Markets Roadmap

March 2025

NESO
National Energy System Operator

Navigation

Navigating the document

Forward & back a page

Use the forward and back arrows on each page to move through the document

On desktop
you can use your keyboard arrow keys to change page

On tablet
you can swipe to change page

Please view in full screen mode to see all content

Contents

Links

Click on underlined purple text to navigate to external links

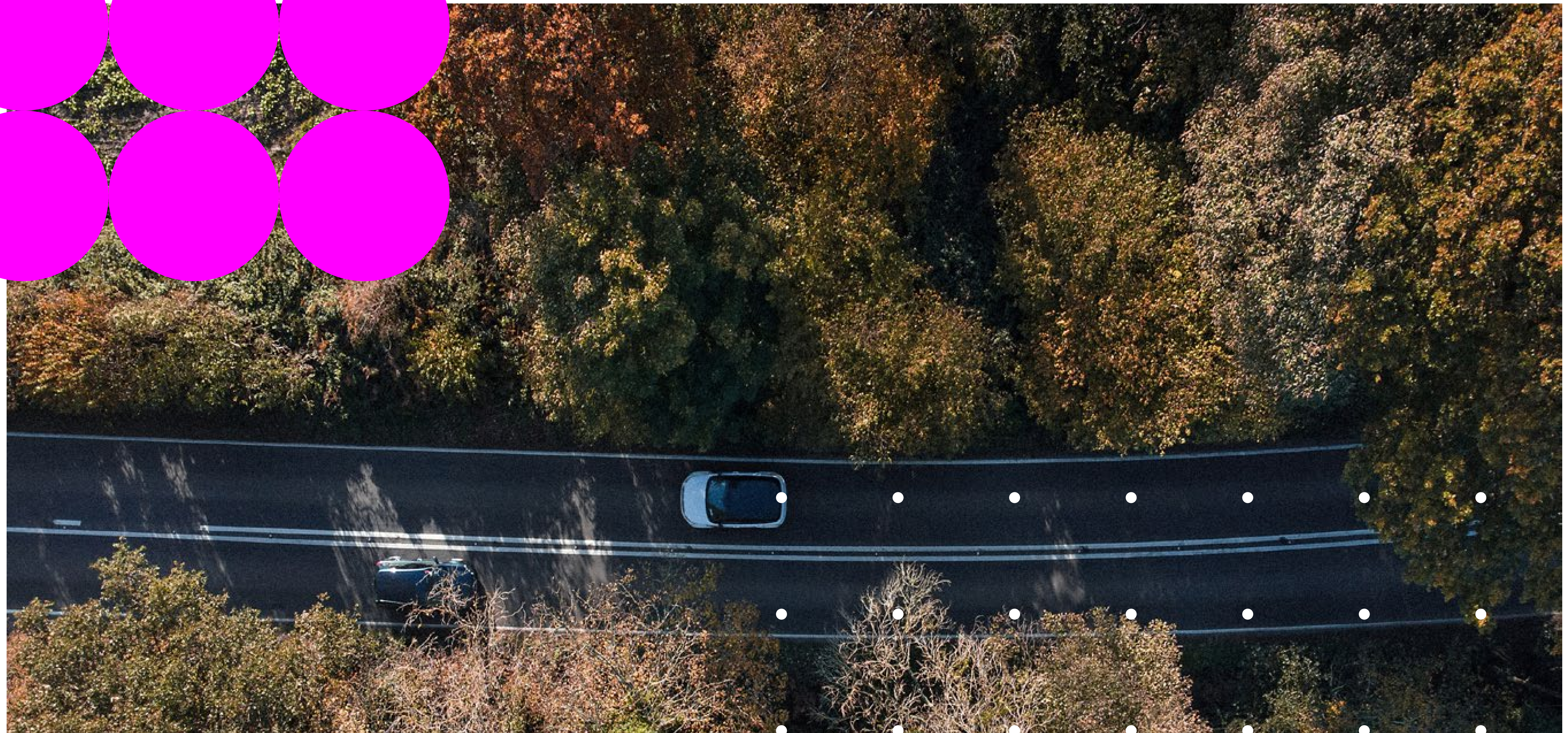
To help you find the information you need quickly and easily we have published the report as an interactive document.

Open the PDF in Acrobat Reader to view all interactivity.

Contents

01

NESO'S 2025 electricity Markets Roadmap



Foreword

Welcome to the first electricity Markets Roadmap as NESO, in which we share with you our plans for those markets NESO owns and operates.

Our electricity Markets Roadmap plays an important role as our primary means to share with you our markets strategy as well as shorter-term plans and activities all in one place. It explains the reasons behind market reform, which essentially relate back to the energy trilemma, now enshrined in our NESO primary duties. We are publishing this year alongside our Operability Strategy Report (OSR) and have shown throughout how we are designing our markets in response to the system challenges identified in the OSR.

Becoming NESO has given us new whole energy system responsibilities, such as strategic network planning for gas and electricity, in addition to our core role as the operator of the electricity system. We also now have responsibility to develop GB's Spatial Strategic Energy Plan and Regional Energy Strategic Plans. This requires us to take a carefully coordinated, whole system approach to planning GB's energy system for net zero in 2050 and the role of markets in meeting those needs. As we are still establishing ourselves in these roles, this roadmap can't reference the outcomes of these plans for now and remains focussed on our electricity markets. Additionally, it is important to note, that the reforms here are agnostic to the outcome of the Review of Electricity Market Arrangements (REMA), focussing instead on the immediate needs of a rapidly decarbonising electricity system.

Finally, I cannot avoid mentioning the herculean challenge facing all of us in the energy industry. Late last year, the government's Clean Power Action Plan was published. NESO has a pivotal role to play in delivering this ambition. It will affect all areas of our work and our markets are no exception. Through open and competitive markets, NESO will be able to access the services that we know we will need, in a cost-effective way. They are also able to help incentivise the new assets and sources of flexibility needed for the energy transition. Getting our market design right is vital for the clean power 2030 ambition and for ensuring that we have the capabilities needed for secure, low-cost and low-carbon system operation.

Rebecca Beresford
Director of Markets

Executive summary

Welcome to the 2025 edition of the NESO electricity Markets Roadmap.

This publication is to provide clarity to our stakeholders about how and why we are reforming our balancing services markets. It sets the strategic direction for NESO markets in response to changing market conditions and evolving operability needs, as set out in our Operability Strategy Report (OSR).

In last year's roadmap, we outlined our focus on removing barriers, providing clearer market signals, and being more transparent and collaborative. This year, with new government policy for clean power by 2030, we have renewed ambition to operate a secure, cost-effective energy system and are proactively taking action to expedite delivery of our actions where possible.

The Government's 'Clean Power 2030 Action Plan' sets out how to achieve 95% clean electricity in GB by 2030; the implications of this for system operation are outlined in this year's OSR. The electricity Markets Roadmap complements that forward look by laying out our plans to evolve, reform and develop our balancing services markets, which are our key mechanism to ensure that we have the capabilities needed for secure, low-cost and low-carbon system operation.

Addressing this trilemma means:

Supporting Government's Review of Electricity Market Arrangements to reduce electricity bills

NESO continues to support broader wholesale market reform as part of the Review of Electricity Market Arrangements (REMA) alongside DESNZ and Ofgem as we believe this will reduce costs to the consumer. The outcome of this process should result in a wholesale electricity market design which is appropriate for a renewables-dominated system, instead of one designed around a comparatively small number of fossil fuelled plant.

We will need to continue to work closely with DESNZ, Ofgem and industry to finalise and then implement the choices made by government at the end of the REMA programme. In parallel, we will also continue to implement appropriate incremental reforms to the BM in advance of a REMA decision and ensure that further developments to our markets are coherent with the longer-term direction of travel.

Enabling the flexibility needed for Clean Power 2030

Our Clean Power 2030 advice to Government highlighted the significant capacity gaps which must be filled to achieve Government's ambitious target. In December, we published our Enabling Demand Side Flexibility report, combined with second phase of our Routes to Market review. These form the basis of a significant workstream for NESO over the coming years, the primary focus of which is to enable participation from all kinds of flexible assets in NESO energy balancing services, such as response, reserve, constraint services and the Balancing Mechanism (BM). Key priorities from this work include:

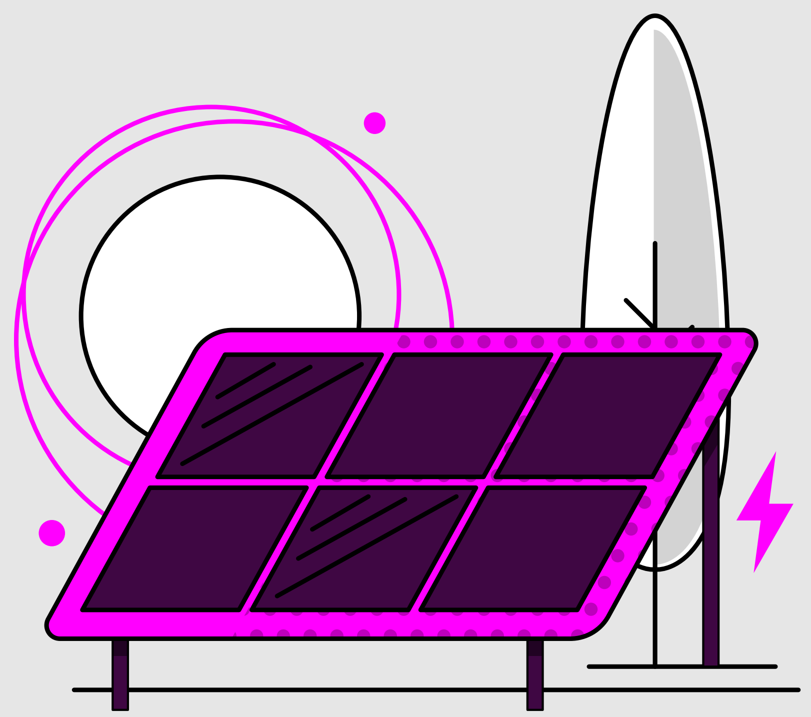
- removing barriers to the BM for all types of flexible assets
- making stacking of services possible across NESO's and distribution network operators' markets by default
- integrating this work into DESNZ's Low Carbon Flexibility Roadmap, of which NESO are co-authors.

The OSR describes the changing system conditions in detail using illustrative examples, which highlight the importance of cross-sector action to deliver on all kinds of flexibility. This year we will continue to collaborate with DESNZ, Ofgem and industry in the development of the Low Carbon Flexibility Roadmap about how to enable flexibility more broadly; for example, emphasising the importance of the Market-wide Half Hourly Settlement (MHHS) programme to unlock vast amounts of flexibility through wholesale market signals.

Improving our dispatch efficiency to enable lower costs and maintain security of supply

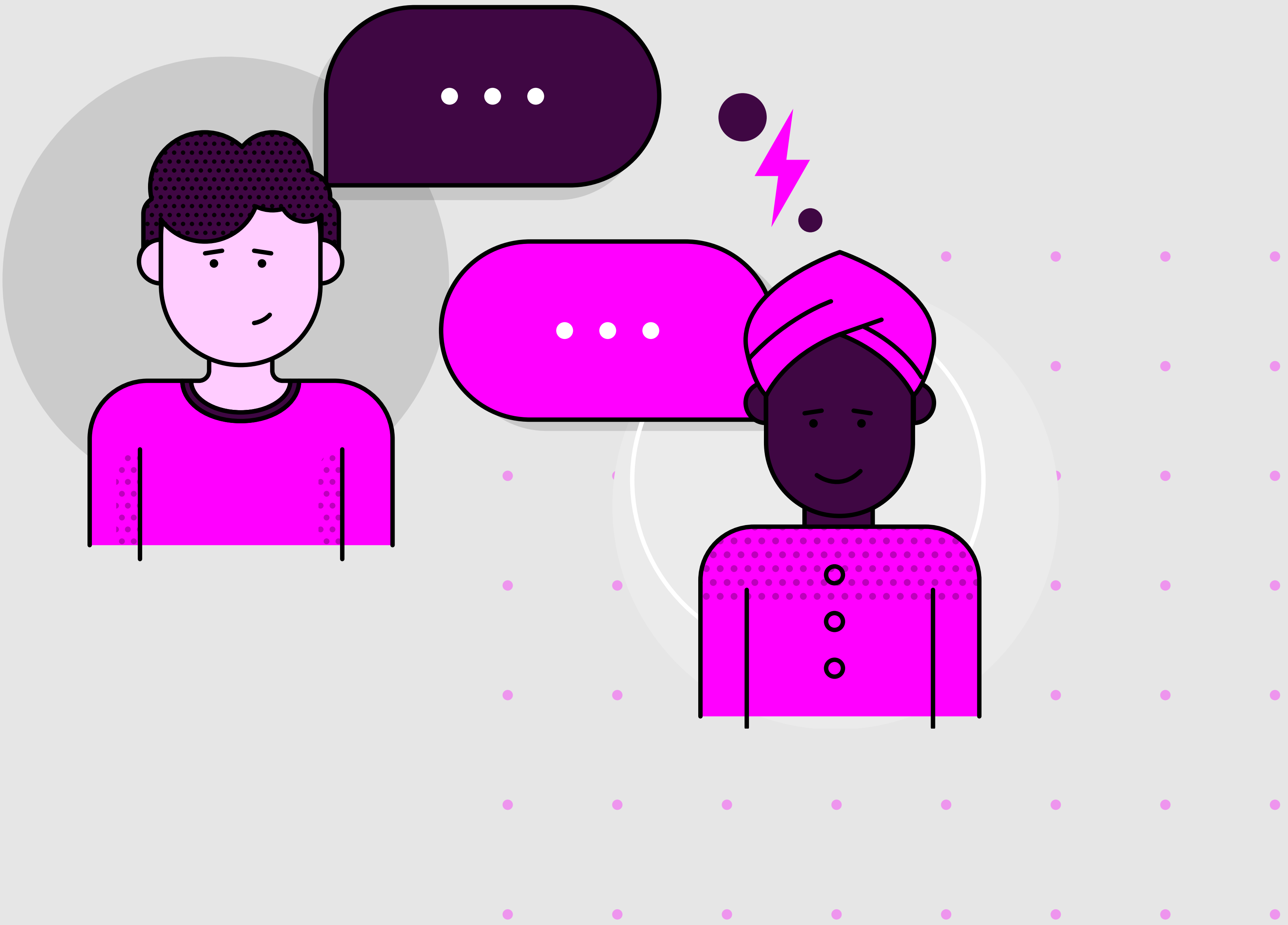
Ensuring smaller, flexible assets are able to participate equally in the BM remains in a priority, as they are a vital part of operating a low carbon system and managing the peaks and troughs of variable renewable generation. Our new balancing platform has supported a large increase to battery utilisation. Since its launch in 2023, there has been a 324% increase in battery dispatch volume and an 60% increase in small Balancing Mechanism Unit (BMU) dispatch volume.

To accelerate progress in this space, we have developed a new skip rate dataset, enabled 30-minute dispatch instructions for energy-limited assets, launched the first releases of Balancing Reserve and Quick Reserve in March and December 2024 respectively, and continue to develop our Open Balancing Platform to include new features like Fast Dispatch. Yet, we acknowledge there is significantly more work to do. We will continue to improve our visibility and situational awareness and ensure that our markets are transparent and accessible as well as delivering value to consumers (e.g., through the launch of Slow Reserve and network services markets).



Becoming NESO

On 1 October, we became the National Energy System Operator, an independent system planner and operator, following designation by the UK Government. Markets underpin all of NESO's primary and secondary duties. They will help to enable net zero by procuring crucial services through competitive means to achieve efficient, economical outcomes whilst ensuring security of supply for all consumers.



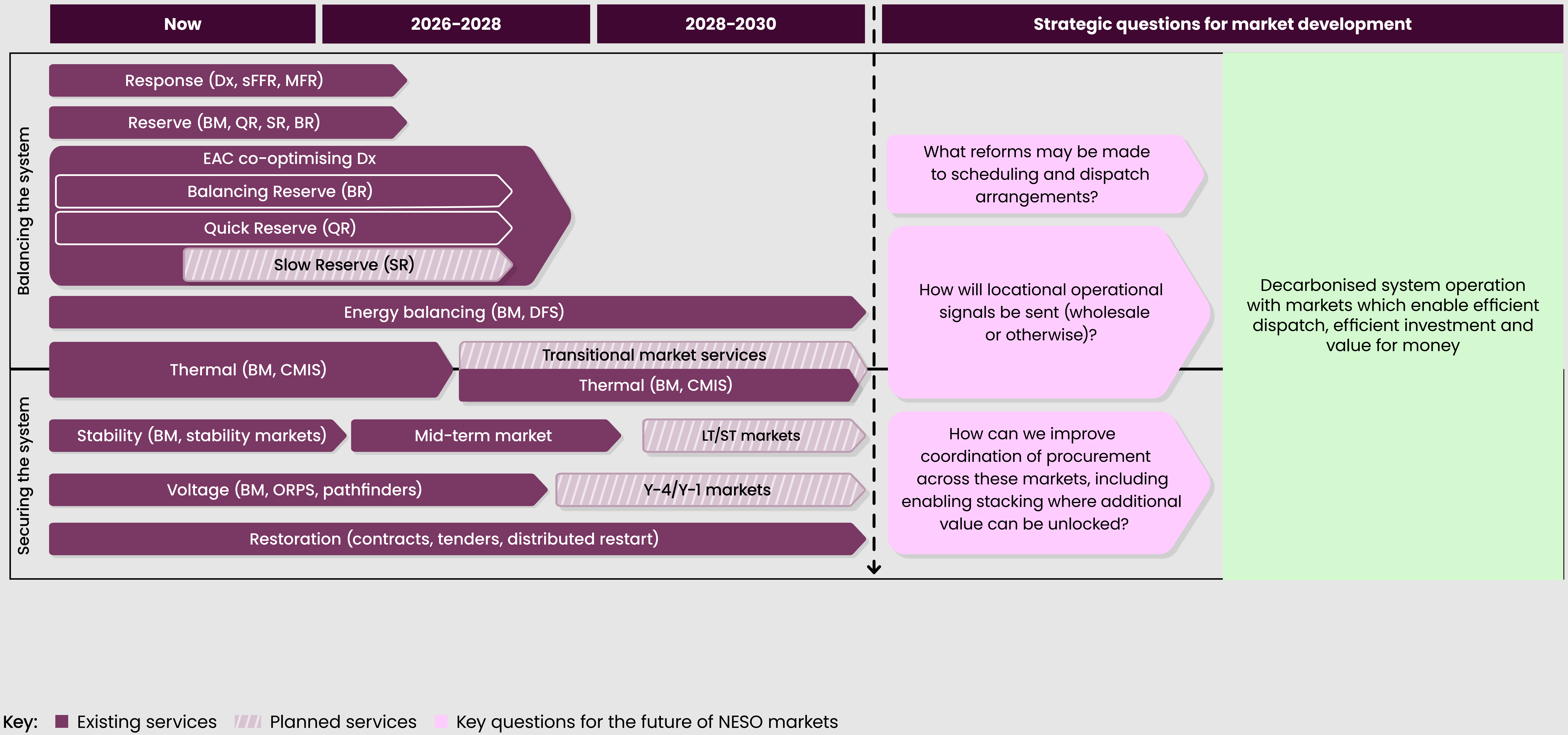
Balancing costs remain high but NESO actions are having an impact

In aggregate, balancing costs declined in 2024 for the second successive year to £2.56 bn. The most notable increase in costs is related to management of thermal constraints which increased to £1.4 bn in total. Given the trend of new generation outpacing new network build, thermal constraints are expected to rise further by 2030. We will continue to work with industry to reduce costs where possible, such as by designing innovative solutions through the Constraints Collaboration Project and seeking to remove distortions in the BM from subsidy support mechanisms through Balancing Settlement Code modification P462.

However, there has been a notable decrease in the costs of managing the system in other areas, such as stability and response. The ability to co-optimise dynamic services in the Enduring Auction Capability has significantly improved the efficiency of our response procurement, reducing total costs of procuring dynamic response by 20%. The continued availability of solutions contracted for stability, voltage and constraint management under our Network Services tenders delivered approximately £154 m in savings across 2024 versus the counterfactual.

This publication provides more detail on the different cost and volume trends for each area, as well as signposting relevant market reforms, system transformation, and other initiatives that are directly addressing the primary drivers for reform. Overall, it's important to note that whilst we are doing all we can to reduce balancing costs, rapid network build and wholesale market reform will have the biggest impact on cost reduction.

Forward-looking view of our markets



Market descriptions

Response (dynamic services, Static Firm Frequency Response, Mandatory Frequency Response)

2030 goal for frequency: Response and reserve procurement will be co-optimised where possible, with intraday an/or locational procurement if it is proven to be more efficient for providers and NESO.

Reserve (Balancing Mechanism, Quick Reserve, Slow Reserve, Balancing Reserve)

2030 goal for frequency: Response and reserve procurement will be co-optimised where possible, with intraday an/or locational procurement if it is proven to be more efficient for providers and NESO.

Energy balancing (Balancing Mechanism, Demand Flexibility Service)

2030 ambition for energy balancing: We are exploring the long-term direction for the Balancing Mechanism as part of our REMA work. In the meantime, we will continue to improve access and level the playing field for dispatch, ensuring this is coherent with our other routes to market including the Demand Flexibility Service (DFS).

Thermal (Balancing Mechanism and Constraint Management Intertrip Service)

2030 ambition for thermal: More accurate market signals will enable supply, demand and flexibility assets across transmission and distribution to solve congestion. REMA will determine whether these signals are sent through the wholesale market. Constraints Collaboration Project will help to inform any additional market and technical solutions.

Stability (Balancing Mechanism, stability markets)

2030 ambition for stability: There will be three stability markets (Y-4, Y-1 and day ahead) giving market participants an availability payment and reserving their capacity for our need. We will also allow stacking between ancillary services where possible.

Voltage (Balancing Mechanism, Obligatory Reactive Power Service, pathfinders)

2030 ambition for voltage: We will have a variety of means to send investment and dispatch signals for reactive power. We will work closely with DNOs on coordinating voltage management across distribution and transmission networks.

Restoration (contracts, tenders, distributed restart)

2030 ambition for restoration: Increased number of restoration service providers, including distributed energy resources (e.g. hydrogen, energy storage, wind) procured through competitive service tenders.

Introduction

Objectives & scope

The electricity Markets Roadmap will remain focussed on the electricity markets which NESO is responsible for and operates for now, but we will support cross-sector collaboration and advocate whole system thinking which is imperative to achieve our overarching decarbonisation goals. In addition, we are also starting to develop a Gas Future Markets Plan which will set out the actions, projects and plans needed to transition market and industry arrangements for a decarbonised energy system.

NESO's electricity Markets Roadmap will:

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

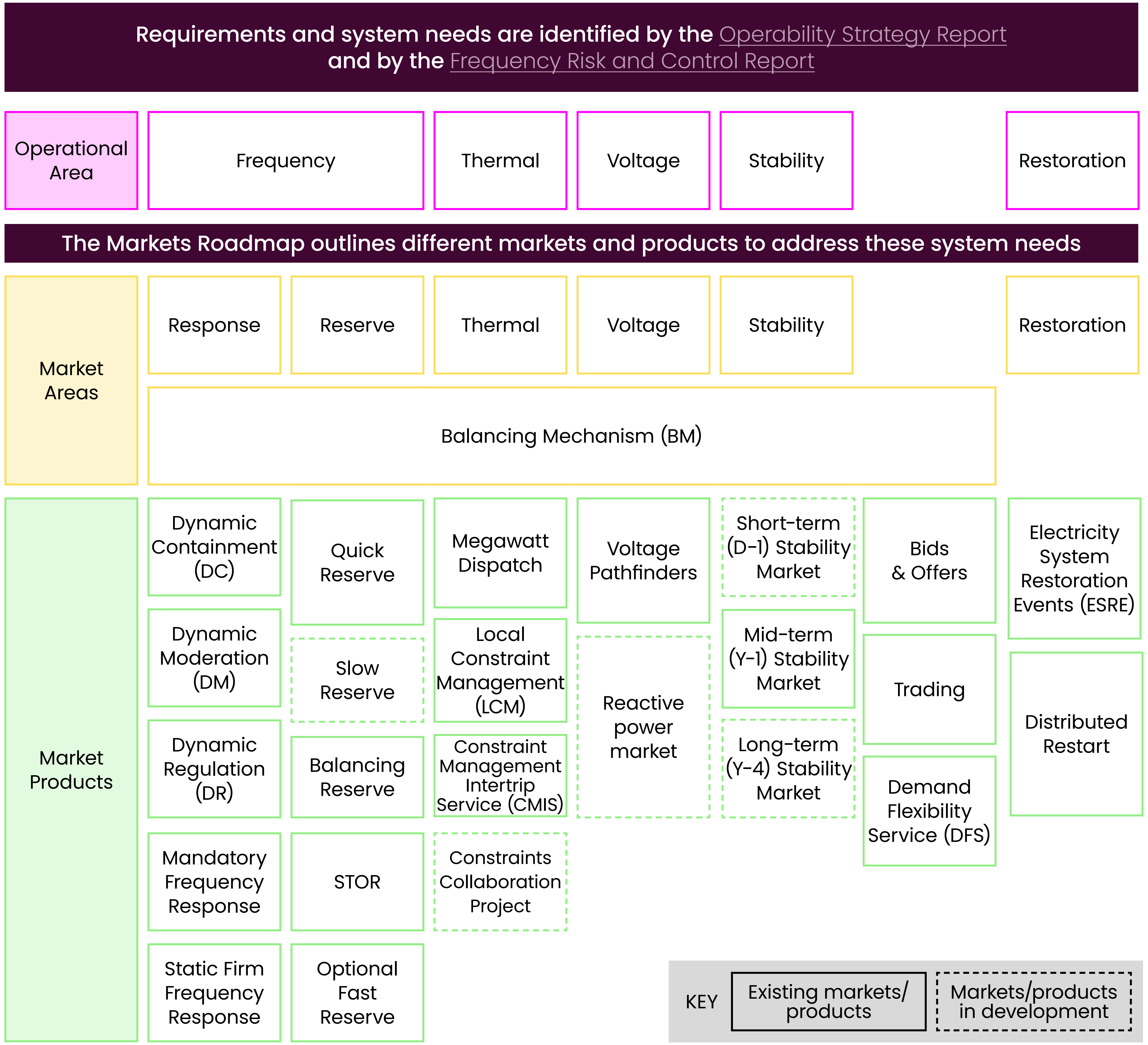
Design options for market reform should be assessed against our robust Market Design Framework. Actions should be taken to deliver value for current and future consumers.

2 Provide a clear and transparent view of market reforms in a co-ordinated, coherent way which is accessible

For each of our market areas, we describe how the landscape is changing, how the volumes and costs of our actions have trended over the last 12 months, and our view of how our markets should evolve going forward. Alongside this annual publication, we update Delivery Plans for each market area on a monthly basis. This can be found on the main Markets Roadmap webpage.

3 Share strategic direction for NESO markets and how we are working to enable Clean Power 2030 and sector decarbonisation

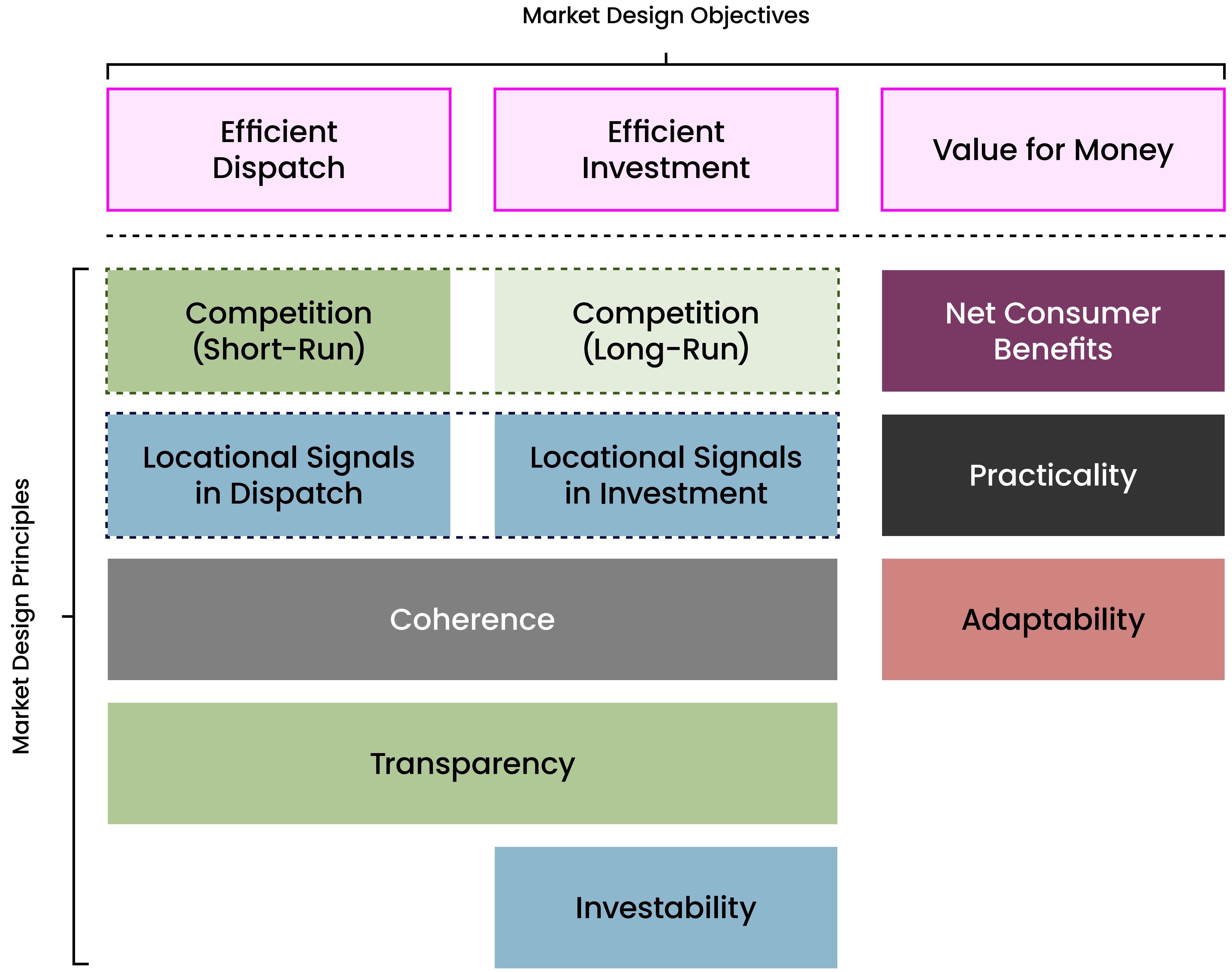
Many of our ancillary services were designed and introduced to enable us to operate the system at zero carbon for short periods by 2025. The focus of the Markets Roadmap now turns to new medium-term goals, such as supporting Government to enable its Clean Power action plan. Nevertheless, it is also vital we maintain a strong focus on what is required to ensure energy security and lower costs in the long run.


Requirements and system needs are identified by the Operability Strategy Report and by the Frequency Risk and Control 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)
Dynamic Moderation (DM)
Dynamic Regulation (DR)
Mandatory Frequency Response
Static Firm Frequency Response
Quick Reserve
Slow Reserve
Balancing Reserve
STOR
Optional Fast Reserve
Megawatt Dispatch
Local Constraint Management (LCM)
Constraint Management Intertrip Service (CMIS)
Constraints Collaboration Project
Voltage Pathfinders
Reactive power market
Short-term (D-1) Stability Market
Mid-term (Y-1) Stability Market
Long-term (Y-4) Stability Market
Bids & Offers
Trading
Demand Flexibility Service (DFS)
Electricity System Restoration Events (ESRE)
Distributed Restart
KEY
Existing markets/ products
Markets/products in development

Market Design Framework

In 2021, we introduced our Market Design Framework (MDF), which underpins all of our market reform decisions. It is used to analyse the efficiency of our existing markets, helping to drive continuous improvement and identify new opportunities for reform. In 2024, we used the MDF to develop our reactive power markets and the Constraints Collaboration Project.

Any new market design must support the fulfillment of the below market design objectives. To do that, we test designs against each of the market design principles.



Objective
Efficient Dispatch

Alignment with the trilemma challenges

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

Objective
Efficient Investment

Alignment with the trilemma challenges

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

Objective
Value for Money

Alignment with the trilemma challenges

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

Principle
Competition (Short Run)

Definition

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

Principle
Competition (Long Run)

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

Principle
Locational Signals in Investment

Definition
The procurement method ensures that capacity is constructed in the right places.

Principle
Locational Signals in Dispatch

Definition
The procurement method ensures that services are delivered in the right places.

Principle
Coherence

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

Principle
Transparency

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

Principle
Net Consumer Benefits

Definition
The costs to consumers do not outweigh the benefits conferred by the procurement method.

Principle
Investability

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

Principle
Practicality

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

Principle

Adaptability

Definition

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

NESO Publication Map

	Strategy	System Need	Policy & Procurement
Electricity	Holistic Network Design Enabling Demand Side Flexibility Beyond 2030 Balancing Costs Report Operability Strategy Report	Frequency Risk and Control Report Summer Outlook Winter Outlook Resource Adequacy Study Electricity Ten Year Statement Transitional Centralised Strategic Network Plan	electricity Markets Roadmap
Whole Energy	Clean Power 2030 Strategic Spatial Energy Plan Centralised Strategic Network Plan Regional Energy System Plan Innovation Strategy	Future Energy Scenarios	
Gas	Gas Options Advice Document	Gas Network Capability Needs Report	Gas Future Markets Plan

HND

Holistic Network Design

Cadence: Standalone

The Holistic Network Design network provides a recommended offshore and onshore design for a 2030 electricity network, that facilitates the Government’s ambitions and enables investment and delivery of infrastructure across Great Britain. The publication details the four equally considered design objectives to make sure the most appropriate approach is taken forwards, including cost to consumers, deliverability and operability, impact on environment, and impact on local communities.

For more information click here.

FRCR

Frequency Risk and Control Report

Cadence: Annual

The Frequency Risk and Control Report includes an assessment of the magnitude, duration and likelihood of transient frequency deviations, forecast impact and the cost of securing the system and confirms which risks will or will not be secured operationally.

For more information click here.

Summer Outlook

Cadence: Annual

The Summer Outlook report contains our view of the electricity system for the coming season and is designed to support the industry in its preparations. The report outlines our assessment of Great Britain's projected electricity needs covering security of supply, any potential operational challenges and an assessment of the wider energy market context.

For more information click here.

Enabling Demand Side Flexibility

Cadence: Standalone

Enabling Demand Side Flexibility is a response to the urgent need for mobilising flexibility as Great Britain shifts towards a greener future. Our strategy aims to investigate the no-regret actions NESO, alongside other industry bodies, can take together to sharpen the market signals for flexibility in the medium term. It outlines our vision, the desired outcomes and associated activities needed in the next five years to unlock the flexibility required for achieving a net zero electricity system.

For more information click here.

Winter Outlook

Cadence: Annual

The Winter Outlook Report presents our view of electricity security of supply for the winter ahead. This report builds on the Early View of Winter, providing our latest assessment of margins, operations and markets.

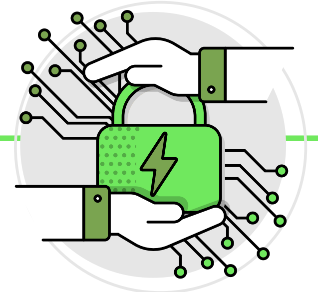
For more information click here.

Beyond 2030

Cadence: Standalone

Beyond 2030 is a ground breaking investment plan for the future of the GB electricity network, recommending upgrades and new infrastructure for electricity networks, both on and offshore. The document builds on the Holistic Network Design, and is a transitional plan, which is a stepping-stone before NESO develops the Centralised Strategic Network Plan.

For more information click here.



Resource Adequacy Study

Cadence: Yet to be published

This study will align with the CP30 publication of November 2024, but looks beyond this to consider security of supply in 2035 and 2040. The purpose is to identify long lead-time actions which need to be taken now to ensure a smooth and secure pathway towards a Net Zero energy future.

For more information click here.

BCR

Balancing Costs Report

Cadence: Annual

The Balancing Costs report provides a comprehensive review of balancing costs incurred and our best outlook of costs in the future. We then outline how certain parts of NESO's balancing costs strategy aim to impact those costs in the future.

For more information click here.

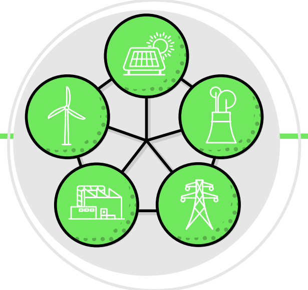
ETYS

Electricity Ten Year Statement

Cadence: Annual

The Electricity Ten Year Statement is NESO's view of future transmission requirements and the capability of Great Britain's National Electricity Transmission System (NETS) over the next ten years. It is important in helping us to understand where investment and development are needed to help us achieve our zero-carbon ambition. Our key messages explain that the key system needs insights from our latest (FES) analysis.

For more information click here.



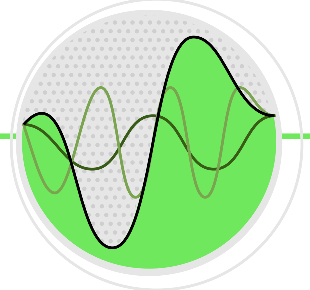
tCSNP

Transitional Centralised Strategic Network Plan

Cadence: Standalone

This publication is an intermediate phase as we develop the enduring CSNP. It is a Refresh of our Beyond 2030 report published in March 2024 that recommended reinforcement projects.

For more information click here.



MR

electricity Markets Roadmap

Cadence: Annual

The electricity Markets Roadmap outlines what we are doing to reform the ancillary services and balancing markets and why we are doing it, giving participants the ability to build investment cases and stakeholders the confidence that we are making the right design decisions.

For more information click here.

OSR

Operability Strategy Report

Cadence: Annual

The OSR outlines the operability challenges we expect to face as we transition to a clean power electricity system in 2030 and a net zero system beyond 2030. The report covers seven key areas of system operability: adequacy, flexibility, frequency, thermal, voltage, stability and restoration.

For more information click here.

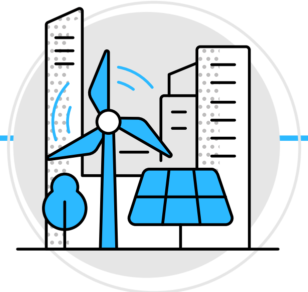
CP2030

Clean Power 2030

Cadence: Standalone

The Clean Power Plan includes analysis of multiple pathways that enable a clean power system by 2030, with varying energy generation and demand mixes, transmission network requirements, implications for connections and any system operation considerations; including recommended actions for Government and Industry.

For more information click here.



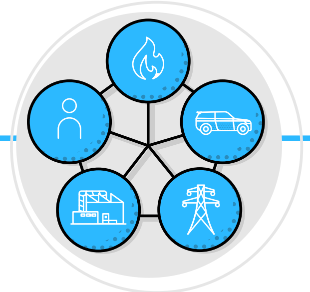
FES

Future Energy Scenarios

Cadence: Annual

Future Energy Scenarios (FES) outlines NESO pathways to net zero which represent different, credible ways to decarbonise our energy system as we strive towards the 2050 target.

For more information click here.



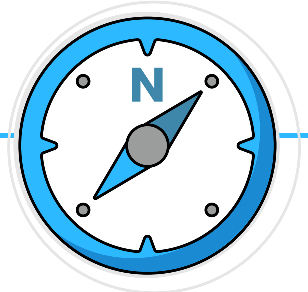
SSEP

Strategic Spatial Energy Plan

Cadence: TBC

The Strategic Spatial Energy Plan (SSEP) will help accelerate and optimise the transition to clean, affordable and secure energy across Great Britain by providing greater clarity to industry, investors, consumers and the public on the shape of our future reformed energy system. The first SSEP will be a GB-wide plan that will map potential locations, quantities and types of electricity and hydrogen generation and storage infrastructure over time.

For more information click here.



CSNP

Centralised Strategic Network Plan

Cadence: Every 3 years

An independent, coordinated, and long-term approach to transmission network planning in Great Britain. It will identify the best options to connect power to the people and sources that need it, using the findings of the SSEP.

For more information click here.

RESP

Regional Energy System Plan

Cadence: Every 3 years

The Regional Energy Strategic Plans (RESPs) will develop coordinated whole energy system planning and governance across Scotland, Wales and nine English regions. They will help coordinate stakeholders to set out regional energy infrastructure needs and unlock investment at a distribution level. They will ensure that pathways are developed for each region and that these are coherent with national ambitions. As our understanding of the local landscape and ambitions increases, the RESPs will be able to feed more granular, bottom-up data into the SSEP and FES as appropriate.

For more information click here.

IS

Innovation Strategy

Cadence: Annual

The Innovation Strategy signals to the regulator and external innovators our innovation priorities for the year ahead, supporting NESO's secondary duty of facilitating innovation and our licence condition of developing an innovation strategy for gas and electricity. It sets out the focus of innovation resources and funding, such as Network Innovation Allowance, Strategic Innovation Fund and other mechanisms.

For more information click here.

GOAD

Gas Options Advice Document

Cadence: Bi-annual

The Gas Options Advice Document assesses the investment options put forward by National Gas Transmission plc, to provide high-level advice to Ofgem on the relative merits of those options.

For more information click here.

GNCR

Gas Network Capability and Needs Report

Cadence: Bi-annual

The Gas Network Capability and Needs Report sets out the needs for future needs for capability on the national gas transmission system, the 'National Transmission System' (NTS), owned and operated by National Gas Transmission plc (NGT).

For more information click here.

Gas Future Markets Plan

Cadence: TBC

The Gas Future Markets Plan will set out the actions, projects and plans needed to transition gas market and wider industry arrangements to be fit for a decarbonised energy system.

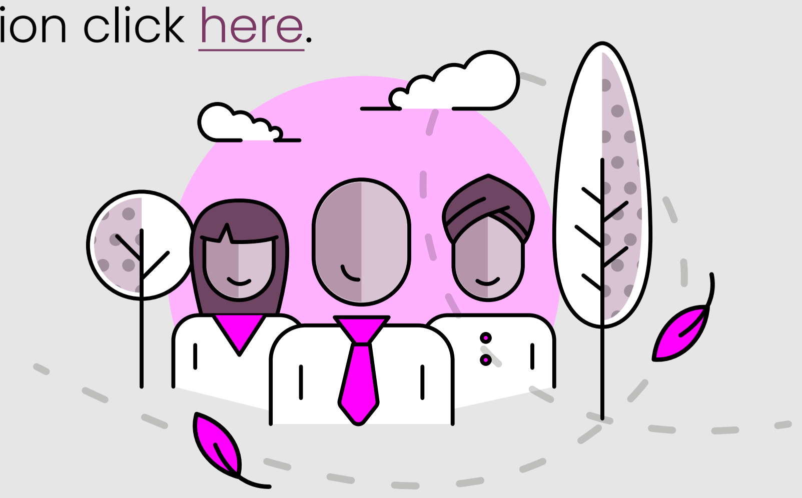
For more information click here.

Markets Engagement

Talking to our stakeholders to understand their perspectives and needs is a crucial part of developing well-designed, cost-effective NESO markets. To get in touch with our team, please contact: box.market.dev@nationalgrideso.com These engagement channels are used primarily for the design of NESO markets. Broader engagement continues to be a core priority with Government, Ofgem and industry on wider market reforms too.

Electricity Markets Advisory Council

One of our key stakeholder groups is the Electricity Markets Advisory Council (EMAC). The EMAC was established in 2022 to bring together experts from all parts of the electricity value chain to help inform our approach to strategic market design and delivery. The group is currently being refreshed and will continue to play an important role throughout 2025. For more information click here.



Markets Forum

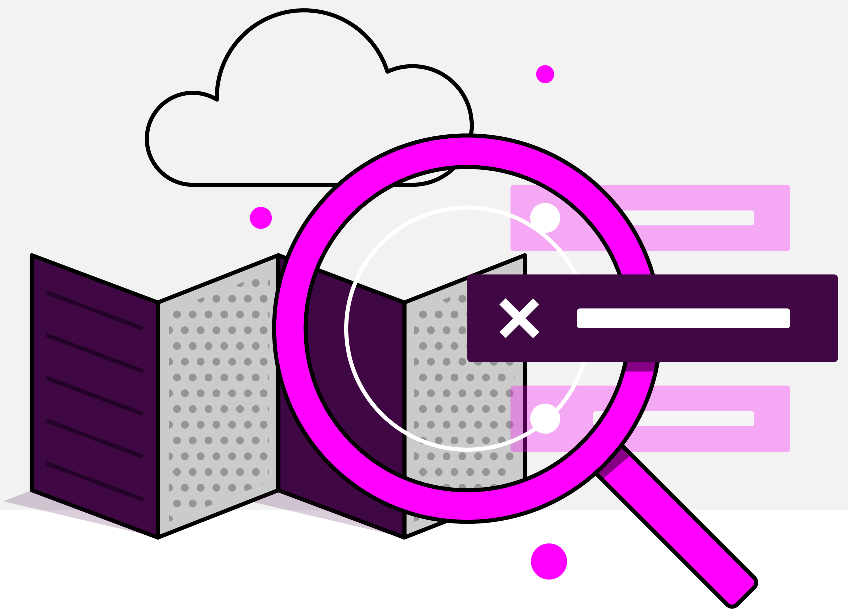
Join our Markets Forums to share your views on current industry priorities and collaborate on ways to tackle these challenges.

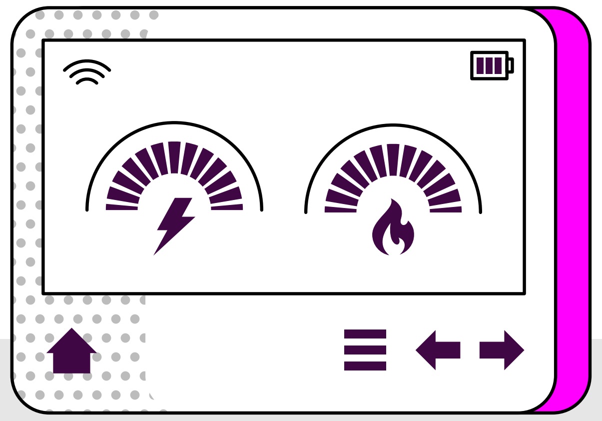
You'll hear about our current strategy and policy positions, and shape decision making around developing market solutions, so get involved.

Markets Forums will follow a more holistic, whole energy approach, however you'll hear from us with product specific engagement touchpoints at relevant points throughout the year.

Breakout discussions, networking sessions and panel debates will give you the opportunity to collaborate with industry colleagues as well as the NESO Markets team.

More information can be found here:
Markets Forum webpage.





Power Responsive

Power Responsive is a stakeholder-led programme, facilitated by NESO, that works with industry to unlock demand side flexibility through an agile, collaborative approach. It brings together industry and energy users to work together in a co-ordinated way. A key priority is to grow participation in DSF, making it easier for households and businesses to get involved and realise the financial and carbon-cutting benefits. The role of Power Responsive is to:

- Remove barriers for Demand Side Flexibility (DSF) in NESO Markets.
- Raise awareness of DSF opportunities.
- Act as a voice for DSF with NESO and wider industry.

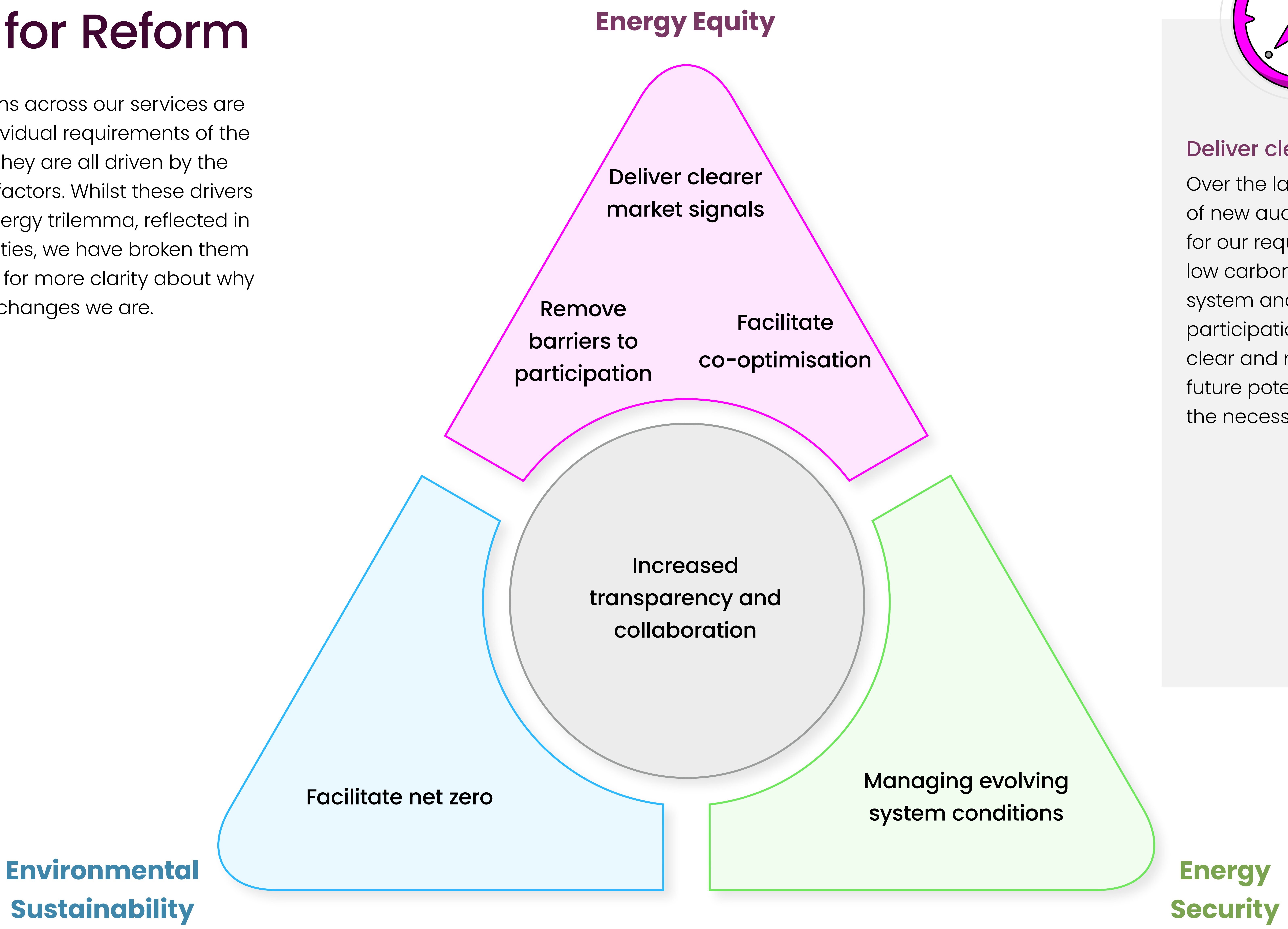
More information can be found here

Market specific engagement

In addition, we engage with stakeholders in smaller, more focussed, forums as needed when developing new markets. Throughout 2024, we engaged extensively with industry via multiple channels, including webinars, roadshows, the Operational Transparency Forum, and through designated engagement workstreams such as the Constraints Collaboration Project (CCP). CCP has been a great example of industry collaboration, gathering new ideas and promoting innovation in how market-based solutions can address thermal constraints.

Drivers for Reform

The specific reforms across our services are tailored to the individual requirements of the service. However, they are all driven by the same motivating factors. Whilst these drivers link back to the energy trilemma, reflected in NESO's primary duties, we have broken them down further here for more clarity about why we're making the changes we are.

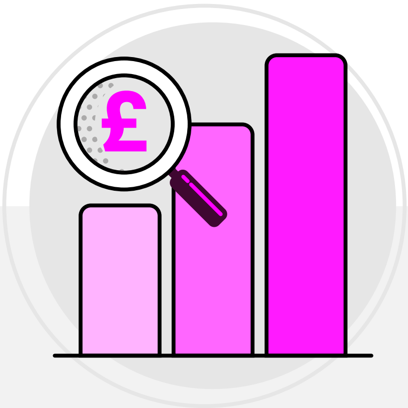


Deliver clearer market signals

Over the last year we have launched a number of new auctions to provide clear market signals for our requirements. We see the vital role new, low carbon assets will play in our future electricity system and the importance of enabling their participation in our services. We aim to provide clear and reliable market signals to highlight our future potential requirements, ultimately supporting the necessary investment decisions.

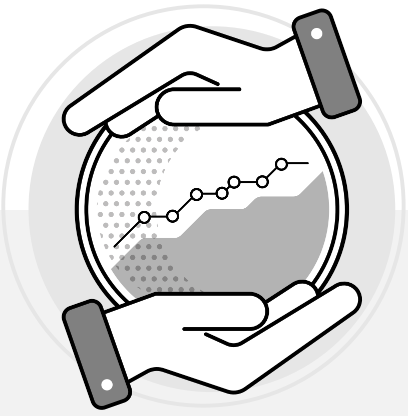
Remove barriers for participation to increase competition

Recognising the shifting asset mix and technology types available, we are keen to ensure that our service design choices do not present an unnecessary barrier to participation. There are fundamental limitations to the services which some assets can deliver, based on a units flexibility, speed of response, or duration of delivery. However, many barriers exist due to factors of policy, IT platforms and holdovers from historical considerations. We are working to prioritise and remove these barriers to enable all kinds of assets to participate on a level playing field, which increases competition and liquidity, reducing unnecessary cost.



Facilitate co-optimisation

Providing opportunities for co-optimised procurement across our services allows service providers to improve the efficiency of their participation. This also enables us to ensure the optimal split of assets across our different services, minimising oversupply in some areas and undersupply in others. Overall, co-optimisation improves liquidity in our services, which primarily improves cost efficiency but can also reduce the risk of supply shortages.

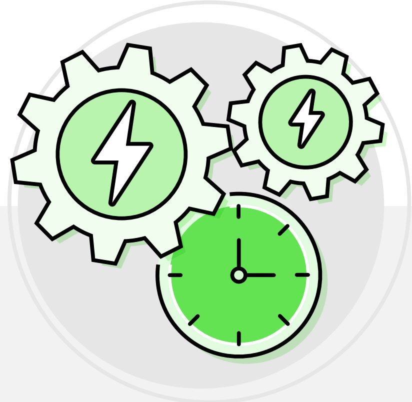


Increased transparency and collaboration

We have continued our focus on collaborative design and transparent communications, seeking to ensure this is central to all of the activities we perform. Transparency of NESO actions helps market participants understand our decision making and enables a more collaborative approach to service design and market reforms. By taking a collaborative approach, we can ensure that broader impacts are considered, and innovative solutions identified which we would not have found on our own. This ultimately improves the effectiveness and efficiency of our services, reducing unnecessary expenditure on suboptimal solutions.

Facilitate net zero

There are many service we currently procure, and processes we follow as part of our system operation which present a barrier to the transition to net zero. To support the broader transition we must adapt these services and processes to ensure that they are coherent with a future zero carbon system. This may involve removing barriers to low carbon alternative sources and providing clear market signals for some services, or reducing our overall requirement in others. Without these changes being taken as part of the managed transition we may find they inhibit the energy transition or risk system security.



Managing evolving system conditions

Conditions on the system are changing. Reductions in system provided inertia and increasing sizes of the largest loss as well as volumes of renewable and small DER, requires new and innovative means of managing the system.

There are growing volumes of wind in Scotland which combined with network outages required to support new connections and network reinforcement, are leading to higher volumes of thermal congestion.

In our role as system operator, we must adapt our tools to prevent these changing conditions from creating serious risks to system security.

The evolving system conditions are explained in more detail in our Operability Strategy Report.

Overview of System Needs

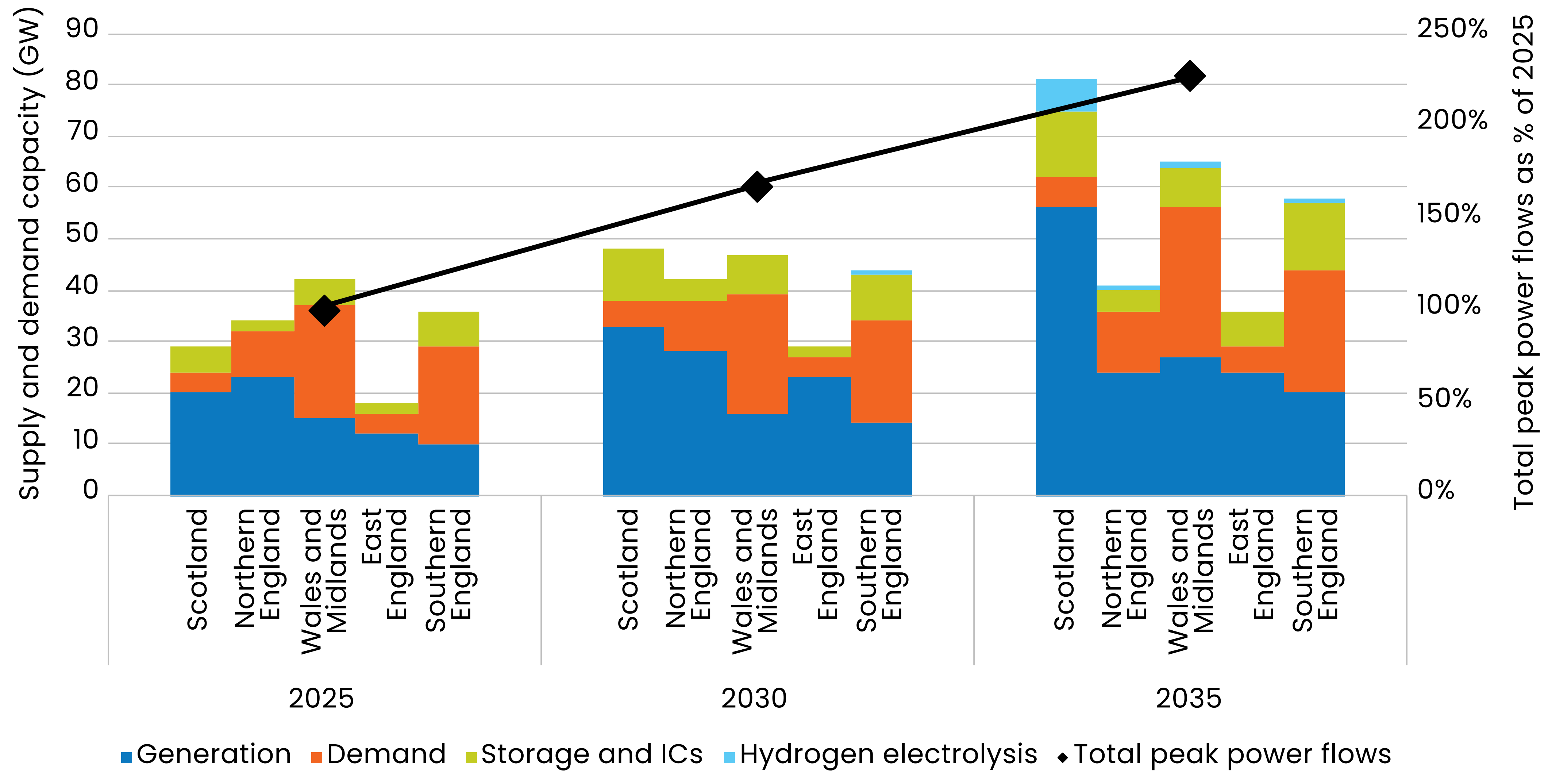
Thermal

Description

The electricity transmission network has limited capacity to transport power. The thermal workstream covers how we manage this capacity.

What are the system requirements?

Figure 1: **Supply and demand capacities with GB aggregated power flows**



How do we calculate our requirements?

The Network Options Assessment (NOA) balances network investment with the forecast cost to constrain generation behind a constraint boundary. Where new capability is recommended by the NOA, in line with the Electricity Ten Year Statement (ETYS), it is delivered by transmission owners. Moving forward, new network capabilities will be published within the Centralised Strategic Network Plan (CSNP).

How do we currently meet these requirements?

Market options: Balancing Mechanism, Trades, MW Dispatch and Local Constraint Market.
Technical options: Re-arranging the network, enhancing network (Constraint Management Intertrip Scheme).

How are our requirements likely to change?

As we move towards Clean Power in 2030 and net zero by 2050, higher volumes of generation will connect to the network. Careful management of where new assets connect to the network will be essential, to reduce costs being incurred through constraining low and zero carbon generation due to insufficient network capacity. Our Strategic Spatial Energy Plan (SSEP) and CSNP will be central in ensuring we plan an optimal future electricity system.

How will we meet these requirements in the future?

Largely through similar means, though new market and non-market solutions may be deployed as a result of the Constraint Collaboration Project.

Overview of System Needs

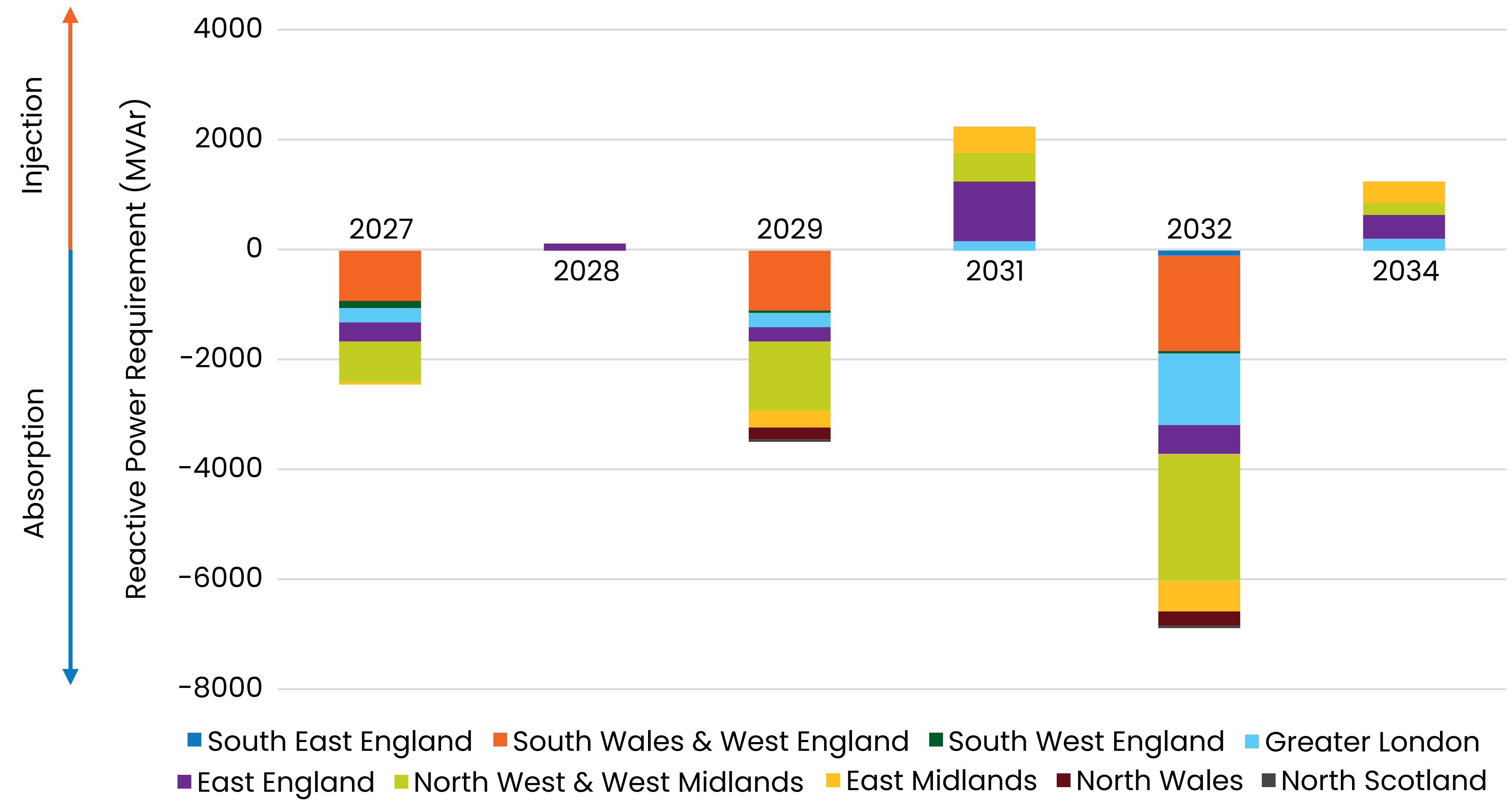
Voltage

Description

Voltage must be kept within set limits all across the electricity transmission system to maintain safe and efficient operation. The absorption of reactive power helps to lower the voltage, the injection of reactive power helps to raise the voltage.

What are the system requirements?

Figure 2: Reactive Power Requirements by Region



How do we calculate our requirements?

We complete voltage system studies across multiple scenarios to determine low and high voltage requirements out to 2030. These are continually revisited and revised to ensure we have sufficient voltage control capabilities to keep voltage within the Security and Quality of Supply Standard (SQSS).

How do we currently meet these requirements?

Market options: Self-dispatching providing reactive power services via Grid Code obligations, Balancing Mechanism dispatch, Network Service Procurement (previously known as pathfinders).
Technical options: Network reconfigurations, Transmission Owner assets.

How are our requirements likely to change?

The energy transition is having a significant impact on voltage management across the transmission network. Meeting our Clean Power 2030 ambition will require removing reliance on carbon emitting generation for the provision of reactive power through the development of new markets.

How will we meet these requirements in the future?

Utilisation of same market and non-market solutions. Increased procurement from Future of Reactive Power Markets.

Overview of System Needs

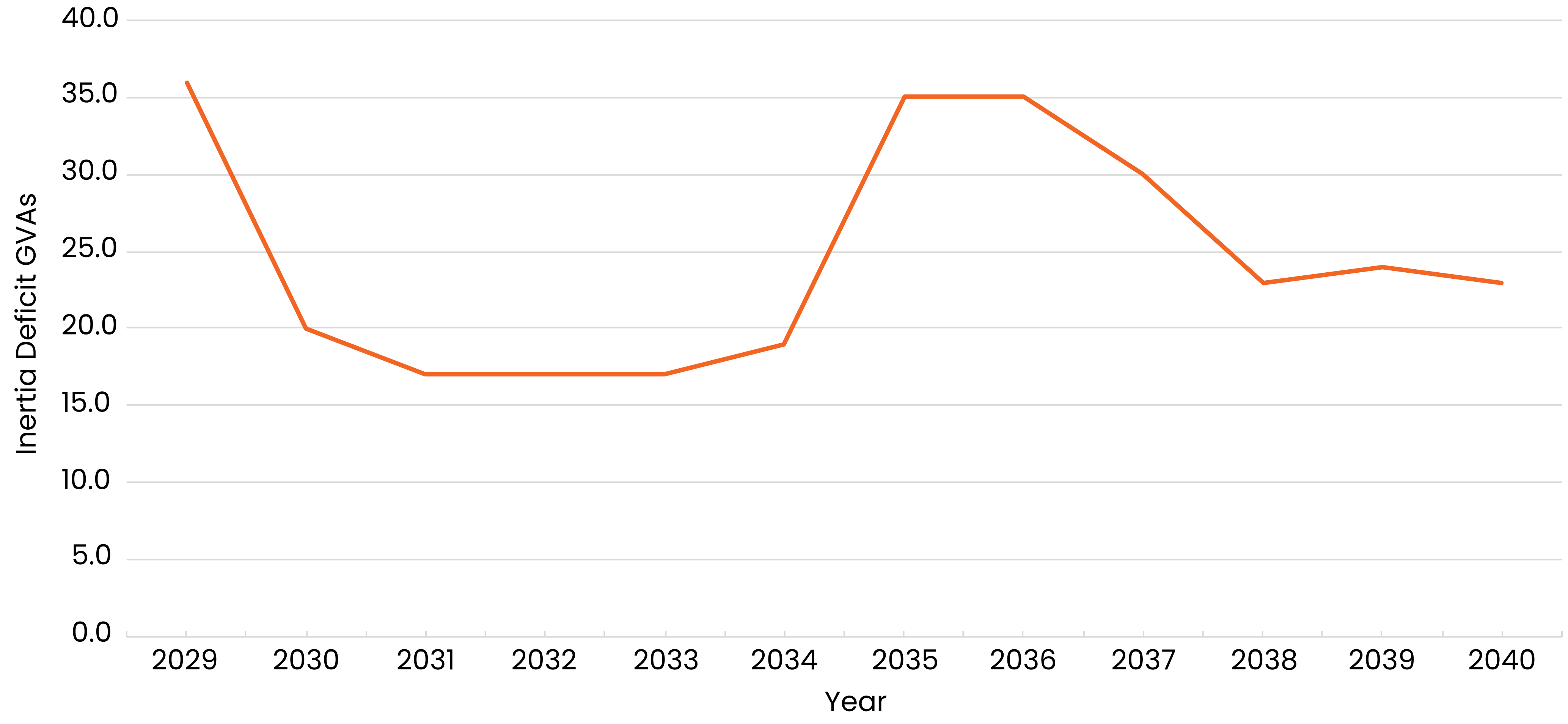
Stability

Description

Stability is the inherent ability of the system to quickly return to acceptable operation following a disturbance. The term is used to describe a broad range of topics, including inertia, system strength and dynamic voltage. If the system becomes unstable it could lead to a partial or total system shut down leading to the disconnection of consumers.

What are the system requirements?

Figure 3: **Peak Inertia Deficit GVAs**



How do we calculate our requirements?

System stability needs are assessed against two key requirements, system inertia and system strength. For inertia, we conduct regular studies to ensure we understand our requirement and publish this annually within the Frequency Risk and Control Report (FRCR). System strength is assessed by determining the amount of short circuit level on the power system; this is typically done through offline studies across a range of time horizons.

How do we currently meet these requirements?

Market options: Balancing Mechanism dispatch, Stability Pathfinders (Phase 1-3), Y-1 Stability market.

How are our requirements likely to change?

Achieving clean power and net zero operation will require reducing our reliance on carbon emitting generation for the provision of stability services, learning to operate the system with lower inertia, and high levels of inverters using grid forming and grid following technologies.

How will we meet these requirements in the future?

The same suite of services, with addition of D-1 Stability / Y-4 Stability markets.

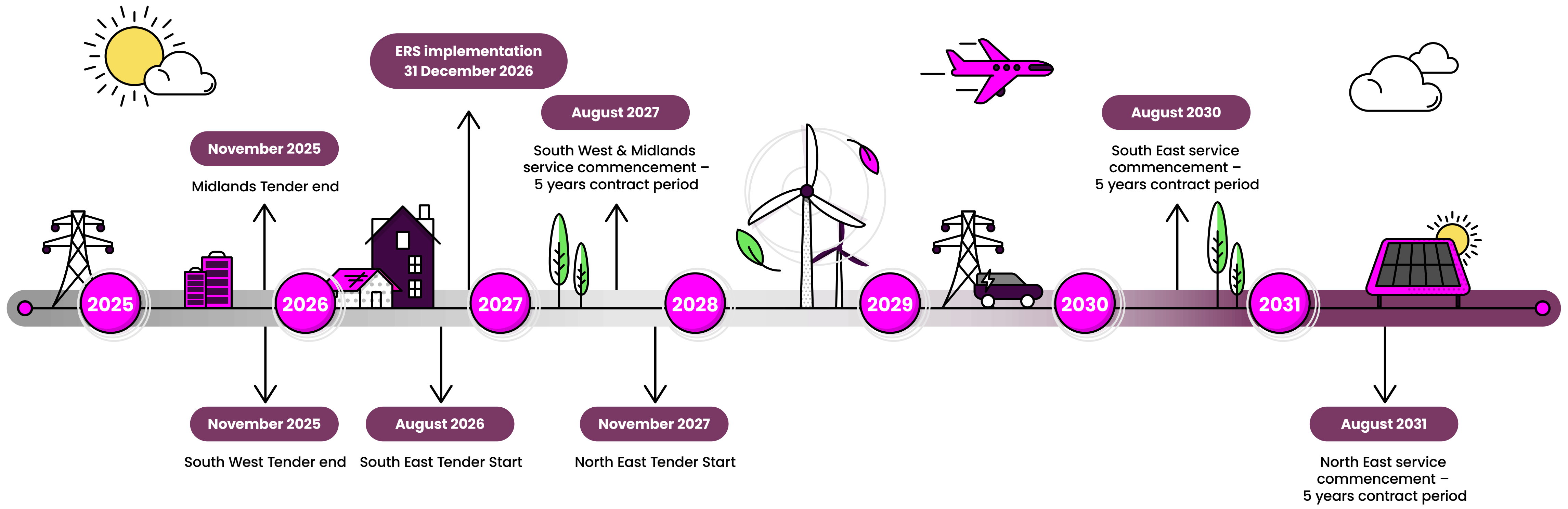
Overview of System Needs

Electricity System Restoration (ESR)

Description

In the unlikely event that part, or all GB experiences a loss of electricity supply, NESO must have sufficient capability and robust plans to restore the network as quickly as possible. This is achieved by the availability of several contracted ESR service providers which can start generating units without reliance on external electricity supplies.

Restoration Service provider tender procurement timeline



How do we calculate our requirements?

We have an annual process in which our ESR requirements are modelled to inform the volume of services required for each transmission system region. By the end of 2026, we will implement the Electricity System Restoration Standard (ESRS), which will define how we will maintain ESR capability to achieve the requirements set at 60% of regional demand to be restored within 24hrs, and 100% within 5 days nationally.

How do we currently meet these requirements?

Regional ESR tenders.

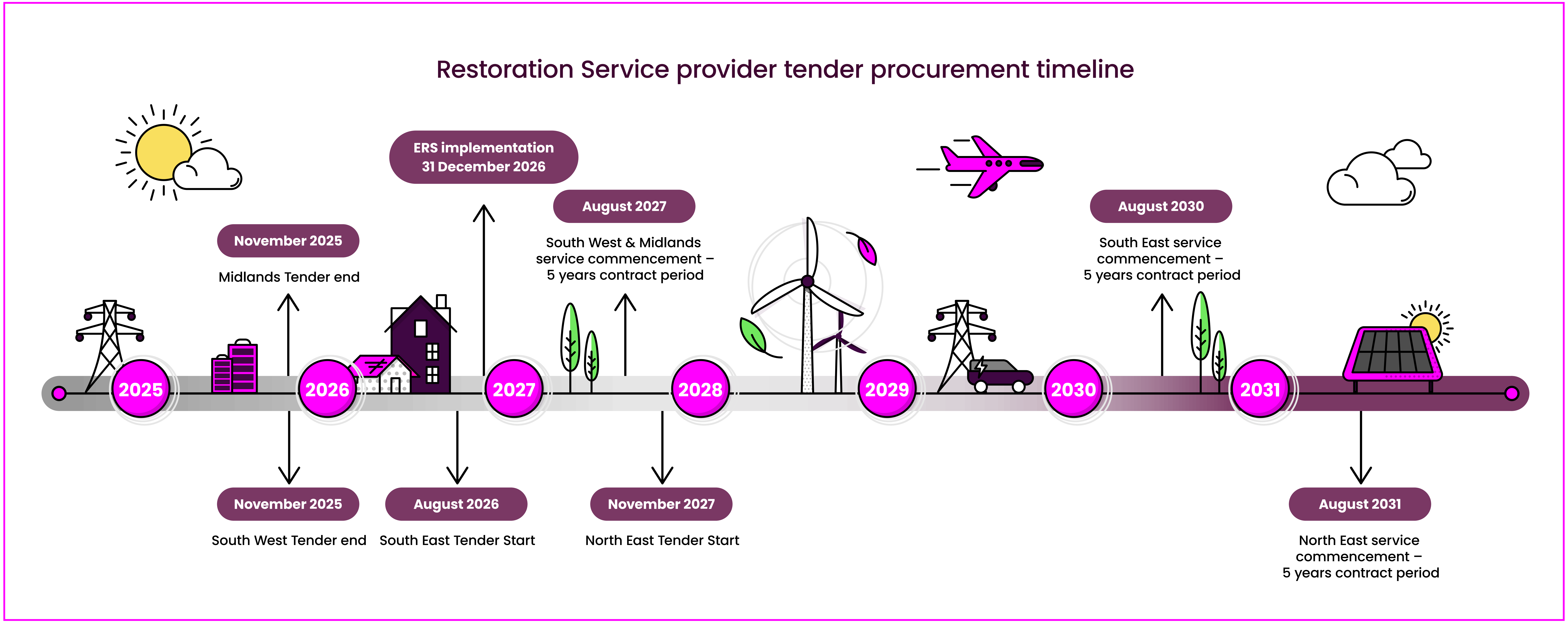
How are our requirements likely to change?

Up to 2030, we expect to see a significant increase in the number of restoration service providers and a higher diversity of technology types across the network. Beyond 2030, we expect that our reliance on carbon emitting resources to provide ESR services will be reduced.

How will we meet these requirements in the future?

Restoration services are primarily procured through fully competitive tender events, which are divided by Restoration Regions and invite submissions from a wide range of technologies. More recently, outputs from the Distributed ReStart project have led to the introduction of categories within tenders, enabling participation from both transmission and distribution connected assets. This approach now forms a fundamental part of the procurement process.

Overview of System Needs



Overview of System Needs

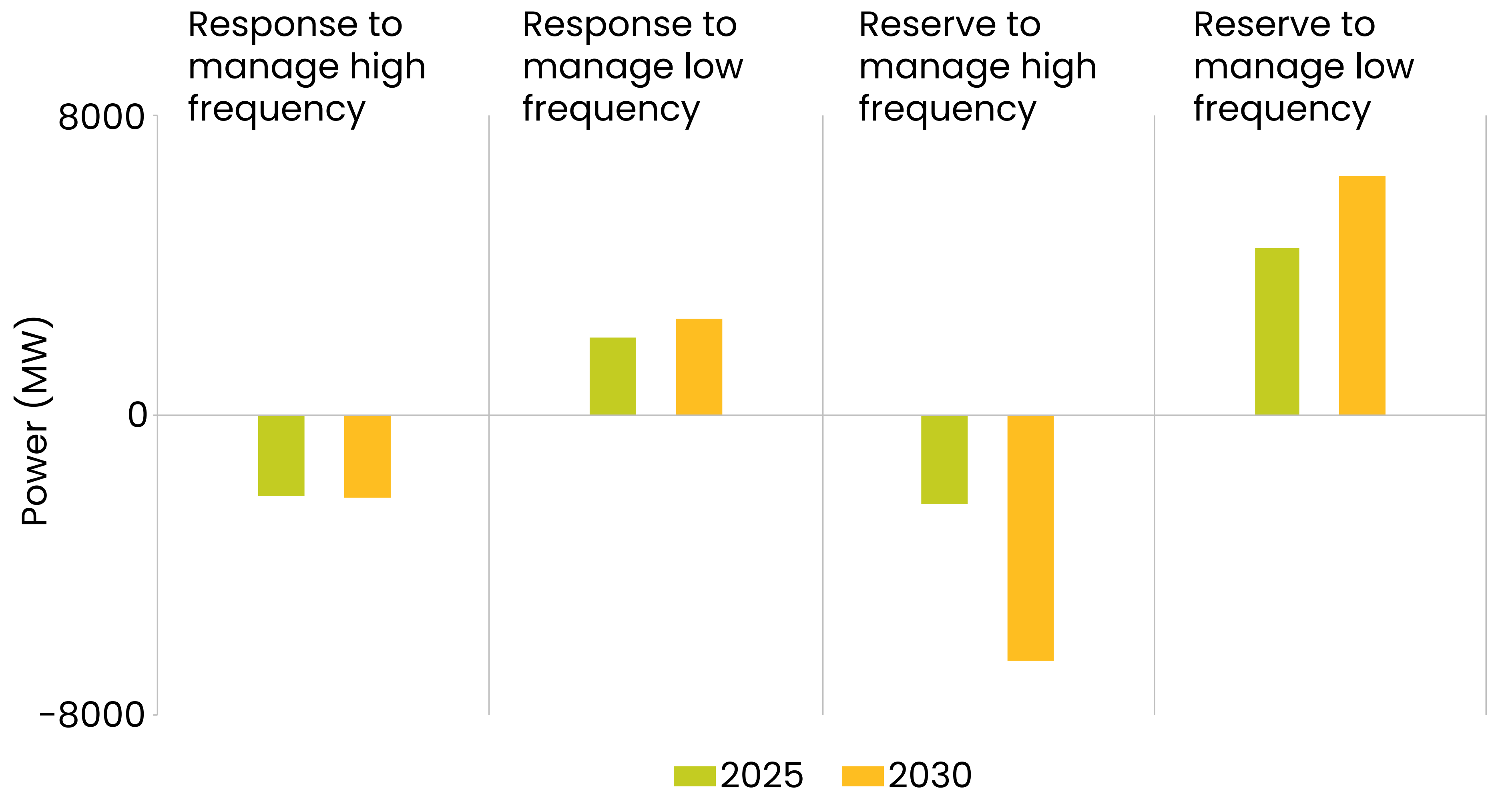
Frequency

Description

Frequency is a measure of the balance between supply and demand. We use response and reserve services to correct imbalances and maintain system frequency close to the target of 50 Hz.

What are our requirements?

Figure 4: **Maximum Daily Frequency Service Volumes**



The requirements vary significantly between time of day, week, season and year. The increase in reserve volumes between now and 2030 is largely driven by two factors: Short Term Operating Reserve (STOR) transitioning to Slow Reserve (SR) and Wind Reserve (WR) levels increasing to manage the increased variability in wind output as more of wind connects to the network.

How do we calculate our requirements?

Frequency requirements are outlined within the Security and Quality of Supply Standard (SQSS) and the System Operation Guidelines (SOGL) are anticipated to remain unchanged to 2030 and beyond. Response and reserve requirements are assessed and published on the NESO website daily.

How do we currently meet these requirements?

Response: Dynamic Containment, Dynamic Moderation, Dynamic Regulation, static Firm Frequency Response, Mandatory Frequency Response.

Reserve: Balancing Mechanism, Short Term Operating Reserve (STOR) (transitioning to Slow Reserve), Quick Reserve (QR), Balancing Reserve (BR), legacy arrangements.

How are our requirements likely to change?

Our response and reserve requirements are heavily influenced by factors that impact frequency volatility, uncertainty, replacement energy volumes, such as the size of the largest loss on the system, inertia levels, and the volume of renewables connected to the network.

How will we meet these requirements in the future?

Response: Largely the same products will be used, potentially with the introduction of intraday and locational procurement.

Reserve: We will begin the transition from STOR to Slow Reserve in 2025, and we will continue the QR transition. There is a potential for some reserve services to have intraday and locational procurement introduced.

Overview of System Needs

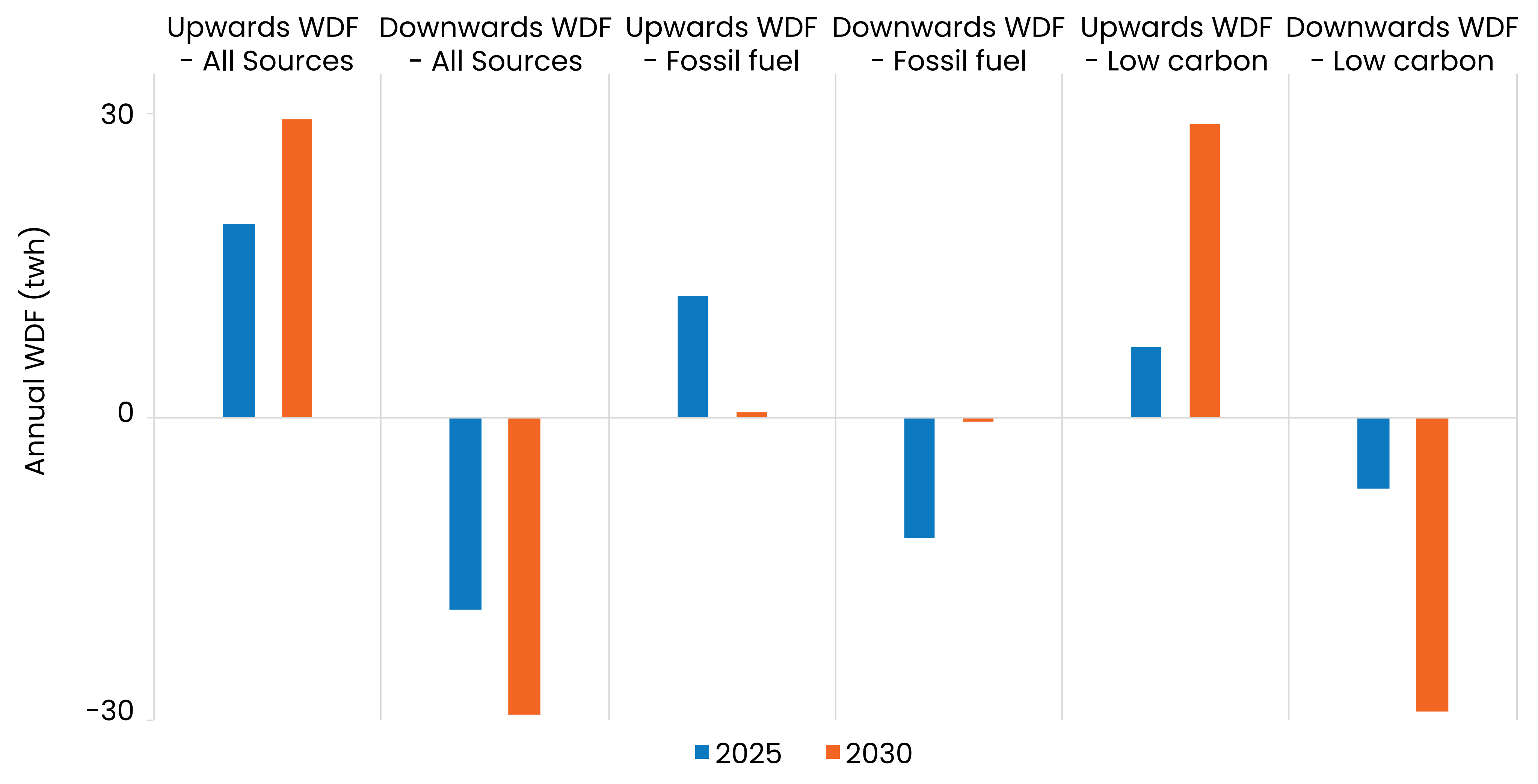
Within-Day Flexibility

Description

Within-day flexibility is the ability to adjust the flexible parts of supply and demand as the inflexible parts vary over the day. To achieve a clean power electricity system, fossil fuelled flexibility will have to be replaced with low carbon sources.

What is our within-day flexibility advice?

Figure 5: **Annual within-day flexibility volumes: wholesale and residual**



What is our role?

The operability needs for within-day flexibility (WDF) will primarily be met in the wholesale market, as participants and consumer respond to price signals. GB market arrangements incentivise supply and demand to self-balance in the wholesale market, encouraging participation of flexible resources. NESO acts as the residual balancer by making close to real-time adjustments, predominantly in the Balancing Mechanism, to maintain system frequency.

To ensure we have the appropriate tools and capabilities to manage residual balancing needs, NESO will continue to monitor energy market changes that may impact WDF needs. This includes assessing the wider energy transition and changes to market arrangements, such as the Review of Electricity Market Arrangement (REMA).

What is our within-day flexibility outlook?

Increasing dependence on variable renewable generation alongside a reduced volume of flexible fossil fuel plant will require additional WDF to effectively balance the system. System advances, such as higher deployment rates of smart domestic assets, the development of Market-wide Half Hourly Settlement (MHHS), and the increasing volume of bi-directional assets, are expected to increase the volume of within-day flexibility available. Demand-side changes, such as electric vehicles and domestic heat pumps (HP), can both increase WDF needs and offer sources of additional WDF.

How does NESO support within-day flexibility?

NESO continues to enable system wide WDF in its role as the residual balancer and through the delivery of programmes such as: Enabling Demand Side Flexibility (EDSF), QWIDFLEXER, CrowdFlex, Demand Flexibility Service and the review of operational metering requirements.

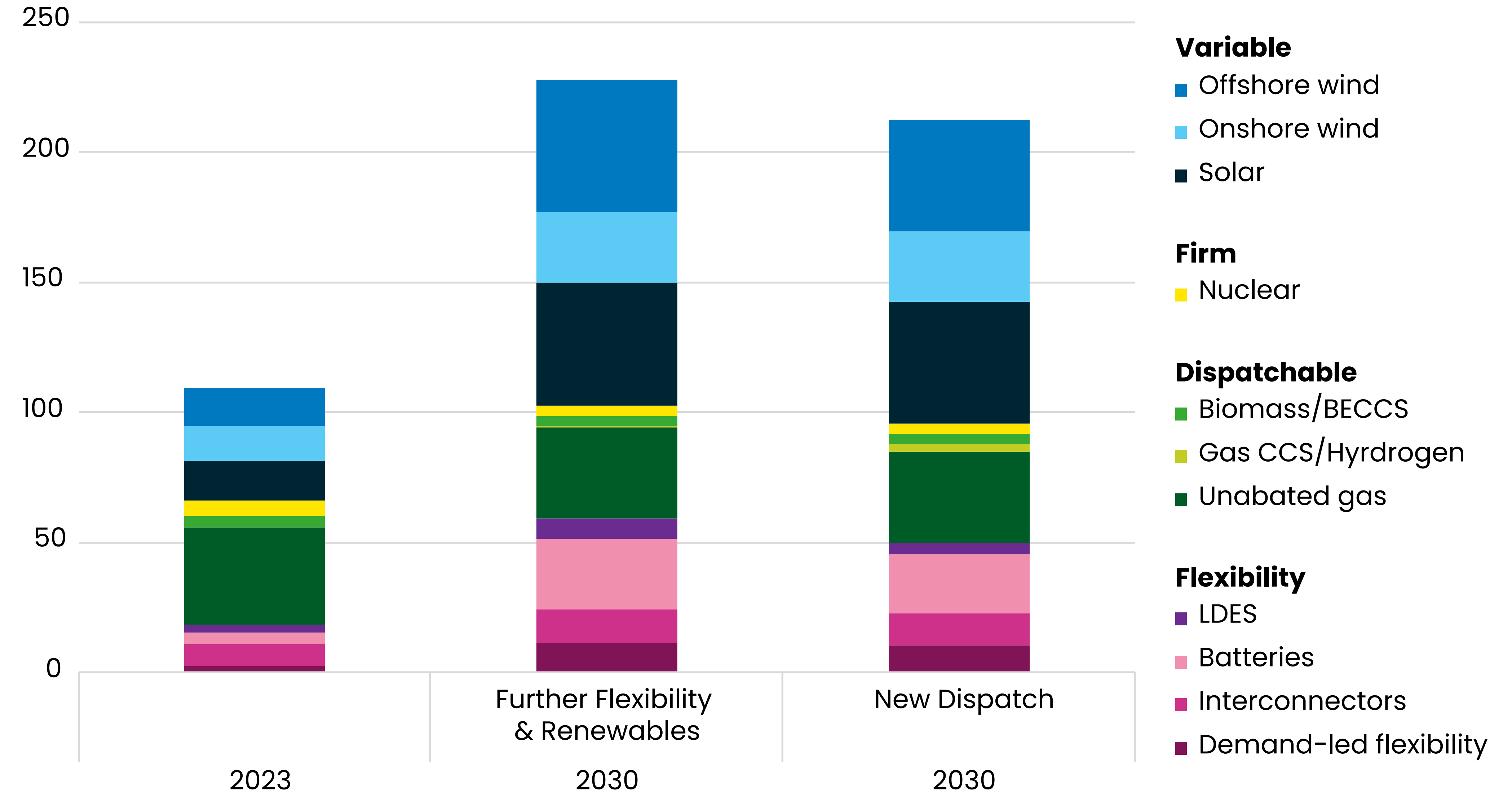
Overview of System Needs

Adequacy

Description

Adequacy measures whether there are sufficient available resources to meet electricity demand throughout the year. Generally, this is when demand is highest in winter periods and when there are unfavourable weather conditions.

Figure 6: **Clean Power 2030 Installed Capacity**



What is our adequacy advice?

We will publish a report in Spring 2025 which looks in depth at security of supply through the 2030's. This builds on our Clean Power 2030 advice to Government and our previous study with Afry from December 2022 which looked at resource adequacy in the 2030's.

What is NESOs role in ensuring sufficient adequacy?

NESO supports DESNZ in meeting its statutory standard of 3 hours of Loss of Load Expectation (LOLE) by setting Capacity Market requirements that adhere to this standard. We inform Government, Ofgem and industry of our latest research which is communicated publicly via several publications including Future Energy Scenarios (FES) and Clean Power 2030. In October 2024 we published advice to Government outlining two main pathways to 2030. These were developed using analysis set out in FES.

How will we continue to provide adequacy advice in the future?

NESO will continue to advise Government, Ofgem and industry through the aforementioned documentation. Looking forward, we will continue to present updated analysis for resource adequacy from the Electricity Market Reform delivery team.

How may adequacy needs change?

Higher volumes of weather dependent renewables will require enhanced modelling capabilities to ensure security of supply risks are adequately captured.

02

Balancing the System

Balancing Mechanism

Introduction

What is the BM and why is it important?

The Balancing Mechanism (BM) is our primary tool to balance supply and ensure system security on GB's transmission network. At gate closure (60 minutes before delivery), Physical Notifications (PNs), which reflect the expected level of generation or consumption, become final. The BM is where NESO 'takes over' from the wholesale market to refine the energy balance over the 90-minute balancing window, while accounting for system constraints, such as stability, voltage management and thermal constraints.

BM participants must submit prices and volumes to the BM which represent their willingness to pay or be paid to adjust their self-dispatched positions; this takes the form of "Bids" (to reduce generation or increase demand) and "Offers" (to increase generation or reduce demand). Broadly, the Bids and Offers accepted for energy balancing actions feed back into the wholesale market as the System Imbalance Price, which fulfils a key function of the BM. Exposure to the System Imbalance Price incentivises wholesale market actors to balance the system on a national basis. The underlying principle is that NESO is a 'residual balancer', however, the increasing volume of system actions being observed is in contrast to the intended purpose of the BM.

What are the services procured in the BM?

BM actions are categorised either as 'energy' tagged or 'system' tagged. However, there is not perfect separation between these categories, as some actions can resolve multiple system needs or can be a consequence of previous actions.

Energy – Actions taken to resolve the overall energy imbalance after system actions have been taken. This includes the provision of services for frequency response and reserve.

System – Actions taken for system management reasons, such as thermal constraints, network stability, or voltage. These actions are removed from the System Imbalance Price calculations.

When issuing redispatch instructions in the BM, we are required to minimise total system cost, which means the immediate lowest priced action in £/MWh may not always be the most economic choice, as we are optimising across multiple potential services a unit may be able to provide (energy, frequency response, reserve, and management of system constraints).

Summary

How is the landscape changing?

The electricity system continues to decarbonise at pace, with several new records broken in 2024. We recorded the highest yearly zero carbon generation at 51%, a minimum carbon intensity record of 19 g CO_2/kWh on 15 April, and a maximum wind record of 22,523 MW on 18 December. In addition, on 30 September Ratcliffe Power Station came off the system for the final time to mark the end of 142 years of coal power generation in GB.

However, the GB electricity market was designed around a system consisting mostly of large, dispatchable generators, limited asynchronous generation, and broadly inelastic demand. The intended role of NESO was of a 'residual balancer'. Since then, the penetration of renewable generation onto the grid, greater interconnection with European markets, and deployment of flexible, embedded technologies has changed the way we operate the system.

How have costs and volumes evolved in the last year?

The total volume of Bids and Offers taken in the BM increased by 23%, compared to 2023. As a proportion of national demand, balancing actions increased to 14% in 2024, from 11% in 2023. System actions are driving this trend, as the proportion of system actions in the BM increased from 44% to 56%, mostly driven by thermal constraints. The total cost of BM actions stayed approximately the same at £1.9 bn, where the decline in the volume (and therefore cost) of energy actions offset the increase in system actions costs. We expect thermal constraints to be the major driver of future balancing costs.

What is driving the need for reform?

The role of the BM is being stretched so that, at times, it resembles a central dispatch market but without the appropriate tools or framework. As such, the BM as intended is no longer operating in the context it was designed for. Many incremental changes have been made to the market design to adapt to changing conditions; however, there is a case for further reform to the current arrangements.

The Scheduling and Dispatch 'Case for Change', published last year, established a better understanding of the operational challenges and identified three key limitations with the status quo that any future design must address, and has provided a framework to how the market reforms in this chapter are considered.

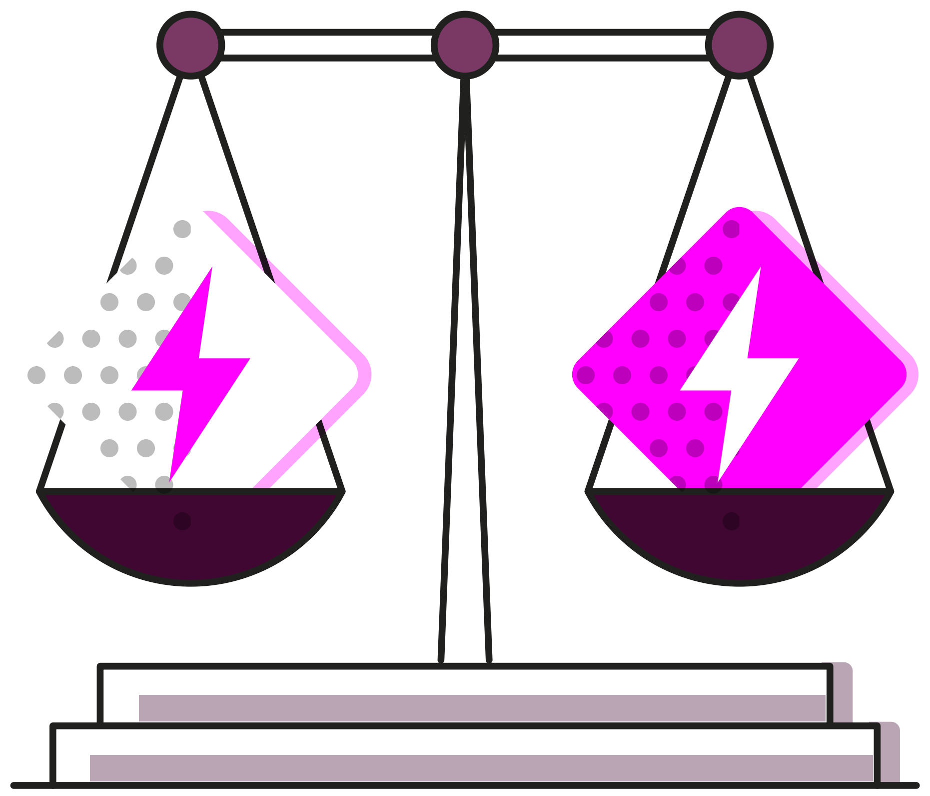
Incentives: The energy markets do not provide scheduling incentives in line with system needs and operational requirements

Visibility and access: Incomplete NESO visibility of market outcomes and limited access to some resources impacts coherence between wholesale market and balancing

Intertemporal issues: The current dispatch mechanism does not facilitate effective optimisation of costs and unit constraints over time

How are we implementing market reform?

In the short-term, we are continuing to develop our ancillary service markets to meet new system needs most efficiently, and are working with industry to address the challenges around how energy-limited assets are dispatched in the BM. We are considering improvements to our reserve and response procurement and will continue to explore new constraint management solutions through the Constraints Collaboration Project (CCP). Moreover, our balancing capabilities are being improved to manage an increased number of market participants and maximise the use of small, flexible technologies.



Volumes

Total Bids and Offers

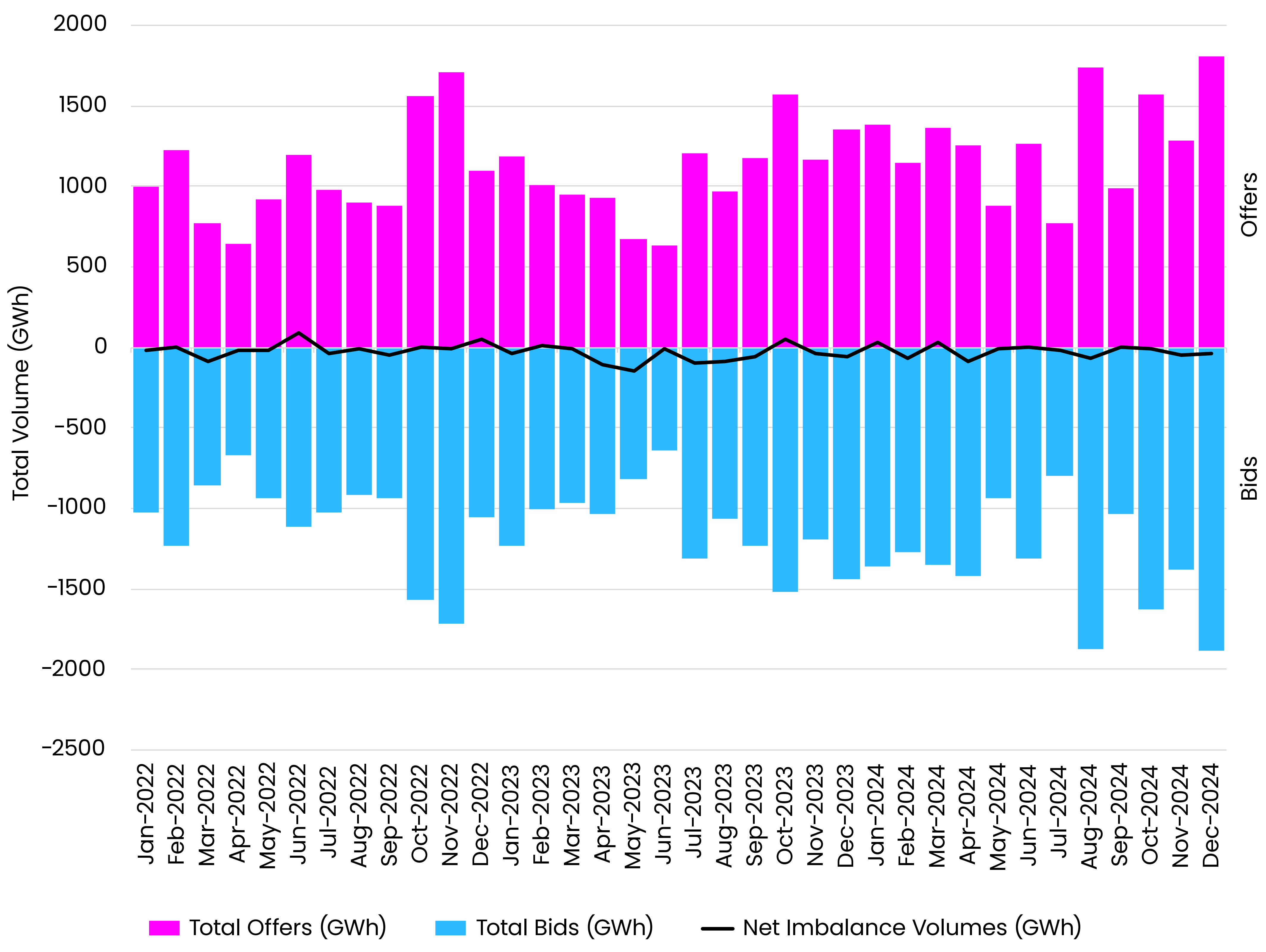
NESO takes Bids and Offers through the BM to balance supply and demand and secure the system. Balancing actions are driven by factors including changes in weather forecasts or system conditions (e.g. higher demand outturn), market participants not delivering according to their contracted position, unexpected outages or plant trips, or rebalancing actions as a result of prior system actions. The Net Imbalance Volume (NIV) is the net of all energy and system balancing actions for a given settlement period and shows whether the system was long (oversupplied) or short (undersupplied).

The total volume of Bids and Offers to balance supply and demand has increased by 23% to approximately 32 TWh, up from 26 TWh in 2023. In other words, our redispatch actions as a proportion of national demand equated to 14% in 2024, an increase from 11% in 2023.

December was the month with the highest observed volumes of Bids and Offers, at 3.6 TWh. This was the windiest month of the year, setting a new wind power record, with wind accounting for 41% of the generation mix. Conversely, July was the month with the lowest observed balancing volumes, at 1.5 TWh, corresponding with low wind generation.

As shown in BM Figure 1, the overall market length for 2024 was predominantly long, as the NIV was negative in 10 out of 12 months. The system was on average long (on a monthly level) by -26 GWh, compared to -50 GWh in 2023 and -8 GWh in 2022.

BM Figure 1: Total Bids and Offers instructed Jan 2022 - Dec 2024



Volumes

System and energy balancing volumes

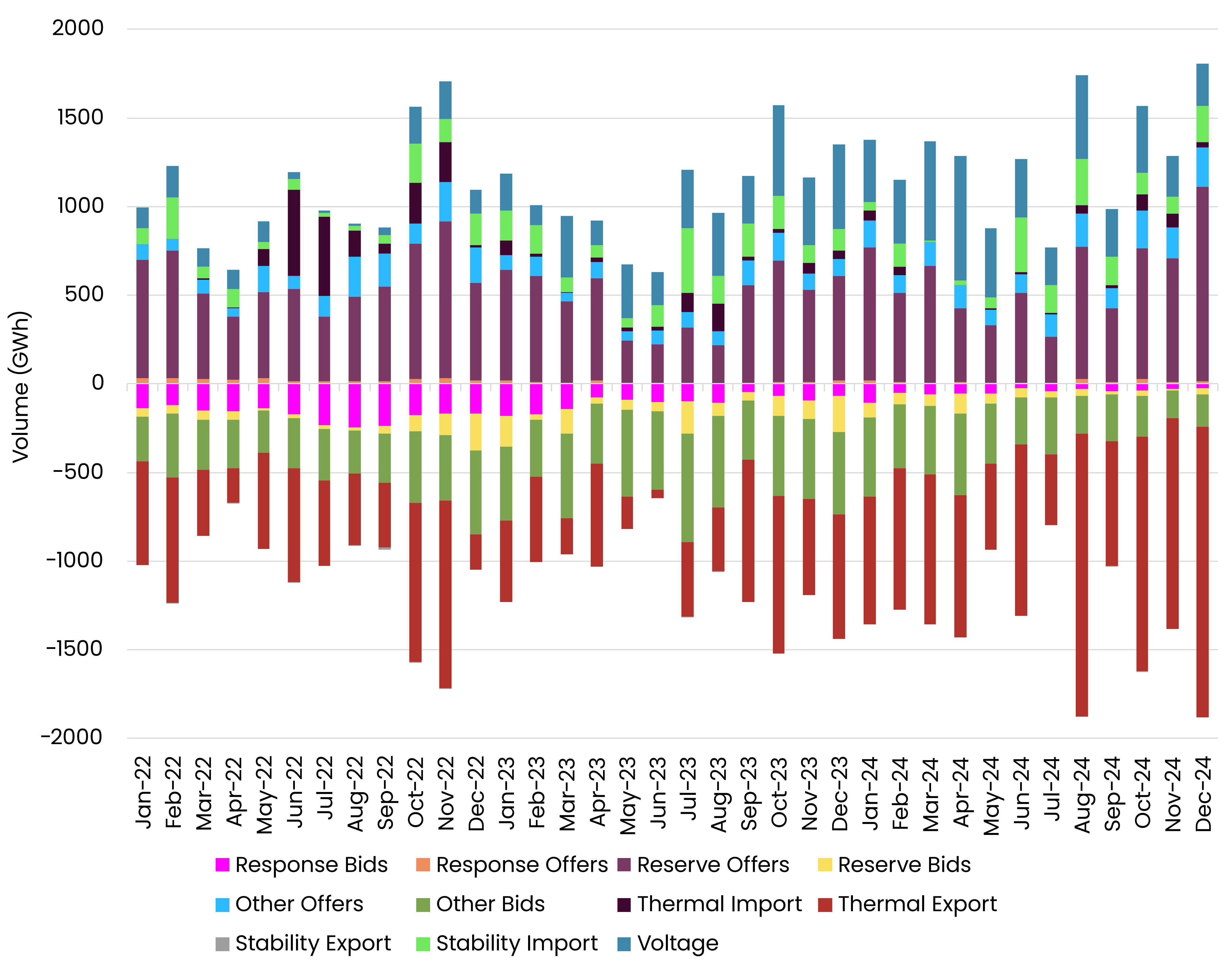
The volume of system-tagged BM actions increased by 6 TWh, from 12 TWh to 18 TWh, an increase of 50% which reflects a continued trend towards greater intervention by NESO to resolve system issues. Overall, the proportion of system actions in the BM increased to 56%, compared to 44% in 2023.

Actions to resolve thermal (predominantly export) constraints increased the sharpest in 2024, rising by 89% compared to 2023, to 12 TWh. This was due to a combination of high wind outturn and outages on the network in Scotland. These outages are to facilitate network reinforcement which will increase the available transfer capacity and in turn, should reduce constraint volumes. Thermal constraints accounted for 66% of system actions in 2023, an increase from 50% in 2023.

Meanwhile, voltage management actions increased by 24% to 4 TWh, whereas stability actions decreased by 11% to 1.5 TWh.

Energy-tagged actions declined by 7%, from 15 TWh in 2023 to 14 TWh in 2024. The volume of response procured through the BM continued to decline, with a 50% reduction from 1.4 TWh to 0.7 TWh. Similarly, reserve procurement declined by 47%, from 3.2 TWh to 1.7 TWh. Conversely, 'Other' (which includes constraint margin and other minor components) increased from 10 TWh to 11 TWh.

BM Figure 2: System and energy balancing volumes Jan 2022 - Dec 2024



Volumes

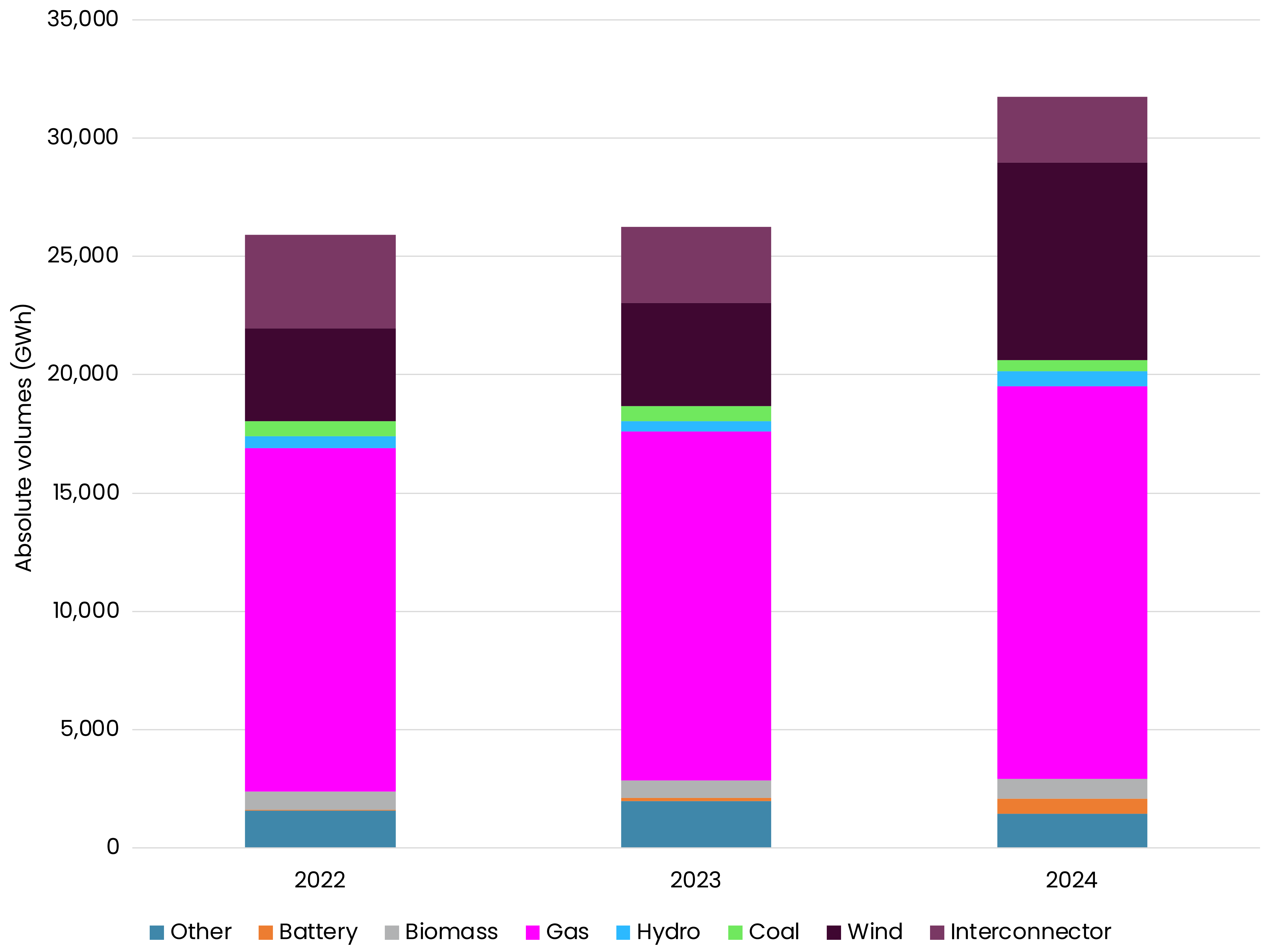
By technology

In 2024, gas plants made up the largest share of the volume of BM actions at 53%; however, this has declined by 5% since 2023. These actions are predominantly 'offers' (to increase generation).

Wind units accounted for 25% of the volume of BM actions in 2024, an increase of 10%. Contrary to gas plants, these actions are mostly bids (to decrease generation) to resolve thermal constraints.

The launch of the Open Balancing Platform (OBP) has supported a large increase to battery utilisation, with instructions to batteries increasing 4-fold from 810 MWh daily average volume in 2023 to 3,434 MWh daily average volume in 2024. Since the launch of OBP Release 1 in 2023, there has been a 324% increase in battery dispatch volume and an 60% increase in small BMU dispatch volume.

BM Figure 3: Absolute balancing volumes by fuel type



Costs

Total balancing costs

Total cost of actions in the Balancing Mechanism (BM) and via trades totalled £1.9 bn in 2024, in line with 2023 despite the increase in volume of actions taken in 2024. System tagged actions accounted for 89% of costs (£1.7 bn), compared to 68% (£1.3 bn) in 2023, driven by thermal constraints. Energy tagged actions, meanwhile, declined to £199 m from £593 m (66% decrease). The cost of procuring frequency response through the BM decreased by 27% from £22 m to £16 m, corresponding to the decline in volume procured of 50%, which reflects the continued procurement of response services from dynamic products outside the BM.

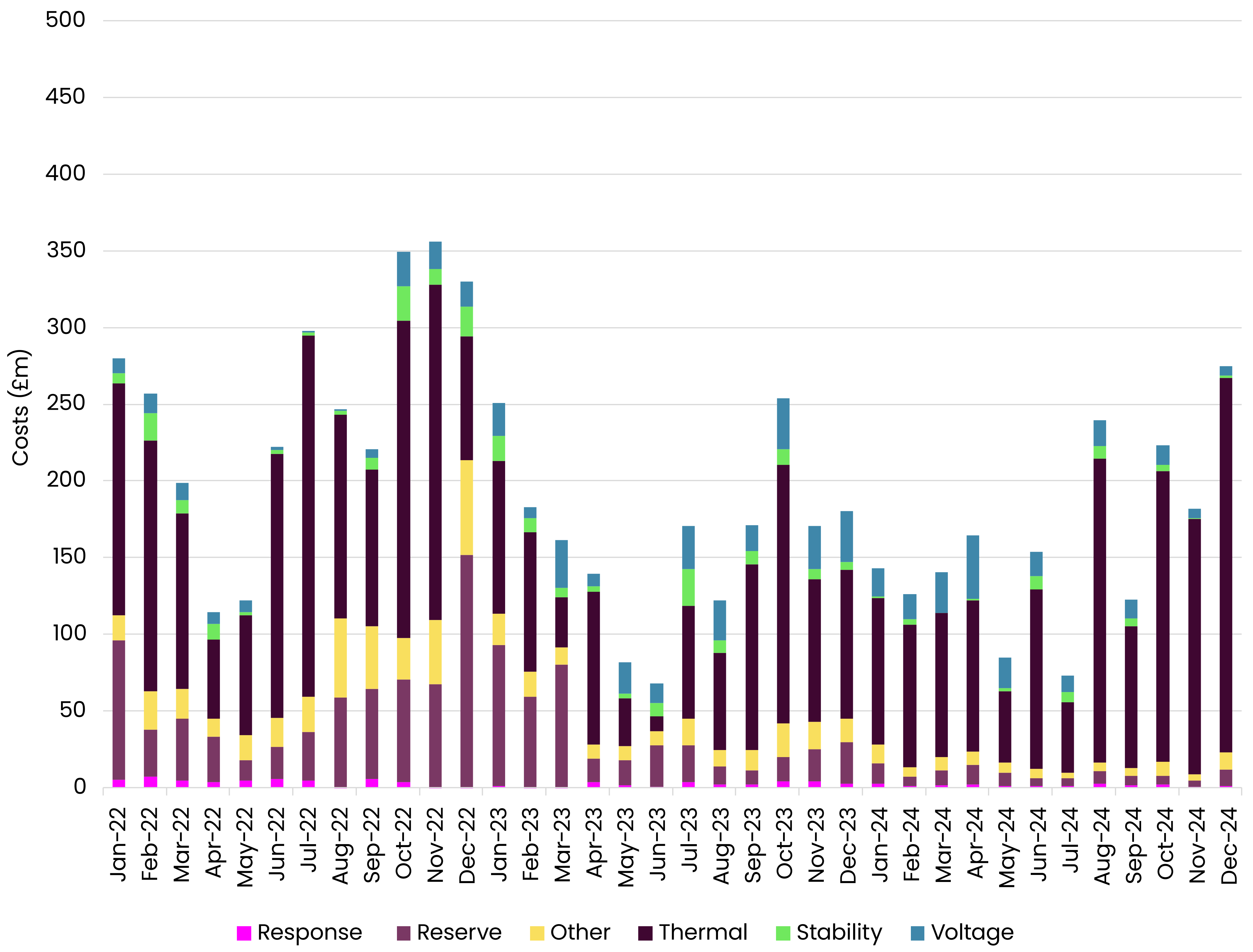
System actions

The biggest driver of system costs continues to be thermal constraints, the cost of these actions totalled £1.5 bn in 2024, from £980 m the previous year – an increase of around 51%, compared to an 89% increase in the volume of actions. Thermal costs made up the greatest proportion of system actions costs (88%), with the majority of this being the cost of turning on additional units to replace curtailed energy. Meanwhile, costs for system inertia requirements declined by 60% from £110 m to £43 m, and voltage management costs declined by 23%, from £265 m to £203 m. This cost reduction is in part due to the availability and effectiveness of stability and voltage pathfinder assets which also offset the need for further intervention via the BM.

Monthly trends

December observed the highest balancing costs at £274 m, corresponding with the month with the greatest volume of actions (and highest wind generation). Notably, thermal constraints made up the greatest proportion of costs in every single month.
The month with the lowest spend was July, where £73 m was spent on balancing actions.

BM Figure 4: System and energy balancing costs Jan 2022 - Dec 2024



This reflects the cost of actions taken in the BM and via trades, and excludes costs associated with ancillary services procurement (e.g., non-BM and availability fees.)

Market Reforms – Ongoing in the short-term

We have categorised market reforms using the framework developed in the NESO Scheduling and Dispatch Case for Change in the Review of Electricity Market Arrangements (REMA). We consider short-term reforms as those which we have high confidence in being delivered and could be implemented within the next two years. Beyond this, a range of further reforms have been identified which have a lower certainty of being delivered but could be implemented ahead of enduring market arrangements under consideration as part of REMA. We are also undertaking non-market reforms to try and make scheduling and dispatch arrangements more efficient.

Incentives

Visibility and access

Intertemporal issues

Reserve reform

In 2024, we launched Balancing Reserve and Quick Reserve services. Balancing Reserve was launched to provide a price signal at day-ahead and secure volume ahead of the real-time procurement of operating reserve through the BM. Quick Reserve was introduced to replace Fast Reserve as our fast-acting reserve service. In 2025, we plan to launch Slow Reserve, which will replace Short Term Operating Reserve (STOR), the service to secure the largest loss on the system. Further reforms to Balancing Reserve and Quick Reserve are also planned. See Reserve chapter for further details.

New 'system' ancillary services

We are developing explicit markets for system services, such as voltage and stability, to reduce the volume of system actions in the BM and meet our requirements at a lower cost. See chapters on Stability and Voltage for more information.

Market Reforms – Ongoing in the short-term

We have categorised market reforms using the framework developed in the NESO Scheduling and Dispatch Case for Change in the Review of Electricity Market Arrangements (REMA). We consider short-term reforms as those which we have high confidence in being delivered and could be implemented within the next two years. Beyond this, a range of further reforms have been identified which have a lower certainty of being delivered but could be implemented ahead of enduring market arrangements under consideration as part of REMA. We are also undertaking non-market reforms to try and make scheduling and dispatch arrangements more efficient.

Incentives

Visibility and access

Intertemporal issues

GC0166 code modification

The introduction of new parameters for energy-limited, bidirectional assets aims to address the challenges around how they are scheduled and dispatched in the BM. At the time of writing, the modification was at the workgroup consultation stage, with the workgroup report expected in April 2025.

GC0117 code modification

The proposal aims to improve transparency and consistency of access arrangements across GB by harmonising and lowering the mandatory MW threshold for new BMUs. Over time, this will increase the amount of BM participants submitting PNs and which are directly instructible by NESO. The final modification report was published in May last year and we are currently awaiting a decision by Ofgem.

300 MW operational metering trials

In 2024, NESO agreed to allow up to 300 MW small, aggregated asset (SAA) BMUs to join the BM under the relaxed operational metering trial, whilst an independent review of operational metering standards took place. There are currently three SAA BMUs registered, with a total deliverable capacity of 13 MW, and several other SAA BMUs are expected to be registered by early spring 2025. The main ongoing barriers to more providers joining this initiative are reaching 1 MW deliverable capacity in a Grid Supply Point (GSP) group and meeting BM settlement requirements.

Final Physical Notification (FPN) accuracy

We published a guidance note to provide BMUs and other market participants with a clear understanding of how we monitor 'Good Industry Practice' on FPN accuracy in accordance with the Grid Code BC 1.4.2(a). The purpose was to ensure transparency and provide guidance on how we interpret these requirements. Since then, we have consulted with the market to understand if it would be beneficial to clarify our views on good industry practice in relation to the preparation of PNs within the FPN guidance note.

Market Reforms – Ongoing in the short-term

We have categorised market reforms using the framework developed in the NESO Scheduling and Dispatch Case for Change in the Review of Electricity Market Arrangements (REMA). We consider short-term reforms as those which we have high confidence in being delivered and could be implemented within the next two years. Beyond this, a range of further reforms have been identified which have a lower certainty of being delivered but could be implemented ahead of enduring market arrangements under consideration as part of REMA. We are also undertaking non-market reforms to try and make scheduling and dispatch arrangements more efficient.

Incentives

Visibility and access

Intertemporal issues

Short-term reforms to address intertemporal issues under a self-dispatch market are very limited; however, we do expect the above reforms to have some consequential benefits. For example, the introduction of Balancing Reserve should reduce the need for pro-active scheduling actions in the BM. Additionally, GC0166 could facilitate more effective optimisation of energy-limited assets.

Market Reforms – Planned or in development up to 2030

We have categorised market reforms using the framework developed in the NESO Scheduling and Dispatch Case for Change in the Review of Electricity Market Arrangements (REMA). We consider short-term reforms as those which we have high confidence in being delivered and could be implemented within the next two years. Beyond this, a range of further reforms have been identified which have a lower certainty of being delivered but could be implemented ahead of enduring market arrangements under consideration as part of REMA. We are also undertaking non-market reforms to try and make scheduling and dispatch arrangements more efficient.

Incentives

Visibility and access

Intertemporal issues

Closer to real-time reserve and response procurement

By procuring our reserve and response needs closer to real-time (e.g. intraday), we can have greater certainty over market and system conditions, and therefore what our procurement needs are. In turn, this should minimise the under or over procurement of reserve and response and reduce costs to consumers. This reform is currently being explored.

Locational procurement of reserve and response

The locational procurement of reserve and response can mitigate instances whereby procured capacity is "sterilised" behind a constraint, which then needs to be replaced outside the constraint boundary through the BM at a cost. The effectiveness of this reform depends on accurately forecasting when constraints will be active. In January 2025, we set out our initial thinking on this reform and requested feedback from industry. Find out more here.

New constraint management solutions (incl. AS for constraints)

Last year, we launched the Constraints Collaboration Project (CCP). The project focuses on a collaborative approach between NESO and industry to seek solutions to thermal constraints that can be deployed efficiently, both economically and technically, ahead of network reinforcement and fundamental market reform. Find out more in the Thermal chapter.

Balancing and Settlement Code (BSC) modification P462

The proposal aims to remove subsidy distortions from bids in the BM when curtailing CfD (Contracts for Difference) / ROC (Renewables Obligation Certificate). Currently, subsidised assets factor lost subsidy costs into their BM bid prices, which drives non-subsidised assets to adjust their bid prices accordingly and increases costs to consumers. The proposal would pay the lost subsidy explicitly outside of the BM to remove it from the bid price. At the time of writing, the BSC modification was being assessed by the workgroup and is not planned for consultation until the end of this year.

Market Reforms – Planned or in development up to 2030

We have categorised market reforms using the framework developed in the NESO Scheduling and Dispatch Case for Change in the Review of Electricity Market Arrangements (REMA). We consider short-term reforms as those which we have high confidence in being delivered and could be implemented within the next two years. Beyond this, a range of further reforms have been identified which have a lower certainty of being delivered but could be implemented ahead of enduring market arrangements under consideration as part of REMA. We are also undertaking non-market reforms to try and make scheduling and dispatch arrangements more efficient.

Incentives

Visibility and access

Intertemporal issues

Portfolio ramp limits for Balance Responsible Party (BRP)

Following on from the GC0154 modification, and due to current and expected future operational challenges, we have taken a holistic look at current ramping arrangements, and the development and rollout of both current and future technologies. We believe that reform of current ramping arrangements is needed, to address operational issues. Our approach to mitigating these issues will be developed over the coming months.

Market Reforms – Planned or in development up to 2030

We have categorised market reforms using the framework developed in the NESO Scheduling and Dispatch Case for Change in the Review of Electricity Market Arrangements (REMA). We consider short-term reforms as those which we have high confidence in being delivered and could be implemented within the next two years. Beyond this, a range of further reforms have been identified which have a lower certainty of being delivered but could be implemented ahead of enduring market arrangements under consideration as part of REMA. We are also undertaking non-market reforms to try and make scheduling and dispatch arrangements more efficient.

Incentives

Visibility and access

Intertemporal issues

As stated, options to address intertemporal issues under self-dispatch are very limited. However, as part of our REMA scheduling and dispatch work, we have identified reforms which aim to increase transparency through increasing the information available to the market and NESO. These reforms are not significant enough to reach the threshold for decision-making as part of REMA and therefore should be considered as part of our usual activities. To find out more, please refer to REMA scheduling and dispatch options.

Market Reforms – Non-market reforms

We have categorised market reforms using the framework developed in the NESO Scheduling and Dispatch Case for Change in the Review of Electricity Market Arrangements (REMA). We consider short-term reforms as those which we have high confidence in being delivered and could be implemented within the next two years. Beyond this, a range of further reforms have been identified which have a lower certainty of being delivered but could be implemented ahead of enduring market arrangements under consideration as part of REMA. We are also undertaking non-market reforms to try and make scheduling and dispatch arrangements more efficient.

Balancing Programme

The Balancing Programme is leading work to develop and enhance NESO's balancing capabilities to ensure it can meet changing system and market conditions, such as managing an increasing number of market participants and maximising the use of flexible technologies, whilst optimising balancing costs.

In last year's Markets Roadmap, we highlighted the first major step in enhancing our balancing capabilities through the launch of the OBP Release 1. This launch included the bulk dispatch functionality to issue multiple instructions simultaneously to batteries and small BMUs based on a least cost solution. Release 1 was also the foundation for all future OBP system developments. Other key changes and deliverables in 2024 include the introduction of Fast Dispatch, the 30-minute rule for storage assets, and enabling functionality for market services, e.g., Balancing Reserve, BM Quick Reserve. In the latter part of 2024, we also delivered the Dispatch Efficiency Monitor.

30-minute rule	In March 2024, we transitioned to the 30-minute rule (which replaced the 15-minute rule) to enable batteries to be dispatched for longer. This relies on the submission of Maximum Export Limit (MEL) data about a unit's state of charge for the next 30 minutes; this is an interim solution which will be replaced by new storage parameters as part of GC0166.
Fast dispatch	In April 2024, the Fast Dispatch functionality went live in the battery zone to provide the Control Room with the capability to dispatch assets quicker i.e., <10seconds in response to frequency deviations.
Dispatch efficiency monitor	The monitor helps us to measure the efficiency of our dispatch decisions in near real-time and can be used highlight areas to improve and optimise economic dispatch.

Future OBP releases are planned throughout BP3 including optimisation within a constraint, management of all assets, both BM and non-BM via OBP, and enablement of new reserve products. For more information on the Balancing Programme and to sign up to receive the latest updates, click here.

Within-day Flexibility

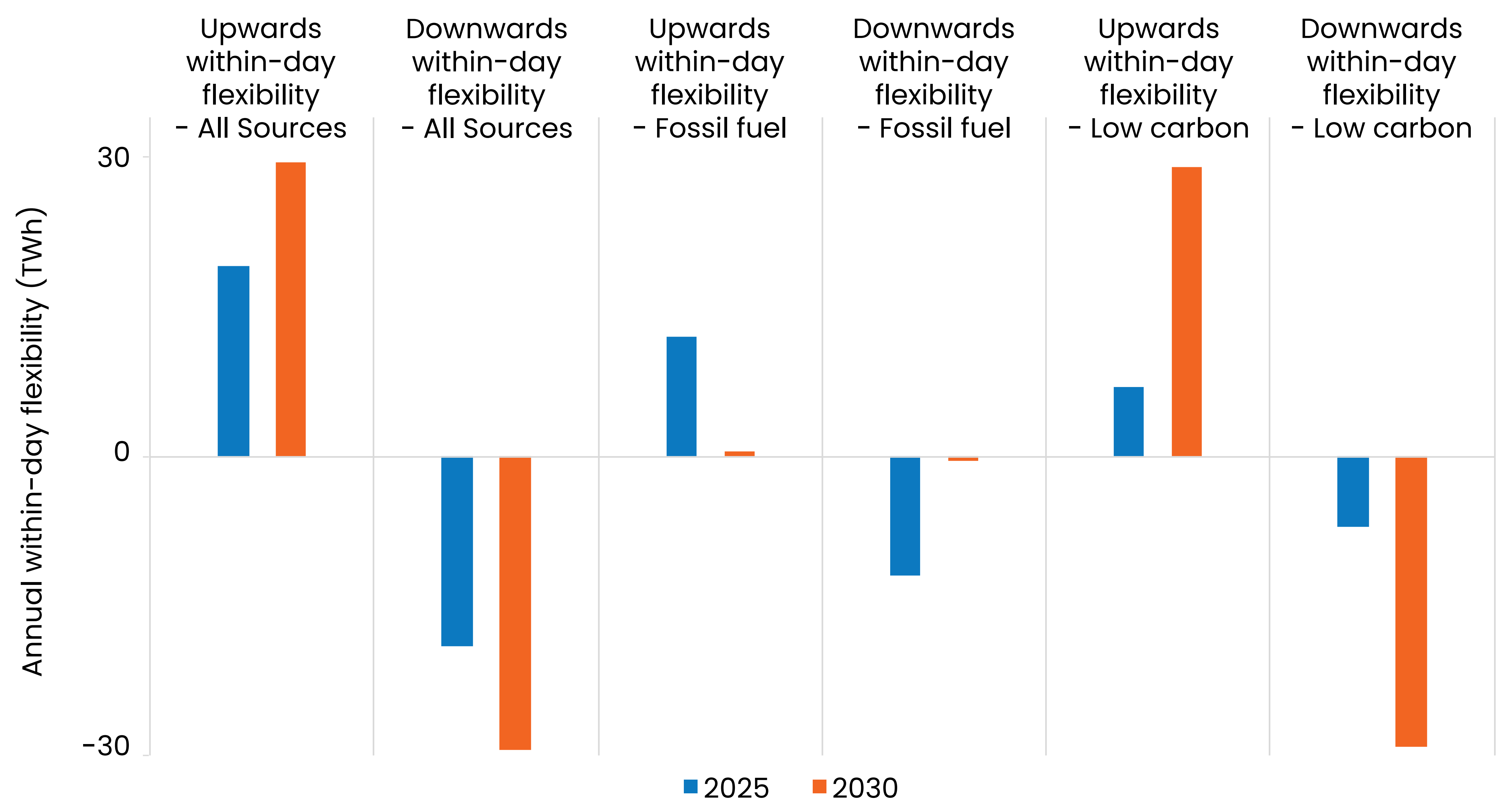
Introduction

What is within-day flexibility and why is it important?

Within-day flexibility refers to the ability to adjust electricity generation or consumption to meet fluctuation in supply and demand over the course of a day. As we continue to decarbonise, we will see increasing numbers of variable, weather-dependent generation on the network and a decrease in the volume of dispatchable conventional assets. At the same time, decarbonisation of heating, transport and wider society through electrification is increasing the volumes of demand that can be flexible.

Within-day flexibility is used to match demand and generation across daily peaks and troughs, usually lasting for a couple of hours. A deficit in renewable generation would be resolved through "upward-flexibility", either increasing the amount of energy available to the network or decreasing energy demand, and vice-versa for downward flexibility. Locational flexibility may be needed to shift energy within a day for managing constraints on the transmission and distribution network.

WDF Figure 1: **Annual within-day flexibility volumes: wholesale and residual**



How is within-day flexibility delivered now?

To date, most within-day flexibility needs have been met by dispatchable generation like gas-fired plants, storage and interconnectors. As we move towards a clean power electricity system and the availability of fossil fuelled flexibility declines, flexibility has a critical role ensuring our energy supply needs can be securely met at the most efficient cost.

Price signals sent via the wholesale market (and products offered by retail suppliers) are intended to incentivise flexible assets to increase or decrease output to balance supply and demand. NESO, as the residual balancer, can then take any residual balancing actions through the Balancing Mechanism (BM) or use the Demand Flexibility Service and/or trades as margin tools.

BM	As the residual balancer, we take actions in the Balancing Mechanism to manage supply and demand imbalances in the real-time. The BM is our primary route to accessing flexibility across all technologies.
DFS	The demand flexibility service (DFS) launched in winter 2022 as an emergency tool to enable new demand side flexibility to help us manage peak electricity demand. In 2024, DFS transitioned from an enhanced action to an in-merit margin service. It helps us manage the system security in the most economical way as well as ensuring a route to market for assets which are not currently able to participate in our balancing services markets.
Trading	We can buy or sell electricity in advance of the BM where we foresee an opportunity to alleviate margin or system issues in a more cost efficient way. This is typically done as part of the Grid Trade Master Agreement (GTMA). Trading with interconnectors to alter flows in and out of GB is the most prominent example of these trades to provide within-day flexibility.

Where will we get it from in future?

It is envisaged that demand-side solutions will increasingly be employed for within-day flexibility, alongside other sources of generation and storage. Zero-carbon within-day flexibility will include both generation and demand to resolve both deficits and surpluses in generation. From an energy balancing perspective, our current analysis is showing that total annual within-day flexibility volumes will grow from 39 TWh today to approximately 58 TWh by 2030. We anticipate up to 27 GW of additional energy storage capacity by 2030, becoming the largest source of zero-carbon within-day flexibility. Besides storage, electric vehicle (EV) smart charging, vehicle-to-grid technologies, smart appliances, and smart heating will be important source of within-day flexibility as well. Importantly, the reformed wholesale and retail market will be fundamental to enabling within-day flexibility, enabling various technologies to participate in markets and respond to market signals, ensuring that supply and demand are balanced effectively.

Spotlight: enabling demand-side and distributed flexibility

There is a lot of focus on enabling flexibility in light of new Government targets for Clean Power by 2030 and the significant benefits which can be realised in terms of security of supply and lower whole system costs. This section spotlights some of the work which is happening in the demand-side and distributed flexibility space specifically.

Enable Demand Side Flexibility in NESO Market Report

We have published the Enabling Demand Side Flexibility in NESO markets report to address the urgent need for mobilising demand side flexibility in our markets. This report clarifies our vision, target outcomes and strategic outcomes. It also explores the no regret market reform actions which can be taken in the medium term to sharpen the explicit market signals for demand side flexibility and remove barriers. It will form one part of an overarching programme wider collaborative work which will be needed to scale up all types of low carbon flexibility to meet clean power by 2030. We are committed to ensure this work evolves in line with the changing landscape such as Clean Power 2030, Review of Electricity Market Arrangements, Market Facilitator and MHHS implementation.

Route to Market Review

The "Enabling Demand Side Flexibility in NESO Markets" report outlines that identifying and removing barriers is a strategic priority for NESO. Our Clean Power 2030 advice to Government highlighted that we need to ensure that demand side flexibility is enabled to participate in markets where it can meet system operability needs. This review aims to identify and prioritise barriers, set out our approach to removing them and timeframes for doing so. A key indicator for success will be seeing a material increase in volume of demand side flexibility participating in our services. We have concluded the stage one and two of this review, the outputs can be found on our website.

300 MW Small Aggregated Asset Balancing Mechanism (BM) trial

As part of our ongoing commitment to remove barriers to participation for distributed flexibility, DNV are conducting an independent review on NESO's behalf to understand and quantify the impacts of changing operational metering requirements to something more relaxed and achievable for small-scale aggregated assets. In parallel with this review, we are also running the 300 MW Operational Metering derogation which allows providers to enter the BM with <1 MW assets with relaxed operational metering requirements. So far, we have two providers with live BMUs utilising the relaxed requirements with a total flexible volume of around 13 MW that has been instructed by control room over 550 times. More info can also be found on our Power Responsive webpage.

CrowdFlex

CrowdFlex is a NESO led innovation project investigating the potential of domestic flexibility as a reliable grid management resource. The project is in its Beta phase and has successfully completed its first large-scale domestic flexibility trials, with project partners OVO and Ohme EV's customers being incentivised to use their electricity flexibly through turn-up and turn-down events or 'smart charging' assets like EVs. These trials are also testing how different recruitment messages affect participation and are gathering data to build models of domestic flexibility. Consumer surveys have been conducted with 3,600 participants and have started to reveal some interesting insights. Further trials are underway. The annual progress report has been published, detailing how CrowdFlex is playing a pivotal role in establishing domestic flexibility as a reliable resource for grid balancing and operations.

Introduction to DFS as an in-merit tool

The Demand Flexibility Service (DFS) has undergone several key changes in 2024 to enhance its flexibility, transparency, and efficiency. Most notably, it has transitioned from an enhanced security of supply action to a merit-based margin tool continuing to offer a route to market for flexibility which is unable to access our core markets. The service is procured within-day and competes against alternative actions to ensure that we have enough margin available. DFS can also now be stacked with the Capacity Market (CM) and DNO flexibility services, allowing participants access to multiple revenue streams. Further service improvements have also been made in terms of sub-meter participation and performance incentives.

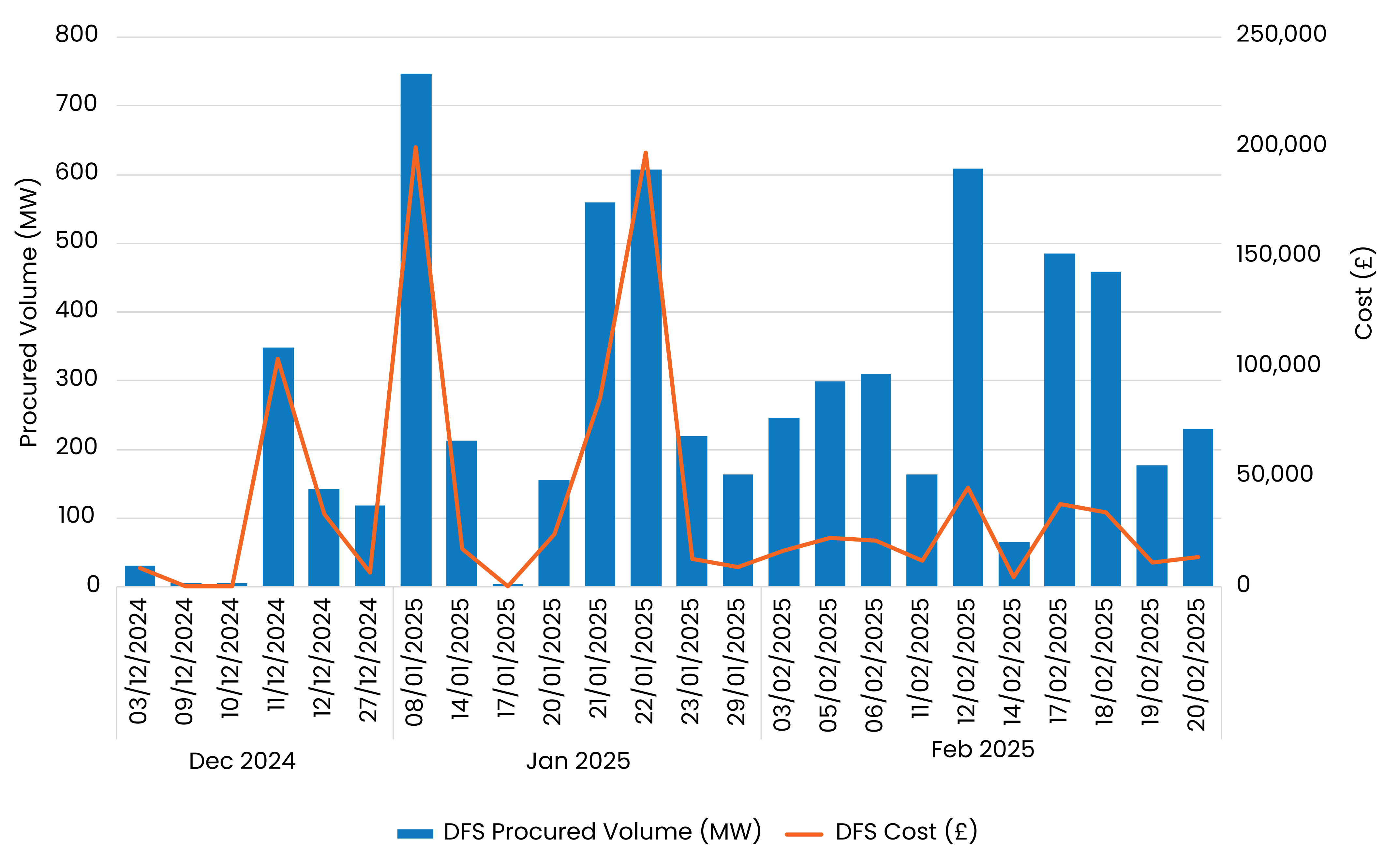
DFS events in 2024

At the time of writing, there have been over 40 Service Requirements published with 28 resulting in accepted volume since it's approved changes from Ofgem in November 2024. In February 2024, we published a webinar recording sharing how DFS has been operating since its approved changes. During this webinar we flagged some key statistics such as £400,000 forecasted savings against alternative actions so far, 1.73 m MPANs registered and accepted prices ranging from £59-£1,290/MWh.

Future potential for DFS

As shared at our latest webinar, NESO has committed to reviewing how and what evolving the DFS to provide a bi-directional aspect supporting negative margin alongside the existing service which procures positive margin. The DFS will be shaped by broader workstreams such as locational procurement and the Constraints Collaboration Project to progress any additional suitable developments.

WDF Figure 2: Demand Flexibility Service events - Winter 2024/25



Key enablers for flexibility

Support Market-wide Half Hourly Settlement (MHHS)

MHHS aims to settle electricity usage in half-hour intervals, enabling more accurate settlement and billing, better demand forecasting and the encourage the development of innovative products like Time-of-Use tariffs. It is vital to unlock the full potential of demand side flexibility. Timely delivery of MHHS in the retail market has been identified as one of the key actions in the Clean Power 2030 Action Plan. We are actively involved in implementing and governing MHHS through modifications to existing codes.

Route to Market Review Stage 3 Report

We are progressing to Stage 3 of our Route to Market Review. We aim to conclude this review by initiating our proposed iterative barrier removal process and publishing a stage 3 report. This will lay out our approach to tackling barriers and process for doing so. This will include a further breakdown of each of the activities being undertaken to remove the prioritised barriers, an update on where each of the barriers sits in our barrier removal process, and how we will engage and collaborate with stakeholders regularly as part of this iterative process. We expect to publish stage 3 of this review in April 2025.

Low Carbon Flexibility Roadmap and Market Facilitator Delivery Plan

We are collaborating with DESNZ and Ofgem to develop the joint Low Carbon Flexibility Roadmap, set for publication later this year. This roadmap will consolidate existing and new actions to enhance both short- and long-duration flexibility, supporting the transition towards clean power by 2030 and net zero by 2050. It will outline specific measures to drive the deployment of low-carbon flexible technologies and establish a framework for planning and tracking the implementation of these key measures.

Our vision for enabling the seamless movement between markets and removing barriers within NESO markets aligns with the Market Facilitator's intention to grow and develop local flexibility markets which are accessible, transparent and coordinated. We are working closely with Elexon, Ofgem and the industry to design the Market Facilitator role, ensuring clear definitions of the roles and responsibilities for all parties. Additionally, we are committed to supporting Elexon in creating the two-year delivery plan to align all Distribution Network Operator (DNO) and NESO flexibility market arrangements, ensuring the Market Facilitator is well positioned for long-term success.

Response

Introduction

What is response?

Frequency response services react in real-time to automatically balance supply and demand and maintain frequency on the grid. Contracted assets achieve this through continuous measurement of system frequency, when frequency deviates away from 50 Hz, units will change their generation or demand to help restore frequency to 50 Hz. Our Dynamic Moderation (DM) and Dynamic Regulation (DR) services are pre-fault and our Static Firm Frequency Response (SFFR) and Dynamic Containment (DC) services are categorised as post-fault. SFFR helps to restore the frequency to 49.8 Hz following a fault. Dynamic Containment also meets this requirement but additionally arrests the initial drop in frequency due to its faster reaction time. Mandatory Frequency Response (MFR) was designed to operate in pre-fault and post-fault scenarios, however as inertia on the system decreases it is becoming less effective as a post-fault service. DC, DM and DR (collectively referred to as dynamic services) each include a high-frequency and low-frequency variant.

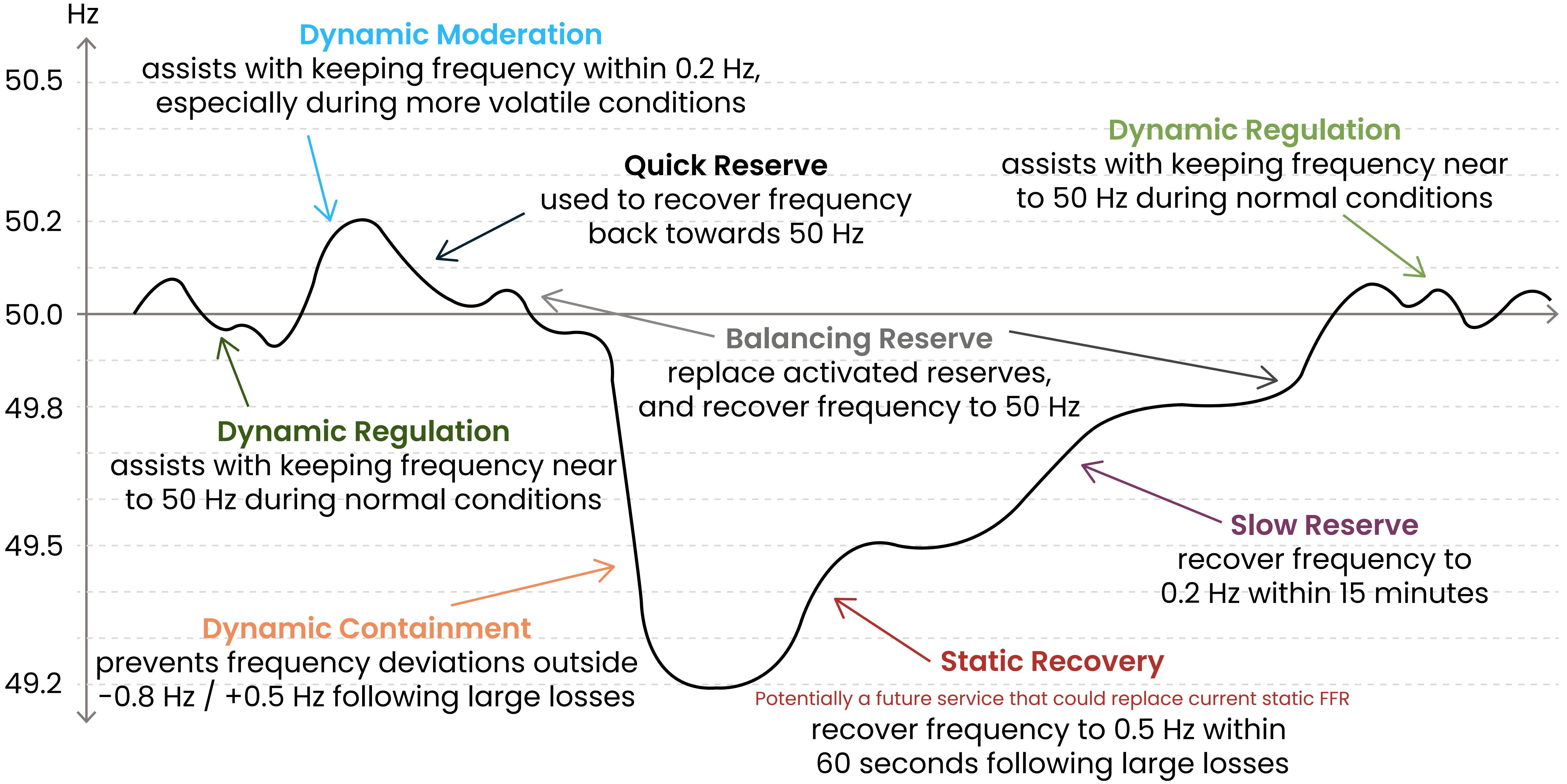
Frequency response webpages

How do we procure response services?

We procure an increasing majority of our volumes at day-ahead in 4-hour EFA block contract lengths through our pay-as-clear (PAC) dynamic services and SFFR markets. Our MFR service is procured in real-time on a pay-as-bid basis and, aside from very few legacy, bespoke, bilateral contracts categorised as Commercial Frequency Response (CFR), is currently our only within-day service and therefore is used to cover any increases in requirement following our day-ahead auctions.

Service	Procurement timeframe	Contract length	Payment mechanism	Pre-fault/ Post-fault
Dynamic Moderation	Day ahead (2pm)	4 hours	PAC	Pre-fault
Dynamic Regulation	Day ahead (2pm)	4 hours	PAC	Pre-fault
Dynamic Containment	Day ahead (2pm)	4 hours	PAC	Post-fault
Static FFR	Day-ahead (11am)	4 hours	PAC	Post-fault
Mandatory Frequency Response	Real-time	N/A	PAB	Post-fault

How our new Dynamic Services may be used alongside our future response and reserve products



Summary

How is the landscape changing?

Lower levels of inertia and increased variable renewable generation on the system creates more volatile frequency variations. Volumes of responsive assets such as interconnectors, Battery Energy Storage Systems (BESS) and flexible, electrified demand can also drive frequency changes as they respond to price signals.

How have costs and volumes evolved over the last year?

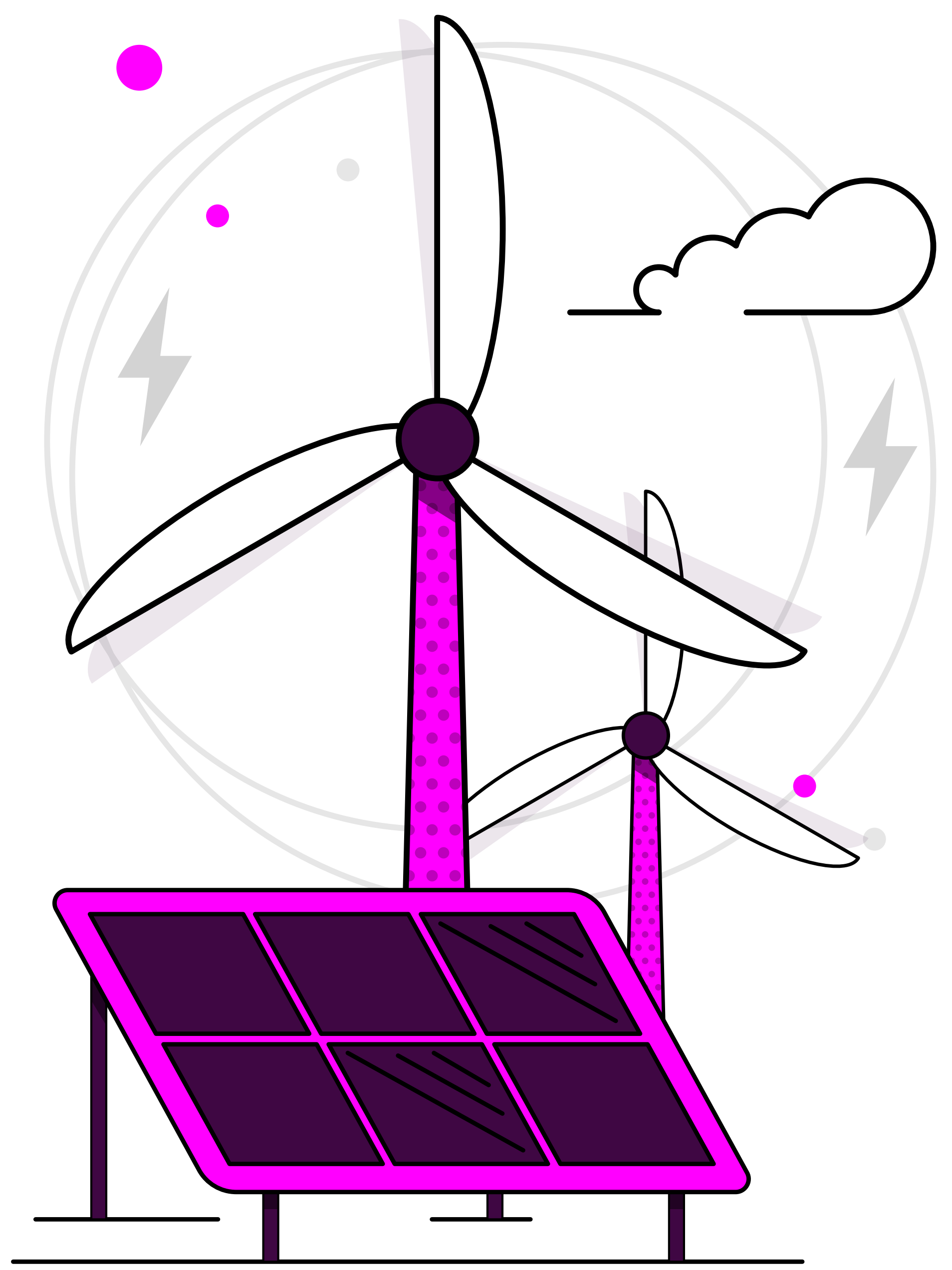
Volumes of response procurement increased in 2024 as a number of policy changes were introduced to improve system security and manage reduced inertia levels. This was despite a continued transition towards using our dynamic services to replace Mandatory Frequency Response (MFR). This increase in volumes was not reflected in response spend, with our cost-effective, co-optimised Enduring Auction Capability (EAC) auctions delivering a cost reduction against 2023.

What is driving the need for reform?

We are expecting our MFR service to become less effective at providing frequency response in comparison with our dynamic services over the coming years meaning an improved real-time service will be required. Further cost savings and efficiency improvements are a key focus as we evaluate service reforms.

How are we implementing market reform?

We are seeking to enhance our within-day service options with some of the benefits we have seen in our dynamic services. This could include updated technical requirements to ensure the service is effective at managing frequency and the opportunity for commercial participation which could deliver cost savings similar to those we have seen in our day-ahead services.



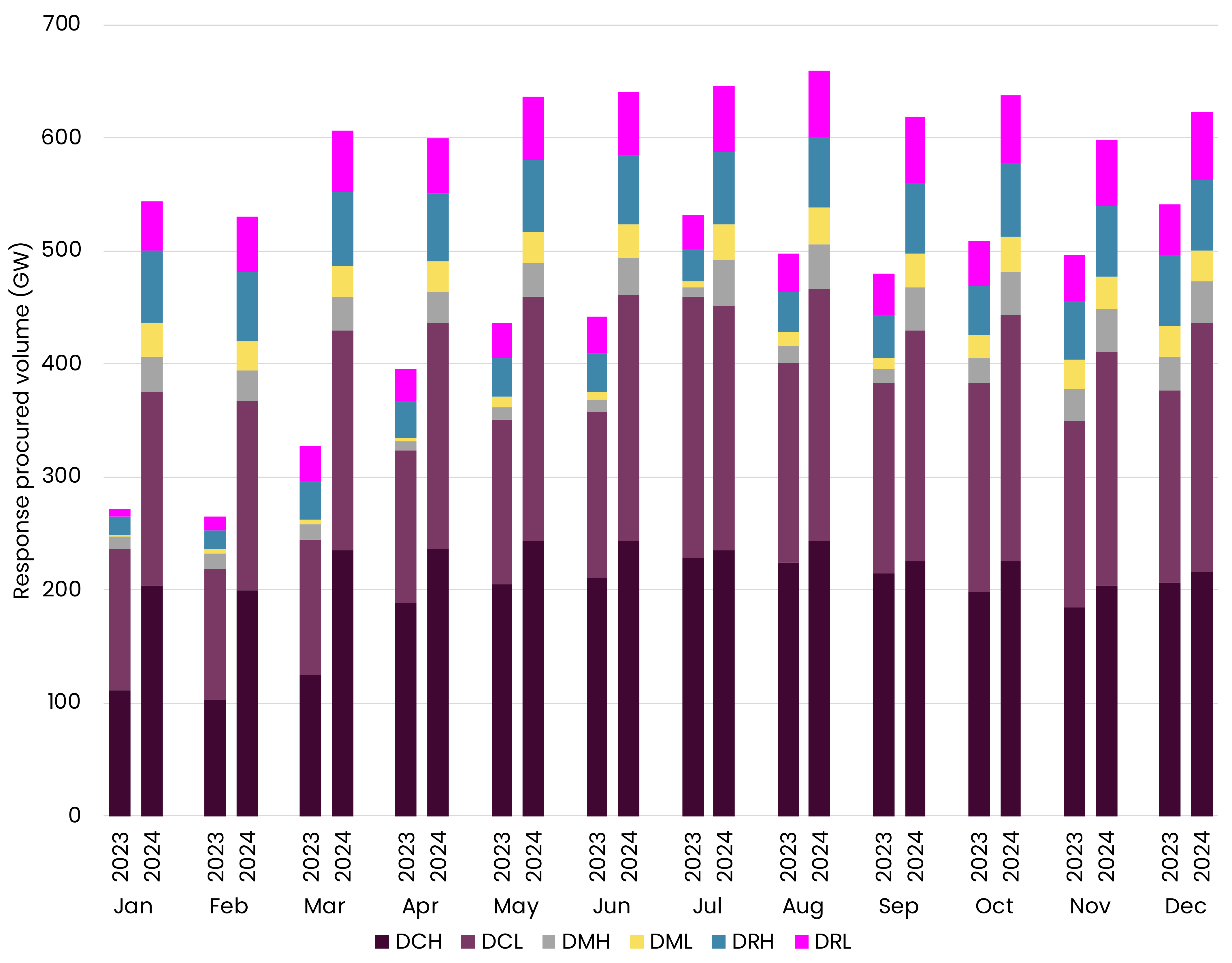
Volumes

Dynamic services

2024 saw increases in volume procured for each of our dynamic services. Dynamic Containment (DC) volumes have increased due to changes in our requirements setting to better manage the risks on the system in line with our latest system modelling, rather than the size of the generation and demand losses being secured. At the end of February changes were made to the forecast methodology for DC and the response requirement policy came into effect, both of which contributed to the increased procurement. As the minimum inertia requirement on the system continues to be reduced through the Frequency Risk and Control Report (FRCR), the volume of response holding across our dynamic services is required to increase. This is particularly significant over the summer period as lower generation and demand levels mean inertia more regularly drops to the new minimum threshold of 120 GVAs; the Dynamic Moderation (DM) High requirement was increased from June and July to support this.

Increased usage of Dynamic Regulation (DR) has allowed the procurement of MFR to be reduced. This has helped reduce overall response costs and the carbon intensity of generation. A drop in DR offered capacity is also seen in some periods which may be partly increased by the requirement for volume in our new Balancing Reserve service which sees an overlap in participating technologies. The DR low-frequency requirement cleared on average 92% of the requirement between April and September. This was due to pricing exceeding the price we were willing to pay rather than due to a limitation of available volume. A change to the buy order methodology was introduced in early Autumn to increase the price we accept which improved this cleared percentage.

RP Figure 1: Dynamic services volumes 2023-24



Volumes

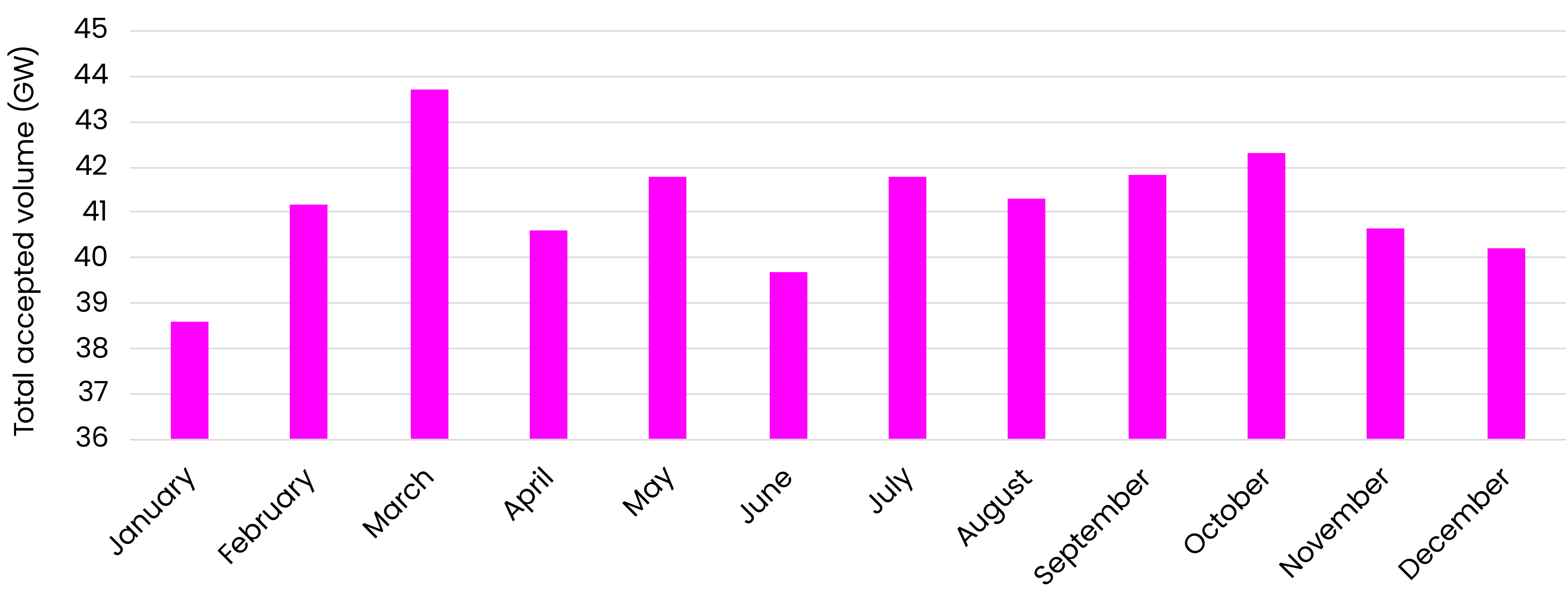
Static Firm Frequency Response (SFFR)

Static FFR requirement in 2024 has continued to remain steady at around 42 GWh per month with a high of 43.7 GWh in March and a low of 38.6 GWh in January. This requirement is expected to remain steady until reforms are brought in for SFFR over the coming years.

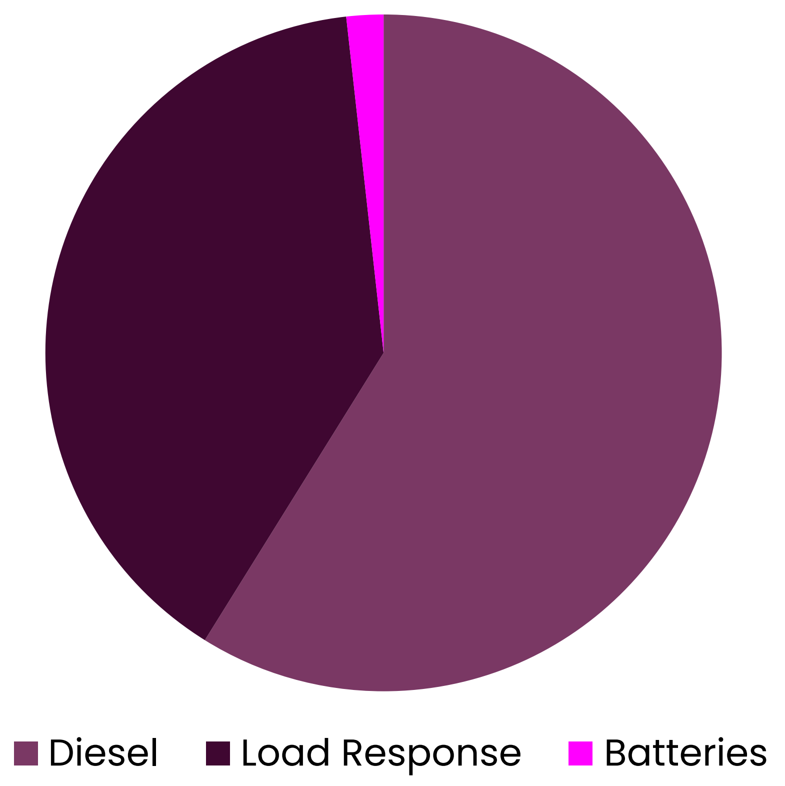
Mandatory Frequency Response (MFR)

2024 volumes of MFR are significantly lower than 2023 as a result of the increased usage of our dynamic services, being the first full year of uncapped procurement of DM and DR. Overall MFR procured volumes have dropped by over 33% with the requirements for each of the three delivery types (Primary, Secondary and High) falling by between 31% and 36%. Our reliance on, and usage of, the mandatory service is expected to continue to reduce in the coming years with further use of the day ahead dynamic services and progression of options for a within day commercial service opportunity.

RP Figure 2: Total accepted SFFR volume by month



RP Figure 3: SFFR accepted volume by technology type



Costs

Dynamic services

The Enduring Auction Capability (EAC) was implemented in October 2023 and allows the co-optimised procurement between the services as well as splitting. We saw impressive early cost benefits from launch and this has continued throughout 2024 helping achieve a reduction in clearing prices for all services and a 20% reduction in overall total cost despite the considerable 41% increase in volumes, giving an overall 43% reduction in average clearing price from £3.40 /MW/h down to £1.93 /MW/h. The markets have been well supplied throughout 2024 with significant liquidity enabling relatively stable low prices. These services also remain a core component of being able to operate a zero-carbon system securely.

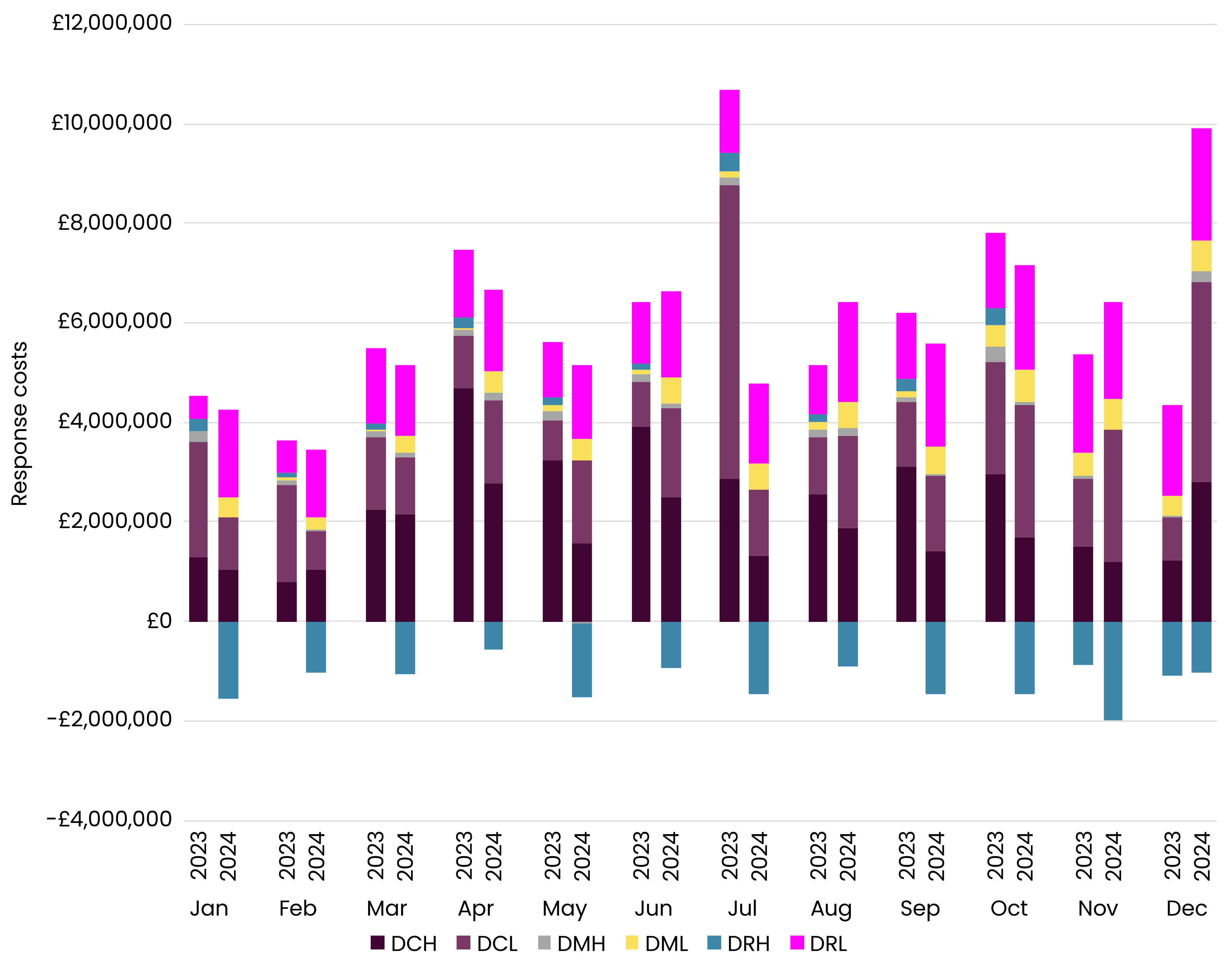
Static Firm Frequency Response (SFFR)

SFFR costs reduced by 14% in 2024 compared to 2023 to £1.79 m. This was primarily driven by a reduction in peak prices seen in the second half of the years but we have seen a reduction in costs throughout the year. The average monthly cost was £149 k with the lowest cost month in August with a total spend of £106 k and the highest cost month being January at £186 k.

Mandatory Frequency Response (MFR)

MFR costs continued the declining trend of the past two years as increased usage of dynamic services has reduced the volumes procured. This total costs for 2024 were 43% below those seen in 2023.

RP Figure 4: Dynamic services costs 2023 - 2024



Market Reforms

We have launched our range of day-ahead commercial services and increased the procurement of these to allow significant offset of the Mandatory Frequency Response (MFR) service and the retirement of our Dynamic Firm Frequency Response service. We are now considering options for further efficiency improvements to the day-ahead services and how we can best manage our within-day requirements. Over the last year we have published the Enabling Renewable and Interconnector participation in GB ancillary services report and the Demand Side Flexibility Routes to Market Review. We will be considering opportunities to directly and indirectly reduce barriers to our response services, beyond those detailed below including operational metering requirements and participation of whole MW integers. We will continue to signpost updates and webinars via our Energise newsletter.

- Instructible Dynamic Response
- 30 minute contracted windows
- Static Response
- Dynamic Services locational procurement
- Stacking and co-optimisation
- Operational improvements
- ABSVD for non-Balancing Mechanism Units

Instructible Dynamic Response

Given the cost and effectiveness of the dynamic services, we are keen to take advantage of this benefit within-day. Our primary within-day service, MFR, is expected to become less effective at managing frequency, particularly post-fault due to the increased speed of changes we see with lower inertia levels and faster changes in generation and demand. In addition, it is not compliant with energy regulations. Ofgem have granted NESO a derogation to use the service until 2029. We are looking to develop a within-day commercial service with both non-mandatory and mandatory elements as this should provide significant cost savings whilst maintaining system security through access to assets with mandatory participation. Instructible dynamic response will require new capabilities to be developed on a number of key strategic platforms. We will be progressing service design, alongside engagement with industry in 2025, and will communicate timelines for formal consultation and implementation via our monthly delivery plan updates as soon as we are able to.

Market Reforms

We have launched our range of day-ahead commercial services and increased the procurement of these to allow significant offset of the Mandatory Frequency Response (MFR) service and the retirement of our Dynamic Firm Frequency Response service. We are now considering options for further efficiency improvements to the day-ahead services and how we can best manage our within-day requirements. Over the last year we have published the Enabling Renewable and Interconnector participation in GB ancillary services report and the Demand Side Flexibility Routes to Market Review. We will be considering opportunities to directly and indirectly reduce barriers to our response services, beyond those detailed below including operational metering requirements and participation of whole MW integers. We will continue to signpost updates and webinars via our Energise newsletter.

- Instructible Dynamic Response
- 30 minute contracted windows
- Static Response
- Dynamic Services locational procurement
- Stacking and co-optimisation
- Operational improvements
- ABSVD for non-Balancing Mechanism Units

30 minute contracted windows

We seek to reduce barriers to entry and allow assets to provide accurate and reflective prices in our auctions as well as to improve access for other asset types. We are investigating the potential impacts of transitioning from using four-hour EFA block service windows to 30 minute Settlement Period contracted windows which could support this goal and align providers bidding granularity with that of our day-ahead reserve services.

Market Reforms

We have launched our range of day-ahead commercial services and increased the procurement of these to allow significant offset of the Mandatory Frequency Response (MFR) service and the retirement of our Dynamic Firm Frequency Response service. We are now considering options for further efficiency improvements to the day-ahead services and how we can best manage our within-day requirements. Over the last year we have published the Enabling Renewable and Interconnector participation in GB ancillary services report and the Demand Side Flexibility Routes to Market Review. We will be considering opportunities to directly and indirectly reduce barriers to our response services, beyond those detailed below including operational metering requirements and participation of whole MW integers. We will continue to signpost updates and webinars via our Energise newsletter.

- Instructible Dynamic Response
- 30 minute contracted windows
- Static Response
- Dynamic Services locational procurement
- Stacking and co-optimisation
- Operational improvements
- ABSVD for non-Balancing Mechanism Units

Static Response

As a post-fault service, SFFR offsets some of our Dynamic Containment (DC) volumes for a typically lower cost. As SFFR only helps to restore the frequency post-fault, it does not require the speed or variable delivery of DC to arrest the falling frequency, which broadens eligibility to include less versatile, lower cost technologies. It also provides an alternative option for assets which benefit from a lower cycle rates or delivery hours. Whilst current volumes procured are limited, we expect the requirement for restoration of frequency to increase in future years as demand increases, ultimately increasing the requirement we could be meeting with SFFR. For SFFR to fulfil this requirement and remain an effective, long-term, low-cost part of our response suite, we are considering some changes. These changes may include updated metering requirements, co-optimised procurement with dynamic services, improved visibility and control of the units as well as some adjustments to the service delivery parameters. We aim to consult on static response reform in late 2025 or early 2026.

Market Reforms

We have launched our range of day-ahead commercial services and increased the procurement of these to allow significant offset of the Mandatory Frequency Response (MFR) service and the retirement of our Dynamic Firm Frequency Response service. We are now considering options for further efficiency improvements to the day-ahead services and how we can best manage our within-day requirements. Over the last year we have published the Enabling Renewable and Interconnector participation in GB ancillary services report and the Demand Side Flexibility Routes to Market Review. We will be considering opportunities to directly and indirectly reduce barriers to our response services, beyond those detailed below including operational metering requirements and participation of whole MW integers. We will continue to signpost updates and webinars via our Energise newsletter.

- Instructible Dynamic Response
- 30 minute contracted windows
- Static Response
- Dynamic Services locational procurement
- Stacking and co-optimisation
- Operational improvements
- ABSVD for non-Balancing Mechanism Units

Dynamic Services locational procurement

Currently we procure all response services from one national pool. As network constraints become more variable, the proportion of units which are effectively sterilised represent a growing inefficiency of procurement. We are considering processes and options available to better align procurement with regions for which response delivery will be effective which should reduce costs and risks to system security for under delivery. Locational procurement is a very complex design and delivery requiring alignment of changes, and co-ordination of backlogs, on a number of strategic platforms that are central to multiple major cross-market changes. We will be progressing service design options assessment, impact assessment and delivery planning in 2025, alongside engagement with industry. We will communicate timelines for formal consultation and implementation when this phase is complete.

Market Reforms

We have launched our range of day-ahead commercial services and increased the procurement of these to allow significant offset of the Mandatory Frequency Response (MFR) service and the retirement of our Dynamic Firm Frequency Response service. We are now considering options for further efficiency improvements to the day-ahead services and how we can best manage our within-day requirements. Over the last year we have published the Enabling Renewable and Interconnector participation in GB ancillary services report and the Demand Side Flexibility Routes to Market Review. We will be considering opportunities to directly and indirectly reduce barriers to our response services, beyond those detailed below including operational metering requirements and participation of whole MW integers. We will continue to signpost updates and webinars via our Energise newsletter.

- Instructible Dynamic Response
- 30 minute contracted windows
- Static Response
- Dynamic Services locational procurement
- Stacking and co-optimisation
- Operational improvements
- ABSVD for non-Balancing Mechanism Units

Stacking and co-optimisation

We have continued to see significant cost savings from the introduction of revenue stacking and co-optimisation of response and reserve services, particularly for those services on our EAC platform. Through 2025 we will be continuing to evaluate and progress options to allow increased stacking and co-optimisation of dynamic services with other response and reserve services. Whilst some combinations of services may not be stackable, we recognise there is typically an improvement from stacking, in the efficiency of our auction clearing and costs. We will be maintaining ongoing engagement with industry for both our response and reserve services. More information on revenue stacking across our services can be found in the Revenue Stacking chapter.

Market Reforms

We have launched our range of day-ahead commercial services and increased the procurement of these to allow significant offset of the Mandatory Frequency Response (MFR) service and the retirement of our Dynamic Firm Frequency Response service. We are now considering options for further efficiency improvements to the day-ahead services and how we can best manage our within-day requirements. Over the last year we have published the Enabling Renewable and Interconnector participation in GB ancillary services report and the Demand Side Flexibility Routes to Market Review. We will be considering opportunities to directly and indirectly reduce barriers to our response services, beyond those detailed below including operational metering requirements and participation of whole MW integers. We will continue to signpost updates and webinars via our Energise newsletter.

- Instructible Dynamic Response
- 30 minute contracted windows
- Static Response
- Dynamic Services locational procurement
- Stacking and co-optimisation
- Operational improvements
- ABSVD for non-Balancing Mechanism Units

Operational improvements

Given the critical role frequency services play in our system security we have been working to deliver a much-improved level of visibility and control for real-time frequency management using our dynamic services. We will be introducing changes to bring non-BM requirements for 24/7 baselines and metering in line with our BM requirements to enhance visibility of these units and ensure that a level playing field is maintained. We are also revising our performance monitoring and penalties process to fairly reward and incentivise higher performing units. Changes to performance monitoring and penalties will be phased in throughout 2025 and 2026.

Market Reforms

We have launched our range of day-ahead commercial services and increased the procurement of these to allow significant offset of the Mandatory Frequency Response (MFR) service and the retirement of our Dynamic Firm Frequency Response service. We are now considering options for further efficiency improvements to the day-ahead services and how we can best manage our within-day requirements. Over the last year we have published the Enabling Renewable and Interconnector participation in GB ancillary services report and the Demand Side Flexibility Routes to Market Review. We will be considering opportunities to directly and indirectly reduce barriers to our response services, beyond those detailed below including operational metering requirements and participation of whole MW integers. We will continue to signpost updates and webinars via our Energise newsletter.

- Instructible Dynamic Response
- 30 minute contracted windows
- Static Response
- Dynamic Services locational procurement
- Stacking and co-optimisation
- Operational improvements
- ABSVD for non-Balancing Mechanism Units

ABSVD for non-Balancing Mechanism Units

As part of our work to promote fair competition and provide a level playing field, we are investigating options to apply applicable balancing service volume data (ABSVD) for non-BMUs through a joint ad hoc Article 18 and Condition 9 consultation.

Reserve

Introduction

What is reserve?

Reserve is used to manage energy imbalances and losses of generation or demand. When instructed, contracted units deliver changes to their power input or output to increase or decrease the amount of energy on the system. Both response and reserve services are used to manage frequency on the system; reserve services are manually dispatched whereas response is automatically activated based on measurement of system frequency.

With lower inertia levels, the system benefits from faster reserve delivery. With larger swings of energy imbalances and increasingly large losses to secure, having large volumes of reserve available is essential. As we transition to operate the system with a lower carbon intensity, we will need to increase our usage of zero carbon sources of reserve. We seek to reduce barriers to enter our reserve services for all asset types to facilitate this.

Frequency reserve webpages +

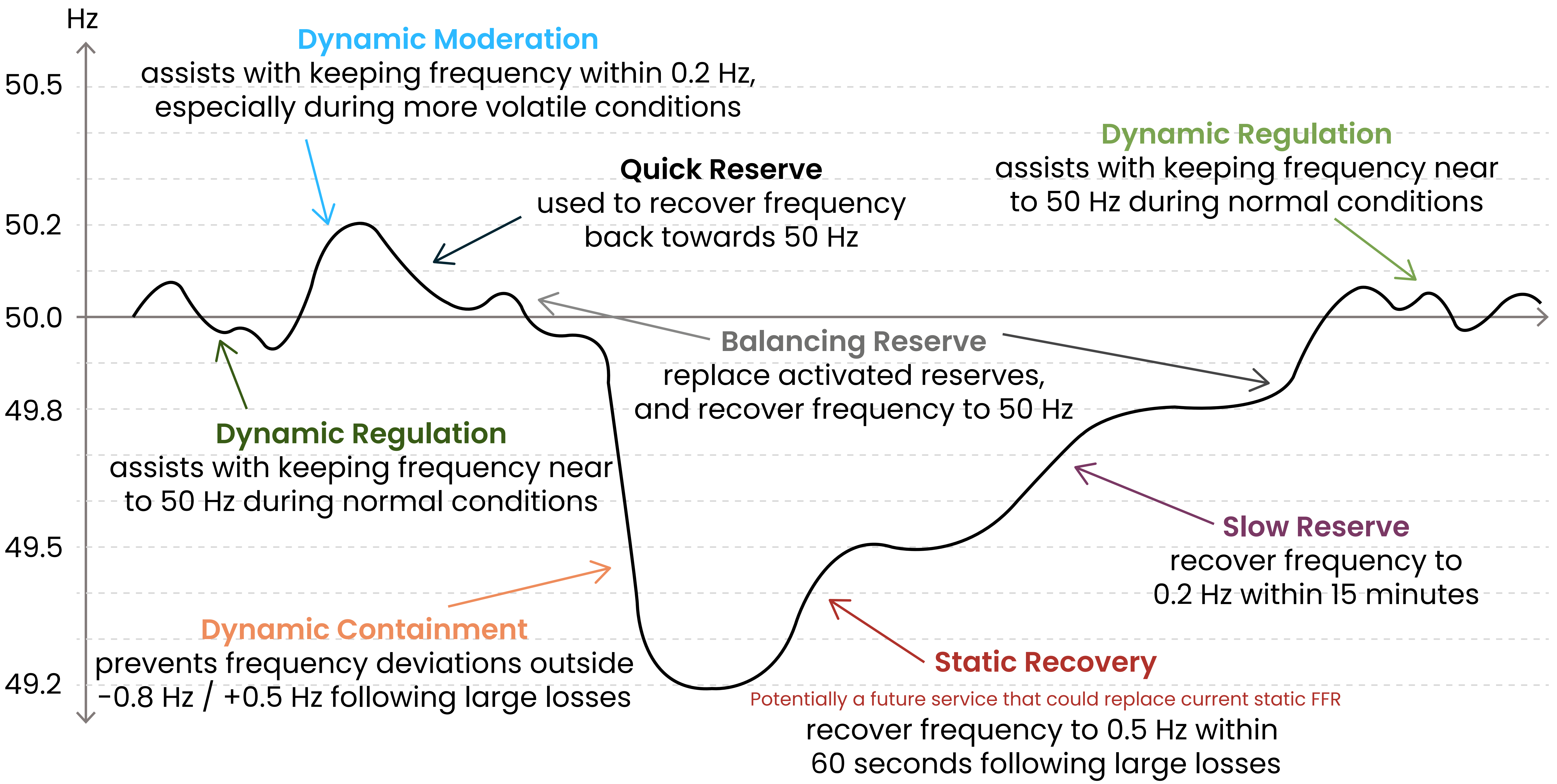
Operating reserve and Balancing Reserve are both used to manage pre-fault and post-fault imbalances. Fast Reserve and the new Quick Reserve service are also both used to manage pre-fault and post-fault imbalances but as their names suggest they both require their contracted change in generation or demand to be achieved in a shorter period.

Short Term Operating Reserve (STOR) and the planned Slow Reserve service are designed to act in post-fault scenarios to restore energy imbalances. The current STOR service only secures the system from a low frequency event, whereas the proposed Slow Reserve service will be bi-directional and will secure against both losses of generation and demand.

How do we procure reserve services?

We procure STOR and Balancing Reserve at day-ahead through auctions in the morning and Quick Reserve at the day-ahead stage through an auction in the afternoon, aligning with our dynamic response procurement. All three of our day-ahead auctions use a pay-as-clear pricing structure. Operating reserve, Optional Fast Reserve and some legacy/bespoke arrangements for spin-gen and spin-pump are all procured within day within operational timescales (between real time and about 4-hour ahead).

How our new Dynamic Services may be used alongside our future response and reserve products



Summary

How is the landscape changing?

As we transition to net zero, we are seeing increased penetration of variable renewable generation combined with lower inertia on the system which is increasing the speed and size of the energy swings which reserve services need to manage.

How have costs and volumes evolved over the last year?

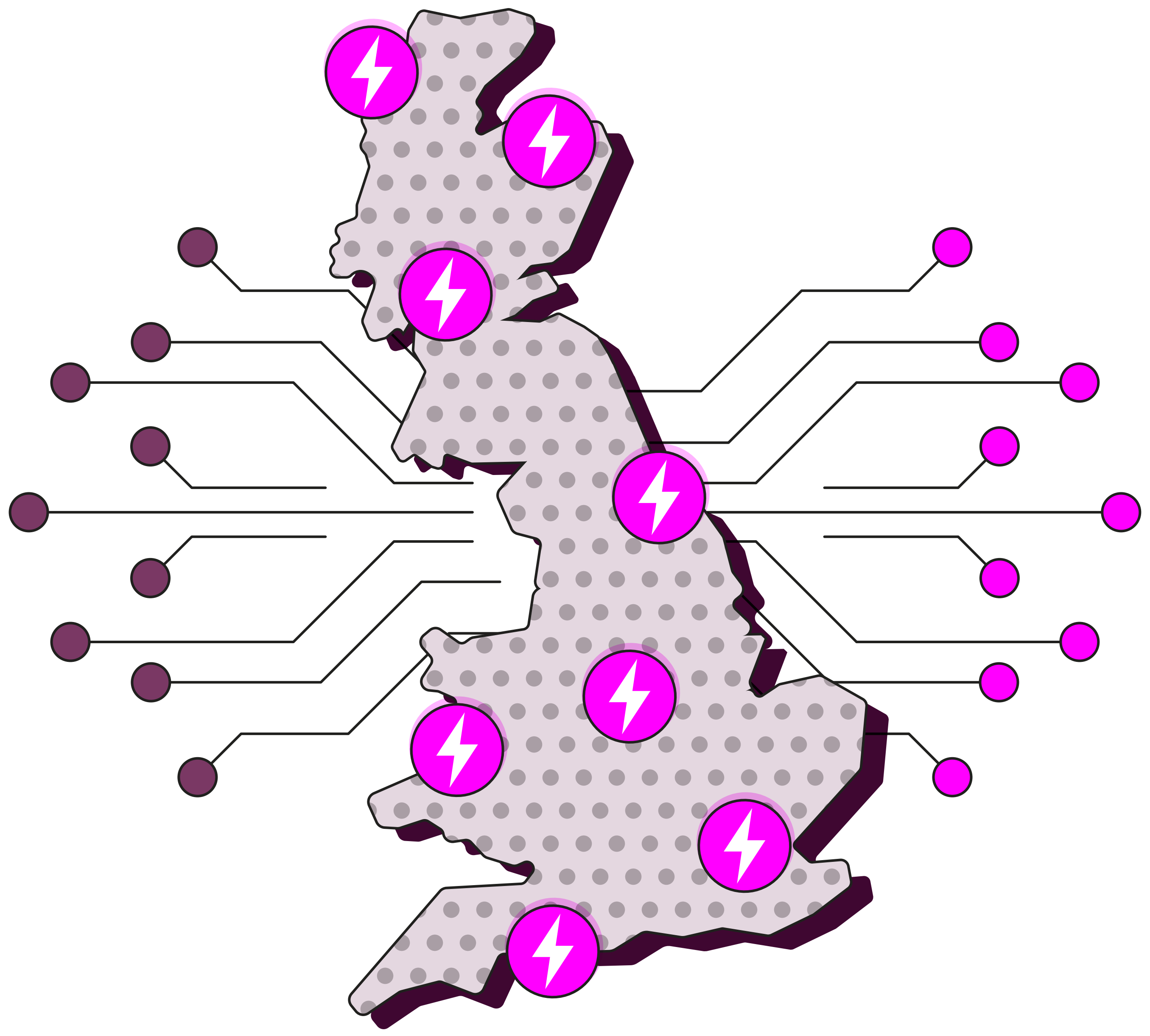
Our overall requirements have remained fairly consistent with last year. Our Fast Reserve costs and volumes having increased slightly and our STOR costs and volumes have continued to reduce. Our reporting methodology for operating reserve is different from previous Markets Roadmap publications with some reserve actions being taken to manage constraints now being captured under constraint actions rather than reserve volumes. This explains the reduction in reported operating reserve costs and volumes.

What is driving the need for reform?

As energy swings become larger and faster, we require more effective reserve services to ensure that system frequency remains secure. Reducing cost and barriers to participate is also a key focus to ensure that we continue to maintain liquid markets which represent value to the consumer as we transition to more renewable forms of generation.

How are we implementing market reform?

We have delivered Balancing Reserve and Quick Reserve in 2024 and are planning to launch Slow Reserve in 2025 to complete our suite of new day-ahead reserve services. This will support us in unlocking revenue stacking and co-optimised procurement for most of our response and reserve services which should drive lower prices. We are continuing to progress with our Dynamic Reserve Setting project to better optimise our reserve requirement setting. We will also be considering opportunities for introducing locational procurement of reserve to improve the efficiency of our procured reserve volumes.

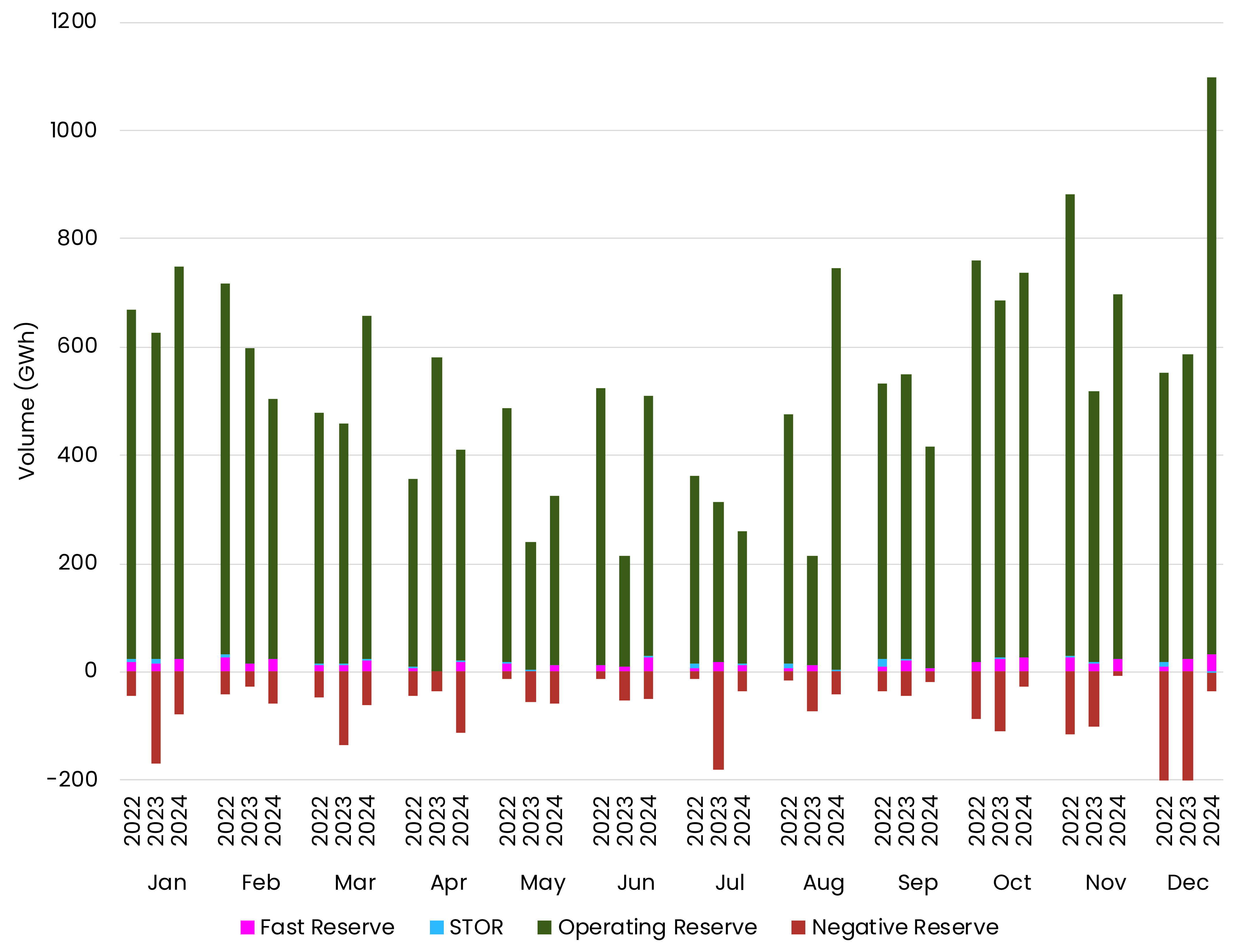


Volumes

Absolute reserve volumes

Overall reserve dispatch volumes increased by 13% from 6.78 TWh in 2023 to 7.69 TWh in 2024. This was primarily as a result of an increase in operating reserve volumes which account for the majority of our procured volumes and increases in this of 27% and 33% increase in Fast Reserve outweighed reductions in STOR and negative reserve volumes. This reverses the reduction we saw from 2022 to 2023 with higher overall volumes in 2024 than we have seen in previous years reflecting the increased volatility on the system.

RV Figure 1: Reserve absolute volumes 2022-2024



Volumes

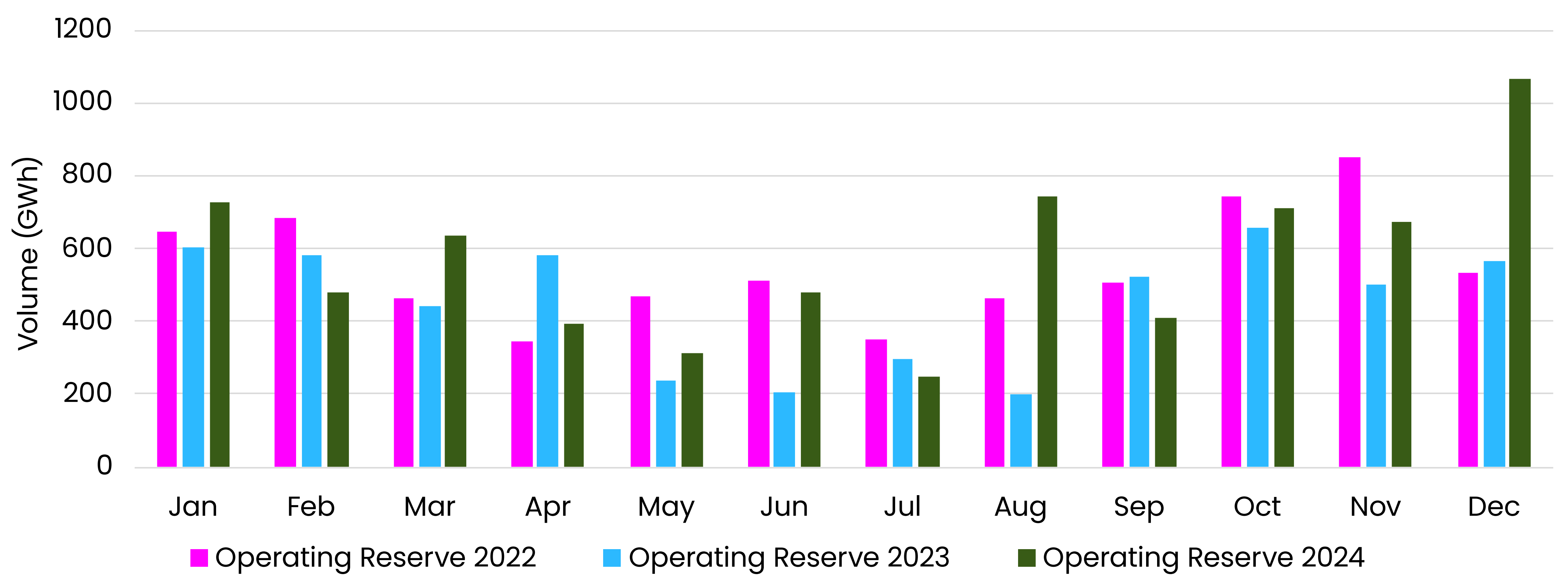
Operating reserve and Balancing Reserve

Operating reserve volumes have increased by 27% from 5.40 TWh to 6.87 TWh. This again reverses the downward trend from 2022 to 2023 with 2024 volumes slightly exceeding those from two years earlier. Part of the increase in volumes is also due to an increase in the amount of actions taken to provide replacement energy for constraints that also provided reserve which are included in the reserve figures. We continue to see the trend of higher volumes being required between October and January. Securing access to BR volumes at day-ahead has seen average availability clearing prices of £1.38/MW/h for Negative BR and £3.68/MW/h for Positive BR. We have consistently met our Positive BR firm requirement for 400 MW since launch primarily through a combination of gas units (72%) and batteries (27%). Negative BR has cleared on average 23% of its 400 MW firm requirement primarily through a combination of gas units (60%), batteries (31%) and wind (7%).

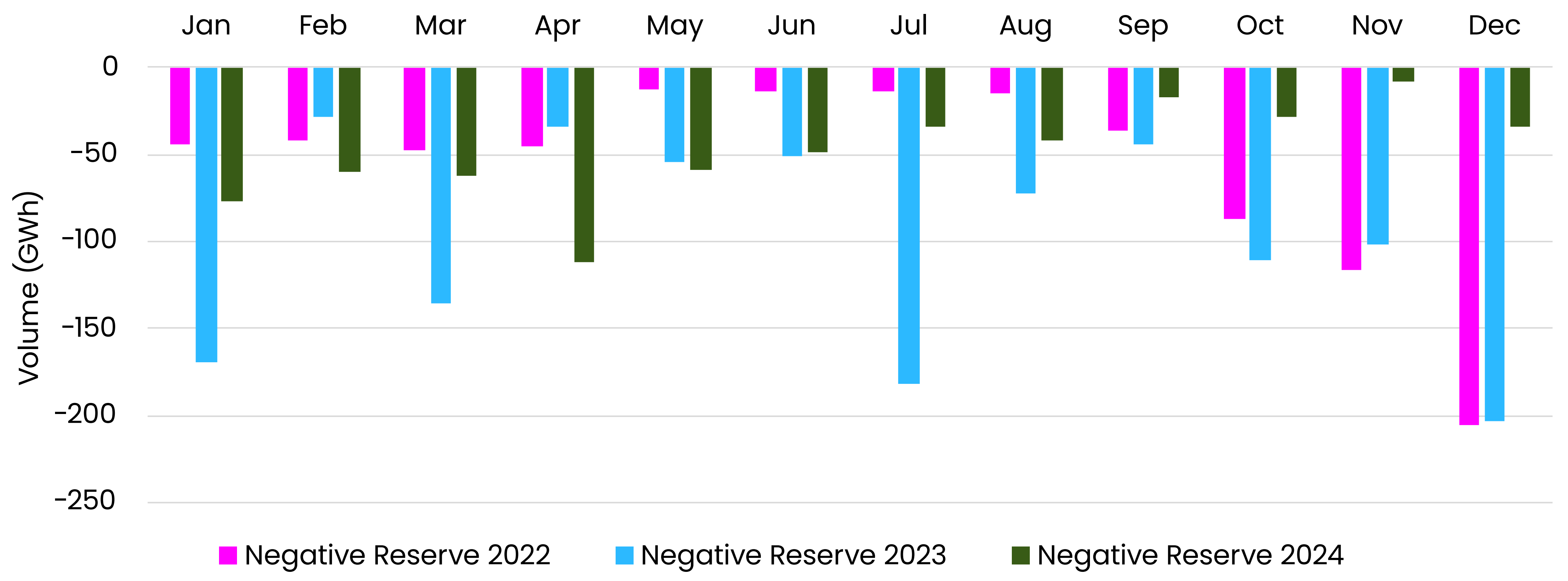
Negative operating reserve & Balancing Reserve

Contrary to positive operating reserve trends, negative operating reserve volumes have dropped 51% from a 1189 GWh in 2023 to 582 GWh in 2024. This 2023 figure is an outlier when comparing against 2021 and 2022 data, with these years having seen volumes around 680 GWh.

RV Figure 2: Operating reserve and Balancing Reserve 2022-24



RV Figure 3: Negative operating reserve and Balancing Reserve 2022-24



Volumes

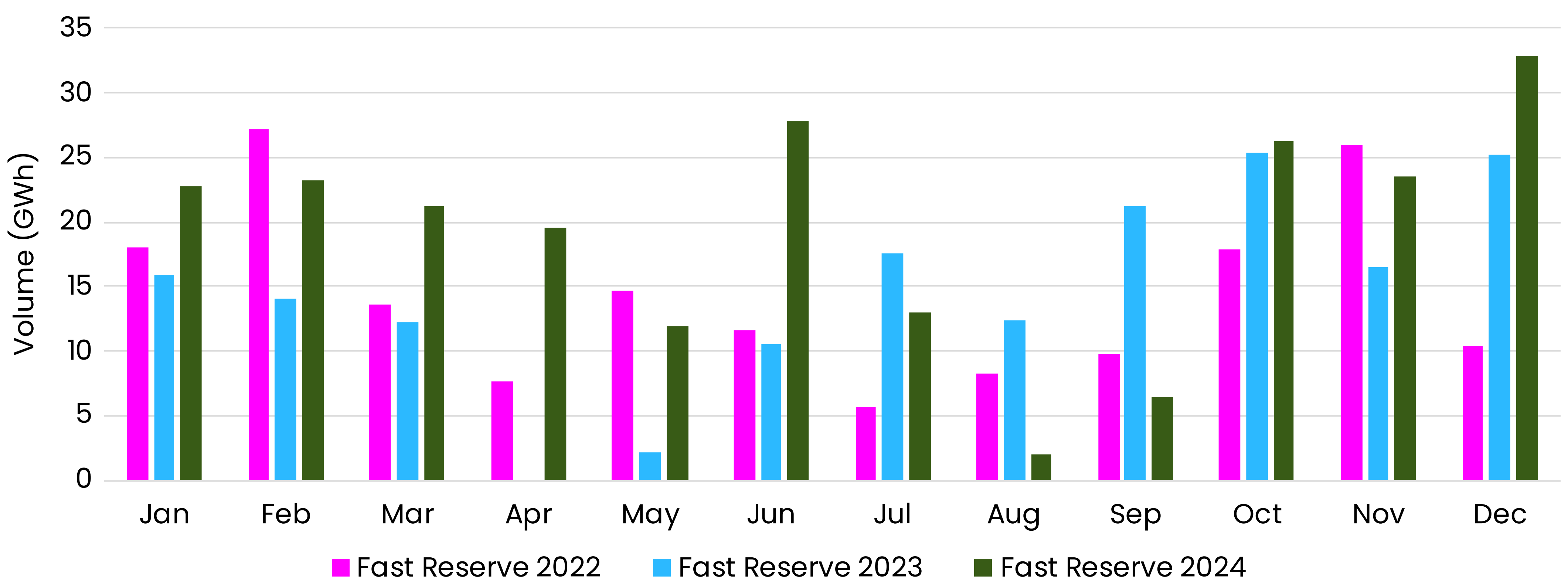
Fast Reserve and Quick Reserve

Combined volumes of our Fast Reserve and its replacement Quick Reserve have increased by 33% from 173 GWh to 231 GWh. With Quick Reserve having only been introduced at the start of December there has been limited opportunity to see the impacts of this service. Since the service launched we have been procuring 300 MW of Positive QR overnight and 500 MW during the day. Our Negative QR procurement has remained steady at 300 MW. We expect these to remain as our minimum requirements going forward. The average availability clearing prices for these volumes has been £5.75/MW/h for Negative QR and £8.51/MW/h for Positive QR.

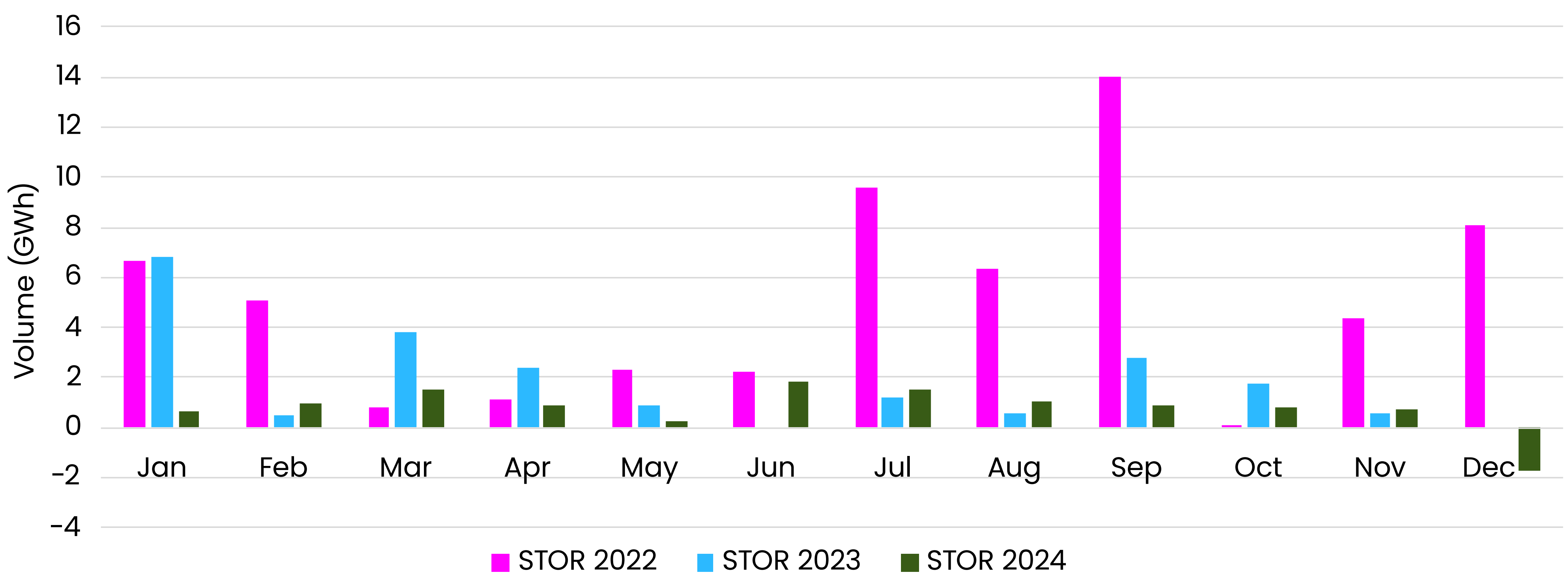
Short Term Operating Reserve (STOR)

STOR volumes have remained low throughout 2024 with 37% of the requirement compared to 2023. This brought dispatch down from 21 GWh to 13 GWh and reflects fewer events where losses have needed to be secured using STOR. These volumes are likely to remain low, only securing the largest generation loss, until the introduction of bi-directional Slow Reserve which has added capability to secure the largest demand loss.

RV Figure 4: **Fast Reserve 2022-24**



RV Figure 5: **STOR 2022-24**

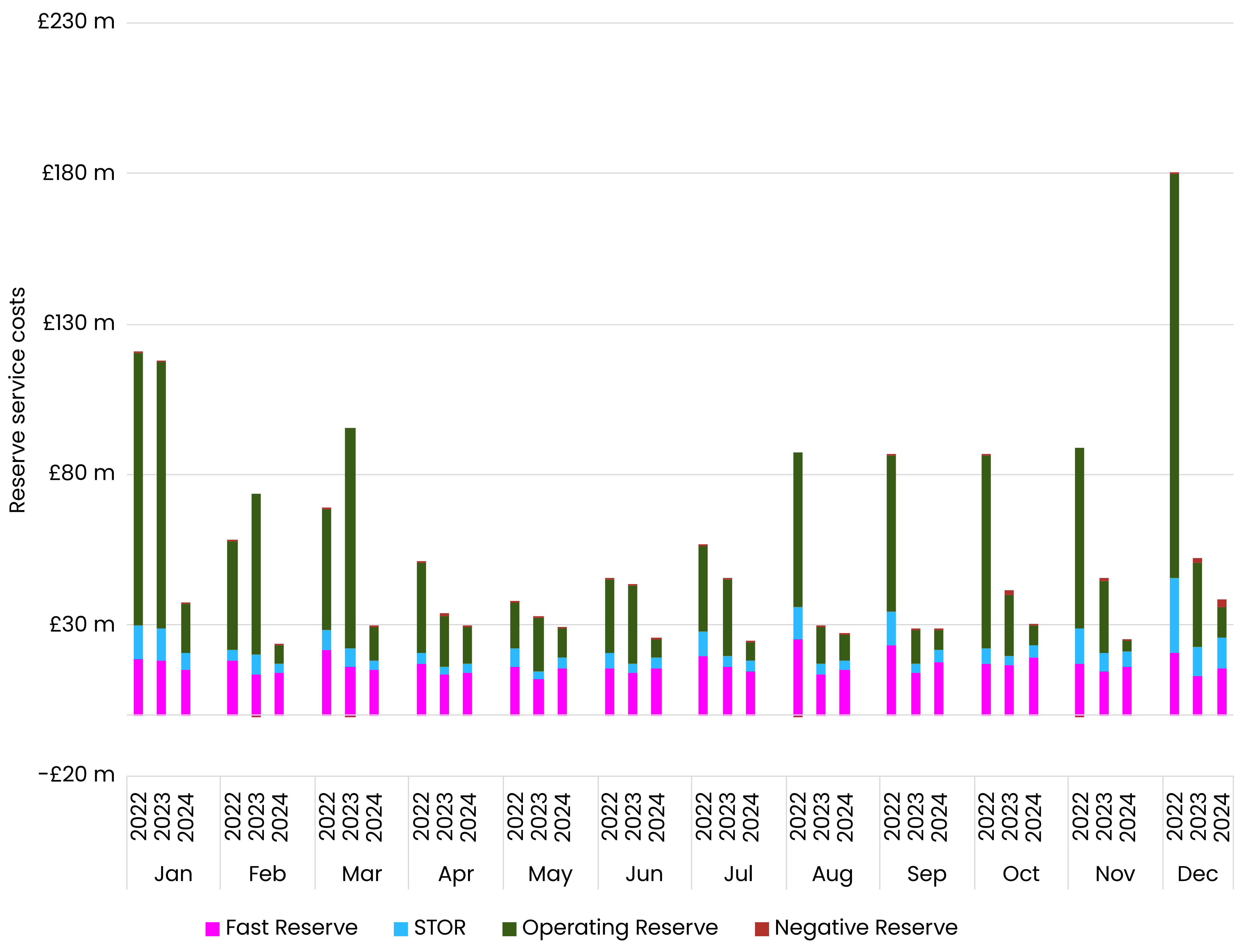


Costs

Absolute reserve costs

Overall reserve costs dropped by 46% compared to 2023 levels from £634 m to £344 m. This was primarily driven by a significant reduction in operating reserve costs which accounted for the majority of our reserve costs in 2023. Some of this cost reduction can be attributed to a reduction in wholesale costs between the two periods and the increased proportion of actions to provide replacement energy for constraints that also provided reserve. The launch of Balancing Reserve and Quick Reserve demonstrate more explicit procurement of our reserve requirements. We expect further benefits from these services, as well as Slow Reserve, to be realised from 2025 onwards.

RV Figure 6: **Reserve costs 2022 – 2024**



Costs

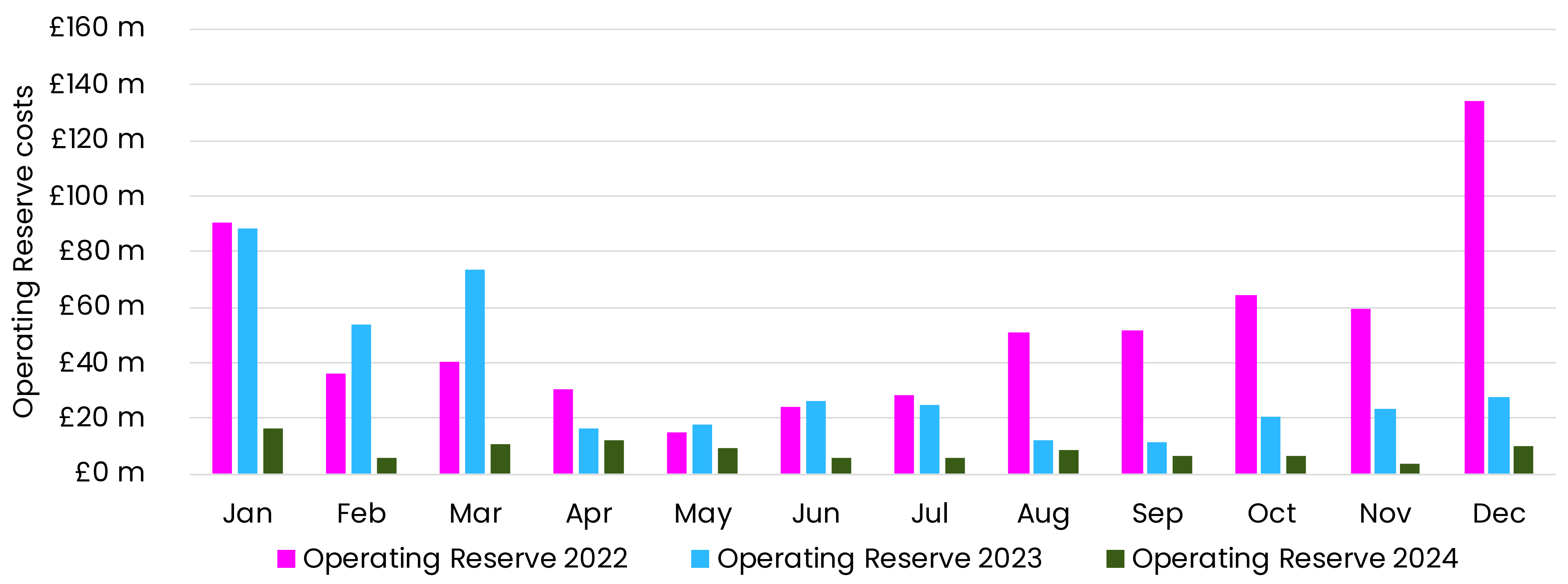
Operating reserve

Operating reserve costs have dropped by 74% from £397 m to £103 m. A small proportion of these costs to manage operating reserve is offset by additional spend on the new Balancing Reserve service which seeks to procure operating reserve capacity more explicitly, increasing competition and market transparency. Some of this overall cost reduction is due to lower wholesale prices on average when comparing data with 2023, but the majority of this difference is due to the way actions are tagged in the BM and reported in this year's Markets Roadmap document. In 2024, we saw a lot more actions which were taken for multiple reasons; namely when replacing energy during a period of thermal congestion. Sometimes, NESO also need to take actions during these periods to procure additional reserve capability, so the actions to replace energy and procure reserve are co-optimised together. These are typically tagged as constraint actions, hence there has been a significant uplift in thermal volumes. Please see the thermal chapter for more information.

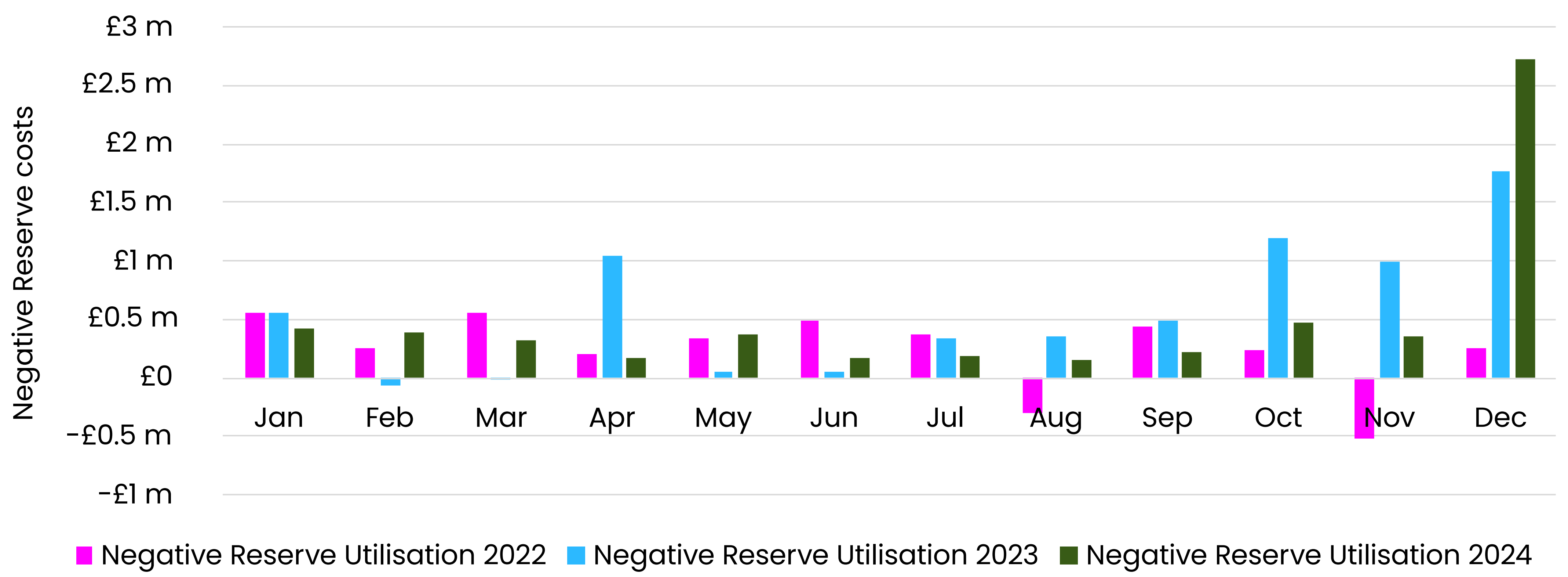
Negative operating reserve

Negative operating reserve costs have also fallen by 12% from £6.8 m in 2023 to £5.97 m in 2024. This has been driven by the reduction in dispatched volume despite fewer negative reserve actions being procured at a negative cost. As the system transitions away from traditional thermal plant with higher marginal costs for generation, there may continue to be reducing numbers of negatively priced generation turn-down bids.

RV Figure 7: Operating reserve costs 2022-24



RV Figure 8: Negative operating reserve costs 2021-24



Costs

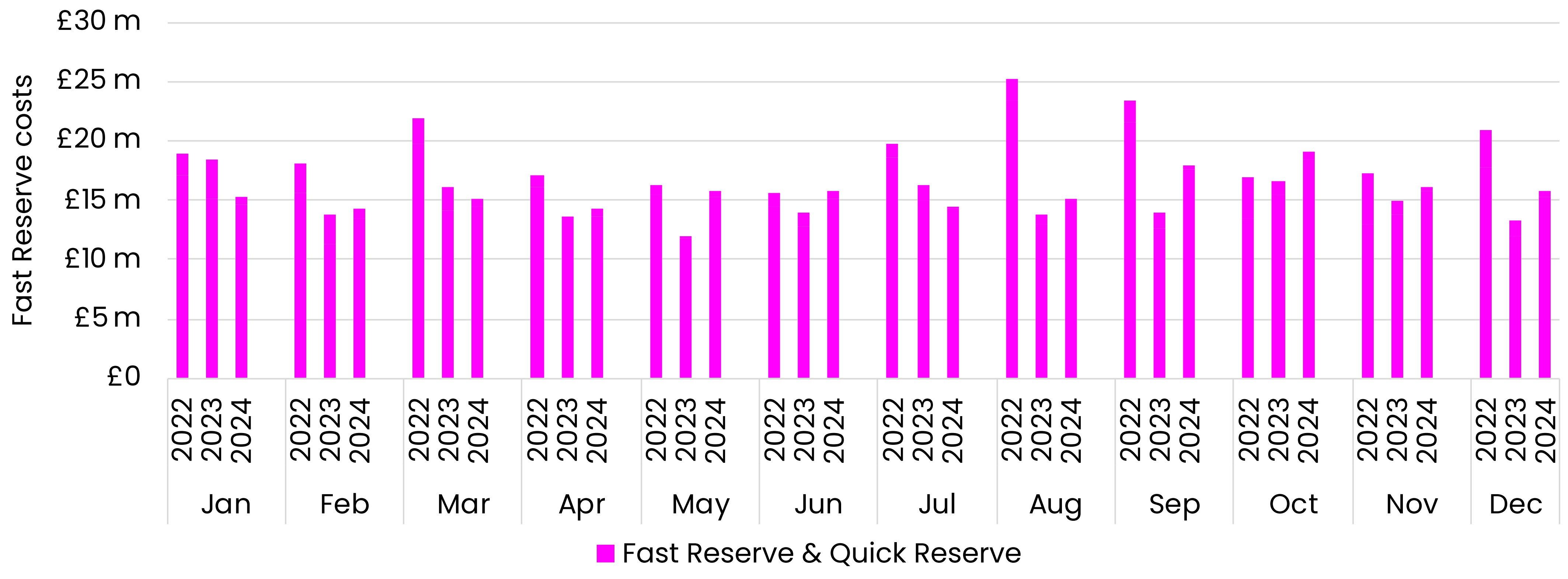
Fast reserve and Quick Reserve

As with volumes, Fast reserve and Quick Reserve costs saw an increase in costs growing by 6% from £176 m to £188 m. This cost increase is lower than the 21% increase in dispatched volumes due to lower unit prices for gas and wholesale energy. Quick Reserve has also provided a more transparent signal to the market and demonstrated the value of designing competitive markets.

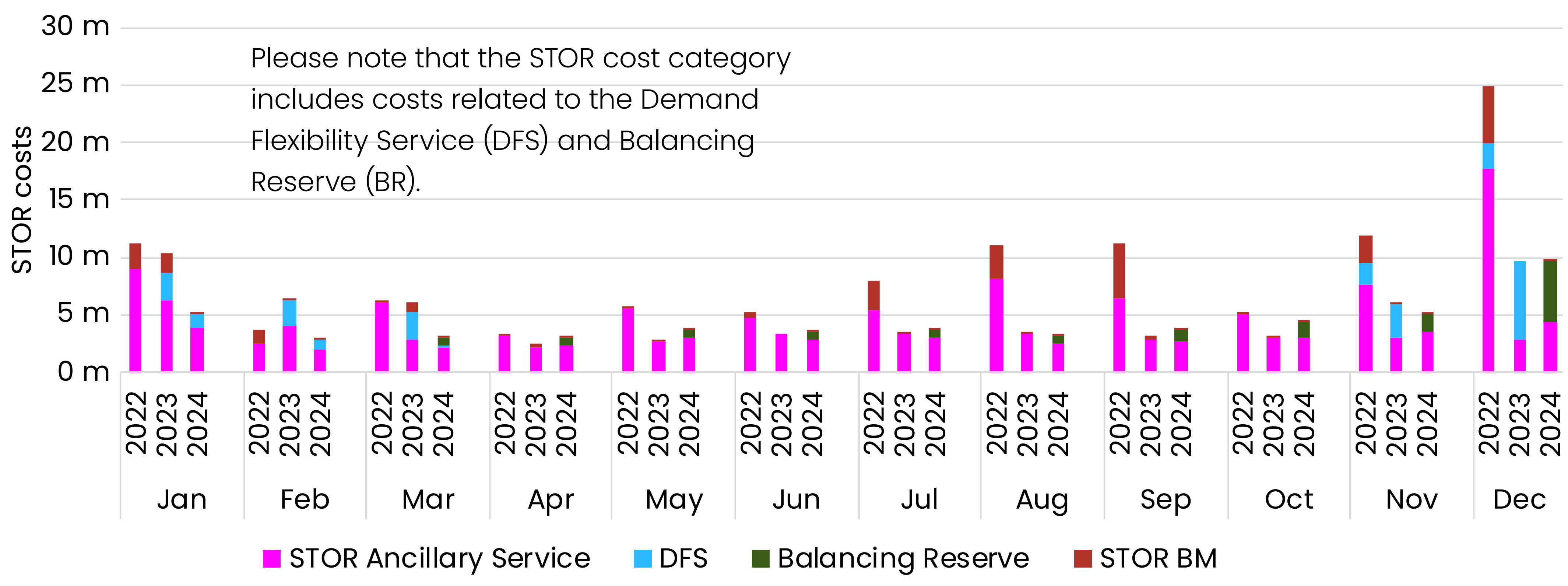
STOR

STOR costs have dropped slightly in 2024, decreasing 14% to £52 m from £60 m in 2023. Due to NESO system categorisation and reporting, this cost category includes costs for DFS and Balancing Reserve as well as STOR ancillary service fees and STOR BM instructions. The true STOR BM and ancillary service costs have dropped 17% from £44 m to £37 m. With very limited utilisation, the set costs for availability form a significant proportion of the overall service costs and mean that percentage cost savings are dampened compared to percentage reduction in dispatch volumes.

RV Figure 9: Fast reserve cost 2022-24



RV Figure 10: STOR cost 2022-24



Market Reforms

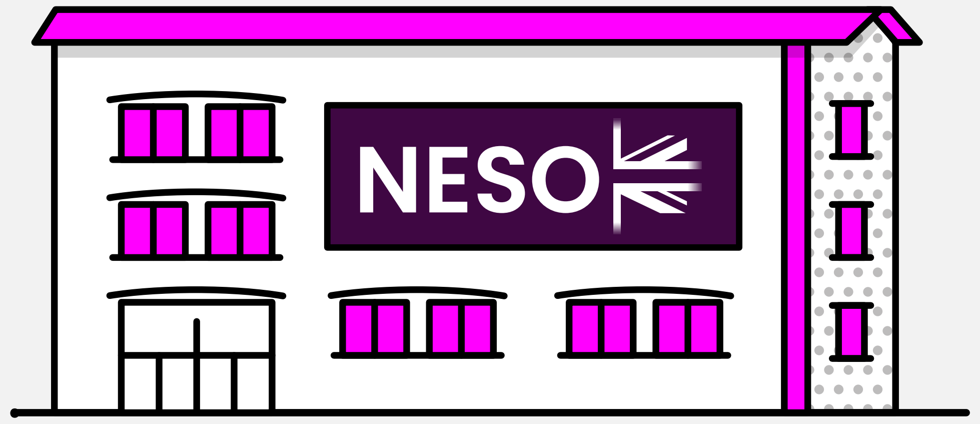
We are continuing to progress with launching our new day-ahead services allowing us to transition away from our legacy reserve services. Alongside this, we are prioritising options over the next few years to enhance and improve the efficiency of our procurement process through locational procurement, stacking and co-optimisation, as well as two Dynamic Reserve Setting projects.

We will also be further assessing the recommendations and outputs from our Demand Side Flexibility Routes to Market Review and Enabling Demand Side Flexibility in NESO Markets reports to allow us to prioritise reforms accordingly. Any changes to our delivery plans will be communicated through the monthly delivery plan section on our Markets Roadmap webpage.

- New services
- Locational procurement
- Revenue stacking
- Co-optimisation
- Dynamic Reserve Setting (national)
- Dynamic Reserve Setting (regional)

New services

In 2024 we launched Balancing Reserve (BR) and Quick Reserve (QR) services. Balancing Reserve was launched to provide a pricing signal at day ahead and secure volume ahead of the real-time procurement of operating reserve. Quick Reserve is brought in to replace Fast Reserve as our fast-acting reserve service. In 2025 we are expecting further reforms to QR and BR as well as the launch of our new Slow Reserve. This will replace our current STOR service which is used to secure our largest loss on the system. We expect that for Quick Reserve phase 2 will be delivered in the summer of 2025, supported by additional development of our Open Balancing Platform (find out more in the BM chapter), which will enable Quick Reserve dispatch instructions to be sent outside of the Balancing Mechanism. Improvements are planned for Balancing Reserve to account for the delivery durations of storage bids with updates to ensure confidence that assets will be able to deliver throughout their contracted period.



Market Reforms

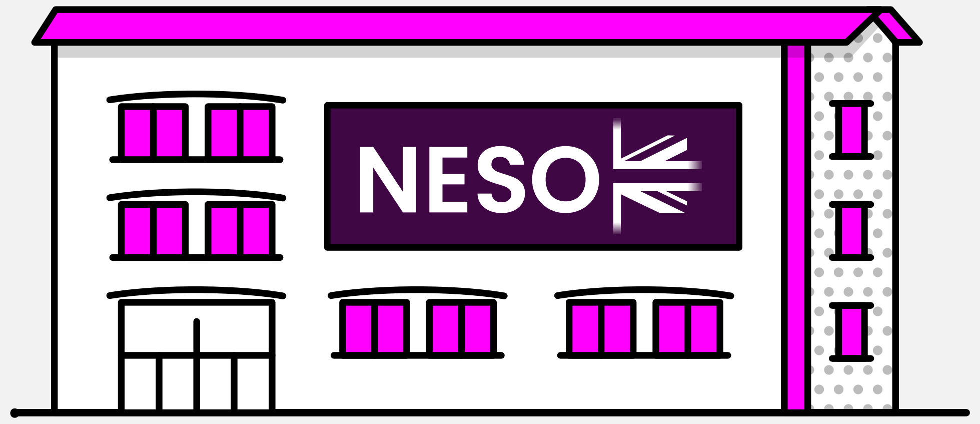
We are continuing to progress with launching our new day-ahead services allowing us to transition away from our legacy reserve services. Alongside this, we are prioritising options over the next few years to enhance and improve the efficiency of our procurement process through locational procurement, stacking and co-optimisation, as well as two Dynamic Reserve Setting projects.

We will also be further assessing the recommendations and outputs from our Demand Side Flexibility Routes to Market Review and Enabling Demand Side Flexibility in NESO Markets reports to allow us to prioritise reforms accordingly. Any changes to our delivery plans will be communicated through the monthly delivery plan section on our Markets Roadmap webpage.

- New services
- Locational procurement
- Revenue stacking
- Co-optimisation
- Dynamic Reserve Setting (national)
- Dynamic Reserve Setting (regional)

Locational procurement

Beyond these new launches and day two improvements, we are considering further changes similar to those under consideration for response services. Locational procurement would allow us to limit procurement to unconstrained regions. This would help to improve the efficiency of our procurement by reducing the number of contracted units which find their output sterilised behind a constraint boundary. Locational procurement is a very complex design and delivery requiring alignment of changes, and co-ordination of backlogs, on a number of strategic platforms that are central to multiple major cross-market changes. We will be progressing service design options assessment, impact assessment and delivery planning in 2025, alongside engagement with industry. We will communicate timelines for formal consultation and implementation when this phase is complete.



Market Reforms

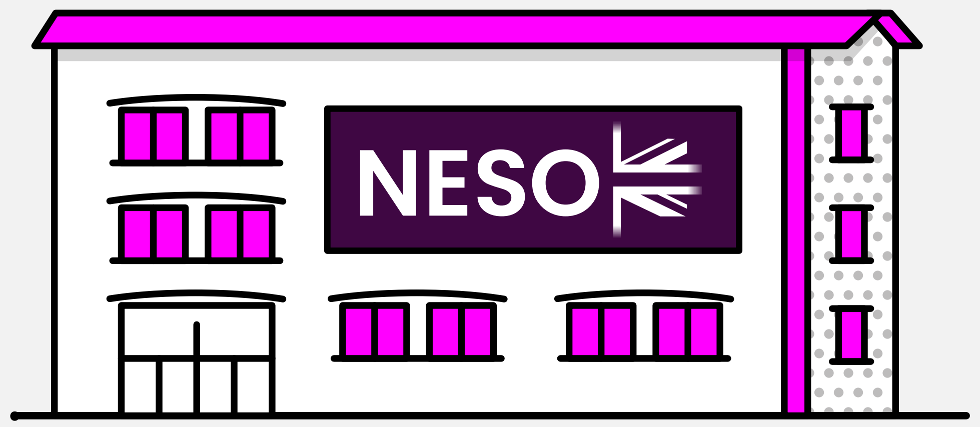
We are continuing to progress with launching our new day-ahead services allowing us to transition away from our legacy reserve services. Alongside this, we are prioritising options over the next few years to enhance and improve the efficiency of our procurement process through locational procurement, stacking and co-optimisation, as well as two Dynamic Reserve Setting projects.

We will also be further assessing the recommendations and outputs from our Demand Side Flexibility Routes to Market Review and Enabling Demand Side Flexibility in NESO Markets reports to allow us to prioritise reforms accordingly. Any changes to our delivery plans will be communicated through the monthly delivery plan section on our Markets Roadmap webpage.

- New services
- Locational procurement
- **Revenue stacking**
- Co-optimisation
- Dynamic Reserve Setting (national)
- Dynamic Reserve Setting (regional)

Revenue stacking

Revenue stacking options are under consideration for allowing splitting across our dynamic services in response and our new reserve services (Balancing Reserve, Quick Reserve and proposed Slow Reserve). We have seen significant benefit from stacking across our response services and would like to expand this to our reserve services, where possible. Whilst our intention is to enable stacking across our services, some combinations will require system changes to enable and take some time to deliver. Other combinations may be determined to not be stackable. Through 2025 we will continue to evaluate and progress options to allow increased stacking and co-optimisation of our new Reserve services.



Market Reforms

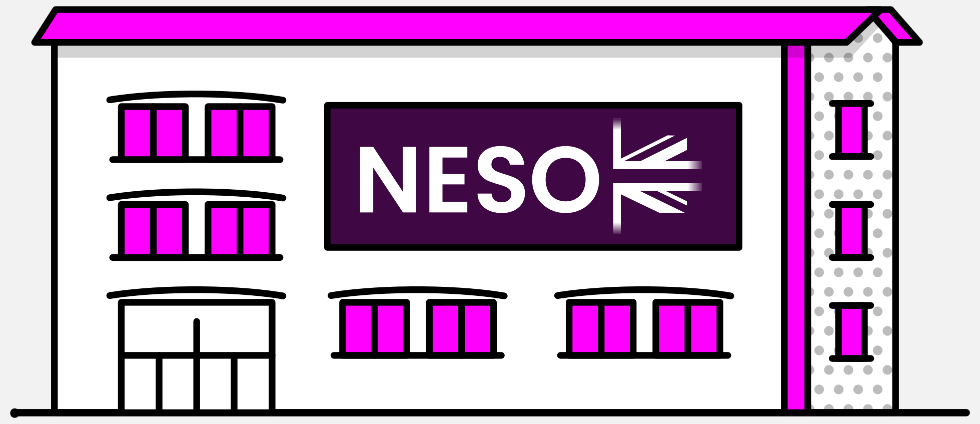
We are continuing to progress with launching our new day-ahead services allowing us to transition away from our legacy reserve services. Alongside this, we are prioritising options over the next few years to enhance and improve the efficiency of our procurement process through locational procurement, stacking and co-optimisation, as well as two Dynamic Reserve Setting projects.

We will also be further assessing the recommendations and outputs from our Demand Side Flexibility Routes to Market Review and Enabling Demand Side Flexibility in NESO Markets reports to allow us to prioritise reforms accordingly. Any changes to our delivery plans will be communicated through the monthly delivery plan section on our Markets Roadmap webpage.

- New services
- Locational procurement
- Revenue stacking
- Co-optimisation
- Dynamic Reserve Setting (national)
- Dynamic Reserve Setting (regional)

Co-optimisation

The Enduring Auction Capability (EAC) platform has allowed for co-optimisation of Quick Reserve with our dynamic response services further improving the efficiency of our overall frequency service procurement. It achieves this by selecting the most effective service for each asset where the asset owner has offered multiple services which can be delivered. The proposed Slow Reserve service is planned to be included in the co-optimised procurement, benefiting from the improved efficiency of the market clearing.



Market Reforms

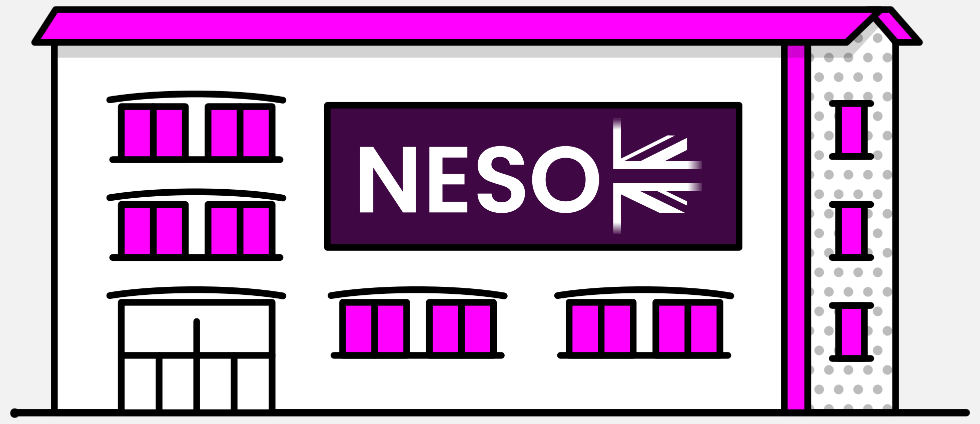
We are continuing to progress with launching our new day-ahead services allowing us to transition away from our legacy reserve services. Alongside this, we are prioritising options over the next few years to enhance and improve the efficiency of our procurement process through locational procurement, stacking and co-optimisation, as well as two Dynamic Reserve Setting projects.

We will also be further assessing the recommendations and outputs from our Demand Side Flexibility Routes to Market Review and Enabling Demand Side Flexibility in NESO Markets reports to allow us to prioritise reforms accordingly. Any changes to our delivery plans will be communicated through the monthly delivery plan section on our Markets Roadmap webpage.

- New services
- Locational procurement
- Revenue stacking
- Co-optimisation
- Dynamic Reserve Setting (national)
- Dynamic Reserve Setting (regional)

Dynamic Reserve Setting (national)

We started a Dynamic Reserve Setting (DRS) project with the Smith Institute in 2021 to move from our fixed reserve procurement volumes each day to a dynamic process which, considers at a national level any variations in our requirement. This dynamic profile uses probabilistic machine learning to provide a robust reserve recommendation, supported by an explanation of the factors impacting its suggestion such as weather, time of day and historical and future forecasts. DRS supports our Electricity Network Control Centre (ENCC) in balancing system security with reserve costs, leading to better optimised headroom management, unit dispatch and ultimately delivering better value for money to consumers.



Market Reforms

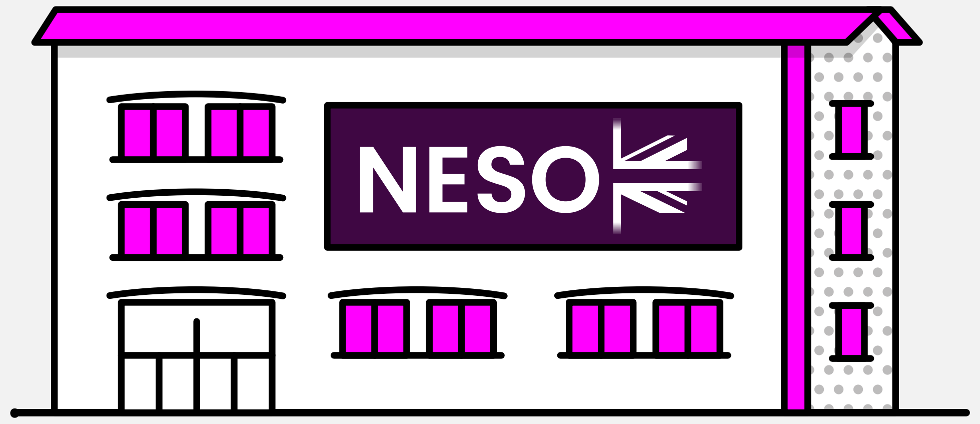
We are continuing to progress with launching our new day-ahead services allowing us to transition away from our legacy reserve services. Alongside this, we are prioritising options over the next few years to enhance and improve the efficiency of our procurement process through locational procurement, stacking and co-optimisation, as well as two Dynamic Reserve Setting projects.

We will also be further assessing the recommendations and outputs from our Demand Side Flexibility Routes to Market Review and Enabling Demand Side Flexibility in NESO Markets reports to allow us to prioritise reforms accordingly. Any changes to our delivery plans will be communicated through the monthly delivery plan section on our Markets Roadmap webpage.

- New services
- Locational procurement
- Revenue stacking
- Co-optimisation
- Dynamic Reserve Setting (national)
- Dynamic Reserve Setting (regional)

Dynamic Reserve Setting (regional)

The national Dynamic Reserve Setting (DRS) project has effectively estimated reserve requirements at the national level, balancing risk and cost. However, different locations across Great Britain need varying reserve amounts. To address this, in October 2024 we launched a regional DRS innovation project with Smith Institute. This project aims to estimate the feasibility of enhancing DRS by developing dynamic models that predict reserve needs at finer spatial resolutions. It is expected to end in September 2025. If regional DRS is found to be feasible, we will consider proceeding with an implementation project. Regional DRS may be able to reduce costs by procuring reserve where needed, lowering transmission losses, avoiding constraints that make reserve inaccessible, and allowing for offsetting reserve in neighbouring regions, further reducing overall costs while improving system security.



03

Securing the System

Stability

Introduction

What is stability?

Stability is the inherent ability of the system to quickly return to acceptable operation following a disturbance. The term is used to describe a broad range of topics, including inertia, short circuit level (SCL) and dynamic voltage support. If the system becomes unstable it could lead to a partial or total system shut down leading to the disconnection of consumers. To maintain power system stability, we need sufficient amounts of inertia, SCL and dynamic voltage support. We are obliged to have a minimum amount of inertia on the network, which along with frequency response services, maintains system frequency. From a more locational perspective, we are also required to ensure the system remains strong and resilient to disturbances by maintaining fault levels. Stability services have traditionally been provided by synchronous generation, which can contribute inertia and SCL when supplying the grid with electricity, as well as by dedicated network assets. However, some forms of low-carbon generation do not automatically provide the same level of stability needed by the network as they are non-synchronous. A summary of our future requirements can be found in the Operability Strategy Report & Clean Power 2030 document.

Stability webpages

How do we procure stability services?

Stability Markets (Long-term, Mid-term and Short-term)	Balancing Mechanism
Stability markets are part of our Network Services workstream, alongside voltage and constraint management intertrip services. The stability market design innovation project recommended the design of three stability markets (short-, mid-, and long-term). The long-term (Y-4) market is the enduring evolution of our three Stability Pathfinders, the last of which concluded in 2022. The mid-term (Y-1) market launched in 2023 and the short-term (D-1) market is undergoing further design work.	We use the Balancing Mechanism to schedule and dispatch units to meet minimum inertia levels when required, and maintain compliance with our Security and Quality of Supply Standard (SQSS) obligations. These actions offer close to real-time options for increasing inertia or managing local stability issues which can be common during periods of high invertor-based generation. The BM is flexible but can be expensive and may result in cheaper forms of generation being curtailed to make room for synchronous machines.

Summary

How is the landscape changing?

Our stability requirements are changing as more non-synchronous generation connects to the network and displaces synchronous generation. Our inertia requirements are becoming more dynamic as they fluctuate according to weather-driven generation and demand. In 2024, we reduced our minimum inertia operating threshold to 120 GVA.s and have proposals through the Frequency Risk and Control Report process to lower this further to 102 GVA.s which should reduce the volume of actions required to manage system stability. We also study the network to produce a view of locational stability such as short circuit levels and dynamic voltage which are also impacted by increased penetration of non-synchronous generation.

How have costs and volumes evolved in the last year?

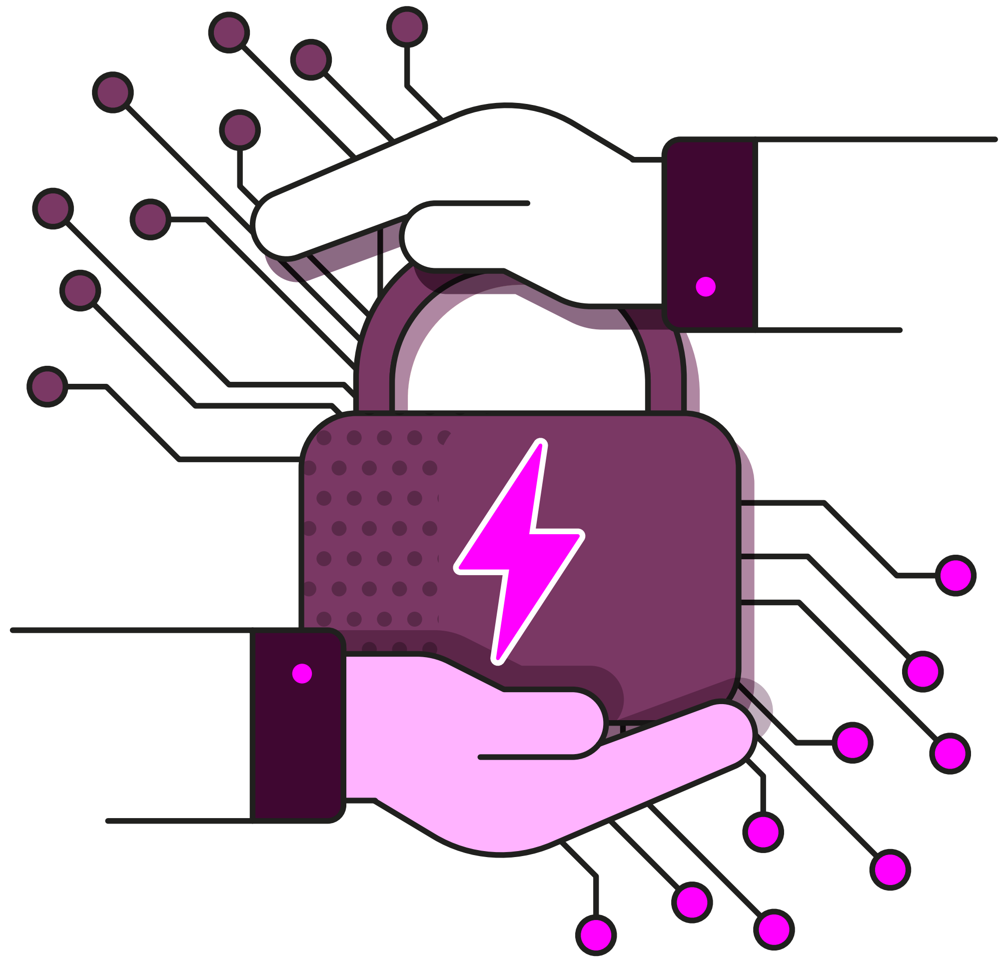
The volume of BM actions to increase system inertia has decreased by 11% in 2024 compared with the previous year. This corresponded with a much greater reduction (60%) in the costs associated with instructing BM units to synchronise. These trends are driven primarily by the reliable performance of assets contracted under Stability Pathfinder Phase 1, a reduction in the minimum inertia threshold to 120 GVA.s, and lower overall fuel costs for thermal synchronous generators.

What is driving the need for reform?

As with our other ancillary services markets, we are committed to procuring stability services more competitively and transparently versus the Balancing Mechanism counterfactual. Stability requirements have diurnal and seasonal trends which are sometimes difficult to predict; hence ensuring that sufficient capability is accessible to provide these services on a high-availability basis is very important to maintain system security. New technologies (e.g., grid-forming technology) and modifications to synchronous plant to be able to operate at 0 MW export (as well as new-build) present a significant opportunity to diversify our technology mix and meet our stability requirements more effectively.

How are we implementing market reform?

In 2023, we launched our first stability market – the mid-term (Y-1) market – for delivery from October 2025. In 2024 it was announced that this first tender procured 5 GVA.s inertia in total from five providers and is estimated to deliver consumer savings in excess of £47 m throughout the first delivery year. We have kicked-off the second delivery year (for delivery from October 2026) and an Invitation to Tender is now live for participants to submit bids. We are now launching the Long-term Stability Market through the Long-term 2029 Tender to meet future stability needs identified across Great Britain from 2029 onwards. For more information please see our Long-term 2029 webpages.



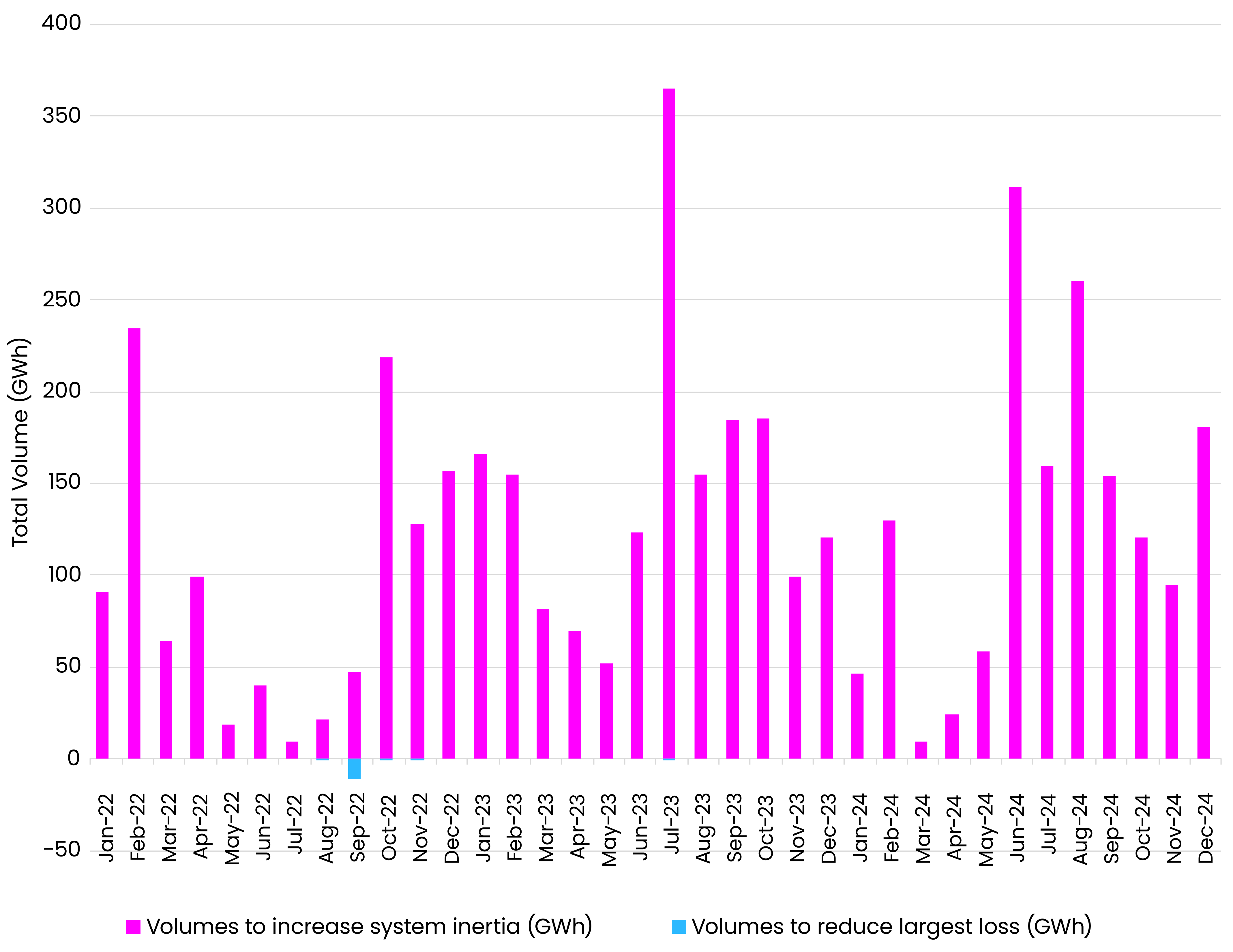
Volumes

Balancing Mechanism and trades

In the last 12 months, the volume of actions taken to increase system inertia (1,545 GWh) has decreased by 11% in comparison with 2023 (1,750 GWh). This figure does not include the contributions from Stability Pathfinder Phase 1 units which were all in service throughout 2024.

June 2024 had the highest amount of intervention (311 TWh) with March being the lowest (51 GWh). There were several changes in the minimum inertia policy throughout 2024, including an initial reduction from 140 GVA.s to 130 GVA.s at the end of February, followed by a further reduction to 120 GVA.s in June. The peak in Summer 2024 can be explained by increased NESO defensive measures put in place to manage sporadic sub-synchronous oscillation events. We have found no link between the existence of SSO and the amount of the inertia on the system; however actions taken to synchronise additional units to increase damping in the regions where SSO occurred, did coincidentally increase system inertia. Similarly, July 2023 remains a particular outlier for this reason too. These volumes and costs are very small in the wider context of balancing actions.

ST Figure 1: **Inertia management volumes Jan 2022 - Dec 2024**



Volumes

Stability Markets – Mid-term (Y-1) Market

In 2023, we launched the first round of the Mid-term (Y-1) Stability Market for delivery October 2025 to September 2026. A competitive tender process, comprising both technical and commercial assessments, ran throughout 2024 and awarded five contracts for the provision of 5 GVA.s inertia. All successful bidders were Great Britain Grid Forming – Synchronous (GBGF-S) providers. Details of the successful and unsuccessful bids can be found on our Mid-term (Y-1) Stability Market webpage.

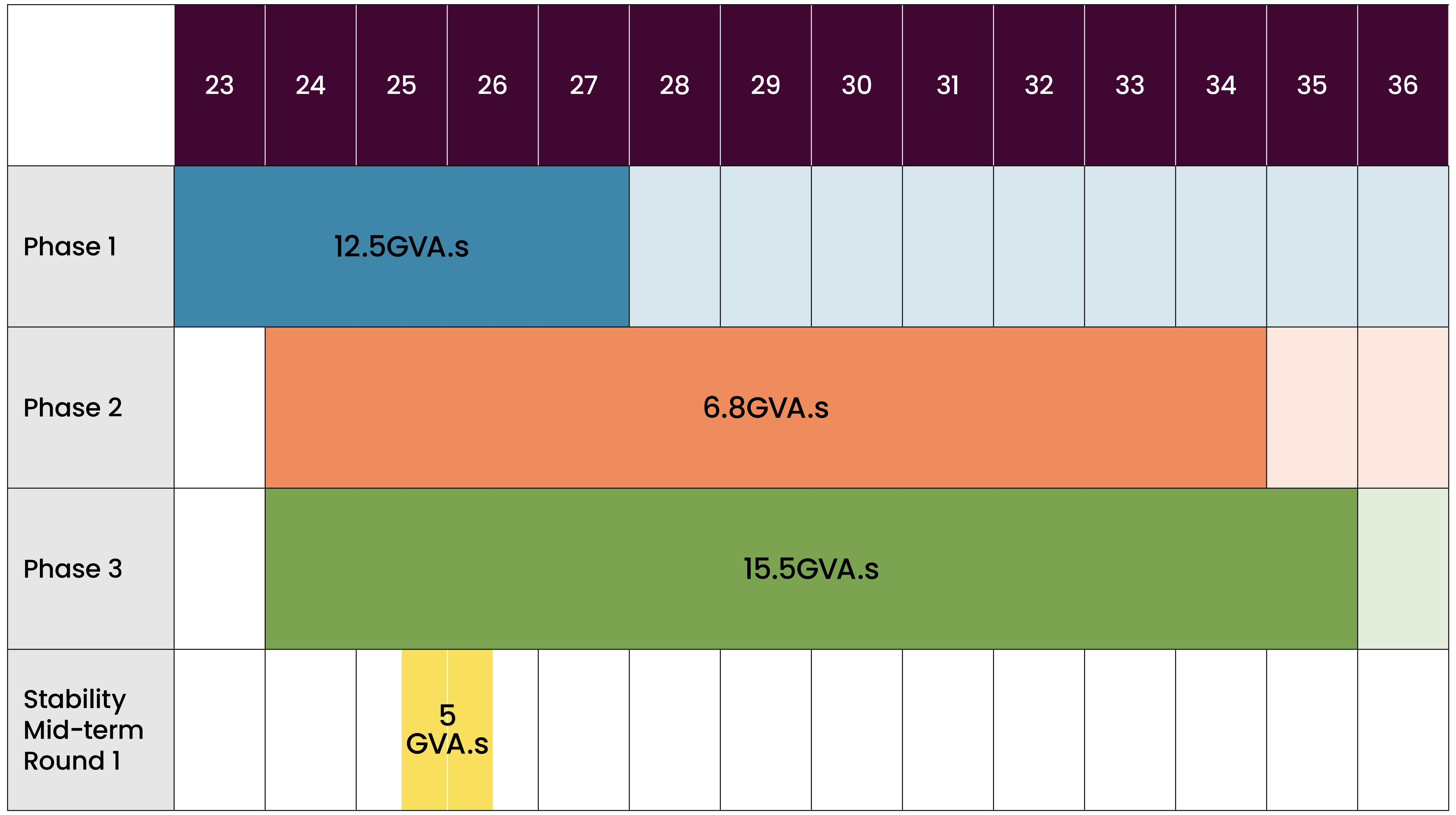
Stability Pathfinders

Units commissioned under Stability Pathfinder Phase 1 remained operational throughout 2024 and were utilised significantly to reduce actions required in the Balancing Mechanism. Detailed information on the availability and utilisation of all live pathfinder units is now published on the NESO Data Portal.

Whilst not directly procured in the last 12 months, new assets contracted under Stability Pathfinder Phase 2 are also continuing to go live. This includes the first ever grid-forming battery energy storage system at Blackhillock which will provide valuable inertia and SCL support in Scotland.

More information on the start of commercial operation of these units will be provided through the Operational Transparency Forum and the aforementioned utilisation dataset. In 2024, we also terminated 13 agreements which were signed as part of Stability Pathfinder Phase 3. You can find out more here.

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



Costs

Balancing Mechanism (BM)

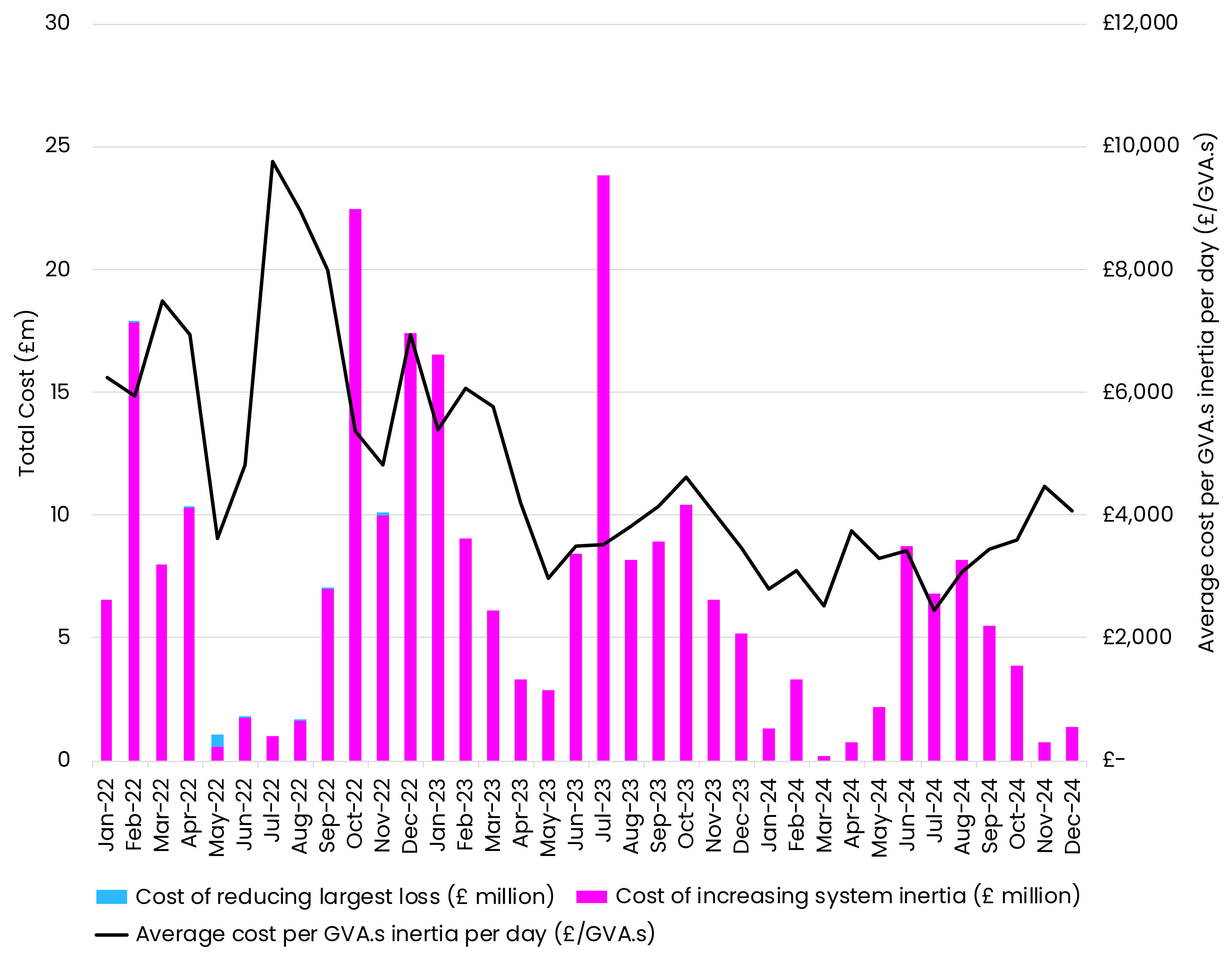
In alignment with the reduced volume of BM actions taken to increase system inertia, BM costs also decreased across 2024. This decrease equated to a 60% decline (£43 m) in comparison with 2023 (£109 m). The most expensive month was June and the least expensive March, in accordance with those being the months of highest and lowest NESO intervention respectively. Much of this reduction can be attributed to lower short-run marginal costs for thermal synchronous generators that were often instructed to increase system inertia. However, the reduction in minimum inertia policy from 140 GVA.s to 120 GVA.s has also had a marked impact.

The average cost per unit of inertia instructed in the BM (represented by the average total cost per GVA.s per day) was also lower in 2024 than in 2023 which suggests we not only took fewer actions in the BM, but they were also cheaper on average.

Stability Markets – Mid-term (Y-1) Market

The five contracts awarded as part of round 1 of the Mid-term (Y-1) Stability Market are anticipated to cost £25.3 m based on forecasted utilisation rates throughout the first delivery year (2025/26). Against the alternative options for increasing inertia on the network, we forecast that this could lead to consumer savings in excess of £47 m for the 12 months commencing October 2025. The award of these contracts will also help contribute to the stability of the GB power system using zero-carbon solutions.

ST Figure 3: **Inertia management costs Jan 2022 - Dec 2024**



Market Reforms

In our 2024 Markets Roadmap, we highlighted the rationale for launching the Mid-term (Y-1) Stability Market as a priority following the completion of the Stability Market Design Network Innovation Allowance innovation project. Previously, the only mechanism of accessing additional stability services was the BM and new long-term stability Network Services tenders, so this market was intended to provide a clear route to market for existing assets (and those in construction) to provide inertia on a high-availability basis. We are now launching the Long-term Stability Market through the Long-term 2029 Tender to meet future stability needs identified across Great Britain from 2029 onwards. For more information please see our Long-term 2029 webpages.

We are also currently working with industry to explore a Grid Code modification that would require newly connected Type D Generation Modules (50 MW and above and/or connected at 110 kV or above) and HVDC Systems to have grid-forming capability. This is a control technique that allows asynchronous resources to mimic the behaviour of traditional synchronous machines to provide SCL and inertia. This industry expert group met several times in 2024. The primary objective of this proposed mandate is to improve locational system strength, which is expected to deteriorate as large, grid-following, non-synchronous assets (e.g., offshore wind, HVDC links) continue to connect to the system. It is not expected to mandate a minimum inertia quantity, so any code modification will be developed in harmony with our suite of stability markets. The long-term market will also remain our primary tool for accessing additional SCL in regions where a mandate would not be effective.

Long-term (Y-4) Stability Market

Mid-term (Y-1) Stability Market

Short-term (D-1) Stability Market

Long-term (Y-4) Stability Market

We have identified system needs for stability from 2029 onwards and have recently launched the new Long-term 2029 Tender. This tender constitutes the launch of the first tender as part of the long-term (Y-4) stability market, whilst simultaneously procuring reactive power and restoration services via a bundled tender process. More information on the launch of this tender can be found on our dedicated Long-term 2029 webpage.

Market Reforms

In our 2024 Markets Roadmap, we highlighted the rationale for launching the Mid-term (Y-1) Stability Market as a priority following the completion of the Stability Market Design Network Innovation Allowance innovation project. Previously, the only mechanism of accessing additional stability services was the BM and new long-term stability Network Services tenders, so this market was intended to provide a clear route to market for existing assets (and those in construction) to provide inertia on a high-availability basis. We are now launching the Long-term Stability Market through the Long-term 2029 Tender to meet future stability needs identified across Great Britain from 2029 onwards. For more information please see our Long-term 2029 webpages.

We are also currently working with industry to explore a Grid Code modification that would require newly connected Type D Generation Modules (50 MW and above and/or connected at 110 kV or above) and HVDC Systems to have grid-forming capability. This is a control technique that allows asynchronous resources to mimic the behaviour of traditional synchronous machines to provide SCL and inertia. This industry expert group met several times in 2024. The primary objective of this proposed mandate is to improve locational system strength, which is expected to deteriorate as large, grid-following, non-synchronous assets (e.g., offshore wind, HVDC links) continue to connect to the system. It is not expected to mandate a minimum inertia quantity, so any code modification will be developed in harmony with our suite of stability markets. The long-term market will also remain our primary tool for accessing additional SCL in regions where a mandate would not be effective.

Long-term (Y-4) Stability Market

Mid-term (Y-1) Stability Market

Short-term (D-1) Stability Market

Mid-term (Y-1) Stability Market

Following the successful completion of the first mid-term market delivery year (2025/26) which procured 5 GVA.s inertia, we have launched the tender for the second delivery year (2026/27). This is seeking to procure 15 GVA.s inertia between October 2026 and September 2027. We are now in the Invitation to Tender (ITT) stage, which is due to close on 16 May 2025. We anticipate new, capable assets will enter the market this year so the main objective for the mid-term market is to grow market liquidity and meet our inertia needs as cheaply as possible. Notable changes from the first delivery year include an amendment to the payment mechanism for GBGF-I providers, as well as a revised approach to calculating liquidated damages, acting on feedback we have received from market participants that these could be calculated more proportionately.

Market Reforms

In our 2024 Markets Roadmap, we highlighted the rationale for launching the Mid-term (Y-1) Stability Market as a priority following the completion of the Stability Market Design Network Innovation Allowance innovation project. Previously, the only mechanism of accessing additional stability services was the BM and new long-term stability Network Services tenders, so this market was intended to provide a clear route to market for existing assets (and those in construction) to provide inertia on a high-availability basis. We are now launching the Long-term Stability Market through the Long-term 2029 Tender to meet future stability needs identified across Great Britain from 2029 onwards. For more information please see our Long-term 2029 webpages.

We are also currently working with industry to explore a Grid Code modification that would require newly connected Type D Generation Modules (50 MW and above and/or connected at 110 kV or above) and HVDC Systems to have grid-forming capability. This is a control technique that allows asynchronous resources to mimic the behaviour of traditional synchronous machines to provide SCL and inertia. This industry expert group met several times in 2024. The primary objective of this proposed mandate is to improve locational system strength, which is expected to deteriorate as large, grid-following, non-synchronous assets (e.g., offshore wind, HVDC links) continue to connect to the system. It is not expected to mandate a minimum inertia quantity, so any code modification will be developed in harmony with our suite of stability markets. The long-term market will also remain our primary tool for accessing additional SCL in regions where a mandate would not be effective.

Long-term (Y-4) Stability Market

Mid-term (Y-1) Stability Market

Short-term (D-1) Stability Market

Short-term (D-1) Stability Market

The launch of the Mid-Term (Y-1) Stability Market was prioritised above other stability market development to provide additional certainty to NESO in terms of securing firm access to inertia capability but also added certainty for market participants via longer duration agreements. The design of the short-term (D-1) stability market is intended to facilitate further competition close to real-time and top up capacity procured via the mid-term market. Progressing the short-term market depends on whether a system requirement exists closer to real-time and whether there are eligible market participants capable of delivering additional inertia to that assumed in the background. We have recently identified some technical challenges in relation to whether assets with grid-forming technologies will be able to provide variable inertia under the current compliance and grid code rules. We are keen to discuss this with industry further and will signpost engagement opportunities on our short-term market webpage.

Voltage

Introduction

What is voltage?

Voltage refers to the "pressure" or "driving force" that pushes electrical current through the transmission network, and is measured in volts. We manage the voltage of the transmission system by either absorbing or injecting reactive power onto the network. Doing so permits NESO to maintain safe and efficient operations in adherence to our Security and Quality Supply Standards (SQSS).

Reactive requirements are forecasted to increase from 2,450 MVAr in 2027 to 6,900 MVAr in 2032. Voltage requirements are also highly locational; a provider in one region may not be able to alter the voltage levels in another part of the country.

For the latest breakdown of our regional requirements, please refer to the Operability Strategy Report (OSR).

This growing requirement is primarily driven by an increase in renewable generation which is connecting often away from demand centres. Simultaneously, the increased contribution from renewables is reducing the volume of self-dispatching synchronous generation which typically provides voltage support close to where it is needed.

How do we access voltage services?

- Self-dispatching generation
- Network Assets
- Balancing Mechanism and Trades
- Network Services (formerly called pathfinders)
- Short-Term Tenders

Self-dispatching generation: The Grid Code mandates all transmission-connected[1] generators to have a minimum capability to both absorb and inject reactive power, though this differs between generator types. Traditional synchronous generating units are mandated to provide reactive power services over their full operating range (i.e. from their Stable Export Limit (SEL) to their Maximum Export Limit (MEL)). For Offshore Transmission Owners (OFTOs), System Operator Transmission Code (STC) modification CM085 has been approved which will require these assets to provide access to reactive power capability when windfarm output is <20%. This is estimated to save £48-65 m in 2027 alone by displacing the need to invest in physical infrastructure. Assets are currently paid the Obligatory Reactive Power Services (ORPS) price.

1 Distributed connected assets may also have obligations to provide lead and lag capabilities, e.g., as part of their Grid Code obligations.

Introduction

What is voltage?

Voltage refers to the "pressure" or "driving force" that pushes electrical current through the transmission network, and is measured in volts. We manage the voltage of the transmission system by either absorbing or injecting reactive power onto the network. Doing so permits NESO to maintain safe and efficient operations in adherence to our Security and Quality Supply Standards (SQSS).

Reactive requirements are forecasted to increase from 2,450 MVAr in 2027 to 6,900 MVAr in 2032. Voltage requirements are also highly locational; a provider in one region may not be able to alter the voltage levels in another part of the country.

For the latest breakdown of our regional requirements, please refer to the Operability Strategy Report (OSR).

This growing requirement is primarily driven by an increase in renewable generation which is connecting often away from demand centres. Simultaneously, the increased contribution from renewables is reducing the volume of self-dispatching synchronous generation which typically provides voltage support close to where it is needed.

How do we access voltage services?

- Self-dispatching generation
- Network Assets
- Balancing Mechanism and Trades
- Network Services (formerly called pathfinders)
- Short-Term Tenders

Network Assets: Transmission Owners (TO) and commercial providers can provide MVArs when required from network assets such as shunt reactors, static synchronous compensators and capacitors. Where NESO identifies voltage needs, it may seek to meet this through commercial routes such as Network Services tenders or instruct the relevant TOs to build assets. Alternatively, the TOs themselves may seek to build assets subject to approval from Ofgem.

Introduction

What is voltage?

Voltage refers to the "pressure" or "driving force" that pushes electrical current through the transmission network, and is measured in volts. We manage the voltage of the transmission system by either absorbing or injecting reactive power onto the network. Doing so permits NESO to maintain safe and efficient operations in adherence to our Security and Quality Supply Standards (SQSS).

Reactive requirements are forecasted to increase from 2,450 MVAr in 2027 to 6,900 MVAr in 2032. Voltage requirements are also highly locational; a provider in one region may not be able to alter the voltage levels in another part of the country.

For the latest breakdown of our regional requirements, please refer to the Operability Strategy Report (OSR).

This growing requirement is primarily driven by an increase in renewable generation which is connecting often away from demand centres. Simultaneously, the increased contribution from renewables is reducing the volume of self-dispatching synchronous generation which typically provides voltage support close to where it is needed.

How do we access voltage services?

- Self-dispatching generation
- Network Assets
- Balancing Mechanism and Trades
- Network Services (formerly called pathfinders)
- Short-Term Tenders

Balancing Mechanism and Trades: When reactive power services are required, but there are no suitable providers self-dispatching, we will synchronise units through bids/offers within the Balancing Mechanism, or pre-gate closure trading where cost effective. Units dispatched typically must alter their output to provide the intended reactive power service, therefore we pay units both a synchronisation cost (the bid/offer price) and a utilisation price (the ORPS price). Instructing a unit to synchronise may cause a system imbalance, such that we instruct another asset to turn up/down to ensure the system remains in balance.

Introduction

What is voltage?

Voltage refers to the “pressure” or “driving force” that pushes electrical current through the transmission network, and is measured in volts. We manage the voltage of the transmission system by either absorbing or injecting reactive power onto the network. Doing so permits NESO to maintain safe and efficient operations in adherence to our Security and Quality Supply Standards (SQSS).

Reactive requirements are forecasted to increase from 2,450 MVAr in 2027 to 6,900 MVAr in 2032. Voltage requirements are also highly locational; a provider in one region may not be able to alter the voltage levels in another part of the country.

For the latest breakdown of our regional requirements, please refer to the Operability Strategy Report (OSR).

This growing requirement is primarily driven by an increase in renewable generation which is connecting often away from demand centres. Simultaneously, the increased contribution from renewables is reducing the volume of self-dispatching synchronous generation which typically provides voltage support close to where it is needed.

How do we access voltage services?

- Self-dispatching generation
- Network Assets
- Balancing Mechanism and Trades
- Network Services (formerly called pathfinders)
- Short-Term Tenders

Network Services (formerly called pathfinders): Following the success and learnings of NESO’s pathfinders, we have continued to competitively procure locational reactive power requirements under the Network Services programme as a route to market. These tenders focus on locational reactive power needs in certain areas of the network. See the results of our latest competitive tender, Voltage 2026, here. Network Services is designed to promote competition between TOs and the market to provide competitive alternatives to the Balancing Mechanism.

Introduction

What is voltage?

Voltage refers to the "pressure" or "driving force" that pushes electrical current through the transmission network, and is measured in volts. We manage the voltage of the transmission system by either absorbing or injecting reactive power onto the network. Doing so permits NESO to maintain safe and efficient operations in adherence to our Security and Quality Supply Standards (SQSS).

Reactive requirements are forecasted to increase from 2,450 MVAr in 2027 to 6,900 MVAr in 2032. Voltage requirements are also highly locational; a provider in one region may not be able to alter the voltage levels in another part of the country.

For the latest breakdown of our regional requirements, please refer to the Operability Strategy Report (OSR).

This growing requirement is primarily driven by an increase in renewable generation which is connecting often away from demand centres. Simultaneously, the increased contribution from renewables is reducing the volume of self-dispatching synchronous generation which typically provides voltage support close to where it is needed.

How do we access voltage services?

- Self-dispatching generation
- Network Assets
- Balancing Mechanism and Trades
- Network Services (formerly called pathfinders)
- Short-Term Tenders

Short-Term Tenders: NESO reserves the right to run short-term tenders when a temporary reactive power need is identified, for example to cover a generator or transmission asset outage.

Summary

How is the landscape changing?

In Markets Roadmap 2024, we reported on a residual requirement of 1,300 MVAr by 2025. Reactive requirements are forecasted to increase from 2,450 MVAr in 2027 to 6,900 MVAr in 2032. See the 2025 OSR for more details and a regional breakdown.

How have costs and volumes evolved over the last year?

Costs and volumes for reactive power instructions are classed as either synchronisation or utilisation.

Synchronisation volumes in the Balancing Mechanism (BM) rose by 28.3%, reflecting a greater intervention by NESO in BM or via trades to access additional reactive power from assets not self-dispatching. Utilisation volumes are further split into lead or lag, and these decreased by 8.6% and increased by 8.9% respectively.

Total costs reduced by 30.4%, comprising of a £86.3 m and £64.4 m reduction in utilisation and synchronisation costs respectively. These savings primarily stem from lower wholesale prices across 2024, MVArs provided by self-dispatching units when/where required and economic assets through Pathfinders going live.

What is driving the need for reform?

NESO reforms are primarily driven by the changing technological landscape. Namely, the continued connection of generation far from demand centres, displacement of self-dispatching synchronous generation and demand for reactive power on the distribution network has decreased, shifting many regions from importing to exporting. The drive for greater competition, more transparency and lower system costs, provides a clear case for change and the need for market and code reform(s).

How are we implementing market reform?

Over the past year, we have progressed various market reforms.

The Future of Reactive Power project:

1. Long-Term (Y-4) market: System studies have been completed and we have recently launched the Long-term Voltage Market through the Long-term 2029 Tender. More information can be found here.

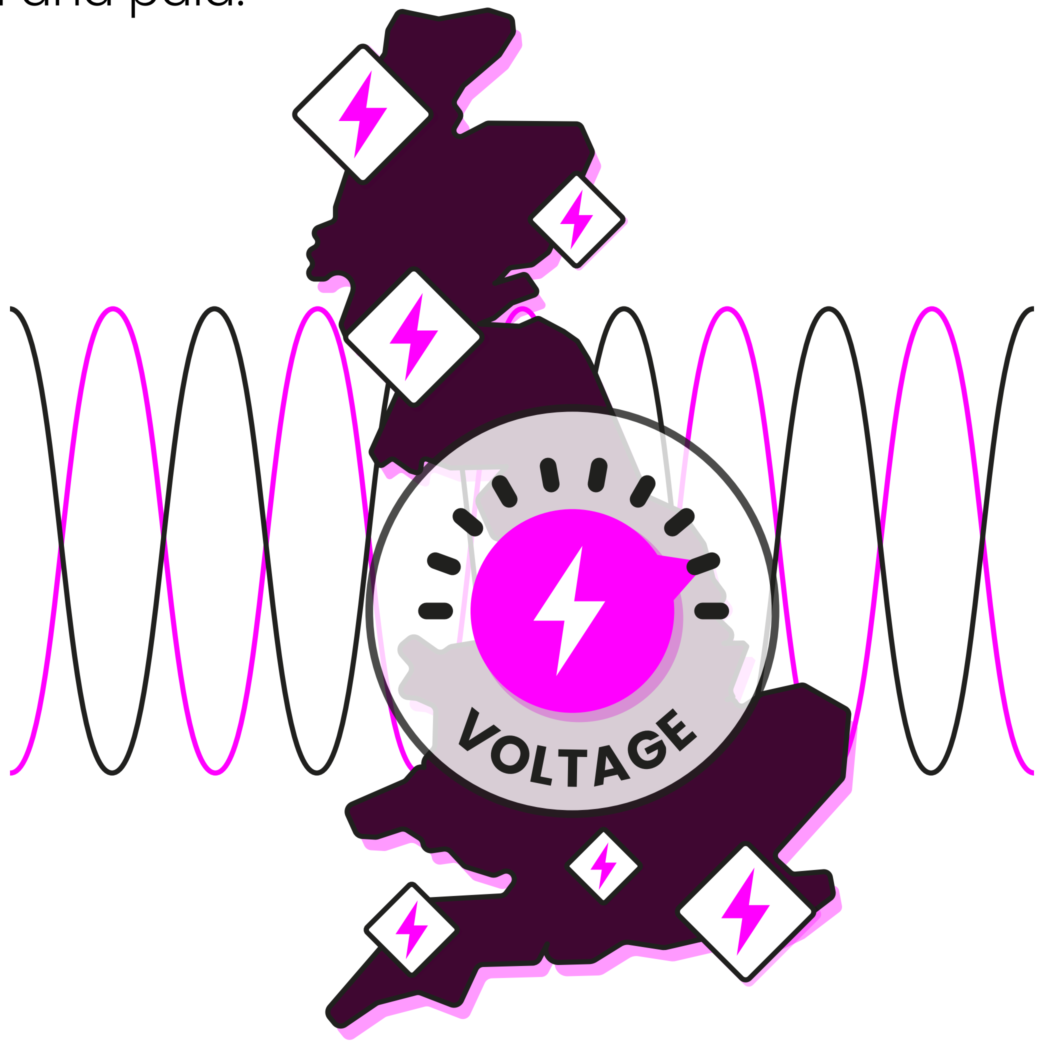
2. Mid-Term (Y-1) market: We have continued to assess the merits/drawbacks of implementing this market. We will be announcing our recommendation in Q1 2025.

3. Short-Term (D-1) market: We will continue to assess the feasibility of a short-term market, however the development of this market is currently on hold until completion of the Obligatory Reactive Power Service (ORPS) review.

Throughout 2024, we have also explored a mid-term reactive power market in more detail and the long-term market is ready to implement when a need arises.

Our Network Services tender, Voltage 2026, has successful contracted 200 MVAr and 446 MVAr of effective absorption in London and the North of England respectively. The combination of shunt reactors and Battery Energy Storage Systems (BESS) will deliver a forecasted consumer saving of £318 m across the 10-year period, whilst aligning with the Governments Clean Power 2030 ambitions.

Our review of the ORPS payment methodology is underway, with the aim of deriving value for consumers through identifying potential reforms to how ORPS is designed, calculated and paid.



Volumes

Balancing Mechanism: Synchronisation and Utilisation

Over 2024, reactive power utilisation volumes rose by 8.9% for lag actions and decreased by 8.6% for lead (VT Figure 1). As in previous years, there is a clear seasonal requirement, with greater lead actions needed during the summer months and lag actions during the winter period. This continues the trend of NESO actions being primarily lead actions (absorption of reactive power).

Synchronous volumes rose by 23.8% compared to 2023. As shown in VT Figure 2, instructions to synchronous units peaked during the summer. This was especially evident in Southwest England where reactive power issues were exacerbated by network and generator outages.

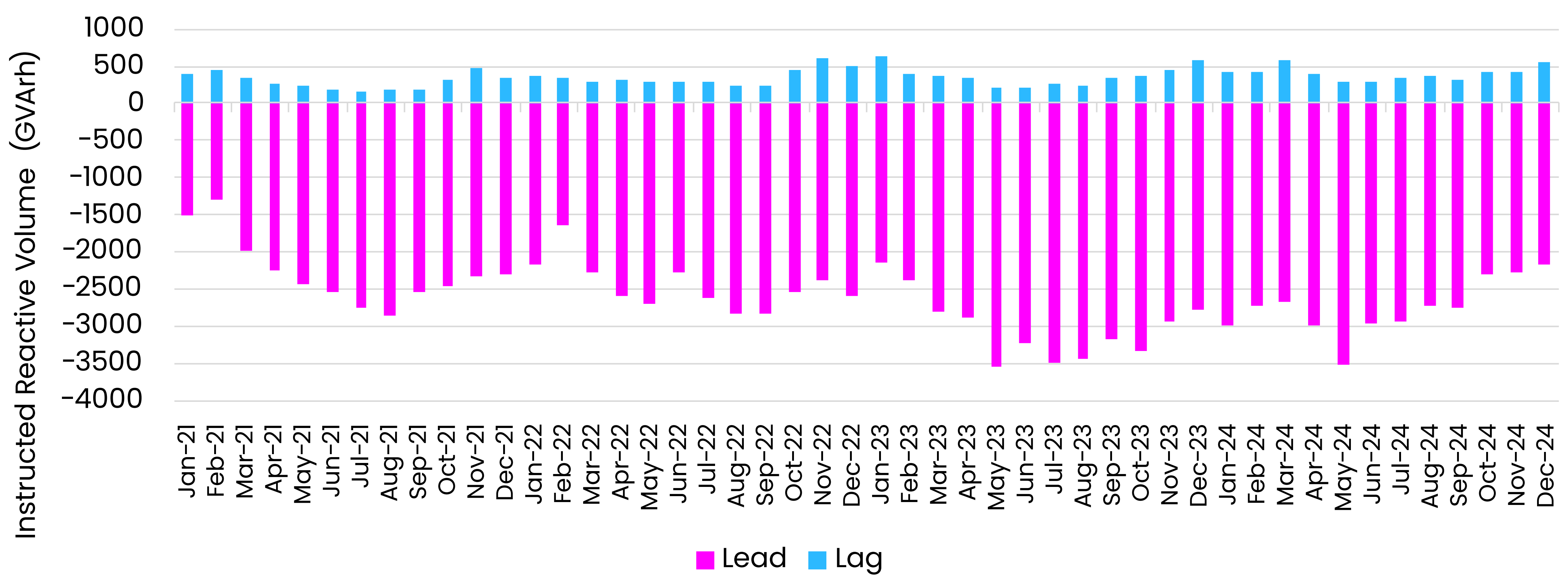
However, this rise is not witnessed everywhere. As demonstrated in both VT Figure 3a and 3b, specific regions have witnessed a decrease in NESO instructions in 2024.

Compared to the previous year, 2024 witnessed an overall increase in the % of reactive power requirements being met by zero carbon assets.

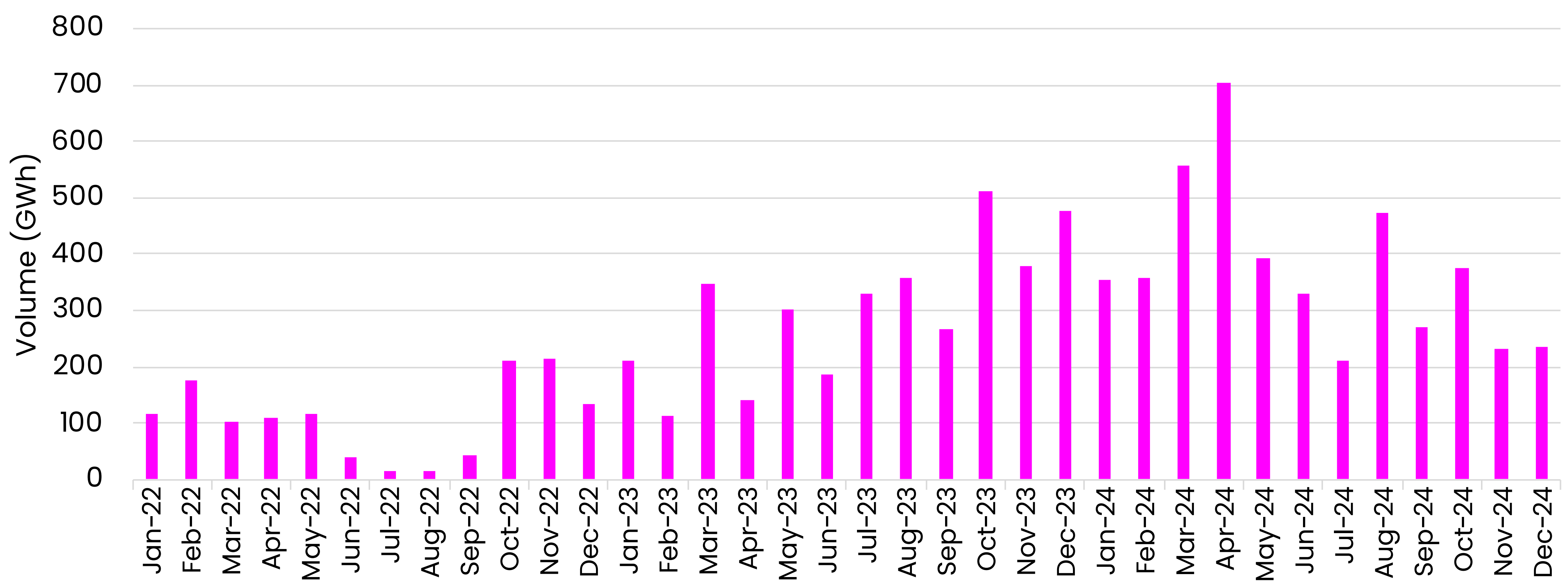
For example, CCGT lead contributions in the Midlands and North regions fell by 17.8% and 31.2% respectively. Across these regions, contributions from nuclear, synchronous compensators, hydro/pumped storage and batteries increased.

Scotland's lead and lag requirements continue to be met predominantly by wind, nuclear and hydro/pumped storage.

VT Figure 1: Lead and lag volumes



VT Figure 2: Voltage synchronisation offers



Volumes

Network Services volumes

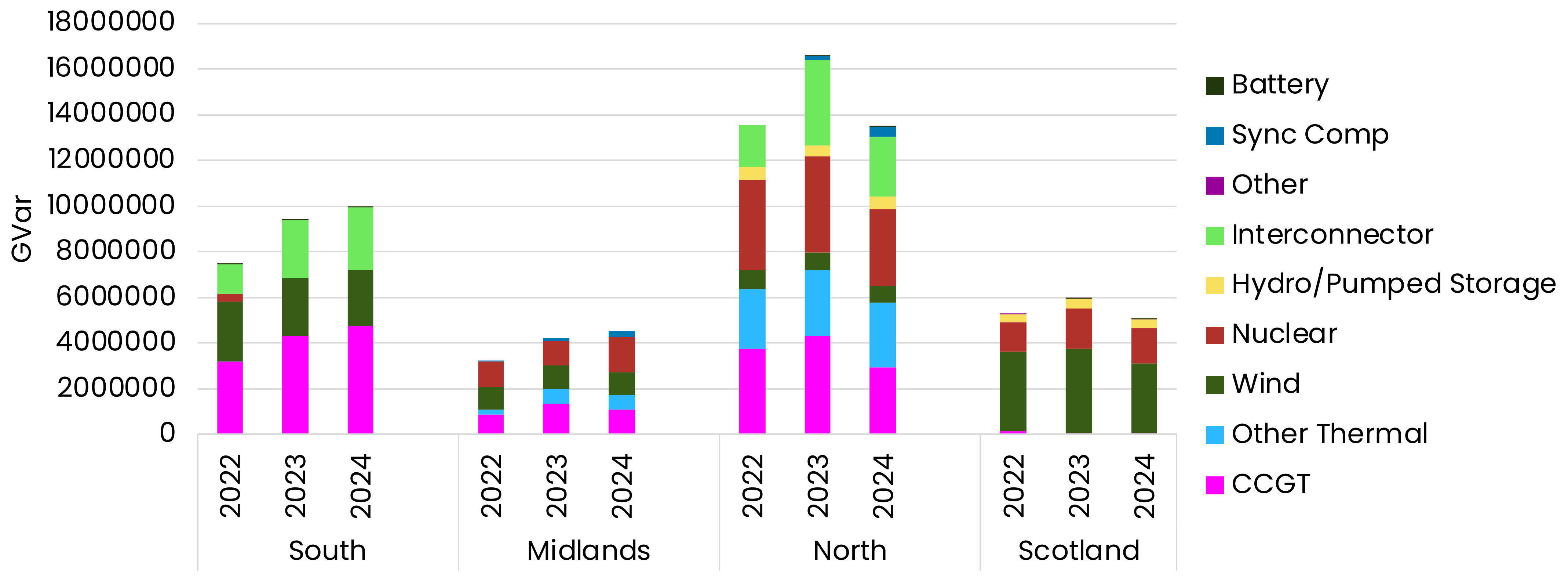
The successful units from the Voltage Mersey Pathfinder, a battery facility and a reactor, are operational in the North region. This represents 240 MVAr of reactive power volume within the Mersey region and reduces our reliance on other generation in the area (as evidenced by the drop in requirements shown in VT Figure 3a and 3b).

The successful units from the Voltage Pennines Pathfinder, a mix of TO assets which are now operational and the Dogger Bank offshore wind farm which is expected to go live next year will provide a total of 700 MVAr of reactive power volume to the North region.

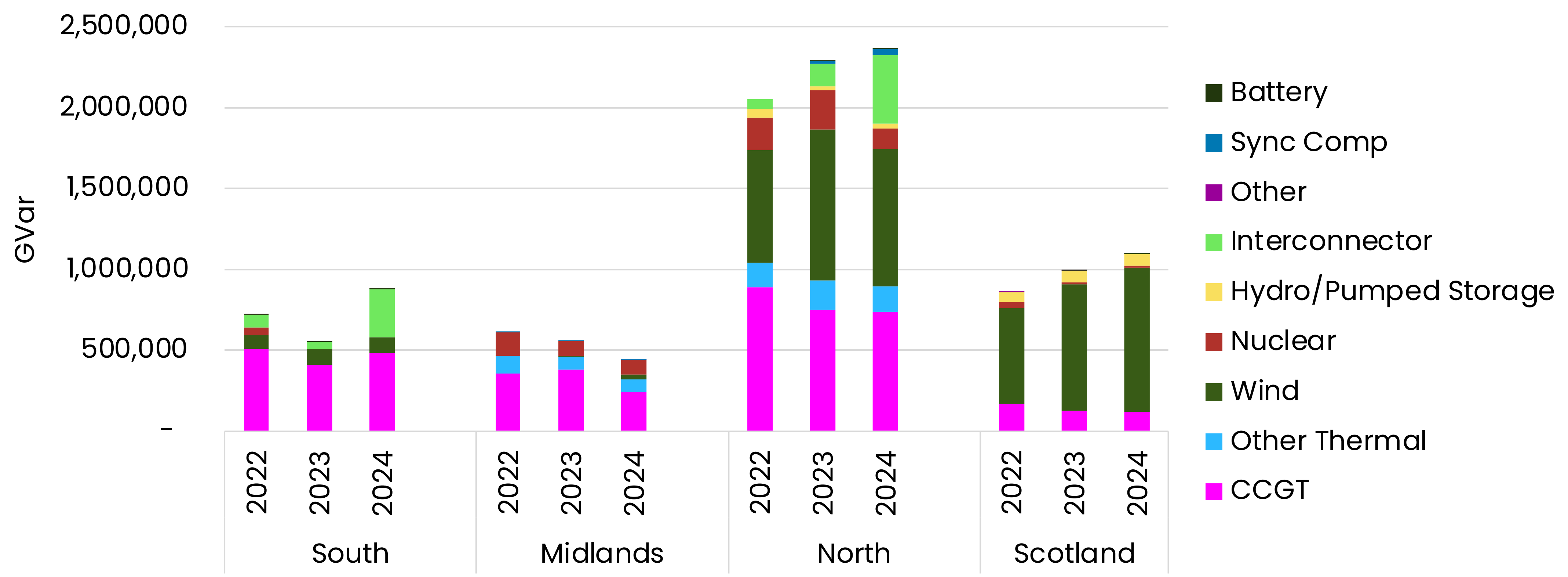
At the end of 2024, NESO announced the results of the Voltage 2026 tender. Three battery units and a shunt reactor will provide 646 MVAr (464 MVAr in the North of England and 200 MVAr in London) of reactive power volume from 2026 onwards.

All Network Service units contracted to date have been zero carbon, supporting our 2025 zero carbon operability ambition and the 2030 Clean Power Plan.

VT Figure 3a: Lead providers by technology and region 2022-2024



VT Figure 3b: Lag providers by technology and region 2021-2023



Please note that the chart scales in VT Figures 3a and 3b differ. This is to allowing clearer illustration of the contributing technologies. Volumes presented here have been updated, validated and re-categorised from last years markets roadmap. This includes the addition of Synchronous Compensators, or 'Sync Comps'. These updates have been backdated from 2021. The volumes illustrated in VT Figure 3a and 3b do not include contributions from Pathfinders.

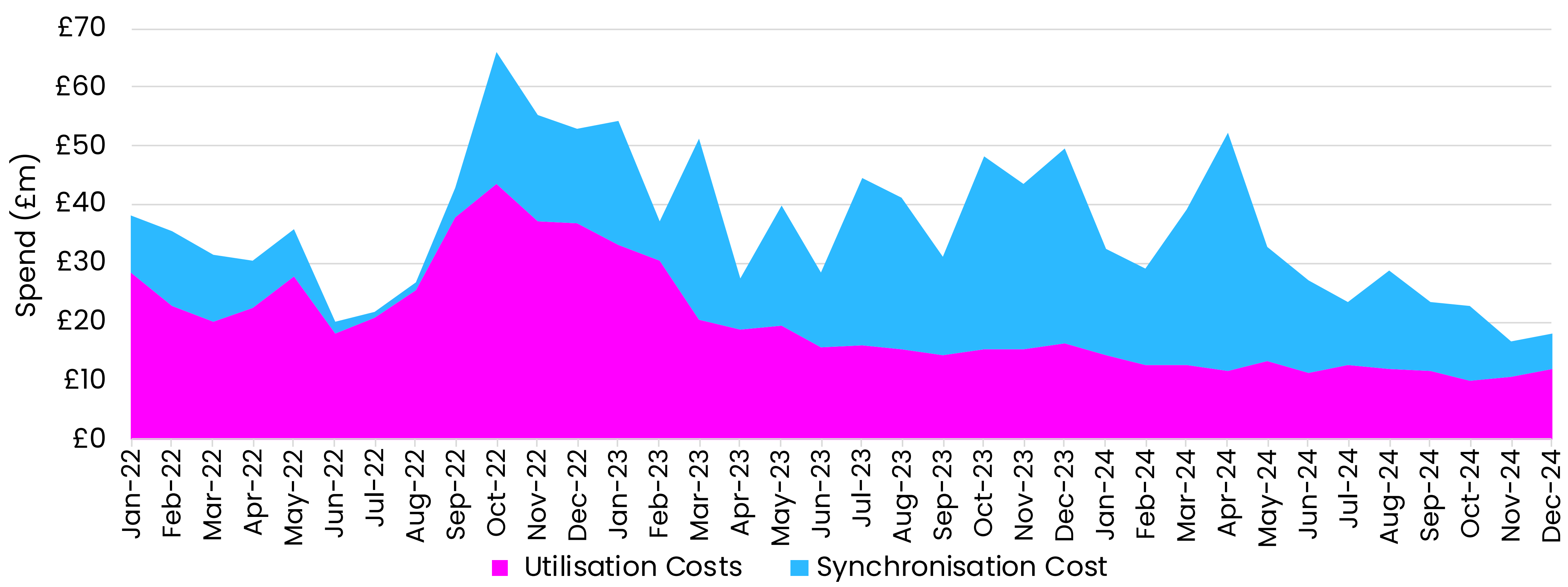
Costs

Balancing Mechanism: Synchronisation and Utilisation

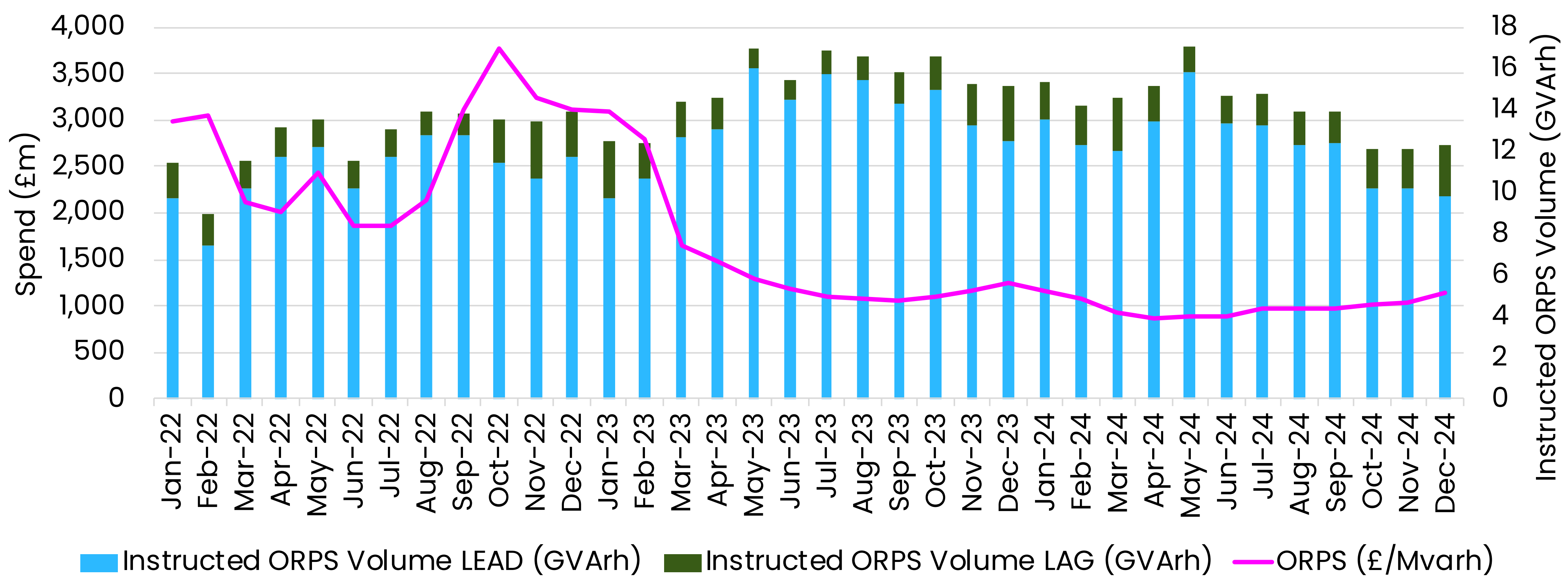
When compared to 2023, VT Figure 4 illustrates how the utilisation costs have decreased by 37.5%. This is largely a result of the stabilisation of gas prices following the peak levels experienced in 2022/23. Similarly, synchronisation costs have also decreased, by 24.2%, reflecting greater periods of MVArs provision from self-dispatching units and Pathfinder assets going live. As shown in VT Figure 5, lead instructions continue to dominate, whilst ORPS prices have remained relatively static across 2024.

We have also provided some additional insight into the regional differences in reactive power. As illustrated in VT Figure 6 the Southwest region has experienced high costs recently due to specific network outages and limited alternative supply of reactive power in the region. We expecting the cost of managing reactive power needs in the Southwest to be lower in 2025, owing to the energising of an interconnector in the region and new network assets connecting.

VT Figure 4: Synchronisation and utilisation costs 2022-2024

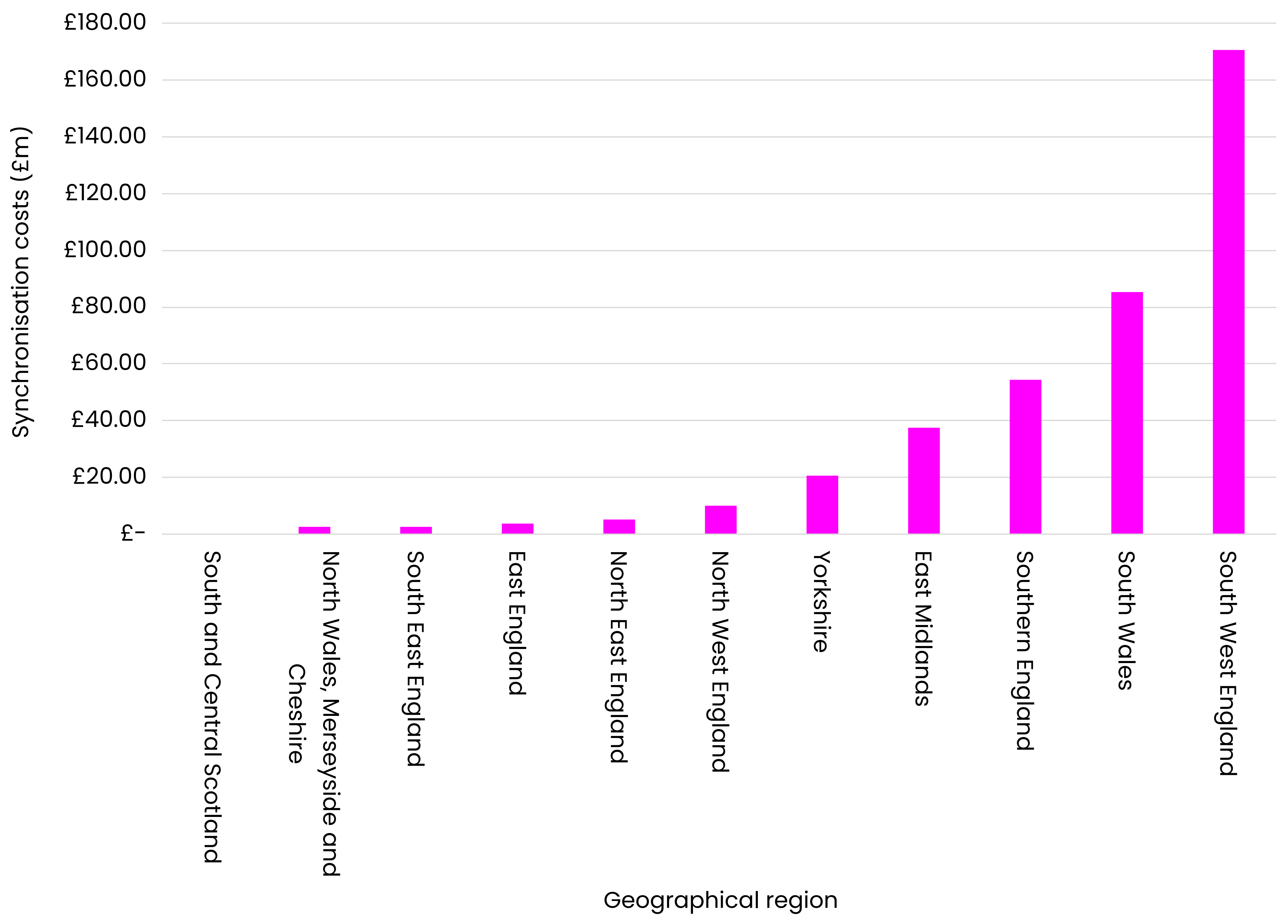


VT Figure 5: Lead and lag dispatch instructions (GVArh) & the cost of ORPS (£/MVArh)



Costs

VT Figure 6: **Synchronisation costs per region in 2024**



Network Services costs

At the end of 2024, NESO announced the tender results of Voltage 2026. These four contracts are worth a combined £83 m and will deliver forecasted consumer savings of £318 m across the ten-year contract period.

The successful units from the Voltage Pennines Pathfinder, a mix of TO assets and the Dogger Bank offshore wind farm, are expected to deliver multi-million pounds of consumer benefit. Similarly, the Mersey Pathfinder contracts which started in 2022 continue to delivery balancing cost savings, mainly attributed to the use of these contracted assets as opposed to using the Balancing Mechanism.

Market Reforms

NESO has progressed several market reforms which will enable us to secure reactive power services in an increasingly competitive, transparent and cost-effective manner.

Future of Reactive Power Long-term

Future of Reactive Power Mid-term

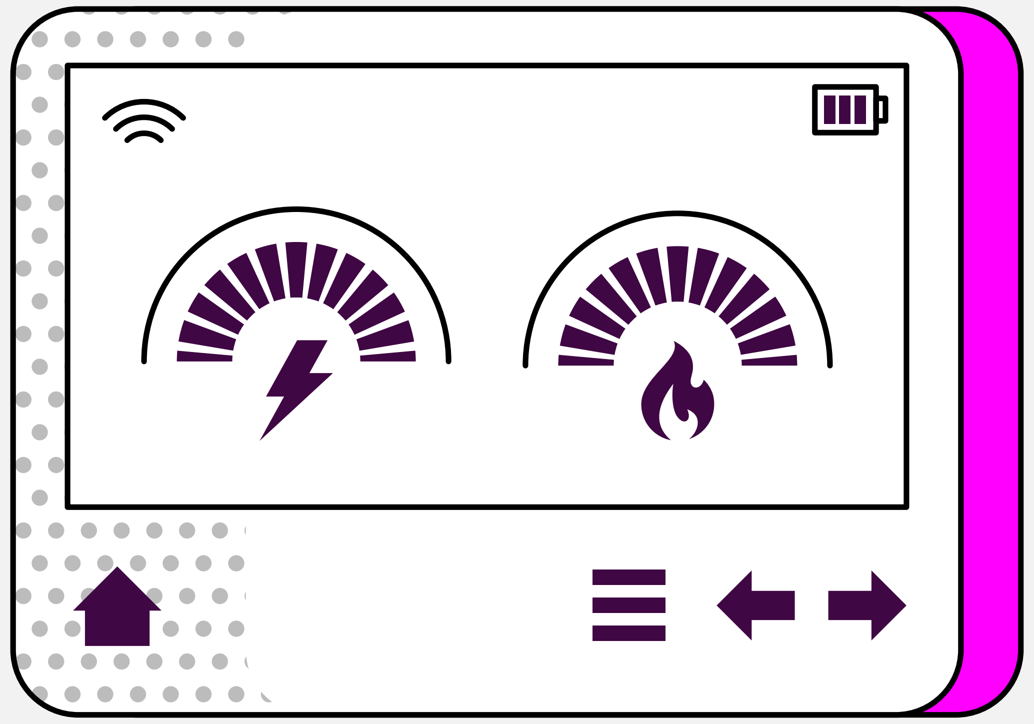
Future of Reactive Power Short-term

Review of Obligatory reactive power service (ORPS)

Future of Reactive Power: Throughout 2024, there has been progress in the design of three possible reactive power markets; Long-term (Y-4), Mid-term (Y-1) and Short-term (D-1).

Long-term (Y-4): Using the learnings from previous pathfinders, the long-term reactive power market will launch under the Network Services programme.

- Implementing the long-term reactive power market will drive locational investment and enable greater competition in the delivery of reactive power service provision.
- We have identified system needs for voltage from 2029 onwards and have recently launched the new Long-term 2029 Tender. This tender constitutes the launch of the first tender as part of the long-term (Y-4) reactive power market, whilst simultaneously procuring stability and restoration services via a bundled tender process. More information on the launch of this tender can be found on our dedicated Long-term 2029 webpage.



Market Reforms

NESO has progressed several market reforms which will enable us to secure reactive power services in an increasingly competitive, transparent and cost-effective manner.

Future of Reactive Power Long-term

Future of Reactive Power Mid-term

Future of Reactive Power Short-term

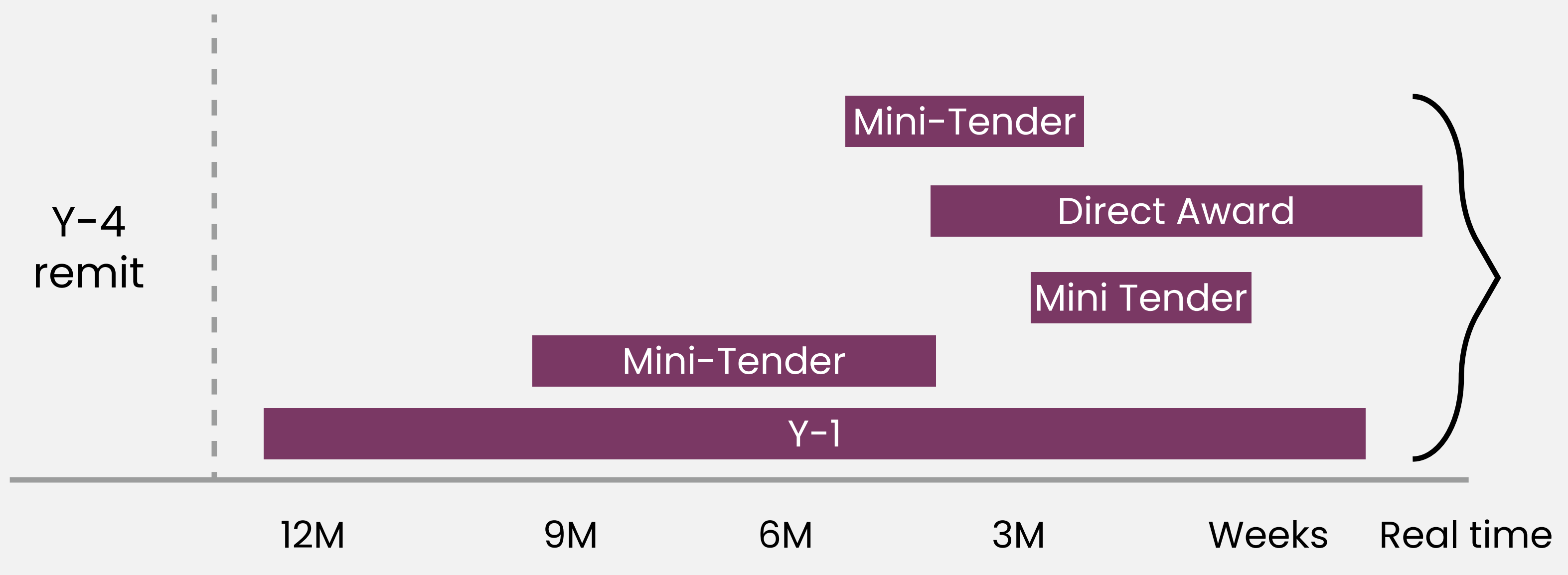
Review of Obligatory reactive power service (ORPS)

Future of Reactive Power: Throughout 2024, there has been progress in the design of three possible reactive power markets; Long-term (Y-4), Mid-term (Y-1) and Short-term (D-1).

Mid-term: NESO are continuing the assess the efficacy of introducing a mid-term reactive power market. The decision is expected at the end of Q1 2025.

As detailed in our November webinar, the current design under review consists of three routes to market:

- Y-1 tender: Where an economic opportunity presents itself on a yearly basis, and there is sufficient competition, eligible assets in the location of need will be invited to bid in for this tender process.
- Mini-tender: Where a need is identified closer to real time than the Y-1 process, with a requirement for less than a year, and there is sufficient competition, eligible assets in the location of need will be invited to bid in for these mini-tender processes.
- Direct award: Where a need is identified, but there is no competition in the region of need, NESO will retain the right of procure directly with an eligible asset.
- An in-depth webinar exploring the proposed market arrangements is scheduled / can be found on the website.



Note, the timescales provided here are indicative only

Market Reforms

NESO has progressed several market reforms which will enable us to secure reactive power services in an increasingly competitive, transparent and cost-effective manner.

Future of Reactive Power Long-term

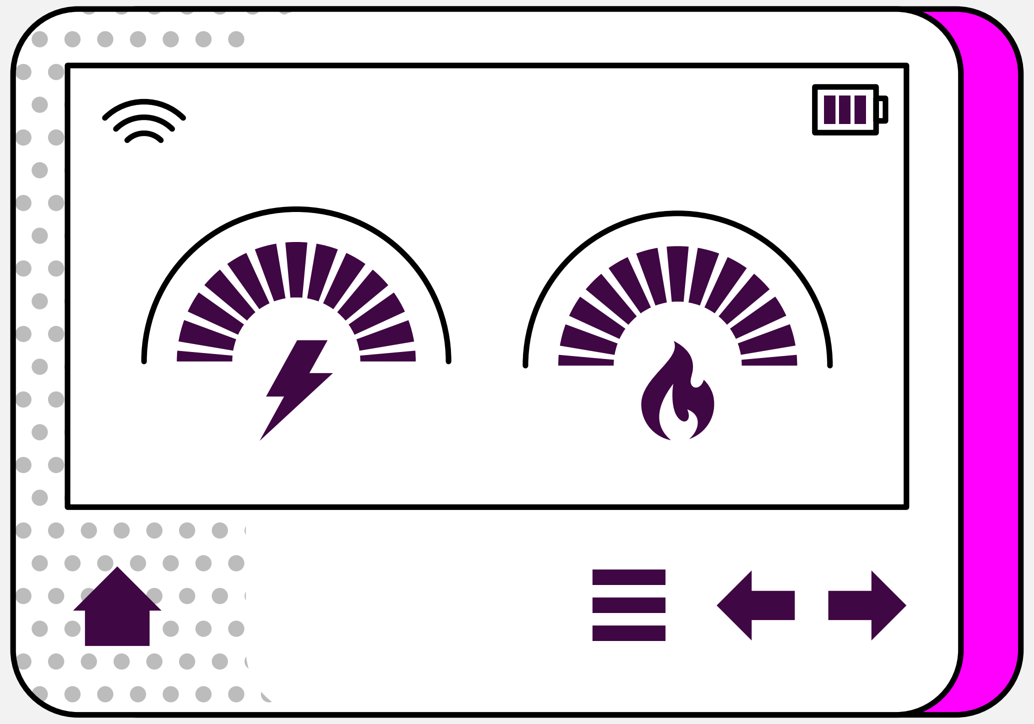
Future of Reactive Power Mid-term

Future of Reactive Power Short-term

Review of Obligatory reactive power service (ORPS)

Future of Reactive Power: Throughout 2024, there has been progress in the design of three possible reactive power markets; Long-term (Y-4), Mid-term (Y-1) and Short-term (D-1).

Short-term (D-1): Further analysis is required to determine the value of a day-ahead market. This work will also consider the output from the review of ORPS. Prior to the introduction of a short-term market, we are continuing the roll out of Commercial Services Agreements (CSAs), providing an option via which generators can receive payment for their additional reactive power capability beyond their mandatory obligations. More information on CSAs can be found here.



Market Reforms

NESO has progressed several market reforms which will enable us to secure reactive power services in an increasingly competitive, transparent and cost-effective manner.

Future of Reactive Power Long-term

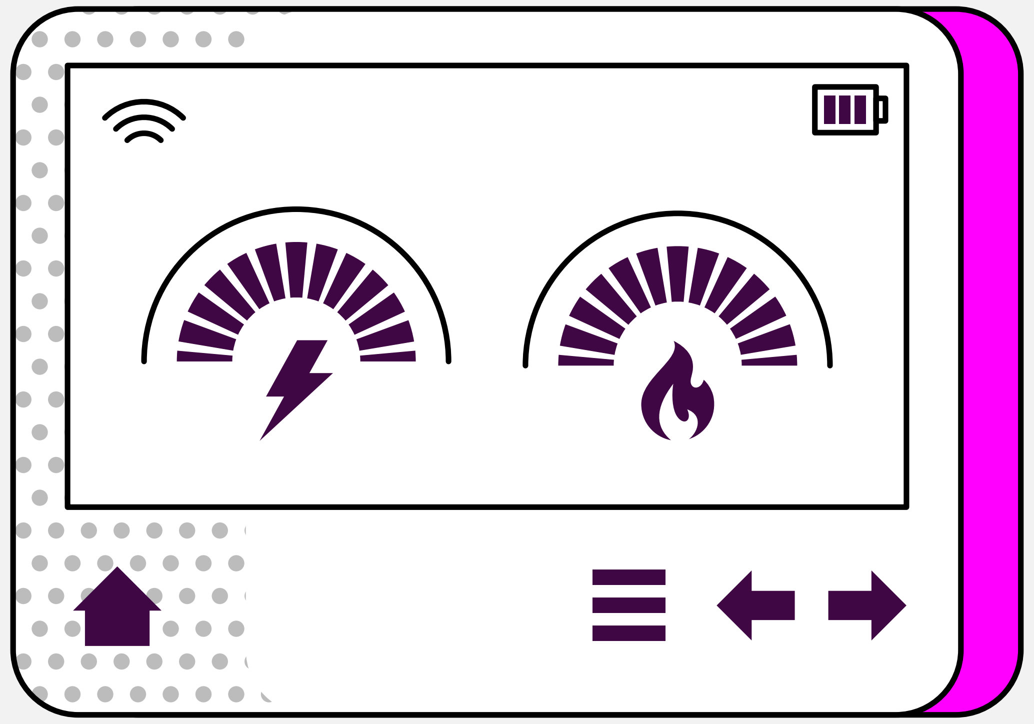
Future of Reactive Power Mid-term

Future of Reactive Power Short-term

Review of Obligatory reactive power service (ORPS)

Review of Obligatory reactive power service (ORPS):
We recognise that the current ORPS methodology needs reviewing as it is based on the Reactive Power Index and Wholesale Power Prices, and on a thermal asset technology mix which is no longer the only source of reactive power.

We have contracted with project partners, DNV, as part of this Network Innovation Allowance Innovation Project to develop an updated payment price model that seeks to more appropriately compensate the current and future mix of generation assets. We expect to publish the recommendations later in 2025.



Thermal

Introduction

What is a thermal constraint?

Thermal constraints refer to an area of the network where there is a surplus of generation or demand that exceeds the physical capacity of the network. To ensure system security, NESO must sometimes reduce generation and/or increase demand behind a constraint as well as increase generation and/or decrease demand in front of the constraint to maintain system balance.

Total thermal constraint volumes and costs are increasing due to renewable buildout outpacing the investment in the network needed to transmit the electricity to centres of demand. A holistic approach to addressing thermal constraints is needed, which balances new network, network optimisation and commercial solutions. The Centralised Strategic Network Plan (CSNP) will look at the infrastructure challenge and wholesale market reform will help provide the right investment and dispatch signals in the long-term.

Constraints Collaboration Project webpages

How do we manage thermal constraints?

Thermal constraints are currently managed using a range of different options. Some of these are market-based, where we procure services competitively to resolve network congestion. Others are more technical solutions, where an action is taken to reduce the volume of constraint actions which may be required and optimise the capability of the existing network.

Market options for thermal constraints

	Balancing Mechanism	Trades	Local Constraints Market	Megawatt (MW) Dispatch Service
Objective	We use bids and offers as both a pre- and post- fault mechanism to instruct Balancing Mechanism Unit's (BMU) to reduce or increase generation and demand at specific locations on the network.	To buy or sell electricity in advance of the BM where we foresee an opportunity to alleviate a constraint in a more cost-efficient way. These are agreements between the NESO and a counterparty, in which we call upon a party to increase/decrease their generation/demand by a specific volume at an agreed price and time.	To access new sources of flexibility to help manage two constrained boundaries between Scotland and England.	To deliver a whole system operational solution to managing transmission network constraints between NESO and each partner Distribution Network Operator (DNO). Enables flexible connections where there are transmission constraints.
Payment Mechanism	Utilisation payment only (£/MWh)	Utilisation payment only (£/MWh)	Utilisation payment only (£/MWh)	Utilisation payment only (£/MWh)
Pricing Mechanism	Prices and volumes determined by Bid-Offer Acceptance (BOA)	Bespoke prices agreed with counterparties	Pay as bid	Pay as bid
Pre fault / Post fault	Pre- and post-fault	Pre-fault	Pre-fault	Pre-fault
Dispatch timescale	Post-gate closure	Post-gate closure	Day-ahead	Within Day

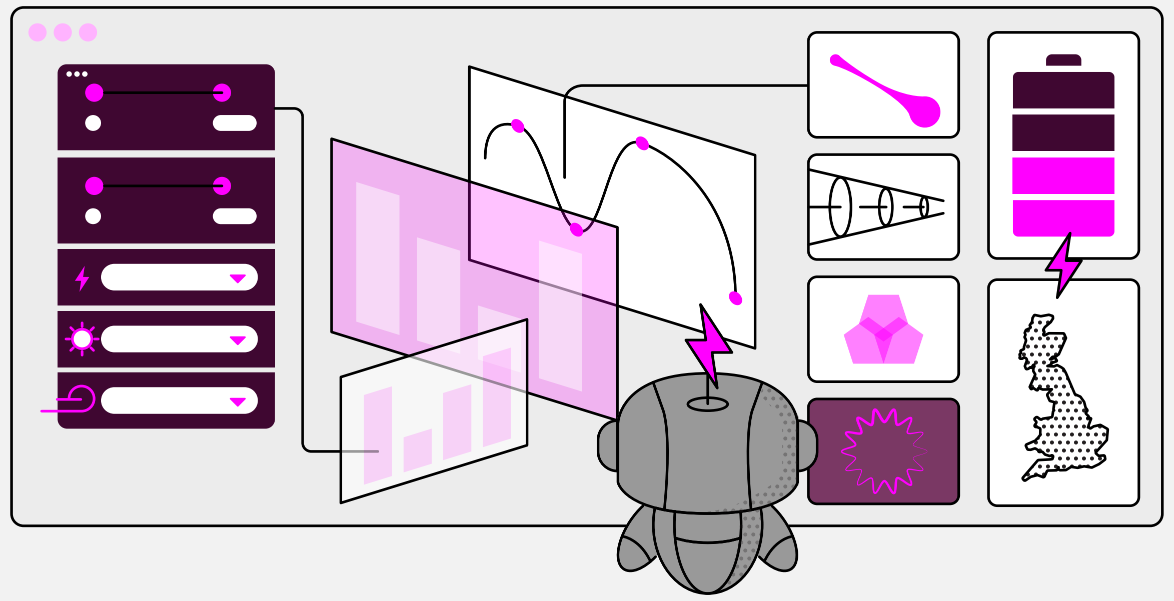
How do we manage thermal constraints?

Thermal constraints are currently managed using a range of different options. Some of these are market-based, where we procure services competitively to resolve network congestion. Others are more technical solutions, where an action is taken to reduce the volume of constraint actions which may be required and optimise the capability of the existing network.

Non-market options for thermal constraints

- Network Build
- Network Optimisation
- Constraints Management Intertrip Schemes (CMIS)

Network Build: Formerly Network Options Assessment (NOA) and Holistic Network Design (HND) identified the most effective infrastructure solutions to address a thermal constraint. Now we're transitioning from the NOA & Electricity Ten Year Statement (ETYS), to a new Centralised Strategic Network Plan (CSNP). The CSNP aims to ensure holistic development of the network, incorporating key aspects of our existing network planning process while providing a more detailed long-term approach. Our most recent publication Clean Power Plan 2030 outlines the importance of timely delivery of 80 works, recommended for before 2030, which could result in a threefold reduction in constraint costs by 2030. In future, the Strategic Spatial Energy Plan (SSEP) and the CSNP will outline an overarching plan, addressing system requirements as well as options to meet the electricity transmission network needs.



How do we manage thermal constraints?

Thermal constraints are currently managed using a range of different options. Some of these are market-based, where we procure services competitively to resolve network congestion. Others are more technical solutions, where an action is taken to reduce the volume of constraint actions which may be required and optimise the capability of the existing network.

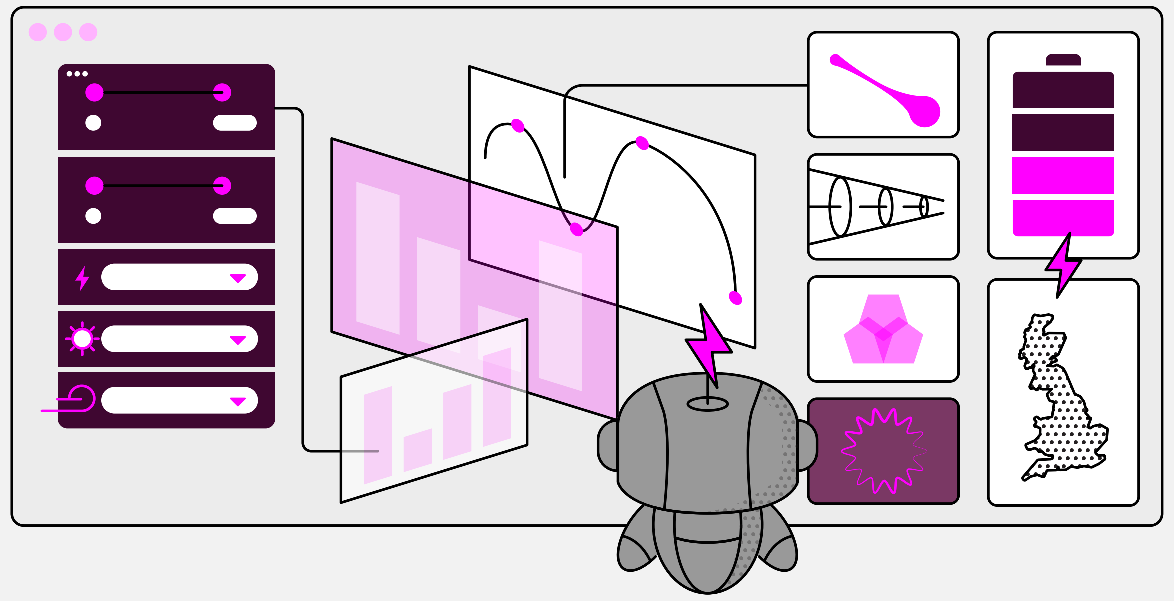
Non-market options for thermal constraints

Network Build

Network Optimisation

Constraints Management Intertrip Schemes (CMIS)

Network Optimisation: We are constantly reviewing how the network is working in close to real-time and real-time. We look for opportunities to change outage timings and duration or how the network is flowing in certain locations, in order to maximise the capacity and optimise the use of our network.



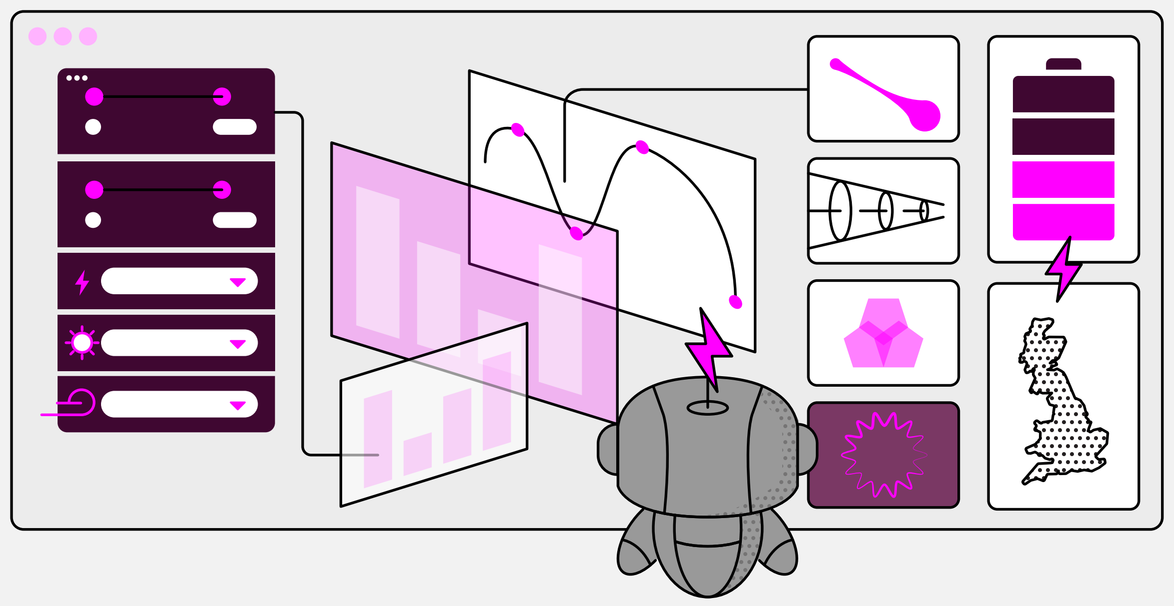
How do we manage thermal constraints?

Thermal constraints are currently managed using a range of different options. Some of these are market-based, where we procure services competitively to resolve network congestion. Others are more technical solutions, where an action is taken to reduce the volume of constraint actions which may be required and optimise the capability of the existing network.

Non-market options for thermal constraints

- **Network Build**
- **Network Optimisation**
- **Constraints Management Intertrip Schemes (CMIS)**

Constraints Management Intertrip Schemes (CMIS):
The CMIS secures a pre-determined volume of generation capacity which can be reduced to zero almost instantaneously (150 ms) in the event of a fault. This allows our control room to transfer greater volumes of electricity across a network boundary. The CMIS is currently operational at the B6 (Anglo-Scottish) boundary and the EC5 (East Anglia) boundary. Intertrip is one of the cost-effective ways to manage constraints. In 2024 NESO paid the users an arming fee of £8 /MWh on average, significantly lower than the average cost to turn down wind generation.



Summary

How is the landscape changing?

A rapidly changing generation mix, with high quantities of new renewable generation connecting to the system outpacing network build is driving thermal constraints costs up.

How have costs and volumes evolved in the last year?

In 2024 we saw 42% and 80% increase in thermal constraints costs and volume, respectively. Thermal constraint costs remained the most significant component of balancing costs, contributing to 58% in 2024 compared to 34% in 2023. Total costs of actions taken to address both export and import thermal constraints via the BM and trades increased significantly in 2024, to £1.4 bn from £985 m in 2023. These increases were driven in large part by planned outages in Scotland aimed at enhancing the transfer capacity across key constraint boundaries and high wind outturn over the summer period while transfer capacity was at its lowest.
It is also important to note that analysis of balancing costs suggests that the average costs of an action taken to manage thermal constraints (in terms of £ /MWh) has decreased in 2024 to £129 /MWh, from £167 /MWh in 2023 (for export constraints). So, whilst the overall volume of constraints is growing as more wind generation is coming online and the transmission network is still being upgraded, the actions being taken by NESO to address the congestion are becoming more efficient.

What is driving the need for reform?

Rising constraint costs are forecasted across all our FES2024 pathways where we predict more than 90 GW of additional wind and solar capacity will connect by 2030. This highlights the importance of widescale network build and reinforcement. However, even with planned network build, our Clean Power Plan publication still sees a residual volume of constraints in our network after 2030. In advance of more substantial market reform via the Review of Electricity Market Arrangements (REMA), we need to manage constraints in the most cost-effective way by enabling participation from all technology types and designing effective routes to market.

How are we implementing market reform?

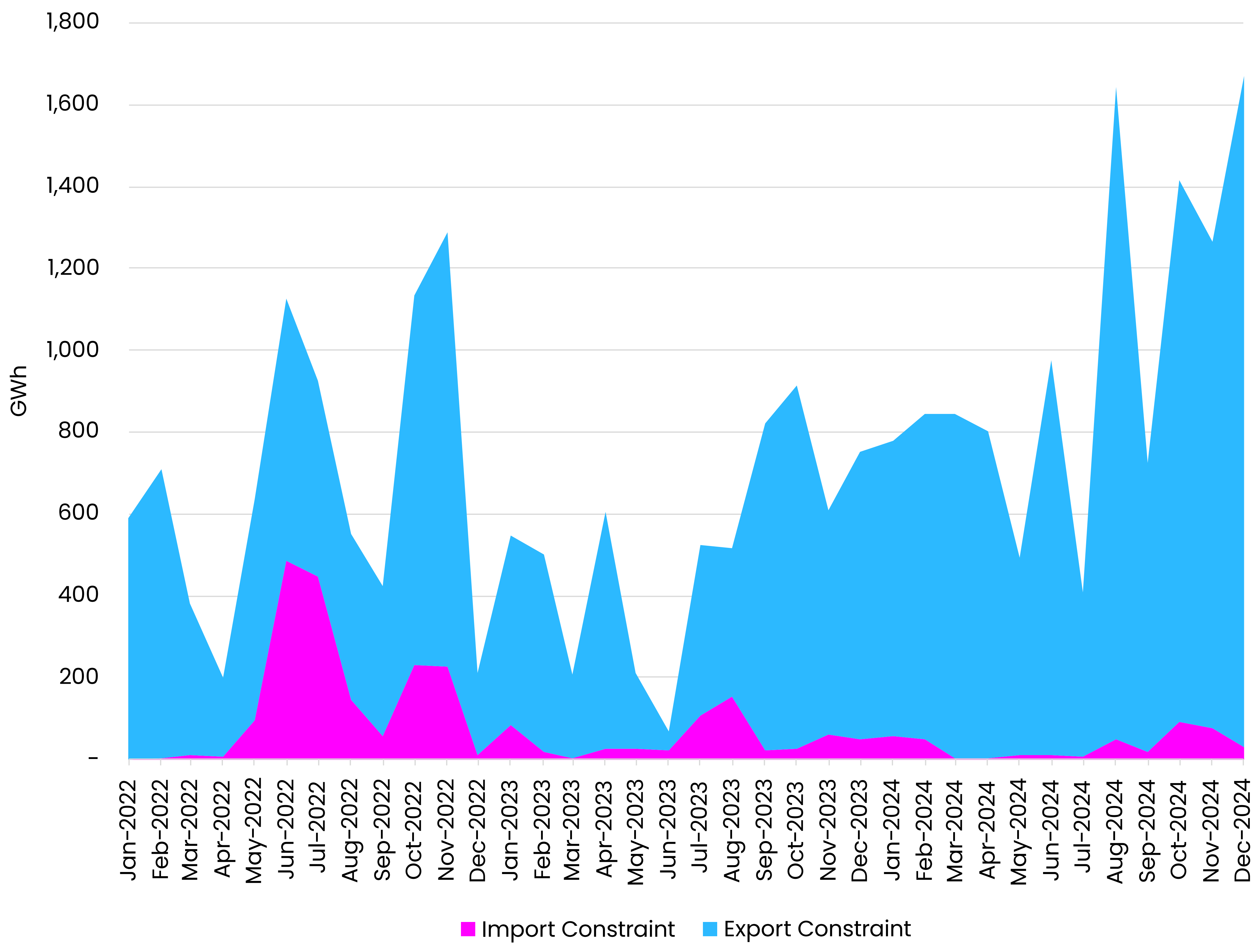
The Constraints Collaboration Project (CCP) ran throughout 2024 and, through co-creation with industry, produced a suite of potential new options for managing constraints more effectively. These include short- and long-term Constraint Management Markets, expansion of intertrip schemes, and novel technical solutions seeking to boost boundary transfer capacities. These have been assessed and are being progressed accordingly – please see our CCP webpages for more information.

Volumes

Thermal constraint volumes

The volume of constraints reached 11 TWh in 2024, an increase of 80% vs 2023 (TH Figure 1). Please note this also includes the contributing volume of actions taken to instruct additional replacement energy and these are not solely curtailment actions. Export constraints continue to dominate constraints volume and are mainly caused by high levels of wind generation being in Scotland, and most demand being in England. This year wind generated 83 TWh across Great Britain, up from 79 TWh in 2023. The contribution of wind to export constraints saw a 118% increase compared to 2023 level. August 2024 saw particularly high volumes due to a combination of high wind and outages impacting key boundaries in Scotland. Over September and October, constraints volume remained high as windy conditions prevailed and extensive works to upgrade the transmission system in the North of Scotland continued.

TH Figure 1: Thermal Constraint Volumes: 2022-2024



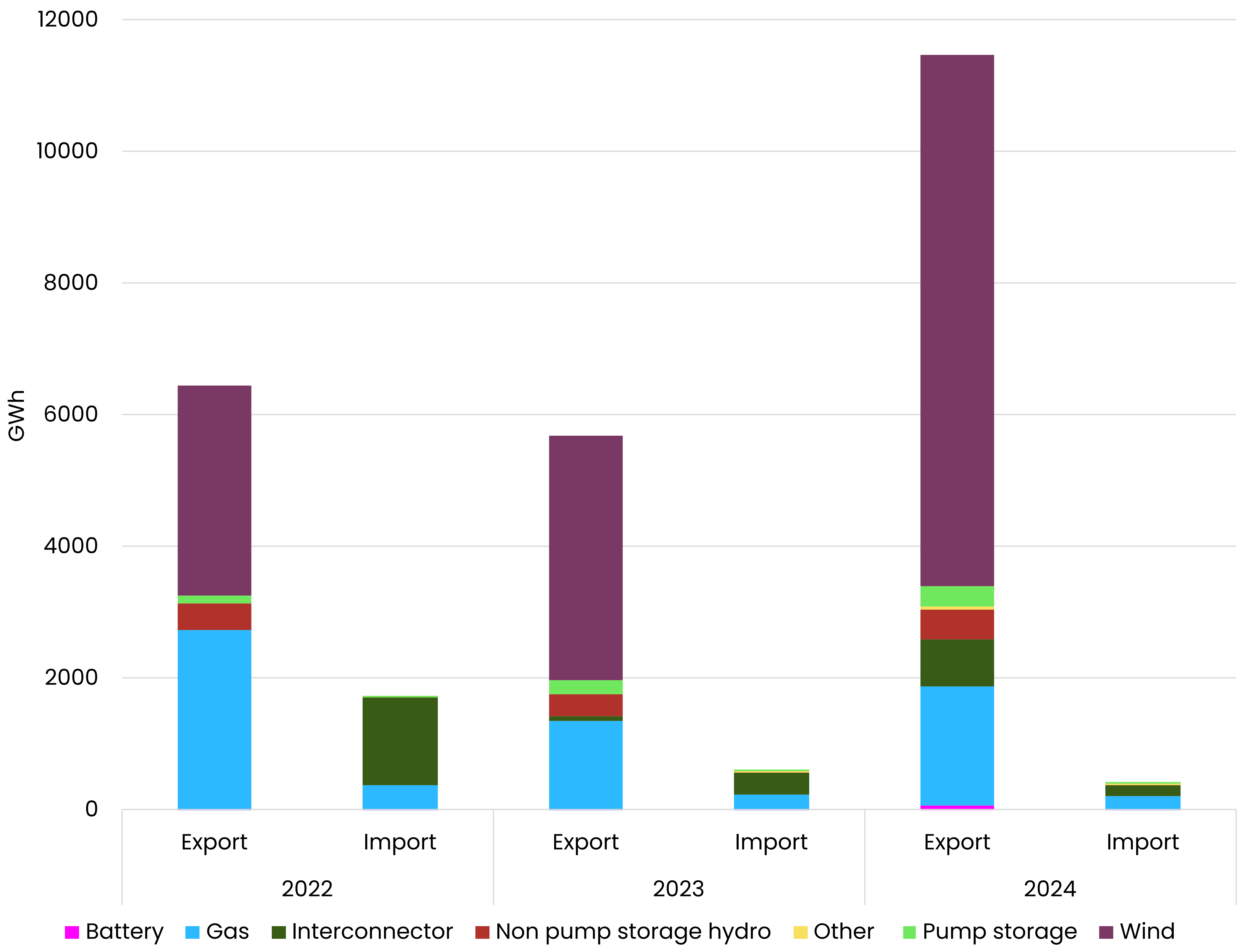
Volumes

Thermal constraint volumes by technology type

Breaking down export constraint volumes by technology (TH Figure 2), wind and gas units continue to make up the greatest proportion of actions. Actions to curtail wind generation are taken behind a constraint, while replacement energy (often via gas units) are typically ramped up on the other side of a constraint to maintain a balanced system. In 2024, curtailment constraints increased by 118% compared to 2023, primarily due to higher overall wind generation and the commissioning of new wind farms located behind key transmission bottlenecks. Additionally, extensive network reinforcements in Northern Scotland have resulted in long duration circuit outages, restricting the amount of generation flowing out of North Scotland. Actions to replace energy also increased by 34% in 2024 compared to 2023.

On the import constraint data, constraint volumes have shown a downward trend in recent years. In 2024, actions to resolve import constraints dropped to 394 GWh, a 33% decrease from 2023. Instructions to gas units accounted for 55% of the constrained import volume.

TH Figure 2: Operating reserve and Balancing Reserve 2022-24



Costs

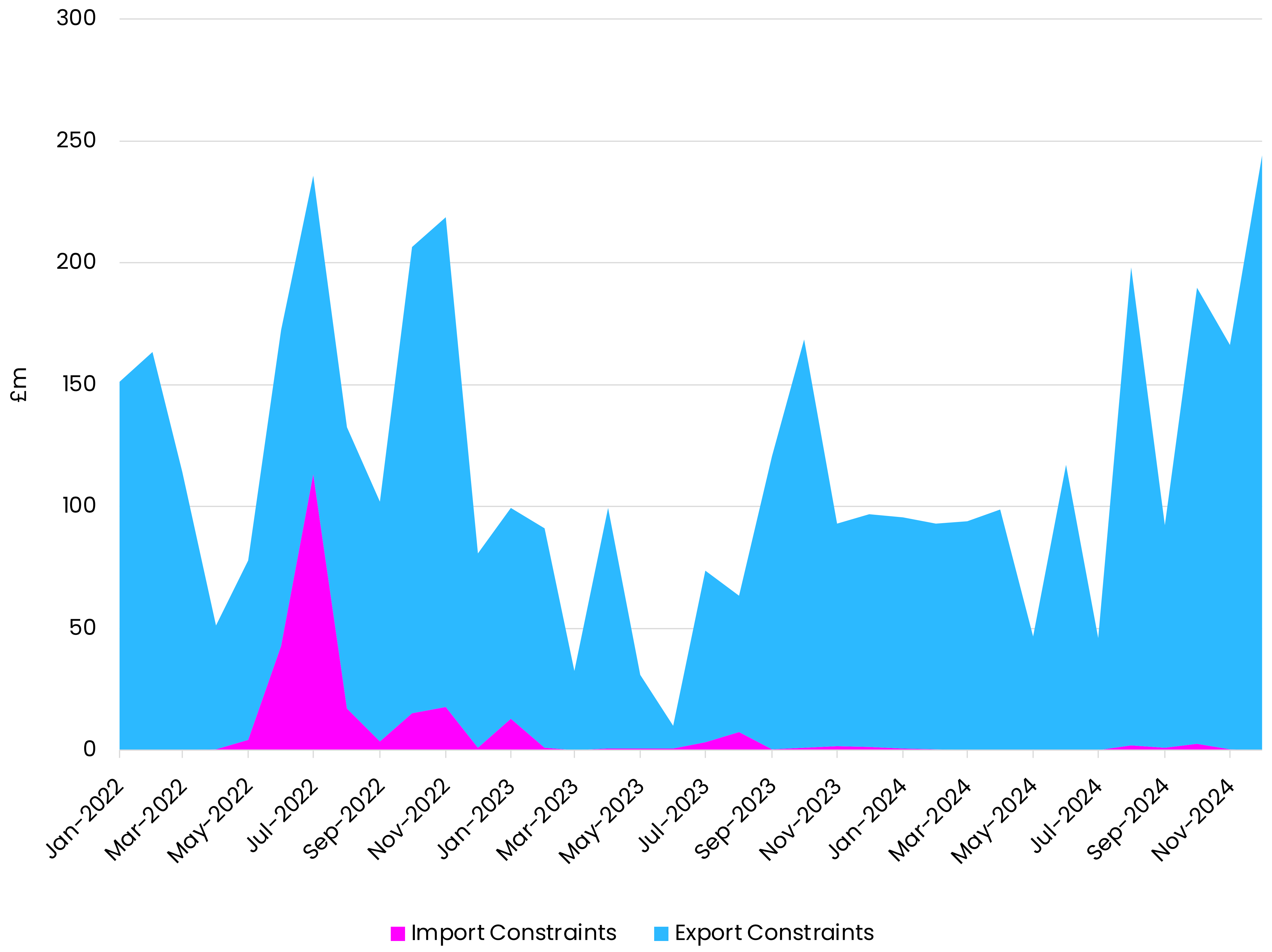
Thermal constraint costs by import and export

Import and export thermal constraints costs via the BM and trades rose significantly in 2024, to £1.4 bn from £985 m in 2023 (TH Figure 3). The fourth quarter of 2024 was particularly high at approximately £600 m in total costs, almost half of the costs of 2024. In part, this can be attributed to high constraint volume which was due to combination of especially high wind outturn and outages impacting key boundaries in Scotland. The significant works in north Scotland to upgrade the network from 275 to 400 kV and build new circuits in the B2-B4 region have also resulted in long-lasting circuit outages, restricting the amount of generation flowing out of north Scotland and driving costs up.

However, the costs associated with instructing additional units to turn on and increase energy output to rebalance the system after curtailment actions have been taken makes up the most significant proportion of this substantial cost increase in 2024. As described in the Reserve chapter, actions can be taken for a multitude of reasons, including operating reserve, energy balancing and system management. It is not always possible to accurately tag these to one category of action over another. This year's Markets Roadmap reflects this challenge, as costs in the operating reserve category have decreased by £290 m whilst there has been a sharp increase in constraint costs. The recategorisation of some of these reserve actions into constraint actions more accurately reflects the cause of the costs and should support better information sharing going forward.

We have observed a reduction in the volume weighted average cost for constraint management actions at certain boundaries, in part due to greater competition and liquidity in the BM. We continue to try and improve access to the BM (e.g., the 300 MW small-aggregated asset trial, further OBP developments) and alternative constraint management solutions (e.g., LCM) to reduce this average cost further.

TH Figure 3: Thermal constraint costs: 2022-2024



Market Reforms

Over 2024, NESO has progressed on a number of market reforms which will enable us to manage the volume and cost of thermal constraints in a cost-effective, transparent, and competitive manner.

Future Ancillary Service Design: Constraints Collaboration Project

Existing market improvement

Whole system coordination

Future Ancillary Service Design: Constraints Collaboration Project (CCP)

Alongside further network reinforcement and prior to possible reforms to the wholesale market, we are exploring other options to reduce constraints costs in the short term. Throughout 2024, NESO has coordinated the Constraints Collaboration Project (CCP). This is a NESO-led, industry collaboration project, which has been assessing constraint management measures which can be implemented and deliver results ahead of and into the 2030s. These proposed measures include “Demand for Constraints” (a long-term constraint management market), short-term constraint management markets, expansion of the intertrip scheme, and two potential battery-based solutions: “Grid Booster” and “Transfer Booster / Boundary Flow Smoothing”. Through open collaboration with more than 35 stakeholders, we assessed and shortlisted a range of potential services which seek to deliver cost savings through encouraging wider participation, introducing more advanced technical solutions, and sending stronger investment signals.

More information on CCP and the latest developments can be found on our webpage here.

Market Reforms

Over 2024, NESO has progressed on a number of market reforms which will enable us to manage the volume and cost of thermal constraints in a cost-effective, transparent, and competitive manner.

Future Ancillary Service Design: Constraints Collaboration Project

Existing market improvement

Whole system coordination

Existing market improvement

Local Constraint Market (LCM)

We will continue to facilitate a low-barrier, route to market for non-BM demand-side flexibility via our Local Constraints Market which operates on the most congested boundaries between Scotland and England. Throughout 2024, we have worked hard with the industry to remove barriers to entry and increase participation; namely the recent implementation of ABSVD opt-out solution for non-BM providers and permission of asset metering. More information on LCM can be found here.

MW Dispatch (MWD)

We are progressing from initial go live and will continue engaging with DNOs over 2025 to enhance use of MW Dispatch via RDPs 3 & 4 with a series of enhancements. This would be build on the initial deliveries with UK Power Networks (UKPN) and National Grid Electricity Distribution (NGED).

Intertrip scheme in East Anglia (EC5)

We have a tender ongoing for an enduring service for Intertrip capability in East Anglia. This will build on the current interim contracts we have with some generators and will include an upgrade to the scheme to allow tripping in stability timescales 200 ms from the current 10 sec de-load.

Wholesale market reform

We are working with DESNZ to make sure that any possible market reforms will help provide the right investment and dispatch signals to help alleviate thermal constraints.

Market Reforms

Over 2024, NESO has progressed on a number of market reforms which will enable us to manage the volume and cost of thermal constraints in a cost-effective, transparent, and competitive manner.

Future Ancillary Service Design: Constraints Collaboration Project

Existing market improvement

Whole system coordination

Whole system coordination

Balancing and Settlement Code (BSC) modification P462: We recognise code modifications are another means to manage constraint costs. For example, P462 modification proposes to reduce consumer cost potentially caused by the interaction between the BM and support mechanism arrangements. This will be done by removing distortion of support mechanisms (such as Contracts for Difference (CfDs) and the Renewables Obligation (RO) schemes) from bids in BM to reduce actions being taken outside of consumer cost order when following the Bid stack merit order. More information on P462 and its wider impact on BM can be found here.

Balancing Mechanism reform: We will continue to improve the Balancing Mechanism and remove barriers to BM entry for small and aggregated units, including batteries. More information on the Open Balancing Platform (OBP) can be found in the BM chapter.

Connection reform: The most recent connection reform enables projects that can materially reduce network constraints to be included within the reformed connections queue and/or of being accelerated under the reformed connections process, due to the significant associated benefits that they can provide to GB consumers. More information on connection reform can be found here.

Restoration

Introduction

What is restoration?

Restoration refers to the process of restarting the grid following a National Power Outage (NPO), which could be either a partial or total shut down. Restoration service providers can be any kind of electricity source with the ability to self-start and supply electricity, without external electrical supplies. These providers power up their local network, creating a power island, which enables other generators to start up and some demand to be restored. This power island grows and links up with other power islands, until the full grid is restored. World-first trials, performed on the GB grid in 2023, have shown that the restoration of supplies can be achieved using distributed assets.

How do we procure restoration services?

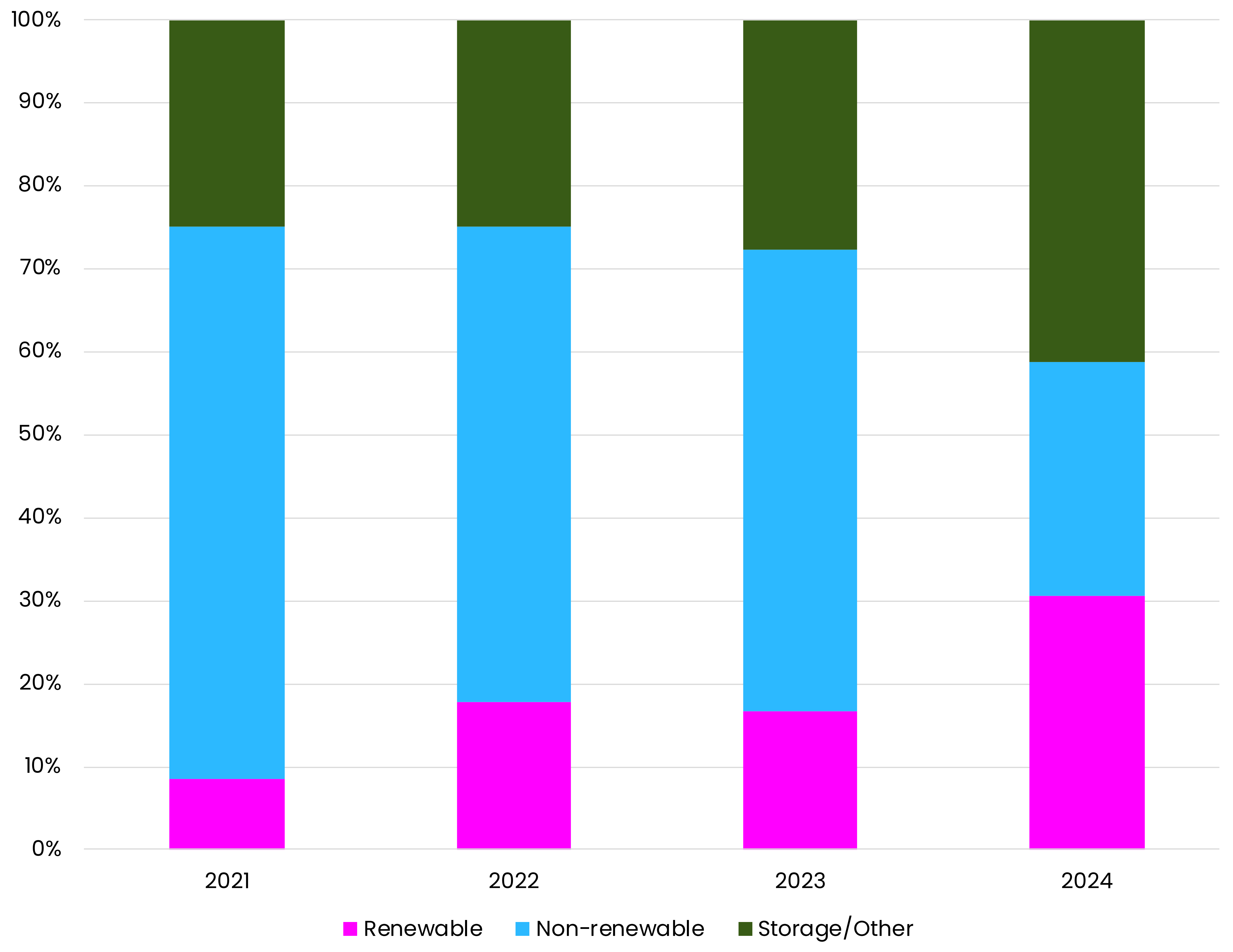
Most restoration tenders are procured locationally, so for each region of the GB grid, a competitive tender, known as an Electricity System Restoration Event, is run to determine which assets will provide restoration services for the next three or more years. Once a service is procured, NESO works closely with the local network owners and operators to create a plan that enables the system to be restored as fast as is safely possible. The Electricity System Restoration Standard (ESRS) is a relatively new standard, which is changing aspects of our approach, including requiring that in future, the distribution and transmission networks work together more closely to restore demand fast enough to meet the ESRS requirements.

Restoration webpages +

Tender participants

In 2024, two tenders were completed for southeast and northern regions of GB. Contracts were awarded to a total of 27 providers across a multitude of services such as Primary, Top-up and Distributed Restart services. Given the strategic importance of restoration at times of emergency, we cannot share details of who has been awarded contracts or the volumes. We can, however, show the different types of providers which participate and have been awarded contracts, showing a mix of renewable, non-renewable, storage and other sources.

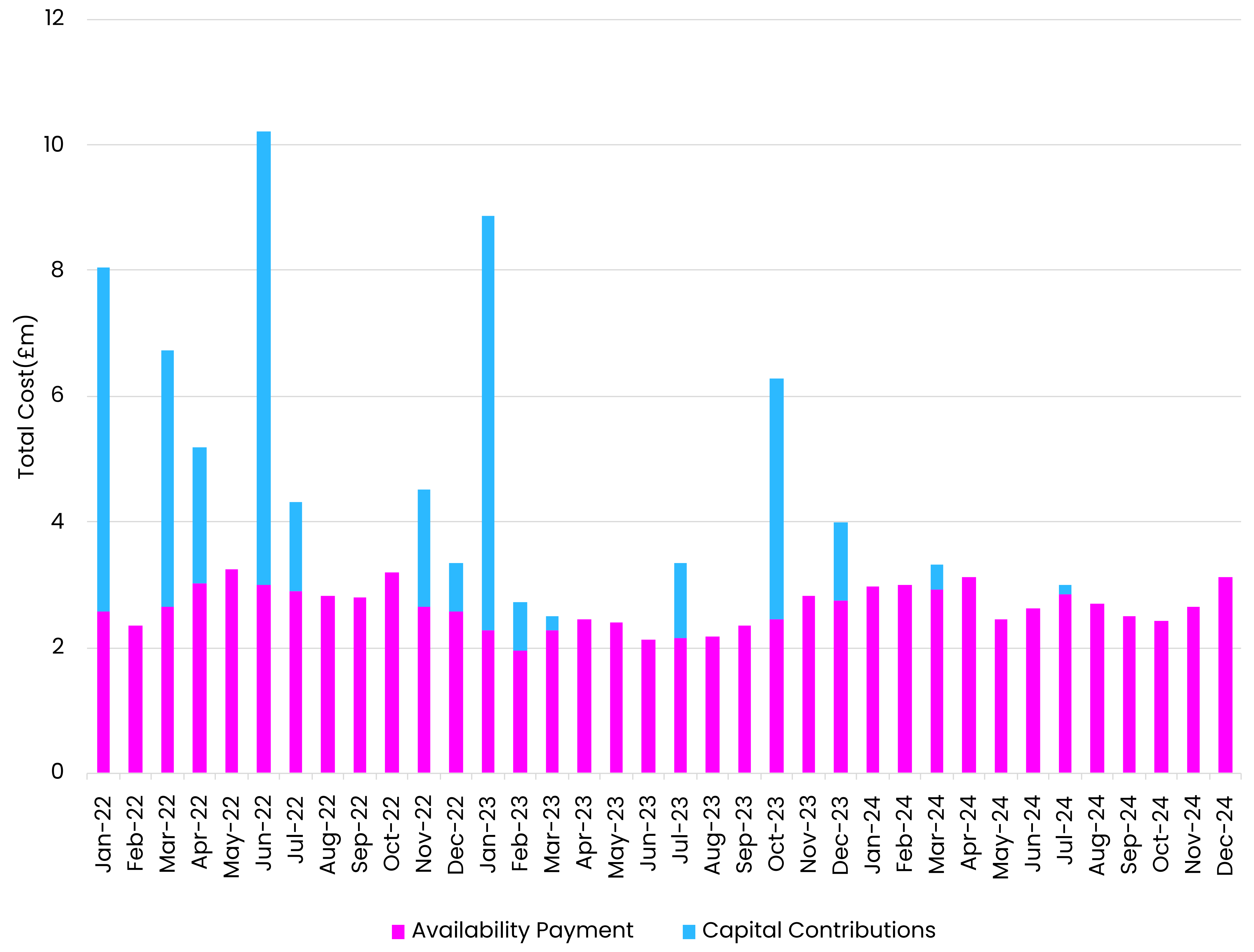
RT Figure 1: ESR Providers by Fuel Source 2021-2024



Costs

Overall costs for restoration services have fallen by 20% in 2024 in comparison to last year, down to approx. £34 m. Availability payments within restoration costs have remained relatively stable over time, while capital contributions can make a big difference. Whilst these dropped to just £500 k in 2024, we expect an increase in the coming year as a result of the recent southeast and northern tenders, due to new providers coming on board and existing providers requiring upgrades.

RT Figure 2: **Restoration Costs Jan 2022 - Dec 2024**



Market Reforms

Overall, we are taking a holistic strategy to restoration, involving both top-down, bottom-up and zero-carbon methods being used where required. A more detailed explanation of both current and new restoration approaches can be found in Electricity System Restoration Assurance Framework 2024/25. We are also currently in tender for restoration capability for the Southwest & Midlands region scheduled to conclude in November 2025.

NESO have recently launched the Long-term 2029 tender. This tender allows procurement of new and additional restoration capability, whilst simultaneously procuring stability and reactive power services. More information on the launch of this tender can be found on our dedicated Long-term 2029 webpage.

We continue to develop separate routes to market for distribution connected restoration services following the successful trial of Distributed Restart, as well as how we continue to contract with existing restoration capability.

Electricity System Restoration Standard (ESRS)

Decarbonisation

Grid Code

The recent introduction of the **Electricity System Restoration Standard** (ESRS) means that we now have to be able to restore 60% of national demand per region within 24 hours of a total or partial system shutdown, once acknowledged as a system restoration event (with 100% of supplies restored within 5 days). Reaching these new restoration timeframes both regionally and nationally has required some reforms to our approach. For example, our southeast and northern tenders included distribution level assets. This is following the successful trial of Distributed Restart, which means we now have restoration providers at distribution level included within our main restoration tenders and have signed contracts at both levels. Also, within the ESRS and NESO Procurement Guidelines is the provision that when tenders do not give us the intended restoration coverage we are obliged to have, we can bilaterally contract with generators to ensure we comply with the standard.

Market Reforms

Overall, we are taking a holistic strategy to restoration, involving both top-down, bottom-up and zero-carbon methods being used where required. A more detailed explanation of both current and new restoration approaches can be found in Electricity System Restoration Assurance Framework 2024/25. We are also currently in tender for restoration capability for the Southwest & Midlands region scheduled to conclude in November 2025.

Please update this section: NESO have recently launched the Long-term 2029 tender. This tender allows procurement of new and additional restoration capability, whilst simultaneously procuring stability and reactive power services. More information on the launch of this tender can be found on our dedicated Long-term 2029 webpage.

We continue to develop separate routes to market for distribution connected restoration services following the successful trial of Distributed Restart, as well as how we continue to contract with existing restoration capability.

Electricity System Restoration Standard (ESRS)

Decarbonisation

Grid Code

As the **decarbonisation** of the electricity system continues apace, so the approach taken to restoration is evolving to match. Whilst we will need to ensure that we can restart the grid whatever the weather or time of day, we have revised the historic tender service terms, so that they are non-discriminatory in terms of technology and create a level playing field for all types of technologies. This means that renewable generators can participate in tenders now alongside more traditional generators and we are able to have a mix of different types of generation, renewables as well as fossil-fuelled assets, providing restoration services. In addition, we're participating in an innovation project (SIF Blade), which is testing restoration provision from offshore wind. The project is currently in testing phase and is looking to investigate the technical developments required for offshore wind farms to contribute to system restoration and aims to provide a clear commercial path for them, while demonstrating the benefit to the energy consumer.

Market Reforms

Overall, we are taking a holistic strategy to restoration, involving both top-down, bottom-up and zero-carbon methods being used where required. A more detailed explanation of both current and new restoration approaches can be found in Electricity System Restoration Assurance Framework 2024/25. We are also currently in tender for restoration capability for the Southwest & Midlands region scheduled to conclude in November 2025.

Please update this section: NESO have recently launched the Long-term 2029 tender. This tender allows procurement of new and additional restoration capability, whilst simultaneously procuring stability and reactive power services. More information on the launch of this tender can be found on our dedicated Long-term 2029 webpage.

We continue to develop separate routes to market for distribution connected restoration services following the successful trial of Distributed Restart, as well as how we continue to contract with existing restoration capability.

Electricity System Restoration Standard (ESRS)

Decarbonisation

Grid Code

Another change to the restoration landscape is **Grid Code** modification (GC0156), which Ofgem approved in early 2024. Part of this modification is to require all CUSC parties to have 72 hours resilience, such that in the event of a total or partial shutdown all CUSC parties are able to come back online within their cold start times, for a period of 72 hours, once external grid supplies are restored. For our restoration services this means that more assets will be able to participate in restoration tenders and should enhance competition and decrease costs to consumers.

04

Revenue Stacking

Revenue Stacking

Introduction

What is revenue stacking?

Revenue stacking is where an asset participates in multiple markets, to maximise its value to the energy system. Therefore, assets with the capability to meet multiple requirements can participate in multiple markets simultaneously. This increases the flexibility for market participants and also provides an opportunity to reduce costs for end consumers where flexible assets can be more efficiently utilised.

The benefits of revenue stacking and co-optimisation have been evidenced by the launch of the Enduring Auction Capability (EAC) in November 2023, which enabled all jumping and splitting of dynamic response products. As reported in the Response chapter, the subsequent increase in market liquidity has contributed to a 20% reduction in total dynamic response costs, despite the 41% increase in volume over 2024. This rise in market liquidity can be partly attributed to the introduction of EAC.

We are committed to maximising the ability to stack services, so there is increased market participation and liquidity across the whole system, better NESO-DNO coordination, and improved competition, resulting in added value for consumers. Our Enabling Demand Side Flexibility and Routes to Market Review publications also highlight where we think actions should be prioritised to unlock additional benefits, enable seamless transition between markets, and grow flexibility.

Our focus with regards to stacking in anticipation of the Market Facilitator becoming operational includes:

- Evolving legacy services to facilitate stacking with response and reserve services. This includes Dynamic Containment, Dynamic Moderation, Dynamic Regulation response services with Balancing Reserve and Quick Reserve. This should consider analysing the opportunities of splitting in the same and opposite directions (e.g., positive QR with negative BR), and learnings should be considered for Slow Reserve.
- Ensuring services to procure flexibility can be stacked with other services including at Distribution Network Operator (DNO) level.
- Introducing NESO's initial view over the stacking design principles, in collaboration with ENA, in our market design principles.
- Engaging with the newly appointed Market Facilitator, through workshops and consultations, to define and agree the stacking objectives.

Revenue stacking breakdown

Revenue stacking can be split into three categories: 'Co-delivery', 'Splitting' & 'Jumping':

- **Co-delivery:** a single asset receives multiple payments for using the same capacity, at the same time, in the same direction.
- **Splitting:** a single asset receives multiple payments for using different capacity, at the same time.
- **Jumping:** a single asset receives multiple payments for services in different times (adjacent or non-adjacent).

Co-delivery

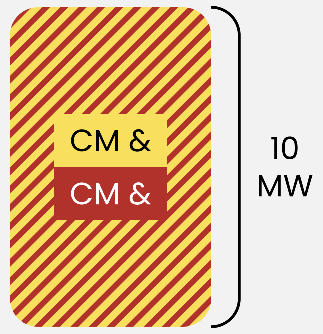
Splitting

Jumping

Co-delivery

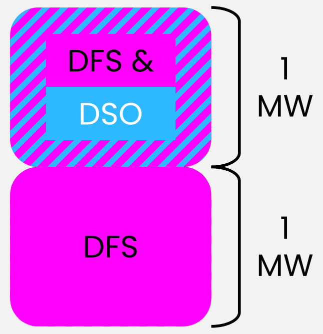
- A single asset receives multiple payments for using the same capacity, at the same time, in the same direction.
- The theoretical example below shows how a single asset can be paid for providing Capacity Market (CM) and Dynamic Containment (Low). The asset, which can offer 10 MW of generation turn up, is able to be paid twice for that 10 MW. The Capacity Market can be co-delivered with 'relevant balancing services' as defined here.
- The example in the middle illustrates that a single asset (or group of assets) can co-deliver the Demand Flexibility Service (DFS) and a scheduled DNO service. The asset, which can deliver demand turn down of 2 MW, can deliver and be paid against both the DFS and DNO service.
- NESO will work with the DNOs and with the newly appointed Market Facilitator towards making an industry wide decision for the future of co-delivery.

The **Capacity Market (CM)** and **Dynamic Containment (DC)**



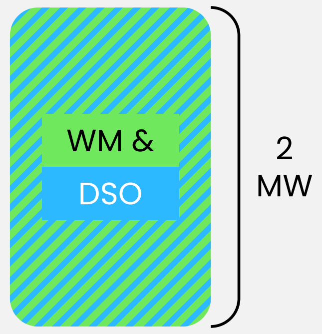
Combining the Capacity Market with any **Relevant Balancing Service.**

Demand Flexibility Service (DFS) and a scheduled **DSO service**



Delivering DFS as well as a scheduled DNO service. Overdelivering on the DNO service is likely.

Wholesale Market and a **DSO service**



When participating in DSO services, providers must also trade their DSO utilisation in the Wholesale Market to avoid imbalance cost.

Revenue stacking breakdown

Revenue stacking can be split into three categories: 'Co-delivery', 'Splitting' & 'Jumping':

- **Co-delivery:** a single asset receives multiple payments for using the same capacity, at the same time, in the same direction.
- **Splitting:** a single asset receives multiple payments for using different capacity, at the same time.
- **Jumping:** a single asset receives multiple payments for services in different times (adjacent or non-adjacent).

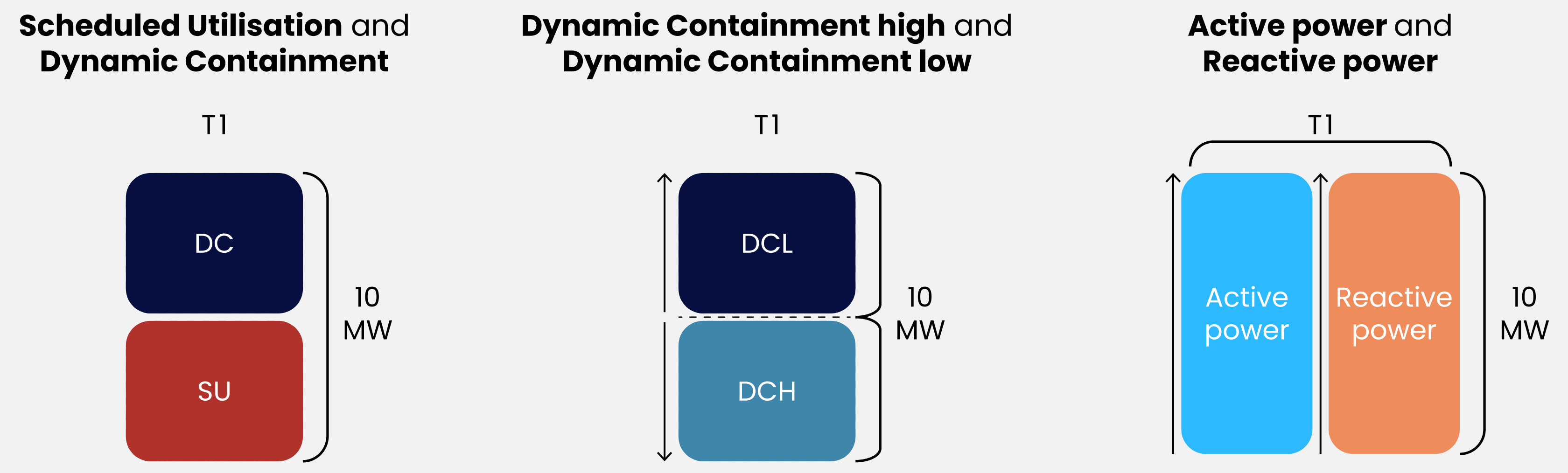
Co-delivery

Splitting

Jumping

Splitting

- A single asset receives multiple payments for using different capacity, at the same time.
- The examples on the right show different ways of splitting flexible capacity between two services. The first example illustrates where services are in the same direction, and where the baseline of one service may be adjusted for the other. Examples 2 illustrates where services are delivered in opposite directions - either because of adjusted baselines, or because services are not required simultaneously (e.g. Dynamic Containment High and Low). The final example shows additional stacking potential in cases where an asset can provide flexibility in both active (kW) and reactive power (kVA).



Using part of the capacity to provide one service and the rest to provide another service, in this case SU and DC.

Delivering high and low services at the same time. In this case, DC high and low.

It is possible for some technologies to provide active and reactive power simultaneously.

T = Time | DC = Dynamic Containment | SU = Scheduled Utilisation / WM = Wholesale Market

Revenue stacking breakdown

Revenue stacking can be split into three categories: 'Co-delivery', 'Splitting' & 'Jumping':

- **Co-delivery:** a single asset receives multiple payments for using the same capacity, at the same time, in the same direction.
- **Splitting:** a single asset receives multiple payments for using different capacity, at the same time.
- **Jumping:** a single asset receives multiple payments for services in different times (adjacent or non-adjacent).

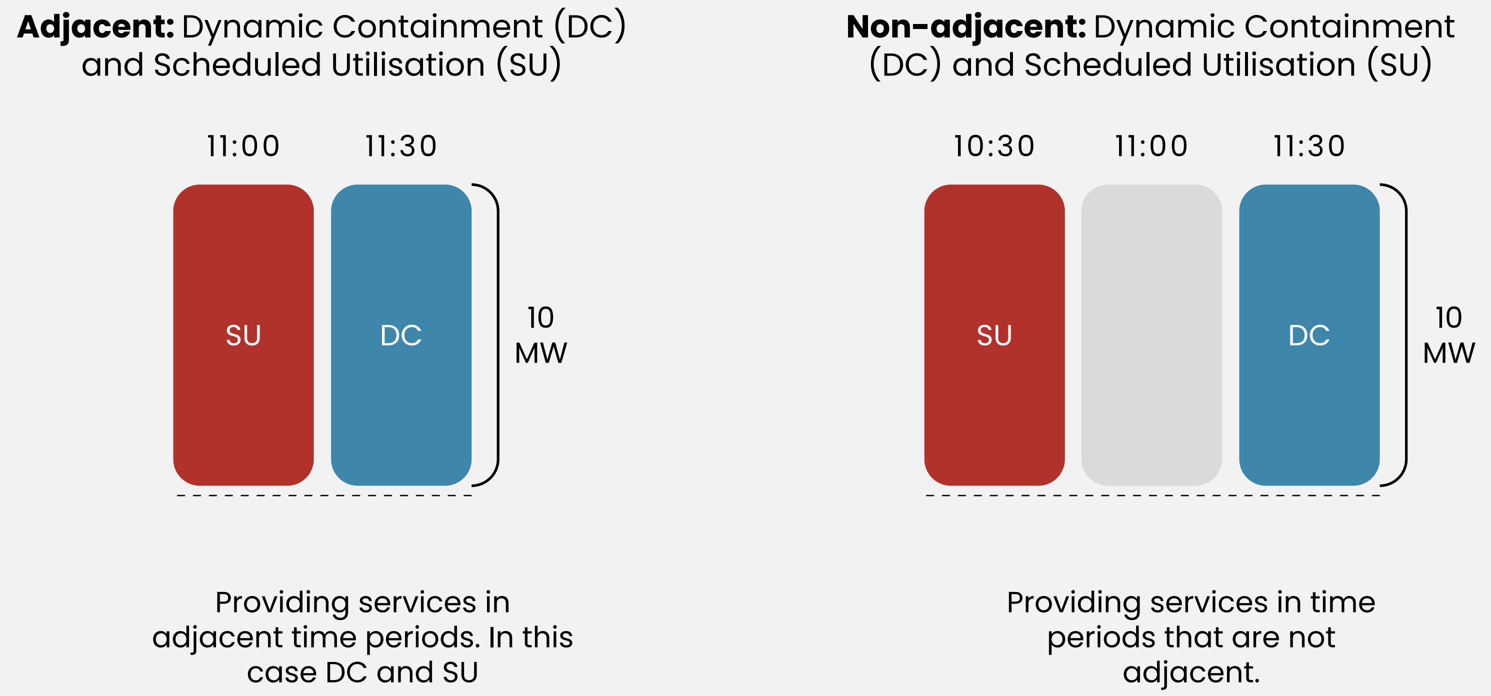
Co-delivery

Splitting

Jumping

Jumping

- A single asset receives multiple payments for services in different times (adjacent or non-adjacent).
- Examples where Jumping is permitted are widespread. That said, providers should consider any technology related constraints (e.g., maximum duration of response or time between activations). There may also be limitations how quickly assets can be registered or de-registered from a service.



T = Time | DC = Dynamic Containment | SU = Scheduled Utilisation

Revenue Stacking Opportunities

As reported in the 2024 Markets Roadmap, NESO has been working with the Open Networks programme to analyse NESO and DNO revenue stacking opportunities. The ENA Flexibility Products and Stacking group is looking to deliver clearer resources for flexibility service providers, a set of design principles to ensure that new services are stackable by default and a reduced set of DNO products. In anticipation of the Market Facilitator taking over the ENA working group, the group's deliverables have been concluded for the previous year, and the key outputs are presented below:

- Agreed the initial view of the stacking design principles which compromise of a set of features, identified as common barriers to stacking, that should be avoided wherever practical. This checklist should be updated as required by the Market Facilitator and embedded within the design and approval processes for new NESO and DNO services.
- Delivered the revenue stacking explainer and FAQs.
- Delivered the technical service requirements tool.
- Delivered the revenue stacking assessment tool which was agreed by NESO and the DNOs.
- Currently, the ENA Baselining group is looking to define consistent standards for baselines, with an explicit objective to consider how any changes will impact product stackability.

More information about what is being done to improve revenue stacking can be found in the stacking explainer document.

Splitting

The information presented here displays the most up to date views at the time of publication. As our stacking rules evolve, so it will the opportunities to stack across different markets. To be kept up to date with the latest information, please visit the ENA website.

			NESO												DNO							
	CM	WM	BM	BR	QR	SR	STOR	DC	DM	DR	SFFR	MWD	LCM	DFS	PR	SO	OU (2 & 15 Mins)	OU (WA)	SA+ OU (2 mins)	SA+ OU (DA)	VA+ OU (2 & 15 mins)	VA+ OU (DA & WA)
CM																						
WM																						
BM															SD	SD		SD		SD		SD
BR															SD	SD		SD		SD		SD
QR															SD	SD		SD		SD		SD
SR																						
STOR															SD							
DC															SD	SD		SD		SD		SD
DM															SD	SD		SD		SD		SD
DR															SD	SD		SD		SD		SD
SFFR															SD	SD		SD		SD		SD
MWD																						
LCM																						
DFS															SD	SD	SD	SD	SD	SD	SD	SD
PR			SD	SD	SD		SD	SD	SD	SD	SD			SD								
SO			SD	SD	SD			SD	SD	SD	SD			SD								
OU (2 & 15 Mins)														SD								
OU (WA)			SD	SD	SD			SD	SD	SD	SD			SD								
SA+OU (2 mins)														SD								
SA+OU (DA)			SD	SD	SD			SD	SD	SD	SD			SD								
VA+OU (2 & 15 mins)														SD								
VA+OU (DA & WA)			SD	SD	SD			SD	SD	SD	SD			SD								

KEY	
N/A	
Explicit Yes	
Implicit Yes	
Implicit No	
Explicit No	
No Data	
Same direction action	SD

Abbreviations

CM	Capacity Market
WM	Wholesale Market
BM	Balancing Market
BR	Balancing Reserve
QR	Quick Reserve
SR	Slow Reserve
STOR	Short Term Operating Reserve
DC	Dynamic Containment
DM	Dynamic Moderation
DR	Dynamic Regulation
SFFR	Static Firm Frequency Response
MWD	MW Dispatch
LCM	Local Constraint Market
DFS	Demand Flexibility Service
PR	Peak load reduction
SO	Scheduled Utilisation
OU (2 & 15 Mins)	Operational Utilisation
OU (WA)	Operational Utilisation
SA+OU (2 mins)	Scheduled Availability + Operational Utilisation
SA+OU (DA)	Scheduled Availability + Operational Utilisation
VA+OU (2 & 15 mins)	Variable Availability + Operational Utilisation
VA+OU (DA & WA)	Variable Availability + Operational Utilisation

NESO

National Energy
System Operator