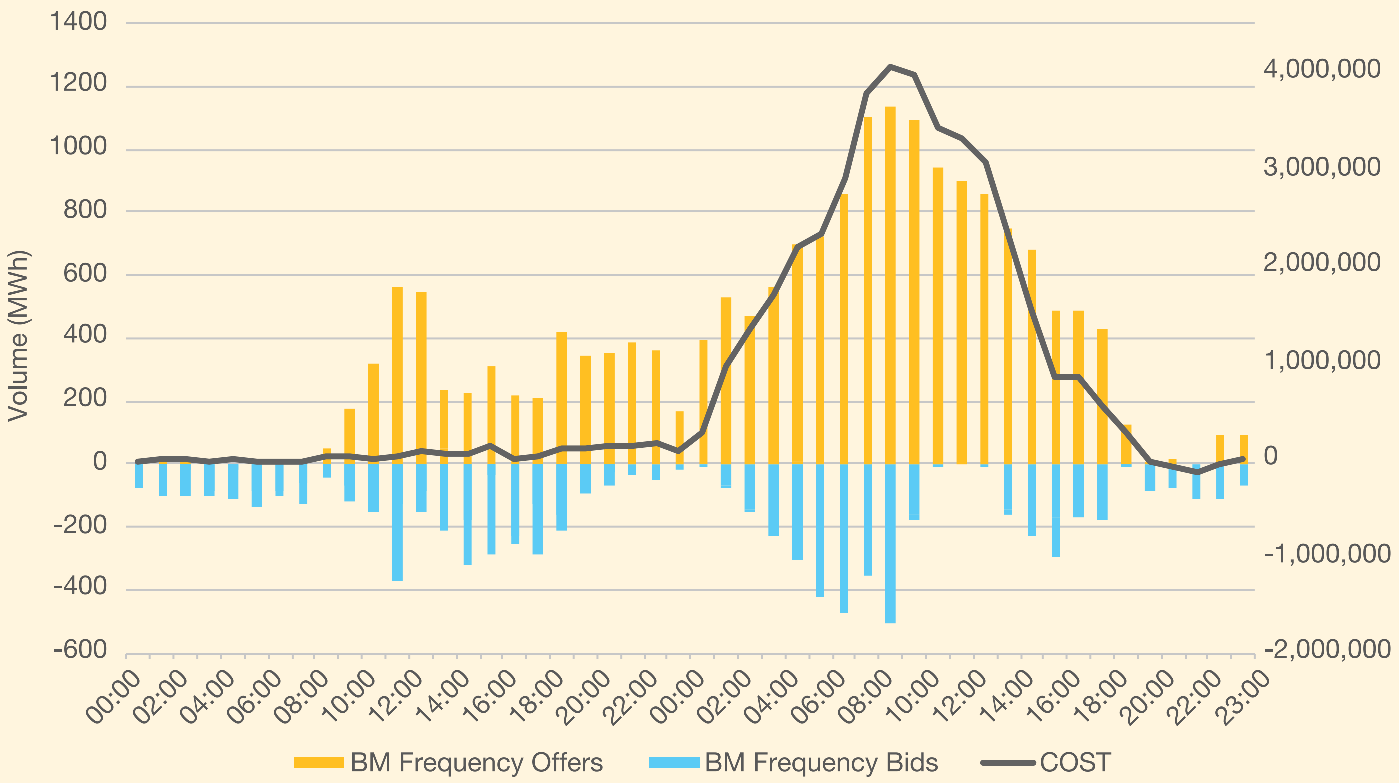
Balancing Mechanism - Market Insight: BM Costs

Our highest cost day in 2022 was Monday 24th January where the daily spend was c£40m. A key cost driver was margin management across the darkness peak period (17:00-18:00). A more recent example of immoderate behaviour was on 12th December where costs reached c£30m.

BM Figure 6: 24 Jan: Offers and Bids cost



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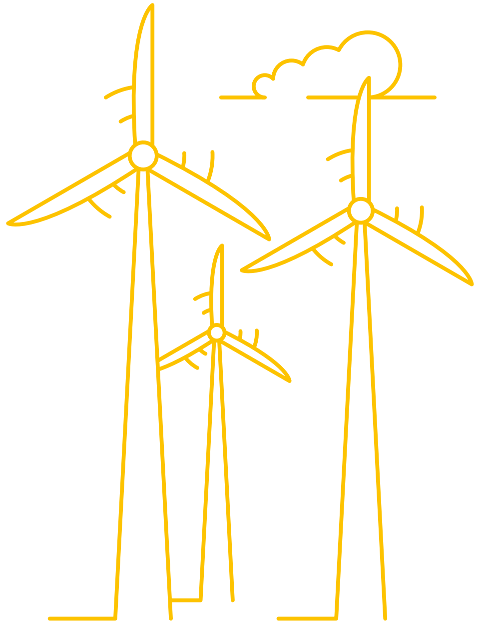
Balancing Mechanism - Drivers for Reforms

As GB's electricity system integrates higher volumes of intermittent capacity, we are seeing increasingly high costs for managing energy and system constraints. Listed here are key issues highlighting opportunities to improve market efficiency and driving the need for market reform.



Actions for managing energy and system constraints have increased across the board

BM costs continue to increase, there is a question if underlying drivers of scarcity pricing across BM and wider markets are efficient

The BM is currently high carbon intensity; our IT systems and control room processes present barriers to entry for emerging low carbon flexible assets

Actions for managing energy and system constraints have increased across the board

The BM's initial purpose was to provide a market for residual energy balancing; however, this role has changed significantly with changes to our technology mix and the need to manage increasing penetration of intermittent generation. Actions for managing GB system and energy requirements are increasing and are expected to continue to increase in line with future operability requirements.

The heterogeneity of products in the BM (system and energy balancing) raises questions regarding the efficiency of pricing (pay-as-bid), the practicality of system operator actions in operational terms, and if creating more homogenous products promotes greater competition or introduces complexity for participants.

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Balancing Mechanism - Drivers for Reforms

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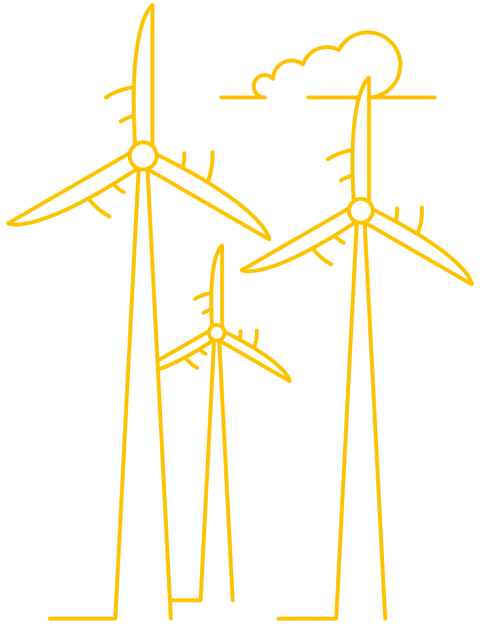

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The BM is currently high carbon intensity; our IT systems and control room processes present barriers to entry for emerging low carbon flexible assets

BM costs continue to increase, there is a question if underlying drivers of scarcity pricing across BM and wider markets are efficient

Over the last two years we have observed increased volatility of BM prices and high balancing costs, particularly during times of tight margins. We have moved procurement of some ancillary services, such as frequency response, to day-ahead to reduce high prices in the BMs; however, we need to explore the trade-offs (e.g. liquidity) associated with this general approach and whether it is the right one for consumers in the long run.

An additional consideration is how scarcity pricing in the BM interacts with the Capacity Market, which should also reduce the incidence of high-cost days by ensuring there is sufficient plant available to dispatch. We believe the lack of coherency between markets is ultimately leading to inefficiently high price outcomes both in energy (wholesale market and BM) and capacity markets.

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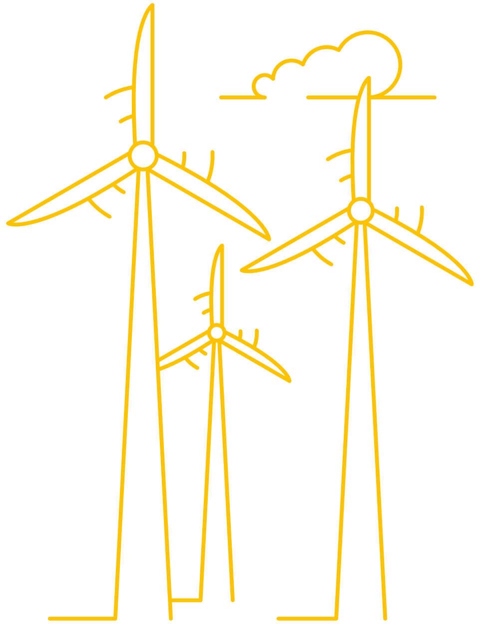
Balancing Mechanism - Drivers for Reforms

As GB's electricity system integrates higher volumes of intermittent capacity, we are seeing increasingly high costs for managing energy and system constraints. Listed here are key issues highlighting opportunities to improve market efficiency and driving the need for market reform.



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The BM is currently high carbon intensity; our IT systems and control room processes present barriers to entry for emerging low carbon flexible assets

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BM Figure 3: BM Bids and Offers by Technology Type illustrates that we are particularly reliance on gas for redispatch in the BM. Last year's Markets Roadmap illustrated that the total volume of BM energy balancing actions is expected to increase significantly, and unless we replace unabated gas with lower carbon alternatives the net carbon intensity (i.e. difference between bid and offer volumes) of these actions will likely remain the same or increase.

Transformed control centre systems are a vital enabler for net zero. Our current systems and control room processes need to develop and keep pace with emerging technologies. Increasingly we are seeing interest from suppliers and aggregators to enter the BM with small-scale assets within aggregated portfolios. Current systems are not flexible enough to deal with many smaller units, and the manual nature of some ESO control room processes limits high volumes of instructions to many assets.

Stakeholders have also requested greater transparency of our dispatch decisions. A key consideration for dispatch efficiency and transparency is the manner in which data is collected and reported. Improved reporting standards can offer greater potential for the market to optimise operations through improved operational visibility of distributed energy resource activity in real time.

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Balancing Mechanism - Market Reforms

Several short and long-term issues underpin our decision to conduct a more broad-based assessment of the BM market design. We are undertaking this work as part of a wider assessment of dispatch mechanism design to feed into DESNZ' REMA process. How any reforms to the BM interact with our ongoing transformation to control room processes is key to the future success of the market and will be a major consideration in our market design work.

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Balancing Mechanism - Market Reforms

Short-term reforms we have recently introduced to manage rising balancing costs

Reducing BM costs and actions we take for energy and system management

ESO has a program called 'balancing costs portfolio' which is proactively mitigating increasing balancing costs while awaiting network transmission investments planned for 2030. We are delivering short term initiatives to reduce balancing costs from very high levels arising in the last two years by reducing the volume of actions we take in the BM.

The launch of the Frequency Risk and Control Report (FRCR) significantly reduced our volume of actions on Frequency Management, (e.g. from 28.3TWh in 19/20 to 17.9TWh in 21/22). FRCR with our accelerated loss of mains programme has resulted in a decrease of the actions we take in the BM to manage Stability (100% decrease in BM Stability volumes from 2021 to 2022), reducing balancing costs by c£435m over BP1. For more information, please refer to the Stability chapter.

We have accelerated changes to reduce costs for winter 22/23 introducing a new balancing reserve product which is **subject to Ofgem approval**, will go-live in March 2023 is forecast to reduce balancing costs by c£121m over winter 2023/24, and c£873m between 2023-2025. This new product is intended to remove actions in the BM to manage reserves. For more information please refer to the Reserve chapter.

Initiatives to promote greater competition and participation in BM via IT systems and control room processes

The Open Balancing Programme (OBP) is developing the future balancing capabilities that our control room needs to deliver reliability and system security, replacing legacy IT systems. It will deliver greater visualisation and automated support for decision making. While we wait for the new system to be fully deployed, we will continue to make changes to existing systems to aid the control room in improving dispatch efficiency and supporting new markets. The new system will not distinguish between BMUs and non-BMUs but will treat everything as a "unit" that can participate in different markets. By 2027, our new optimisation tools will harmonise services into one solution, co-optimise the services, and then provide a single merit order while obeying transmission system constraints. By providing a "bulk dispatch" capability control engineers will be able to issue at least 50 instructions at a given time via automated solutions. OBP will greatly reduce instances of skip but still obey the physical constraints that are part of the transmission system.

Our BM Wider Access programme aims to simplify access to the BM for all technologies and providers, particularly for non-traditional providers and aggregators. It introduced the concept of a Virtual Lead Party (VLP) that will be able to register BMUs as small as 1MW. We are also improving routes to market for customers with smart technologies such as Electric Vehicles (EVs) and Heat Pumps. Our recent market trial with the Powerloop consortium provided insight into how Vehicle to Grid enabled EVs could participate in the BM. The trial alongside feedback from industry showed operational metering requirements is a significant blocker for small-scale assets participating in the market. To address this a working group has been set up through the stakeholder led Power Responsive group.

Continued market monitoring

In addition to our short-term reforms/activities, our market monitoring team is working closely with Ofgem to ensure markets deliver competitive outcomes. Following the BM Review and concerns around immoderate trading behaviour, Ofgem's minded-to position is to introduce a licence condition prohibiting generators from seeking 'excessive benefit' in the BM after submitting zero MW physical notifications.

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Balancing Mechanism - Market Reforms

We are considering both incremental and fundamental reforms to the BM as we develop our long-term market strategy

Wholesale market design and dispatch mechanism reform via REMA

Net Zero Market Reform programme was established in 2021 to assess holistic changes to the GB electricity market design, to support DESNZ in their Review of Electricity Market Arrangements (REMA). In Phase 3, we concluded that real-time, dynamic locational signals are needed to ensure efficient dispatch and investment. We are now in phase 4 of the programme, which involves evaluating investment elements and holistic market design and policy packages and will share our conclusions on the future direction of market reform in summer 2023.

Following the publication of the REMA consultation in 2022, in order to mitigate concerns highlighted in the consultation, DESNZ are considering whether incremental reforms including BM reforms could act as an interim solution either aligned with long-term reforms or as a standalone option. As part of this work, DESNZ are considering changes to settlement periods and gate closure times, cash-out changes, and administrative offer pricing rules as per Ofgem's Open Letter on Winter 21 Balancing Costs.

More fundamental market design changes such as the consideration of centralised vs self-dispatch design, and other wholesale market changes continue to be examined by REMA and these reforms will impact our dispatch processes and BM design.

Capacity market reform via REMA

Our Net Zero Market Reform programme and REMA work is also exploring how the Capacity Market could be improved, as either a standalone option or more fundamental redesign, or if it should be replaced by an alternative. Reforms need to link renumeration more directly to the probability of actual availability, the relative value of availability across different stress events, and the duration of availability. We are also aware of the need to carefully manage the exit of high carbon plant if it is still needed to support system security and operability while low carbon alternatives are developed. On 27th February 2023, we published an Assessment of Investment Policy and Market Design Packages, conducted by Baringa and commissioned by ESO, evaluating alternative options to the Capacity Market.

Developing ancillary service markets ahead of BM timescales

A key consideration is greater convergence between the BM and other ESO markets or if we should continue to develop markets to remove actions from the BM. We are investigating if developing ancillary services markets ahead of BM timescales mitigates high BM costs or increases costs and complexity for market participants as multiple small and bespoke markets potentially reduces liquidity and competition.

We have moved firm procurement of some ancillary services out of the BM in recent years and into markets with procurement timescales ahead of one hour before delivery and continue to consider developing markets ahead of BM timescales, e.g. potentially introducing day-ahead procurement of stability services. These options are being explored and developed under the Reactive & Stability Market Design programmes. An example of trade-offs we will assess include the balance between short- and long-term procurement, balancing the need to send investment signals and deliver value for money to consumers through an efficient resource mix that can meet future operability requirements. For more information, refer to the Voltage and Stability chapters.

Decarbonisation considerations

Constructing the merit order to dispatch low carbon flex ahead of fossil fuel generation is being considered as part of REMA. While this discussion is ongoing, we believe that increasing price transparency of system service value will help to accelerate investment in low carbon flexibility. This can be done by procuring more separate products (as discussed above) and via reform to ESO's dispatch processes.

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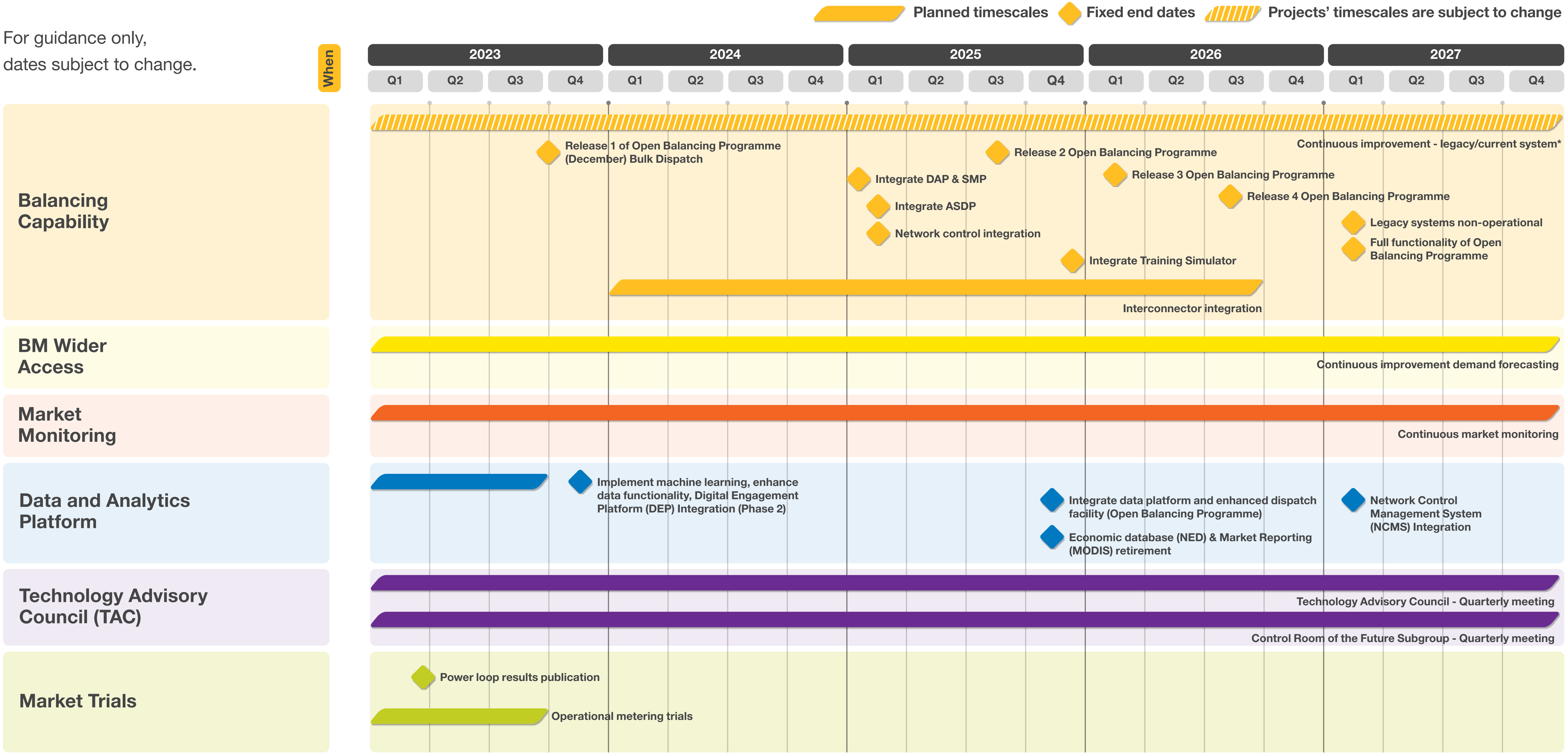
Balancing Mechanism - Delivery Plan

For guidance only,
dates subject to change.



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Balancing Mechanism - Delivery Plan

Balancing Capability

What?

Developing the future balancing capabilities that our control room needs to:

- Deliver reliability and system security
- Replace legacy IT systems
- Enable management of units on both transmission and distribution level
- Provide a single merit order while considering transmission constraints
- Facilitate a level playing field for emerging and existing technologies, BMUs and Non-BMUs in dispatch decisions

BM wider access

What?

We are enabling wider access to the Balancing Mechanism to non-traditional providers to allow the participation of a Virtual Lead Party as small as 1MW and enhancing the interface between NGESO and market participants. We will also be future proofing our Balancing Capability in our new Open Balancing Platform to accommodate sub MW dispatch, changes in dynamic parameters and implementation of state of energy signals which can be enabled subject to code changes and industry agreement.

Market Monitoring

What?

Our surveillance work covers all the services procured by the ESO, including monitoring of balancing markets as these constitute wholesale energy markets or derivative products. All products and services procured by the ESO, including acceptance through the balancing mechanism, are monitored for market manipulation or insider trading.

Data and Analytics Platform

What?

We aim to publish the data that is most valuable to stakeholders, accessible through our data portal. We will also share analysis and insight of how we make operational ecisions. Giving more clarity of operational decision-making will allow stakeholders to make better informed decisions.

Technology Advisory Council (TAC)

What?

An external stakeholder group to advise and input into the ESO's technological transformation. The Control Room of the Future looks at optimisation issues, Artificial Intelligence, digitalisation to control operational environments.

Market Trials

What?

We are collaborating with Octopus Energy on a Vehicle-to-Grid innovation project (Powerloop) to investigate the viability of Evs participating directly in the BM, and running a new trial for domestic reserve scarcity to understand the pathway for participation of domestic flexibility.

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Get in touch

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