Electricity System Operator

Markets Roadmap

March 2022

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Navigation

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Download the PDF in Acrobat Reader to view all interactivity.

Page navigation explained

Back a page

Forward a page

Return to contents

From here you can navigate to any part of the publication

Buttons

Button

Access additional information by hovering on the rectangular buttons positioned beneath many of our charts

Expand content

Click the plus symbol to expand or enlarge content

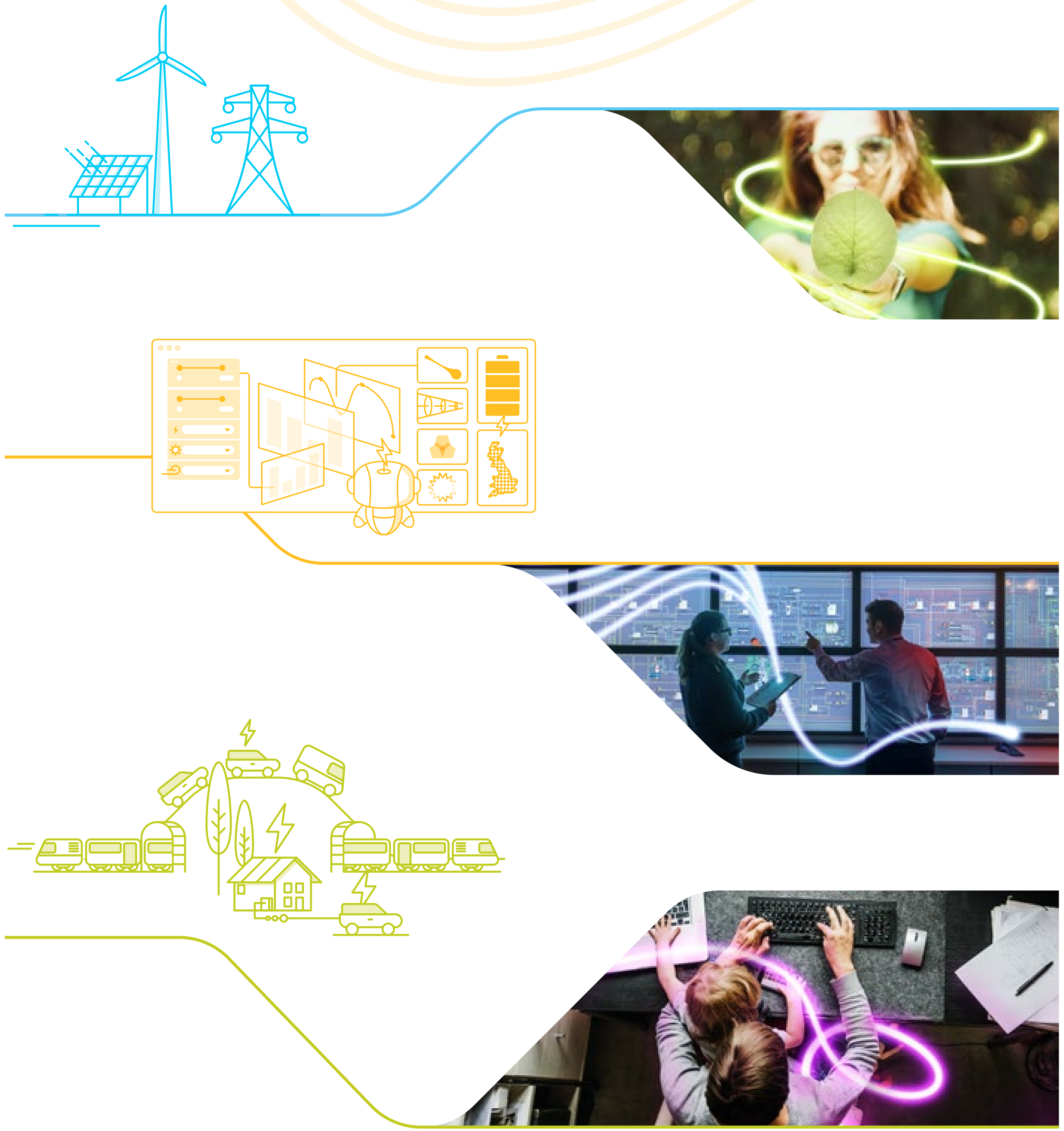
More information

Click the info symbol for more information

Text Links

Click highlighted orange text to navigate to an external link. Or to jump to another section of the document

Contents



Introduction

Foreword

I am pleased to publish the second edition of National Grid ESO's Markets Roadmap. As we set our focus to 2035, it has never been more critical for us to provide clarity and ambition in our market reform plans. Ultimately, our markets are an enabler, providing the right signals for industry to invest in and deliver a zero carbon energy system. The goal for us all is clear, and I hope that this evolving Markets Roadmap provides a transparent path for achieving that goal.

Kayte O'Neill
Head of Markets, National Grid ESO

Since we published our first Markets Roadmap in March 2021, wider energy markets have gone through a volatile 12 months. Not long after emerging from COVID lockdowns and energy demand starting to return to normal, the global gas crisis hit, leaving consumers facing record increases in their energy bills.

This last year has also seen the UK Government significantly step up its net zero ambitions, announcing that by 2035, the electricity system needs to be fully decarbonised. Not only will this require unprecedented levels of investment in zero carbon technologies, but it means operating the system in a completely different way than we do today.

ESO balancing and ancillary services markets are at the heart of this transition. But our current suite of markets need significant reform if they are to deliver the clear and efficient investment and dispatch signals needed to operate a zero carbon system. And events of the last year crystallise the fact that they must deliver value for money for consumers.

This publication aims to provide our stakeholders with the confidence that we are making the right decisions to achieve these objectives. To do this, we clearly set out what we are doing in terms of market reform and why; the progress we have made and what is yet to do; and we set out the strategic and design questions we are grappling with and how industry can get involved in helping us answer them. We have also refreshed our market design principles, which we will use in a much more transparent way going forward to assess and validate any decisions we make.

It is vital that we bring our stakeholders along on this journey. Since last March, we have stepped up our industry engagement through our quarterly Markets Forum events, market reform workshops, webinars and consultations. These have provided an opportunity for us to tap into the vast experience and insights of our stakeholders and have informed significant improvement in our market and product design and implementation. Alongside the launch of this Markets Roadmap, we have also held our first Markets Advisory Council, which going forward will embed broad industry perspectives in our market reform and strategy.

I look forward to working with you to continue making this Markets Roadmap a reality in 2022/23.

Markets Roadmap / Introduction 05

Purpose and Scope

This page is interactive.
Click the ⊕ to expand or enlarge content.

The purpose of the Markets Roadmap is to:

1 Give our stakeholders confidence that we are making the right market reform and design decisions

2 Share what strategic questions we are currently tackling and signpost how industry can work with us to answer them; and

3 Provide a clear and transparent view of what market reforms we are introducing, why we are introducing them, and when.

1 **We have reviewed and enhanced our Market Design Principles, to provide a robust framework for design and accountability**

When we consider market reform, any design options should be assessed against a robust set of market design principles. Last year we introduced our principles for the first time, and this year we have reviewed and enhanced these (see page 8).

Requirements and system needs are identified by the Operability Strategy Report

Operational Area	Frequency		Thermal	Voltage	Stability		Restoration

The Markets Roadmap outlines different markets and products to address these system needs

Market Areas	Response	Reserve	Thermal	Voltage	Stability		Restoration
	Balancing Mechanism (BM)						
Market Products	Dynamic Containment (DC)	Quick Reserve	Regional Development Programmes (RDP)	Voltage Pathfinders	Stability Pathfinders	Bids & Offers	Electricity System Restoration Events (ESRE)
	Dynamic Moderation (DM)	Slow Reserve	Local Constraint Management (LCM)	Reactive power market	Stability market		Distributed Restart
	Dynamic Regulation (DR)		Constraint Management Pathfinder				

KEY: Existing markets/ products | Markets/products in development

Markets Roadmap / Introduction 06

How the Markets Roadmap fits in with other ESO publications

The Markets Roadmap complements the information shared in our other publications and ESO business plans.

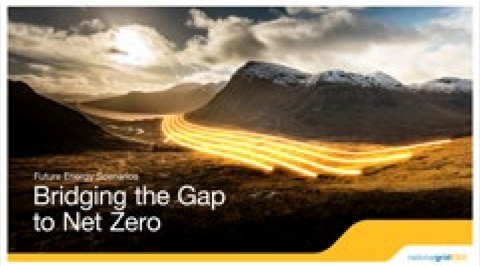
Primarily, this report should be read in conjunction with our annual Operability Strategy Report (OSR), which explains operability requirements based on the changing nature of the electricity system. The Markets Roadmap covers how we plan to reform Balancing Services Markets to be able to meet those requirements in line with our Market Design Principles and Objectives. Throughout this report we have used data and assumptions from the FES 2021 scenarios. The FES Bridging the Gap report focuses on how flexibility needed to manage peaks and troughs between now and 2035 can be delivered. The report considers different areas including markets, digitalisation, operability requirements, and consumer aspects. Our Net Zero Market Reform work examines the holistic changes to current GB electricity market design that will be required to achieve a fully decarbonised electricity system by 2035.

Operability Strategy Report (OSR)

Published annually in December

Future Energy Scenarios (FES)

Published annually in July



FES Bridging the Gap

Published annually in March

Net Zero Market Reform

Bespoke market reform project with findings published in Nov 2021 and April 2022

Markets Roadmap / Introduction 07

Our Market Design Objectives and Principles

In the 2021 Markets Roadmap, we set out key principles that underpin our design decisions for ESO markets. Since then, we have revised our principles, as part of a framework to ensure that we are designing markets in a robust, comprehensive and transparent way.

- We have defined a set of Market Design Objectives that reflect what outcomes we expect from market procurement.
- We have revised our Market Design Principles to align with our new objectives. The principles break down the objectives into testable concepts that are mutually exclusive and collectively exhaustive.

These new objectives and principles will allow us to make market design decisions that are robust, well-evidenced and justifiable. We will be transparent in how we use this framework, giving our stakeholders confidence in how and why we are making reform decisions. This framework will also enable us to assess the effectiveness of our current market designs, and identify where they can be improved.

Market Design Objectives

Ultimately, at ESO, markets are a tool to help us achieve security of supply at the lowest cost for customers, while enabling the transition to net zero. When it comes to designing those markets, we believe that if they meet three objectives (our new Market Design Objectives), they will be the most effective tools to help us deliver the trilemma.

Objectives[1]	Definition
Efficient Dispatch	Meets balancing service needs in real time using the optimal combination of supply and/or demand-side resources.
Efficient Investment	Gives investors sufficient certainty over revenues to obtain financing, ensuring future system requirements are met by the right technology mix in the right locations, at lowest cost to society.
Value for Money	Selects outcomes that are in the best interest of current and future consumers.

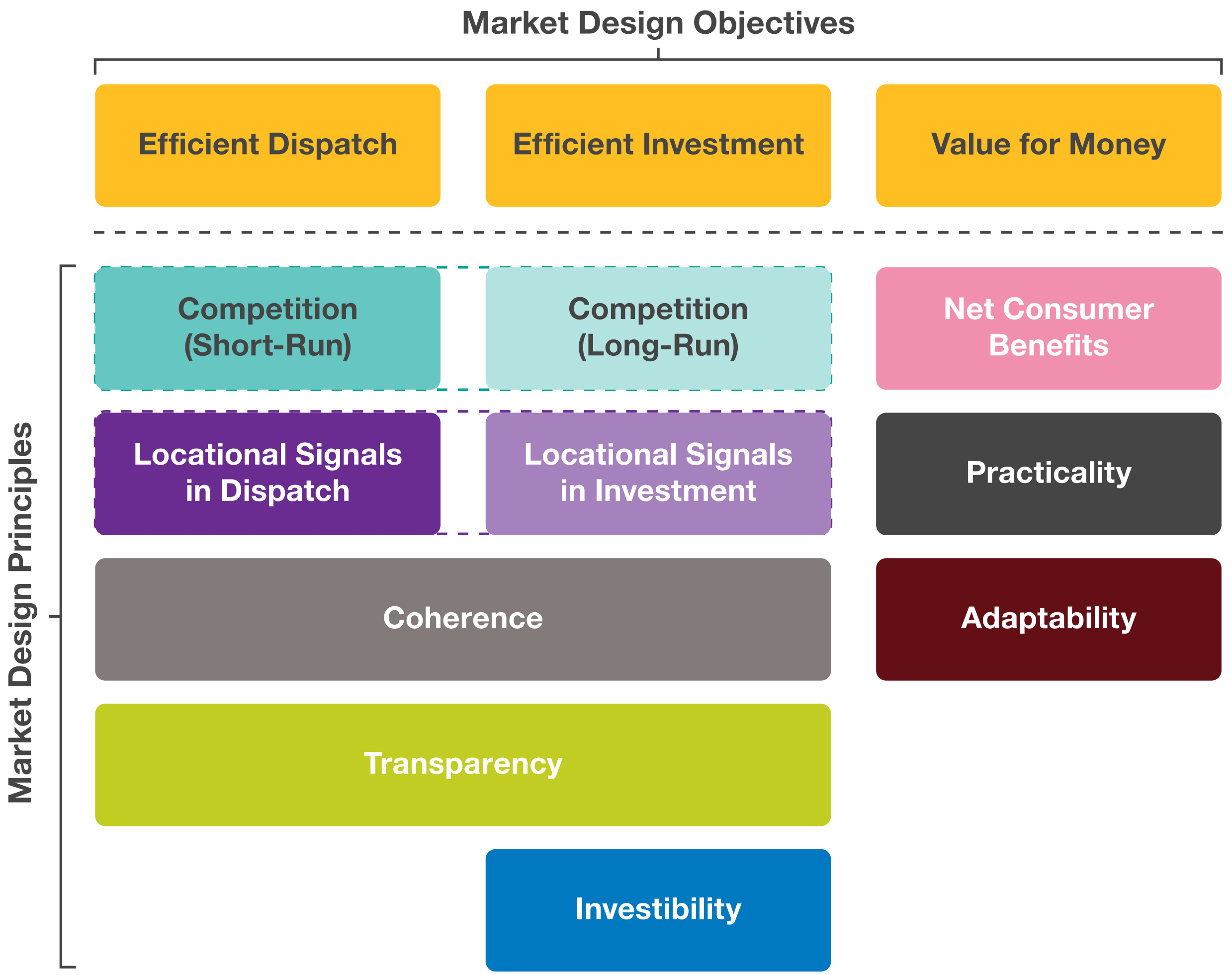
[1] Well-functioning markets deliver outputs required by society using the minimum quantity of resources. This is captured by our efficient dispatch and investment objectives. We include Value for Money to ensure our market designs account for the distributional impact on consumers and future uncertainty (e.g. in system requirements, or in changes to the wider technology, market or policy landscape).

Markets Roadmap / Introduction 08

Our Market Design Objectives and Principles

Market Design Principles

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



Click Market Design Objectives and Principles for more information.

Markets Roadmap / Introduction 09

The transformational stages of our market development process

Our market development process is one that spans several transformational stages, from the strategic end of the spectrum where we need to understand the different long-term futures within which our market needs to operate; through developing and assessing different market options to understand which one would work best; then designing that market in detail; and ultimately implementing it into business as usual. But the development does not stop there – we look to continuously improve our existing markets, learning from stakeholder and provider insights as well as adapting to emerging market trends, to keep optimising our suite of markets and products.

We know how important it is for market participants to have as much certainty of the direction of travel of our market reforms as possible. This is why we are introducing these Market Transformational Stages to this year's Markets Roadmap. Depending on which particular stage a reform activity sits will determine:

1. **The level of certainty of the final outcome.** At the Strategy stage, we are still assessing what the future could look like. Certainty will increase as we move through Development, Design and Delivery.
2. **The level of detail of the solution.** At the Development stage we will have a high-level view of the preferred solution, with limited details. As we move through Design and Delivery, more and more details of the market design will be locked down.
3. **How stakeholders can get involved.** At the Strategy stage we will look for support in understanding how the future landscape might evolve. In Development, we will work with stakeholders to understand the impact of different market designs on their business and operations. Through Design and Delivery, we want to fine tune details with stakeholders and test the products. In Post Implementation we are continuously gathering feedback from stakeholders.

We hope the introduction of these Market Transformational Stages provides further clarity and transparency to our stakeholders as to where we are with various market reforms, and how to engage with them. We welcome any feedback as to how this process can be improved.

Markets Roadmap / Introduction 10

The transformational stages of our market development process

Transformational Stages Definitions:

Market Transformation

Strategy	Some market reform questions are highly strategic in nature. We need to understand how the future energy system will evolve, how our operational requirements will change, and how wider markets and government policy could shift, in order to figure out what success looks like for our balancing services markets in this future.
Development	Once we have a high-level vision of what the future should be, we need to assess all available market reform options and understand which option will most efficiently achieve our strategic ambitions. We then need to set out a high-level plan for how we deliver this preferred option.
Design	We need to further define the recommended market option(s) by designing product and platform specifications in detail along with producing a detailed delivery plan.
Delivery	We prioritise and execute each feature of our delivery plan, embedding the new market into our BAU processes. In recent years this has often taken the form of “soft-launches” of products and outstanding market design questions have moved back to the design or development stage to enable us to achieve rapid and agile market transformation.
	BAU Processes
Post Implementation	We monitor our markets to determine how well we have met our Market Design Objectives and identify potential improvements. Depending on the nature of these improvements, they are dropped into different Transformational Stages for development, design or delivery.

Co-creation with industry

Markets Roadmap / Introduction 11

Market Areas

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Frequency Response

Our response markets must facilitate zero and low carbon options for frequency management. Our strategy is to replace our existing dynamic frequency products with close to real time procurement of our new suite of frequency products: Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR). Moving procurement closer to real time will make it easier for intermittent providers to participate effectively. In line with our market design principles, we will remove barriers to entry to our response markets. This will increase market liquidity, enabling competition to drive down prices and deliver value for the end-consumer.

System inertia has and will continue to decrease, and we are experiencing increasing variations in electricity supply and demand. These trends have created a need for faster-acting frequency response products and drive our response requirements. The Operability Strategy Report published our anticipated requirements for each of the new services by 2025 and highlighted that managing more volatile energy imbalances is the next big challenge.

Our new response markets will eventually meet most of our response requirements. We will gradually phase out procurement through the monthly FFR tender once markets for our new pre-fault products, DM and DR are well established. Information on our volume requirements can be found in our response market information report, published monthly.

Future Considerations

The UK Government's Net Zero Strategy has committed to a decarbonised power system by 2035. To enable this transition, at lowest cost to consumers, we need robust and efficient response markets. We must deliver new options for intra-day response procurement which will require more granular settlement period service delivery windows. We must also consider how our services can evolve to maximise participation from zero carbon providers, under a range of different system conditions.

What is Frequency Response?

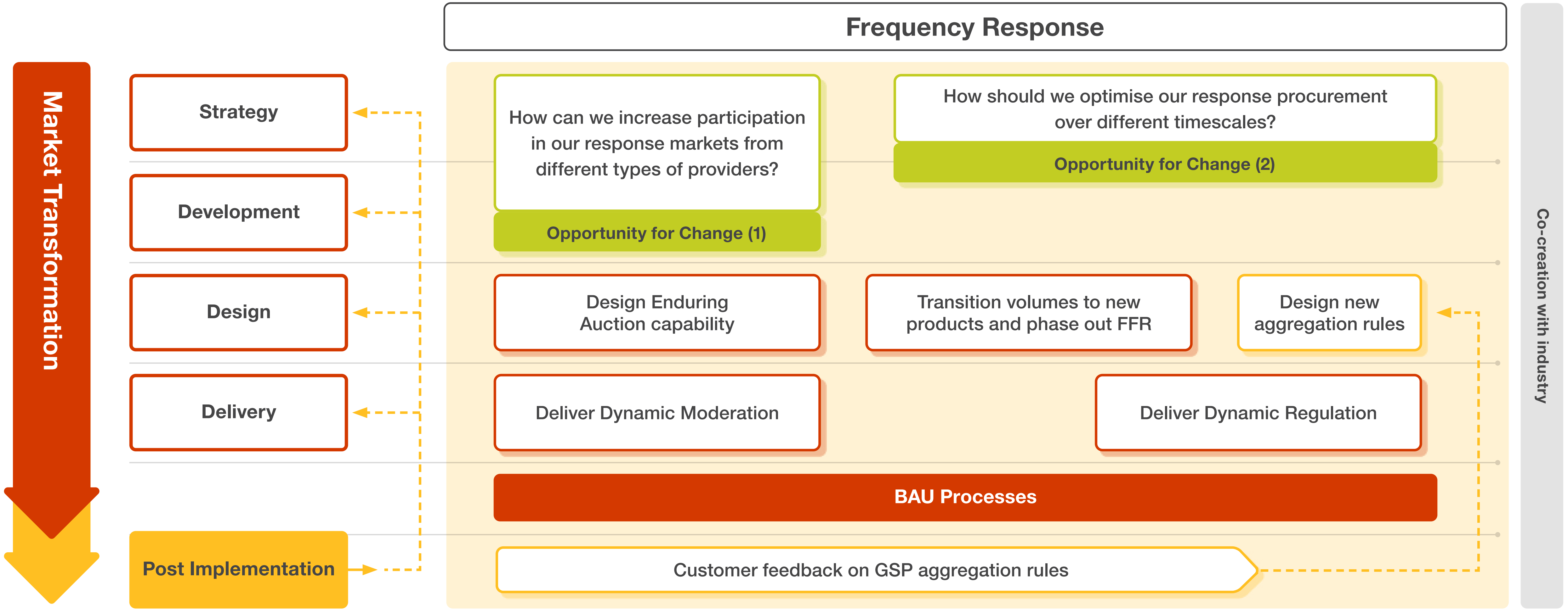
We procure frequency response services to manage system frequency within Security and Quality of Supply Standard (SQSS) limits around 50Hz. The services support us in managing frequency both on a second-by-second operational basis, and in post-fault situations where there is a sudden loss of generation or load, which creates a mismatch between demand and supply. In 2021, most of our response holdings were in the form of the Grid Code defined products 'Primary', 'Secondary' and 'High' (P/S/H).

Markets Roadmap / Market Areas / Frequency Response 13

Frequency Response

Market Transformational Stages

We work on the projects and strategic questions within this graphic simultaneously.



Markets Roadmap / Market Areas / Frequency Response 14

Frequency Response

Market Information: **How we procure frequency response services**

	Firm Frequency Response (FFR) – monthly tender	Dynamic Low High (DLH) – weekly auction trial	Mandatory Frequency Response (MFR) in real time	Dynamic Containment (DC)
Product description	We use Primary, Secondary and High (P/S/H)[1] for both pre and post fault frequency management. Our pre-fault requirement is typically 550MW. Our post-fault requirement varies depending on the largest loss, demand and system inertia.			Designed to arrest the change in frequency following a sudden imbalance, DC is a post-fault product. The aim is to contain frequency within +/-0.5Hz. DC is 'unbundled' with two separate products: Dynamic Containment Low (DCL, launched Oct 2020) and Dynamic Containment High (DCH, launched Nov 2021).
	Providers bidding in for a dynamic P/S/H contract through the monthly FFR tenders can submit different levels of low and high response.	DLH was a symmetrical P/S/H product where providers offered equal volumes of Primary, Secondary and High frequency response for one or more of the Electricity Forward Agreement (EFA) blocks in a given week. The trial ended in November 2021.	Capabilities of P/S/H for MFR are tested before the BMU is energised and are contained within the response capability tables in the provider's Mandatory Ancillary Services Agreement (MSA).	
Timing of procurement	Procured via the FFR monthly tenders. Results from the FFR tender rounds are published in the middle of the month for delivery in the month following.	Procured via the FFR Weekly Auction Trial. Providers could bid in for any of the six EFA blocks over a given EFA day and link bids together to ensure they would receive contracts for all proposed EFA periods or none of them.	Procured via the Balancing Mechanism. Our control engineers look at the merit order of submitted MFR prices and system requirements instructing providers to deliver in real-time.	Procured through a day ahead auction. Providers can submit their bids for each EFA block up to two weeks ahead.
Price determination	FFR procured via the monthly tender is paid on a pay-as-bid basis. Providers are paid for their availability during agreed delivery windows.	The Weekly Auction Trial used a new auction algorithm to explore the benefits of a pay-as-clear market. Successful contract holders received a £/kW clearing price which was set for each individual EFA block in the upcoming week.	MFR is paid via a payment methodology contained within the CUSC. All providers with an MSA can update their submitted prices monthly.	DC prices are determined by a pay-as-clear auction. We cap DC prices at the cost of alternative actions. Providers are paid for their availability during EFA block delivery windows.

1 Primary and Secondary are low frequency services, providers must increase generation or reduce demand when system frequency falls. Primary response must respond fully within 10 seconds and lasts for a subsequent 20 seconds. After this point Secondary response takes over and continues to support the frequency until 30 minutes post event. Units providing the High frequency product will decrease their output or increase demand within 10 seconds to return frequency to the operational range.

Markets Roadmap / Market Areas / Frequency Response 15

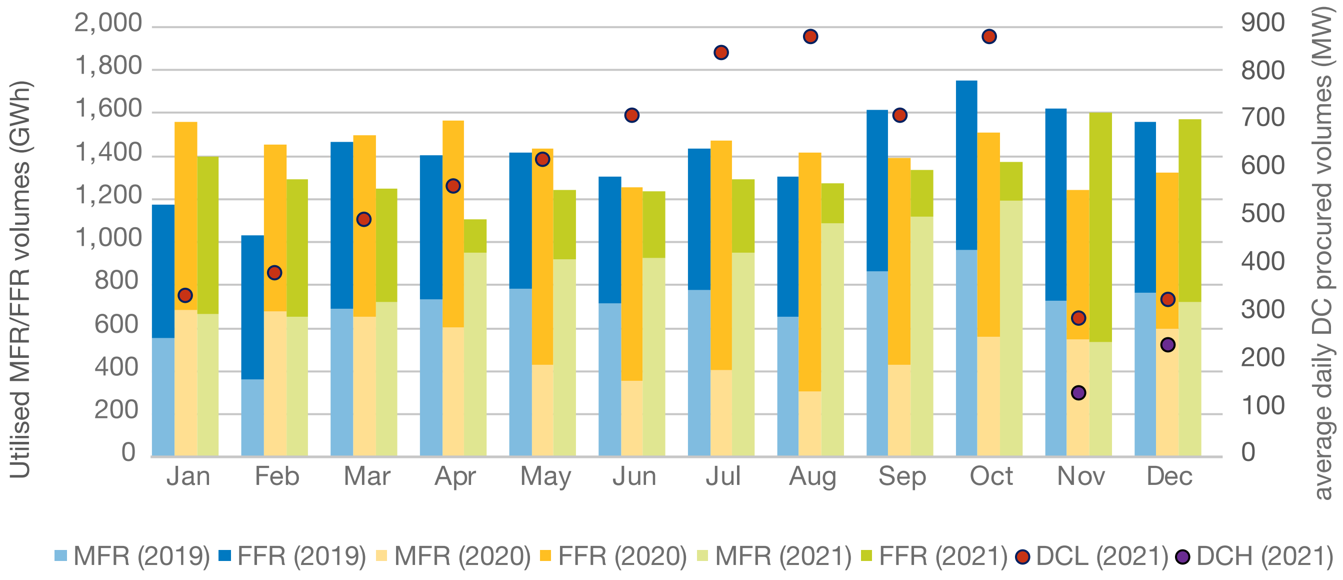
Frequency Response

Market Information: **Frequency response volumes**

This chart shows frequency response volumes of MFR and FFR utilised over the past three years (2019 – 2021) as well as the daily average contracted volume of DC (both DCL and DCH) for each of the months in 2021.

The introduction of DC in October 2020 began to reduce the volumes available to us in the monthly FFR market as providers who could meet the technical requirements moved to day-ahead DC where prices were higher. This can be seen in the chart as more of our P/S/H requirement has been met by MFR than FFR from March to October 2021 compared to the previous years. Following the introduction of EFA block procurement for DC however, this picture has changed as providers seek out greater certainty but often lower prices in the monthly FFR tenders. This is a complex issue and more detailed information on our strategy for winter 2021 response procurement can be found in this DC webinar.

Response volumes: Jan 2019 - Dec 2021



Note: The FFR category includes dynamic volumes procured through the monthly FFR tenders. The chart does not include volumes of the legacy products spin gen LF or Enhanced Frequency Response (EFR).

We are now using DC to offset some of our post-fault requirement for P/S/H. Following the introduction of our new pre-fault dynamic frequency products, DM and DR, the absolute volumes of pre-fault P/S/H we procure through MFR or the FFR monthly tender will start to fall. Our day-ahead response markets are affected by the commercial opportunities available in other markets. This can be seen clearly in the dip in average daily DC volume in September 2021 as providers withdrew their assets from the DC market to chase lucrative opportunities elsewhere. This may continue to be a procurement challenge for our day-ahead markets going forward but is more likely to bite over winter when our requirement for DC is lower. We will continue to monitor our new response markets and activity in potential “opportunity cost markets” like the BM or wholesale markets closely to inform our pricing and procurement strategies.

Markets Roadmap / Market Areas / Frequency Response 16

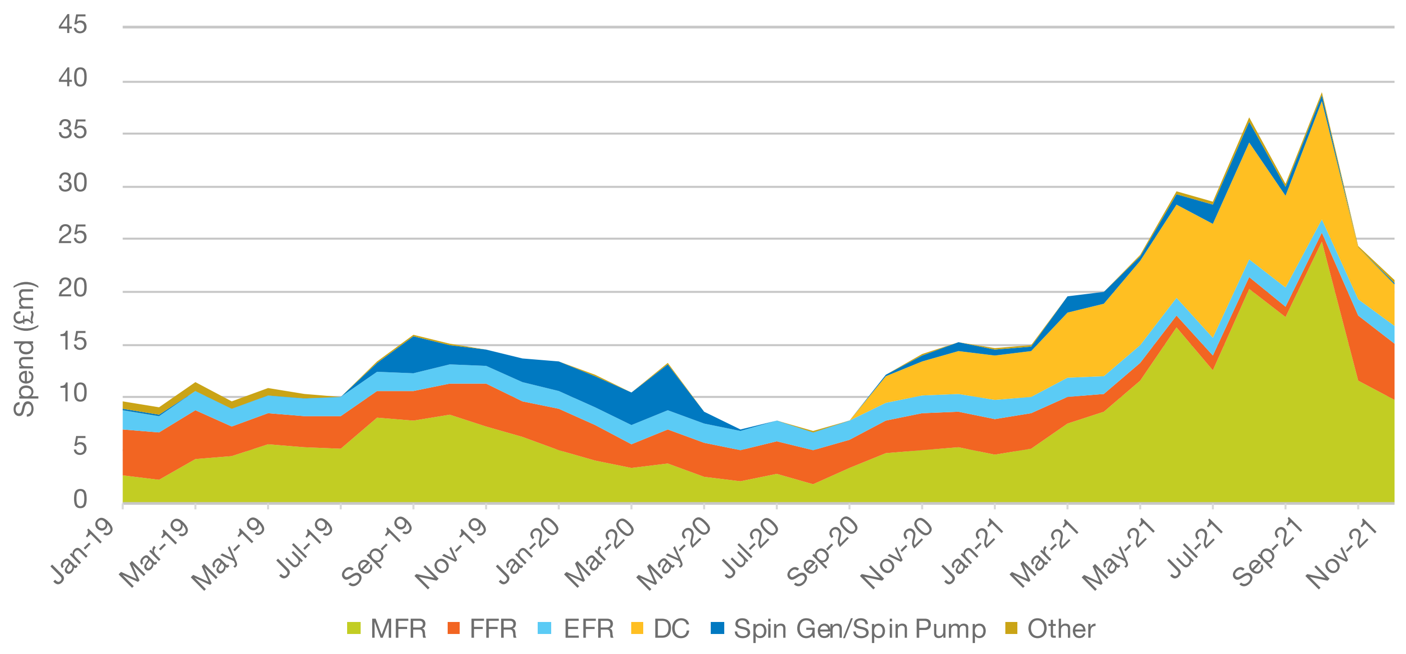
Frequency Response

Market Information: **Frequency response costs**

This chart shows total spend on frequency response services between January 2019 and December 2021 (inclusive).

In November 2021 we adjusted our cap on the DC clearing price and, following the implementation of Phase 2 of the Frequency Risk and Control Report and a move to EFA block delivery windows, revised our requirements. This has led to substantially lower £/MW/hour clearing prices in EFA blocks 3 (07:00 – 11:00) and 4 (11:00 – 15:00) as our revised requirements have introduced real price competition in DCL provision over these periods. In EFA blocks 5 and 6 however prices have been higher with an average of over £23/MW/hour in EFA 6 over November and December. Overall, this new approach has led to far lower total spend on DC in November and December than previous months.

Response costs: Jan 2019 - Dec 2021



Note: The Other category includes commercial BM response and Non-BM demand side response. Spend on the weekly auction trial and FFR bridging is included in the FFR category. Spend on RoCoF/inertia and reducing largest loss is included in the Stability chapter. Where applicable, Response Energy Payments are included.

Looking forward to 2022, we will continue to encourage new providers into the DCL and DCH markets to help us meet our summer DC requirements at low cost. Strong procurement of DC volumes will enable us to take fewer actions to reduce the Rate of Change of Frequency (RoCoF). This means that spend on increasing inertia or reducing the largest system loss would be expected to decrease. More information on these actions can be seen in the Stability chapter. As we launch further new products (DM and DR) and begin to transition some volume away from monthly FFR tenders, a big challenge will be correctly sending market signals across a monthly tendered market and a day-ahead market.
We look forward to hearing industry views on how best to efficiently manage this transition.

Markets Roadmap / Market Areas / Frequency Response 17

Frequency Response

This page is interactive.
Click the ⊕ to expand or enlarge content.

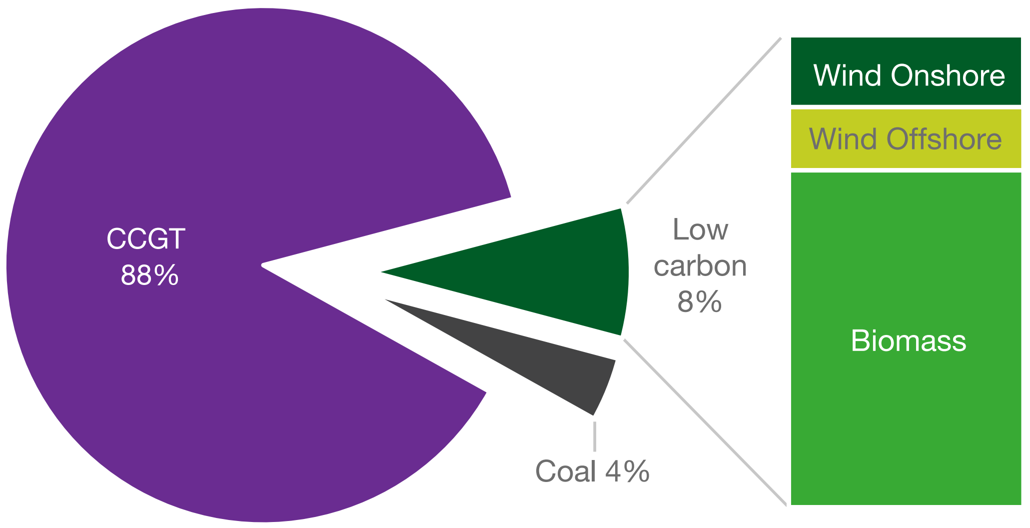
Market Information: **Frequency response providers**

These pie charts show the technology types who provided services in three of our response markets in 2021. Our newest market, DC, is dominated by battery storage providers who can provide the fast-acting response we need.

The majority of our MFR holding comes from CCGTs. Our control room engineers are aiming to access the necessary P/S/H response at lowest cost. The costs are calculated by including unit repositioning as well as the MFR prices they have submitted to the ESO. Typically, zero carbon providers like wind are in receipt of a Contract for Difference (CfD) or Renewables Obligation (RO) subsidy which means that to recover lost revenue from generation they set high bid prices. It is often not economical to instruct them for Primary or Secondary response compared to gas or coal generators.

The monthly FFR tender has a mixture of BM, non-BM and aggregated providers and has proved a reliable way to access P/S/H from smaller and low carbon providers. Our new pre-fault response markets, DM and DR, will also serve as strong routes to market for non-BM providers as well as BM providers.

MFR utilisation by technology type (P/S/H)



MFR utilisation | Dynamic Containment | FFR monthly tender

The carbon intensity of balancing services will become an increasingly important topic on the journey towards a decarbonised electricity system. We set ourselves a target to lead this transition in 2019 with our ambition to develop the markets, tools and strategies to be able to operate a zero carbon system by 2025, a full decade ahead of the UK governments target. We expect that as the generation mix decarbonises the options available to us via the BM for MFR will become naturally lower carbon too. To speed up this transition we need to ensure that we are opening up opportunities in our response markets outside the BM to access sufficient volumes, this is our first “Opportunity for Change” later in this chapter. Whilst we will be working to open up the DC market to other providers, battery storage will remain a key provider group offering us access to fast-acting zero carbon flexibility.

Markets Roadmap / Market Areas / Frequency Response 18

Frequency Response

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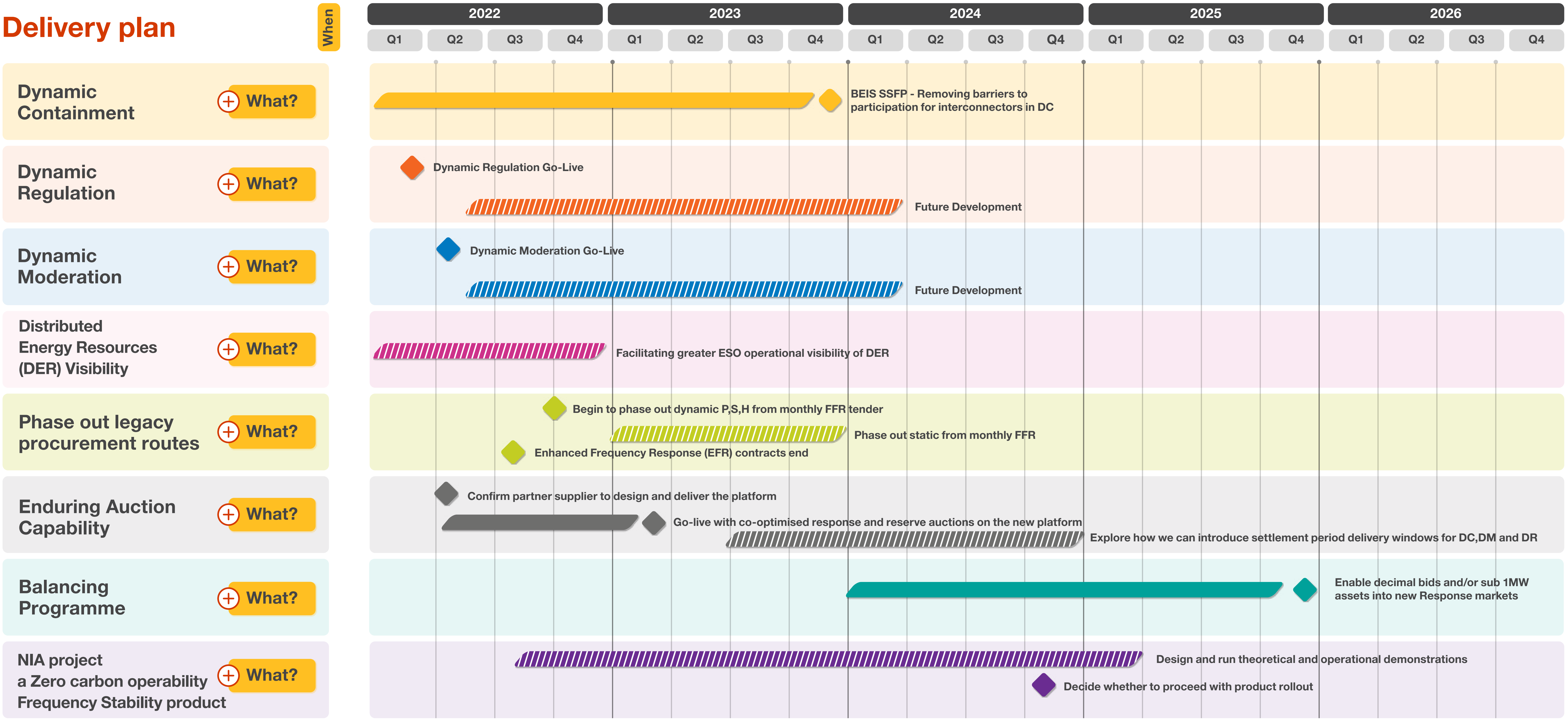
Planned timescales | Fixed end dates | Projects' timescales are subject to change

Delivery plan



Markets Roadmap / Market Areas / Frequency Response 19

Frequency Response

Opportunity for Change (1) – **Making our response markets more accessible**

Improving access to response markets for a broader range of providers could increase market liquidity and place downwards pressure on prices, delivering value for the end consumer.

Our markets need to be designed as simply as possible, without unduly restricting new and existing providers from competing. We want to encourage a greater range of providers to participate in our response markets including existing monthly FFR providers (many of which are smaller DSR units), wind generators and interconnectors alongside the strong and growing participation we already see from battery storage units.

As we saw in autumn 2021, high BM and wholesale market prices have encouraged battery storage providers to switch their assets from DC to other markets. Alongside this, DC providers have been entering the monthly FFR tenders seeking firm contracts when they perceived a high risk of not securing sufficient agreements in day-ahead DC auctions.

When there are few providers participating in a market, we risk not being able to fulfil our procurement target. A market with few providers is also likely to clear at a higher price, as providers recognise that there is minimal competition and have little incentive to bid in at their marginal cost. They may start to exercise market power and increase clearing prices.

However, we have seen strong growth in participation since we launched the DC market and by December 2021 were fulfilling 97% of our requirement. We hope to build on this progress in 2022 as we make our markets more accessible.

We will continue to explore ways in which we can enhance the accessibility of our new response markets and encourage participation from a range of providers as we roll out DM and DR.

Frequency Response

Opportunity for Change (1) – **Making our response markets more accessible**

Key strategic questions

- **Do the benefits of reducing the minimum unit size or enabling decimal bids outweigh the costs of implementation?**

The DC market currently restricts unit size to between 1 and 100MW. Providers must submit their bids in whole MW integers as our existing control room IT systems are unable to accommodate decimal place entry. We received feedback from smaller providers that this minimum unit size may exclude them from participating if they cannot access the market via aggregation. They also fed back that the requirement to submit integer bids is a barrier. We formed BSC issues group 94 in April 2021 to better understand these barriers to entry. This has offered smaller providers the opportunity to engage with us further on these issues, as well as raise any other barriers to entry they may face. As we continue to reform our balancing services markets, we will make significant changes to our IT systems and processes which will deliver improvements to the services we offer and make us ready to meet future system challenges. These IT changes include updates to our systems for access to the Balancing Mechanism, particularly for smaller units. We anticipate that this transformation programme will be delivered by 2025 with >1MW and decimal bid submissions expected to be included in the design of the new tools.

- **Would settlement period delivery windows enable more participation in response markets?**

Our plans are to introduce even more granular procurement, procuring DCL and DCH for settlement period delivery windows. We expect this to support participation from renewable providers who could struggle to offer reliable volumes across a 4-hour EFA block delivery window. This will happen following our launch of the enduring auction capability once we are comfortable that the new auction processes are meeting our needs and delivering value for consumers. Moving to settlement period delivery windows will be an essential step on the road to intra-day procurement of response products.

- **How can we maximise participation from aggregated DER in our new response markets?**

Through direct engagement with providers following the launch of DC and via industry forums, providers highlighted aspects of the DC service design that created barriers to entry, one of which was our limits on aggregation. Aggregators need to bring together many small assets or “subsites” to reach our minimum unit size but receiving operational visibility of the subsites into the ESO control room can be difficult. We have been working closely with industry to review the risks related to aggregating at GSP group for DC and have determined aggregation at GSP group will deliver optimal consumer value by enabling increased participation in our DC markets. We will also be permitting aggregation at GSP group for our new response products DR and DM. We are in the process of improving our control room systems and IT architecture to accommodate the changing electricity system and this work will continue throughout our RIIO-2 price control. To enable us to quickly remove this barrier to entry to the DC market we will collaborate with market participants throughout 2022 to find better ways of providing the data that our control room engineers need to manage network constraints, whilst enabling the full delivery of response services.

Markets Roadmap / Market Areas / Frequency Response 21

Frequency Response

- **Does unbundled or bundled procurement of response services lead to greater participation?**

We have worked to unbundle procurement for both DM and DR (live in spring 2022) and have offered unbundled procurement of DC since we launched the high frequency DC service in November 2021. We believe that this will lead to greater participation in our markets. This is because providers can choose whether they want to offer the high or low frequency version of the service without having to provide the service in the opposite direction. We expect that high response products will be more attractive for generators like wind or solar who are in receipt of energy linked subsidies. They are more likely to be able to access competitively priced footroom rather than the headroom needed to provide a low frequency service. However, providers can link their bids for the same delivery window to ensure that they are selected for both the low and high direction or neither if they wish to. This provides flexibility for different types of asset. The share of participating linked bids volume in DC increased from 2-4% in November 2021 (the first month it was offered) to 10% -14% in December 2021, indicating that providers are getting more familiar with this bidding option.

- **What are the barriers to participation from interconnectors in our response markets? How could we mitigate these barriers? What impact might that have on response markets?**

Since the launch of Dynamic Containment, we have been engaging with interconnector owners and operators to identify blockers to participation. We published a report in December 2021 which contains comprehensive details of five identified barriers to entry for interconnectors to participate in DC. We will look to trial ways of mitigating them in 2022. Before we enable interconnector participation in our new response markets, we will perform a cost-benefit analysis to model the possible impacts to make sure that the introduction of interconnector volumes does not destabilise the markets or create unsustainable market outcomes.

Markets Roadmap / Market Areas / Frequency Response 22

Frequency Response

Efficient dispatch
Efficient Investment
Value for Money

Opportunity for Change (2) – **Optimising procurement over different timescales**

Our strategy for monthly or intra-day response procurement of P/S/H should complement our planned day-ahead procurement of DC, DM and DR and deliver efficient outcomes.

When setting our procurement strategy for frequency response we consider both our pre-fault and post-fault requirements. DC is designed for use in post-fault situations and enables us to secure larger system losses than if we only used P/S/H. We can use DC to offset our post-fault requirement for P/S/H. DM and DR are designed for use to regulate pre-fault changes in frequency and make the system better prepared to recover frequency if a fault were to occur.

We intend to replace procurement of pre-fault monthly tendered FFR-P/S/H with a combination of DM and DR. DM and DR are more effective at meeting our system needs than the pre-fault P/S/H they are replacing, and therefore we will need lower volumes of DM and DR compared to our existing requirement for pre-fault P/S/H.

Implementing new services requires a period of transition as we review how the new products perform on the system and interact with the control room's toolkit, as well as reviewing providers' ability to deliver the services. During this transition the procurement of the legacy services will be slowly reduced as the volumes of the new services increase.

Our aim is to offset the P/S/H we currently buy with DC, DM and DR. We will continue to require access to intra-day procurement of response which will make up any shortfall from the DC/DM/DR markets and allow us to adapt to any new information that may increase our response requirement. Our current route for intra-day procurement of response services is via the BM with the majority of this through the MFR service.

Ultimately, we want to introduce intra-day procurement of DC, DM and DR to enable us to reduce our requirement for mandatory response services procured through the BM improving the transparency and coherency of our response procurement.

We will share clear and transparent information about our response requirements and procurement strategy through our monthly Market Information Reports.

Markets Roadmap / Market Areas / Frequency Response 23

Frequency Response

Opportunity for Change (2) – **Optimising procurement over different timescales**

Key strategic questions

- **What is the best way to deliver transparency and clarity of our DC, DM and DR requirements to industry participants?**

We are enhancing our Market Information Reports to share a rolling 12-month view of our expected procurement volumes in each of the new markets. We have also shared a view of what our longer-term maximum requirement could be in each market through the annual Operability Strategy Report. However, we need to make sure that providing information on our yearly expectations doesn't restrict us from making full use of the advantages of day-ahead procurement. Close to real time procurement allows us to tailor our buy orders as more information about system conditions like wind forecasts and generator or equipment outages becomes available. This approach will deliver the most cost-effective outcomes for consumers.

We recognise that there is a potential conflict in providing high level expectations of our requirements at the year ahead stage but then adjusting them to fit evolving system conditions much closer to real time. To try and balance these competing needs we're also planning to develop a rolling 4-day forecast for DC to show our requirements close to real time.

Markets Roadmap / Market Areas / Frequency Response 24

Reserve

Our reserve products need to adapt to be fit for the future electricity system and to complement our new response product suite. We are currently designing new standardised reserve products: Quick Reserve (QR) and Slow Reserve (SR). By 2025, we will have grown our new reserve markets, removing barriers to entry to ensure a wide range of technology types can and do participate in the markets. We will work with DSOs and industry through Open Networks to understand how our new reserve services can be stacked with DSO services, supporting participation in multiple markets for DER where possible.

The Operability Strategy Report published our anticipated requirements for each of the new reserve services in 2025. The report also explains the European Code obligations that we as the System Operator of the GB synchronous area must abide by, and how they have influenced the design of our new reserve products.

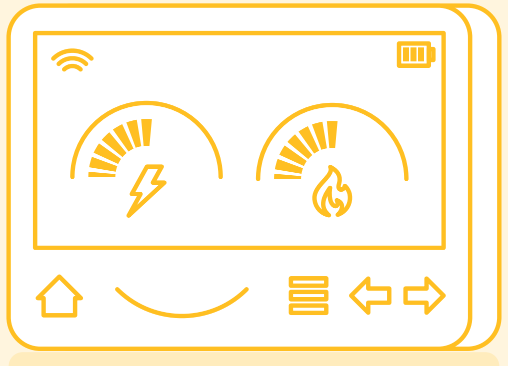
Eventually our new reserve products will replace the existing Short Term Operating Reserve (STOR) product entirely and reduce our requirement for operating reserve accessed through the BM.

Future Considerations

We anticipate a growing need to reduce generation or increase load when supply outstrips demand as new interconnectors introduce large potential swings in supply/demand and growth in renewable capacity brings sustained periods of high renewables that may coincide with periods of low demand. Our new negative reserve products will deliver more options for us to manage these conditions which will support the transition to a predominantly renewable, highly interconnected electricity system of the future. To enable this transition, we need to make sure that our markets for new reserve products are robust and mature. To manage more unpredictable system conditions in the future we will consider our options for procurement of our new faster reserve products within the day of delivery.

What is Reserve?

Reserve is the capability to deliver upward or downward energy within a specified timescale. It is used to ensure that sufficient flexibility is available for secure system operation. If required, energy delivery is manually instructed within gate closure timescales either to manage energy imbalances or to complement automatic frequency response services. Today, we use a mix of balancing services products like Short Term Operating Reserve (STOR), the Balancing Mechanism (BM) and trading to access reserve.

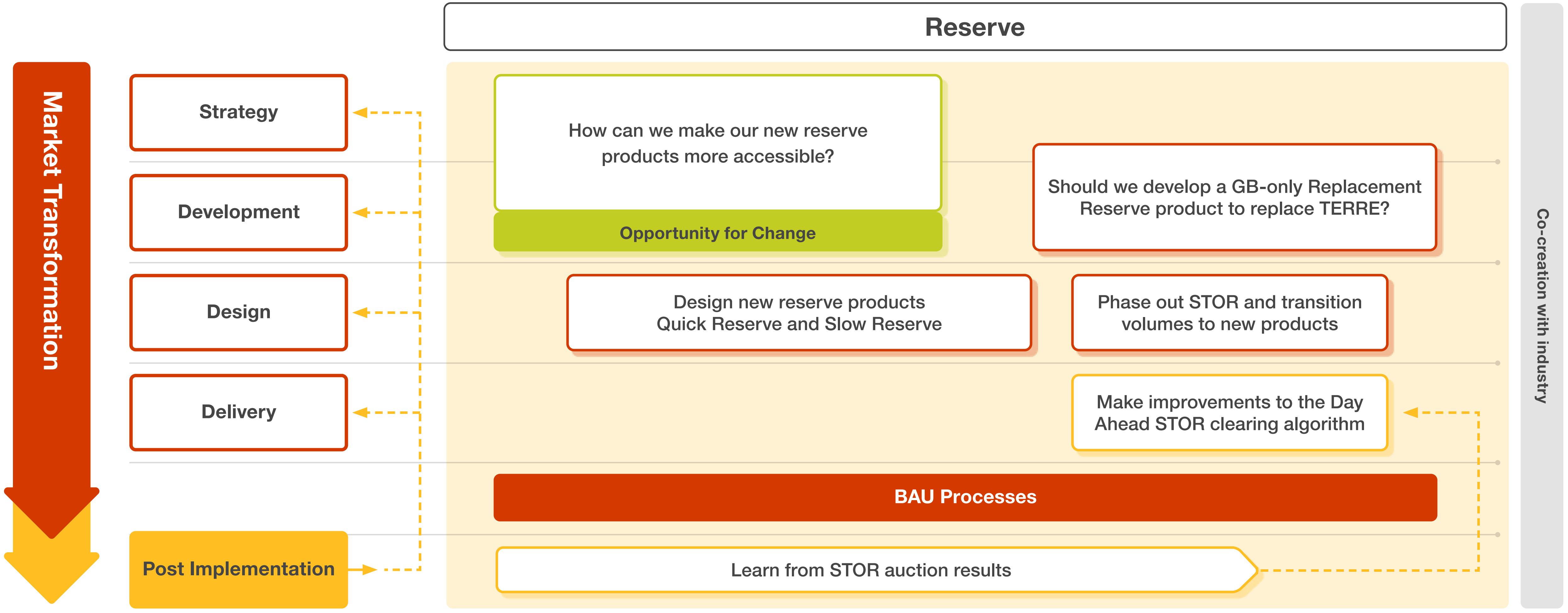


Markets Roadmap / Market Areas / Reserve 25

Reserve

Market Transformational Stages

We work on the projects and strategic questions within this graphic simultaneously.



Markets Roadmap / Market Areas / Reserve 26

Reserve

Market Information: **How we procure reserve services**

	Operating Reserve (BM bids/offers)	Short Term Operating Reserve (STOR)	Optional Fast Reserve	Optional Downward Flexibility Management (ODFM)	Legacy/Bespoke arrangements
Product description	Accepting bids and offers in the BM allows our control room engineers to reposition BMUs after gate closure. This provides access to injections or reductions in MW when needed.	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.	BM Fast Reserve reaches full delivery within 2 minutes of instruction, NBM Fast Reserve requires delivery to start within 2 minutes of instruction.	ODFM required a reduction in generation to meet the need for additional downwards flexibility during periods of very low demand & high renewable output.	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.
Timing of procurement	Bids and offers to reduce or increase energy onto the system are made in real time through the BM.	We procure STOR day-ahead of delivery.	Optional fast reserve is procured at intra-day timescales.	ODFM was procured in April 2021 in advance of potential delivery over the summer and ended in October 2021.	Services are procured in real time via the BM to contracted units.
Price determination	Bids and offers accepted through the BM are paid as bid (£/MWh). Suitable units are selected in merit order.	STOR is procured in a pay-as-clear auction. The auction sets a daily clearing price (£/MW/hour) which is paid to successful providers. A separate utilisation price can be selected up to 90 minutes before the start of the delivery window and is paid if the unit is instructed.	Providers are paid an arming fee to place assets into rapid delivery mode for both pre and post fault activation.	ODFM was paid on a utilisation only basis following a sign-up window. Signed up providers submitted prices for energy turn down and if utilised units were taken in merit order.	These services are typically contracted bilaterally with specific providers and as such have different costs depending on the bilateral agreement.

Markets Roadmap / Market Areas / Reserve 27

Reserve

This page is interactive.
Click the ⊕ to expand or enlarge content.

Market Information: **Reserve volumes**

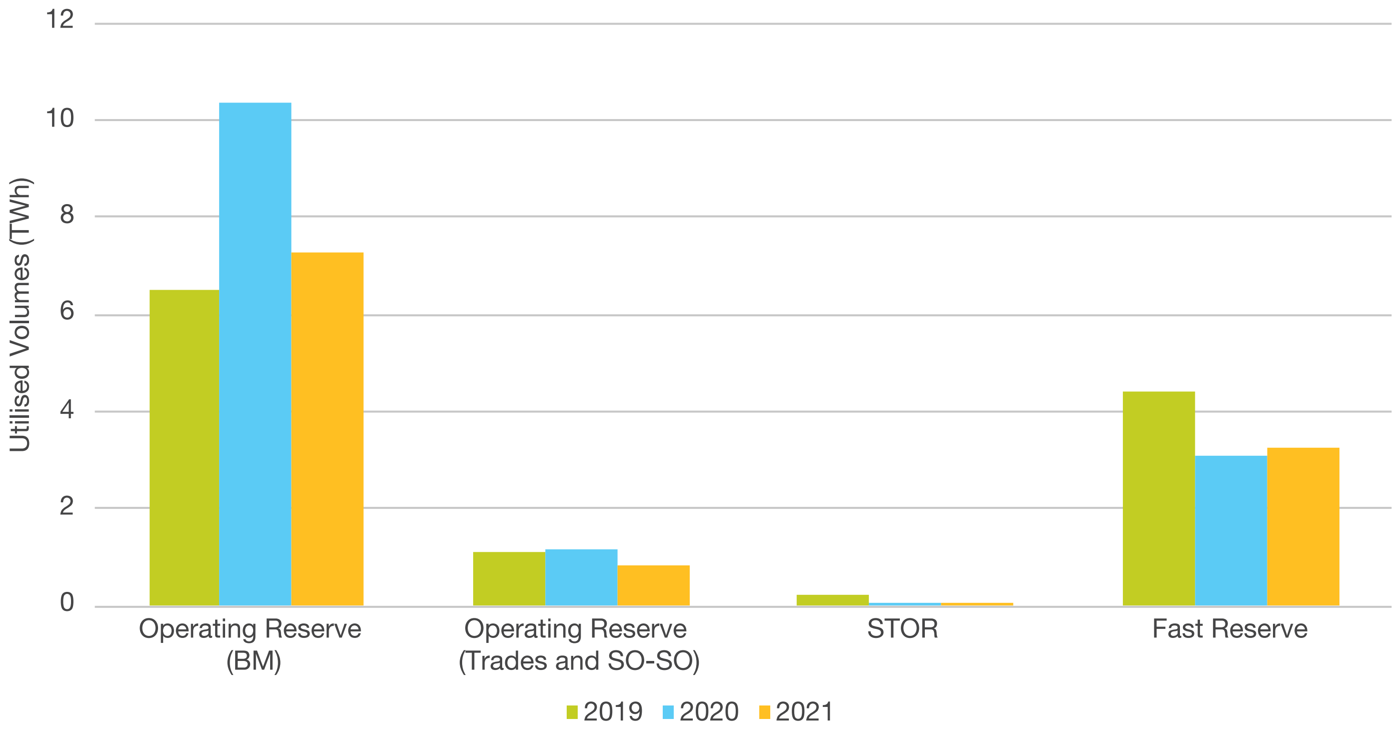
Chart 1: Reserve Volumes 2019 – 21

This chart shows total reserve utilisation volumes across 2019, 20 and 21. Fast reserve utilisation has fallen as expected with the cessation of monthly tendered procurement of the firm service from January 2020. There was a spike in reserve volumes procured through the BM in 2020. This was driven by actions required over Autumn and Winter to secure the system with multiple electricity margin notices issued to indicate that capacity was needed due to cold temperature, low wind output, and system outages.

Chart 2: DA STOR volumes Apr 21 – Dec 21

Our current procurement target is to hold 1700MW of STOR. Around 400MW comes from Long-Term STOR contracts leaving approximately 1300MW to be procured through the day-ahead market. If prices are particularly high, we will procure a lower volume. Throughout the latter part of 2021 we saw several instances where the market failed to provide sufficient STOR volumes to meet our requirement in the Day-Ahead market. To solve this issue of undersupply in the STOR market we have taken two actions: raised awareness of our buy curve, which is publicly available on the ESO website, to show industry how much we value positive reserve; and reviewed and increased our price cap in the STOR market. Early evidence suggests that these initiatives have been successful, and we will continue to monitor this and adapt our approach where necessary.

Reserve volumes: Jan 2019 - Dec 2021



Note 1: This chart only includes STOR utilisation not availability.

⊕ Reserve volumes ⊕ STOR availability

Our experience with the STOR market in 2021 highlights an overarching challenge which is the need to increase participation in our day-ahead reserve markets. We believe that increasing product standardisation and transparency will help to encourage more providers to participate; these are fundamental tenets of our ongoing reserve reform programme.

Markets Roadmap / Market Areas / Reserve 28

Reserve

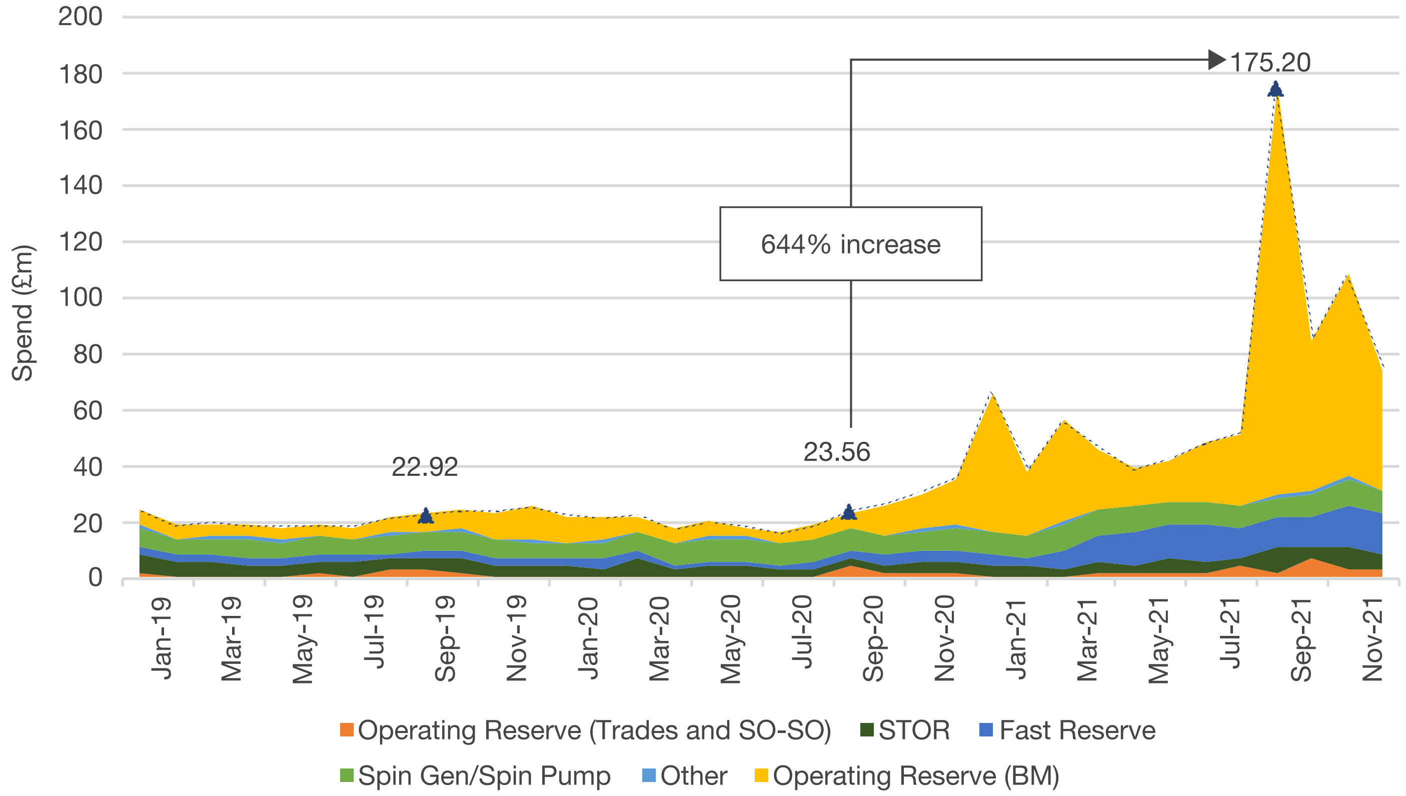
Market Information: **Reserve costs**

This chart shows monthly spend on reserve services between January 2019 and December 2021 (inclusive). The largest and most volatile component of our reserve spend over the past three years has been Operating Reserve accessed through bids and offers in the BM.

The impact of the record high BM prices in Autumn 2021 can be seen clearly. The data labels in the chart bring out total reserve spend across all products for September 2019, 20 and 21. The highest monthly spend recorded over this three-year period was in September 21, almost 6 and half times larger than the spend in the same month the year before.

Our new standardised reserve products will promote more effective competition between potential service providers and open up the markets to greater volumes of non-BM assets. This is likely to be particularly beneficial in providing more options for downwards flexibility as there are many distribution connected renewable generators and demand side response units which are likely to find turn-down services easier than turn-up. Access to downwards flexibility will become increasingly vital on days with very high renewable output and low demand which will see frequently on the electricity system of the future. Enabling non-BM providers to participate will create more competition and put downwards pressure on availability prices as well as providing alternative options to accessing reserve through the BM.

Reserve costs: Jan 2019 - Dec 2021



Note: Negative reserves are included in the Operating Reserve categories. The Fast Reserve category includes spend on both firm and optional variations of the product. The Other category includes BM warming, demand turn-up, GT fast start and Hydro Rapid Start.

Markets Roadmap / Market Areas / Reserve 29

Reserve

This page is interactive.
Click the ⊕ to expand or enlarge content.

Market Information: **Reserve providers**

Chart 1: STOR providers

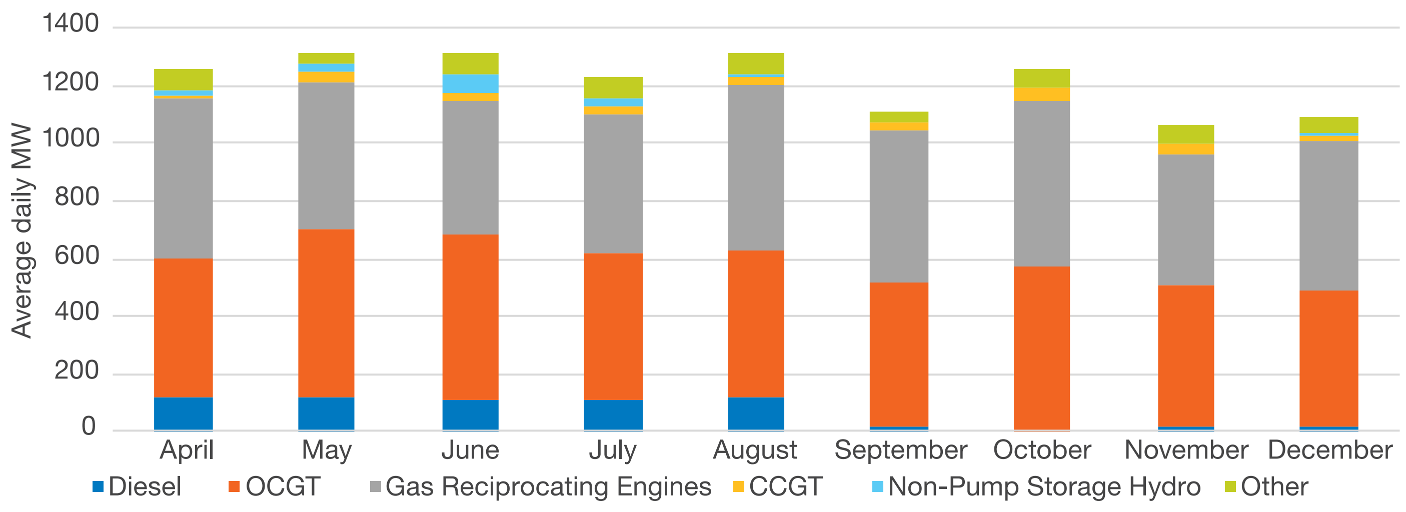
This chart shows the proportions of daily STOR by different technology groupings. The current market is mostly made up of gas reciprocating engines and open-cycle gas turbines which can respond quickly to an instruction and ramp up from 0MW within the 20 minutes required by the STOR service which means they won't have to be running (and burning fuel) unless instructed to provide the turn up service.

Chart 2: Operating reserve providers

Reserve accessed through the BM, operating reserve, is dominated by high carbon units which are usually cheaper to reposition for reserve. Although we expect the proportion of low carbon reserve providers to grow as the overall generation mix continues to decarbonise.

Our existing STOR market is comprised mostly of high carbon providers. We will be closely monitoring our new positive slow reserve market (which will be a natural successor to the STOR market) once launched to confirm that is compatible with the operation of a zero carbon electricity system. We believe that moving from one 24-hour delivery window to more granular delivery windows will make it easier for intermittent generators such as wind to provide a positive reserve service.

STOR providers by technology type: 2021



Note: Day-ahead STOR procurement only began on 1st April 2021 so there is no data for Jan-Mar 2021 inclusive. The "Other" category includes aggregated assets with a mixed technology portfolio underneath one unit ID or any unit that is not in the following list Biomass/Batteries/Coal/CCGT/Diesel/Gas Reciprocating Engines/Load Response/Non-Pump Storage Hydro/Nuclear/OCGT/Pump Storage/Solar/Wind.

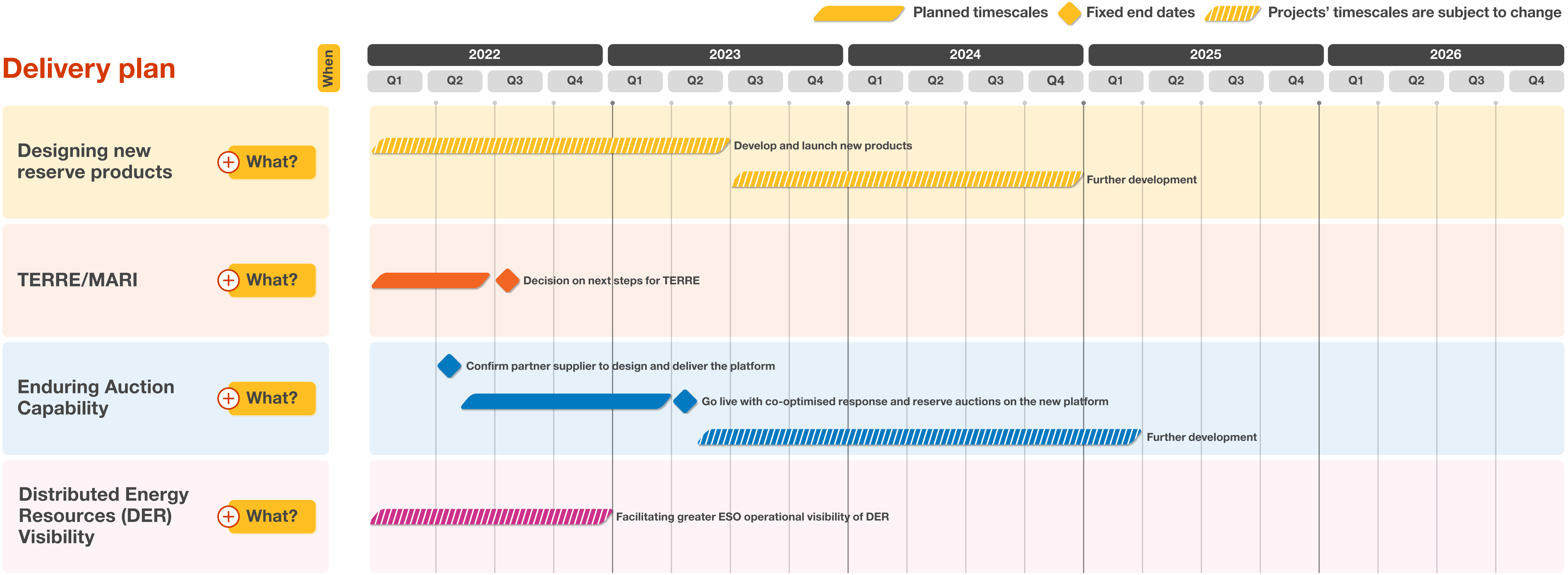
⊕ STOR providers ⊕ Operating reserve

Markets Roadmap / Market Areas / Reserve 30

Reserve

This page is interactive. Click the ⊕ to expand or enlarge content.

Delivery plan



Markets Roadmap / Market Areas / Reserve 31

Reserve

Efficient dispatch

Efficient Investment

Value for Money

Opportunity for Change – **Increasing participation in our new reserve markets**

Increasing participation in our reserve products will provide significant consumer benefits by improving competition.

Our key challenge in reserve reform is attracting sufficient providers to offer their services for our new reserve products Quick Reserve and Slow Reserve to create competitive and liquid markets. This will allow us to procure greater volumes of reserve outside of the BM and deliver value for consumers.

Our new products will increase market participation by:

- Creating a route to market for non-BM providers to offer a turn down service (Negative Slow Reserve and Negative Quick Reserve).
- Protecting a route to market for existing STOR providers through the Positive Slow Reserve product.
- Aligning with the requirements set out in the System Operation Guidelines (SOGL) by providing a route to return frequency to normal limits within 15 minutes from an excursion.
- Enabling us to explore the costs and benefits of a pre-fault reserve product.
- Standardising the service parameters of our two new reserve products allowing market participants to compete on price alone.
- Reducing barriers to entry for weather-driven providers, wind and solar, by introducing more granular delivery windows. This represents an improvement on the existing 24-hour STOR contracts and should make it easier for weather-driven non-BM providers to offer their services.
- Simplifying our suite of reserve products to improve transparency and accessibility.

We need to open participation routes to new providers and engage closely with industry to understand and mitigate barriers to entry.

Reserve

Opportunity for Change – **Increasing participation in our new reserve markets**

Key strategic questions

- **How can we access more reserve services from low-carbon providers?**

To support our ambition for zero carbon operation by 2025 we need to understand why we aren't seeing market participation from dispatchable zero carbon generators like nuclear and energy storage or intermittent renewables like wind and solar PV and whether it is feasible to change the technology of our reserve providers. There are a few factors that could be influencing this lack of participation.

To provide a positive reserve service a contracted provider must hold headroom to be able to deliver additional MW onto the system if required. Many low-carbon providers are in receipt of energy linked subsidies and therefore would require significant compensation to make it economic for them to hold headroom and forego a portion of their possible subsidy revenue. This often makes gas or coal more economic to utilise for positive reserve services.

Secondly, other balancing services like our response services may be more attractive than our existing reserve products to energy limited providers like battery storage. At present we don't allow stacking between response and reserve services and therefore providers must choose whether to offer their asset into a response or reserve market. This may change in the future as we introduce greater co optimisation functionality to our day-ahead auctions.

Lastly, there may be elements of our existing procurement routes for reserve services that create barriers to entry for low and zero carbon providers. One such example is that there is currently no regular procurement of a negative reserve (turn down) product which is accessible to non-BM providers. We intend to introduce unbundled procurement of reserve services which will create this missing route to market. We hope the Negative Slow Reserve and Negative Quick Reserve markets will be attractive to distribution connected renewable providers. We plan to work closely with weather-driven generators throughout 2022/23 as we continue to develop our new suite of reserve services to understand barriers to entry and whether we can utilise new data feeds like Power Available to support their participation in our markets.

Markets Roadmap / Market Areas / Reserve 33

Thermal

As more weather-driven low carbon generation is connected, mostly at the edges of the system we need to manage an increasingly congested transmission network. Analysis undertaken as part of the Network Options Assessment (NOA)[1] shows that one of our most constrained boundaries (the Anglo-Scottish B6) could be congested 86% of the time in the winter by 2030. If we are to reasonably manage increasing constraint costs, we need to work with market participants, transmission network owners (TOs) and distribution network operators (DNOs) to develop innovative whole system solutions for managing transmission network constraints. These new solutions must offer opportunities to new sources of flexibility.

To manage our constraints today, we typically redispatch generation through Bid Offer Acceptances (BOAs) in the Balancing Mechanism (BM), or we instruct interconnectors outside of the BM via trades. Due to increasing generation volumes, our most constrained boundaries today are the north-south boundaries which move power from Scotland and Northern England to demand centres further south. However, other boundaries across the system are becoming increasingly congested including the South Coast and East Anglia. The Operability Strategy Report (OSR) shows that, by 2030, some areas of the network will see peak power flows which are 400% greater than current boundary capability.

We need to find economic and innovative solutions across different voltage levels to help manage the cost of these constraints. Through our Constraint Management 5-Point Plan (see delivery plan on page 40 for more information) we are developing some short-term tactical solutions to reduce the number of actions we need to take in the BM and help alleviate some of the constraints across our most congested boundaries. We are also progressing with our Regional Development Programmes (RDPs) which will introduce more competition in constraint management services from distribution connected providers. All of these projects are in line with BEIS Smart Systems and Flexibility Plan to develop and publish plans to implement regular and dependable markets for managing thermal constraints.

Future Considerations

To reach our net zero targets we will see more renewable technologies and embedded generation connect to the network, which may add to rapidly increasing network constraints. Ultimately, major investment in transmission network capacity will be needed to connect these vast amounts of new assets, and to avoid high levels of curtailment. Market based solutions from our Constraint Management 5-Point Plan and RDPs will help to alleviate a small portion of the rising costs.

What is Thermal?

Thermal constraints are caused when the amount of power the market wishes to flow across the network is higher than the physical limitation of the network. This causes bottlenecks on the system which limits how energy can be transmitted across Great Britain. As ESO we must manage this congestion to ensure the network operates safely.

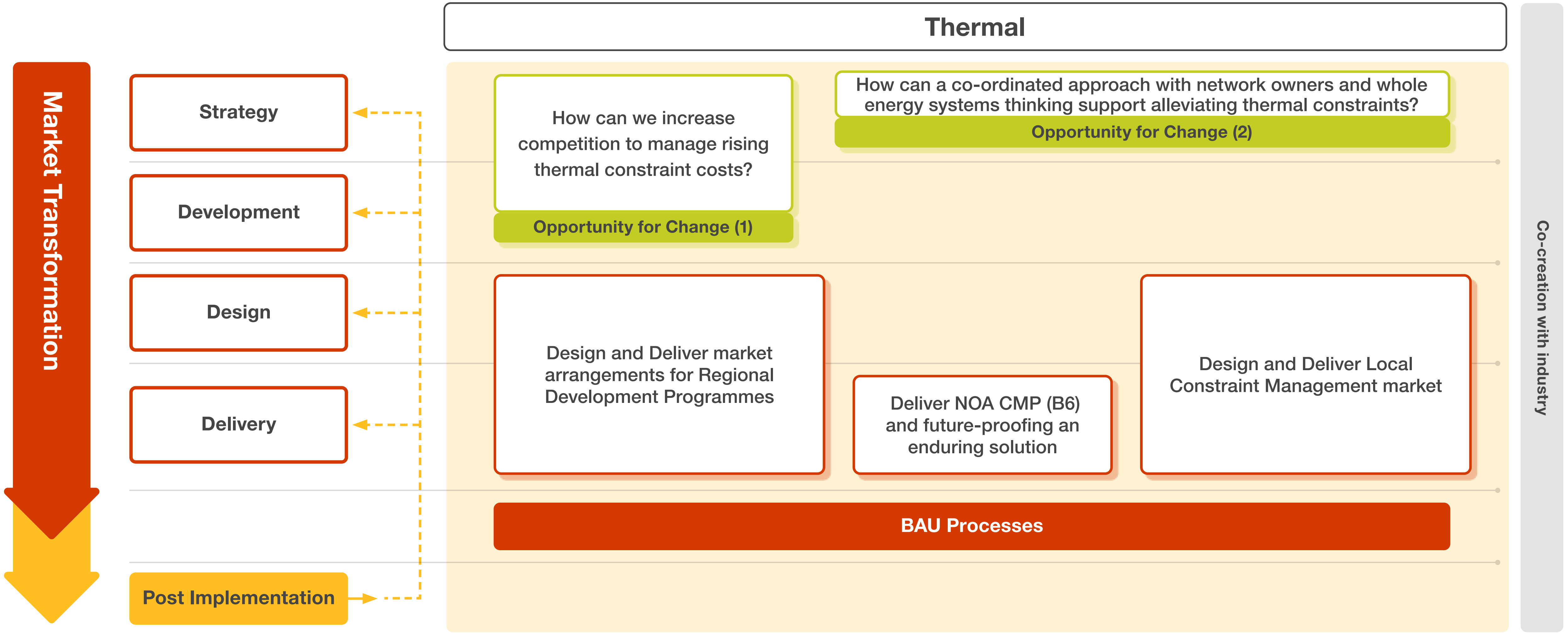
1 Network Options Assessment 2022 download (nationalgrideso.com)

Markets Roadmap / Market Areas / Thermal 34

Thermal

Market Transformational Stages

We work on the projects and strategic questions within this graphic simultaneously.



Markets Roadmap / Market Areas / Thermal 35

Thermal

Market Information: **How we procure thermal services**

	Balancing Mechanism	Trades
Product description	When there is a thermal constraint on any part of the transmission network we can manage this by asking generators to reduce their electricity output. However, to ensure the system is balanced, we also need to buy the same amount of electricity from another provider in a different part of the transmission system.	We use interconnectors to manage thermal constraints when we don't have access to enough generation to meet demand in the constrained area.
Timing of procurement	Transmission thermal constraints can be managed in real time through the BM via Bid Offer Acceptances (BOAs).	We run an intra-day auction by sending out requirements to all counterparties that require capacity on interconnectors ahead of time.
Price determination	The price of bids and offers are submitted by generators to either reduce or increase their generation on one or another part of the network to reduce thermal constraints and maintain energy balance.	Counterparties submit their volumes and pay-as-bid prices to us.

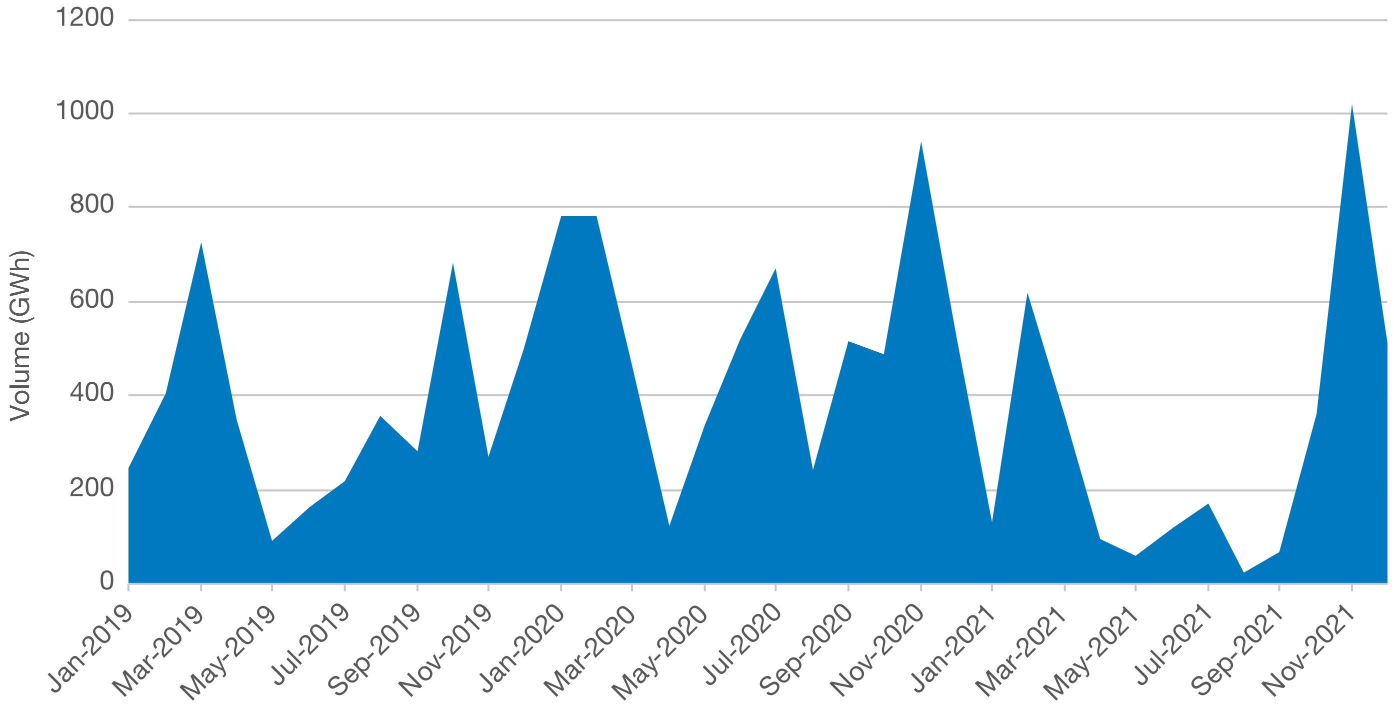
Markets Roadmap / Market Areas / Thermal 36

Market Information:
Thermal constraint management volumes in the BM and trades

This graph shows the volume of actions taken to manage transmission thermal constraints from January 2019 to December 2021. Most of the actions to manage thermal constraints were carried out through the BM during this time. From 2019 to 2020 there was a 49% year on year (YoY) increase in annual thermal constraint management volume, driven by high-wind output in Scotland. Network outputs and demand variations also drove the increase in the BM actions, the highest variations YoY were in January, July, and November 2020.

However, from 2020 to 2021 there was a 45% total YoY decrease in the volume of thermal constraint actions taken. This was mainly due to a return to a more normal (more similar to pre-COVID) demand pattern, as well as weather output across the same period year on year, with significantly less windy months in 2021. Experiencing more windy conditions over Oct-Nov 2021 required relatively higher volumes of BM actions to bid-off wind generation in Scotland.

Thermal constraint volumes: Jan 2019 - Dec 2021



The Future Energy Scenarios (FES) Consumer Transformation scenario forecasts an additional 40GW of total installed onshore and offshore wind capacity between 2022 and 2030. In addition, Consumer Transformation also forecasts an additional 10GW increase of interconnection capacity between 2022 and 2030. Currently, interconnectors don't participate in the BM, but as their capacity increases we are working to reduce barriers to them participating in balancing services to manage increasing thermal constraint volumes.

Over the long-term the right transmission investments at the right time and appropriate locations will further support managing the thermal constraints on the most congested parts of the network.

Markets Roadmap / Market Areas / Thermal 37

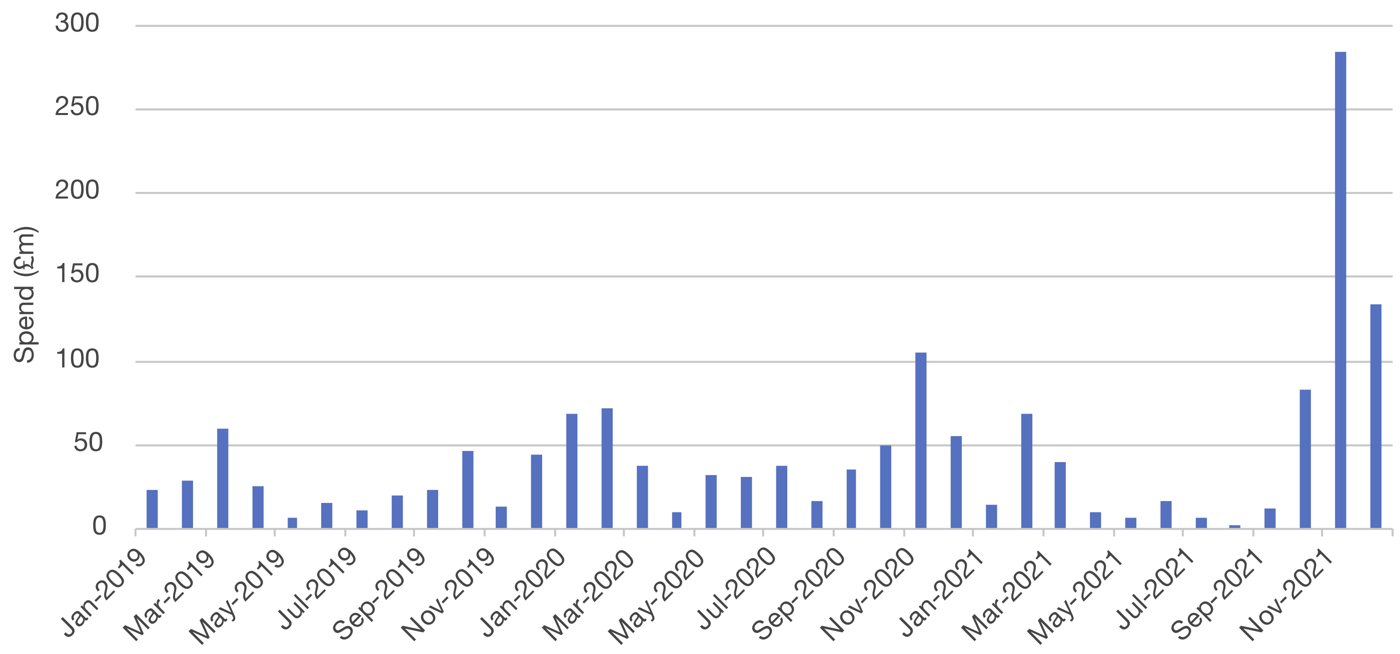
Thermal

Market Information:
Thermal constraint management costs in the BM and trades

This chart shows the cost for managing thermal constraints in the BM and via trades from January 2019 to December 2021. The trend in costs has, by and large, followed the trend in volumes seen on the previous page. As volumes increased between 2019 and 2020 (Jan-Dec) the overall costs also increased by 73%, and as volumes decreased between the first halves of 2020 and 2021 (Jan-Jun) costs similarly decreased by 38%.

The notable exception is of course in late 2021, when constraint costs rise disproportionately compared to volumes. This is symptomatic of the wider BM cost increases, driven by global gas price rises.

Thermal constraint costs: Jan 2019 - Dec 2021



The rapid increase in thermal constraint management costs since October 2021 sharpens our focus on developing new solutions through our Regional Development Plans (RDPs) and our Constraint Management 5-Point Plan to reduce some of our exposure to potentially very high costs in the BM.

Thermal constraint costs will keep rising if capacity on the network isn't sufficient enough to offset unconstrained market positions. Ultimately, we will need to significantly build out the transmission network. But this must be economically optimised against the level of curtailment in the system.

Markets Roadmap / Market Areas / Thermal 38

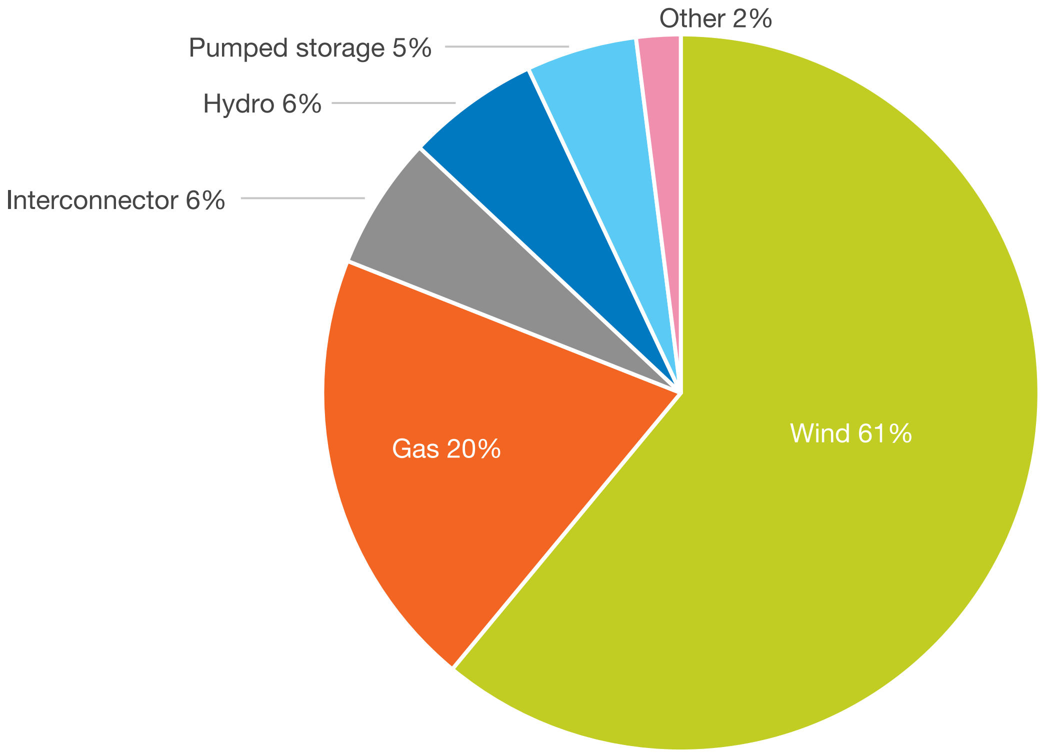
Thermal

Market Information:
Thermal constraint management providers

This chart shows the bid and offer volume procured from different technologies from January-December 2021. Over 60% of the volume procured in 2021 was from wind (2.2 TWh) driven by high wind output which required wind providers to be bid-off in the BM due to the constraints across north of England and Scotland. Gas providers made up the second highest volume provision, due to offers to turn up during low-wind days or to re-balance supply on other parts of the network (below the constrained areas). Interconnectors that are traded to manage thermal constraints outside of the BM made up approximately 6% of the overall technology mix.

To manage thermal constraints more efficiently, we need to ensure that our markets are accessible to different types of technologies by removing barriers to entry. We are increasing participation of Distributed Energy Resource (DER) through our RDPs as well as our future Local Constraints Market. See Opportunity for Change (1) for more details on these activities.

Thermal providers by technology type in 2021 (volume)



Markets Roadmap / Market Areas / Thermal 39

Thermal

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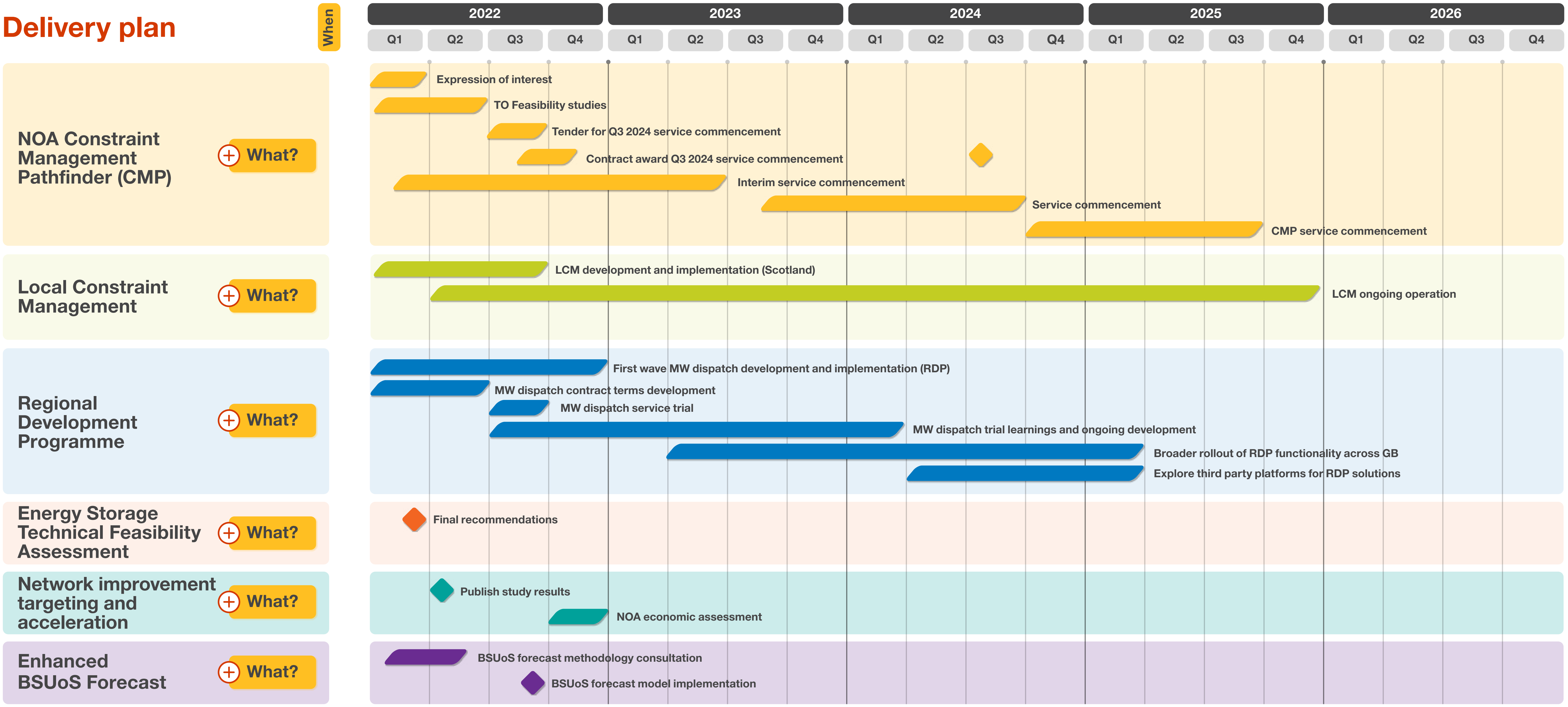
Planned timescales · Fixed end dates · Projects' timescales are subject to change

Delivery plan



Markets Roadmap / Market Areas / Thermal 40

Thermal

Efficient dispatch

Efficient Investment

Value for Money

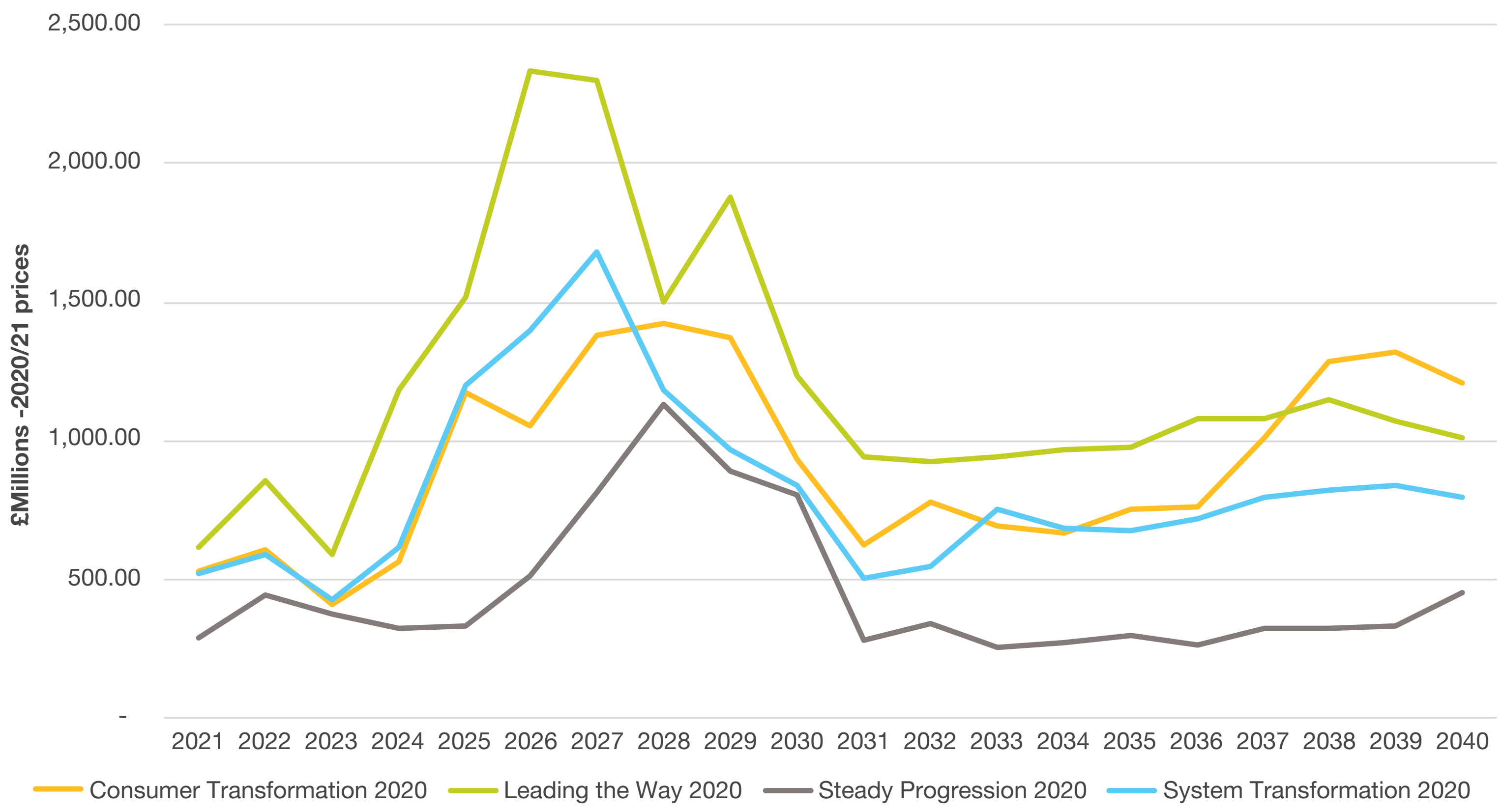
Opportunity for Change (1) – **Increasing competition to manage rising thermal constraint costs**

Rising and unpredictable costs in the balancing mechanism means we need to increase competition and explore alternative ways to manage thermal constraint.

The NOA 2020/21 shows modelled thermal constraint cost will increase significantly in this decade from c.£0.5bn to between £1bn and £2.5bn/year[2]. Long lead times for large transmission investments like the HDVC link on the East coast impact rising costs. As shown in the graph, the thermal constraint costs would reduce again at the end of the decade when new major transmission investments are delivered.

Increased market competition and alternative short-term tactical solutions should place downward pressure on costs and deliver better value to the end consumer.

Modelled Constraint Cost after NOA 2020/21 Optimal reinforcements



2 Modelled Constraint Costs NOA 2020/21 download (nationalgrideso.com)

Markets Roadmap / Market Areas / Thermal 41

Thermal

Opportunity for Change (1) – **Increasing competition to manage rising thermal constraint costs**

Key strategic questions

- **How can we increase competition by introducing alternative short-term solutions to manage thermal constraints?**

According to BEIS Smart Systems and Flexibility Plan, we need to develop and publish plans to implement regular and dependable markets for managing thermal constraints. Below are some of the activities we are undertaking in this space (refer to the delivery plan for more details):

- We need to reduce barriers to entry for new providers. As part of our Constraint Management 5 Point-Plan, the NOA Constraint Management Pathfinder (CMP) is looking for alternative ways to reduce the cost of managing constraints at various places and therefore, reduce the need for build solutions. CMP is looking to competitively procure 800MW of existing transmission connected generation which can be disconnected when armed and tripped. Following a fault, generation which is armed will be disconnected by the Anglo-Scottish Intertripping Scheme.
- The whole-system aspect of our Constraint Management to 5-Point Plan encompasses implementation of a Local Constraint Market (LCM) in the short term and RDP in the longer term as a solution to rising thermal constraint costs. These initiatives will create new competitive markets for DER to provide constraint management services to us.
- The LCM is intended to be a short-term tactical solution utilising flexibility from DER to reduce constraint costs on the B6 Anglo-Scottish boundary. The service will employ a third-party platform solution to be able to instruct, monitor and pay DER for providing a constraint management service. This solution, in theory, could be 'lifted and shifted' to other areas of the network for managing constraints and we will assess the overall benefits of the LCM on the B6 boundary and use learnings from the project to take forward further development work on thermal constraint management markets.
- In contrast, RDPs are being delivered in co-ordination with DNOs and seek to fully integrate any new tools and services developed through the RDP into all aspects of both ESO and the partner DNO's processes. RDPs are facilitating DER participation in transmission constraint management services, by requiring DER to provide us with visibility and control of their output to facilitate their connection to the network. The service will be a turn to zero service in the first instance which DER will be compensated for and is currently designed for non-BMU assets more than 1MW. However, we may look to facilitate market access for smaller providers in the future.
- As part of our 5 Point-Plan, we have been investigating the technical feasibility of energy storage to reduce constraint costs on our most constrained boundaries. The project considered storage acting exclusively for constraint management and concluded that the timing and duration of boundary constraints make it difficult for storage to both significantly reduce the constraint cost and achieve sufficient utilisation to have an attractive business case. However, storage could still play a useful role competing alongside other technologies to reduce constraints, while also providing other balancing services. We will work to understand how storage providers can compete in constraint management services which can be stacked with other services.

- **How can we improve our trading capability to trade greater volumes of interconnector capacity and other technologies?**

There will be up to 27GW (FES 2021 Leading the Way scenario) of interconnection capacity by 2030. Greater automation of trading processes is required to mitigate against the risk of manual errors and to ensure that we can continue to meet demand for trading, particularly with increasing volume of interconnector counterparties. The current process could move to an auction platform that will future proof our trading capability allowing us to continue trading reliably, economically, and efficiently as GB's interconnection with Europe increases over the coming years.

Markets Roadmap / Market Areas / Thermal 42

This page is interactive.
Click the ⊕ to expand or enlarge content.

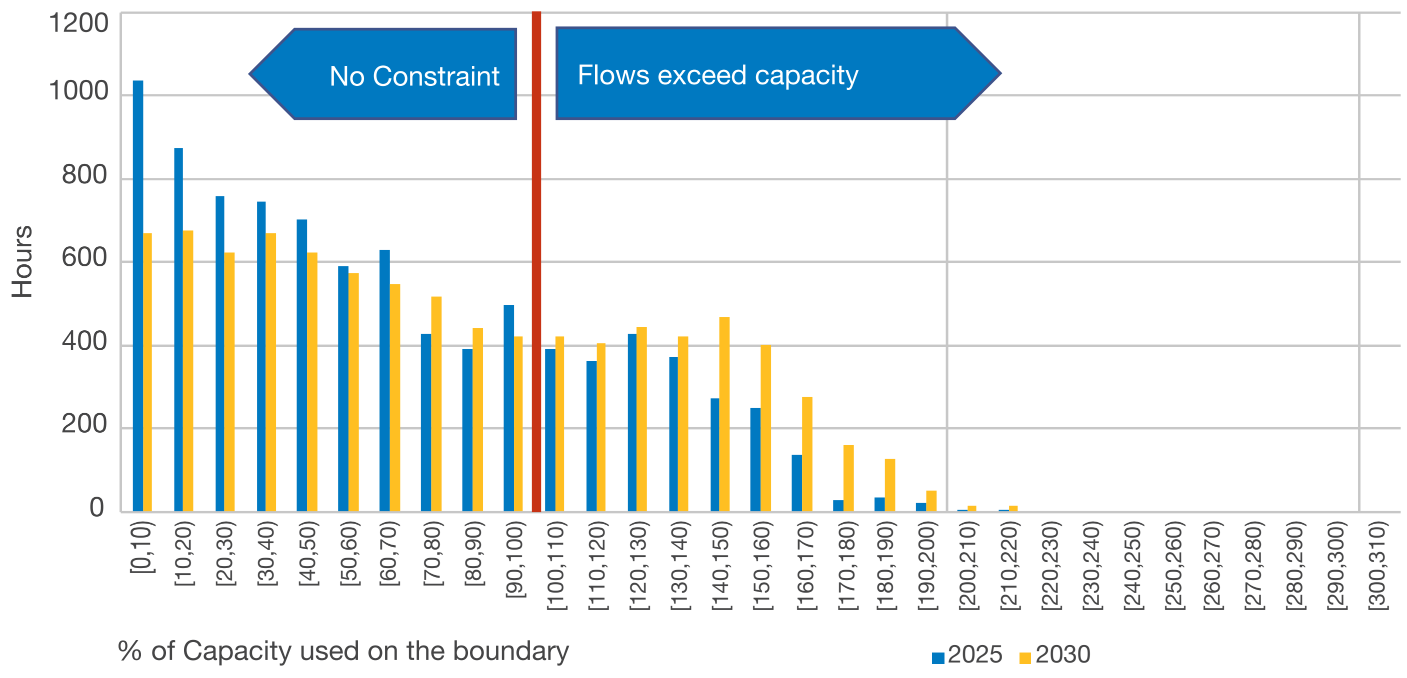
Efficient dispatch
Efficient Investment
Value for Money

Opportunity for Change (2) – **Developing a coordinated approach to manage high thermal constraint volumes**

Future characteristics of network constraints will change over time including the location and frequency of constraints. This is driven by the changing and increasing generation pattern, and new transmission network providing additional capacity. However, in the next decade, on many key boundaries the forecast flow will be above the boundary capabilities for significant periods.

These plots show the frequency of flows over two key boundaries using the FES Leading the Way scenario – B6 the Anglo-Scottish boundary, and further south, B8 the North of England to Midlands boundary. The frequency of forecast flows on each of these boundaries, normalised to the capacity of the boundary, is shown for 2025 (blue) and 2030 (orange). In the background is assumed that NOA (2021/22) optimal reinforcements are made. In the case of B6, there is an improving picture between 2025 and 2030 where new capacity reduces the frequency when the boundary is forecast to be constrained. In contrast, further south, on B8 there is slight shift in the opposite direction where the boundary is slightly more constrained in 2030. This is part of a broader trend. As these northern boundaries are the most congested, they benefit from increase in capacity in the later part of this decade. However, this causes the constraint problem to move, in part, further south and we see constraints in future into the Midlands.

Frequency of flows on B8, comparing 2025 and 2030



⊕ Frequency of B6 flows ⊕ Frequency of B8 flows

There is a need to develop a co-ordinated approach with network owners at different voltage levels to ensure cost-effective investments and facilitate the increased connection of DER. Other than coordinating network investment to facilitate increasing amounts of generation capacity, we must look holistically at GB market design to ensure we are providing the right investment and dispatch signals for assets to site in the right place, and for flexibility to site and operate in ways that will benefit the system. Our Net Zero Market Reform work is investigating this in detail.

Markets Roadmap / Market Areas / Thermal 43

Thermal

Opportunity for Change (2) – **Developing a coordinated approach to manage high thermal constraint volumes**

Key strategic questions

- **How can we co-ordinate with network owners to manage transmission thermal constraints more efficiently, considering the dynamic characteristics of the constraints?**

The Network Improvement Targeting and Acceleration project is the final workstream in the Constraint Management 5-Point plan. We are working with the Transmission Owners to investigate if they can advance the delivery of some NOA options to help manage thermal constraints.

Working collaboratively with TO and DNO stakeholders, the Network Access Planning (NAP) team has identified and recorded over 89 instances where we have taken actions that resulted in thermal constraint savings. These actions included moving outage dates, reducing return to service times, re-evaluating system capacity, proposing, and facilitating alternative solutions for long outages that impact customers. Through these initiatives we saved just over £1bn managing 13TWh between April 2021 and February 2022. The NAP team will continue working with stakeholders to identify more cost saving solutions to reduce thermal constraint costs in the future.

- **What role could the Distributed System Operators (DSOs) play in the provision of thermal services and how could we enhance our DER visibility?**

We will work with DNOs to facilitate increased DER participation in constraint management markets whilst also recognising the continued development of DSO flexibility markets. Our current RDPs are focussing on facilitating instructions for a new service called MW dispatch which will manage transmission constraints via DNO Distributed Energy Resources Management Systems (DERMS) or Active Network Management. However, we also intend to explore other methods of service instructions, such as web-based methods, to ensure we maximise participation in regional constraint markets.

Also, through the Open Networks Project we are exploring how products can be stacked across DSO and ESO markets. Clarity on which products can be stacked should incentivise more DER to provide transmission constraint management via initiatives such as RDPs.

We will also be looking to increase the operational visibility of DER to us to help plan and operate the network and ensure greater co-ordination of services between ESO and DSOs.

- **How could whole energy systems thinking and a coordinated approach between different vectors such as hydrogen enable us to manage constraints?**

According to our FES 2021, the production of hydrogen via electrolysis helps to maximise the use of renewable electricity generation. We need to ensure locations for electrolysers are situated optimally. Our Net Zero Market Reform programme is investigating how wider market signals for location and dispatch could help achieve this outcome.

Markets Roadmap / Market Areas / Thermal 44

Restoration

By 2025, we will have rolled out more competitive restoration tenders across different regions. As restoration services mature, we will reduce more barriers to improve market access for more providers such as interconnectors and Distributed Energy Resources (DER). The Distributed Restart project will demonstrate how we can re-energise the network from the distribution to transmission level.

By the end of 2026 the new Electricity System Restoration Standard (ESRS) will be implemented and will require the ESO to restore all electricity demand within 5 days and 60% demand within 24 hours[1], in Great Britain (GB). We will work with industry across a range of areas to develop the approach to deliver the new standard.

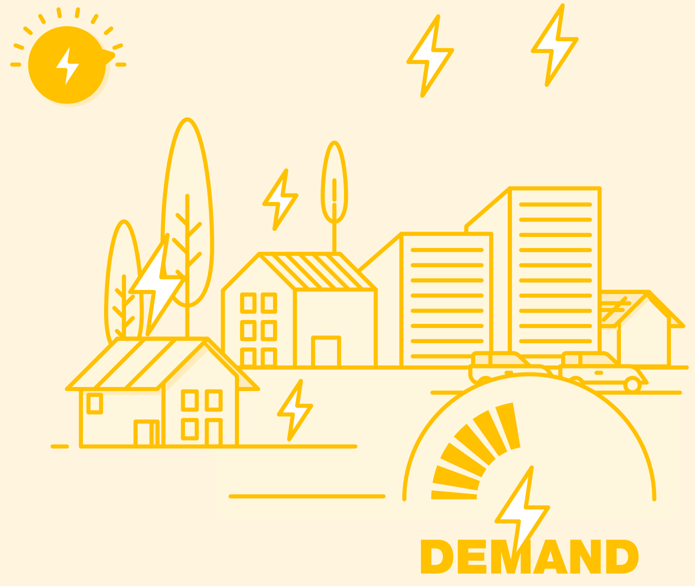
Today our restoration services are mostly procured through commercial contracts with traditional providers like CCGTs. In 2019 we tendered for two regional Electricity System Restoration Events (ESRE): South West & Midlands and Northern Regions, which will commence in 2022. These types of new competitive tenders will ensure there will be less reliance on restoration from traditional providers and will include a wide range of technologies connected at different voltage levels, specifically from our Distributed Restart initiative.

Future Considerations

Tighter regulation from the implementation of the ESRS will mean more reliable and faster restoration time across GB restoration zones. Our competitive process will evolve with the introduction of services procured from distribution providers, and any potential emerging technologies such as hydrogen may play a greater role in restoration.

What is Restoration?

Provision from restoration services ensures that, in the unlikely event of loss of power to some or all of the electricity system, we have a robust plan to restore power as quickly as possible.

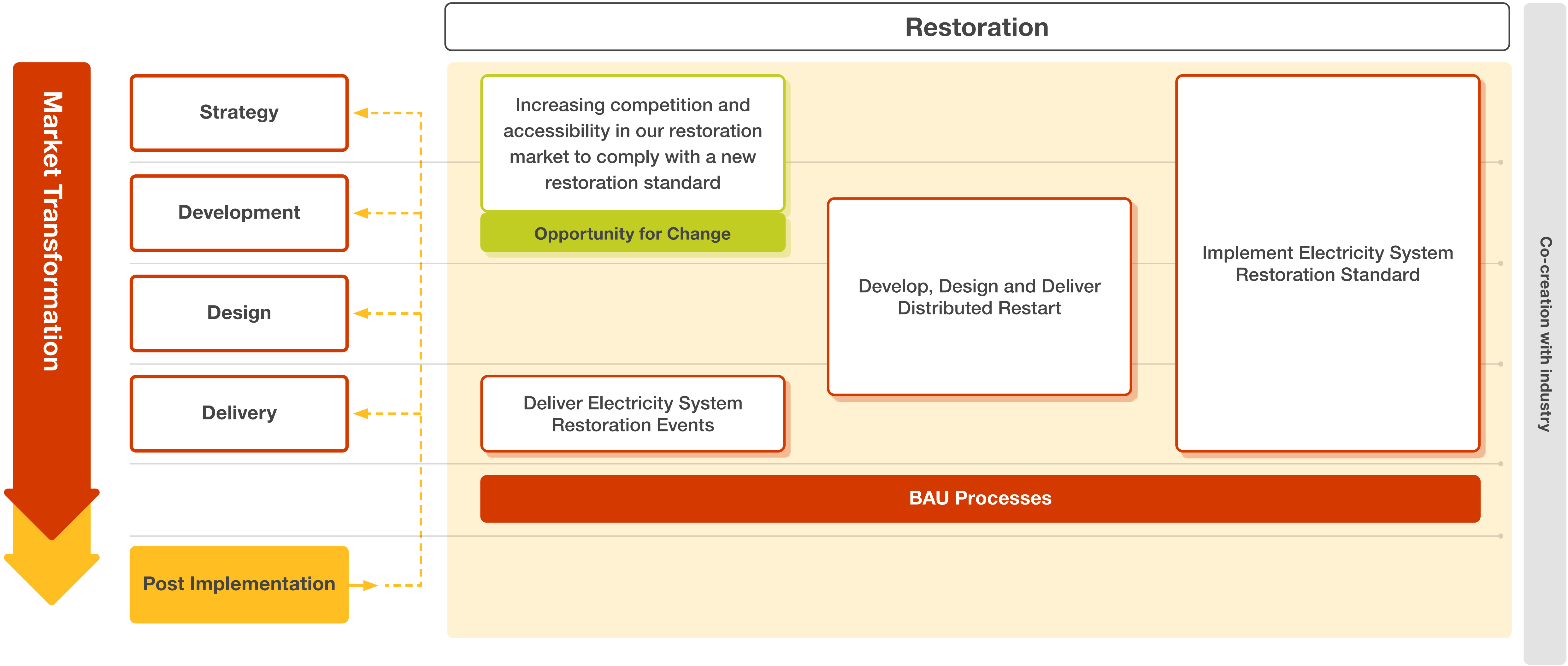


1 Introducing a new 'Electricity System Restoration Standard': policy statement - GOV.UK (www.gov.uk)

Restoration

Market Transformational Stages

We work on the projects and strategic questions within this graphic simultaneously.



Markets Roadmap / Market Areas / Restoration 46

Restoration

Market Information (2021): **How we procure restoration services**

	Electricity System Restoration Events	Bilateral Agreements
Product description	In November 2020 we awarded our first tenders for Electricity System Restoration (ESR) in South West and Midlands, a new market mechanism to competitively procure restoration services from a wide pool of providers across different GB regions. The procurement principles for ESR have been developed and outlined in the Black Start Strategy and Procurement Methodology 2021/2022 This report explains how our procurement process will enable a fair market.	Bilateral agreements are mostly with traditional generators such as CCGTs. Where we determine that a bilateral contract is the most economic and efficient approach, we shall ensure that any restoration costs will be assessed in accordance with the value provided to the system. Power stations with existing bilateral agreements have the ability for at least one of their gensets to start-up from shutdown and energise a part of the total system, or to be synchronised to the system upon instruction from us.
Timing of procurement	Bids are typically submitted two years ahead of service delivery.	Contracts are agreed at two years ahead of service.
Price determination	The cost of ESR services are controlled by the market through a pay-as-bid mechanisms which are ran by us on an ad hoc basis, assessed in accordance with the published Technical Requirements and Assessment Criteria and the Commercial Evaluation Methodology. Providers will be entitled to: • Payment rate: £/SP Availability only* • Works Contribution (the payment for new or furbishing plants only) *In addition to the Availability payment there are several other payment options available to ESR service providers which are broken down later in the next section.	For availability payments, providers will offer a fixed price to be paid annually, this is then worked out into a £/settlement period and paid monthly to providers.

Markets Roadmap / Market Areas / Restoration 47

Restoration

Market Information: **Restoration costs**

There are a number of different costs associated with restoration services.

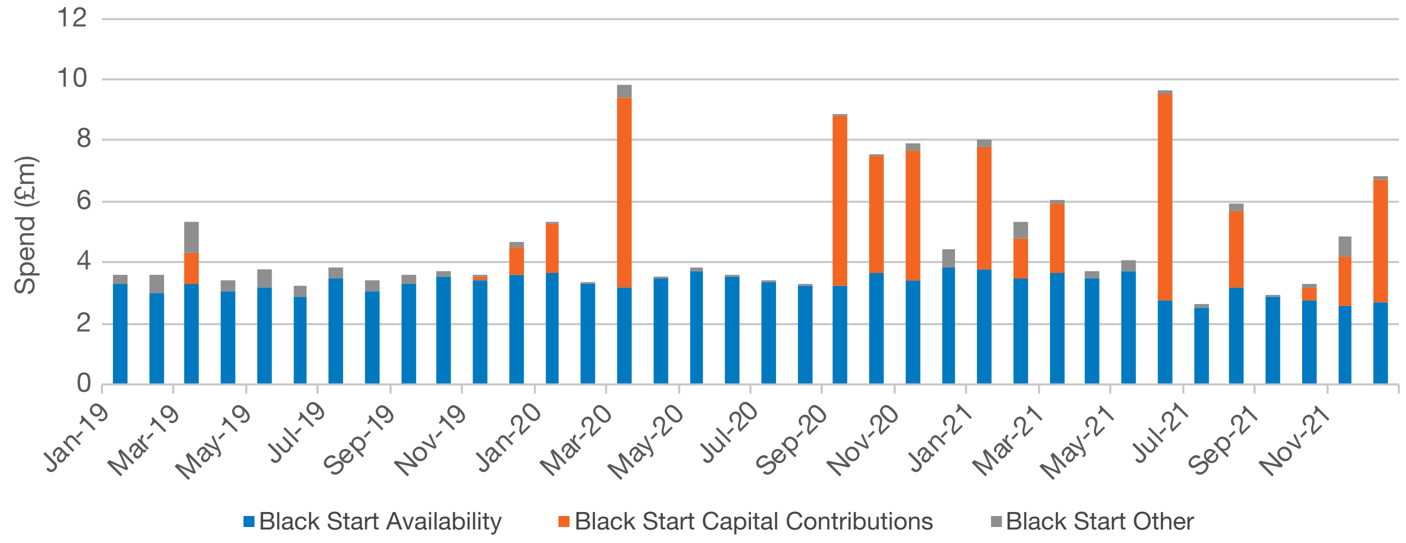
The two key cost elements are:

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. These payments are pretty consistent from month to month and year to year.
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, testing and warming requirements.

For more information on calculation costs for Restoration, click here.

Restoration costs: Jan 2019 - Dec 2021



It is challenging to forecast the future market value for restoration; however, we can expect to see an overall rise in costs. This is directly related to the increase in the number and types of providers who will be providing restoration services, especially from the distribution network. In line with the new restoration standard, it is likely that in the future, costs for training new providers such as DER will need to be included. Training costs are intended to develop capability in the short term, but longer term, we expect the overall costs for restoration services to reduce with greater market liquidity.

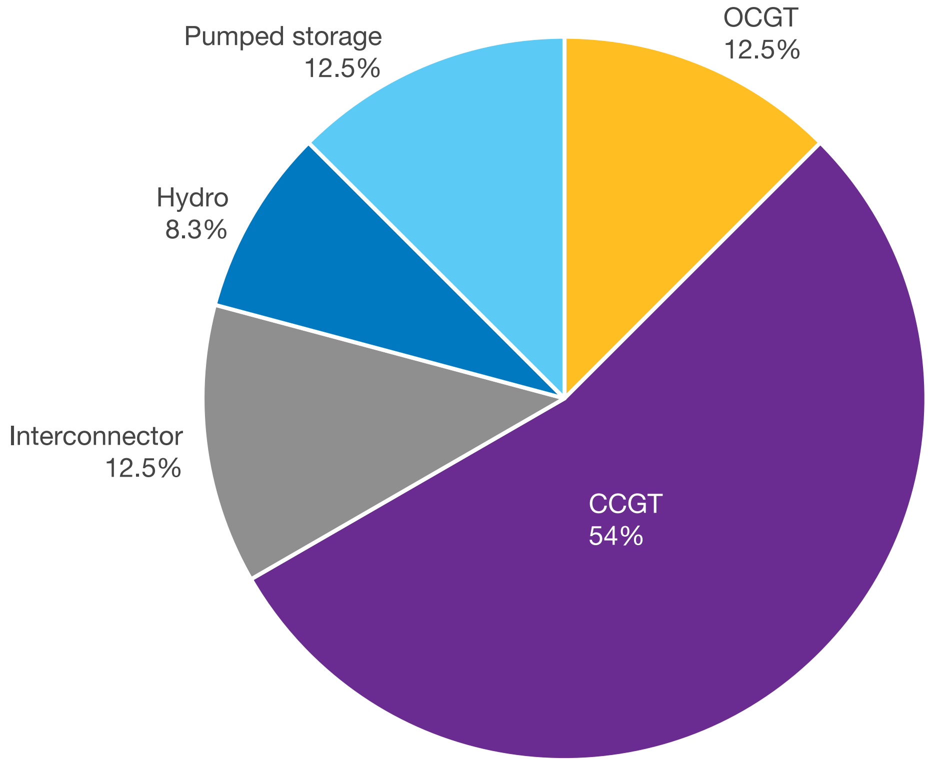
Markets Roadmap / Market Areas / Restoration 48

Restoration

Market Information: **Restoration providers**

Traditionally we tend to procure restoration services from transmission connected generators only (minimum requirement of 100MW). The existing bilateral agreements and competitive tender contract winners are made up of 24 providers across six regions (South West, Midlands, North West, North East, South East and Scotland). The graph shows breakdown of service providers by their fuel type, with CCGT being the dominant provider for ESR provision with a share of 54%.

Restoration providers by technology type in 2021



The participation of batteries and wind in recent tenders shows how other technologies can contribute to system restoration. Through the feasibility process of the tenders, we determined that these providers could meet the technical requirements. At present, not all generators will be able to meet the minimum technical requirements for ESR and therefore they may play a part in later stages of the restoration approach (outlined in the ESRS) rather than delivering a ESR service. We will continue to develop technical requirements to realise the benefits of renewable generators such as wind to allow a broader range of restoration providers to deliver this service in the future.

Markets Roadmap / Market Areas / Restoration 49

Restoration

This page is interactive. Click the ⊕ to expand or enlarge content.

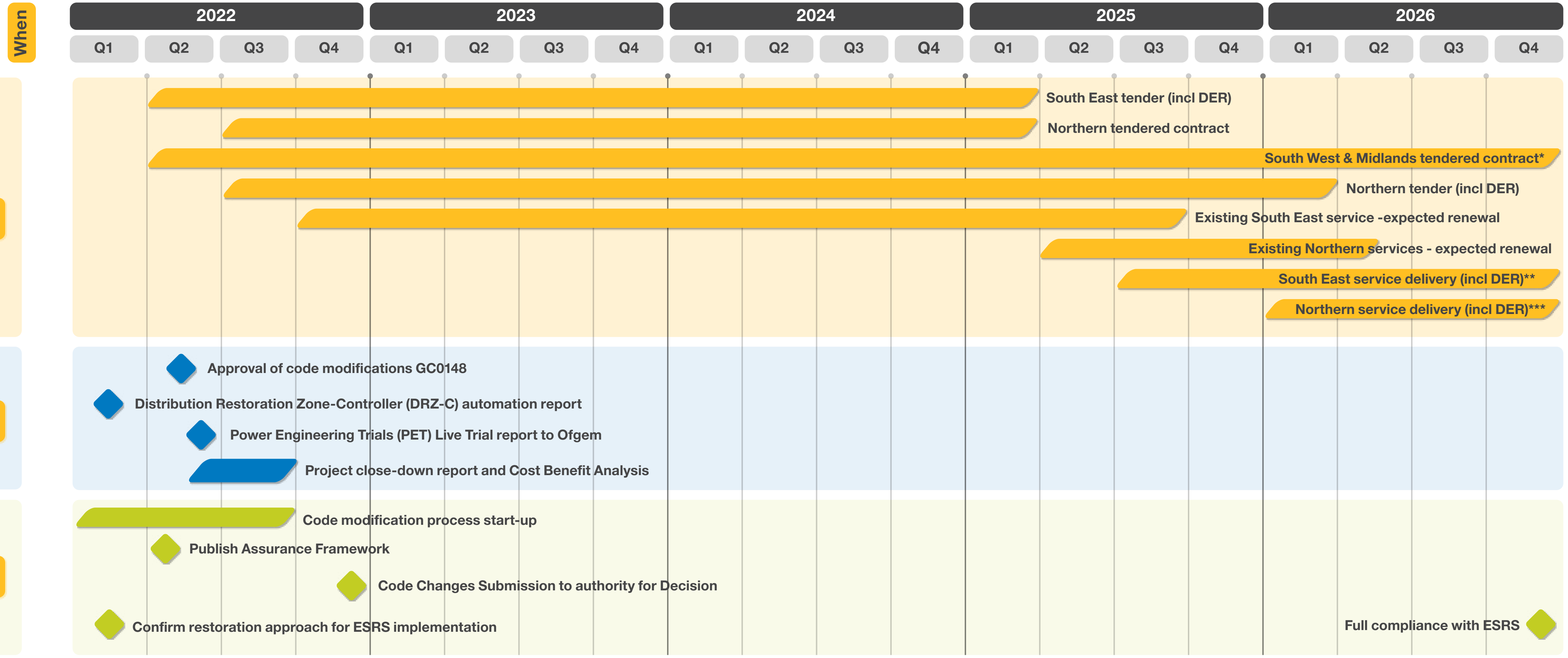
Planned timescales | Fixed end dates | Projects' timescales are subject to change

Delivery plan

Electricity System Restoration ⊕ What?

Distributed Restart ⊕ What?

Electricity System Restoration Standard ⊕ What?



* End date Q2 2027
** End date Q3 2028
*** End date Q4 2028

Markets Roadmap / Market Areas / Restoration 50

Restoration

Opportunity for Change – **Increasing competition and accessibility in our restoration market to comply with a new restoration standard**

As the system decarbonises, we will reduce our reliance on restoration from traditional providers. The new Restoration Standard introduces new capabilities and targets that will realise more consumer and societal benefits.

In October 2021, BEIS released a Policy Statement setting out the need to stregthen the current regulatory framework. They suggested introducing a legally binding target for the restoration of electricity supplies in the event of nationwide or partial power outage on the national electricity system. This is the new ESRS.

The ESRS will require us to have sufficient capability and arrangements to restore 100% of GB's electricity demand within 5 days and 60% demand regionally within 24 hours by 31st December 2026. The outcome of the ESRS aims to reduce restoration time across GB and ensure consistent approach across all regions[2].

Efficient dispatch

Efficient Investment

Value for Money

The loss of traditional providers means it will be challenging to meet the new ESRS targets by 2026 with the same traditional transmission connected assets, therefore we need to ensure more restoration providers across voltage levels can enter the market by 2026 to create a more competitive market.

2 Introducing a new 'Electricity System Restoration Standard': policy statement - GOV.UK (www.gov.uk)

Markets Roadmap / Market Areas / Restoration 51

Restoration

Opportunity for Change – **Increasing competition and accessibility in our restoration market**

Key strategic question

- **How can we create competition and improve accessibility for service provision of new restoration capability?**

Distributed Restart is a world-first initiative, which investigates how to re-energise the system bottom up in the event of a blackout through Disturbed Energy Resources (DER)[4]. This project seeks to remove our dependence on carbon intense generators, and explore how alternative technologies such as wind, solar, and hydro can be used to restore power to the transmission system in the unlikely event of a blackout. The project will look to resolve challenges such as organisational coordination, commercial and regulatory frameworks, and power engineering solutions between us and DNOs. The project will create more competition in restoration and allow access for more technologies.

The automation design of Distributed Restart technology is more efficient than the existing manual processes used for restoration, and this automation is a key element of enhancing restoration timescales. However, early indications of this project suggest that although provision from DER will play a vital role in restoration, we may still need to supplement with provision from traditional sources. We will continue to work closely with DNOs to understand how we can accelerate DER for restoration.

In the interim with the Electricity System Restoration Events (ESRE), we still have an opportunity to look at specific requirements and contract terms that will make this market accessible to new providers and these will be considered as part of the next tender (South East region) which will competitively procure restoration services from more distribution connected assets.

In the medium to longer term we will work with industry to ensure we can bring on new source for restoration, such as wind which have participated in past ESRE tenders.

4 What is the Distributed ReStart project?: National Grid ESO

Markets Roadmap / Market Areas / Restoration 52

Stability

We aim to create new markets to address the increasing need for stability services. We have been testing different market approaches with the development of a series of stability pathfinders. Through our Stability Market Design innovation project we are investigating an optimal enduring market design for the procurement of stability services.

The growth of non-synchronous generation continues to drive a decline in the inherent stability of the system. As a result, our requirements for stability services continue to increase. The Operability Strategy Report highlights our system inertia requirements. For zero carbon operation by 2025, our minumum inertia requirement is 90GVAs plus largest infeed loss.

Stability is currently procured through the Balancing Mechanism (BM) and trading as well as via new commercial pathfinders. The stability pathfinders 1, 2, and 3 ensure we meet our requirements until the end of 2027, but additional needs arise beyond this date. In addition, the management of stability has become increasingly expensive, and the current commercial barriers can be challenging for stability providers. To solve these challenges and ensure we are procuring future requirements in the most efficient way possible, we are exploring different competitive procurement routes for stability services.

Future Considerations

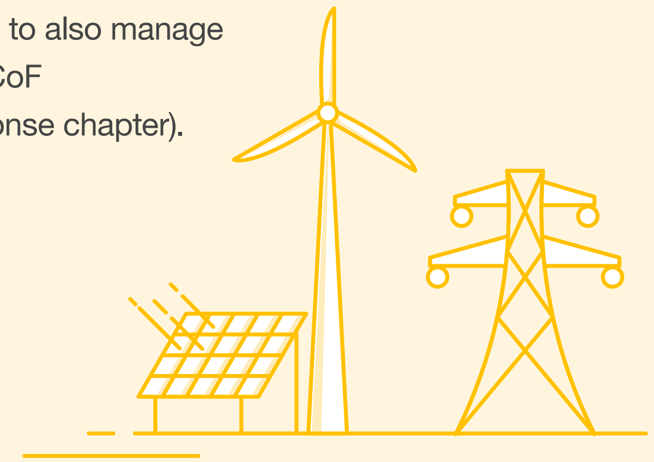
Future market arrangements need to respect existing market participants but also make sure new technologies can support stability management. In particular, renewable technologies, including converter designs and associated control algorithms, are evolving and can now replicate stability behaviours (grid forming capability). However, there is currently no route to procure stability services from these technologies.

What is Stability?

Stability products include inertia, short circuit level (SCL) and dynamic voltage support. Inertia on the power system resists the Rate of Change of Frequency (RoCoF).

The procurement of stability interacts with some other market arrangements and initiatives:

- The Accelerated Loss of Mains Change Programme (ALoMCP) will allow a higher RoCoF and therefore reduce system inertia requirements.
- New faster acting frequency services, like Dynamic Containment (DC), will enable the system to also manage higher RoCoF (see Response chapter).

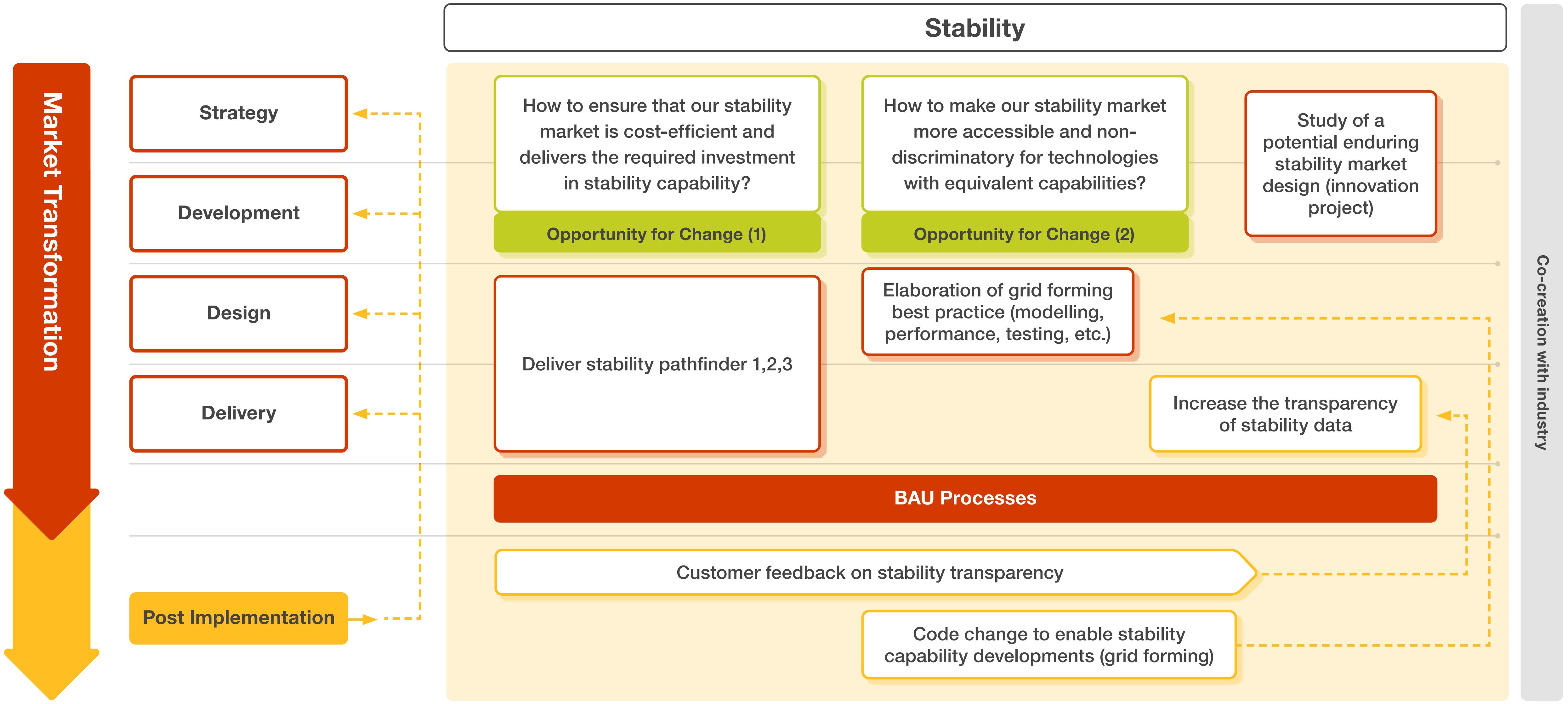


Markets Roadmap / Market Areas / Stability 53

Stability

Market Transformational Stages

We work on the projects and strategic questions within this graphic simultaneously.



Markets Roadmap / Market Areas / Stability 54

Market Information: **How we procure stability services**

The current arrangements allow for the procurement of stability services across different timeframes: multi-year pathfinder contracts for future expected stability requirements and short-term actions in our balancing tools (the Balancing Mechanism and trading). As part of the pathfinder selection process, we consider our ability to access stability support through the BM as the counterfactual. In addition to those procurement routes, stability is inherently provided by synchronous generators operating in the wholesale market, as well as synchronous elements of demand (e.g. motors).

	Balancing Mechanism (BM)	Trades	NOA Stability Pathfinders
Product description	The BM is the primary tool used to ensure the system dispatch is compliant with the physical needs of the system. Procuring stability services through the BM requires providers to inherently deliver stability services as a "by-product" whilst delivering active power. Stability is managed through: - Reducing the largest loss: turn down the largest infeed and turn up other smaller generation to ensure system remains in balance. This aims to keep the RoCoF within limits. - Inertia management: turn up synchronous generation and turn down non-synchronous generation to ensure system remains in balance.	We use interconnectors to manage stability. Similar to the BM, stability services are provided as a "by-product" of trades. Trades on interconnectors enable us to reduce the largest loss on the system and keep the RoCoF within limits.	Stability pathfinders procure inertia, short circuit level (SCL) and dynamic voltage. Providers bid with "user-defined" capabilities for inertia, SCL and dynamic voltage (bids without pre-defined ratio but a guidance on ratio for pathfinder phase 3). Pathfinders procure firm availability and are open to all technologies capable of providing the products, but only for providers that meet the "additionality criteria"[1].
Timing of procurement	We access this capability by sending instructions in real time through the BM.	We run intra-day auctions by sending out requirements to all counterparties that require capacity on interconnectors ahead of time.	Pathfinder tenders procure availability several years ahead of the contract start date[2]. This allows time for asset build.
Price determination	Bids and offers to manage system stability are remunerated as defined in the BM (pay-as-bid and utilisation only).	Counterparties submit their volume and price to the ESO and are remunerated pay-as-bid.	Pathfinders are pay-as-bid and remunerated with utilisation and/or availability payment pathfinder phase 3 is only availability. The tendered £/settlement period rate sets the availability payment. The selection process is competitive with the most economic and technical compliant solutions being selected for service delivery (pathfinder phase 3 also has non-price criteria).

1 While pathfinders are open to all technologies, current contract requirements include the additionality criteria to stimulate investment in new stability capability and providers.
2 Note that in every phase, not all solutions have the same start dates.

Markets Roadmap / Market Areas / Stability 55

Stability

Market Information: **Stability volumes**

Balancing Mechanism and trades

Actions in the Balancing Mechanism and trades are required to meet periods of stability shortfalls[3]. We observe high volumes in 2020 due to low demand levels during the pandemic. When demand is lower, overall generation is lower and the impact of a generation loss is more important as it corresponds to a higher proportion of the overall generation levels. The average monthly volume to reduce the largest loss (trades) is 699GWh in 2020, compared to 334GWh in 2019. Similarly, the average monthly volume to increase system inertia (RoCoF tagged actions in the BM) is 81GW in 2020, compared to 26GWh in 2019.

In 2021 we observe a decrease with the volume reaching an average of 315GWh to reduce the largest loss and 46GWh to increase system inertia. This is because our first pathfinder started delivering stability services in 2020 and Dynamic Containment also started at the end of 2020. Importantly, the implementation of Frequency Risk and Control Report (FRCR) had a positive effect in reducing the volume of BM and trading actions needed from May 2021. The FRCR establishes a process for assessing reliability versus cost to identify quick, short-term improvement that could drive high benefits for consumers.

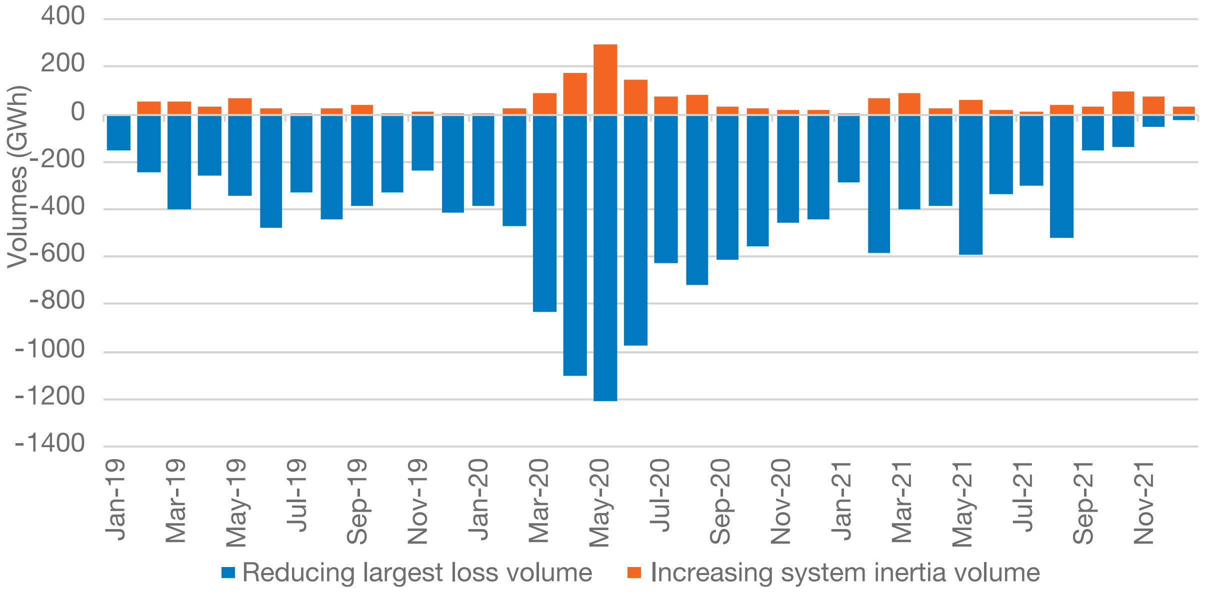
Pathfinders

Pathfinders are long-term contracts and only pathfinder phase 1 started delivering stability services. This table shows the volume of stability services procured through pathfinder contracts.

The volume provided by our three pathfinders is 33.5GVA.s for inertia and 23.4GVA for Short Circuit Level. The provision of dynamic voltage is also part of the tender requirements in phases 2 and 3.

Stability provided via our pathfinders, in addition to the expected stability being provided by the energy market, will cover our operational requirements until the end of 2027 (Operability Strategy Report).

Inertia management volumes: Jan 2019 - Dec 2021



Pathfinder	Location	Start[4]-finish	Volume
Phase 1	National	2020-2026 (6yrs)	12.5GVA.s inertia
Phase 2	Scotland	2024-2034 (10yrs)	6GVA.s inertia & 8.4GVA SCL
Phase 3	England/Wales	2025-2035 (10yrs)	15GVA.s inertia & 8GVA SCL

While our pathfinders cover our stability requirements until the end of 2027, our requirements will continue to increase beyond this. At present, there is no enduring market that is dedicated to stability, outside of the pathfinder process. However, enduring market solutions are being investigated through our Stability Market Design innovation project to ensure efficient procurement strategy as well as a route to market when pathfinder contracts end.

3 Data from ESO Data Portal: Constraint Breakdown Costs and Volume - Dataset| National Grid Electricity System Operator (nationalgrideso.com)
4 The start dates are not fixed and not all solutions have the same start dates.

Markets Roadmap / Market Areas / Stability 56

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Click the ⊕ to expand or enlarge content.

Market Information: **Stability costs**

Balancing Mechanism and trades

This chart shows the costs of our BM actions and trades for reducing the largest loss as well as increasing the system inertia. It also gives an indicative value of the average monthly price for accepted offers being tagged for system inertia in the BM. This data is reported on our data portal[5]. It is important to note that any one BM action can be taken for a combination of reasons, so the data below is a best endeavours process to identify inertia management related costs.

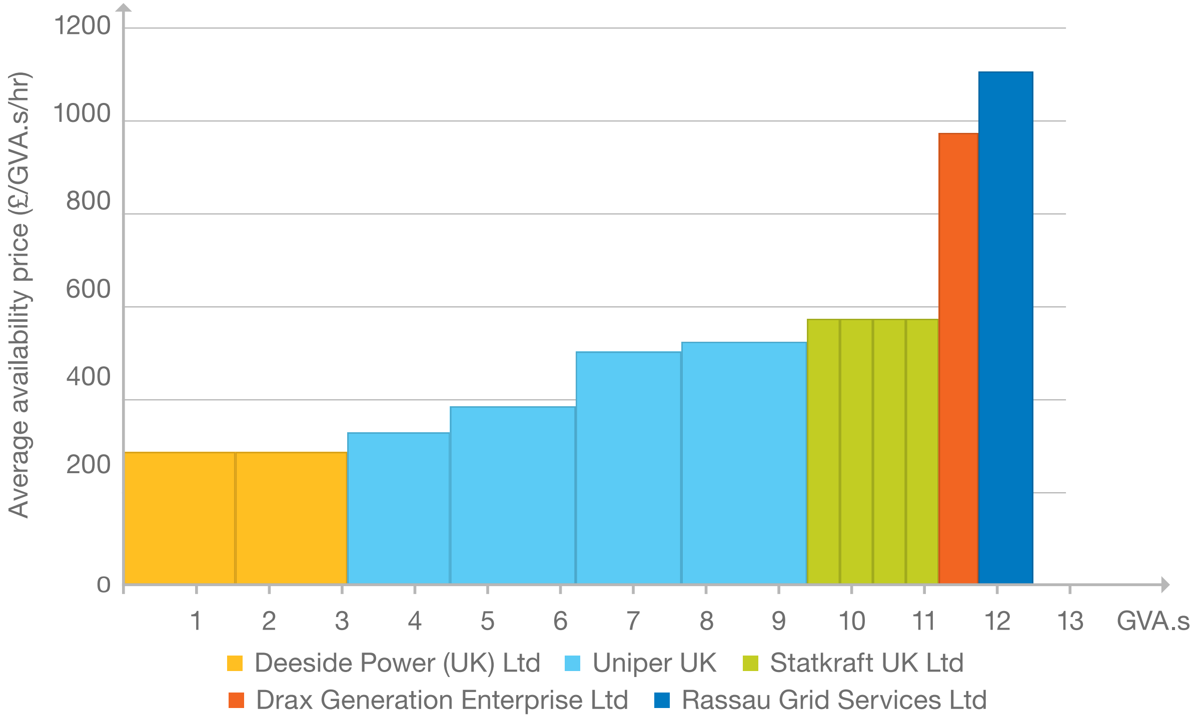
The average price for inertia was £2,310/GVA.s/hr over the 2019-2021 period. The changes in BM volumes due to the delivery of our first pathfinder in 2020, the start of Dynamic Containment at the end of 2020 and the implementation of Frequency Risk and Control Report (FRCR) in May 2021 all had a positive effect on the costs (as discussed on previous page). We also notice very high prices at the end of 2021 (average of £5,353/GVA.s/hr for Jul-Dec) due to various reasons as explained in the BM chapter such as high gas and carbon prices, scarcity pricing, etc.

Pathfinders

This chart shows the tender results of pathfinder 1. The tender results of pathfinder 2 and 3 are not yet available.

In 2021, our stability pathfinder Phase 1 costs amounted to £52.5m (12.5GVA.s at a volume weighted average availability price of £480/GVA.s/hr). Note that costs between pathfinders and the BM are difficult to compare because pathfinders provide stability throughout the year and the BM only when the stability service arise in real-time. The frequency of requirements will therefore be considered when deciding the volume to be

Stability Pathfinder 1: tender results[6]



Inertia management costs

Stability Pathfinder 1

Stability pathfinders are long-term contracts looking for a cost-effective way to contract stability services to cover our baseload requirements. Actions are also required in the BM to cover additional stability requirements that arise in real-time. We have seen high costs over the past few months in the BM. In addition, the BM is not a dedicated market for stability and therefore does not provide a market signal to invest in stability technologies. It also fails to access stability services from new providers such as renewables with grid forming capabilities. A key challenge going forward is to define market arrangements for the long- and short-term procurement of stability to reach a cost-efficient outcome.

5 ESO Data Portal: Constraint Breakdown Costs and Volume - Dataset| National Grid Electricity System Operator (nationalgrideso.com) and ESO Data Portal: System Inertia Cost - Dataset| National Grid Electricity System Operator (nationalgrideso.com)
6 The figure shows Stability Pathfinder 1 tender results. The prices accepted in the Phase 1 were assessed against the alternative actions required for accessing inertia without the service. Prices accepted in Phase 1 should not be used to indicate prices that will be accepted in Phase 2,3 or beyond.

Markets Roadmap / Market Areas / Stability 57

Stability

Market Information: **Stability providers**

Pathfinders

The first pathfinder attracted bidders dedicated for stability provision such as rotating stabilisers, synchronous condensers, re-purposed thermal generators, and pumped storage. For the second and third pathfinder, a wider range of technologies is also expected to take part.

Balancing Mechanism

Actions can be taken in the BM to access stability service when required.

- Reducing the largest loss: In 2021, this has typically been managed through changing interconnectors' infeeds or changing the ouput from groups of plants all connected to a single point on the grid.
- Inertia management: This requires turn-up of synchronous generators (mainly gas-fired units) and turn-down of non-synchronous generators (typically renewables).

In addition to pathfinders and actions in the BM, stability services are also exogenously provided by the wholesale market as a "by-product" of synchronous generation (mostly gas and coal units).

The pathfinder approach is successful in supporting our transition to zero carbon. In addition, further developments of an enduring stability market may accelerate the transition to a decarbonised system. This could open new routes to market for stability providers and enable the participation of new zero carbon technologies while reducing carbon actions in the BM. Our objective for any future stability market is to be non-discriminatory between technologies with equivalent capabilities.

Markets Roadmap / Market Areas / Stability 58

Stability

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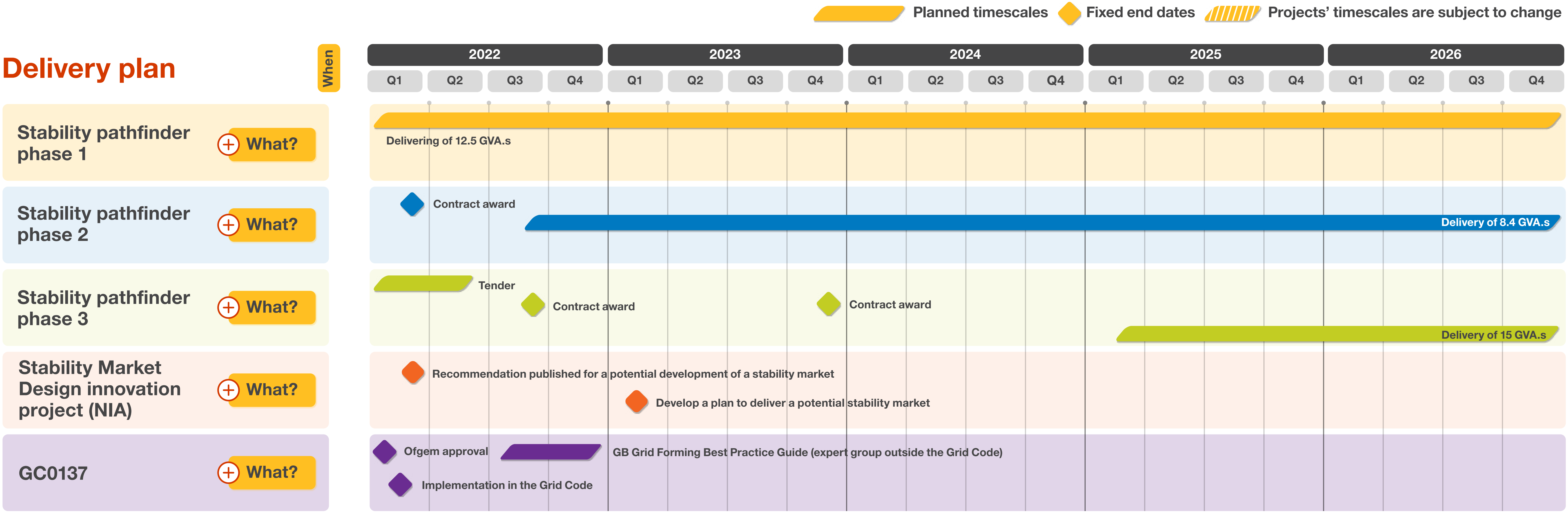
Delivery plan



Stability

Efficient dispatch

Efficient Investment

Value for Money

Opportunity for Change (1) – **Ensuring stability requirements are met**

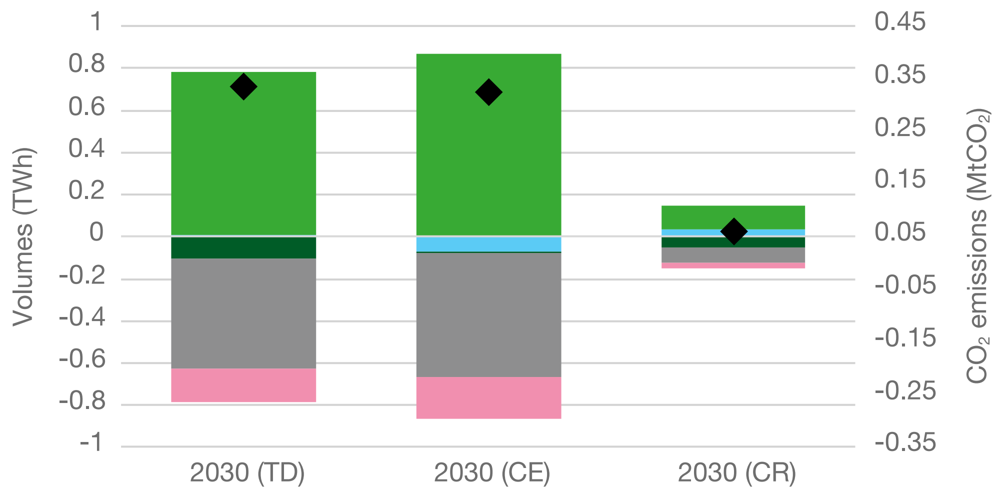
The volumes expected to be procured via pathfinders 1, 2 and 3 mean there is only a small need for additional capacity to meet average stability requirements in 2030. However, there will still be periods in the future where redispatch actions are needed to procure sufficient stability services.

A study undertaken on behalf of ESO by consultants Afry[7] explored the future development of stability requirements (focussing on inertia and SCL). Considering the stability capacity procured in pathfinders 1, 2, and 3 is available in 2030, the study shows that, on average, there is enough inertia on the system to meet our requirements. Whilst some regions have enough SCL capability, others don't (e.g. South Coast, South Wales). To meet SCL requirements, it is therefore estimated that there is a small need for additional investment beyond what has been and is being procured in the pathfinders.

Despite pathfinders and these capacity additions, there are still circumstances where additional inertia and SCL will be required. This implies the need to take action in the BM. The redispatch actions are likely to increase CCGT output and reduce the need for imports, given the nature and location of the requirements. This implies additional costs due to redispatch actions as well as an increase in carbon emissions.

It is important to note that this analysis was executed using an average weather year, and taking into account average availability rather than specific outage schedules and scenarios. We would expect more extreme conditions to drive up requirements.

Redispatch volumes and CO_2 emissions increase



FES 2019 scenarios: Two Degrees (TD), Consumer Evolution (CE), Community Renewables (CR)

Other · Interconnector · Onshore wind · CCGT · Biomass · CO_2 emisssions

We need to investigate stability market design options that could deliver additional investment and lead to potential savings by lowering redispatch costs and volumes.

7 The study was based on FES 2019 data. The assumptions are therefore likely to have changed, potentially altering our requirements. Further analysis of stability requirements based on FES 2021 data is expected to be available in the second half of 2022.

Markets Roadmap / Market Areas / Stability 60

Stability

Opportunity for Change (1) – **Ensuring stability requirements are met**

Key strategic questions

- **What market design option is optimal for stability services: short-term only, long-term only, or a combination?**

Our Stability Market Design innovation project is exploring a potential enduring solution for the procurement of stability services. The study shows that short-term only or long-term only arrangements can be exposed to issues of over and/or under procurement or to overexposure to short-term volatility or scarcity. A market with a combination of short- and long-term procurement timeframes could promote cost efficient outcomes. A combination could also incentivise wider participation, reducing risks for the ESO as the sole buyer and also for service providers.

- **If a long-term stability procurement continues to exist, what are the possible design options?**

The stability pathfinders currently offer long-term contracts to stability providers who meet the additionality criteria. The Stability Market Design innovation project investigates more complex design options for long-term contracts. This could introduce potential changes from the pathfinder approach including changes in lead time, contract duration, and remuneration. Different eligibility criteria are also considered, from markets with additionality criteria (similar to the pathfinder approach) to markets where all providers and technologies can participate (new or existing, in- or out-merit). In comparison with an "ad-hoc" pathfinder approach, an enduring long-term market could also increase the certainty of future stability procurement for investors/developers.

- **If a short-term stability market is developed, what are the possible design options?**

At the moment, there is no dedicated short-term stability market. We currently access stability services in short-term through our balancing tools, but this could lead to inefficiencies in re-dispatch. The Stability Market Design innovation project investigates the introduction of a potential dedicated short-term market. One potential market design could be at day-ahead stage with separate procurement for the three relevant stability services (inertia, SCL, dynamic voltage support). The development of a short-term market could reduce cost inefficiencies associated with redispatch, increase transparency of stability costs and provide real-time market prices for stability. However, these benefits would need to be weighed against the costs of implementation and operation.

Markets Roadmap / Market Areas / Stability 61

Stability

Opportunity for Change (2) – **Making our stability market more accessible**

The current routes for stability procurement are closed to some potential stability providers such as weather-driven renewables. In addition, existing providers of stability services that inherently provide stability through normal market dispatch should be carefully considered.

Pathfinders are open to all technologies but include an additionality criteria as the focus of pathfinders is to stimulate new investment. Therefore, new stability providers can participate in pathfinders (new synchronous generators when they operate at 0MW). Existing or retiring assets can also participate in certain circumstances.

Pathfinders also require a high level of availability as their objective was to provide stability solutions that contribute in all system conditions. Technologies that cannot guarantee this high level of availability may need to have additional equipment (e.g. storage) to deliver the required availability.

Renewable technologies can replicate some of the stability characteristics (called "grid forming" capability). However, the current pathfinder design is less suitable for weather-driven providers as they are unable to commit to meeting long-term availability thresholds and additionality requirements.

The current market arrangements are also less attractive for existing providers as they are not directly rewarded for the provision of stability services. When stability services are provided as a by-product in the wholesale market or after instruction in the BM, there is only a remuneration based on their active power output (£/MWh). This should be carefully considered as this could lead to potential inefficiencies such as early plant closure.

We need to balance providing a level playing field for all providers to access stability markets with ensuring value for money of stability services.

Stability

Opportunity for Change (2) – **Making our stability market more accessible**

Key strategic questions

- **Who should be eligible for the provision of stability services?**

Our Stability Market Design innovation project is exploring different eligibility criteria. A future stability market design could be "selective" e.g. targeting only top-up services, new technologies or specific technical characteristics or could be "global", considering new and existing, in- and out-merit service providers.

- **Could renewable providers deliver stability solutions?**

New converter designs and associated control algorithms are evolving and can replicate some of the stability characteristics. The Grid Code modification GC0137 proposes to add a non-mandatory technical specification relating to GB Grid Forming Capability. This will be fundamental to provide the opportunity to renewables to take part in a stability market.

- **What is the optimum timeframe for procurement to avoid discrimination between technologies with equivalent capabilities?**

There is a wide range of technologies that could provide stability services. While some would favour short-term approaches to only deliver when available (e.g. weather-driven providers) or needed (e.g. technologies running in the energy market), dedicated stability providers such as synchronous condensers have extremely low marginal cost. Long-term market solutions seem more appropriate for those dedicated solutions that are one of the lowest cost solutions for meeting our stability requirements throughout the year. A combination of short- and long-term market approach could accommodate the participation of different technologies.

- **How can we ensure that TO solutions can compete effectively and fairly with third party solutions to provide stability services?**

We want to find solutions to stability management that are in the best interests of consumers. Whilst there are challenges in evaluating the optimal solution due to the different business models of network owners and commercial parties, considering both TO and third-party solutions could improve overall economic efficiency. The stability pathfinders enable the indirect participation of TOs, providing a regulatory backstop where TO assets compare costs to those of a potential commercial solution. We also note the development of an Early Competition Plan to set out how early competition for onshore transmission could be introduced in future. We will be using the lessons-learned through our pathfinders to help inform this development.

Markets Roadmap / Market Areas / Stability 63

Voltage

We need new, cost-effective routes to access reactive power in the right locations to manage system voltages. We are exploring the potential benefit of reactive power markets to provide a clear, transparent, and consistent signal to industry about the value of reactive power services.

This journey began with the ground-breaking voltage pathfinders; these tenders are specifically targeted at regions where we anticipate a voltage compliance risk. At time of publication we are still exploring the benefits of expanding market-based procurement for reactive power services. If we believe this is the optimal solution to access reactive power services at lowest cost to consumers, we will look to implement a market in due course.

The Operability Strategy Report shows that we will lose access to substantial quantities of reactive power (MVAr) capability by 2025. The report also shows that our requirement for reactive power absorption to manage high voltage conditions will continue to increase.

There are two in-flight projects that are helping us to reform our procurement options for reactive power services: the Future of Reactive Power (FoRP) – Reactive Market Design NIA project and the NOA High Voltage Pathfinders. There are also several ongoing initiatives to improve the way in which we share voltage data. These activities will support us in developing a procurement strategy for reactive power that delivers maximum value for consumers.

Future Considerations

As the generation mix and system needs change, we need to consider whether the industry codes and frameworks are sending the right signals to network owners and developers regarding their voltage obligations and reactive capability. In line with net zero ambitions for the power sector we will need to make sure we are not dependent on high carbon providers to support voltage management and can access new sources of reactive power. Due to the locationally restrictive nature of our reactive requirements, we need to develop market frameworks that deliver solutions in the right locations and avoid market power issues.

What are Voltage services?

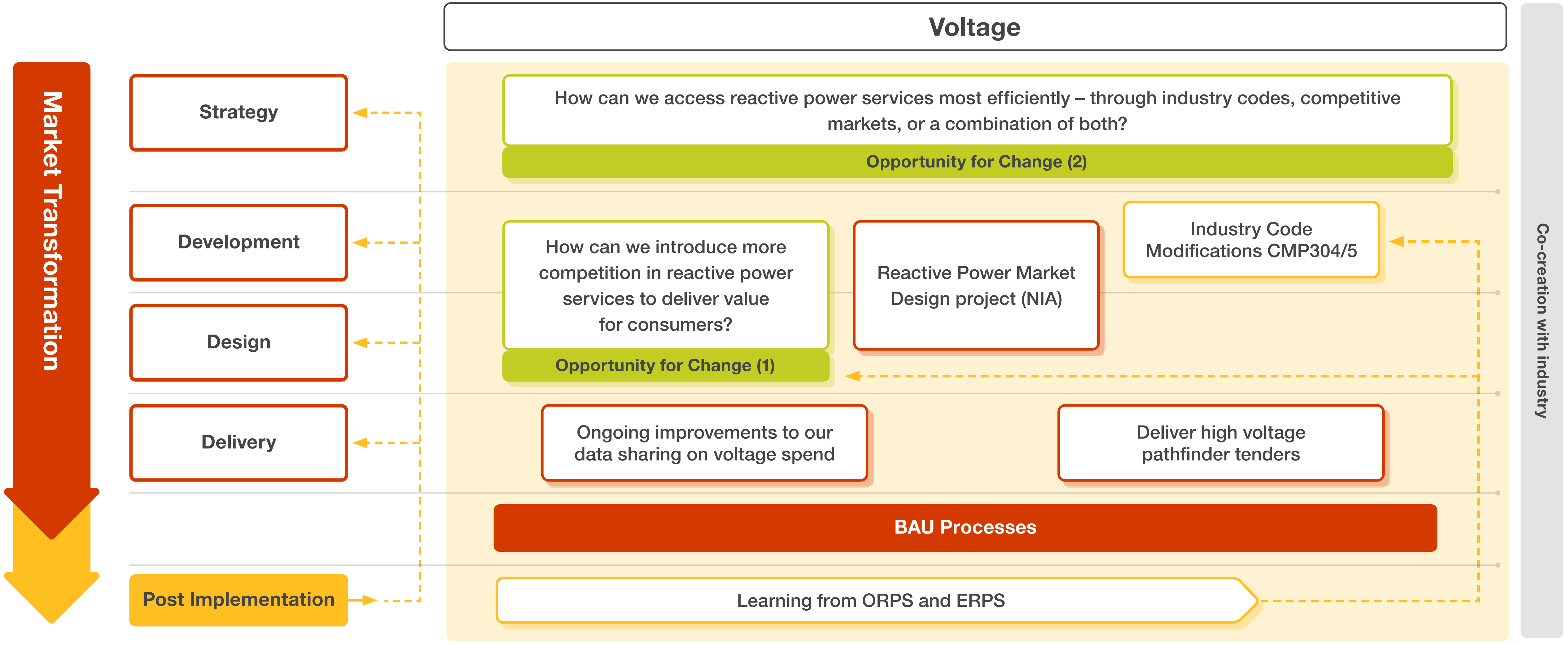
We currently access reactive power through three main routes: from TO network assets (shunt reactors, capacitors, SVCs and STATCOMs), the Obligatory Reactive Power Service (ORPS) and our NOA Voltage Pathfinders. Where we have a short-term voltage need (for example to cover an outage on TO equipment, or to manage our requirements before a pathfinder contract starts) we have run ad-hoc tenders for short-term voltage contracts. We also manage voltage in some regions by switching out circuits which are contributing to voltage gain, this action reduces our need for reactive power services but could reduce our level of redundancy.

Markets Roadmap / Market Areas / Voltage 64

Voltage

Market Transformational Stages

We work on the projects and strategic questions within this graphic simultaneously.



Markets Roadmap / Market Areas / Voltage 65

Markets Roadmap / Market Areas / Voltage 66

Market Information: **How we procure reactive power services**

	Obligatory Reactive Power Service (ORPS)	NOA Voltage Pathfinders	TO Network Assets (delivered through the price control)
Product description	The Grid Code requires all transmission connected generators to have the capability to both absorb and inject reactive power[1]. In addition, the Grid Code also requires all Large and Medium Power Stations which are distribution connected to have a Reactive Capability (definitions of Large and Medium can be found here).	The pathfinders are procuring firm capability (>90% availability, reactive power absorption only) to provide reactive power services in specific regions. They enable competition between network owners and commercial parties to deliver reactive power solutions.	There are many TO assets on the transmission network which can be used to manage voltage levels. These assets currently make up an important part of our voltage management toolkit.
Timing of procurement	This capability can be instructed in real time when the generator is generating at or above its Stable Export Limit (SEL) or above 20% of its installed capacity. Where reactive power is needed, and there are no suitable providers already generating, we will synchronise units through the offers in the BM or pre-gate closure trading to access their capability.	Pathfinder tenders procure availability to provide reactive power several years ahead of the contract start date. This allows time for asset build enabling new-build assets to participate.	TOs submit plans to build new assets with reactive capability in their business plans for each price control. We can also trigger investment in reactive assets through an SO-TO Code (STC) planning request.
Price determination	A £/MVArh ORPS price is determined monthly using a methodology contained in Section 4 of the Connection and Use of System Code (CUSC). The ORPS price is indexed to an average of three separate month ahead wholesale power price indices as well as inflation.	Pathfinder contracts are pay-as-bid with potential providers submitting an availability fee (£/SP) as part of the tender process. The Pennines and Mersey pathfinders have not included utilisation payments and successful providers agree to give up their potential ORPS utilisation payments for the duration of their contract if applicable.	Payment for TO owned reactive compensation equipment is made monthly based on the assets' inclusion in the TO's regulated asset base (RAB) and recovered by the ESO, on behalf of the TOs, through TNUoS charges. There are no additional payments made to utilise the equipment.

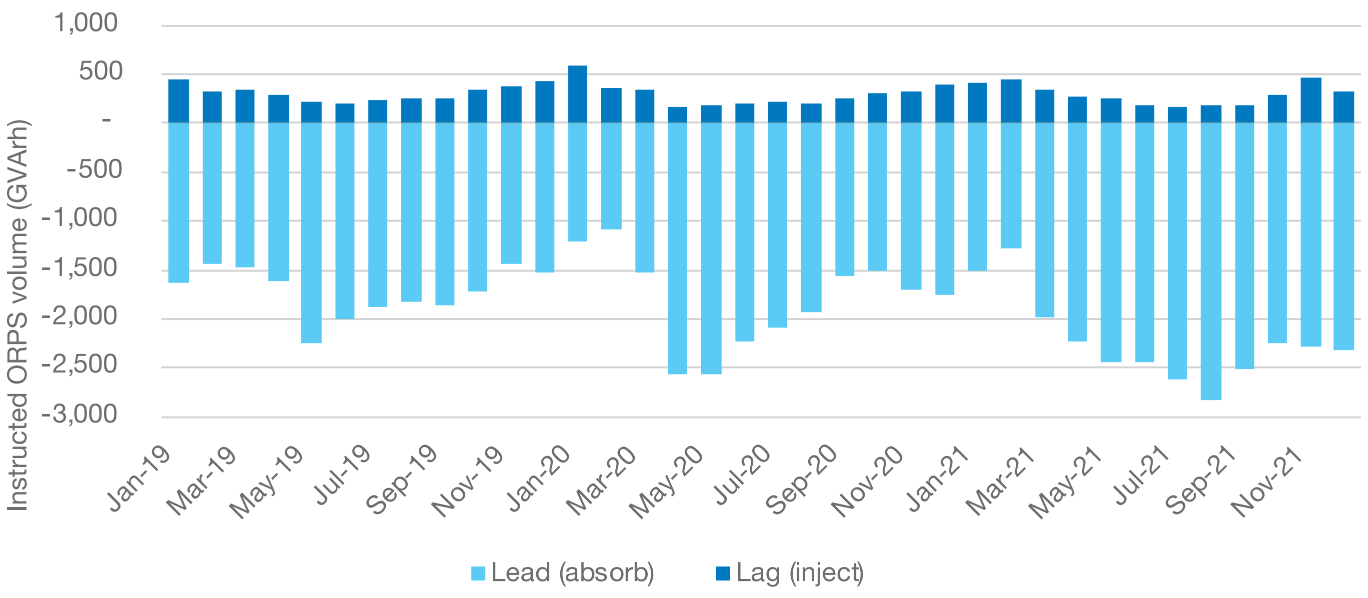
1 The Grid Code refers to operation with leading or lagging power factors when setting out reactive power obligations. Our publicly available data on ORPS utilisation uses this terminology as well. For generators a "leading" power factor will result in some consumption or absorption of reactive power which helps to reduce the voltage in the surrounding network while operation with a "lagging" power factor will result in the injection or production of reactive power onto the system which increases the voltage in the surrounding network.

Voltage

Market Information: **Reactive power volumes**

This chart shows the volumes of reactive power absorption (lead) and reactive power injection (lag) procured through ORPS across the Jan 19 – Dec 21 period. We see higher levels of absorption over the summer when we typically have a more lightly loaded network which places upwards pressure on system voltages. This has increased over the past three years. This increase is driven by voltage spill at the Grid Supply Point (GSP) from the Distribution network, changes to the demand loads on the system and the increasing volumes of Embedded Generation. The Operability Strategy Report (p47) explains this phenomenon in more detail.

ORPS volumes: Jan 2019 - Dec 2021



Note: Volumes provided by network assets and contracted pathfinder units have not been included in this chart.

Our need for reactive power absorption, especially over the summer months, is projected to increase. At present we are meeting some of our summer needs through the ORPS capability of large thermal units which are often out of merit in the summer conditions which produce high voltage challenges. This comes with additional cost to synchronise the unit and additional MW which we don’t need. We therefore need to find alternative routes to access reactive power absorption in summer.

One approach could be to secure access to MVAr absorption through a market for reactive power which we are exploring through the Future of Reactive Power project. A course of action which we take alongside securing the absorption of reactive power is to try and mitigate high voltage incidences through operational switching. We identify the circuits that produce the highest voltage gain on the network and can reconfigure the network to take those circuits out of service safely and securely. More information on operational switching strategies can be found in our voltage screening report.

Markets Roadmap / Market Areas / Voltage 67

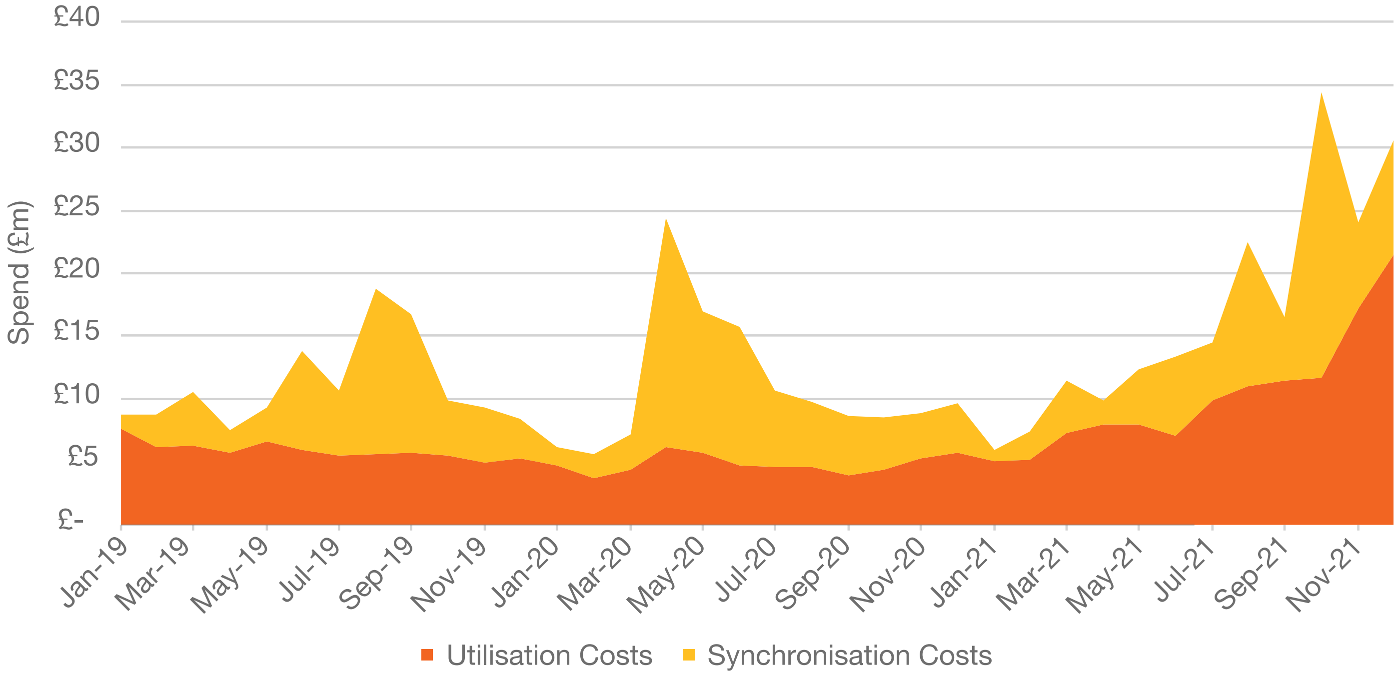
Market Information: **Reactive power costs**

This chart shows the cost for ORPS utilisation payments and synchronisation costs tagged as voltage actions from January 2019 - December 2021 inclusive. Synchronisation costs are the costs of accepting offers in the BM to bring dispatchable units online and then instruct them to inject or absorb reactive power. The region with the highest spend on ORPS over this three-year period was the East Midlands with £74.3m incurred. For this region the cost of synchronising thermal plant to be able to access reactive power capability was the main cost component.

In the autumn/winter of 2021 we also saw the ORPS price start to rise. Recent extreme wholesale prices have roughly tripled the ORPS rate from a previous average for 2019 and 2020 of £2.85/MVArh to £10.63/MVArh in December 2021.

Our spend on synchronisation costs shows a clear annual pattern. It increases over the summer as we need to bring thermal plant in the right location onto the system through accepting BM offers to instruct them to provide MVAr.

ORPS costs: Jan 2019 - Dec 2021



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 2021.

Due to the specific locational nature of reactive power requirements and noting that it is not possible to transmit large volumes or reactive power across the system, the pool of BMUs that can be called upon to provide ORPS can be small. This means that we can end up facing high and volatile offer prices in the BM with no other option but to accept them. This is likely to remain an issue with any sort of close to real time procurement of reactive power. Through our Future of Reactive power project, we are considering the right balance of long and short term procurement for this service given its uniquely locational requirements.

We publish data about our voltage spend every month for 19 voltage regions in GB.

Markets Roadmap / Market Areas / Voltage 68

Voltage

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Market Information: **Reactive power providers**

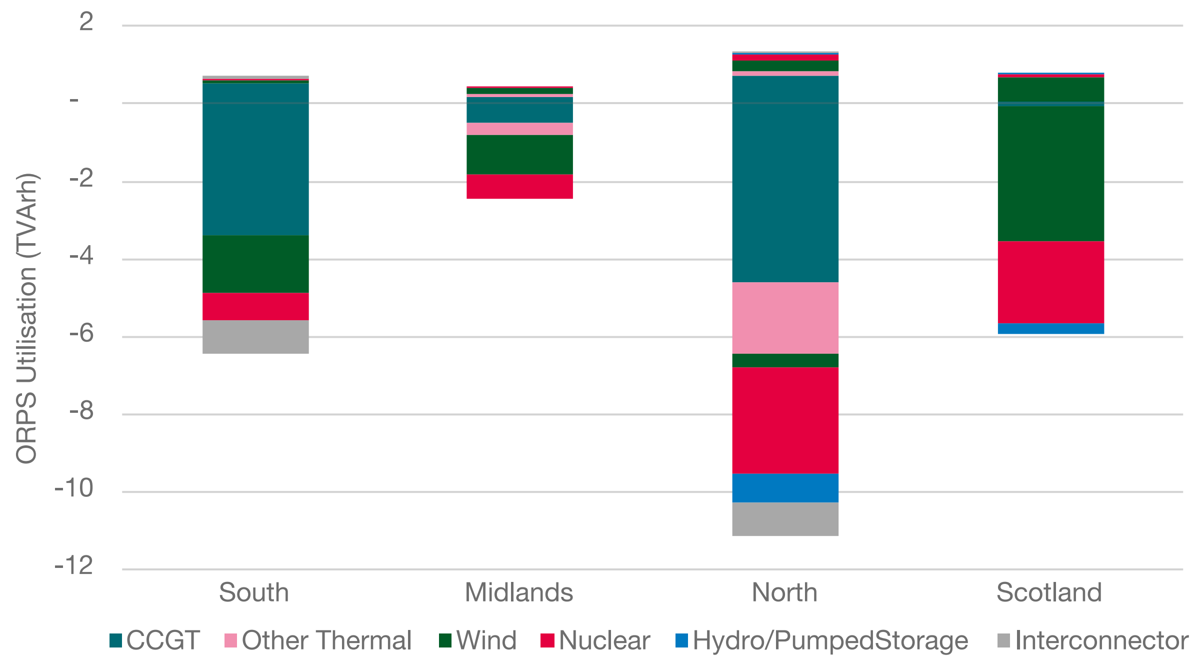
Chart 1: ORPS providers[2]
This chart shows the volume of reactive power utilised through the ORPS service during 2021. Lead volumes (absorption of reactive power) are included as negative values whilst lag volumes (injections of reactive power) are positive.

The generation instructed to provide the service is broadly reflective of the generation mix in that region: wind dominates provision in Scotland whilst CCGTs are prevalent in the South. Voltage Source Converter (VSC) interconnectors have a high capability to provide reactive power services and the connection of NSL and IFA2 in 2021 has seen interconnector utilisation increase.

Chart 2: Mersey Pathfinders entrants
This chart shows the 40 entrants to the Mersey high voltage pathfinder that passed the technical assessment stage. Most of the solutions entered were zero carbon. The two winning bids were a shunt reactor and a battery.

Chart 3: Pennines Pathfinder entrants
This chart shows the 36 entrants to the Pennines high voltage pathfinder that passed the technical assessment stage. The winning bids were shunt reactors and the onshore HVDC assets of an offshore wind connection.

ORPS providers by technology type



Note: volumes provided by network assets are not included.
Pathfinder volumes are shown as effective MVAr.

⊕ ORPS providers ⊕ Mersey Pathfinder ⊕ Pennines Pathfinder

Our reliance on CCGT units to provide reactive power services needs to be addressed to prepare for a zero carbon power system by 2035. At present, CCGTs can only provide reactive power services when they are also generating MW unless they were adapted to running in Synchronous Compensator mode. This means that utilising them to manage network voltages can be a high carbon action to take if the unit has not already been dispatched through the wholesale market. Usage of zero carbon voltage management solutions such as wind and interconnectors is increasing, and the results from the pathfinders have shown that zero carbon provision of reactive power can meet high availability requirements for reactive power absorption. We will need to consider all of these factors as we determine the optimal routes for procuring reactive power services in the future.

2 The dataset used to create this chart is published monthly and can be found on our data portal.

Markets Roadmap / Market Areas / Voltage 69

Voltage

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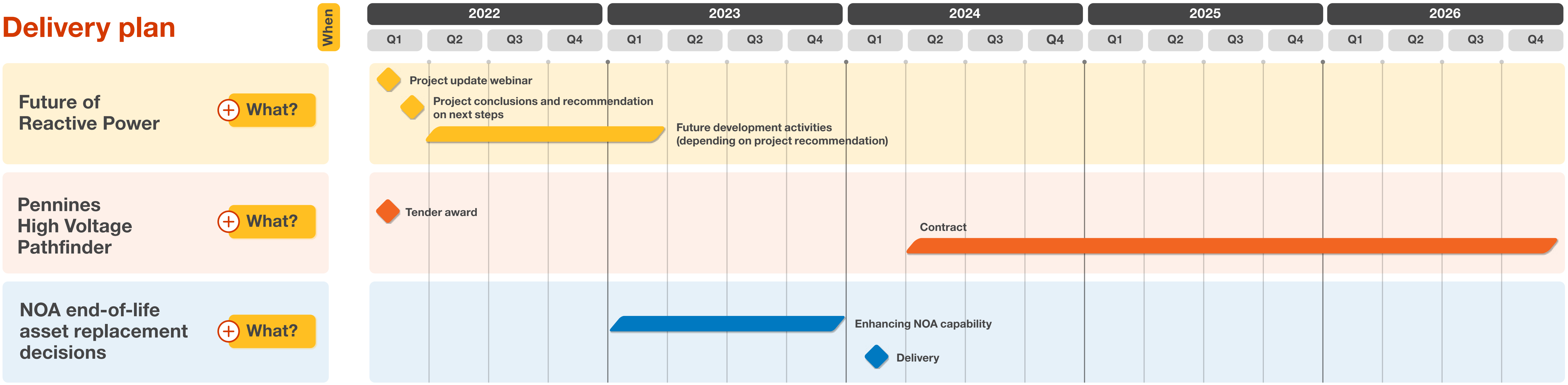
Planned timescales
Fixed end dates
Projects' timescales are subject to change

Delivery plan



Markets Roadmap / Market Areas / Voltage 70

Voltage

Efficient dispatch

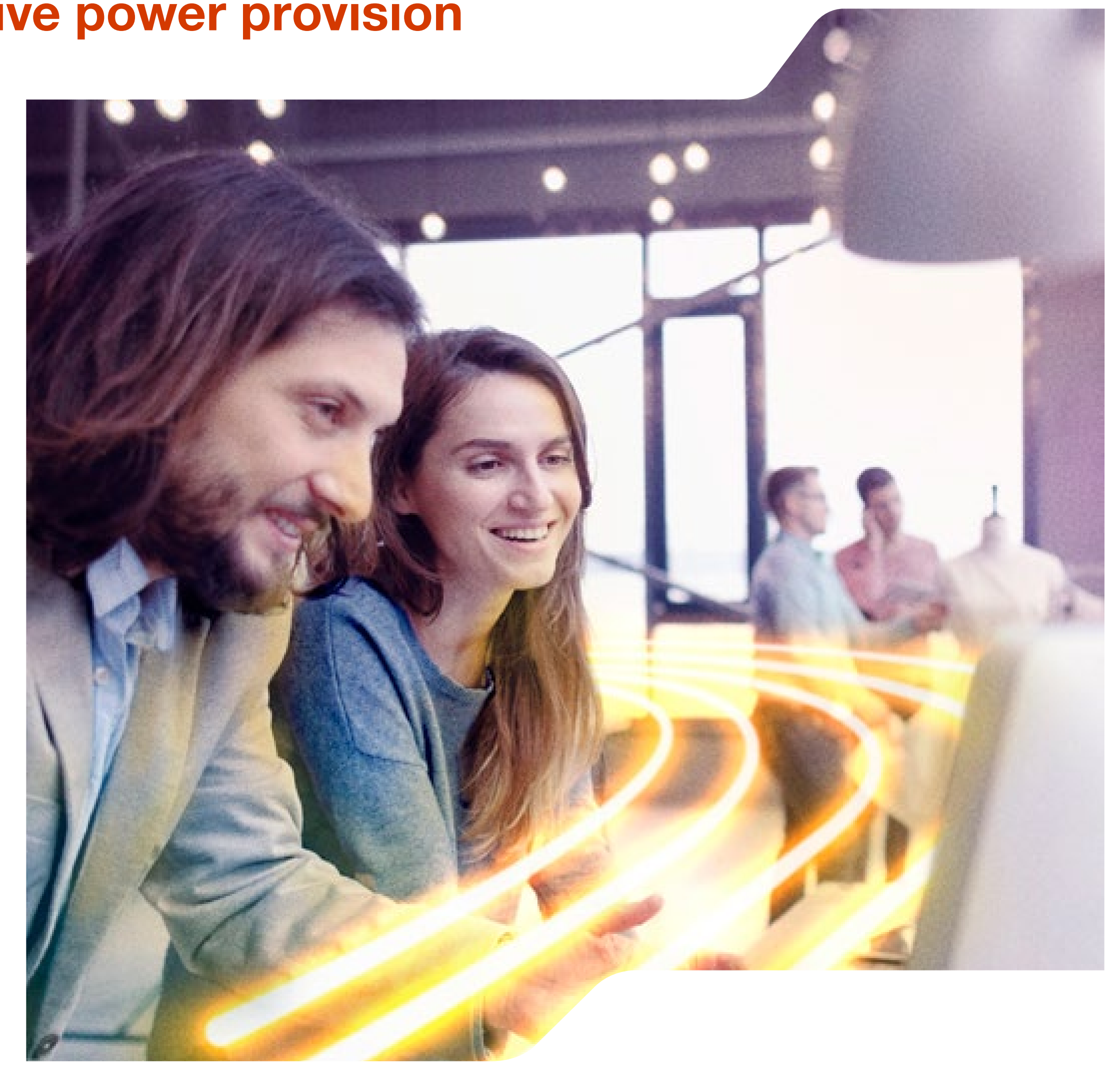
Efficient Investment

Value for Money

Opportunity for Change (1) – **Enhancing competition in reactive power provision**

Delivering competition in reactive power provision is challenging but could provide significant consumer benefits.

- Reactive power services are uniquely locational. Providers in one region can be completely ineffective at meeting a need in another region. This is due to the difficulty in transporting reactive power over distance. This unavoidable feature of reactive power services creates risks for us in meeting our operational needs and for the end consumer who may be exposed to extreme costs in situations where we are a ‘distressed buyer’ due to the lack of options in a particular region.
- To reduce the chances of this we want to open new routes to access more reactive power capability from both new and existing providers and signal the locations in which we need more reactive power provision. There are two possible avenues of new reactive capability: Distributed Energy Resources (DER) and additional capability connected to the transmission network whether that is completely new transmission assets or additional capability from our existing providers.



We need to open participation routes to new providers whilst ensuring operability and cost protections are in place.

Markets Roadmap / Market Areas / Voltage 71

Opportunity for Change (1) – **Enhancing competition in reactive power provision**

Key strategic questions

- **What barriers exist to accessing reactive capability from DER?**

Through our Future of Reactive Power project, we have identified several potential barriers which may restrict the volume of reactive power available from DER providers. A key output of the project is a paper explaining the challenges and offering potential high-level initiatives to allow DER to offer reactive power services to meet transmission voltage needs.

- **What role could the DSOs play to best enable DER solutions to participate in a reactive power market?**

In partnership with UK Power Networks (UKPN) we ran an innovation project called Power Potential, which concluded in 2021, to explore reactive power provision from DER to meet transmission voltage needs. For the project UKPN acted as a neutral market facilitator both to organise delivery of the dynamic voltage service and to transfer payments. We are using learnings from the project through the FoRP project, working closely with the DSOs to share ideas about how to enable DER to participate in a potential market. Work will be continued through the next phase of the project in conjunction with the ENA's Open Networks workstreams.

- **How can we best support effective and fair competition between third party solutions and TO/DNO led solutions to provide reactive power services?**

We have demonstrated through our NOA high voltage pathfinders that competition between network and third-party solutions can deliver consumer benefit. However, there are challenges in identifying the optimal procurement solution when network owners and commercial parties have very different business models. The Mersey pathfinder tender set a foundation to allow network solutions to compete directly with third party options using TO costs as the counterfactual proposal to a market delivered solution. We have worked to incorporate lessons learned from the Mersey pathfinder through the Pennines tender such as using the same infrastructure costs to compare solutions and providing more information at an early stage of the tender.

- **What is the optimum mix of long- and short-term procurement to deliver efficient markets?**

Locking in too much long-term capacity could mean overholding capability when we don't need it. Waiting until closer to real-time could lead to insufficient new investment meaning we can't access the services we need to operate the system. This is particularly difficult for reactive services where our requirement fluctuates over the day and across seasons depending on network configuration and load patterns. The FoRP project is developing a procurement strategy to determine how to split procurement across different timescales.

Markets Roadmap / Market Areas / Voltage 72

Voltage

Efficient dispatch

Efficient Investment

Value for Money

Opportunity for Change (2) – **Accessing reactive power services through industry codes or market solutions or a combination**

We can access reactive power to manage system voltages through the industry codes and frameworks (a code-governed route e.g. ORPS, network assets) or through a commercial solution (a market route e.g. voltage pathfinder tenders). Determining the optimal route for different situations will help to secure the system at lowest cost.

Throughout this chapter we have shown that procuring reactive power services through market mechanisms can be challenging. As a result, most system operators across Europe use their respective industry codes and frameworks to set obligations on system users to support voltage management. The boxes below give a high-level definition of how the GB industry codes set out provisions for reactive power services and help us to manage voltage in both pre and post fault conditions.

Connection and Use of System Code (CUSC)	Contains the ORPS and ERPS price setting methodologies and rules of payment
SO-TO Code (STC)	Sets out the obligations for reactive transfer between TO networks
Grid Code	Contains provider requirements for reactive capability at different levels of active power output
SQSS	Sets out the acceptable pre and post fault network voltages for day-to-day system operation

We believe that competitive procurement of reactive power services can deliver consumer value. However, there is also a role to play for code-governed provision of reactive power. To help these two approaches work coherently together, there must be clear and reasonable obligations on code signatories to support voltage management that complements any market-based procurement.

Markets Roadmap / Market Areas / Voltage 73

Opportunity for Change (2) – **Accessing reactive power services through industry codes or market solutions or a combination**

Key strategic questions

- **What is the best way to incentivise investment in reactive capability from converter-based technologies?**

Most new transmission connections are wind, solar and interconnectors; these technologies use AC/DC converters which can often inject or absorb reactive power at very low levels of active power output with minimal extra investment. This is not reflected in the Grid Code.

Updating Grid Code requirements to increase reactive capability required from asynchronous generators at low levels of active power output could deliver more options for managing voltages. An alternative route is a market-based solution which would offer an incentive for these types of provider to invest in reactive capability. We believe that a commercial solution will deliver better value in this instance. A market solution could send investment signals to site reactive equipment where it will be most useful, rather than mandating additional investment to all new connections and be open to both existing and new connections whereas a change to the Grid Code requirements would only affect new connections.

- **How can we send the right signals to offshore developers to deliver cost-effective siting of reactive compensation equipment?**

Reactive power injected or absorbed offshore must travel a long distance to manage onshore voltages. This means that, for the purposes of system operation, reactive compensation equipment is better located as close as possible to the area of need.

Developers should be encouraged to site their reactive compensation equipment where it is most useful for managing onshore voltages. This will require co-ordination between the industry codes and incentives sent through market-based procurement methods.

- **Is the ORPS methodology still fit for purpose?**

The ORPS methodology as written in Section 4 of the CUSC hasn't been reviewed in many years. Following the conclusion of the Future of Reactive Power project we will need to consider whether changes should be made to ORPS to ensure the service works coherently with any new market arrangements.

- **How should third-party MVAr only assets be treated within the industry codes?**

Pathfinders are designed to encourage the development of innovative solutions to meet system needs. One such successful example is Mersey Reactive Power Limited (MRPL) which is the first example of a shunt reactor that is not part of a generator connection or owned by the incumbent TO. Ofgem agreed to grant MRPL an Electricity Transmission Licence in January 2022.

Balancing Mechanism

The Balancing Mechanism (BM) is the real time energy balancing market and is core to ensuring reliable and economic system operation. Our ambition is to simplify accessibility to the BM for all technologies and to enable the participation of all market providers above 1MW.
We also want to develop our tools and processes to be able to manage the increasing volume of bids and offers and enable the dispatch of new technologies and market participants.

A study undertaken in 2021 for the ESO by consultants LCP[1] shows the volume of BM actions required in the future for energy balancing is expected to increase considerably. This is mainly the result of increasing imbalances as wind penetration grows.

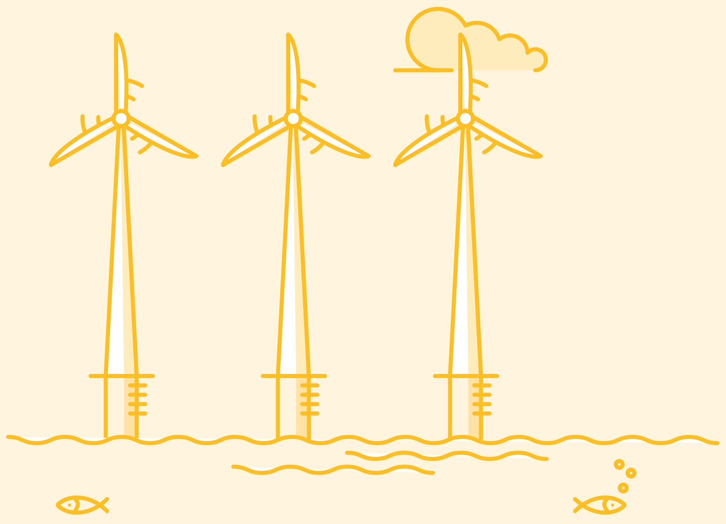
To manage the increase of bids and offers, as well as the increase of providers and data, it is essential that we invest in BM tools and systems. New ways to plan and dispatch market providers are being developed through our enhanced balancing capability programme. We also aim to increase transparency of our BM actions, as we recognise that clear real-time price signals are a key aspect of providing efficient market incentives.

Future Considerations

We also want to consider the impact of our BM actions on our ambition to operate a zero carbon system. We need to continuously review the routes to the BM to ensure it is accessible for low carbon technologies. To address the overall BM carbon impact, we are also looking at new market solutions to enable to move some system actions to other markets outside of the BM.

What is the BM?

The Balancing Mechanism (BM) is the market we use to manage system operation in real time. It is used to dispatch bids and offers, which are offered by a variety of providers (Balancing Mechanism Units, or BMUs[2]) and represent a willingness to increase or decrease their energy output in exchange for payment through arrangements set out in the Balancing and Settlement Code.



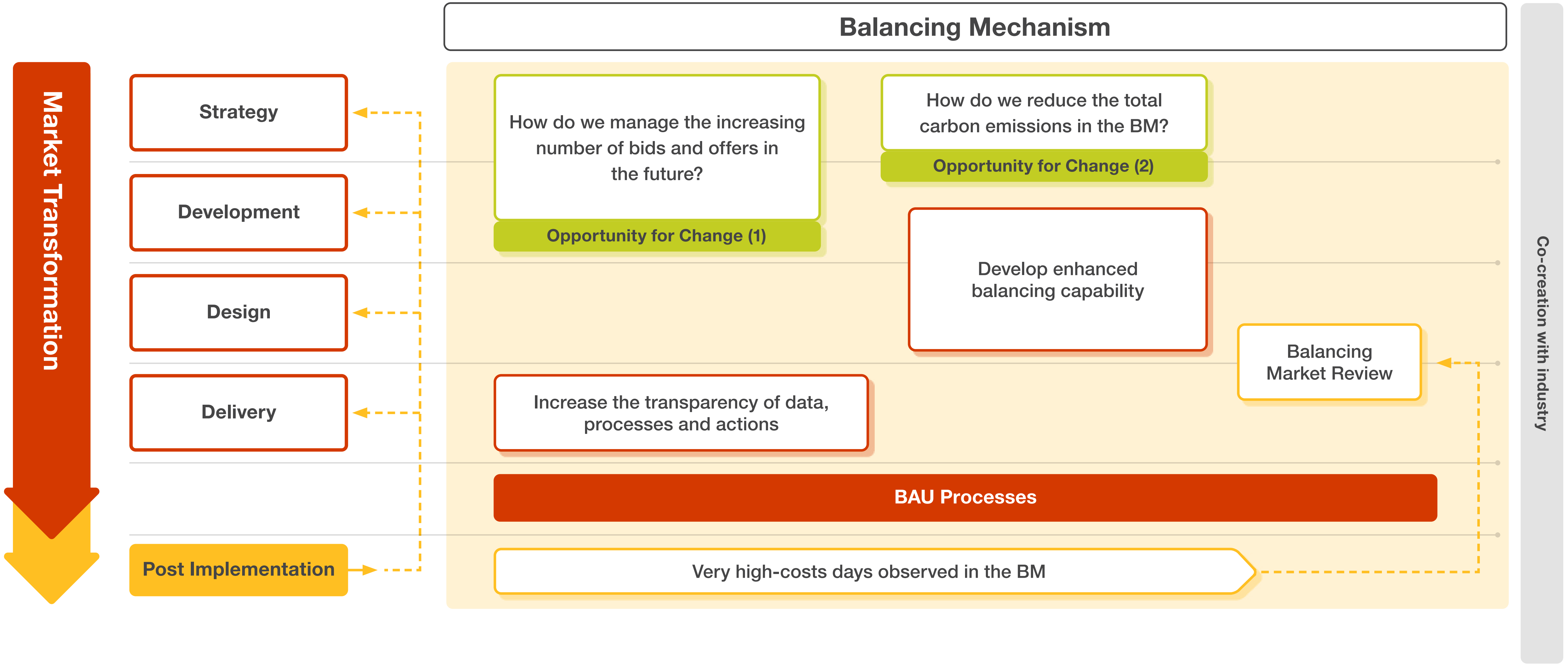
1 This study is different from the BM Review and is undertaken using a simplified dispatch modelling approach.
2 For clarification, the analysis within this chapter does not include actions on non-BM assets outside of the Balancing Mechanism. In addition to the Balancing Mechanism, we have another dispatch tool, the Ancillary Services Dispatch Platform (ASDP) system, for the participation of non-BM providers for ancillary services.

Markets Roadmap / Market Areas / Balancing Mechanism 75

Balancing Mechanism

Market Transformational Stages

We work on the projects and strategic questions within this graphic simultaneously.



Markets Roadmap / Market Areas / Balancing Mechanism 76

Balancing Mechanism

Market Information: **How we procure bids and offers**

	Bids and Offers
Product description	The Balancing Mechanism allows market parties to submit offers to sell energy (by increasing energy output or decreasing consumption) to the system and bids to buy energy (by decreasing energy output or increasing consumption) from the system. Different routes are possible to participate in the Balancing Mechanism (more information here): • Traditional route (primary BMU): The Grid Code obliges parties to register depending on the type and size criteria with ESO. This route requires signing a Connection Agreement with ESO. • Supplier route: Requires participant to be a registered supplier with Elexon and enables the registration of “additional” BMUs. Under this route, aggregation is permitted as well as participation of BMUs as small as 1MW. • Virtual Lead Party: VLP is an independent aggregator that controls (potentially on behalf of a third party) electricity generation and/or electricity demand from a range of assets. This route was driven by European development for TERRE[2] but also enables registration of BMUs as small as 1MW. Bids and offers are used for a range of different reasons: • Response: to position the response providing units into their frequency sensitive mode[3]. • Reserve: to provide sufficient available margin (headroom and footroom) to manage uncertainty of generation and demand. • Thermal: to manage thermal constraints on the network by reducing generation (or increasing demand) above a constraint and doing the opposite below the constraint to maintain energy balance. • Voltage: to manage the voltage level by controlling the volume of reactive power that providers can absorb or generate. • Rate of Change of Frequency (RoCoF): to maintain a stable system, sometimes we need to reduce the largest loss/gain or increase the number of synchronous generation units on the system. Bids and offers are also used to manage energy imbalance, ensuring that supply and demand volumes are balanced in each settlement period.
Timing of procurement	The BM is divided into 48 markets per day (settlement periods of 30min). The gate closure is one hour before the start of each settlement period. After the gate closure, we can instruct (or dispatch) parties to increase or decrease their generation or consumption. Participants in the BM provide a set of available volumes and prices for bids and offers, as well as technical data such as ramp rates (e.g. how quickly a BMU can alter its generation or consumption).
Price determination	The BM is a pay-as-bid market (utilisation only). Bids and offers are predominantly dispatched in a price merit order, considering the technical parameters such as location and ramp rates. These instructions are firm. This means the instructions are associated with a volume and a non-delivery of the instructed volume will lead to imbalance costs.

2 The Trans-European Replacement Reserve Exchange (TERRE) is a European platform for trading reserve products with electricity Transmission System Operators (TSOs) in Europe. The VLP route was created to facilitate the participation of independent aggregators (parties who do not have to supply their consumers).
3 Frequency sensitive mode means the operating mode in which a BM participant can change his output is a way to provide frequency response services.

Markets Roadmap / Market Areas / Balancing Mechanism 77

Balancing Mechanism

This page is interactive.
Click the ⊕ to expand or enlarge content.

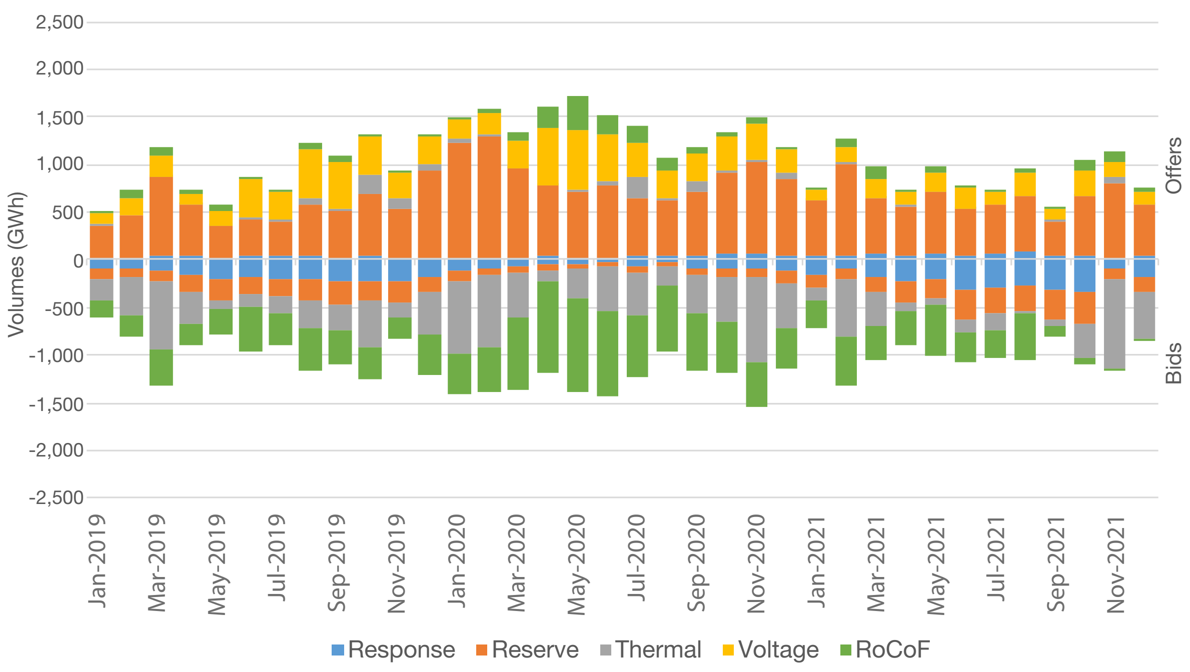
Market Information: **BM volumes**

The graphs show the volumes of bids and offers and trading for system actions, as well as for energy balancing. The monthly average of our bids and offers volumes over the past three years (2019-2021) utilised for system actions is ~1TWh. The monthly average volume utilised for the management of energy imbalance is ~1.2TWh. This volume is larger due to the need to resolve the Net Imbalance Volume (NIV) for every half hourly settlement period.

The main drivers of offer system volumes are the management of reserve (29%) and voltage (12%). During spring and summer of 2020, we observed higher volumes of actions as the low demand during pandemic meant we needed to take more actions to synchronise more conventional generation to provide voltage support and sufficient headroom and footroom margins. The autumn and winter of 2020 also required a high volume of action to secure sufficient reserve with multiple Electricity Margin Notices (EMNs) issued to indicate that a larger cushion of spare capacity was needed due to a range of factors including cold temperature, low wind output, and system outages.

The main drivers of bid service volumes are the management of RoCoF (38%) and thermal constraints (33%). Thermal constraints management primarily consists of bids to reduce wind generation during windy days. RoCoF actions are mostly bids because of the need to reduce the largest generation loss. We observe higher RoCoF volumes in 2020 due to low demand. When demand is lower, a generation loss will have a higher impact on the system and there is a higher risk of relays being triggered. The implementation of Frequency Risk and Control Report (FRCR) also had a positive effect and reduced the volume of actions needed from May 2021. More information regarding the evolution of volumes for each operability service is available in their corresponding chapter.

System actions volumes: Jan 2019 - Dec 2021



⊕ System actions volumes

⊕ Energy imbalance volumes

In the future, the utilisation of bids and offers could be impacted by the evolution of our balancing services markets. The creation of markets for voltage and stability services, as well as the development of new market solutions for thermal, could reduce the number of related actions in the BM. Similarly, the reform of response and reserve products could also impact the number of our actions. On the other hand, the increase of wind penetration suggests an increase of actions to be taken for thermal constraints management. This could also lead to additional imbalances due to forecasting errors. The volume of actions for energy balancing reasons are therefore expected to increase (see Opportunity for Change 1).

Markets Roadmap / Market Areas / Balancing Mechanism 78

Balancing Mechanism

This page is interactive.
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Market Information: **BM costs**

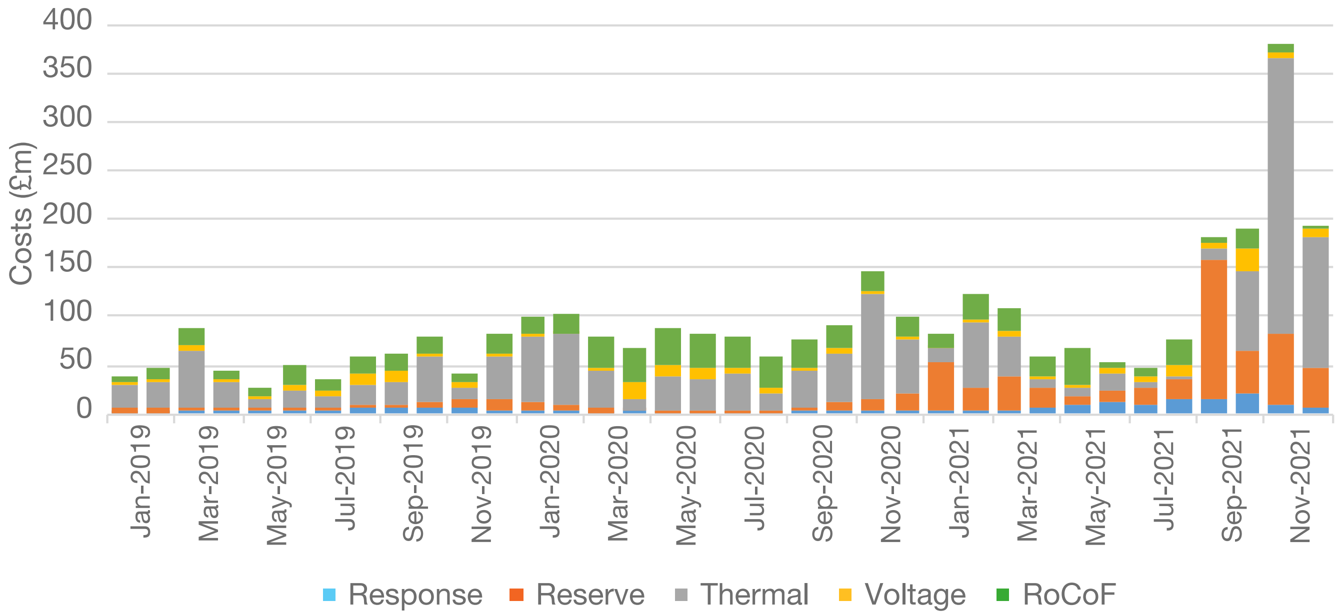
The monthly average cost of bids and offers utilised for system actions before Sept 2021 is £74m, while we observe a huge increase to £236m for Sept-Dec 2021. In 2021, we also notice higher reserve costs, with the monthly average cost being £41m in 2021, while the average cost was £6m in 2019-2020. While the energy imbalance volumes are similar to the system actions volumes, the costs for energy imbalance are smaller due to both bids and offers costs mostly cancelling each other and energy imbalance actions being dispatched in merit order.

The high costs in the BM are due to the increase in wholesale market prices, driven by global gas supply shortages and the increasing cost of emissions. Many of our actions are impacted by these higher prices and therefore, although the volumes are lower than the previous year, costs increased in 2021. 2021 was also impacted by demand bouncing back, sustained periods of low wind output, and reduced levels of power imported from Europe due to IFA interconnector outage. This all contributed to tight margins and resulted in an increase of the cost of operating reserve (scarcity pricing).

We observed very high costs in the BM with bids and offers prices reaching above £3,000/MWh on several occasions in Sept-Dec 2021 period. Our most expensive day was on 24th November, where the cost to balance the GB's electricity network totalled £64m (the average daily cost before Sept 2021 is £2.6m). The costs were mostly high in the afternoon. Thermal constraint actions accounted for ~90% of the costs on that day. To fully understand the factors driving the market on some very high-cost days, we have launched the Balancing Market Review.

More information regarding the evolution of the costs for each operability service is available in their corresponding chapter.

System actions costs: Jan 2019 - Dec 2021



⊕ System actions costs ⊕ Energy imbalance costs ⊕ 24th Nov: bids and offers

The costs in the BM are often reflective of the marginal price in the generation mix and therefore reflective of the wider system trends (e.g. high gas and carbon prices). In the future, we expect prices in the BM to be generally lower due to increasing renewable penetration leading to more periods with lower and negative pricing. We also expect the price to be more volatile with some peak prices due to any potential rise in gas price and the need to turn on thermal plants for a short period of time. In the longer term, some of the increasing costs in the BM can be managed more economically through enhancing market competition.

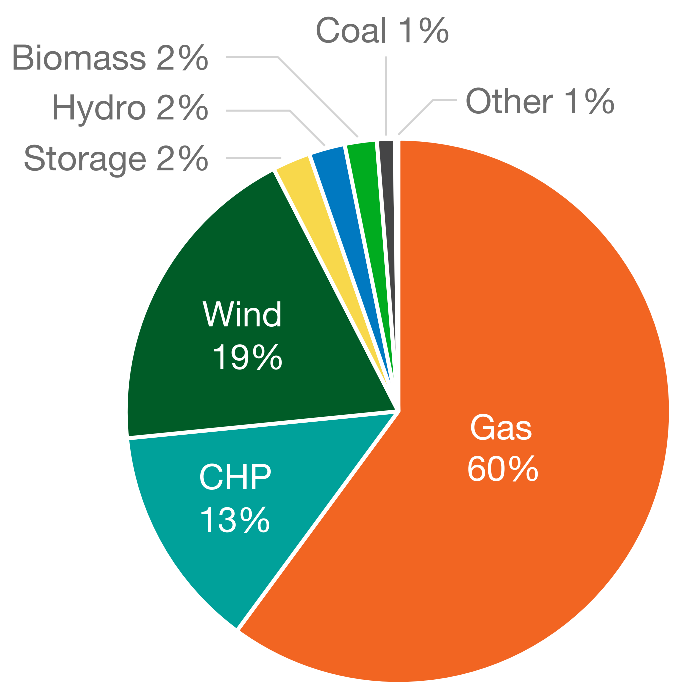
Markets Roadmap / Market Areas / Balancing Mechanism 79

Market Information: **BM providers**

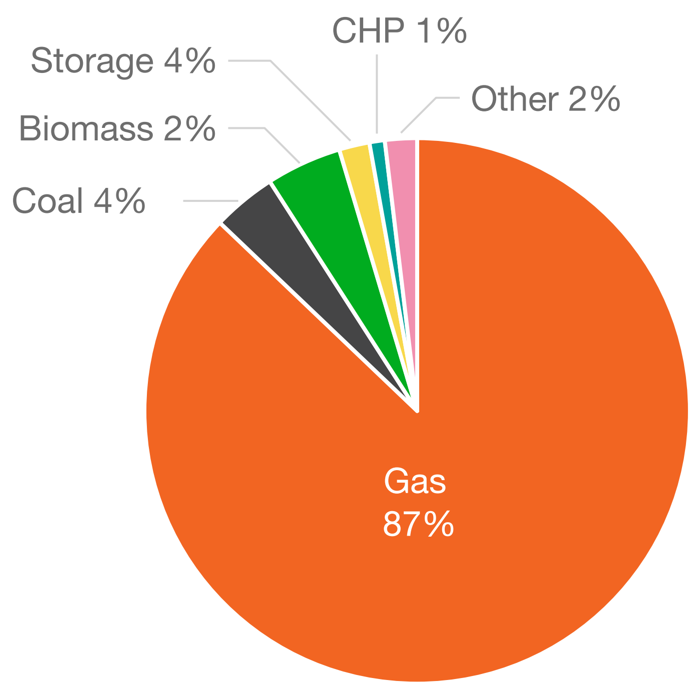
The charts below show the breakdown of bids and offers between providers. The volume of accepted bids and offers are currently dominated by gas (60% of bids and 87% of offers). Low carbon technologies such as wind, biomass, and storage provide only a small volume of bids and offers. Note that we have not included interconnectors in the charts, to represent only bids and offers actions and not trades.

Our bids and offers instructions are technology agnostic as we dispatch on merit order, while maintaining safe and secure system operation. The providers of bids and offers are reflective of the generation mix available after market closure. As we prepare for a zero carbon power system by 2035, we will have to continuously review accessibility and routes to markets to ensure greater deployment of flexible and zero carbon assets in the BM.

Bids by technology type (volume)



Offers by technology types (volume)



Balancing Mechanism

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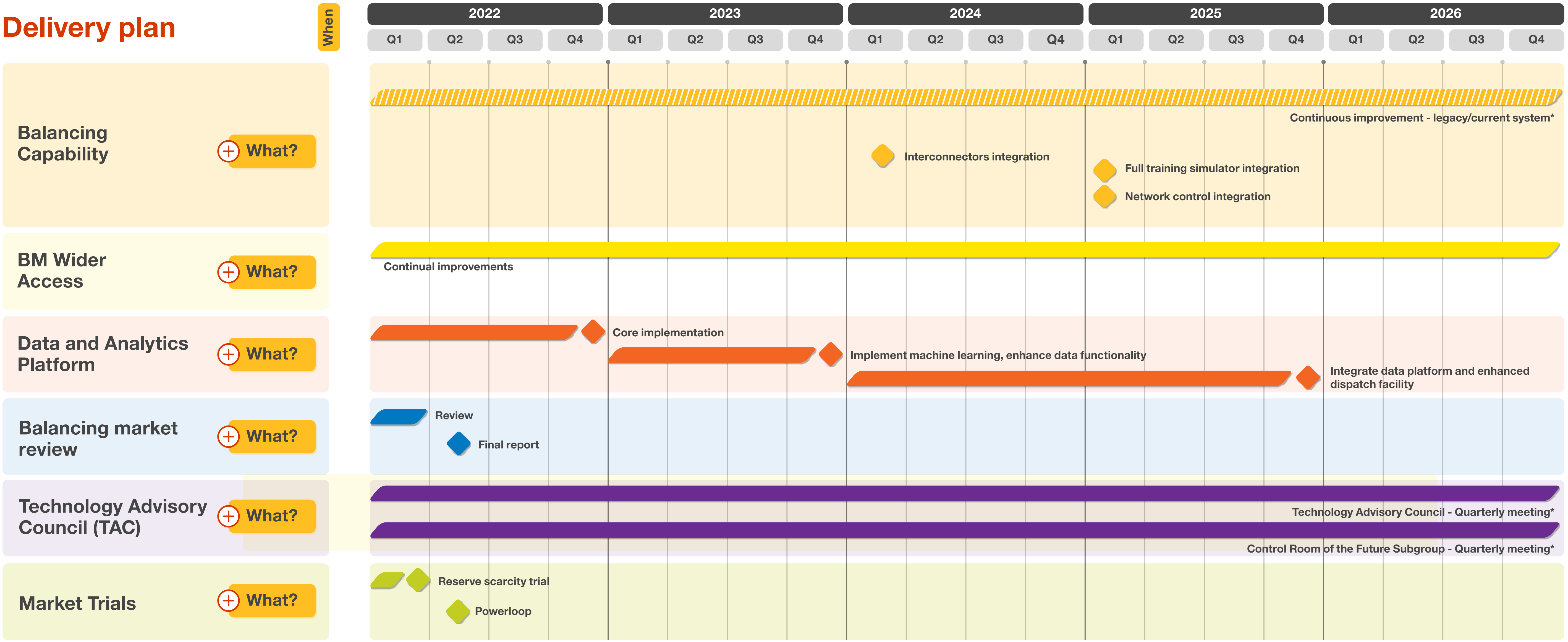
Planned timescales | Fixed end dates | Projects' timescales are subject to change

Delivery plan



Q1 2024 subject to balancing scoping review.

*End date TBC

Markets Roadmap / Market Areas / Balancing Mechanism 81

Balancing Mechanism

Efficient dispatch
Efficient Investment
Value for Money

Opportunity for Change (1) – **Increasing numbers of bids and offers for energy balancing**

As the system moves towards zero carbon, the volume of bids and offers for energy balancing will increase significantly.

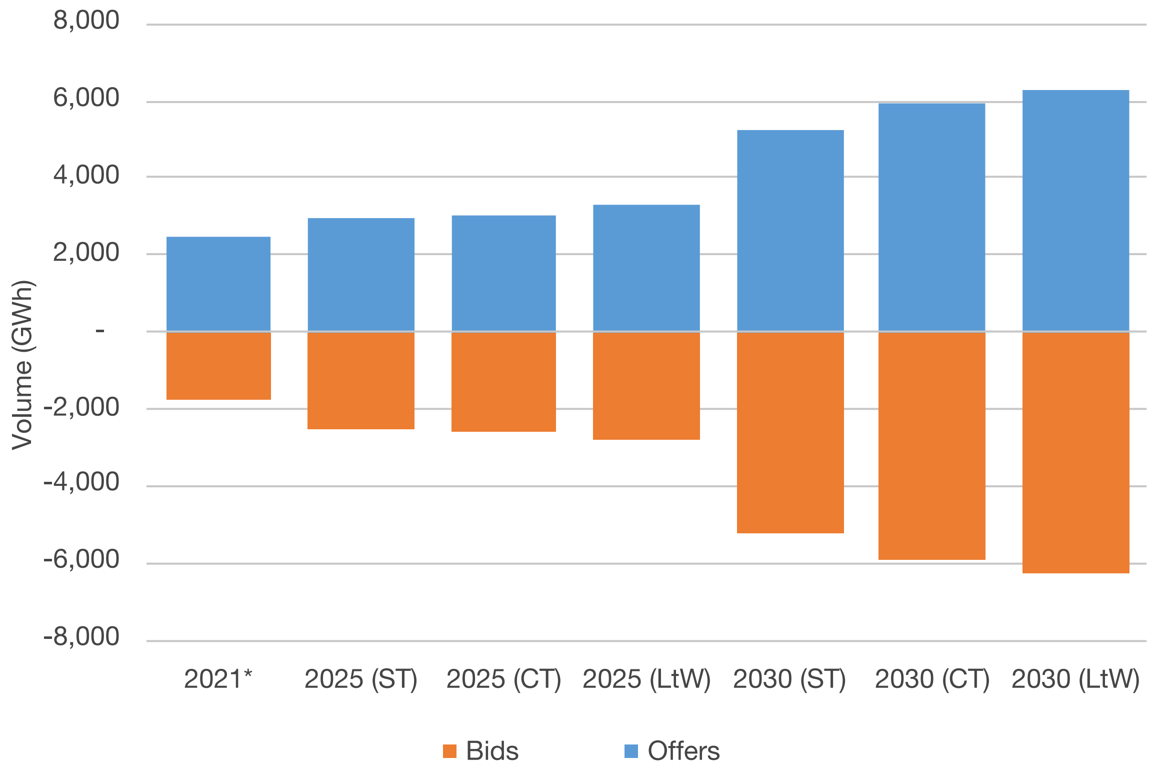
A study undertaken in 2021 for the ESO by consultants LCP[4] analysed the evolution of total accepted volume of bids and offers. It is important to note that this study focussed only on the use of bids and offers to manage energy imbalances; therefore, it did not include the system actions taken in the BM to resolve constraints or other system requirements.

The study estimated there will be a small increase in the gross volume of bids and offers towards 2025 and a larger increase towards 2030. As wind penetration continues to grow rapidly, the fact that it cannot be perfectly forecasted will have a greater impact on imbalance.

- In 2025, there is only a small increase in the volume of bids and offers. The growth in wind penetration is partially offset by improvements in wind forecasting. The study assumed 15% improvement in wind forecasting from asset owners over the next 5 years.
- By 2030, however, there is a much more noticeable difference, with volumes of bids and offers both becoming much larger. The total wind capacity increases from 39GW in 2025 to 69GW in 2030 (Consumer Transformation scenario), but the study assumed no further wind forecasting improvement from asset owners from 2026.

To manage the increasing volume of bids and offers, it is essential that we enhance the transparency of data, processes, and actions in the BM.

Total accepted volume of bids and offers for energy balancing



FES scenarios: System Transformation (ST), Consumer Transformation (CT), Leading the Way (LtW)

4 This study is different from the BM Review and is undertaken using a simplified dispatch modelling approach. The balancing market is simulated based on fundamental analysis with the starting point being the wholesale market dispatch. Imbalance volumes are calculated based on wind, solar and demand perturbations (forecasting error). The model also applies a shift on imbalances to align average cash-out and wholesale prices.

Markets Roadmap / Market Areas / Balancing Mechanism 82

Balancing Mechanism

Opportunity for Change (1) – **Increasing numbers of bids and offer for energy balancing**

Key strategic questions

- **What tools do we need to be able to efficiently manage the expected increase of bids and offers?**

We are developing an enhanced balancing capability via a new dispatch facility to manage increasing number of actions expected in the BM. Our new dispatch facility will enable us to assess more data, more market participants, and more complex scenarios. We want to embrace new technology and harness the power of automation and innovation in data analytics, including artificial intelligence. Those new ways of working will complement or replace our existing capability while ensuring continued safe, secure, and economic system operation.

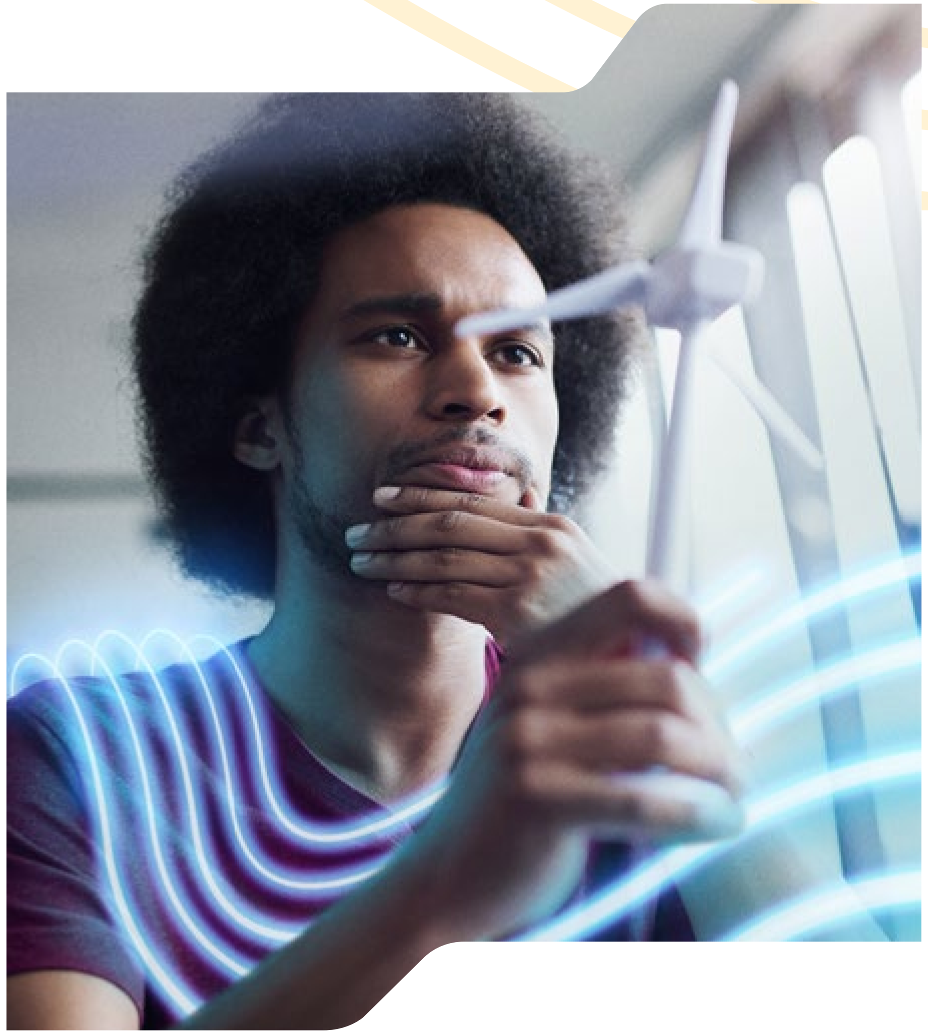
We have established a Technology Advisory Council (TAC) to help guide and inform the development of new systems (encompassing processes and technological solutions), which must facilitate greater volumes of data. The TAC ensures that we work with the industry on the development of new systems, and enables input into key design, development, and testing phases of our solutions development.

- **How can we support wind forecasting improvement from asset owners?**

Asset owners have the responsibility to provide accurate generation forecasts. Market participants can access our wind forecasting data to support them in making informed generation forecasts. Our intention is to enhance transparency and publish the most valuable data for stakeholders on our Data Portal. In particular, we are developing more accurate, frequent, and granular wind forecasts.

- **How could our market developments outside the BM impact the volume of bids and offers?**

Other market developments are taking place outside the BM, e.g. the reform of our ancillary services markets and our NOA pathfinder projects for stability and voltage management (more information in other chapters). As a consequence of those developments, the volumes of bids and offers in the BM could change. For instance, the potential development of voltage or stability market could reduce the volume of actions in the BM related to the management of those products.



Markets Roadmap / Market Areas / Balancing Mechanism 83

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Efficient dispatch
Efficient Investment
Value for Money

Opportunity for Change (2) – **Evolving carbon emissions in the BM for energy balancing**

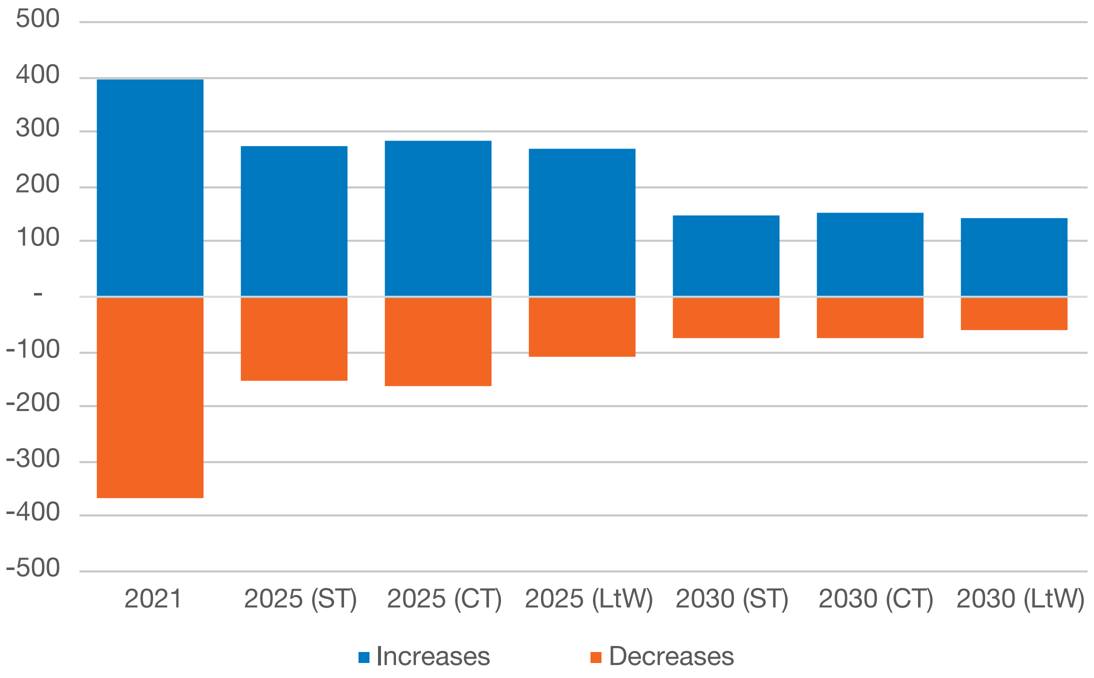
Although we do see greater participation of lower carbon technologies, and the average carbon intensity of our BM instructions will decrease, the total net carbon emissions of BM actions could remain relatively the same.

The study undertaken in 2021 for the ESO by consultants LCP[5] looked at the impact of the evolution of BM providers in 2025 and 2030. The analysis of the carbon intensity of our balancing actions illustrates that the average carbon intensity of accepted bids and offers decreases significantly as the system decarbonises. However, the total carbon emissions associated with accepted bids and offers stays roughly the same, unless unabated gas is replaced with lower carbon alternatives such as hydrogen or CCS estimated to enter in 2030. This is due to increase of BM actions by 2030 as explained in the Opportunity for Change (1).

Sensitivity analysis – Interconnectors participation:
Currently, interconnectors do not directly participate in the BM and our participation in project TERRE is not possible due to EU-Exit. With interconnectors forming an increasing proportion of GB's generation mix, this study assumed they will be able to participate directly in the BM.

The study estimates interconnector carbon emissions to be based on the closest domestic generator in the merit order[6]. Without interconnectors, we observe higher levels of accepted offers from high-carbon generation and higher levels of accepted bids from low-carbon generation such as wind and solar. Both these changes would have a detrimental impact on carbon emissions from the BM. We observe an increase in our net total carbon emissions particularly in 2030, where they could rise up to 1m tonnes instead of 0.5m tonnes (in Consumer Transformation scenario).

Carbon intensity of average accepted bids and offers for energy balancing (g/kWh)



FES scenarios: System Transformation, Consumer Transformation, Leading the Way

Carbon intensity | Carbon emission | Carbon emission No Interconnectors

To be able to manage the system in the net zero future, we need to continuously review the routes to the BM to be able to ensure accessibility to all technologies and providers.

5 This study is different from the BM Review and is undertaken using a simplified dispatch modelling approach. The balancing market is simulated based on fundamental analysis with the starting point being the wholesale market dispatch. Imbalance volumes are calculated based on wind, solar and demand perturbations (forecasting error). The model also applies a shift on imbalances to align average cash-out and wholesale prices.
6 For example, when importing at a high price similar to the price of CCGT, we will assume that interconnection has the same carbon intensity of CCGT, but when importing at a very low price similar to wind/solar, we will assume the interconnection imports has a carbon intensity of zero.

Balancing Mechanism

Opportunity for Change (2) – **Evolving carbon emissions in the BM for energy balancing**

Key strategic questions

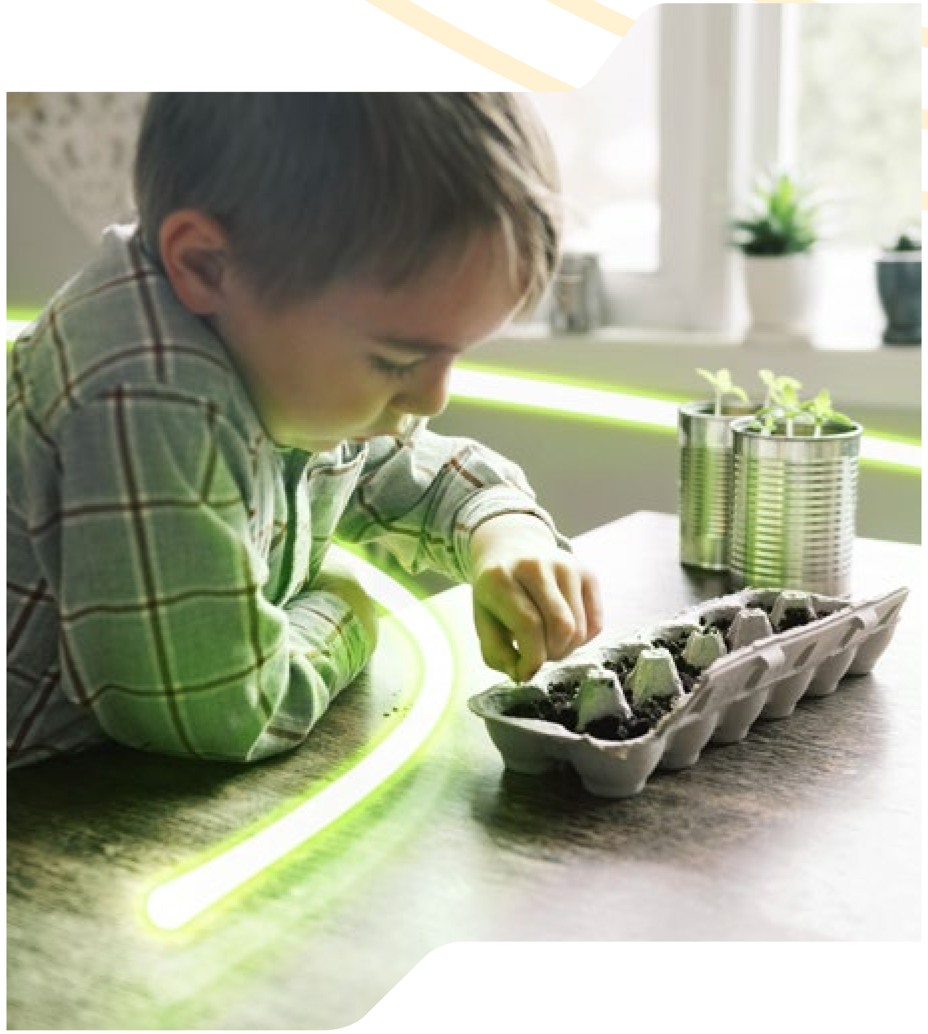
- **Are routes to the BM adequate for the future?**

Our Balancing Mechanism Wider Access programme aims to simplify access to the BM for all technologies and providers, and in particular 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. A new IT interface, Application Programming Interface (API), has also been created to improve the route for submission of data at an aggregated level, and to enhance the interface with market participants so data submission is more efficient and cost-effective for smaller and aggregated units. In the future, we will continue to monitor our market accessibility as new participants enter the BM.

Through our market trials, we are also committed to ongoing activities to better understand routes to market and test our current process and capability. They set the foundations for the participation of new technologies in the BM. As an example, we are collaborating with Octopus Energy on the vehicle-to-grid project Powerloop, looking at the pathway for their participation in the BM.

- **How do we solve the participation of interconnectors in the EU-Exit context?**

Interconnectors currently do not directly participate in the BM as they do not control the energy flow on the link, which is determined by their capacity holders and the System Operators. Before EU-Exit, we had been preparing to participate in EU balancing platforms with other System Operators, however this was prohibited under the terms of EU withdrawal. In the future, different options remain to be further analysed. For instance, the creation of a new balancing market alongside EU balancing platforms or the direct participation of interconnectors in the BM.



Markets Roadmap / Market Areas / Balancing Mechanism 85

Market interactions & service stacking

Market interactions & service stacking

Why are market interactions important?

Revenue stacking has become increasingly important to the economic viability of market participants in the energy industry. Many balancing services providers will hold Capacity Market agreements or CfD contracts and could also be using their assets to capture revenues in the wholesale power market. DER service providers may also be looking to participate in DSO flexibility services markets. To recognise this, we have included coherency as one of our key market principles. This principle represents our aims to ensure balancing services markets are interoperable, allow market participants to choose which market(s) they enter, and offer opportunities for revenue stacking where technically feasible.

This section of the Markets Roadmap highlights some interactions between markets which we must take into consideration as we undertake market reforms. It also looks at service stacking, across ESO services as well as some ongoing Open Networks Project workstreams which are exploring stacking between ESO and DSO services.

Markets Roadmap / Market interactions 87

Market interactions & service stacking

Our role in wider industry markets & our Net Zero Market Reform project

As the ESO, we have a privileged role at the heart of the energy system, which means we are uniquely placed to assess how markets could be reformed so they function coherently as a suite to enable the decarbonised electricity system of the future. We are using this position to work closely with Ofgem and BEIS to consider how energy markets need to change to deliver on the UK government's net zero ambitions.

The Net Zero Market Reform (NZMR) project was established in early 2021 to examine the changes to current GB electricity market design that will be required to achieve net zero. The project is different to other market reform projects ESO have previously undertaken as it has a longer-term focus as far into the future as 2035 and 2050 and will look at the full suite of GB electricity markets and policies, not just those run by the ESO. We published our findings following Phases 1 and 2 of the project in this report with the next publication to be published in April.

Phase 1: Scoping and Stakeholder Landscape (completed March 21)	Analysis of the GB market landscape and review of international case studies. The purpose of this phase was to set out the scope of future phases of work.
Phase 2: Case for Change analysis and identification of options (completed November 21)	Deep dives into current and future market issues, defining market objectives and success criteria, identifying a list of market reform options to tackle the issues along with a logical framework for assessing those options.
Phase 3: Assess solutions and present recommendations (to be completed April 22)	Assessment and evaluation of credible market design options against market objectives and success criteria, followed by recommendations for where reforms should be prioritised.

Input from our stakeholders through co-creation workshops, webinars and discussions has been crucial throughout this project – please visit our webpage to find out how you can get involved.

Markets Roadmap / Market interactions 88

Market interactions diagram - **Interactions across time**

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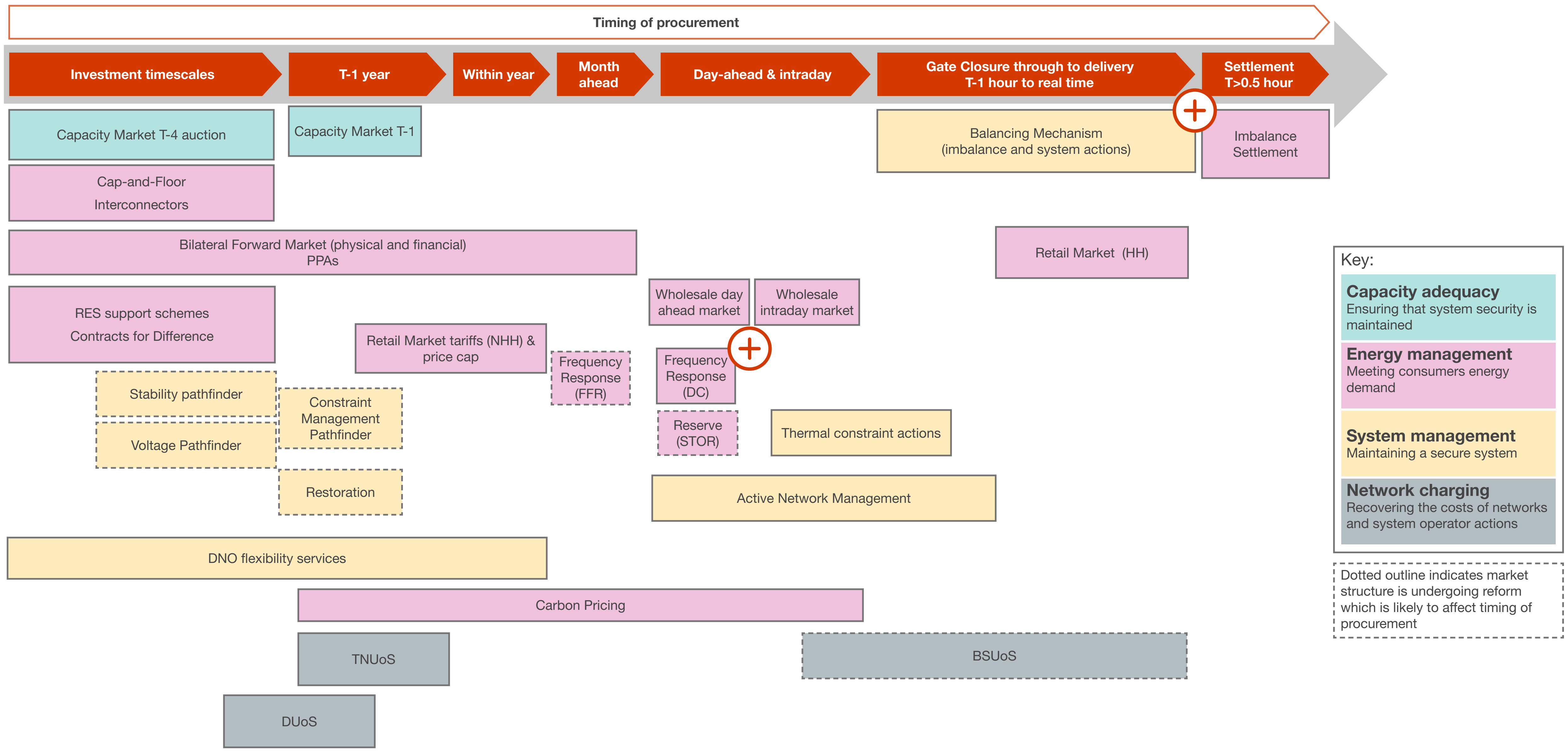
Time | ⊕ Location



Markets Roadmap / Market interactions 89

Market interactions & service stacking

Service Stacking across ESOs current product suite

The table on the next page shows our latest view of how our response, reserve and restoration products can stack with each other and across the Capacity Market and BM. We have also included the rules for stacking contracts from our voltage, stability and constraint management pathfinders. The stacking status is shown assuming capability from the same asset is to be committed in each market during the same delivery window[1].

We have chosen not to include products for which service specification have not yet been defined such as the possible Reactive Power and Stability market designs which are being explored through two Network Innovation Allowance (NIA) projects. We will look to communicate our decisions on stacking for these markets and take feedback from industry as part of the detailed design process for new products. We have also not included legacy products which will be phased out in coming years e.g. the monthly FFR tenders.

The table is designed to provide clarity on stacking rules. For the purposes of this table, we show only two colours – green (the services can be stacked) and red (the services cannot be stacked). There are some qualifications or caveats around service stacking that providers may need to be aware of, these are explained in the text box to the right of the table.

We advise market participants to contact their account manager or commercial.operation@nationalgrideso.com with any questions related to their individual assets for more detailed information.

1 The term delivery window is used to enable us to refer to the simultaneous holding of contracts from these different markets. A delivery window is usually the shortest amount of time a contract for a given service can be offered for. In the DC market this is currently a four-hour EFA block, in the Balancing Mechanism bids and offers are made with up to minute granularity whilst Capacity Market agreements are at least one year in duration.

Markets Roadmap / Market interactions 90

Market interactions & service stacking

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		Dynamic Containment		DM	DR	STOR	Slow Reserve		Voltage Pathfinders	Stability Pathfinders	CMP	Restoration contracts	BM	Capacity Market
		DC-LF	DC-HF				Negative	Positive						
Dynamic Containment (DC)	DC-LF		1	2		3			5		6	9	11	14
	DC-HF													
Dynamic Moderation (DM)														
Dynamic Regulation (DR)														
Short Term Operating Reserve (STOR)							4						12	
Slow Reserve (SR)	Negative													
	Positive													
Voltage Pathfinders										7	8	10	13	
Stability Pathfinders														
Constraint Management Pathfinders (CMP)														
Restoration Services													9	
Balancing Mechanism, bids and offers (BM)														15

1
DC-LF and DC-HF can be stacked together through linked or independent bids during the same delivery window. Providers can choose whether to offer the same or different MW capabilities for the low or high direction of the product.

Stacking in the same delivery window allowed

Stacking in the same delivery window not allowed

⊕ Click for information

Markets Roadmap / Market interactions 91

Market interactions & service stacking

The ENA's Open Networks project is exploring service stacking between ESO and DSO products

The Energy Networks Association's (ENA) Open Networks project brings together DNOs, TOs and the ESO to support the development of solutions that enable the transition to a smart and flexible electricity system. A key question for market providers, the ESO and DSOs is to understand how ESO, and DSO products will work together both in procurement and operational timescales.

This will inform decisions on whether providers can hold contracts for one ESO or DSO service at the same time as another– in essence, whether the services can be stacked. Work to answer this complex question has been ongoing through Open Networks since 2019 and is progressing well, this can be seen through the output of the relevant workstreams listed below.

ON19-WS1A-P5: Co-ordination and co-optimisation of services
Open Networks produced a comprehensive report showing which products can be stacked with other products across DSO and ESO markets. Due to the scale of service reform in the ESO this is due to be revisited in 2022 through the ON22 work programme.

ON21-WS1A-P5: Primacy Rules for Service Conflicts
This workstream is developing rules to determine the prioritisation of service delivery across Transmission and Distribution when there are conflicts between ESO and DSO requirements.

ON22-WS1A-P6: Stackability of flexibility services across ESO and DSO products
This project will review and update the DSO flexibility products as required based on latest market developments and stakeholder feedback. This project will also review stackability of products and progress actions to remove barriers to service stacking. Work will kick off in April 2022.

Markets Roadmap / Market interactions 92

Get in touch

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Markets leadership organisational structure and contact details.