ESO RIIO-2 Business Plan 2 (2023-25)

Mid-Scheme 2023-24 Incentives Report

Evidence Chapters

May 2024

ESO

Contents

Role 1
Control Centre operations

ESO

A.1 Plan Delivery for Role 1

Deliverable progress

For Role 1, the RIIO-2 Delivery Schedule received an ambition grading of 4/5, providing us with an ex-ante expectation of Ofgem's assessment of plan delivery if these deliverables are met. The ESORI guidance states that "the Performance Panel should consider that the ESO has outperformed the Plan Delivery criterion if the ESO has successfully delivered the key components of a 4- or 5-graded delivery schedule".

See below an overview of key plan delivery topics for Role 1 over the first 12 months of the Business Plan 2 period.

Balancing Programme

The Balancing Programme has achieved a major milestone in the delivery of Release 1 of our Open Balancing Platform (OBP). This focused on implementing the small Balancing Mechanism (BM) unit (planned delivery) and battery zones (accelerated delivery) delivering enhanced dispatch capability and meeting changing customer requirements whilst reducing costs for consumers. The battery zone was prioritised for delivery following feedback from our ongoing Balancing Programme stakeholder engagement events. This extra delivery was achieved four months earlier than planned (originally April 2024) without impacting the remaining OBP roadmap timescales and deliverables.

By leveraging agile ways of working, we have resolved the early life issues with the issuing of high cost bid-offer acceptances (BOAs) in the two months following go-live. We now have a two-week cadence of smooth small updates or mini-releases which are embedded as business as usual. These updates also included the enablement of Balancing Reserve, which commenced in March 2024. In tandem, we have been reviewing and making changes to Electricity National Control Centre (ENCC) processes to ensure the full benefit realisation of OBP. These include:

- Changing the 15-minute rule for batteries to 30 minutes to allow storage assets to be instructed up to 30 minutes (see EDT/EDL Submissions Guidance)
- Updating the Reserve Policy for batteries

The combined impact of these deliveries can be seen by looking at the instructions and volumes on the battery zone and small BMU zone in 2023-24 and comparing the figures before and after OBP go live:

- Battery zone – since resolution of early life issues there has been an increase of 224% in average daily volume instructed, from 503MWh to 1634MWh.
- Small BMU zone – since Release 1 there has been an increase of 47% in average daily volume instructed, from 564MWh to 833MWh.
- There has been an increase of 312% in the average number of daily instructions issued across the battery and small BMU zones from 299 to 1231. This demonstrates the increased capacity for issuing instructions provided by capabilities in OBP.

Our delivery roadmap of activities is underpinned by robust and transparent engagement with the industry as described in our stakeholder approach.

It is important to maintain the existing products to ensure we meet our obligations across all our activities (including Role 2 and Role 3) and continue to balance safely, securely and economically. We have maintained a robust suite of balancing capabilities across our existing balancing products. We also have an effective and efficient transition plan in place as these are expanded with full range of capabilities required from OBP to be completed in 2026-27.

We have been focussing on ensuring the levels of performance and resilience of the existing products continue to meet the requirements for 24-7 operation. We are also delivering incremental value through developments such as enabling new interconnection, interfacing with OBP, dispatch improvements, enabling Balancing Reserve and delivering Mega Watt (MW) dispatch for NGED and UKPN. These have been delivered through our quarterly releases of BM and Ancillary Services Dispatch Platform (ASDP) product updates.

In addition, this year we have reached a significant milestone for Electricity Balancing System (EBS). We have migrated all operational decisions and processes away from EBS so that in 2024-25 we can focus on fully decommissioning it.

Our RIIO-2 objective is to transition the existing Platform for Energy Forecasting products from the current Oracle cloud solution and energy forecasting system (EFS) to a strategic Azure cloud solution and complete the remaining feature delivery.

In 2023-24, we have had three releases: (1) Strategic Cloud Platform Foundation, (2) Grid Supply Point (GSP) forecast and (3) Forecasting features for enabling Local Constraint Market (LCM).

We have adjusted our forecasting roadmap/backlog to align with consumer value and business requirements. This involves prioritising the retirement of legacy systems, for example (EFS and Operational Platform for Energy Forecasting (PEF)) to reduce technical debt and operational risk. By doing so, we aim to optimise consumer value and maximize the benefits of current and new forecasting products. This has resulted in the acceleration of EFS retirement from the original completion of Q4 2025-26, with specific timescales to be confirmed.

We have re-prioritised activity originally planned for Q4 2023-24 with target completion dates as follows:

1. Wind Power Milestone: Q2 2024-25

2. National Demand Milestone: Q4 2024-25

Other planned BP2 deliverables, development of a wind product is on-going and discovery work for integration of strategic PEF with OBP are also underway.

We have also been setting the foundation for an investment, which was outlined in the original BP2 plan, to replace the existing National real-time energy forecasting product in the ENCC. We have now approved the investment following a discovery process and work on this will commence in 2024-25.

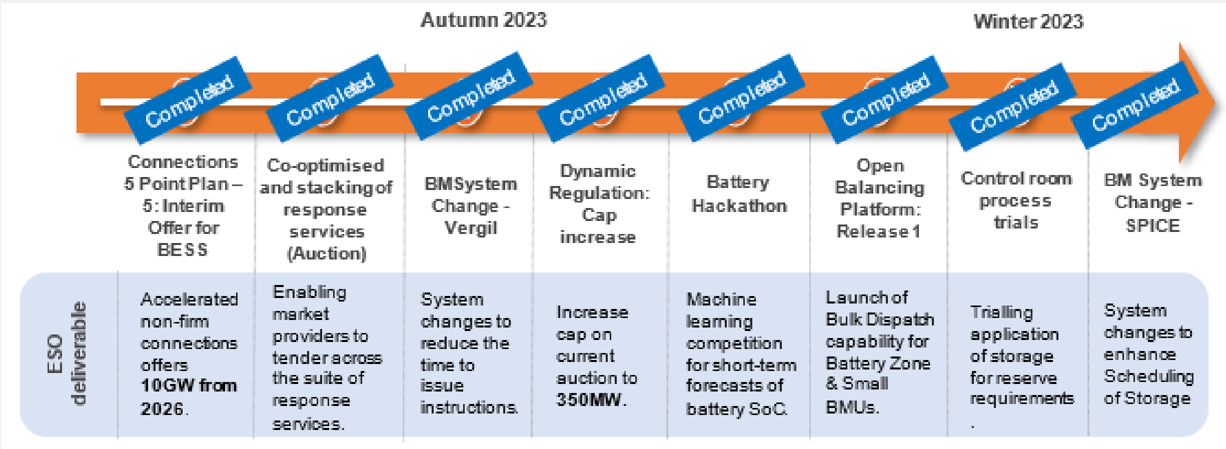
The Balancing Programme have also been leading the ESO engagement with the industry on Grid Code modification Proposal GC0166. This proposal is looking to establish data feeds for the provision of energy available from limited duration assets (GC0166) to be able to provide greater operational awareness of storage capabilities and ensure efficient and economic dispatch. This will facilitate the removal of any additional processes in place such as the 30 (updated from 15) minute rule which is used for batteries. Based on the timing and outcome of this modification, we will deliver required capability in future OBP releases (and existing products dependent on the timing of outcome) to incorporate this data. This will provide the information required to improve balancing decisions in the control centre.

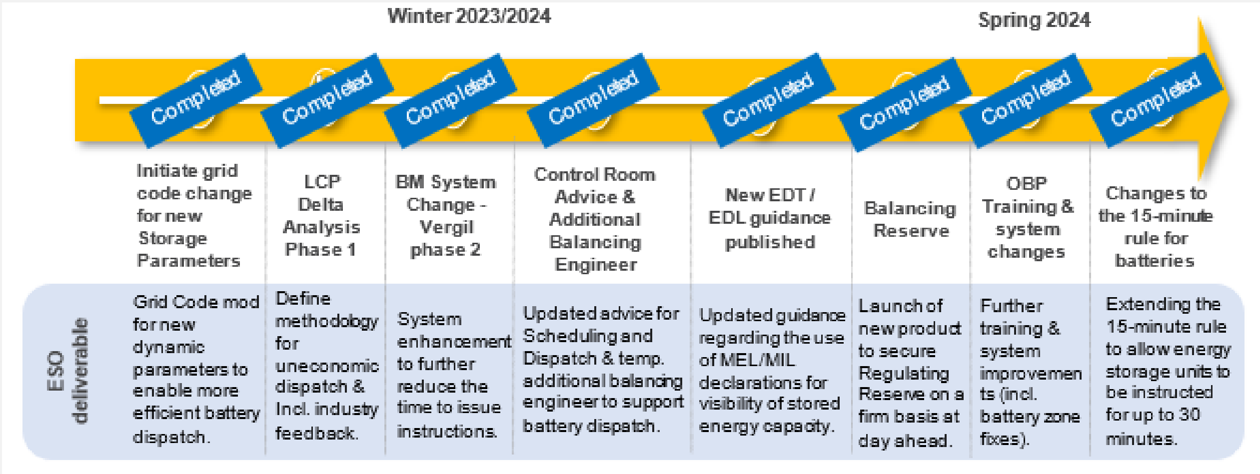
Enhancing the use of storage assets in the Balancing Mechanism

Limited Duration Energy Storage technologies have integrated into our system operations since 2016 and are key in our transition to run the power system with zero carbon emissions by 2035. In April 2021, there were only nine battery units being operated in the system, increasing to 60 by December 2023.

In the last year, stakeholders have told us that we need to improve the dispatch of storage assets in the BM. In response to this feedback we set out a plan in October 2023 detailing how we would enhance the use of storage assets in the BM. This plan was developed collaboratively with the industry focussing on the required capability improvements with respect to systems, processes and people. The plan combined pre-existing planned activity and new deliverables, enabling the enhanced utilisation of these assets.

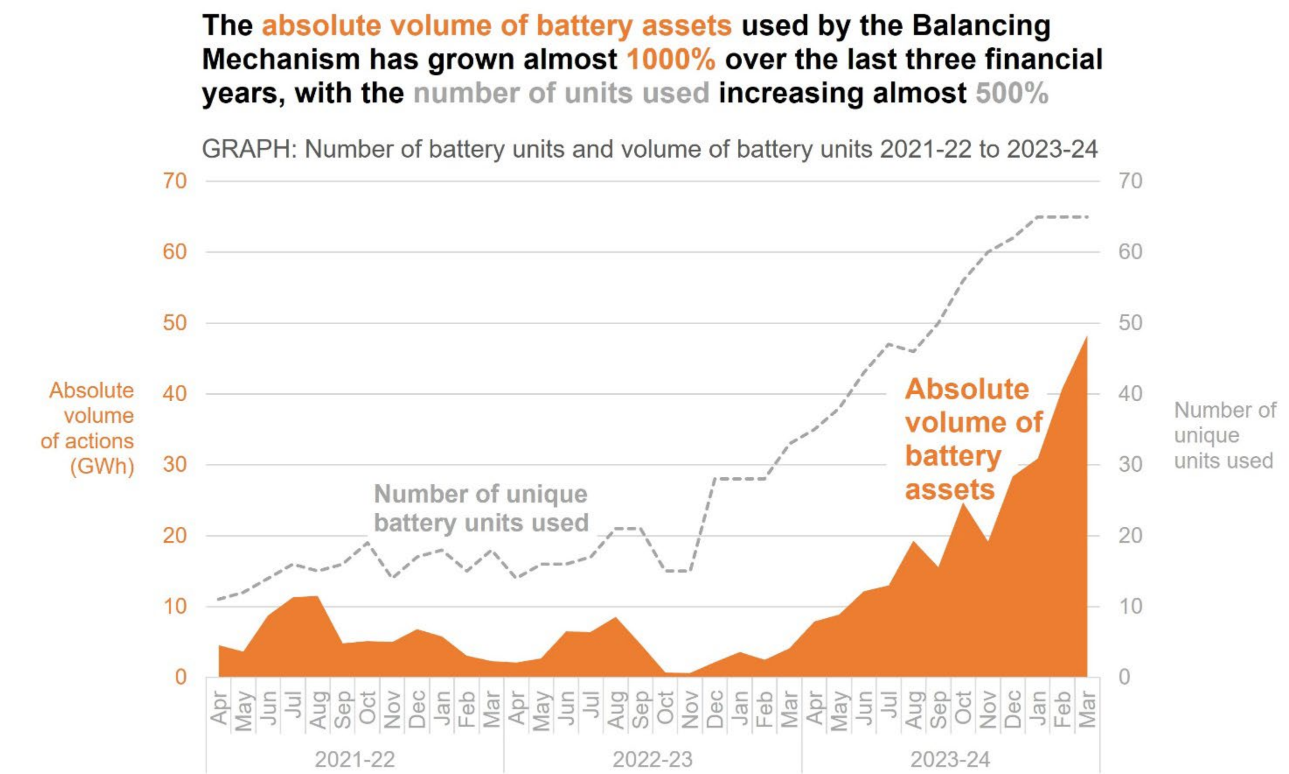
The plan has evolved significantly since October 2023 following collaboration with stakeholders and we have included additional activities targeting further areas of improvement. To date, we have completed 16 activities in total (across all roles), all of which are depicted in the infographics below:


Autumn 2023
Winter 2023
Completed
Connections 5 Point Plan – 5: Interim Offer for BESS
Co-optimised and stacking of response services (Auction)
BMSystem Change - Vergil
Dynamic Regulation: Cap increase
Battery Hackathon
Open Balancing Platform: Release 1
Control room process trials
BM System Change - SPICE
ESO deliverable
Accelerated non-firm connections offers 10GW from 2026.
Enabling market providers to tender across the suite of response services.
System changes to reduce the time to issue instructions.
Increase cap on current auction to 350MW.
Machine learning competition for short-term forecasts of battery SoC.
Launch of Bulk Dispatch capability for Battery Zone & Small BMUs.
Trialling application of storage for reserve requirements.
System changes to enhance Scheduling of Storage

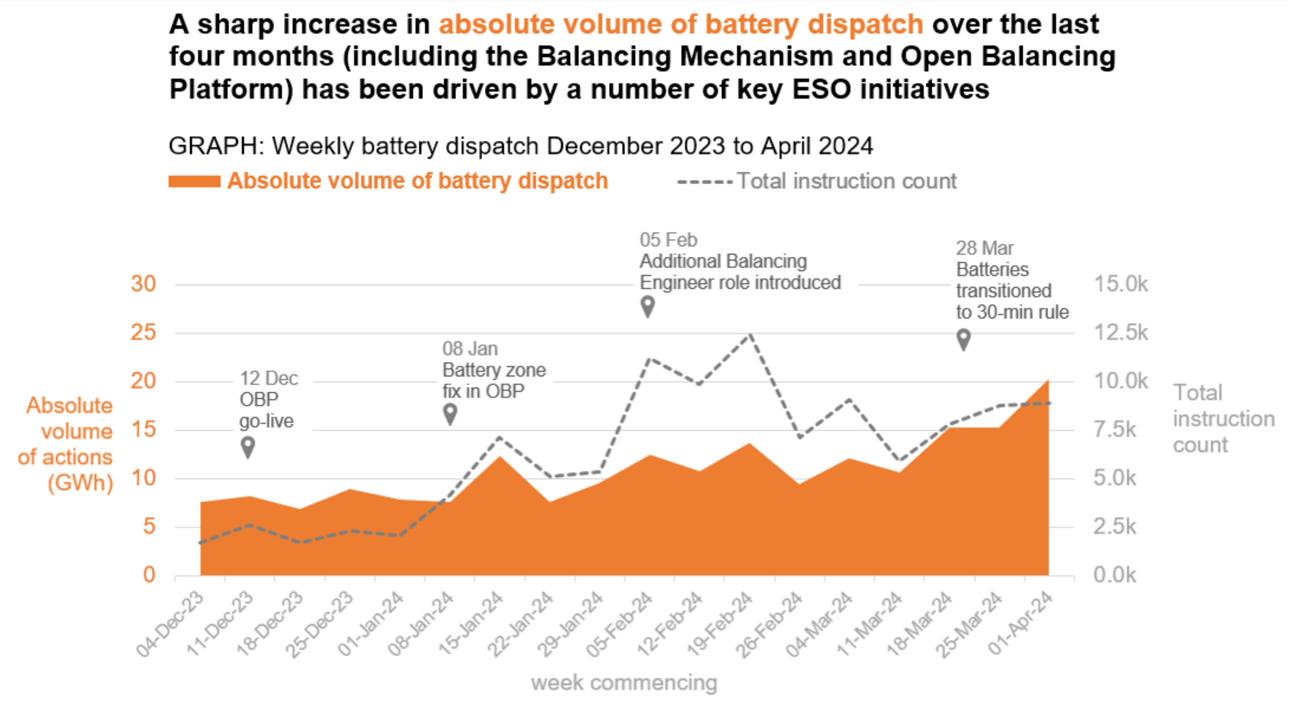

Winter 2023/2024
Spring 2024
Completed
Initiate grid code change for new Storage Parameters
LCP Delta Analysis Phase 1
BM System Change - Vergil phase 2
Control Room Advice & Additional Balancing Engineer
New EDT / EDL guidance published
Balancing Reserve
OBP Training & system changes
Changes to the 15-minute rule for batteries
ESO deliverable
Grid Code mod for new dynamic parameters to enable more efficient battery dispatch.
Define methodology for uneconomic dispatch & Incl. industry feedback.
System enhancement to further reduce the time to issue instructions.
Updated advice for Scheduling and Dispatch & temp. additional balancing engineer to support battery dispatch.
Updated guidance regarding the use of MEL/MIL declarations for visibility of stored energy capacity.
Launch of new product to secure Regulating Reserve on a firm basis at day ahead.
Further training & system improvements (incl. battery zone fixes).
Extending the 15-minute rule to allow energy storage units to be instructed for up to 30 minutes.

To measure the impact of our plan, we have monitored utilisation statistics for number of instructions issued and energy volumes dispatched for these assets.

The chart below displays a view of these for batteries since April 2021.

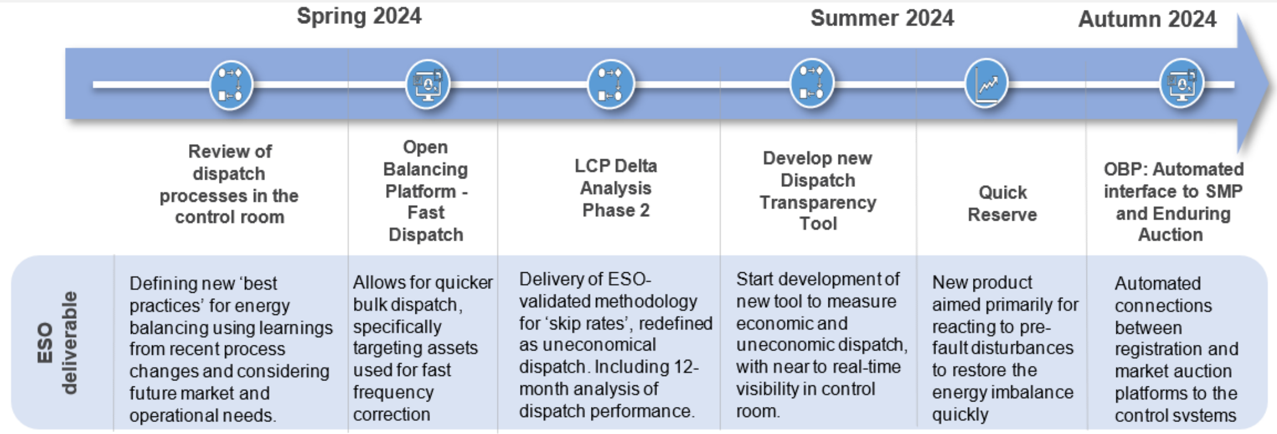


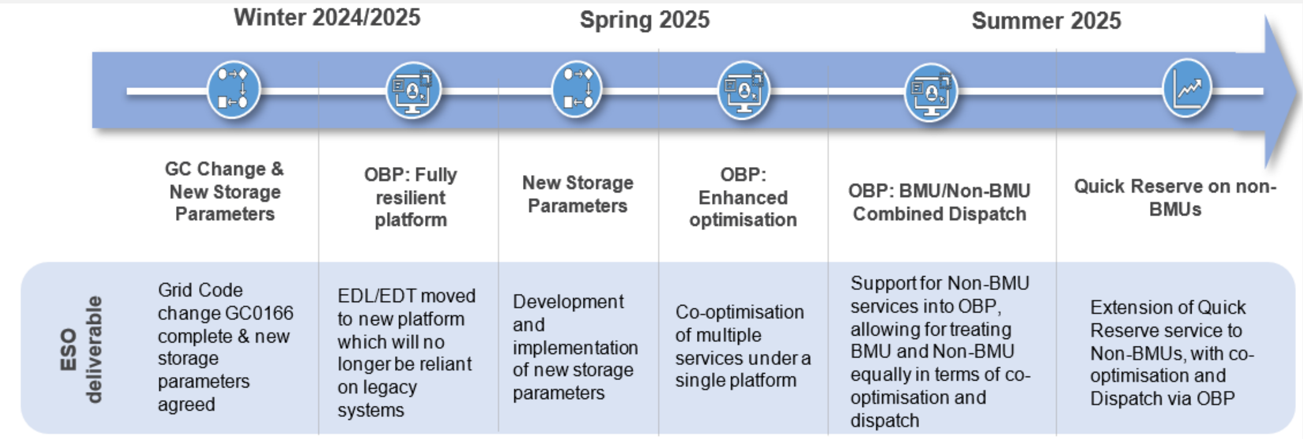
The next chart provides a more detailed view of battery dispatch in recent months, overlaid with key changes implemented from our plan to enhance utilisation of storage assets.



For batteries, this represents an increase of 224% in the average daily volume instructed from 503MWh (April 2023 - January 2024) to 1634MWh (January 2024 - March 2024). For the small BM units, since Release 1 (December 2023) there has been an increase of 47% in average daily instructed volume from 564MWh to 833MWh. The increase in utilisation statistics has also been recognised externally by industry, either through direct feedback to us or via external publications from energy market consultants.

Our current roadmap, is a combination of originally planned activities and additional activities to enhance utilisation of energy storage takes us to the end of 2025 (see infographics below). Some of these activities will require fundamental changes to the way we currently manage these assets to enable more effective operations.





We remain committed to continuing this journey of collaboration and co-creation with the energy industry. Together we will address current and future challenges to enable more efficient operations and a carbon free power system. We will build upon our current engagement and will continue to integrate industry feedback into our plans, maintaining transparency against our progress and ensuring these activities deliver value to consumers.

Network Control

In 2023-24, the Network Control Programme re-baselined the delivery plan to align with an opportunity to adopt a new, more modular platform named GRID OS from our primary vendor General Electric. This pivot to Grid OS has shifted the delivery of our new Network Control Management System (NCMS) toolset back by six months to Autumn 2025. This will allow us to unlock additional benefits both within and after the RIIO-2 period, including a more modular design to future proof the NCMS, meaning we will be able to integrate new applications and interfaces without the need of large-scale projects.

Develop inertia monitoring capabilities and other tools to address emerging technology and system management issues

Following the oscillations experienced in Scotland during summer 2023, the Network Control Programme has worked with our suppliers to roll out two solutions that improve visibility and investigation of these events;

1. A new real-time oscillation awareness tool from Reactive Technologies using their Extensible Measurement Units (XMUs), initially at two north Scotland sites, with negotiations underway to extend wider.
2. Early installation of GE's offline PhasorAnalytics tool, ahead of the planned rollout within the NCMS.

Improvements to our frequency visibility has progressed with connectivity to SSEN's Phasor Data Concentrator, enabling their high-resolution Phasor Measurement Unit (PMU) data to be made available to situational awareness tools such as Frequency and Time Error (FATE), NCMS and Inertia Monitoring. Connectivity to NGET PMU data is expected in late 2024-25.

Delivery of the replacement FATE system was originally scheduled to complete in March 2024. This is now planned to go live in May 2024 following some delays related to integration and implementation of security requirements. The system will initially monitor Scotland until NGET deliver their PMU data in late 2024-25 which will enable the decommissioning of the legacy FATE system.

Discovery work is concluding to enable design of a new system to receive Dynamic System Monitoring data from generators.

We have integrated our two innovative inertia monitoring products with the Data and Analytics Platform (DAP), enabling new dashboards to be created combining inertia data with operational information.

Develop new situational awareness tools

Significant progress has been made in terms of the NCMS work to develop situational awareness tools. We now have a functioning test NCMS environment in the AWS cloud with several systems installed including a test and training system. This has enabled demonstrations of new functionality as well as key functional testing activities. Our project team members have already run over 100 test cases. By June 2025 we aim to have physical systems installed both at GE Vernova and our own premises.

Look-Ahead network analysis capability is a key function of the future NCMS and our requirements have been outlined to the vendor for development, along with sample file sets. However, we have met challenges to ensure an enduring interface is present during data centre migration and on the delivery of a source of forecasting data in the timescales required. By re-baselining this work to align with existing downstream systems we have ensured that go-live timelines will not be impacted.

Benefits have been delivered to control room operations in the form of the Voltage Stability Analysis Tool (VSAT) and Fault Level Analysis Enhancements. VSAT is being used in the control room to calculate, validate, and refine constraint limits in real-time (previously these were calculated for cardinal points only). This enhancement allows optimised operation of the power system. Similarly, enhancements to Fault Level Analysis mean that control engineers can monitor Fault Infeed (system strength) in real-time and identify any issues and schedule generation to ensure stability of the network.

Deliver enhanced network modelling capabilities

The Network Control Programme aims to deliver Common Information Model (CIM) integration for the NCMS and we have derived requirements for CIM integration between online and offline network modelling tools. This will enable modelling efficiencies as well as scenario validation between the two tool sets.

Integration with the OBP has not yet been achieved due to internal factors with the NCMS pivot to GRID OS re-prioritising delivery of this interface. A roadmap and a re-plan for the delivery of the integrations between NCMS and OBP is now in place.

Develop the strategy to upgrade Control Centre video walls and operator consoles

User interface and user experience requirements have been derived for the ENCC operator console and a detailed design is being finalised. This design will now be used to inform the procurement of a solution.

Proof of concept with vendors BARCO and AVEVA have been carried out and are also being used to inform the procurement activity.

Balancing Costs

As part of BP2, in February 2023 we established a new Balancing Costs Team in response to recent increases in balancing costs. The team's purpose is to provide analysis and commentary around causes of and influences on balancing costs, and to drive business and industry change. This work aims to find the right balance between minimising balancing costs and the impact on consumers, while still providing market signals for investment.

In its first year, the team has focused on expanding the delivery of analysis, insights, and reports on balancing costs. In September 2023, we published a new balancing costs webpage to showcase our strategy and portfolio of initiatives to minimise balancing costs, along with unique insights and analysis. We are also producing an annual review of balancing costs that we plan to publish in Spring 2024. This review will outline costs incurred in 2023-24 and give an overview of how cost components may evolve over the next decade. This overview is based on the initiatives outlined in our Balancing Costs Strategy and portfolio of initiatives to minimise balancing costs.

We have also expanded industry engagement on balancing costs during 2023-24. One such case was the workshop on balancing costs that we held on 25 July 2023 with key industry and government members. This forum provided an opportunity for open discussion and views to be expressed on the causes of balancing costs and ways of mitigating high costs in the future. We have also engaged with industry on Physical Notification (PN) misalignment having presented this topic at the Wind Advisory Group and Operational Transparency Forum (OTF) in November and December respectively, again providing the opportunity for industry feedback and discussion. We are also continuing to hold regular workshops and discussions with DESNZ and Ofgem. These include monthly Trilateral meetings to discuss high-level issues impacting balancing costs and promote information-sharing to facilitate cooperative actions between organisations.

Additionally, our balancing costs strategy has improved our performance against Metric 1A. At the start of BP2 we updated the methodology for this metric so it more accurately reflects the drivers of balancing costs that are within our control. Balancing costs for 2023-24 totalled £2.5 billion compared to £4.1 billion in 2022-23.

The Balancing Cost team will continue to build out its capabilities in its second year. The team will also focus on driving new initiatives that will help minimise further increases to balancing costs, which we will be sharing more detail on as they progress.

For much more detail on everything we have delivered in 2023-24, and analysis of balancing costs performance across the year, please see **Metric 1A: Balancing Cost Management**

Scottish Oscillation events (not in BP2 plan)

During June and July 2023, ~8Hz Sub-synchronous Oscillation (SSO) occurred on five separate days, all centred in the Scottish network. The SSO events caused disturbances on the power system, however no demand was lost at any time. We initiated defensive measures and mobilised a significant investigation team working across the ESO and wider industry to immediately focus on the removal of the SSO risk and return the system to normal operation in the shortest timescales. We worked closely with relevant parties to gather and analyse data, and propose, implement and test changes. No link to inertia, short-circuit levels, high wind levels, high transfers across the B6 boundary or decarbonisation in general was identified. Subsequently, we have identified and are progressing a number of activities to reduce the likelihood of SSO in the future. These include guidance for generator connections regarding the testing of damping, a review of the connection compliance process, provisions for Electro-Magnetic Transient (EMT) modelling, and we have accelerated the roll out of enhanced real-time tools and monitoring to provide enhanced situational awareness.

On 8 November 2023, we presented basic details of what happened during the oscillation events to the OTF explaining how the conditions leading to the oscillations were resolved and outlining the conclusions and next steps. (slides 7-15 of OTF 8 November 2023).

Demand Flexibility Service (not in BP2 plan)

Following the creation of the DFS for Winter 2022-23, the service was relaunched for Winter 2023-24. The service allowed us to access additional flexibility when national demand was at its highest (during peak winter days), which was not accessible to us in real time at that time. The service incentivized consumers, both domestic and industrial and commercial (I&C), to voluntarily adjust their electricity usage.

The service was introduced as an ’enhanced action‘ when existing commercial options were exhausted and supply could not meet demand. To build confidence and allow service providers to develop their processes, we committed to running test events in addition to live service activations. For at least the first six tests, a Guaranteed Acceptance Price (GAP) of £3,000/MWh was set to ensure commercial viability and market growth. The outcomes from these test events, along with live events during the winter, would inform the development of future demand side response (DSR) services or enable DSR to access existing services more easily.

A significant development from the previous version of DFS was the ability to instruct the service in three different lead times: Day-Ahead evening, Within-Day morning, and Within-Day lunchtime. This allowed us to assess volume procurement in varying timescales and closer to real-time.

Before Christmas, we conducted six DFS test events, with two events called in each of the three lead times to evaluate their impact on procured and delivery volumes. Additionally, the service was instructed for two live events on 29 November and 1 December, both at the Day-Ahead stage, to ensure greater volumes and delivery certainty as the shorter lead times had not been tested.

Following the Christmas period, one further test was conducted with the GAP. From February onwards, improved electricity margins allowed us to remove the GAP for subsequent tests and explore competitive pricing. Across seven tests, we examined various volume requirements and accepted bids at prices ranging from £150/MWh to £2,500/MWh. We focused exclusively on the Within-Day lead times after Christmas to gain more insights into the service's capabilities close to real-time.

The results of these tests are currently being analysed, and providers were invited to provide feedback by 19 April to inform the future flexibility strategy.

- There are 48 Registered Providers taking part in the service this year, an increase from 31 for winter 22/23
- Around 2.5 million households and businesses have now signed up to take part DFS. This represents an increase of over 50% compared to the previous winter
- Surpassed 1 million registered meters within ten days of launching the service
- Over 3.6 GWh delivered
- 14 tests conducted

Training

We've introduced a number of improvements to the current balancing simulator above what we set out in BP2. This means we have been able to improve the training in the Control Training Unit (CTU) by giving trainees earlier visibility of the tool set and practice in a safe environment outside of the Control Centre. With the initial roll out of the OBP we have been able to use the CTU to train the Control Centre shift teams on the tools. This has resulted in a good uptake of the new tools and an increase in the dispatch of battery generation.

One of the building blocks to the Future Training Simulator is the tool set from investment 110 (NCMS). We had originally planned for this to be delivered early this year but will now land later in summer 2024. This has been delayed due to vendor and data centre availability. It does not affect the critical delivery of the investment as we require the NCMS simulator from October 2024 to begin 'Train the Trainer' sessions ahead of full roll out of the training next year.

Requirement gathering for the overall end-to-end training simulator has begun but, due to a delayed start because of a need to align with projects it is dependent on such as NCMS, they have not completed as expected in March 2024. We now expect to complete this by the end of June 2024. We don't believe this fundamentally affects our ability to have this work completed during the RIIO-2 period.

Recruitment and training remain our top priorities and we are continuing to develop new simulations to enable training to replicate real-time operation.

Recruitment for business-critical roles has progressed well however we have faced several challenges which have included obtaining VISAs, enhanced background checking, onboarding time and time to train by recruiting from overseas. There has been a considerable financial cost and delays in candidates starting training. In most cases there has been an additional need to provide more training in specific GB topics. This has resulted in an extension in the time needed to train but has not compromised the quality of training.

The average cost has also increased as we have had to pay closer to the top of the salary band to attract staff to our roles to compete with others in our sector. We have also faced higher than expected attrition.

The introduction of the workforce management system has significantly reduced the burden of administration and human error around shift management. The introduction of a new mobile phone app in March 2023 allows staff to indicate their availability for overtime, submit leave, meetings, and personal arrangements. Previously this would have been a process that could only be done when working at site. While progress for further functionality is slightly behind schedule, we are confident that it will be complete by the end of BP2.

The need to recruit and train is key to us maintaining our role as the GB System Operator. In the first three years of RIIO-2 we trained 38 new candidates, and our latest view is that we will train 11 candidates in 2024-25 and 15 in 2025-26. This gives a total of 56 new candidates over five years. In addition to this we have trained more than 100 new starters from across the ESO and NG.

Restoration

The GC0156 modification to Facilitate the Implementation of the Electricity System Restoration Standard (ESRS) along with consequential modifications, received approval from Ofgem in February 2024 apart from Balancing and Settlement Code (BSC) modification P451 (compensation arrangements and updating terminologies) which was approved at a later date on 2 April 2024.

We have made progress on the Restoration Decision Support Tool, by clearly defining the requirements while keeping our industry stakeholders informed about its capabilities and progress. We remain confident in meeting our expected implementation date. Our internal delivery plan has faced delays due to resource constraints, which have since been addressed. Despite this, we are still behind schedule internally due to delays in approving the Request for Proposal.

We are incorporating findings from the Distributed Restart project (described in A3.3 Innovation project in Restoration) into our implementation plans. We have shifted our strategy from a top-down approach to a more holistic one, integrating both top-down and bottom-up approaches to restoration. This transition enables us to harness the potential of Distributed Energy Resources (DERs) for restoration purposes. With the implementation of the GC0156 Grid Code modification and consequential adjustments to relevant codes, the necessary framework has been established to empower relevant stakeholders for bottom-up restoration efforts. Additionally, an ongoing tender process for restoration contractors has been initiated, incorporating participation from generators within the DNO network.

We also published the Annual Assurance Framework 2023-24 on schedule in Q1.

Finally, below we give an update on our procurement activities:

Procurement Activities	Update
Northern	The tenders were launched in 2022. The contracts will be awarded in May 2024. Awarded contractors are to be in service by November 2025.
SW and Midlands	New SW and Midlands tenders will be launched within regulatory year 2024-25. We are meeting with relevant stakeholders as part of tender kick offs.
South East	The South East tenders were launched in 2022. The contracts were awarded in December 2023. Awarded contracts are to be in service by July 2025.
Wind – Great Britain	The wind specific tenders were launched in 2022. There were no successful contracts awarded.

Transparency

We reviewed our activities to identify those which contribute to the ongoing delivery of transparency, and published the revised ESO Transparency Roadmaps on 6 July 2023 and 21 December 2023.

We continue to hold the OTF weekly with active participation from industry stakeholders. In December 2023, we issued a survey to all external and internal stakeholders to understand how well the current OTF approach meets their needs and what changes they would like to see. This will identify and drive continuing improvements to these events. We shared high level feedback from the survey at the OTF in January 2024. We're committed to presenting summary outcomes at the OTF and will publish the full survey outcomes later in May 2024. The OTF Survey Report will include individual responses to each feedback comment. All our responses detail the changes we will make to incorporate the feedback/suggestions, or an explanation as to why we cannot address the request.

We continue to engage with stakeholders to explain how we make dispatch decisions and to respond to queries arising from the data published each week. On 2 June 2023 we held our first online Dispatch Transparency event, which was attended by over 300 stakeholders. We also presented at the Balancing Programme

Quarterly event on 15 June 2023 and have engaged with customers bi-laterally. In cooperation with the work on Enhancing Flexible Storage in the BM we are investigating opportunities to make the Dispatch Transparency dataset more accessible. The aim is to ensure that analysis and insights can be made to identify potential improvements for our processes and customer business models. This has included employing external consultants to independently assess BM dispatch transparency and dispatch efficiency. This includes both quantitative analysis and qualitative work including stakeholder engagement and the consultants are expected to report on their findings in June 2024.

We continue to work on the Digital Engagement Platform (DEP), which will make the experience of engaging with us more intuitive and user friendly. The DEP will provide a single sign on for all our services and a personalised user experience with access to information, data and other services including markets, connections and codes. Our approach has been to front-load work on our programme and bring in maximum resources early on. This has meant a slow start on foundations but then acceleration powered by a big team all working together. This has led to delivery using expected resource and budget but often delivering ahead of expected timelines. DEP was ready to integrate with the Data and Analytics Portal (DAP). However, DAP has been delayed until 2026, as explained in the DAP section below. A Change Request has been raised to safeguard money intended for DEP/DAP integration this year until when it is needed.

The Open Data catalogue already provides external users with a view of our Data and enables internal users to develop their own data products to benefit consumers. Work continues to improve cataloguing of data which will continue until after the migration of all our data sources is complete (expected July 2025).

Data and Analytics Platform (DAP)

Over the last 12 months, we have built the essential components of the DAP. This enables us to store reliable data, for internal and industry use, as promised in BP2. A review of the initial DAP infrastructure provided valuable insights, enabling us to refine our delivery approach, specifically configuration and delivery of the technology.

The adoption of a medallion architecture improved the structure and quality of data. This resulted in an estimated 500% increase in overall processing speed compared to the previous implementation by reducing the average data processing time from 30 minutes to just 5 minutes.

This medallion architecture logically organises data in the Data Lakehouse (Data Storage Capability), improving the structure and quality of data incrementally and progressively as it moves through each layer of architecture, from raw to cleaned and conformed to curated business level tables. This ensures data is of high quality and can be trusted by industry and internal users.

The Data Lakehouse architecture combines the beneficial aspects of data lakes and data warehouses. It has provided a highly scalable and high-performing data platform that hosts both raw and curated data sets, used for quick business consumption and to drive advanced business insights and decisions. It stores raw data for data scientists used in business projects and stores cleaned and processed data used for operational reporting and BI (PowerBI).

The Data Lakehouse has enabled us to break down data silos and provide seamless, secure data access to authorised users on a single platform. This delivers process efficiencies, reduced costs, and gives faster access to insights.

DAP has delivered several key end-to-end data source connections, enabling fast data ingestion from sources such as Single Markets Platform (SMP), Performance Analytics Platform (PAP), Elexon, Data Portal, National Economic Database (NED), and Future Energy Scenarios (FES) SharePoint. These enable DAP to support the delivery of key objectives for the business and BP2 commitments. Additional data source connections will be made by September 2024 to support the remaining BP2 commitments.

A further development is the Advanced Analytics Environment (AAE), which enables the creation of Artificial Intelligence and Machine Learning models using a secure, scalable, and centrally managed architecture. It allows data scientists to create models in the AAE using trusted data stored in the DAP Data Lakehouse. PowerBI, a data analytical and visualisation tool, has been added as a DAP end-user tool. This allows end users to access the DAP Data Lakehouse directly and create and share business reports for insights or business operations. This was delivered successfully with the DAP portfolio and helped the delivery of dependent programmes.

The DAP has achieved significant success in fulfilling its promises, such as monitoring inertia, integrating a single market platform, and "proof of concept" for the remediation of End-User Developed Applications (Grey IT). The change in architectural approach has caused delays in delivering platform capabilities that many programs are dependent on. We are collaborating with affected program leaders to establish and approve new delivery dates, which will follow an agreed prioritisation which enables value and benefits. DAP has ensured key priorities are being delivered in line with operational necessity i.e. ASR. We remain confident in the capabilities of the DAP Platform, and continue to work closely with program leaders to meet our commitments.

In addition to DAP delivering a data catalogue service within its platform capabilities, the DAP team has extended the data catalogue services to support an Enterprise Data Catalogue across the ESO (and will replace the existing catalogue used within the open data portal with more robust metadata, where appropriate). This will scan, create, and capture metadata and data lineage of all our data, providing a searchable single view of all available data in the organisation, as well as direct connectivity to the DAP data catalogue services.

The DAP application "landing page" provides an interface for internal end-users to access and use DAP capabilities. Through this page, users request various DAP services such as creating an advanced analytics environment or accessing DAP data.

Market Monitoring

Our Market Monitoring function carries out surveillance work across all the services we procure including monitoring of balancing markets as set out as a continuous activity in our deliverables. Also, in line with our planned deliverables, the Market Monitoring team commissioned an independent review of our processes and controls. The objective of this review was to ensure that the team are fulfilling the licence condition and REMIT obligations of proactively monitoring our balancing markets for suspicious activity. The review concluded that the team have attained a very high standard of practice within a short time, and that policies, processes and risk assessments are well designed and clearly written.

Alongside core monitoring duties, the team published a second Winter Review for 2022-23, focussing on balancing costs. Findings included a reduction in overall balancing costs from the previous year, but an increase in actions to manage operational requirements such as inertia and margin. A report highlight was demonstration that there was a £199m decrease in costs associated to the ‘delay de-synchronisation strategy’ employed across winters 2021-22 and 2022-23 with this trend continuing across winter 2023-2024. It is considered that a combination of the Balancing Market Review, Ofgem’s open letter and the introduction of the Inflexible Offers Licence in October 2023 were significant factors in this cost reduction with the market monitoring providing support against all of these initiatives. Following publication of this report a workshop was held with interested stakeholders in July 2023 to discuss the findings and examine the data that fed into the report, the outputs of this have been used to further develop our cost analysis processes.

In addition, a series of workshops were held with Ofgem to provide transparency of monitoring processes, data and how investigations are structured. This led to useful feedback and insight into what Ofgem need included in our Suspicious Transaction Reports (STRs) and the supporting data, while also providing OFGEM with a clear view of data and tools available to the team.

Market Monitoring have developed robust, fuel specific methodologies for assessing reasonableness of bid and offer prices, continually improving capabilities to screen for compliance with market rules. This has included building bespoke tools for monitoring against all licence conditions such as the IOLC, and a new suite of tools using more sophisticated outlier detection techniques through delivery of the innovation project 3MD. Furthermore, by building detailed subsidy specific models many periods across 2022 and 2023 were identified where the indirect costs of accepting bid prices from units holding contract for difference subsidies were extremely high, leading to an estimated £160M in additional costs to the consumer. This was identified as a flaw in the interactions of the Balancing Mechanism (BM) and policy, and the issue was escalated to LCCC, Ofgem and DESNZ in February 2023 resulting in a Balancing Settlement Code (BSC) modification proposal being recommended and change proposal P462 being issued in November 2023. In line with the principles of the BSC, the scope was broadened to review all contributors to the identified market inefficiency considering all support mechanisms. The function continues to support an active BSC workgroup P462 to review if this is the most appropriate means of resolution, recognising that while this has potential to significantly reduce the cost of balancing it is also a significant change with wider market ramifications.

Forecasting

In BP2, we have continued to enhance our forecasting. This has improved operational decisions by providing the control centre and market participants with better quality and more frequent forecasts.

We have seen a notable improvement in our demand forecasting since the start of BP1, which is now supported by machine learning capability which became operational in 2021. Solar forecasting continues to be a challenge under particular weather conditions, and we continue to liaise with the Met Office to improve this.

We have made significant tactical improvements in addition to our BP2 commitments and are now seeing the benefits from that work. The amendments include reference data corrections and system alignments, a complete update of every windfarm (of which there are more than 200) model and improved diagnostic capability. Additional weather locations have also been requested from the Met Office. Windfarm outage data (when supplied) is now used in the forecasts, and we are improving the wind cut-off (high speed shutdown) representations. We now publish every wind forecast externally, down to windfarm resolution.

Allowing for data corrections, the operational windfarm fleet has grown by approximately 30% since the start of BP2. Our wind forecasts remain sensitive to unstable weather patterns, particularly relating to offshore locations and our 1C Metric performance is now heavily influenced by only a handful of windfarms.

We have made proposals to make minor changes to the 1C Metric to make further allowances for influences beyond our control.

We anticipate additional enhancements to our wind forecasting models later in 2024, with the release of our next-generation wind forecasting product (PEF R5). This product will allow the use of richer weather data (Numerical Weather Prediction (NWP)) and a wider range of models, including AI / machine learning capability.

Further improvements to the demand forecasts will also be realised through improved embedded wind modelling. Improvements to the solar forecasts will be realised in early 2025, through the parallel adoption of technology developed for the PEF product.

Please see our update on the Balancing Programme for details of progress on the Platform for Energy Forecasting (PEF).

Deliverable Status

Our BP2 RIIO-2 deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables, with commentary including explanations for all delayed milestones.

The statuses are defined as follows:

On track	For a milestone date in the future: we're on track to deliver it on time
Complete	Milestone has been delivered
Delayed – consumer benefits	Delayed or de-prioritised to maximise consumer benefits
Delayed – external reasons	Delayed due to factors outside our control (e.g., BREXIT, Covid, Ofgem)
Delayed – internal reasons	Delayed due to factors within our control and/or that we're accountable for
Continuous activity	For certain activities with ongoing delivery (e.g., OTF)
Milestone no longer valid	Removed from Delivery Schedule as no longer required (agreed with Ofgem)

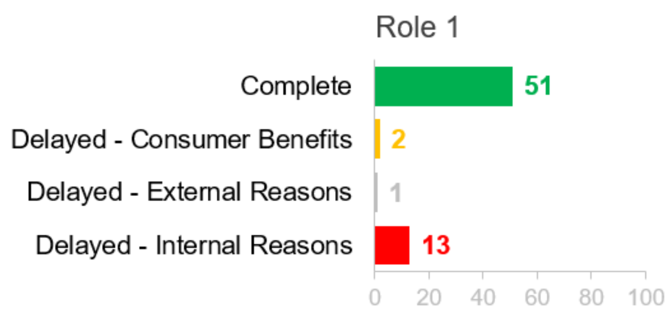
Statuses of 'on track' or 'continuous activity' are not shown as they can only apply to milestones not yet due for completion.

Role 1 - Progress of our deliverables

For Role 1 (Control Centre Operations), the latest BP2 RIIO-2 deliverables tracker lists **52 deliverables** in total, which is made up of **140 milestones**.

- **67** of these milestones were due to be completed by March 2024 or earlier
- Of those:
    - **2** are delayed in order to deliver an improved outcome for consumers
    - **1** is delayed due to reasons outside our control
- Of the remaining **64:**
    - **51** (80%) are now complete
    - **13** (20%) are delayed due to ESO related delays

The results for the 67 milestones due to be completed by March 2024 or earlier are illustrated below:



Role 1 – Milestone status by deliverable

For milestones due by March 2024 or earlier

Ref	Deliverable name (shortened)	Complete	Delayed... Consumer Benefits	External reasons	Internal reasons
D1.1.4	Support development of new methodology under Trade...			1	
D1.1.5	Upgraded legacy balancing and situational awarenes...	1			
D1.1.6	Assessment of future operability challenges commun...	1			
D1.1.7	Produce and publish detailed forecasts and analysi...				2
D1.1.8	Trading solutions to deliver a safe, secure and ec...	1			
D1.2.1	(Now known as 'Future of Balancing') Enhanced bala...	1	2		
D1.2.2	Develop inertia monitoring capabilities and other ...	1			
D1.3.1	Develop and deliver new real-time situational awar...	1			2
D1.3.2	Enhanced network modelling capabilities with onlin...	1			1
D1.3.3	Upgraded Control Centre video walls and operator c...	4			
D1.4.1	Creation of a data and analytics platform that wil...				2
D1.4.2	Continue to facilitate meetings of the Technology ...	4			
D1.5.1	Increased DER visibility in real-time operations	4			
D1.5.2	Whole electricity system operational service coord...	3			
D1.5.3	Development of RDP and LCM functionality into real...	1			
D1.5.4	Increased operational liaison	2			
D1.6.1	Constraint boundary optimisation	1			
D1.6.2	An agile programme of strategic and tactical Balan...	2			
D1.6.3	Stakeholder Engagement on Minimising Balancing Cos	1			
D17.3	Transparency Roadmap	2			
D2.1.1	Develop and drive control centre strategic resourc...	1			
D2.2.1	Development of new modules and (based on feedback)	2			2
D2.2.2	Enhanced training and simulation with DNOs and wid...	1			1
D2.3.1	Upgrades to current simulators, including annual s...				2
D2.3.2	New training methods and platforms, including onli...	3			
D2.4.1	Personalised updates and automated shift logins to...	1			1
D2.4.2	Content and infrastructure for personalised traini...	4			
D3.1.3	Engage and collaborate with industry to plan and d...	1			
D3.1.5	Fully competitive Restoration procurement process...	1			
D3.2.1	Facilitate and compile, on behalf of the GB indust...	1			
D3.2.3	Maintain obligations and requirements against the ...	2			
D3.3.1	Trial case studies based on different technology t...	1			
D3.3.2	Subject to industry adoption, Distributed ReStart ...	2			
TOTAL - Role 1		**51**	**2**	**1**	**13**

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 1. Some of these projects are funded as part of the RIIO-2 price control, and are therefore eligible for consideration as part of the RIIO-2 incentive scheme. The references in the table below provide links to additional information about each project.

Innovation Project Name	Description	Progress update	Deliverables supported	Status	Funding
Solar Nowcasting [1]	Research and develop the use of machine learning & satellite images to nowcast PV at GSP-level.	The project has now incorporated probabilistic forecasting for both GSP and national forecasts. The latest forecast at 0-8hour ahead is providing around 20% accuracy improvement vs. the previous iteration and is also significantly more accurate in comparison with recent PEF data. Evidence from the tool webpage available to ESO suggests that it has been used on 90% of days in the last 10 months, although the context of this needs to be investigated. The project is now considering how the tool can be input into ESO systems following the innovation project completion.	D1.1.7	Delivery	RIIO-2
Dynamic Reserve Setting [2]	Use AI and machine learning to set reserve levels dynamically, at the day-ahead stage.	Following the extension of the original project to allow the development of a proof-of-concept model, the project has now been delivered and is being trialled in the control room and is currently awaiting control engineer sign off and IT productionisation before full implementation (also mentioned under Role 2).	D4.1 (D4.3.3 from BP1)	Delivery	RIIO-2
Co-optimisation of Energy and Frequency-Containment Services [3]	Develop mathematical modelling techniques to achieve co-optimisation of energy and frequency services, to enhance the efficiency and security of the operation for the	The project has developed detailed mathematical formulations of the regional frequency-related constraints in a two-region power system (England and Scotland). Extensive case studies have been carried out to demonstrate the applicability of the regional frequency-stability conditions in co-optimisation problems capturing both energy and multiple frequency services. In	D1.2.1	Delivery	RIIO-2

[1] Solar PV Nowcasting | ENA Innovation Portal (energynetworks.org)

[2] Probabilistic Machine Learning Solution for Dynamic Reserve Setting | ENA Innovation Portal (energynetworks.org)

[3] Co-optimisation of Energy and Frequency-containment services (COEF) | ENA Innovation Portal (energynetworks.org)

	future electricity system.	addition, the tool has been extended to include both centralised optimisation and self-dispatching optimisation. A simplified GB power system integrated with around 600 generators has been employed as the platform to test the proposed frequency-secured framework to demonstrate that it is key to procure inertia and frequency response appropriately among the different regions of the system. Further consideration is needed for the complexity of the whole system with more generators and network components, to overcome some of the inherent limitations of the tool.			
Dispatch Optimiser Transformation[4]	Design a blueprint for transformation of control room tools and processes to meet System Operator needs of the future.	The project included the identification of future capabilities needed to realise the envisioned objectives for future dispatch optimisation, along with a comprehensive analysis of the current state of these capabilities. Once the as-is and to-be states were articulated, a detailed gap analysis was completed to identify the steps required to transition to the desired future state. The project also completed a comprehensive evaluation of input data models, assessing required input and output data for each model as well as data quality and availability. An architectural framework was proposed to support the objectives for future dispatch optimisation.	D1.2.1	Complete, follow-on activities being scoped by business leads.	RIIO-2
3MD (Market Monitoring Model Development)[5]	Explore machine learning methods to identify types of possible market manipulation in the Balancing Mechanism (BM), applying core principles set out in REMIT legislation	Through the creation of anomaly-based detection models as part of the project scope, these models have been embedded into daily ESO processes as each piece of work has completed. This includes monitoring price levels of BM units and creating a new process to assess cases	D18.1.1	Delivery	RIIO-2

[4] Dispatch Optimiser Transformation (DOT) | ENA Innovation Portal (energynetworks.org)

[5] 3MD (Market Monitoring Model Development) | ENA Innovation Portal (energynetworks.org)

[6] REVEAL | ENA Innovation Portal (energynetworks.org)

	and other market rules.	against the new Inflexible Offer Licence Condition (IOLC). Since embedding processes into ESO systems, a number of cases have been identified and escalated to Ofgem, triggering more detailed investigation into market participant behaviours.			
REVEAL[6]	Designing a single environment and developing a Proof of Concept to enable Balancing Trial Capabilities to expedite learnings for unknown elements, such as EV operation.	Having defined a vision, assessed the technical and regulatory feasibility in phases 1 and 2, in phase 3 of this project we have identified, workstream areas to focus on, two technical areas for ongoing consideration (a) Live trial environment and (b) Trial Management Platform and other learnings to support growing maturity of our capability to be fed back into existing business processes. In addition, we have built a backlog of capability requirements to support balancing trial activities going forward and for future consideration. Phase 4 is now being defined whereby a Proof of Concept will be delivered for a live trial environment/sandbox with the aim of building trialling capability going forward.	(No directly linked deliverable)	Delivery	RIIO-2
Scenarios for Extreme Events (SIF Alpha)[6]	This SIF funded project sets out to better understand how whole-energy system resilience can be impacted by extreme events, identifying vulnerabilities, and informing future investment planning decisions.	Currently reaching the end of Alpha Phase this project is designed to evaluate and prototype the creation of a tool to model the risks associated with extreme events, and the impacts these have on the GB energy system for the end consumer, the ESO and Network Operators. Critically, it looks to translate impact into societal disruption narratives that look at consumer-focused resilience i.e., disconnections to critical services and vulnerable consumers. The Alpha phase has focused on defining the language, frameworks, and requirements for extreme event risk assessment. A proof-of-concept model over a region of Scotland has been developed, which models both	(No directly linked deliverable)	Reaching end of Delivery. Moving towards Beta application	SIF Round 2

[6] https://smarter.energynetworks.org/projects/10078787-1/

	the electricity and gas system and explores two scenarios: a weather scenario (a windstorm scenario identified by the Met Office as likely to impact the energy system); and a single asset failure scenario of a failure in a gas terminal to demonstrate the impact of gas network resilience on electricity.	

A.2 Stakeholder Evidence for Role 1

Our incentive scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of our plan delivery. To demonstrate performance against this criterion, we report on our stakeholder satisfaction survey results, as well as describing how we have worked with stakeholders during the year.

Stakeholder surveys

The ESO has commissioned surveys from market research company BMG. These surveys measure satisfaction for each ESO role and are carried out on a six-monthly basis. The survey is targeted at senior managers, decision makers and experts, and includes a wide selection of relevant stakeholders who have had material interactions with the ESO's services. In total we contacted 1496 stakeholders, across all 3 roles.

Role 1

For Role 1, the following question was asked:

> "One of the ESO Roles is focused on Control Centre Operations, which includes key activities such as real-time system operation, system restoration, balancing mechanism review and provision of data and forecasting. Overall, from your experience in these areas over the last 6 months, how would you rate ESO's performance?"

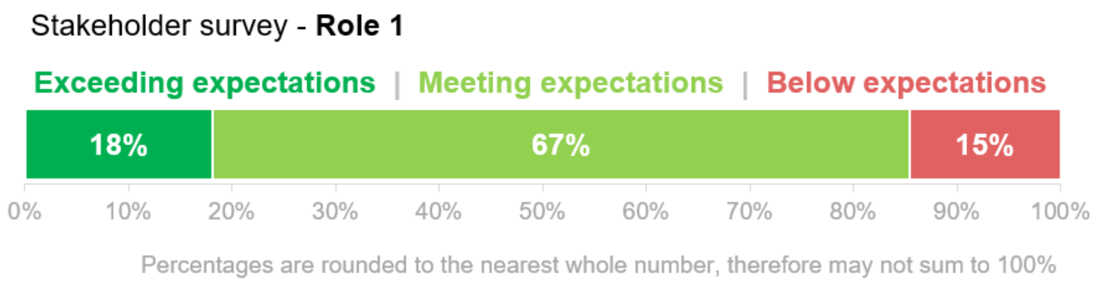
Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

1. If they rated the ESO as below expectations, they were asked what the ESO needed to do to meet their expectations.
2. If they rated the ESO as meeting expectations, they were asked what the ESO needed to do to exceed their expectations.
3. If they rated the ESO as exceeding expectations, they were asked what the ESO did that exceeded their expectations.

For Role 1, we contacted **271** stakeholders, and received **55** responses to this question, which were distributed as follows:

- **18%** exceeding expectations
- **67%** meeting expectations
- **15%** below expectations

(Percentages rounded to the nearest whole number)



	Summary of stakeholder feedback for Role 1
“Exceeding Expectations” **10** stakeholders scored us as “exceeding expectations”. Feedback on what we have done to exceed stakeholder expectations in Role 1 included:	• **Good customer service and stakeholder interactions delivered by Control Room** – Several responders highlighted the helpful nature of the control room from their interactions, the sharing of knowledge, expertise, time, and the supportive nature of the team. One expanded on this, stating that “The control centre operations team always provide excellent service”. • **Effective communications and engagement** – Several responders acknowledged our communications and engagements as a success, suggesting that we have been proactive at engaging through industry events, publications, the OTF and drop ins. • **System operations are impeccable** – One stakeholder commented that “system operations are impeccable”, while another flagged the data portals as a positive. • One stakeholder commented that we were “open to innovation” and enabled “a good working atmosphere”.
“Meeting Expectations” **37** stakeholders scored us as “meeting expectations”. Feedback on what we need to do to exceed stakeholder expectations in Role 1 included:	• **Reduction in Costs** - Several responders expressed that they would like a reduction or removal of costs, such as calling costs and balancing costs. • **An increase in visibility and transparency of information shared** – more transparency and visibility of information is a prominent theme, with stakeholders asking that we share more electrical analysis studies, release more information, and provide insights into how we track key metrics, such as skip rates. One requested “real-time updates on feedback on the causes of outages relating to Electronic Data Transfer (EDT) and Electronic Dispatch Logger (EDL), and mitigations taken” to offer resilience against these causes. One expressed a view of accepted live bid-offer acceptances (BOAs) and the price stack that the control room sees would be helpful. • **Reduce Delays** – Stakeholders requested more timely and accurate communications regarding outages and delayed comms between ourselves and switching. Data delays have been flagged as an issue for stakeholders, making it extremely hard for the market to accurately calculate imbalance prices in real-time with many periods being re-priced post-event. • **More collaboration** – One stakeholder expressed a desire for more collaboration between us and the Transmission Owners (TO) planning teams to improve processes. • Several stakeholders were happy with the services provided, and highlighted improvements to balancing services. Similarly, one stakeholder commented that we had improved our communications across role 1, and that there was a positive “step change in engagement”. Our development of the OBP has been welcome to address skip rates etc, but this does not exceed stakeholder expectations. One stakeholder stated that we already “perform to my high expectations”.

"Below Expectations" **8** stakeholders scored us as "below expectations". In response to being asked what we need to do to meet their expectation, we received the following feedback:	• **Enhance the delivery of data** – Improvements to the way we deliver data is a recurring theme. Several responders indicated data is often provided late while some data sets are lacking, missing, or riddled with errors. One expressed that we must lead and ensure the reliability of live market data in the Balancing Mechanism Reporting Service (BMRS). • **Improve processes across the Control Room** – Several responders said we need to improve processes within the Control Room. They feel that we focus on system faults and causation instead of our role of re-securing the system, there are significant delays in day-to-day outage management as the Transmission Status Certificate (TSC) process is cumbersome and inefficient, and slow manual processes generate a bottleneck and cause delays to planned activities. • **Valuing flexibility in the Balancing Mechanism (BM)** - Two stakeholders expressed concern regarding how we value flexibility in the BM. One suggested we review the value placed on flexibility relative to traditional generation in the Balancing Mechanism (BM) and the ancillary services it procures and develops. One stakeholder expressed "that while the Open Balancing Platform (OBP) is a very good addition to the Control Room operation, it doesn't solve some of the larger issues with valuing flexibility in the BM and that the implementation of Balancing reserve has always favoured large BM units". • Other suggested improvements include: communications need to improve, as do Control Room decisions on storage, we should be more proactive in contacting Distribution Network Operators (DNOs) and be more transparent in sharing information regarding faults to allow stakeholders to assess network vulnerabilities.

Addressing stakeholder feedback in BP2

Effective engagement with stakeholders has been instrumental to the successful deployment and development of our business activities and projects across our Control Room operations across BP2. In the following section, we outline how we have addressed stakeholder feedback gathered via stakeholder surveys and regular project/business activity stakeholder engagement to improve our Control Room operations.

❶ Responding to stakeholder feedback across the Balancing Programme

The Balancing Programme aims to maintain and generate change in our current balancing capabilities to assist our Control Room operations. While evolving our new balancing capabilities, we must deliver reliable and secure system operation, facilitate competition for the benefit of consumers, and meet our ambition for net-zero carbon operability.

Since the Balancing Programme Strategic Review in BP1, we have further improved our approach to stakeholder engagement across BP2. The improvements have helped us implement new capabilities and ensure we continue to deliver our roadmap in collaboration with industry priorities.

Below, we have provided a range of stakeholder evidence that demonstrates how we have reacted to feedback in the Balancing Programme and used it to make improvements.

- **Improvements in our Balancing Programme communications and engagement**

  Across the first half of BP2, we have set up and hosted nine Stakeholder Focus Groups across the following themes: Optimisation, Storage, Forecasting and Technology.

  The Groups are designed to be interactive, enabling industry to share their ideas and concerns, which can help shape deliverables and smooth key transition points. For example, the Storage Stakeholder Focus Group gathered and collated information and concerns from the industry ahead of initiating Grid Code change - GC0166, which covers the development of new parameters for Limited Duration Assets, such as batteries. The feedback helped to address challenges in how these assets are dispatched efficiently.

  Stakeholders told us it would be useful to have more regular communications between the events and better sharing of information. Therefore, to complement our interactive engagement, in August 2023 we launched our Balancing Programme newsletter. We use the newsletter to share regular updates on the programme, release information and outputs of the stakeholder groups, and give opportunities for further engagement including details of events we are facilitating.

- **Delivering greater transparency to stakeholders on our website following stakeholder feedback**

  Following industry requests for better transparency and simpler discovery of information, we changed our website and uploaded content from our BP2 Balancing Programme activities.

  To enable improved visibility of current and future programme delivery we have published:

  - event presentations
  - system demonstrations
  - Q&A sessions
  - content from the Stakeholder Focus Groups.

  Stakeholder engagement materials can be found on our Balancing Programme web page here.

- **Delivering at Pace with the launch of the Open Balancing Platform**

  On 12 December 2023, the Balancing Programme went live with Release 1 of the Open Balancing Platform (OBP). Following the stakeholder feedback we received, we expanded our original scope for Release 1 of OBP to include an additional zone for batteries, which we launched alongside the small Balancing Mechanism Units (BMUs) zone.

- **Delivering on our ongoing commitment to remove barriers for market participants to contribute in Distributed Flexibility**

  Following stakeholder feedback around the current standards being a major barrier, we have committed to enabling up to 300MW of aggregated assets into the Balancing Mechanism (BM). Alongside the initiative, we have commissioned an independent external review of our operational metering standards. This will ensure our enduring standards will be fit for maintaining system security in the current and future energy mix and will provide certainty to stakeholders around any future requirements.

❷ Co-creating a plan to enhance the use of storage assets in the Balancing Mechanism

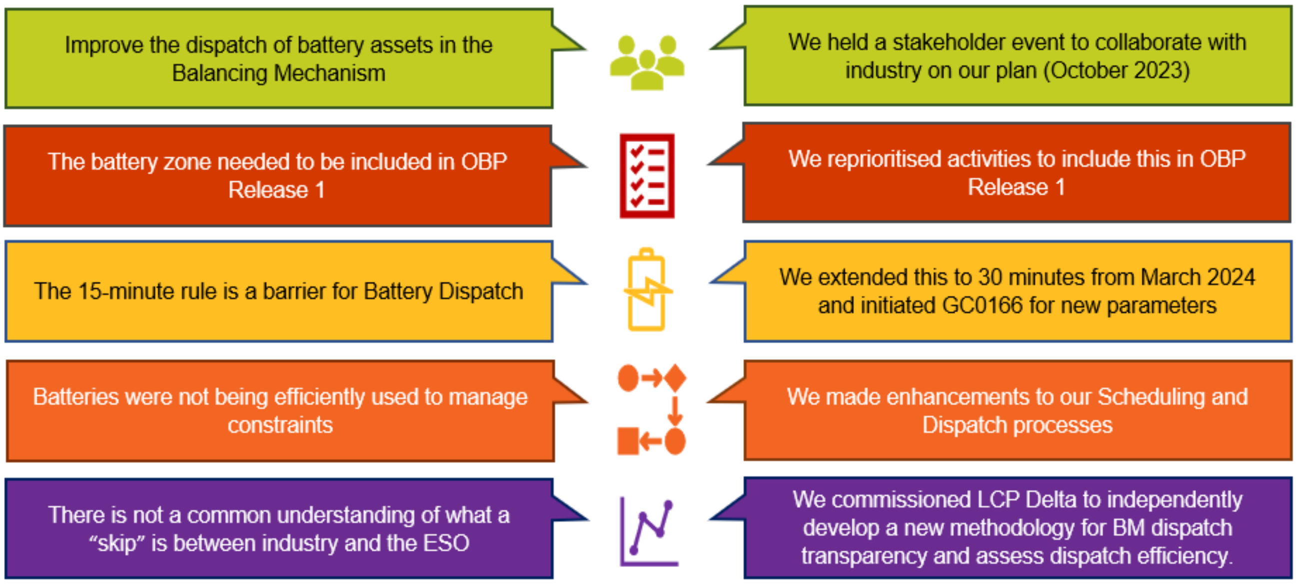
In the last year, stakeholders have told us we needed to improve the dispatch of storage assets in the Balancing Mechanism (BM). Alongside the plan set out in October 2023 detailing how we would enhance the use of storage assets in the BM, we held a stakeholder event to collaborate with the industry on our plan, which focused on:

- Improving dispatch data transparency, providing a deeper understanding of operational actions in the control room and the reasons for these.
- Enhancing system and process capabilities within the Control Room, in line with the transition to the OBP.

- Enabling new Energy Storage parameters to enhance use of storage in the BM.
- Co-creating future capability and market solutions that enable efficient dispatch of all assets in the BM.

At a webinar in February 2024, we presented changes that have been implemented based on stakeholder feedback during Winter 2024, progress against our plan, and future deliverables still to be implemented. The slides from this webinar can be found here, along with a recording of the session here. The figure below captures a summary of feedback received from industry and our response. We have continued to provide updates on this work at the Operational Transparency Forum.

Storage Stakeholder Feedback – "You said, we did"



❸ Addressing feedback from the Technology Advisory Council (TAC)

The Technology Advisory Council (TAC) advises us on our digital, data and technology-related innovation and transformations, including cross-industry initiatives. TAC is made up of a diverse range of experts with significant experience in technology and transformation, including participants from network companies, market participants, consumer groups, academia, and technology companies. It ensures we work closely with the industry on the development of new systems.

We use the TAC to gain insights about the benefits of our technology investments and act on any stakeholder feedback. So far in BP2, examples of feedback we've acted on from meetings and the TAC May 2023 survey include:

1. Focusing on verifying the data accuracy of information coming into the Virtual Energy System (VES). As a result, data accuracy was a major component included in our Minimum Viable Product (MVP).
2. Improving our Network Control Management System by reducing the number of different interfaces with different applications. To help us achieve this, we're close to hopefully approving a concept from General Electric (GE) and their newly acquired partner, Greenbird. This will mean we can manage the number of interfaces more effectively.
3. Providing more regular market updates by giving presentations on topics such as Customer Centric ESO, a focus for us to drive improvements in our customer interactions through data, utilising Customer Relationship Management (CRM) and actively working to improve our customer service. In addition, we restarted the control room of the future subgroup and started a new Digital and Data strategy subgroup to have more detailed discussions with stakeholders.
4. Providing opportunities for more face-to-face engagement with stakeholders.

❹ Enhancing our engagement and transparency to stakeholders through improvements to the Operational Transparency Forum (OTF)

The OTF is a weekly open technical industry forum to offer industry insight into recent operational actions we have taken in the Electricity National Control Centre (ENCC) and answer any questions.

The OTF is fundamentally reliant on effective two-way engagement between us and our stakeholders to achieve a common understanding between our control room operations and the wider industry. To ensure that the OTF is delivering for our partners, we conducted a detailed survey of the OTF in December 2023. The survey aimed to understand how the OTF is meeting customer expectations and establish any improvements we can make to increase customer value following the conclusion of the first term of BP2.

We received 40 external responses to our survey, and 156 feedback comments, all of which we responded to. Several points were raised that we have taken on board and changed our ways of working to ensure we continue to deliver for our stakeholders. For example;

1. During the Q&A aspects of the OTF, some customers preferred visibility of names of those who had already asked questions, while others preferred their names to remain anonymous. To meet the needs of all clients, we offer customers the option to submit questions prior to the session to keep anonymity if required.
2. We were asked to reconsider our position of not commenting on individual Balancing Mechanism Unit (BMUs) in case studies, as commenting on those BMUs in the OTF offer useful insight to industry on best practice and is often available in published data. We therefore have altered our position and will publish individual BMUs if information is already in the public domain.
3. Some attendees requested greater visibility of ESO events as the OTF are unable to provide a full picture, and in some instances OTF may clash with other useful ESO events. Therefore, we have committed to work to improve our internal planning, to avoid conflict with other major industry events or overlap with other ESO events. We plan to better utilise our website events calendar to ensure OTF attendees are aware of all relevant ESO opportunities in one place and promoted well in advance.
4. Several participants feel in-person-only OTF events are not inclusive and all events should have a remote attendance option, when this improvement was previously suggested, ESO did not take on this feedback. Whilst ultimate decision making will remain with individual teams hosting events, there is now strong guidance in place that events should be widely accessible to customers. For example, hosted as virtual or hybrid events unless there is a clear customer need for an event to be in-person only.

A.3 Metric Performance for Role 1

Table: Summary of metrics for Role 1

Metric		Unit	Full year 2023-24 Benchmark	Actual	Mid-scheme status
1A	Balancing Costs	£m	2,703	2,444	Meeting expectations
1B	Demand Forecasting	MW	594	602	Meeting expectations
1C	Wind Generation Forecasting	%	4.6%	5.6%	Below expectations
1D	Short Notice Changes to Planned Outages	#	1-2.5	1.7	Meeting expectations

Metric 1A Balancing cost management

April 2023 to March 2024 Performance

This metric measures the ESO's outturn balancing costs (including Electricity System Restoration costs) against a balancing cost benchmark.

A new benchmark has been introduced for BP2. Analysis has shown that the two most significant measurable external drivers of balancing costs are wholesale price and outturn wind generation. The new benchmark has been derived using the historical relationships between the two drivers and balancing costs:

- The benchmark was created using monthly data from the preceding 3 years.
- A straight-line relationship has been established between historic constraint costs, outturn wind generation and the historic wholesale day-ahead price of electricity.
- A straight-line relationship established between historic non-constraint costs and the historic wholesale day-ahead price of electricity.
- Ex-post actual data input into the equation created by the historic relationships to create the monthly benchmarks.

The formulas used are as follows (with Day-Ahead Baseload being the measure of wholesale price):

Non-constraint costs = 54.48 + (Day-Ahead baseload x 0.52)
Constraint costs = -32.66 + (Day-Ahead baseload x 0.34) + (Outturn wind x 25.72)

Benchmark (Total) = 21.82 + (Day-Ahead baseload x 0.86) + (Outturn wind x 25.72)

**Constants in the formulas above are derived from the benchmark model*

ESO Operational Transparency Forum: The ESO hosts a weekly forum that provides additional transparency on operational actions taken in previous weeks. It also gives industry the opportunity to ask questions to our National Control panel. Details of how to sign up and recordings of previous meetings are available here.

March 2023-24 performance

Figure: 2023-24 Monthly balancing cost outturn versus benchmark

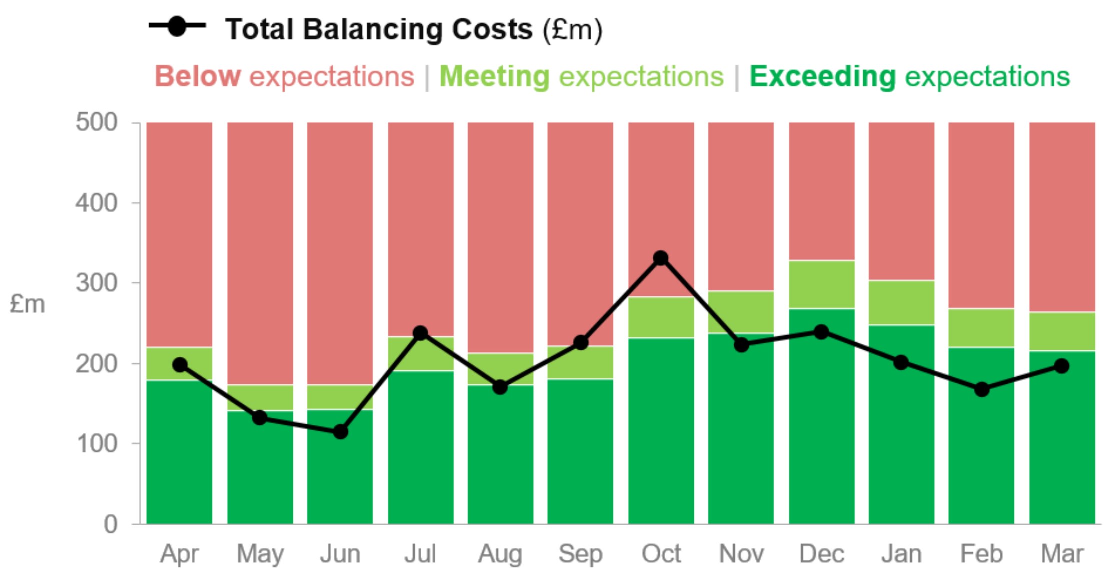


Table: 2023-24 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	3.4	2.6	2.4	4.6	3.8	4.2	6.2	6.1	8.3	7.4	6.6	6.3	55.58
Average Day-Ahead Baseload (£/MWh)	105	81	87	82	86	83	89	99	74	74	61	66	n/a
Benchmark	200	157	158	212	194	201	258	264	299	276	244	241	2462
Outturn balancing costs[7]	**198**	**132**	**115**	**238**	**171**	**226**	**332**	**224**	**240**	**202**	**168**	**197**	**2247**
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

Previous months' outturn balancing costs are updated every month with reconciled values. Figures are rounded to the nearest whole number, except outturn wind which is rounded to one decimal place.

Performance benchmarks:

- **Exceeding expectations:** 10% lower than the annual balancing cost benchmark
- **Meeting expectations:** within ±10% of the annual balancing cost benchmark
- **Below expectations:** 10% higher than the annual balancing cost benchmark

Balancing costs strategy update March 2024

In February 2023, and as part of our RIIO-2 Business Plan (BP2), we established a new Balancing Costs Team in response to recent increases in balancing costs. The team's purpose is to provide analysis and commentary around causes and influences of balancing costs, and to drive business and industry change with the aim of finding the right balance between minimising balancing costs and the impact on consumers while still providing market signals for investment. The team has grown its capabilities since April 2023 and now has six permanent members of staff. In its first year, the team has focused on expanding the delivery of analysis, insights, and reports on balancing costs. In the table below we have outlined new analysis that has been made possible due to the creation of this team, including more detailed tracking and visualisation of cost saving delivered through key initiatives. In its second year, the team will also focus on driving new initiatives that will help minimise further increases to balancing costs, which we will be sharing more detail on as they progress. At the start of BP2 we also updated the methodology for the balancing costs benchmark to include wholesale price as a key external driver of balancing costs alongside outturn wind generation. This metric now more accurately reflects the drivers of balancing costs that are within our control and works well for our current benchmarking. We will continue to monitor if other factors could/should be built into this methodology, including recalculation of the constants and ensuring data is kept up to date.

In September 2023, as part of this new team's work, we published a new balancing costs webpage to showcase our strategy and portfolio of initiatives to minimise balancing costs, along with unique insights and analysis. These are live documents that will be continually updated to reflect the latest developments. The strategy highlights four key levers that we have been using to introduce new ways of minimising costs. Below we highlight some of the initiatives that have had a significant impact under the four levers over the last year. Where possible we have outlined expected cost savings achieved by initiatives compared to the status quo, which in most cases is where equivalent actions are taken through the Balancing Mechanism (BM).

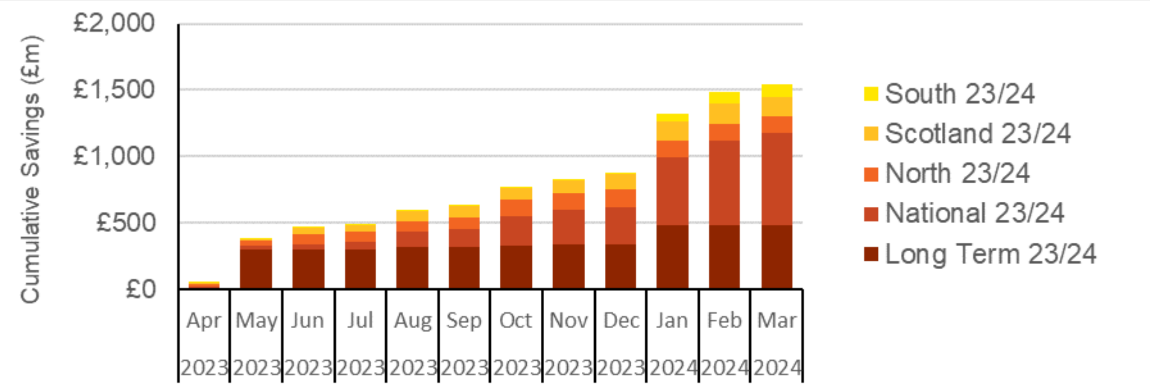
[7] Outturn balancing costs excludes Winter Contingency costs for comparison to the benchmark as agreed with Ofgem. However, in the rest of this section we continue to include those costs for transparency and analysis purposes.

❶ Network Planning and Optimisation

Significant savings have been achieved across 2023-24 through several key initiatives. Firstly, through the Constraint Management Pathfinder (Intertrip Service) that was implemented in April 2022 for the Anglo-Scottish boundary. The Balancing Cost team has been tracking monthly arming costs and savings delivered by this service since its launch, shown in the plot below. Total savings are calculated at approximately £100m compared to equivalent actions in the BM. Another Intertrip Service was recently awarded early-start contracts to manage constraints in the East-Anglia region and is expected to generate around £20m of extra savings from its launch in February 2024.

We have also been further optimising and improving our outage procedure to maximise flows on the electricity system by minimising constraint costs. Our Outage Optimisation initiatives have potentially saved up to £1,543m in balancing costs from April 2023 to March 2024. Requests for network access have risen significantly in recent years, making outage optimisation increasingly challenging and yet more important in managing balancing costs. In the last year, the Balancing Cost team has contributed to more detailed analysis and quantification of these costs and savings which in turn supports strategic planning and prioritisation of actions. Notably this year we have produced a new hot joints dashboard, allowing better tracking of hot joints and the associated cost impacts. Hot joints are assets in the system that tend to overheat under normal operation conditions and for which Transmission Owners declare lower operation ratings to guarantee the integrity of the equipment. We have also performed detailed analysis on the cost impact of Reactive equipment being on outage for extended periods.

GRAPH: Accumulated Savings from Outage Optimisation in 2023-24

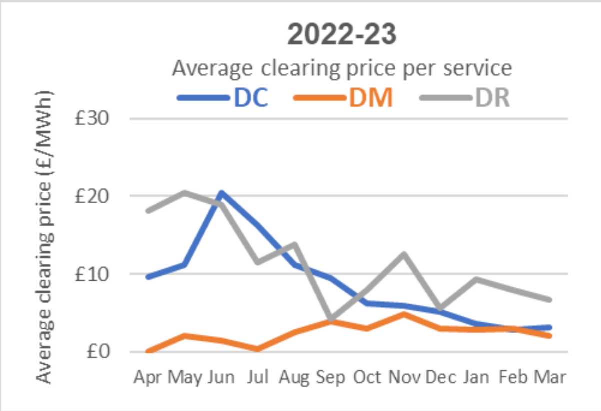


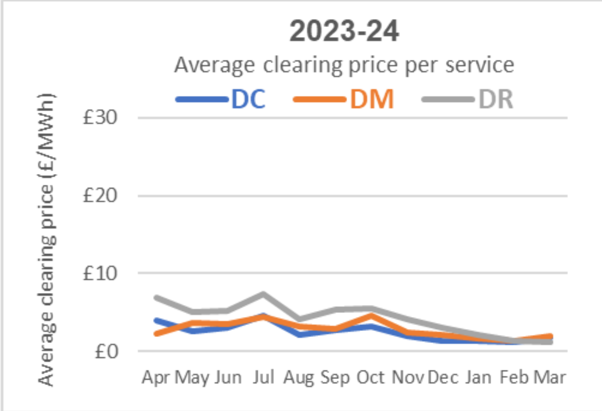
❷ Commercial Mechanisms

As part of our Business Plan, we have been building the future balancing service and wholesale markets by introducing new Dynamic Services. In 2023-24 we have started to see the benefit of more competitive and more liquid markets for our new ancillary services Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR). The plots below show the average clearing price for each of these services (high and low combined) for April 2022 to March 2023 (left) compared with April 2023 to March 2024 (right). The mean of the average clearing price for this financial year is £2.52/MW/h compared to £8.77/MW/h last year for DC, and £4.29/MW/h this year for DR compared to £11.40/MW/h last year. This is because of an increase in the number of market participants, certainty around requirements and an improved auction process due to the continued development of the Single Market Platform. There has been a slight increase in the mean of the average clearing price for DM, however, of £2.86/MW/h this financial year compared to £2.41/MW/h last year. This is because the DM market is less developed than the DC and DR markets. We have been taking action to develop the market and we are now procuring larger volumes than last year, and in the second half of this year DM prices have seen steady reductions.

The introduction of new market mechanisms has led to more competitive and cheaper prices for these services:

GRAPHS: Average clearing price per service for 2022-23 compared to 2023-24





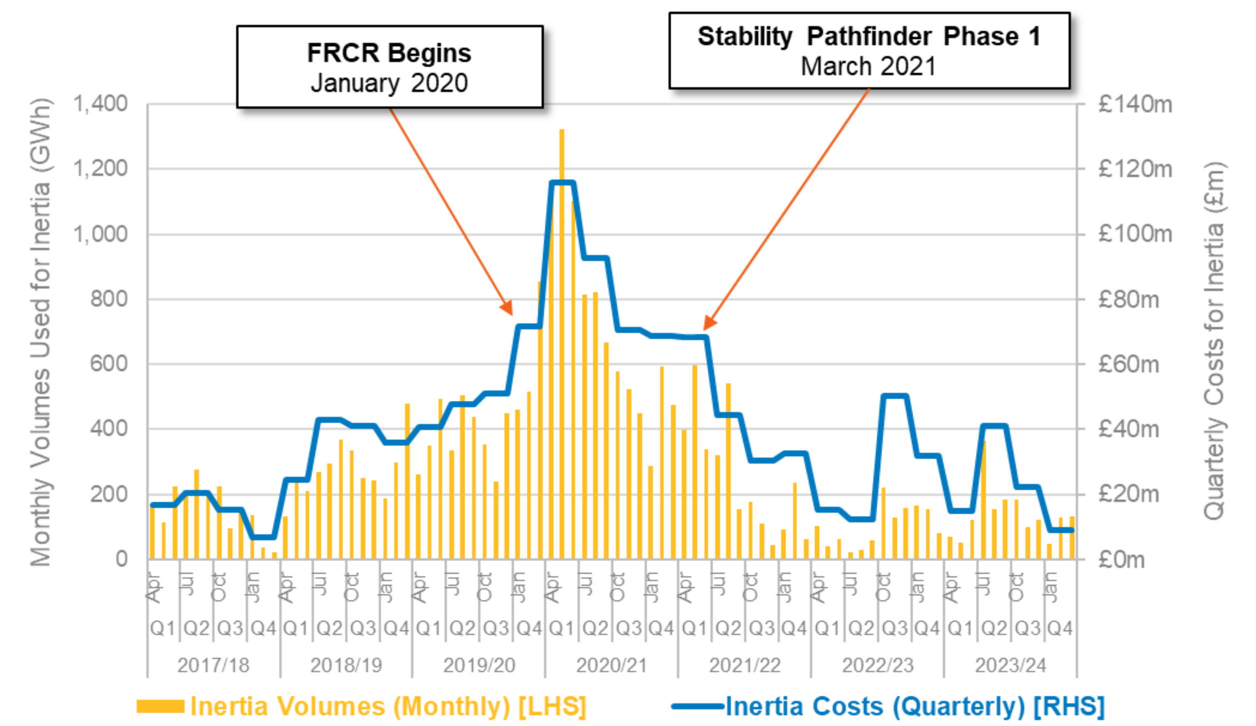
We have also been reforming our reserve services. Our new Balancing Reserve (BR) service has now been approved by Ofgem and the ESO held the first auction on 12 March. The BR service will see us move to day-ahead procurement of the energy reserves we need to respond to system demand in real-time, rather than the current on-the-day system – reducing costs and improving system security. BR is expected to deliver £639m of savings for consumers over the next four years. Furthermore, we are on track to introduce Quick Reserve in summer 2024. This is a new product aimed primarily at reacting to pre-fault disturbances to restore energy imbalance quickly and return frequency close to 50.0Hz.

We also implemented fixed BSUoS in April 2023 alongside improvements to our BSUoS forecasting which is expected to contribute to about £10m per year in consumer savings through reduced credit risks for participants.

❸ Research, Innovation and Engagement

Inertia costs are a balancing cost segment that has seen significant savings realised since the introduction of some of our more innovative initiatives. Total inertia costs across 2023-24 are around 75% lower compared to their peak across 2020-21. Our Frequency Risk and Control Report (FRCR) dynamically assesses the magnitude, duration, and likelihood of transient frequency deviations, the forecast impact and the cost of securing the system. It allows us to change the system's inertia requirements to suit the system conditions. In 2023-24 we have realised notable savings in balancing costs associated with inertia through both the FRCR and the introduction of the new Stability Pathfinder.

GRAPH: Inertia volumes and costs reduced significantly following the introduction of the FRCR and the Stability Pathfinder.



Other benefits resulting from FRCR include the reduction in costs of managing the largest loss, see here for details.

During 2023-24 we have been investigating issues with Physical Notification (PN) misalignment. The concern is that PN misalignment is causing costs incurred for bid or offer acceptance from some generators to be different from the cost that should be incurred, potentially pushing up balancing costs. We are working with Ofgem and DESNZ on measures to mitigate this issue, which is expected to both lower balancing costs and increase Control Room visibility of asset availability.

❹ Research, Innovation and Engagement

The major initiative that will contribute to Balancing Cost savings in this lever is the Balancing Programme, which will see better integration of Distributed Energy Resources (DER), improved forecasting capabilities, and more efficient dispatching capabilities. The first stage of our new platform to support the bulk dispatch of battery storage and small Balancing Mechanism Units (BMU), the Open Balancing Platform (OBP), went live on 12 December 2023. Control room engineers can now send bulk instructions to smaller BMU and battery storage units at the press of a button. The Balancing Costs team is now looking into how savings are realised through OBP and will attempt to track these on an ongoing basis.

Utilisation of storage assets has grown significantly across 2023-24. March 2024 saw a battery dispatch volume of 47.6GWh compared to ~4GWh in March 2022, as shown on the graph in the Plan Delivery section here. This illustrates our commitment to maximising the flexibility of energy offered by battery storage over the last year.

We also hosted an event in London in October 2023 whereby we listened and worked with industry to understand how their storage assets can be more efficiently utilised to assist system balancing. Using this feedback, we assembled a plan aiming to enhance utilisation of storage assets in the BM and deliver dispatch enhancements to Control room operations. This has contributed to improvement of battery dispatch in the Control Room. An example of this is the VERGIL tool which has been updated to dispatch batteries over much faster timescales. Control Engineer roles have also been reviewed to focus more on efficient storage dispatch. We also hosted a follow-up webinar in February highlighting progress to date on enhancing the use of storage in our balancing activities and the future deliverables still to come.

Industry Engagement Update

A comprehensive list of the initiatives that we are undertaking and how they fit into our Balancing Costs Strategy can be found on the Balancing Costs webpage but we are constantly looking for engagement on new initiatives and ideas that can be utilised to minimise balancing costs.

One such case was the workshop on balancing costs that we held on 25 July 2023 with key industry and government members. This forum provided an opportunity for open discussion and views to be expressed on the causes of balancing costs and ways of mitigating high costs in the future. We are planning to run a similar workshop in 2024-25 to update industry on the progress of key initiatives and provide further opportunity to gather views on balancing costs.

Additionally, we are producing an annual review of balancing costs that we plan to publish in Spring 2024 outlining costs incurred in 2023-24 and an overview of how cost components may evolve over the next decade based on the initiatives outlined in our Balancing Costs Strategy and portfolio of initiatives to minimise balancing costs.

We are also continuing to hold regular workshops and discussions with DESNZ and Ofgem. Four workshops were held with both organisations in 2023 in order to better understand balancing costs and what can be done to strike a better balance. Since then, we have been holding monthly Trilateral meetings between DESNZ, Ofgem and the ESO to discuss high-level issues impacting balancing costs and promote information-sharing to facilitate cooperative actions between organisations.

In November, we presented at the Wind Advisory Group (WAG) on the subject of BMU data issues, the main issue of which was PN (Physical Notification) misalignment. This presentation was focused mainly as an information awareness piece, stating why we were looking at misaligned PNs and how they could impact both system security and balancing costs. We also provided an update on our next steps, including conducting a cost impact analysis to determine the effect on balancing costs, looking at short- and long-term solutions to the issue and further engagement with industry. Comments made during the presentation and responses provided through a subsequent feedback form suggested that general sentiment was that industry was glad ESO was looking into this.

We also presented on PN misalignment in December at the Operational Transparency Forum (OTF). The purpose of the update was to engage with broader stakeholders on BMU data issues and provide the opportunity to discuss potential drivers and how we can work with industry to address these issues. Responses were also gathered from this engagement, one of which led to a separate meeting with a stakeholder and we continue to work with industry towards improving the quality of PN submissions..

We plan to host more forums outside of the OTF in the future with industry and will continue with our engagements with DESNZ and Ofgem.

Supporting information

Ongoing data issue: Please note that due to a data issue, over the previous months the Minor Components line in Non-Constraint Costs is capturing some costs which should be attributed to different categories. It has been identified that a significant portion of these costs should be allocated to the Operating Reserve Category. Although the categorisation of costs is not correct, we are confident that the total costs are correct in all months.

We continue to investigate and will advise when we have a resolution.

March 2024 performance

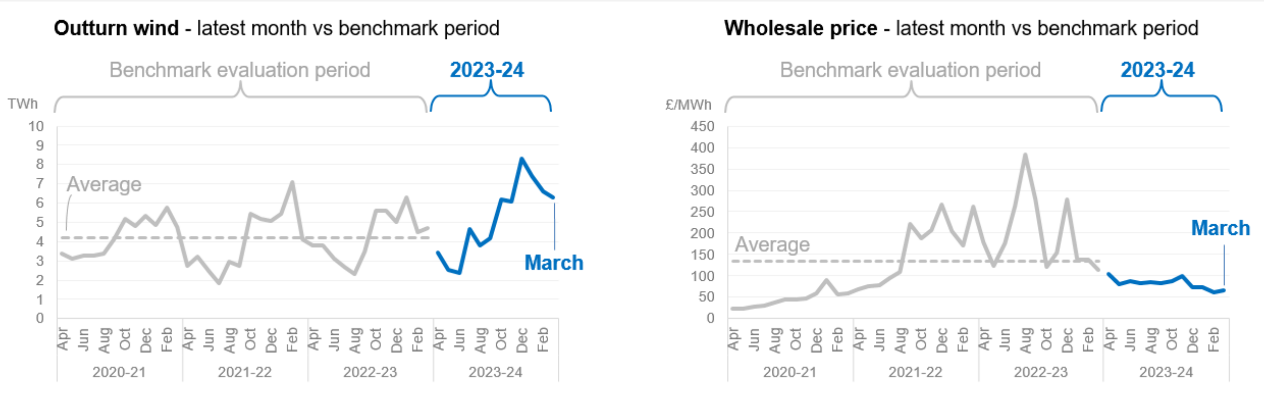
This month's benchmark

As noted in the introduction to this section, a new benchmark was introduced for BP2. The benchmark is derived using the historical relationships between two drivers (wholesale price and outturn wind generation) and balancing costs.

The March benchmark of £241m is lower than February and slightly higher (6%) than the median value of £227m in 2023-24, and this reflects:

- an **outturn wind** figure of 6.3TWh that fell slightly this month but remains very high compared to the benchmark evaluation period (the last three years). The March figure is higher than all but one month of the benchmark period.

- a continued relatively low average monthly **wholesale price** (Day-Ahead Baseload) compared to the benchmark evaluation period (the last three years), although slightly higher than last month's figure, it is the second lowest of the year.



March performance

March's total balancing costs were £197m which is £44m (18%) below the benchmark of £241m, and therefore exceeding expectations. This is the fifth consecutive month and the eighth time that we have exceeded expectations since April 2023. March's overall outturn wind was slightly lower than February 2024, although remains significantly high compared to the rest of the months in 2023-24. The volume weighted average price for bids and offers are higher by £10 per MWh and lower by £18 per MWh compared to last month respectively, however, remains low compared to the rest of the months in 2023-24.

On 12 December 2023, the first stage of our new platform to support the bulk dispatch of battery storage and small Balancing Mechanism Units, the Open Balancing Platform (OBP), went live. The 30-minute rule went into effect thereafter on 11 March 2024. This allowed batteries to be sent to the Balancing Mechanism (BM) for up to 30 minutes instead of the previous 15 minutes. Subsequently, we have seen March had the highest battery dispatch volume (~48GWh) since April 2021, as shown on the graph in the Balancing Costs

Strategy Update section above. This illustrates our commitment to maximising the flexibility of energy offered by battery storage over the last year.

Despite low-cost conditions for March 2024 – with slightly less wind generation, and slightly higher total constraint volumes compared to February, we have seen a significant increase of constraint cost in England & Wales by £14m due to an increase of 107GWh of actions. The total constraint cost is only higher by £7m, due to an offset in Rate of Change of Frequency (RoCoF), Cheviot and a flat spending in constraints sterilised headroom. However, we were still able to make a significant total amount of savings through optimizing outages and trading activities.

Significant savings from outage optimisation have been identified during 2023-24. These savings (deemed as Customer Value Opportunities) are derived from optimising outages in the system to have the least possible impact on end-users. These direct and indirect savings are grouped according to their regional impact: North, South, Scotland, and National. Additionally, long-term savings (Year Ahead) are identified. During 2023-24, cumulative savings of £1.54 billion were achieved, with National savings (identified by national planners delivering direct savings for final users) accounting for roughly 45% of the total direct and indirect savings. The same category also reflects most of the saving opportunities in the system, growing from £12 million in April 2023 to £694 million in March 2024. Some of the most significant saving opportunities during this period include:

- An Operational Capability Limit (OCLR) was acquired for the XS2 circuit for the duration of the re-scheduled XS1 outage in Kintore – Fettersso 275KV (this was originally rejected due to cost). This has a major impact in SSE N-S constraint. Identified on: Jan 2024. Customer Value Opportunity: £59m
- Rejected COCKENZIE-KAIMES outage request due to overlapping with the SMEATON-KAIMES planned outage and causing a drop in SSE+GRMO AND SCOTEX boundary. Identified on: Feb 2024. Customer Value Opportunity: £42m
- Splitting FETT2 to improve SSE N-S limit by 350MW during the XS1 outage. Identified on: Jan 2024. Customer Value Opportunity: £34.8m
- Requested Operational Capability Limit (OCLR) on Hunterston East - Neilston 2 400KV circuit to facilitate outage on Hunterston East - Neilston 1 400KV from 04/03-22/03. Identified on: Jan 2024. Customer Value Opportunity: £33m
- Due to high wind conditions and outages across SSE-SP2, it was agreed with SPT to use the Winter rating of the B145 circuit. Impact on SSE-SP2 by roughly 550MW. Identified on: Oct 2023. Customer Value Opportunity: £18m

Work is still ongoing in quantifying the value of savings from the OBP, but as can be seen from the figure above, a record volume of batteries (48GWh) was dispatched through the BM in March 2024.

Breakdown of costs vs previous month

Balancing Costs variance (£m): March 2024 vs February 2024

		(a) Feb-24	(b) Mar-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-1.2	7.7	8.9	
	Operating Reserve	6.1	11.1	5.0	
	STOR	2.9	3.3	0.5	
	Negative Reserve	0.4	0.3	(0.1)	
	Fast Reserve	14.3	15.0	0.8	
	Response	11.7	14.6	2.9	
	Other Reserve	2.2	2.1	(0.1)	
	Reactive	12.7	13.6	0.9	
	Restoration	3.6	3.2	(0.4)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	2.9	4.9	1.9	
Constraint Costs	Constraints - E&W	19.4	33.2	13.8	
	Constraints - Cheviot	12.1	9.2	(2.9)	
	Constraints - Scotland	57.4	57.8	0.4	
	Constraints - Ancillary	0.7	0.1	(0.5)	
	ROCOF	3.3	0.2	(3.1)	
	Constraints Sterilised HR	20.6	20.2	(0.4)	
Totals	Non-Constraint Costs - TOTAL	55.4	75.8	20.4	
	Constraint Costs - TOTAL	113.5	120.8	7.3	
	Total Balancing Costs	**169.0**	**196.7**	**27.7**	

As shown in the total rows from the table above, both non-constraint & constraint costs increased by £20.4m & £7.3m respectively, resulting in an overall increase of £27.7m compared to February 2024.

Constraint costs: The main driver of the variances this month are detailed below:

- **Constraint-Scotland & Cheviot***: The constraint cost decreased by £2.5m in total, due to the total volume of actions decreased by 1GWh.
- **Constraint-England & Wales***: an increase of 107GWh in volume of the total actions with the constraint cost increased by £13.8m, mainly due to an increase in the import constraint actions by 32GWh for voltage control and to support system inertia.
- **Constraints Sterilised Headroom***: a flat £0.4m increase, despite a decrease of the total volume of replacement energy by 59GWh.

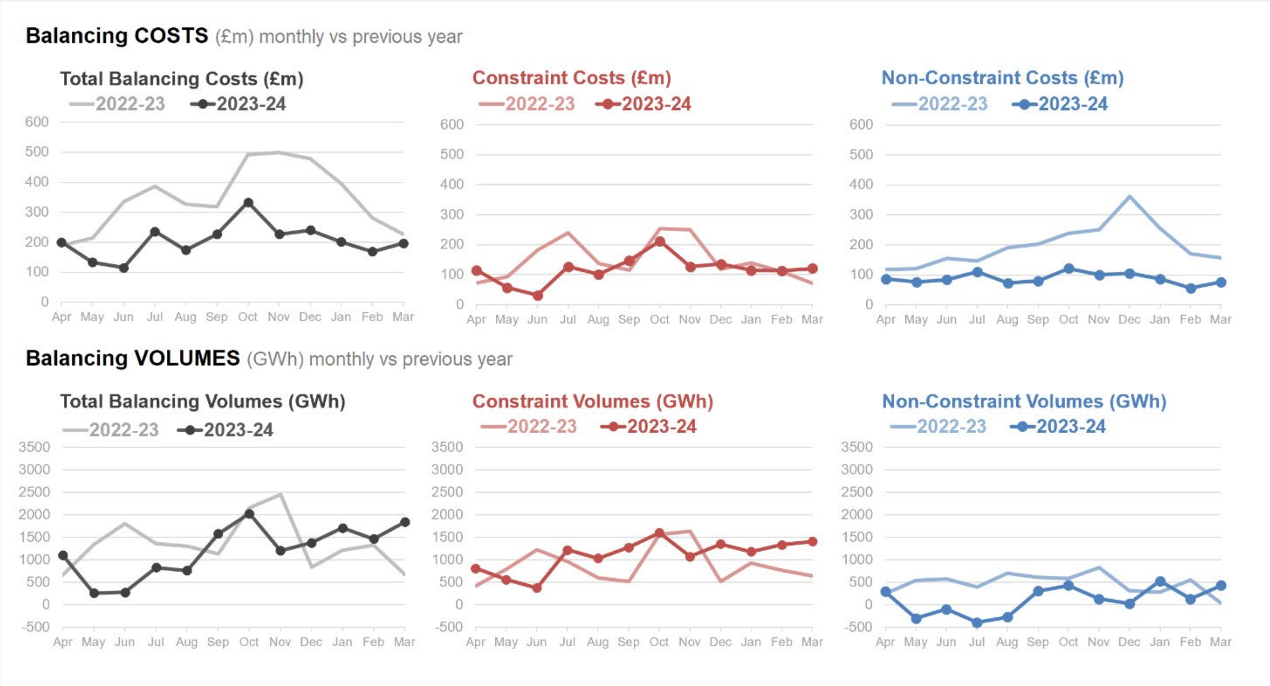
*48 more planned outages compared to last month yet remain lower than the previous months in 2023-24. This month also sees a decrease of the volume weighted average price for offers and an increase of bids following a slightly upward trajectory of electricity prices of the month.

Non-constraint costs: The main driver of the biggest difference this month is:

1. **Energy Imbalance**: £8.9m increase, with a significant increase of 133GWh volume of actions from the BM*.
2. **Operating Reserve**: £5m increase due to using 157GWh more reserve required to secure the system.
3. **Response**: £3m increase due to taking 7GWh more absolute volume of actions.

*Excluding the volume of actions from ancillary services as not yet quantified at the time of writing this report.

Constraint vs non-constraint costs and volumes



Please note that a portion of the **Minor Components** spend contributing to non-constraint cost and volume is mainly Operating Reserve cost and volume. The narrative below discusses the broad themes of spend. The figures will be revised once the data issue is resolved.

Constraint costs

Compared with the same month of the previous year:	An increase of £50m in constraint costs compared to March 2023, due to 367GWh more of volume of constraint actions taken.
Compared with last month:	Constraint costs were £7m higher than in February 2024, due to 44GMh more volume of constraint actions, driven by relatively high outturn wind.

Non-constraint costs**

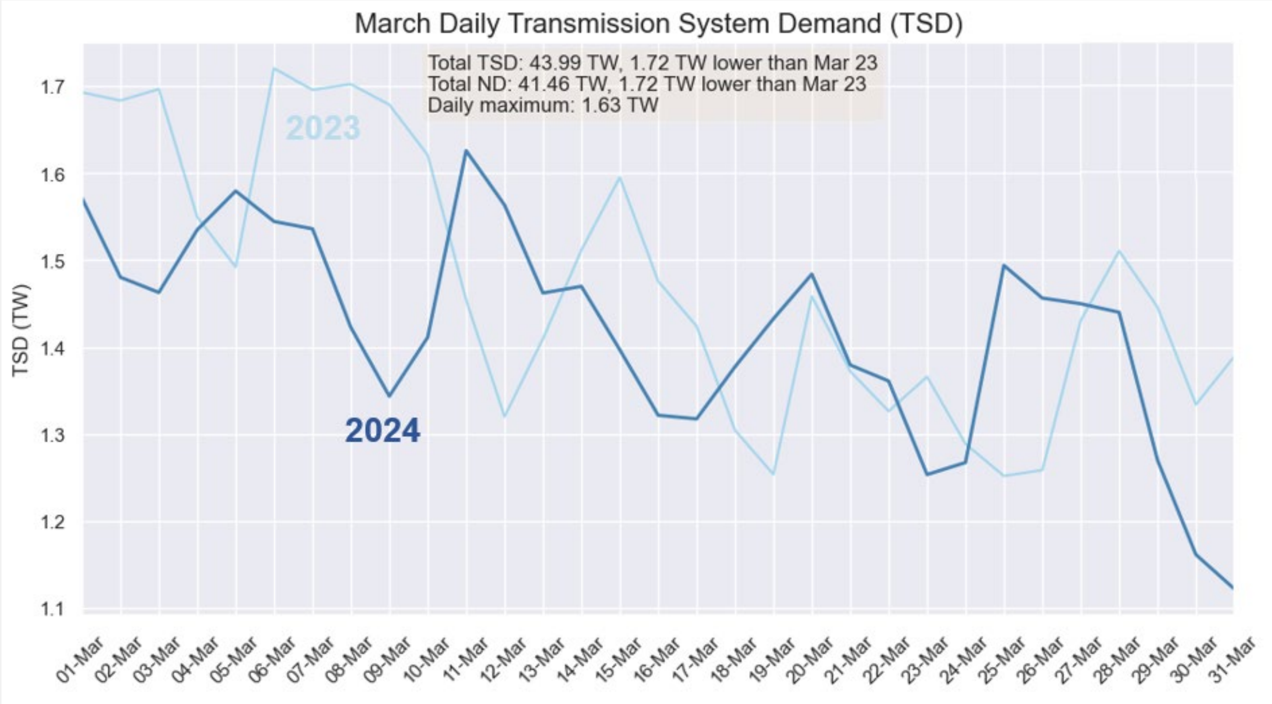
Compared with the same month of the previous year:	Non-Constraint costs were £81m lower than March 2023 despite 392GWh more Volume of actions, this is driven by significantly lower average wholesale prices*
Compared with last month:	Non-Constraint costs were £20.4m higher than February 2024, due to 299GWh more absolute volume of actions were required to balance the system.

* *Average wholesale price for March 2024: £66/MWh compared to £115/MWh for March 2023.*

*** The non-constraint category consists of several subcategories including energy imbalance, response, reserve, and restoration*

March daily Transmission System Demand (TSD*)

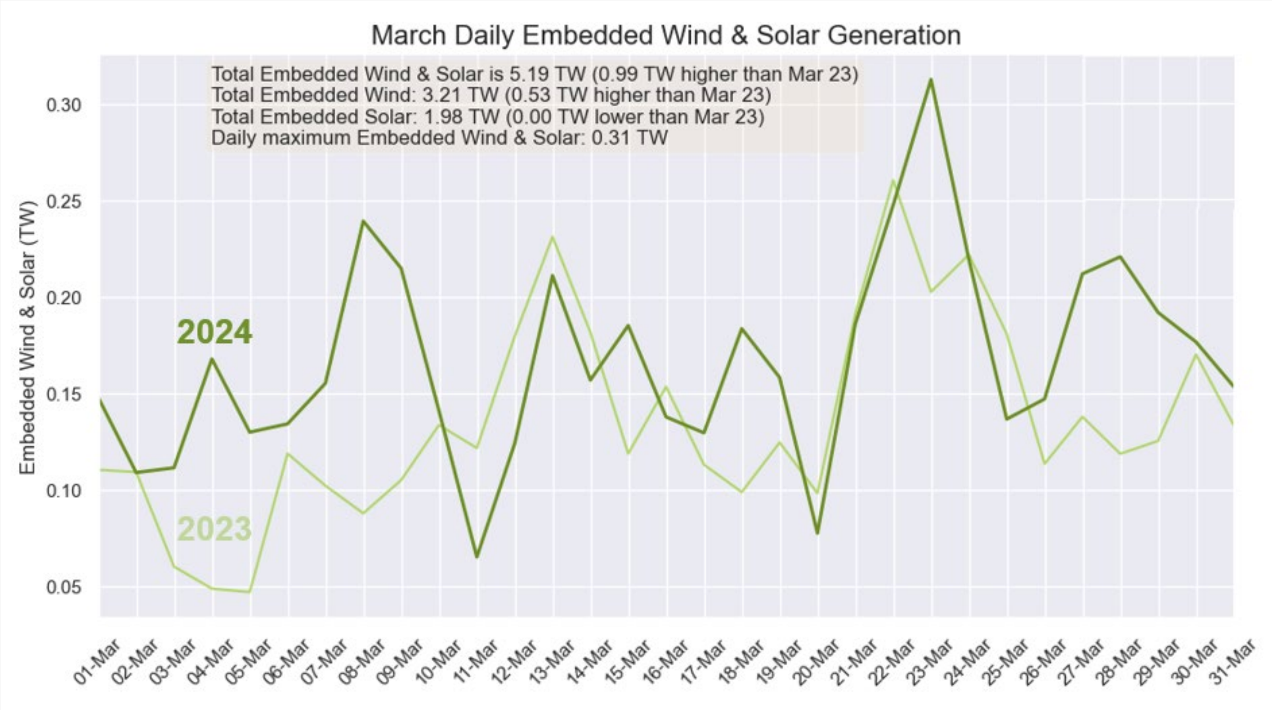
- National Demand (not shown below) was 1.7TW lower than March 2023.
- **Transmission System Demand*** was 1.7TW lower than March 2023.



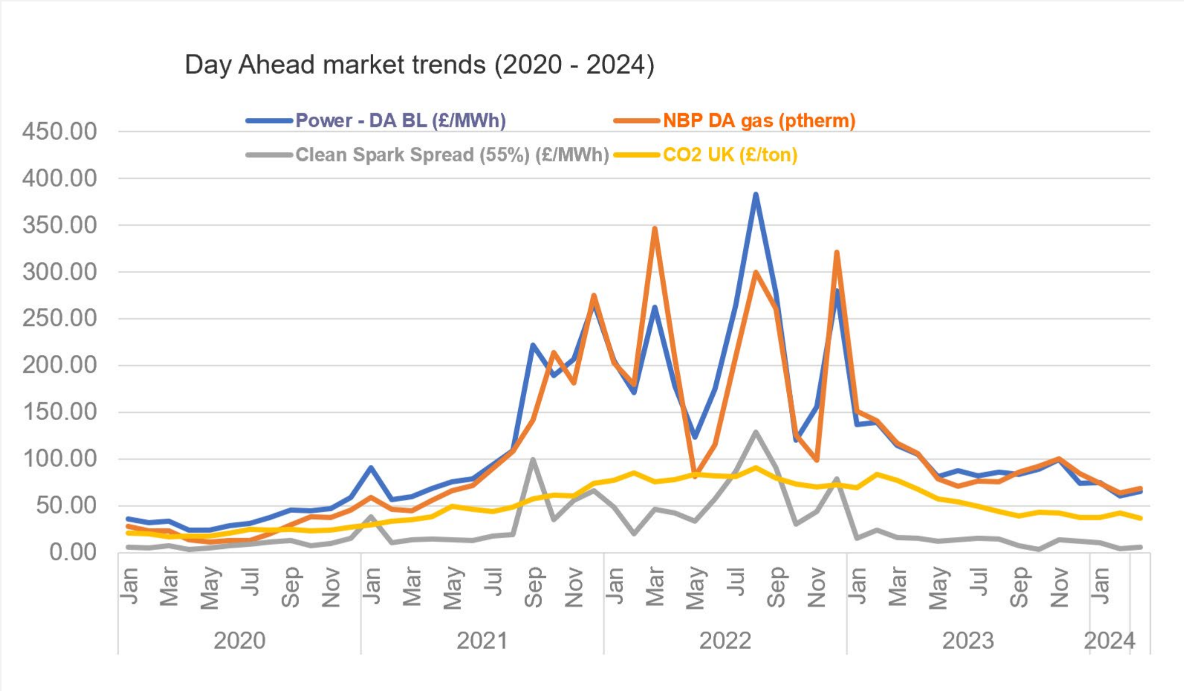
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand includes an estimate of station load of 500MW in BST (British Summer Time) and 600MW in GMT (Greenwich Mean Time).

March daily Embedded Wind and Solar Generation

- **Embedded wind & solar generation** was 0.99TW higher than March 2023.
- The maximum embedded wind & solar generation occurred on 23 March 2024 (0.31TW).



Price Trends in energy markets



DA BL: Day-Ahead Baseload **NBP DA:** National Balancing Point Day-Ahead

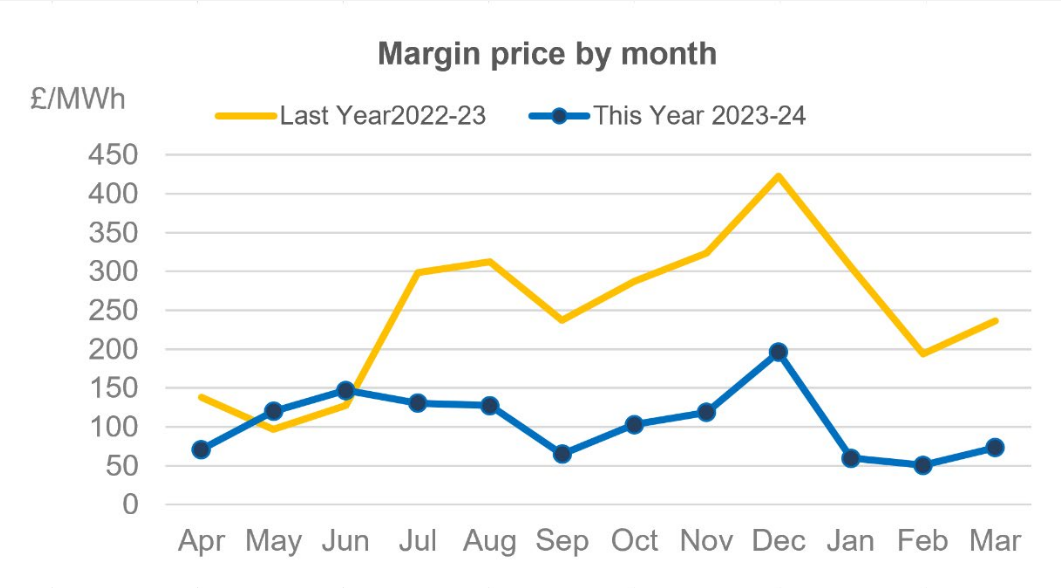
Gas and power had a slight upward trajectory compared to last month with CO_2 and Clean Spark Spread remain relatively steady. All trends remain lower compared to the previous year.

Balancing costs increases/decreases compared with the same period from last year

Comparing the non-constraint costs of March 2024 with those of March 2023, most categories showed a decrease or a small deviation, except:

- **Energy Imbalance** £19m increase due to 24GWh more volume of actions taken to balance the system.
- **Operating Reserve** £62.4m decrease despite 191GWh more volume of reserve required to balance the system, mainly due to the significant lower energy related prices this year compared to last year. On 12 March this year, we launched a new Balancing Reserve (BR) Service to procure both positive and negative reserve on a day-ahead basis, aiming to improve system security and to reduce balancing costs. This will inevitably impact on the costs and volumes of the future operating reserve and negative reserve. Further analysis on the cost impacts will be shared in the coming months. The total spend on BR contracts in March is £780k (subject to performance monitoring review).
- **Reactive** £6.8m decrease, due to a drop in the weighted average price, from £6.4 per MVAR to £3.6 per MVAR.
- **Minor Components** decreased by £10.7m. Last year's excessive cost contained incorrectly allocated cost from operating reserve that we have identified in the last end of the year report.

Drivers for unexpected cost increases/decreases



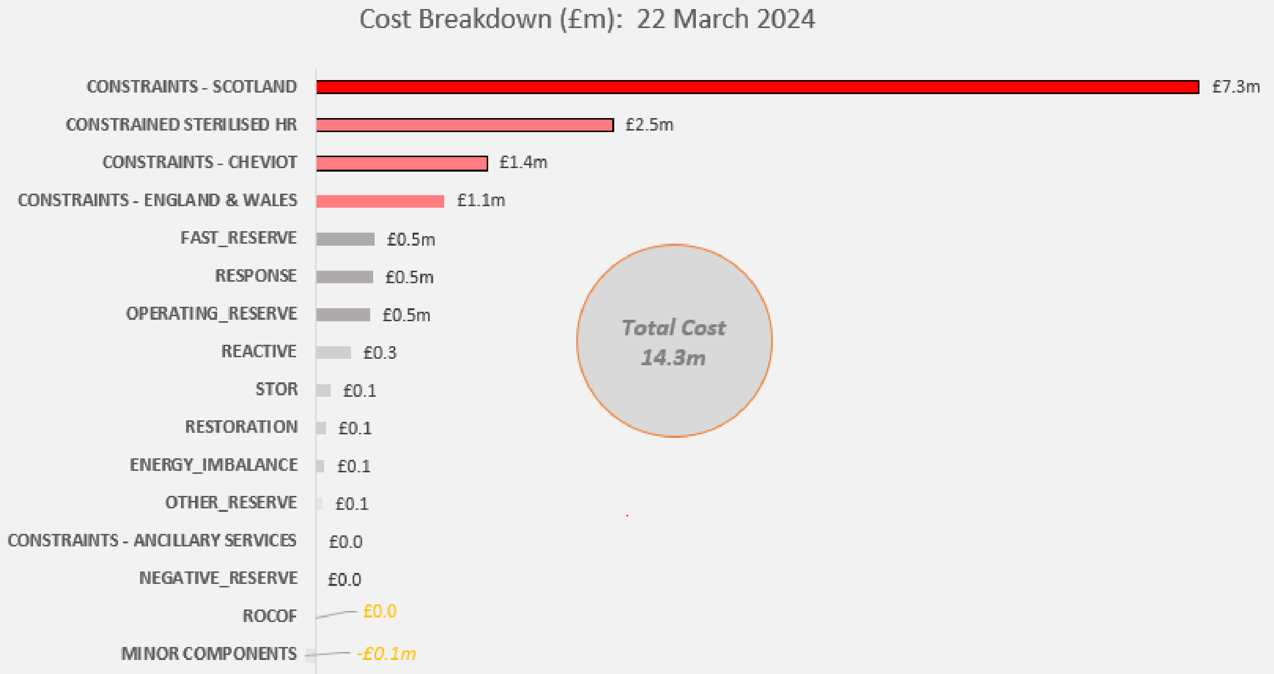
Margin prices (the amount paid for one MWh) have slightly increased compared to February 2024, but is still significantly lower than the corresponding period of the previous year.

Daily Costs Trends

March's balancing costs were £197m. This was £29m higher than the previous month, none of the days were recorded with costs above £15m with around 16% of days having a daily total cost over £10m, with an increase of £0.5m (from £5.8m to £6.3m) average daily cost compared to February 2024.

The lowest total daily cost of £2.37m was observed on 2 March 2024, whilst the highest total cost was observed on 22 March 2024 when the total spend was £14.3m. Constraints in Scotland area were the major cost component driven by high renewable generation and low demand. No individual action was expensive, but high volumes of wind curtailment resulted in high total balancing costs for the day.

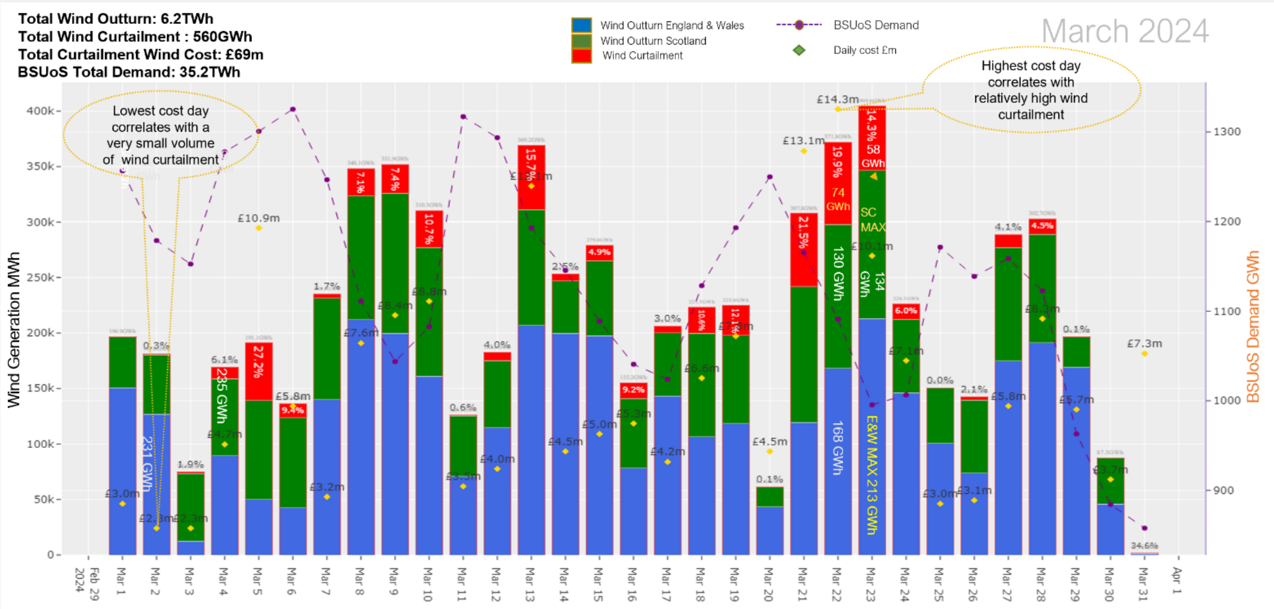
Cost breakdown for 22 March 2024



March Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUoS Demand

The chart below serves the purpose of supporting the transparency and the descriptions above. It is the daily "tour" of wind performance (wind generation: **blue** & **green** bars, and wind curtailment: **red** bars, demand resolved by the balancing mechanism and trades – **purple** dotted line and daily cost - **yellow** diamonds).

With this graph one can trace for example the relationship that may exist in how wind performance and low demand affect the cost of each day.



High-cost days and balancing cost trends are discussed every week at the Operational Transparency Forum
to give ongoing visibility of the operability challenges and the associated ESO control room action.

Metric 1B Demand forecasting accuracy

April 2023 to March 2024 Performance

This metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[8]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each half hour period. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

A 5% improvement in historical 5-year average performance is required to exceed expectations, whilst coming within ±5% of that value is required to meet expectations.

In settlement periods where Demand Flexibility Service (DFS) is instructed by the ESO, this will be retrospectively accounted for in the data used to calculate performance. The ESO shall publish the volume of instructed ODFM to enable this to be done.

Performance will be assessed against the annual benchmark, but monthly benchmarks are also provided as a guide. The ESO will report against these each month to provide transparency of its performance through the year.

March 2023-24 performance

Figure: 2023-24 Monthly absolute MW error vs Benchmark

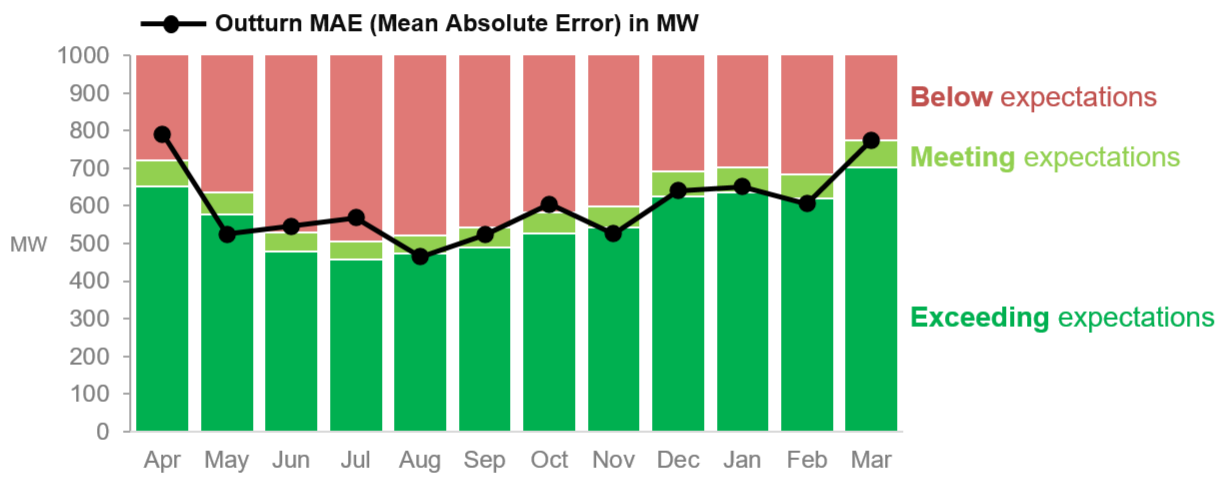


Table: 2023-24 Monthly absolute MW error vs Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	**Full Year**
Benchmark (MW)	687	606	503	481	497	516	554	571	659	669	651	738	**594**
Absolute error (MW)	**791**	**523**	**546**	**569**	**465**	**523**	**604**	**526**	**640**	**651**	**606**	**774**	**602**
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

Performance benchmarks:

- ● **Exceeding expectations:** >5% lower than 95% of average value for previous 5 years
- ● **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- ● **Below expectations:** >5% higher than 95% of average value for previous 5 years

[8] Demand | BMRS (bmreports.com)

Supporting information

April 2023 – March 2024 performance

From April 2023 to March 2024, our performance has met expectations. The mean absolute error (MAE) of our day-ahead demand forecast, averaged across the period, was 602 MW. This is within 5% of the benchmark of 594 MW, and therefore meeting expectations. For more detail on previous months' performance, please see past reports on our website.

The first year of the BP2 period was a rather balanced one for the 1B metric, with four months meeting expectations, four exceeding expectations and four below expectations. When calculated over the full year, we met expectations and improved on the previous financial year's MAE by 14 MW.

The growth of embedded weather driven generation continues to make the system more difficult to forecast, both due to the variability of weather and the lack of visibility of outturns of these assets connected at distribution level.

The creation of additional internal tools for identifying, highlighting and comparing forecasts/errors has aided in improving the accuracy of our forecasts. This is in addition to the regular modelling updates.

March 2024 performance

In March 2024, our performance met expectations, with a mean absolute error (MAE) of our day-ahead demand forecast of 774 MW which is within 5% of the benchmark of 775 MW.

The Met Office reports that March was unsettled, wet and dull, with a succession of frontal systems bringing rain and wind. The month ended with widespread showers and strong winds across the UK.

The effect of the weather was well handled by our demand forecast models through most of the month, with a few larger error days occurring towards the end of the month. The lower accuracy on Tuesday 26 March 2024 was mainly due to the significant solar irradiance error in the weather forecast data supplied by our providers. Errors on the Easter long weekend were due to a combination of factors which all increased the difficulty of producing an accurate forecast, including:

- Easter weekend bank holidays and human behaviour changes
- Clock change day
- Lack of similar profiling day
- Variable weather (solar, wind, rain).

The last time Easter occurred on the same weekend as clock change day was in 2016. Embedded generation and demand profiles have changed significantly since 8 years ago, so our systems had less data to help inform the forecasts. Even without the difficulty of additional bank and school holidays, clock change weekends are often some of the most difficult to forecast accurately.

The distribution of settlement periods by error size is summarised in the table below:

Error greater than	Number of SPs	% out of the SPs in the month (1486)
1000 MW	450	30%
1500 MW	220	15%
2000 MW	85	6%
2500 MW	39	3%
3000 MW	19	1%

The days with largest MAE were 26, 29, 30 and 31 March.

Demand Flexibility Service (DFS) tests were run on 1, 2, 14 and 21 March. These will have affected the national demand outturn but are not included in our forecasts.

Missed / late publications

There were 0 occasions of missed or late publications in March.

Triads

Triads run between November and February (inclusive) each year and therefore did not affect this month’s performance.

Metric 1C Wind forecasting accuracy

April 2023 to March 2024 Performance

This metric measures the average absolute percentage error (APE) between day-ahead forecast (between 09:00 and 10:00, as published on ESO Data Portal here) and outturn wind generation (settlement metering as calculated by Elexon) for each half hour period as a percentage of capacity for BM wind units only. The data will only be taken for sites that did not have a bid-offer acceptance (BOA) during the relevant settlement period.

We will publish this data on our Data Portal for transparency purposes. The benchmarks are drawn from analysis of historical errors of the five years preceding the performance year. 5% improvement in performance expected on the 5-year historical average, with range of ±5% used to set benchmark for meeting expectations.

March 2023-24 performance

Figure: 2023-24 BMU Wind Generation Forecast APE vs Benchmark

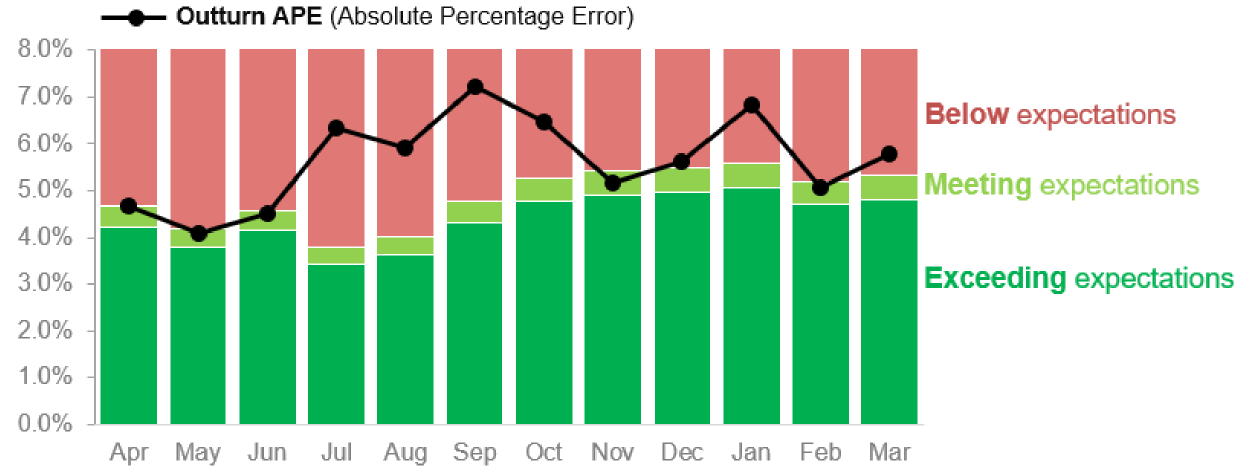


Table: 2023-24 BMU Wind Generation Forecast APE vs Benchmarks

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
Benchmark (%)	**4.45**	**4.00**	**4.36**	**3.61**	**3.83**	**4.54**	**5.01**	**5.16**	**5.23**	**5.33**	**4.94**	**5.07**	**4.62**
APE (%)	**4.69**	**4.08**	**4.50**	**6.34**	**5.90**	**7.23**	**6.48**	**5.16**	**5.61**	**6.82**	**5.08**	**5.80**	**5.65**
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

Performance benchmarks:

- **Exceeding expectations:** < 5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** > 5% higher than 95% of average value for previous 5 years.

Supporting information

April 2023 – March 2024 performance

From April 2023 to March 2024, the average wind power forecast accuracy was 5.65%. This is more than 5% higher than indicative benchmark of 4.67% and therefore below expectations. Allowing for data corrections, the wind fleet capacity that we forecast for this metric has grown by 30% since April 2023. The rapidly expanding wind fleet inherently increases the range of error.

We have largely focused on tactical corrections, to curtail the trend of increasing errors witnessed during the early summer months. The existing suite of legacy systems limits any strategic wind enhancements, so all considered improvements have been undertaken on a realisable benefit basis.

The general trend of performance continues to recover with some exceptional days, but remains largely sensitive to poor quality weather data (available at Day-ahead) or rapidly changing weather patterns. The North Sea remains a significant challenge, with a small number of windfarms routinely contributing to large errors on any given day.

We now also publish all wind BMU forecasts on the Data Portal, along with their locational positions.

For more information on the previous months in detail, please see past reports on our website.

March performance

March performance was below expectations, with forecast accuracy of 5.80%, which is more than 5% higher than the indicative benchmark of 5.07%.

Performance was largely affected by four significant-error days and a period of CfD activity over the weekend of 23/24 March.

Withdrawal of wind units

No units withdrew availability between time of forecast and time of metering.

Missed / late publications

In March there were 0 occasions of late or missing publications of the forecast.

Metric 1D Short Notice Changes to Planned Outages

April 2023 to March 2024 Performance

This metric measures the number of short notice outages delayed by > 1 hour or cancelled, per 1000 outages, due to ESO process failure.

March 2023-24 performance

Figure: 2023-24 Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

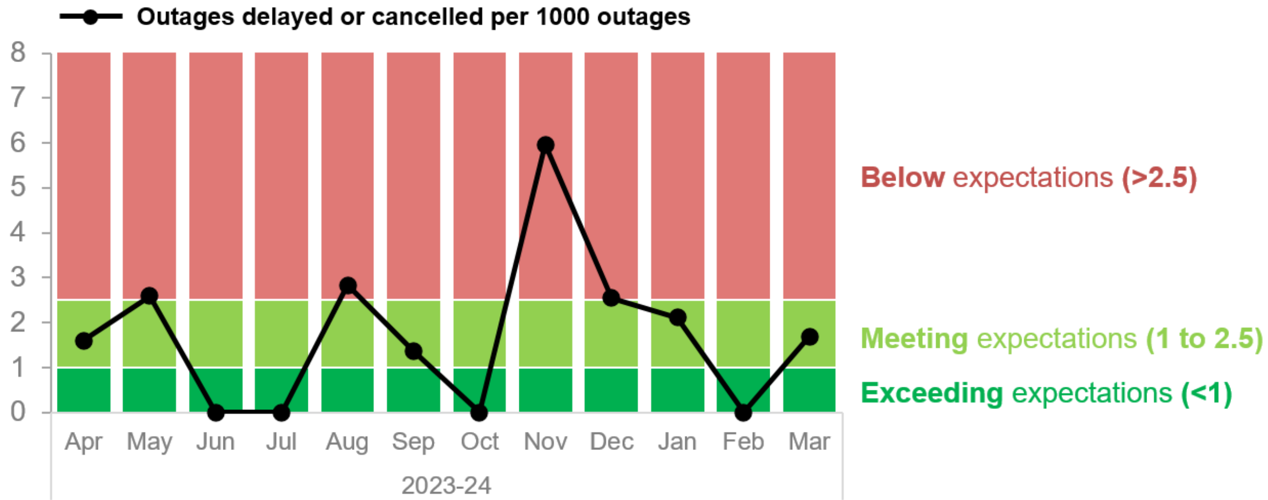


Table: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	624	739	645	644	706	734	704	671	393	472	545	593	**7470**
Outages delayed/cancelled due to ESO process failure	1	2	0	0	2	1	0	4	1	1	0	1	**13**
Number of outages delayed or cancelled per 1000 outages	1.6	2.6	0	0	2.8	1.4	0	6	2.5	2.1	0	1.7	**1.74**
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

Performance benchmarks:

- **Exceeding expectations:** Fewer than 1 outage delayed or cancelled per 1000 outages
- **Meeting expectations:** 1-2.5 outages delayed or cancelled per 1000 outages
- **Below expectations:** More than 2.5 outages delayed or cancelled per 1000 outages

Supporting information

April 2023 – March 2024 performance

From April 2023 to March 2024, we successfully released 7,470 outages and there have been 13 delays or cancellations that occurred due to an ESO process failure. The cumulative number of stoppages or delays per 1000 outages at year close is 1.74 which is within the ‘meeting expectation’s’ range.

For information on the previous events, please see previous reports on our website.

March performance

For March, we successfully released 593 outages and there was one delay or cancellation that occurred due to an ESO process failure. The number of stoppages or delays per 1000 outages is 1.68, which is within the ‘meeting expectations’ range of less than 2.5 delays or cancellations per 1000 outages. The single event can be summarised below:

There was a delay on an outage as there was a voltage discrepancy between TO Offline Transmission Analysis tool and the online real-time analysis tool for a particular contingency. Therefore, the outage was delayed so this could be investigated to determine if it was a real-issue or model related. It was identified that there was a metering issue feeding into the real-time analysis tool which drove the non-compliant voltage. This has been flagged up to the Transmission Owner (TO) to investigate and rectify to prevent a re-occurrence.

A.4 Quality of Outputs for Role 1

The fourth evaluation criterion for the ESO incentive scheme is Quality of Outputs, where the Performance Panel will consider the actual benefits the ESO has realised from delivering its Business Plan, or any outputs additional to the Business Plan.

At the time of publishing BP2, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the BP2 RIIO-2 Business Plan. This was an update from BP1. The relevant CBAs for Role 1 are:

- Control centre architecture and systems (A1)
- Control centre training and simulation (A2)
- Restoration (A3)

In this section, we provide a progress update for each of the activities for which we originally provided a Cost-Benefit Analysis, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence, and describing any sensitivity factors which would impact on the delivery of the stated benefit. Deliverable activity statuses reflect the delivery of RIIO-2 milestones and do not recognise either work completed prior to April 2023 nor progress made towards yet to be completed milestones.

We also provide a specific case study on our **Frequency Strategy (22 December 2023 events)** which was not covered by the original CBA document.

The Panel will also consider the ESO's Regularly Reported Evidence (RRE) as part of the Quality of Outputs criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the ESORI guidance. For Role 1, the items of RRE reported at the end of the year are:

- 1E. Transparency of operational decision making
- 1F. Zero Carbon Operability (ZCO) indicator
- 1G. Carbon intensity of ESO actions
- 1H. Constraints cost savings from collaboration with TOs
- 1I. Security of Supply reporting
- 1J. CNI outages

CBA: Control centre architecture and systems (A1)

BP2 Mid-Scheme view of gross benefits compared to BP2

We now estimate gross benefits of £517m over the RIIO-2 period, which is an increase of £95m compared to the BP2 figure of £422m.

	Estimated gross benefits during RIIO-2 (£m)		
Area	**BP2 Plan view**	**Latest forecast view**	**Variance**
1. Reduced CO_2 emissions - reduced environmental damage from our control centre residual balancing actions.	226	360	**+ 134**
2. Improved situational awareness - estimated 5% improvement in managing constraints from enhanced situational awareness tools.	108	89	**-19**
3. Utilising flexible technology - lowering consumer bills through unlocking the benefits of greater flexibility.	80	63	**-17**
4. Greater interconnection - upgrading our tools to better handle greater levels of interconnection.	6	4	**-2**
5. Reduced BM outage downtime - reduced Balancing Mechanism outage downtime.	2	1	**-1**
Total	**422**	**517**	**+95**

For this CBA in the BP1 End-Scheme Report (May 2023) we reported RIIO-2 benefits as £1.6bn which was a combination of benefits aligned with the original CBA, plus additional benefits not originally included. To allow a clearer understanding of this CBA, we have removed the additional benefits from this section to align with the original CBA methodology. We have then reported the additional benefits separately at the end of this CBA ('Additional Benefits' section below).

The main drivers of the change in the benefits are as follows:

Reduced CO_2 emissions: the benefit has increased significantly. This is not due to any significant change in what we are delivering, but is the result of a change in key FES inputs. This means that a greater amount of carbon can be offset though the deliveries across the programme. This is due to an increased difference between the Falling Short and Leading the Way scenarios in the FES.

This increase is partly offset by a reduction in benefits in the other four areas. This is due to a change in our assessment of when OBP will deliver full 100% value. This was assumed to be within RIIO-2 in the previous CBA for the BP2 Plan but the full replacement of existing systems by OBP will happen in 2026-27 outside of RIIO-2. Full realisation of value for the Network Control Programme will be within RIIO-2 however the assumptions on value realised in the earlier years has been reduced.

Summary of progress in 2023-24

The Balancing Programme has achieved a major milestone this year with the delivery of Release 1 of our Open Balancing Platform. This focussed on implementing the small BM unit and Battery zones which will deliver enhanced dispatch capability to meet changing customer requirement. We prioritised the battery zone for delivery following feedback from our ongoing Balancing Programme stakeholder engagement events. This extra delivery was achieved, accelerated four months earlier than planned without impacting the remaining Open Balancing Programme roadmap timescales.

Following the initial Balancing Strategy Capability Review and the ongoing enduring Balancing Programme engagement events we have been continually rebaselining our roadmap and delivery plans to ensure they deliver value to the consumer and are fully integrating agile ways of working into our delivery approach.

The existing delivery schedule contains components within each milestone which are separate pieces of functionality. In addition to the accelerated delivery of the Battery zone we have accelerated the delivery of Balancing functionality into the Open Balancing Platform in Q4 2023-24 while deprioritising three aspects of delivery (First Tranche of Margin Analysis, Integration of DAP, Integration of SMP).

For the remaining BP2 period and the remaining three milestones for Enhanced Balancing, one milestone remains on track, seven areas of functionality have been planned to be accelerated and four areas of functionality have been deprioritised within the other two milestones. This reprioritisation has been agreed in collaboration with Industry.

For Forecasting: One milestone remains on track and two milestones are delayed within BP2 to ensure we deliver value for the consumer.

This is as a result of an updated PEF strategy with a revalidated forecasting roadmap. We will now accelerate the retirement of the legacy forecasting systems (EFS and Operational PEF) and remove operational and business debt/risk while we deliver new and existing products and features on our strategic Azure cloud platform.

As a result, we have re-prioritised activity planned for Q3 2023-24 with planned target completion dates set as follows:

1. Wind Power Milestone: Q2 2024-25
2. National Demand Milestone: Q4 2024-25

In 2023-24, we have had three releases. (1) Strategic Cloud Platform Foundation (2) Grid Supply Point (GSP) forecast (3) Forecasting features for enabling Local Constraint Market (LCM)

In maintaining the existing products, our focus has been on ensuring the required levels of performance for 24-7 operation. We have also delivered incremental value through enabling new interconnection, interfacing the Balancing Mechanism with the Open Balancing Platform, bulk instruction improvements in Vergil, and enabling Balancing Reserve and MW dispatch for UKPN and NGED.

Across the remaining milestone in BP2:

For the Transforming Network Control project in 2023-24, we have revised our delivery plan to align with the adoption of a new GridOS platform from our supplier. This adjustment has resulted in a shift of approximately six months in the overall delivery of our new NCMS (Network Control and Management System) toolset. However, it provides several advantages beyond RIIO-2, including early access to a more modular design and futureproofing of the system. This eliminates the necessity for another large-scale project in the following years.

We have also deployed in our control room a substantial upgrade of our Voltage Stability Analysis Tool which is now being used to refine, define and validate constraint limits.

We have also rapidly deployed Reactive Technologies Oscillation Guard Pro, a tool to monitor oscillations and reduce operational risk. This product was additional scope identified following post-event analysis of recent oscillation events on the transmission system in Scotland and improves situational awareness.

We have continued to gain benefit across the year from our Fault Level Analysis (FLA) tool enhancements and several enhancements to the Control Training Unit that sped up snapshot build and scenario creation that were deployed in 2022-23. FLA has been used across the year to monitor system strength helping to identify and manage stability issues in real-time.

Combined status by milestone for relevant deliverables
(Activity A1)

Status	Count	%
Complete	**29**	39%
On track	**24**	32%
Delayed – Consumer Benefit	**4**	5%
Delayed – External Reasons	**1**	1%
Delayed - Internal Reasons	**8**	11%
Continuous activity	**8**	11%
Total	**74**	100%

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Supporting evidence

3. Utilising flexible technology

Measuring the direct impact of the deliveries in all the benefits areas is complex and the collective set of impacts across all ESO deliverables is difficult to unpick. Area 3, Utilising Flexible Technology, is one area where it is easy to measure and see the change, and attribute directly to IT deliverables within A1. We can do this by measuring the instructed volumes in the BM for flexible technologies which are contained within the battery and small BM unit zone.

Type	Measure	Rationale and status
Lead indicator	Small BM Unit Dispatch	Increase in dispatch volume of 47% comparing pre and post OBP delivery
Lead indicator	Battery zone Unit Dispatch	Increase in dispatch volume of 224% comparing pre and post OBP delivery

Detail: Calculation of monetary benefit

Below we list the significant factors which have changed the CBA since the BP2 assumptions were derived:

Benefit Area	Assumption Change	Impact
All	Phasing of value from the delivery schedule has been reduced across RIIO-2 with full delivery of capabilities planned to realise the remaining value in 2026-27 outside of the RIIO-2 period	Decreases CBA value
Reduced CO_2 emissions, gCO2/kWh	Difference in Leading the Way and Falling Short FES scenarios. 118.24 in BP2 start vs 287.89 in current CBA	Increase in CBA value
Improved Situational Awareness	Original forecast of constraint costs was £660m for original CBA for 2023-24, Outturn constraint costs for 2023-24 is £1.3bn. In addition, total constraint forecasts in original CBA were £4.7bn compared to current view of £6.8bn.	Increases CBA value

Additional benefits

There are additional benefits which have been created which were not included in the original BP2 CBA.

Platform for Energy Forecasting (PEF)

For PEF we forecast a benefit of £682m over the RIIO-2 period. This will be as a result of an improvement in the accuracy of demand forecasts (Mean Absolute Error) as a direct result of the PEF functionality. This benefit breaks down as follows:

Assumption		Financial Year					
		21-22	22-23	23-24	24-25	25-26	Comments
Day-Ahead Price, £/MWh		200	200	80	80	80	Based on Bloomberg data
Actual (A) / Forecast (F)		A	A	A	F	F	Outturn (Actual) or Forecast
National Demand + Solar	Forecast Improvement (MW)	100	100	119	119	119	Improvement in Mean Absolute Error of demand forecast
	Estimated Balancing Costs Savings (£m)	175.2	175.2	83.4	83.4	83.4	24/7 benefits. Price x Improvement x 365 x 24
Grid Supply Point	Forecast Improvement (MW)		100	100	100	100	Improvement in Mean Absolute Error of demand forecast
	Phased Delivery		30%	70%	100%	100%	Percentage of benefits realised (phased PEF implementation)
	Estimated Balancing Costs Savings (£m)		17.5	16.4	23.4	23.4	8 hours per day benefits. Price x Improvement x 365 x 8
Total Yearly Savings (£m)		175.2	192.7	99.7	106.8	106.8	
Total Savings (£m)		**681.2**					**Sum across RIIO-2 Period**

The decrease in the PEF benefits when compared to the BP1 End-Scheme CBA is a result of falling wholesale power prices in 2023-24 and ongoing assumption of lower wholesale prices in 2024-26 (previous assumption of £200/MWh for 2023-26, now £80/MWh). This reduction has been partially offset by an increase in the improved accuracy delivered by PEF from 100MW for the National Demand Forecast to 119MW from 2023-24 onwards. These factors in combination have seen a decrease in the forecast benefits from £932m to £681m (decrease in £251m) reported at the end of BP1.

Existing Balancing:

The benefits for 2023-24 onwards is £2m annually. This has been calculated as a percentage decrease in balancing costs, with an assumed 0.08% decrease on £2.5bn balancing costs per year.

There are also indirect benefits (but not added to this CBA) from enabling Role 2 and Role 3 activities such as enabling Balancing Reserve and Constraint Management pathfinder.

CBA: Control centre training and simulation (A2)

BP2 Mid-Scheme view of gross benefits compared to BP2

In BP2 we estimated gross benefits of £32 million over RIIO-2. For this Mid-Scheme update, we have not updated the BP2 gross benefits calculation, but instead provide an update on progress along with qualitative evidence of the benefits that A2 will deliver.

		Estimated gross benefits during RIIO-2 (£m)	
Area		**BP2 Plan view**	**Latest view**
1.	**Improved decision making:** Better training and simulation capability, combined with better tools.	25.9	We have provided a written update for Mid-Scheme. In summary, whilst 'Improved decision making' remains broadly on track, we have not seen the benefits expected for 'reduced resource costs' and 'decreased training costs'.
2.	**Reduced resource costs:** New workforce and change management tools, updated shift patterns and working arrangements will create efficiencies and increase staff retention.	4.9	
3.	**Decreased training costs:** Our enhanced training and simulator proposals mean that new starters will have more knowledge and can be trained quicker.	1.3	
Total		**32.0**	

Recruitment and training still remain our top priorities and we are continuing to develop new simulations to enable training to replicate real-time operation.

The challenges we have faced have been the additional cost, onboarding time and time to train by recruiting from overseas. There has been a considerable delay in candidates starting and the need to provide more training in specific GB topics. This has resulted in an extension in the time to train but has not compromised the quality of training.

It is important to note that in order to place new candidates in positions within the Control Room there is a requirement to train and develop existing staff into new roles. We have continued to train all operational staff, both new and established engineers, however this has been hindered by the higher than expected attrition and the time taken to train those joining from outside GB.

Summary of progress in 2023-24

1. Improved decision making	With the introduction of a number of improvements to the current balancing simulator above what we set out in BP2 we have been able to improve the training in the Control Training Unit (CTU) by giving trainees earlier visibility of the tool set and practice in a safe environment outside of the control room. With the initial roll out of the Open Balancing Platform we have been able to use the CTU to train the Control Room shift teams on the tools. This has resulted in a good uptake of the new tools and an increase in the dispatch of battery generation. One of the building blocks to the Future Training Simulator is the tool set from investment 110 (Network Control Management System). We had originally planned for this to be delivered early this year but will now land later in the summer. This has been delayed due to vendor and data centre availability. It does not affect the critical delivery of the investment

	as we require the NCMS simulator from October in order to begin 'Train the Trainer' Training ahead of full roll out of the training next year. Requirement gathering for the overall end-to-end training simulator has begun but due to a delayed start because of internal resource constraints and delays in project mandate, they have not completed as expected in March 2024. We now expect to complete this by the end of June 2024. We don't believe this fundamentally affects our ability to have this work completed during the RIIO-2 period.
2. Reduced resource costs	We have not been able to realise the benefits in line with BP2 as we have seen a higher than expected level of attrition in line with the wider energy industry, coupled with slower recruitment and longer training times (as outlined under '3. Decreased training costs'). The introduction of the workforce management system has reduced the burden of administration and human error around shift management. It has also allowed staff to indicate their availability for overtime, submit leave, meetings, and personal arrangements. Whilst progress is slightly behind schedule on Phase 3, we are confident that it will be complete by the end of BP2.
3. Decreased training costs	We have not seen the reduction in training costs that we expected in transmission and energy roles. In the last couple of years, there has been a reduction in the number of students exiting UK universities with STEM degrees and in particular Power System Engineering (PSE). As a result, many applicants to PSE roles have been from outside the UK. For our most recent recruitment campaign, 95% of applicants were from outside the UK. This has meant that more training has been required as the employees are not familiar with the GB Transmission and Energy System, which operates differently than most other countries. We have had to adapt and broaden training to include topics such as understanding our GB system terminology, locational and geographical challenges, industry codes etc. The average cost has also increased as we have also had to pay closer to the top of the salary band to attract staff to our roles to compete with others in our sector. We have also faced higher than expected attrition. However, we have delivered more training to our existing workforce to enhance and support development. In the first three years of RIIO-2 we trained 38 new candidates, and our latest view is that we will train 11 candidates in 2024-25 and 15 in 2025-26. This gives a total of 56 new candidates over five years. We are behind on the 'Enhanced Training Material' activity with universities and colleges due to changes in personnel and the creation of NESO. However, we have recently established a relationship with Loughborough College to continue the development of our Apprenticeship Training Scheme as well as forming a University Steering group headed up by our Chief Engineer. Relationships also continue with Brunel and Manchester University. We have 8 Industrial Placement (IP) students who will be joining in July 2024. Over the BP2 period we have had 4 IP students in 2022 and 12 in 2023. Other early year schemes have also seen an increase, with 18 Graduates in 2022, and 27 Graduates in 2023, and Higher Apprentices increasing from 8 in 2022 to 12 in 2023. We have decided that now is not the right time to offer summer placements for 2024 as we are in the process of transitioning our placement schemes out of National Grid and transforming them as we become NESO. They have been included in the NESO Early Careers

	strategy for 2025 as they will support the feeder pipeline for apprenticeships. Training Simulation environments are expected to be delivered for UAT however the ability to connect to DNO's will be delayed. We are prioritising the stakeholder engagement with the DNO's to understand their technical requirements and how we connect together in the future.

Combined status by milestone for relevant activities
(Activity A2)

Status	Count	%
Complete	**13**	36%
On track	**11**	31%
Delayed – Consumer Benefit	**-**	-
Delayed – External Reasons	**-**	-
Delayed - Internal Reasons	**8**	22%
Continuous	**4**	11%
Total	**36**	100%

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Detail: Calculation of monetary benefit

The original BP2 benefits figures for this project were calculated based on broad assumptions as outlined below. For Mid-Scheme, rather than generating an updated high-level estimate that may not provide an accurate representation, we provide the written update above for each element, setting out progress to date and qualitative impacts on benefits.

1. Improved decision making

BP2 calculation:

Assumptions	BP2 Plan view
(a) Reserve and response cost estimates	12-year historic average reserve and response costs: £2.4bn over five years of BP2.
(b) Improvement in reserve and response spend	We assume a 4% improvement in reserve and response spend, based on evidence from the introduction of the DER desk in January 2019. To account for potential uncertainty, we halve the 4% benefit to give a 2% reduction in response and reserve spend.
(c) Percentage of maximum annual benefit claimed	Allowing for the time it will take training and simulation enhancements to translate to operational decision-making improvements, we cannot claim the maximum benefit until the end of the RIIO-2 period, and so we claim a reduced benefit in the preceding years. Over the five years this amounts to 54% of the total 2% improvement being claimed.
Calculation	£2.4bn (a) x 2% (b) x 54% (c) = £25.9m
Benefit	£25.9m

2. Reduced resource costs

BP2 calculation

Assumptions	BP2 Plan view
(a) Reduced resource costs	Current inefficiencies in our workforce management tools are costing around £1m per year. New workforce and change management tools, updated shift patterns and working arrangements will create efficiencies and increase staff retention. We believe we can ultimately save around £1.3 million per year, by removing the spend on current inefficiencies and creating further efficiencies. To allow time for them to be embedded, we claim a reduced benefit in the first two years. This creates £5 million savings over RIIO-2. Phasing of benefits: 2021-22: £0.5m 2022-23: £0.5m 2023-24: £1.3m 2024-25: £1.3m 2025-26: £1.3m
Benefit	£5m

3. Decreased training costs

BP calculation:

Assumptions	BP2 Plan view
(a) Reduction in training time	ESO judgement, based on proposed transformational activities, reducing training time from seven months to four months, which is 42%.
(b) Training costs	Historic averages of £75k per candidate.
(c) Number of new starters trained	Based on historic data and forecast industry turnover we assume 30 candidates trained per year, which is 150 over five years.
(d) Percentage of maximum annual benefit claimed	Given that we are implementing enhanced training and developing new tools gradually over the RIIO-2 period, we cannot claim the maximum benefit until the end. So, we claim a reduced benefit in the preceding years, from 0% in 2021-22 to 80% in 2025-26, giving an average of 27% across the five years.
Calculation	42% (a) x £75,000 (b) x 150 (c) x 27% (d) = £1,275,250
Benefit	£1.3m

CBA: Restoration (A3)

BP2 Mid-Scheme view of gross benefits compared to BP2

We estimate gross benefits of £13.1m over the RIIO-2 period, in line with the BP2 figure.

	Estimated gross benefits during RIIO-2 (£m)		
Area	**BP2 Plan view**	**Latest forecast view**	**Variance**
1. Carbon savings	8.5	**8.5**	**-**
2. Benefits from Distributed ReStart NIC project	4.6	**4.6**	**-**
Total	**13.1**	**13.1**	**-**

A high-level CBA was carried out ahead of the Distributed ReStart innovations project, which underpins the estimated gross benefit during RIIO-2 as stated above. We are on track to implement the recommendations from the Distributed ReStart project and in line with the assumptions made, we will start to see the benefits from 2025-26 which is when the first batch of contracted Distributed Energy Resources (DERs) will start providing Restoration Services.

Summary of progress in 2023-24

During the 2023-24 period, we made updates to all the Regulatory Frameworks that were impacted by the new Electricity System Restoration Standard. Additionally, we published the Assurance Framework for the same period. We also progressed the requirements identification for the Restoration Decision Support Tool (RDST) and awarded new Restoration Service contracts to successful generators including Distribution Energy Resources (DERs) to implement the findings from the world first Distributed ReStart project.

The delivery milestone on the RDST is delayed due to lack of Business Analyst resourcing for three months and delays with Request for Proposal (RFP) Gate1 approval. We expect to recover the delay within BP2 timescales.

Combined status by milestone for relevant deliverables
(Activity A3)

Status	Count	%
Complete	**8**	44%
On track	**5**	28%
Delayed – Consumer Benefit	**-**	-
Delayed – External Reasons	**-**	-
Delayed - Internal Reasons	**1**	6%
Continuous activity	**4**	22%
Total	**18**	100%

For detailed commentary on all of the above milestones, please see theRIIO-2 deliverables tracker.

Supporting evidence

Type	Measure	Rationale and status
Lead indicator	Restoration Service Contracts	We awarded nine Restoration Service Contracts to generators in the Southeast region, including DERs in Dec 2023 and currently in the process of tendering in more regions. This increases the number of Restoration Service Contractors on the network.
Driver	Total contract costs, £m	The total cost over a span of five years is £81.2 million. Although this aligns with the previous tender spend from traditional generators, we anticipate that the expenditure on DERs will decrease over time.
Driver	Reduction in restoration services emissions, tCO_2e*	The benefits will be realised in 2025-26 when the Restoration Services go live.

Detail: Calculation of monetary benefit

Carbon savings

Assumptions	BP2 Plan view	Latest forecast view
(a) CO_2 reduction to 2050	We estimate the Distributed ReStart NIC project will lead to a reduction of 810,000 tonnes of CO_2 by 2050. This is through low carbon DER taking part in restoration services, leading to reduced carbon emissions from large generators. Source: Black Start from Distributed Energy Resources - Bid document to Ofgem	Assumption is still valid
(b) Phasing of CO_2 benefits	We assume this reduction is allocated evenly from 2025-26 when the implementation of the project recommendations will start delivering benefits. This means one year of benefit during the RIIO-2 period, which is 1/25th of the total benefit (i.e. one year out of 25).	Assumption is still valid
(c) Carbon price	Average carbon price of £264 per t/CO_2e in 2025-26, based on BEIS Updated Short-Term Traded Carbon Values April 2019	This is in line with the published carbon values
Calculation	810,000 (a) x 1/25 (b) x £264 (c)	Assumption is still valid
Gross benefits	£8.55m	£8.55m

2. Benefits from Distributed ReStart NIC project

Assumptions	BP2 Plan view	Latest forecast view
(a) £m benefit to 2050	The net present value of implementing the recommendations of the Distributed ReStart NIC project is £115 million to 2050. This is due to increased competition in restoration services and reduced costs from the use of some large generators. Cost savings will be passed on to consumers through reduced BSUoS charges. Source: Black Start from Distributed Energy Resources - Bid document to Ofgem	Assumption is still valid
(b) Phasing of benefits	We assume this saving is allocated evenly from 2025, when the implementation of the project recommendations will start delivering benefits. This means one year of benefit (2025-26) during the RIIO-2 period, which is 1/25th of the total benefit (i.e. one year out of 25).	Assumption is still valid
Calculation	£115 (a) x 1/25 (b)	Assumption is still valid
Gross benefits	£4.6m	£4.6m

Consumer benefit case study for Role 1

Frequency Strategy (22 December 2023 events)

Activity

22 December 2023: Demonstration of the ESO Frequency Strategy

Over the past several years, we have delivered numerous projects which have fundamentally changed the way we manage system frequency risks; both in terms of reducing the risks on the system, as well as reducing the costs for managing those risks. This has been achieved through a clear, long running strategy, comprising of several key projects: Frequency Risk and Control Report (FRCR), implementation of Dynamic Containment (DC) and the Accelerated Loss of Mains Change Programme (ALoMCP). See 'Appendix' section at the end of this case study for a summary of these.

The events of the 22 December 2023 demonstrated the benefits of the changes made through our Frequency Strategy. Simultaneous events occurred on the system, resulting in several generation losses occurring, causing a combined transmission connected infeed loss of 1,400MW and reported embedded generation loss of 260MW. The overall loss experienced on the network was in the region of 1,660MW. The events of the day and timestamps are shown in the table below:

Time	Activity	Source
13:09:51.617	An interconnector tripped from importing 1000MW to GB causing a frequency deviation.	ESO
13:10:00.310	A large unit automatically responded to the frequency deviation, changing output from 350MW to 388MW. During the ramping a technical issue occurred, causing the unit to trip at ~388MW.	ESO
13:10:02.682	Caithness – Moray HVDC link tripped. The flow on the link was 200MW before the trip which redistributed across the AC network.	SSEN-T
13:10:02.962	The system frequency dropped below 49.5Hz.	ESO
13:10:09.274	The frequency reached a minimum of 49.266Hz. The estimated total cumulative infeed loss at this time was around 1,400MW. 1100MW of new dynamic response (DM/DR/DC) was utilised over this period.	ESO
13:10:25	Two fast acting units instructed initially, and two further rapid units also instructed.	ESO
13:11:02.240	The system frequency returned to 49.5Hz after 59.3 seconds.	ESO
13:14:51.411	The system frequency returned to above the operational limit (49.8Hz) within 5 minutes. DNOs indicated 260MW embedded generation loss in total.	ESO

The events of 22 December 2023 demonstrated the benefit that these projects have had on system operation by presenting consumer cost saving whilst not sacrificing system security. This has been the largest frequency deviation and lowest frequency experienced on the system since the 9 August 2019 power cut and the implementation of the Frequency Risk and Control Report (FRCR) policy in 2021.

On 22 December 2023, the total loss of 1,660MW resulted in the frequency falling to 49.266Hz. The effect of implementing our Frequency Strategy prevented the frequency falling below 49.2Hz, avoided the need to use Low Frequency Demand Disconnection (LFDD) and returned the frequency to 49.5Hz within 60 seconds.

During the 22 December 2023 event we were contracting 1226MW of our new, fast acting, dynamic low frequency response suite. 1100MW was delivered and operated the way in which it was expected. In addition, the ALoMCP has created significant value through extensively reducing the loss of mains risk and therefore reducing the overall loss experienced.

The paragraphs below explain how our Frequency Strategy relates to the events on the 22 December 2023:

Frequency contained within statutory limits due to fast acting Dynamic Response Procurement and Delivery

We designed new dynamic frequency services to have technical characteristics which allows for very fast-acting delivery following a sudden demand or generation loss. This keeps the system frequency within the statutory limits and reduces the risk of reaching the frequency level which would trigger LFDD. Legacy services, e.g. mandatory frequency response, do not respond as quickly as the new fast services; therefore prior to the introduction of the new services, the events on 22 December 2023 could have led to demand disconnection via LFDD operation. During this event we were contracting 1226MW of our new, fast acting, dynamic low response suite including Dynamic Containment (DC), Dynamic Regulation (DR) and Dynamic Moderation (DM). In total 1100MW were delivered that operated the way in which they were expected. System frequency was maintained above 49.2Hz during the event, avoiding LFDD. Using increased volumes of the legacy frequency services would not have resulted in the same outcome and LFDD would likely have been triggered (based on previous frequency excursions and the 9 August 2019 power cut data).

Reduction in potential consequential loss volumes due to progress of ALoMCP

Large volumes of small, embedded generation had protection systems which would disconnect them from the system during events like the 22 December 2023. Our Accelerated Loss of Mains Change Programme (ALoMCP) has significantly reduced the volume at risk of disconnection during these significant generation loss events, by roughly 24GW. By December 2023, the remaining maximum non-compliant RoCoF capacities under 0.125Hz/s, 0.2Hz/s and 0.5Hz/s tranches are estimated as 125MW, 60MW and 135MW respectively. The maximum capacity which could be disconnected due to vector shift is estimated at 250MW. This means that there has been a significant reduction in the consequential loss size that could have been experienced, helping the system remain more secure following a fault on the network, and helping prevent the need for LFDD.

Without the ALoMCP, a significant volume of further generation would have disconnected, much higher than the 260MW experienced in this instance, likely triggering LFDD and causing widespread consumer impact.

Implementation of FRCR Policy altering response holding volumes, changing minimum inertia and reducing cost through not securing simultaneous events

The first edition of the FRCR policy was published in 2021, in response to the power cut event on 9 August 2019. This edition introduced an operational policy that allows large infeed losses to result in consequential RoCoF loss. However, this is only permissible if the frequency drop can be contained to 49.2Hz and restored to within 49.5Hz within a timeframe of 60 seconds. It is worth noting that most simultaneous losses, where two losses occur either instantaneously or within a short period of time, are already covered as a by-product of this policy.

The estimated yearly saving from implementing of FRCR 2021 and launching DC, e.g. over the period of 1 March 2021 to end of February 2022, was ~£435m. This saving was mainly achieved from a reduction in the number of actions taken to reduce the largest loss. After implementing the frequency policy recommended by FRCR, BOA actions to constrain largest loss size had been significantly reduced,

	whilst we had gradually procured more DC to secure BMU losses. DC is much more cost effective compared to older response services and therefore drives cost saving. The second edition of FRCR assessed and clarified the value in taking additional actions to secure all simultaneous losses. Due to the low occurrence likelihood and high cost to mitigate, FRCR 2022 recommended not to take additional actions to secure simultaneous losses that go beyond the largest securable loss. The event on 22 December 2023 was a simultaneous event where an interconnector and a generation unit both tripped within ~10 secs. Due to the system conditions and response services that were held at the time of the event, system frequency did not drop below 49.2Hz following the event. FRCR 2023 reviewed and confirmed the policy of not securing all simultaneous events. To secure all simultaneous events it is estimated to be £321million additional cost per year in procuring response services. Securing against all simultaneous events would require a significant increase in DC capacity and up to ~3.5 times the volume would be needed, e.g. 3-5GW DC. There are currently insufficient assets on the system or capacity on the market to provide this response. Under this policy of not securing all simultaneous events, an LFDD event could happen once within every 30 years. That also means that to prevent a single LFDD event, it would cost £321m/year over the course of 30yrs, equating to a total cost of approximately £9.63bn. Although our policy now states that we do not specifically secure simultaneous events, other changes implemented through our Frequency Strategy, such as increased DC holdings, have improved our response to simultaneous events as a by-product, with no additional cost to the end consumer. FRCR policy is currently focusing on reducing the minimum inertia on the system. To compensate for this reduction, increased volumes of DC would be held on the system. Increasing the DC holdings should also reduce the risk associated with future simultaneous events, aiming to increase future system security. Following FRCR 2022 where the minimum inertia policy remains 140GVA.s, a total of ~£1.85bn combined yearly saving was estimated from our frequency management strategy, which includes savings achieved from the FRCR policy recommendations (up to 140GVA.s), ALoMCP, launch and growth of the DC market, and savings from stability pathfinders.
Role	Role 1
Key RIIO-2 Deliverables	• D4.1.1 Deliver FRCR report with enhanced look-ahead. FRCR 2024 conducts risk assessment and frequency management policy recommendation for 2024-25 and 2025-26. • D4.1 We manage an end-to-end process to ensure that balancing services are procured to deliver security of supply to lowest cost to consumers. • Activity A1.2 Enhanced Balancing Capability – Balancing programme which delivered the necessary capabilities for the new frequency services.
Is the consumer benefit mainly this year or in future years?	Since 2021, with the launch of DC and addition of the first FRCR policy, consumers are benefiting from a decreased risk of LFDD occurring. After the launch of DR and DM, completion of ALoMCP, and a growth in all new dynamic response service markets, security and cost are both improving. Current and future years will both benefit from the frequency policy in terms of reduced cost and improved system security (when comparing to pre-2021).
Calculation of monetary benefit to consumers	Combined effects from FRCR policy recommendations, ALoMCP, develop and growth of DC and Pathfinder project, gives a total annual saving ~£1.85b. Post implementing FRCR 2023, i.e. minimum inertia policy of 120GVA.s, additional £65m is estimated to be achieved per annum.

Non-monetary benefits	The 22 December 2023 event demonstrates the significant system security benefit that has been realised due to the implementation of the Frequency Strategy. Low Frequency Demand Disconnection (LFDD) was not triggered following simultaneous events that resulted in a loss of ~1,700MW on the system, meaning that consumers were not impacted by these system losses. Using increased volumes of the older frequency services would not have resulted in the same outcome (LFDD would have been triggered). This is based on previous frequency excursions and the 9 August 2019 power cut data.
Appendix	Summary of frequency strategy developments in recent years: **Frequency Risk and Control Report (FRCR):** • The first FRCR was produced in 2021. FRCR provides an annual assessment of the magnitude, duration and likelihood of transient frequency deviations, the impacts and the cost of securing the system. It confirms which risks will or will not be secured operationally. The latest FRCR, published in 2023, recommended reducing the minimum inertia policy from 140GVA.s to 120GVA.s which could deliver better consumer value when managing frequency risks. Reducing the minimum inertia policy also impacts our zero carbon ambitions by reducing the number of carbon emitting units required on the system to provide minimum inertia. **Implementation of Dynamic Response Services:** • DC was launched in 2021 and is a fast-acting response service. It contains frequency within the statutory range of +/-0.5Hz in the event of a sudden demand or generation loss. Since we launched DC, we have been steadily growing the pipeline of providers, improving how we can manage frequency risks on the system. Dynamic Moderation (DM) and Dynamic Regulation (DR) have both been launched, DM provides fast acting pre-fault delivery for particularly volatile periods, and DR is our slower pre-fault service. **Accelerated Loss of Mains Change Programme (ALoMCP):** • The Accelerated Loss of Mains Change programme commenced in 2019 and has made changes to the loss of mains relays on distributed generation. These changes were made to ensure the protection settings of distributed generation acts in the right way in the event of any system disturbance. These changes have been fundamental in reducing our vector shift loss risks, significantly increasing the volume of compliant generation, helping improve the way we secure the system. **Stability Phase 1 Pathfinder:** • The first phase of our stability pathfinder procured inertia services, all of which are now operational. These projects provide inertia to the system, working alongside our dynamic services to help the network become more stable as we decarbonise.

Regularly Reported Evidence performance for Role 1

Table: Summary of RREs for Role 1 for 2023-24

Role 1 RREs don't have performance benchmarks.

2023-24

RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
1E	Transparency of Operational Decision Making	%	94%	91%	98%	93%	96%	97%	92%	87%	87%	88%	90%	91%
1F	Zero Carbon Operability indicator	%	Q1: 84%			Q2: 89%			Q3: 91%			Q4: 90%		
1G	Carbon intensity of ESO actions	gCO2 /kWh	4.7	1.9	2.8	11.6	5.2	10.7	9.5	3.7	8.9	6.6	7.2	7.7
1H	Constraints cost savings from collaboration with TOs	£m	Q1: £509m			Q2: £205m			Q3: £298m			Q4: £720m		
1I	Security of Supply	#	-	-	1	-	-	-	-	-	1	-	-	1
1J	CNI Outages - Planned	#	-	-	1	-	-	1	1	1	-	1	-	1
	CNI Outages - Unplanned	#	-	-	-	-	-	-	-	-	-	-	-	-

RRE 1E Transparency of operational decision making

April 2023 to March 2024 Performance

This Regularly Reported Evidence (RRE) shows the percentage of balancing actions taken outside of the merit order in the Balancing Mechanism (BM) each month.

We publish the Dispatch Transparency dataset on our Data Portal every week on a Wednesday. This dataset details all the actions taken in the BM for the previous week (Monday to Sunday). Categories and reason groups are allocated to each action to provide additional insight into why actions have been taken and ultimately derive the percentage of balancing actions taken outside of merit order in the BM.

Categories are applied to all actions where these are taken in merit order (Merit) or an electrical parameter drives that requirement. Reason groups are identified for any remaining actions where applicable. Additional information on these categories and reason groups can be found on our Data Portal in the Dispatch Transparency Methodology.

Categories include: System, Geometry, Loss Risk, Unit Commitment, Response, Merit

Reason groups include: Frequency, Flexibility, Incomplete, Zonal Management

The aim of this evidence is to highlight the efficient dispatch currently taking place within the BM while providing significant insight as to why actions are taken in the BM. Understanding the reasons behind actions being taken out of pure economic order allows us to focus our development and improvement work to ensure we are always making the best decisions and communicating this effectively to our customers and stakeholders.

We have been publishing the Dispatch Transparency dataset since March 2021, and it has sparked many conversations amongst market participants. As we continue to publish this dataset for BP2 we will also be providing additional narrative to help build trust by explaining:

- actions we are taking to increase understanding of the ESO's operational decision making
- insight into the reasons why actions are taken outside of merit order in the BM
- activity planned and taken by the ESO to address and reduce the need for actions to be taken out of merit order.

March 2023-24 performance

Figure: 2023-24 Percentage of balancing actions taken in merit order to meet requirements in the Balancing Mechanism

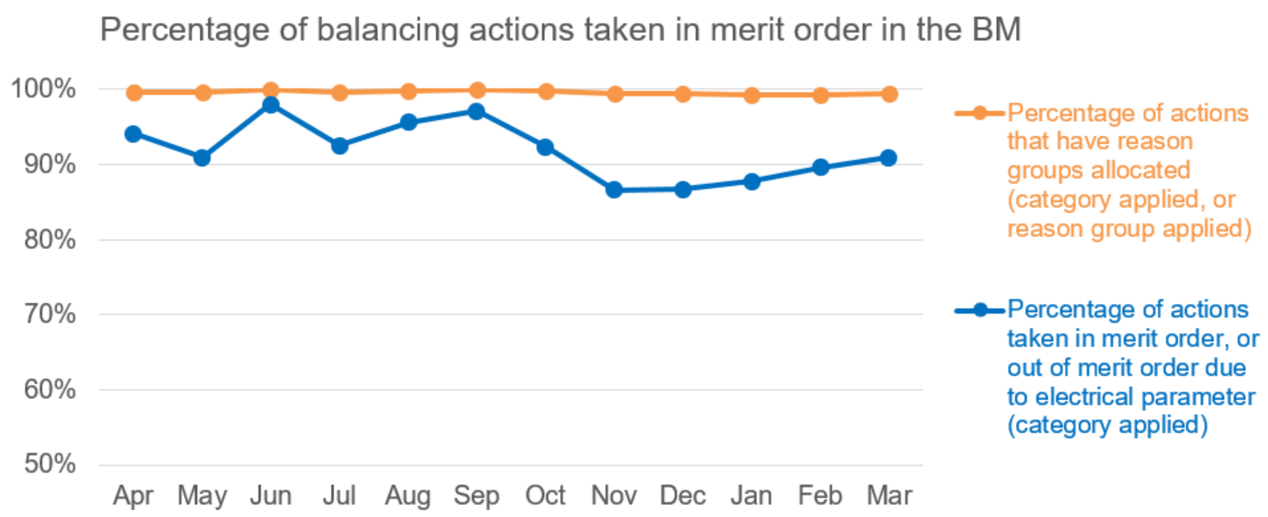


Table: Percentage of balancing actions taken outside of merit order in the BM

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	94.1%	90.9%	98.0%	92.5%	95.6%	97.1%	92.3%	86.6%	86.7%	87.8%	89.6%	90.9%
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.6%	99.9%	99.7%	99.8%	99.9%	99.8%	99.5%	99.5%	99.2%	99.3%	99.4%
Percentage of actions with no category applied or reason group identified	0.3%	0.4%	0.1%	0.3%	0.2%	0.1%	0.2%	0.5%	0.5%	0.8%	0.7%	0.6%

Supporting information

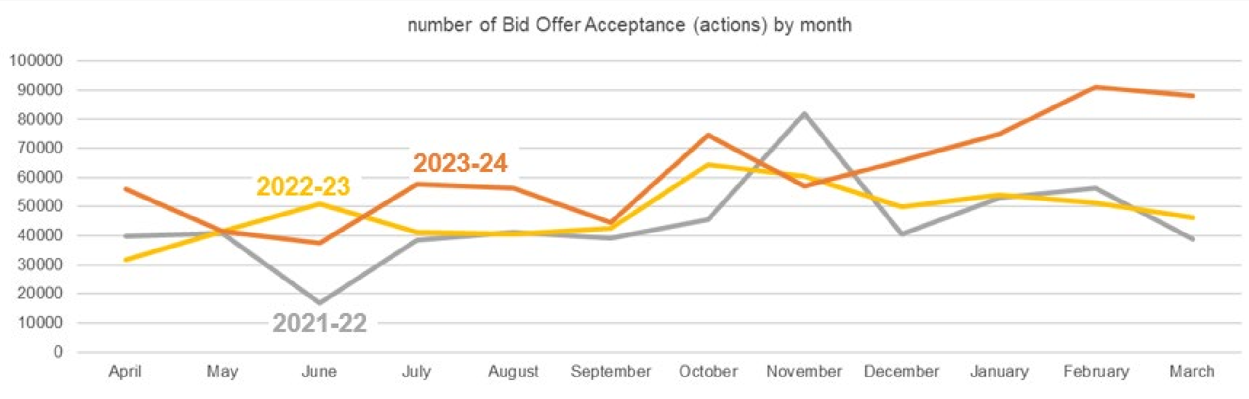
March performance

This month 90.9% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 8.5% of actions were allocated to reason groups for the purposes of our analysis, and the percentage of actions with no category applied or reason group identified remained in line with previous months. During February, there were 87,883 BOA (Bid Offer Acceptances) and of these, only 565 remain with no category or reason group identified, which is 0.6% of the total.

April 2023 – March 2024 performance

This year 91.3% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 99.5% of actions were allocated to reason groups for the purposes of our analysis, and the percentage of actions with no category applied or reason group identified remained in line with previous years. During the year, there were 744,304 BOA (Bid Offer Acceptances) and of these, only 3,383 remain with no category or reason group identified, which is 0.5% of the total.

The number of BOA's will always vary from day to day and month to month in response to the system needs. However, numbers overall are significantly higher for 2023-24 at 30% higher than the previous year and 40% higher than the total of 2021-22. This appears to reflect the control engineers' increasing use of combinations of more economic smaller units to provide services within the BM. We expect this trend to continue following the implementation of the OBP in December 2023.



Other activities

We conducted our first online Dispatch Transparency event in June and incorporated dispatch transparency work into the Enhancing Storage in the BM activities. As part of this we are closely supporting LCP for both phases of their independent analysis to provide greater insight into how the data can be used to identify and explain the reasons for out of merit despatch decisions.

We are developing the detailed plans for delivery of the improvements for Dispatch Transparency data, to incorporate the outcomes of the LCP analysis and continue to improve understanding and reporting. More information on this improvement timeline plus how we intend to engage with wider industry going forward and on an enduring basis will be provided at the follow-up storage webinar following LCP completion of the second phase work, expected May 2024.

In October we transferred the Dispatch Transparency tool onto a stable platform which has resulted in a more reliable delivery of the dataset. We have identified the missing data periods from the published dataset for the current financial year (from 1 April 2023) and continue work to develop a reliable method to retrieve or reconstruct these sections to provide a comprehensive dataset. We are progressing with the code review of the automated process and checks on reference data sources within the other ESO systems to identify and resolve additional root causes. We are committed to maintaining and improving the current Dispatch Transparency tool while we work with industry to build on LCP's recommendation and co-create a new Dispatch Transparency dataset.

RRE 1F Zero Carbon Operability Indicator

April 2023 to March 2024 Performance

This Regularly Reported Evidence (RRE) provides transparency on progress against our zero-carbon operability ambition by measuring the proportion of zero carbon transmission connected generation that the system can accommodate.

For this RRE, each generation type is defined as whether it is zero carbon or not. Zero carbon generation includes hydropower, nuclear, solar, wind, battery and pumped storage technologies. As this RRE relates to the ESO's ambition to be able to operate a zero carbon transmission system by 2025, only transmission connected generation is included and interconnectors are excluded (as EU generation is out of scope of our zero carbon operability ambition). Note that the generation mix measured by RRE 1F and RRE 1G differs.

The Zero Carbon Operability (ZCO) indicator is defined as:

$$ZCO(\%) = \frac{(Zero\ carbon\ transmission\ connected\ generation)}{(Total\ transmission\ connected\ generation)} \times 100$$

Part 1 – Defining the maximum ZCO limit for BP2

Below we define the approximate maximum ZCO limit (using a reasonable approximation of likely operating conditions), the system can accommodate at the start and end of BP2, explaining which deliverables are critical to increasing the limit.

Table: Forecast maximum ZCO% after our operational actions

BP2 2023-25	Maximum ZCO limit	Calculation and rationale
Start of BP2 (Q1 2023-24)	**90% - 95%**	The maximum ZCO% achieved to date is 90%, set in January 2023. New frequency products and voltage and stability pathfinders are the main projects delivering increased ZCO% during the early part of BP2. The methodology for calculating ZCO% is consistent with BP1 and our continued delivery of projects and programmes increases the opportunity to operate the system at higher ZCO%.
End of BP2 (Q4 2024-25)	**95% - 100%**	We expect that our remaining projects, products and programmes will enable us to operate at 100% ZCO in 2025. Our operational strategy is set to deliver some key projects which will increase the maximum ZCO% over the BP2 period. These key deliverables are the deployment of our full suite of response and reserve products, voltage and stability pathfinders, further reduction of minimum inertia requirement via the Frequency Risk and Control methodology (FRCR) and improved tools for monitoring system inertia. These deliverables are either enabling zero carbon providers of ancillary services or increasing the window in which we can operate the system securely.

Part 2 – Regular reporting on actual ZCO

Every quarter we report the ZCO provided by the market versus the ZCO following ESO actions. This is presented at a monthly granularity.

The table below is calculated according to the formula for ZCO for each settlement period for every day over the reporting period. ZCO is a percentage of the zero-carbon transmission generation (hydropower, nuclear, solar, wind, battery and pumped storage technologies) divided by the total transmission generation. Two figures are calculated: one represents the system conditions before ESO interventions are enacted, the other is after. This indicator measures progress against our zero-carbon operability ambition by showing the proportion of zero carbon transmission generation that the system can accommodate.

For each month, the settlement period that has the highest ZCO figure after our operational actions were enacted is displayed. The corresponding market ZCO figure is also included. It is worth noting that this market ZCO figure might not necessarily be the maximum ZCO that the market provided over the month. For example, the maximum ZCO provided by the market in Q2 was 98% on 28 September 2023, settlement period 8. However, for that period the final ZCO dropped to 80% after our operational actions were taken into account, meaning that this was not the highest final ZCO of the month. To see the maximum ZCO provided by the market, this can be found below in *Figure: Q4 2023-24 ZCO by Settlement Period, before and after ESO operational actions* shown by the blue line.

The graphs further below show the underlying data by settlement period and highlight when the maximum monthly values occurred.

Table: Maximum zero carbon generation percentage by month (2023-24)

Month	**Highest ZCO% in the month** (after ESO operational actions)	**ZCO% provided by the market** (during the same day and settlement period)	**Date / Settlement Period**
April	83.6%	90.7%	10 Apr / 36
May	79.6%	88.0%	4 May / 24
June	79.9%	92.3%	10 Jun / 33
July	83.9%	90.9%	3 Jul / 22
August	82.9%	96.0%	19 Aug / 29
September	89.1%	97.1%	24 Sep / 31
October	86.8%	92.0%	3 Oct / 30
November	84.0%	90.2%	2 Nov / 46
December	91.3%	97.5%	28 Dec / 30
January	85.8%	91.3%	1 Jan / 45
February	87.1%	93.7%	4 Feb / 26
March	90.5%	96.7%	23 Mar / 23

Note that the values can change between reporting cycles as the settlement data is updated by Elexon.

Figure: Maximum monthly ZCO% after ESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred) – two-year view

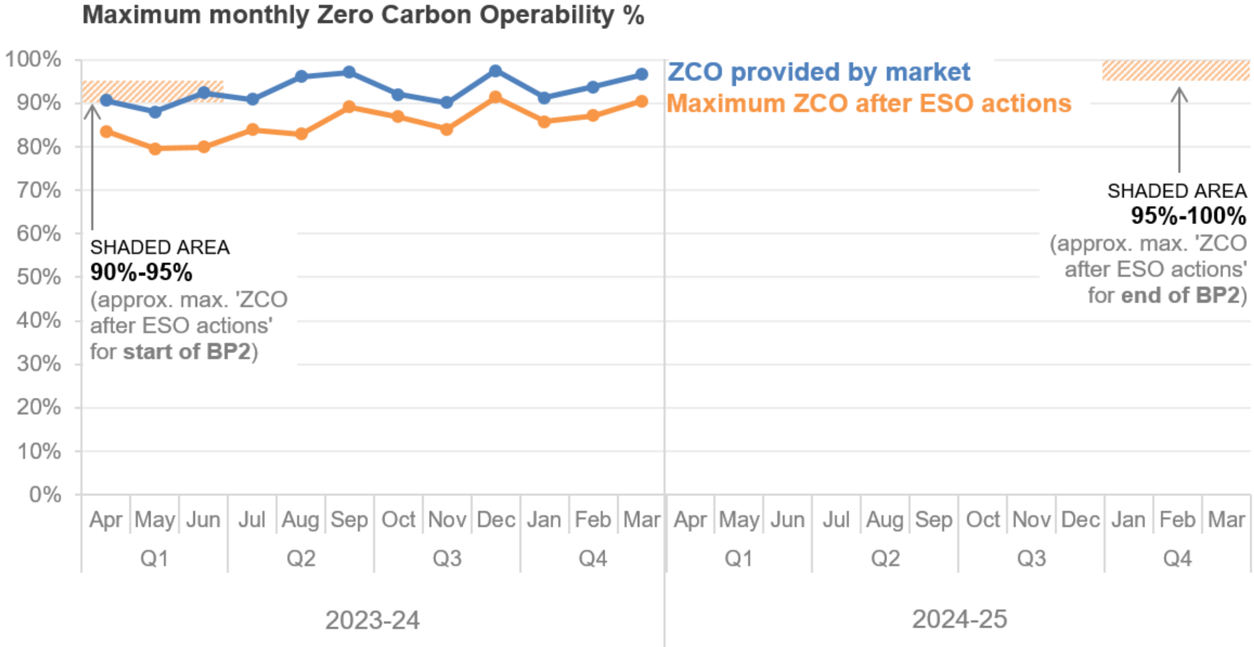
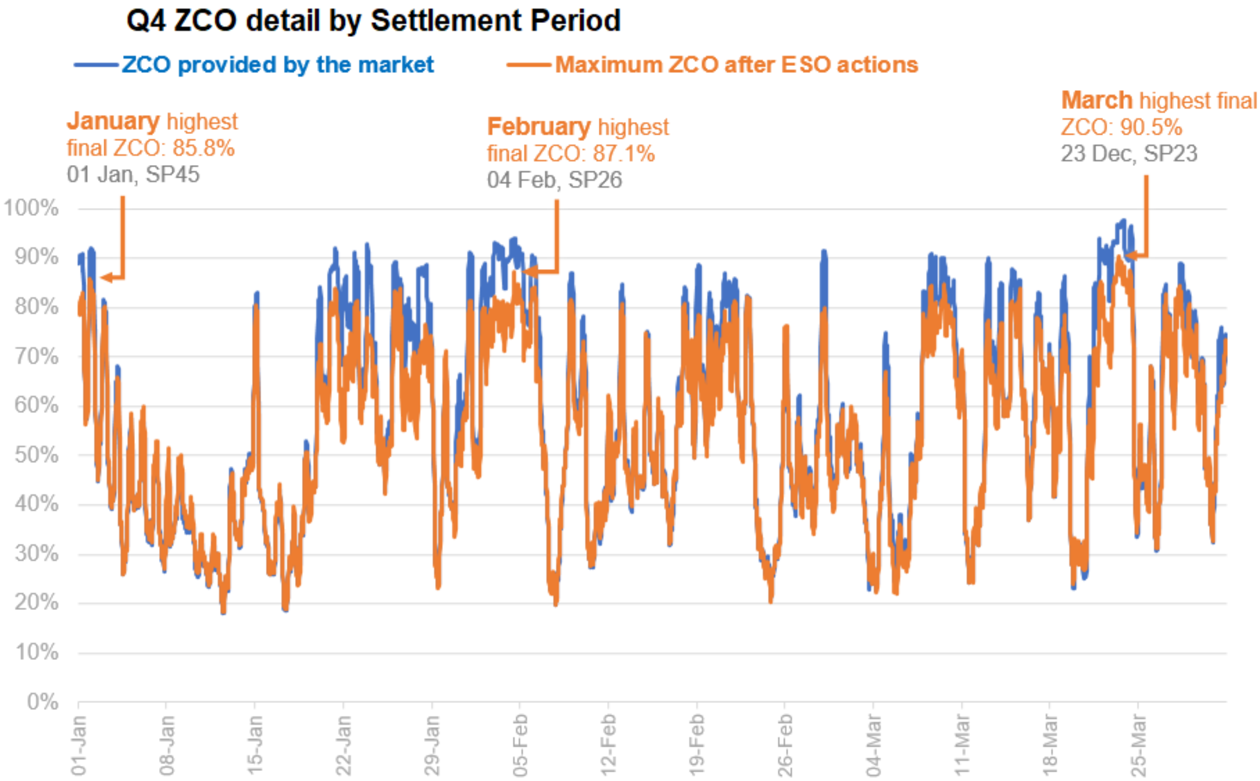


Figure: Q4 2023-24 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

April 2023 – March 2024 performance

Over the last year we have made significant progress towards being able to operate a zero carbon system in 2025. In nine out of the twelve months of 2023-24, we operated a system with higher penetrations of zero carbon generation that the same month of the previous two recorded years. This was accomplished in a record-breaking year for zero carbon generation. The highest ever solar and wind power output was achieved, alongside the lowest fossil fuel generation and carbon intensity.

Q4 Performance

In Q4 2023-24, we have continued to increase the Zero Carbon Operability indicator, operating at a higher ZCO on average than Q4 2022-23. In February and March, the maximum ZCO was more than 4% higher than for the same months last year, continuing the trend we have seen for most of 2023-24.

On January's highest ZCO day, the combination of interconnector exports and bids on wind for margin reasons led to voltage needs on the west side of GB. Power flows on the Western HVDC were altered to solve the voltage needs. Elsewhere, carbon emitting generation was needed to solve voltage and inertia needs.

For February's highest ZCO day, up to 3.6GW of wind were bid down for Scotland and Northern England constraints. Batteries were optimised to provide necessary positive and negative margin which avoided higher cost carbon emitting units. Two carbon emitting units were required for voltage. A further unit was required to provide margin.

On March's highest ZCO day, two carbon emitting units were required for voltage needs throughout the day. A number of offshore windfarms reduced PNs to zero in response to negative prices on some trading platforms. Two further carbon emitting units were required to cover margin and inertia needs.

New reactive power assets, inertia from Stability services and our plans to reduce the minimum inertia requirement by 2025 will negate the need for these actions in future.

The lowest ZCO% this month was on 12 January of just 18%. Low wind of ~3GW coupled with ~40GW of demand meant the system was secure with little intervention from ESO.

Highest final ZCO by month vs previous year

Quarter	Month	2022	2023	Difference
Q1	April	83.7%	83.6%	-0.2%
	May	78.5%	79.6%	1.1%
	June	76.7%	79.9%	3.2%
Q2	July	73.9%	83.9%	10.0%
	August	67.3%	82.9%	15.6%
	September	73.5%	89.1%	15.6%
Q3	October	77.6%	86.8%	9.2%
	November	74.3%	84.0%	9.7%
	December	84.8%	91.3%	6.5%
Q4	January	90.3%	85.8%	-4.6%
	February	82.6%	87.1%	4.5%
	March	85.7%	90.5%	4.8%

RRE 1G Carbon intensity of ESO actions

April 2023 to March 2024 Performance

This Regularly Reported Evidence (RRE) measures the difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the Balancing Mechanism (BM) and the equivalent profile with balancing actions applied.

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO2/kWh associated with it. For full details of the methodology please refer to the Carbon Intensity Balancing Actions Methodology document. The monthly data can also be accessed on the Data Portal here. Note that the generation mix measured by RRE 1F and RRE 1G differs.

It is often the case that balancing actions taken by the ESO for operability reasons increase the carbon intensity of the generation mix. More information about the ESO's operability challenges is provided in the Operability Strategy Report.

March 2023-24 performance

Figure: 2023-24 Average monthly gCO2/kWh of actions taken by the ESO (vs 2022-23)

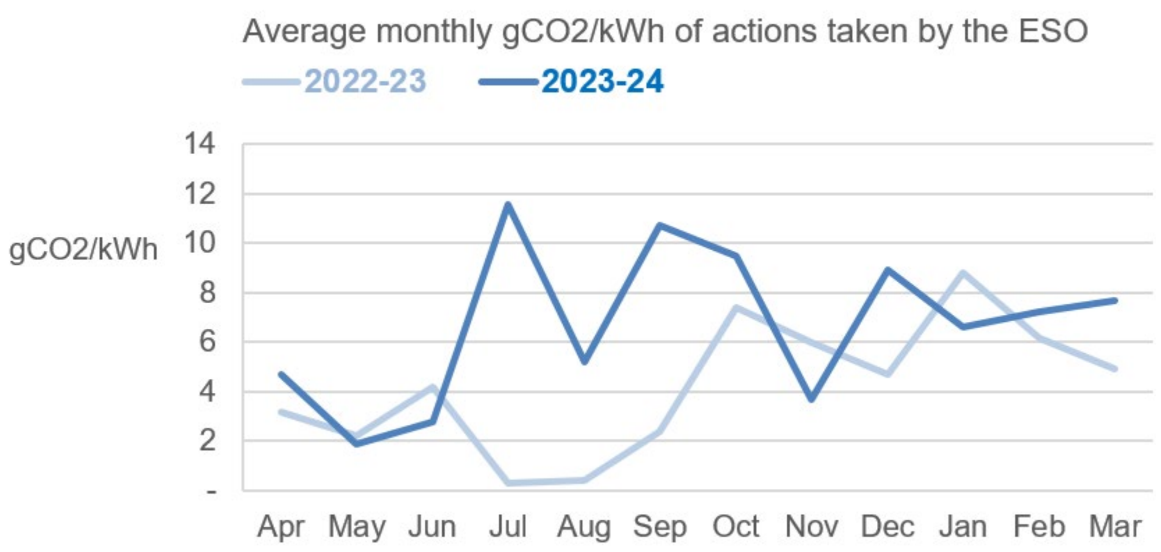


Table: Average monthly gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	4.7	1.9	2.8	11.6	5.2*	10.7*	9.5*	3.7	8.9	6.6	7.2	7.7

Supporting information

***Data issue (Aug-Sep):** As reported previously there are eight days' incorrect data in August, one day's data missing in September and four in October. We have a temporary fix in place which means that data has been complete from November onwards. We're working to correct the August to October data and working on a permanent fix.

April 2023 - March 2024 Performance

From April 2023 to March 2024 the average carbon intensity of ESO actions has been similar to the previous year excluding the summer period (Jul-Sep). This is largely due to interconnector exports in 2022 leading to self-dispatch of carbon emitting generation. This meant most of our system security needs were met with little intervention from the ESO. By contrast, in 2023, interconnector exports were lower than 2022 and therefore more ESO actions were required to ensure system security. This was coupled with additional ESO actions taken to mitigate adverse effects of the unacceptable sub-synchronous oscillations experienced in June and July. The result was an increase in carbon intensity of ESO actions.

However, more recent changes in Q4 such as the reduction in the minimum inertia requirement, increased volumes of response procured and the introduction of balancing reserve, are leading to the ESO operating more low carbon periods than ever before. In 2024, we have operated more periods at <50gCO2/kWh than in all previous years combined.

March Performance

In March 2024, the average carbon intensity of balancing actions was 7.7gCO2/kWh. This is 2.8g higher than March 2023 (which was 4.9gCO2/kWh).

Across the month, ESO actions reduced the carbon intensity in 32% of settlement periods.

The majority of carbon intensity increase from ESO actions, was largely seen between 21-24 March during a period of high wind. Wind generation often delivered ~60% of the generation mix, peaking at 68%. This often required up to 4GW of bids behind constraints in Scotland and Northern England. Batteries and pump storage were optimised to help reduce constraint volumes. Changes to interconnector programs meant carbon emitting units were required to be kept on, increasing the carbon intensity of our actions. Elsewhere, unavailability of sync comps meant additional carbon emitting units were required for stability and voltage needs.

The largest increase to carbon intensity was on 18 March 23:30-00:00. ESO actions increased the carbon intensity from 71 to 128gCO2/kWh. This was mostly from increasing fossil fuel generation to balance the 32GWh of bids which was needed to resolve constraints in Scotland and Northern England. Proactive reassessment of voltage needs through the night meant two carbon emitting units were no longer required, helping to reduce the impact of our actions on carbon intensity from 57g to ~25gCO2/kWh in the early hours of 19 March.

The lowest carbon intensity provided by the market was on the 23 March 20:00-20:30 (20.4gCO2/kWh) with high wind (~19GW) and other zero carbon sources providing around 71% of the generation mix (after ESO actions). A fault outage led to unavailability of reactive power assets, so an additional carbon emitting unit was required.

RRE 1H Constraints Cost Savings from Collaboration with TOs

April 2023 to March 2024 Performance

The Transmission Operators (TOs) need access to their assets to upgrade, fix and maintain the equipment. TOs request this access from the ESO, and we then plan and coordinate this access. We look for ways to minimise the impact of outages on energy flow and reduce the length of time generation is unable to export power onto the network.

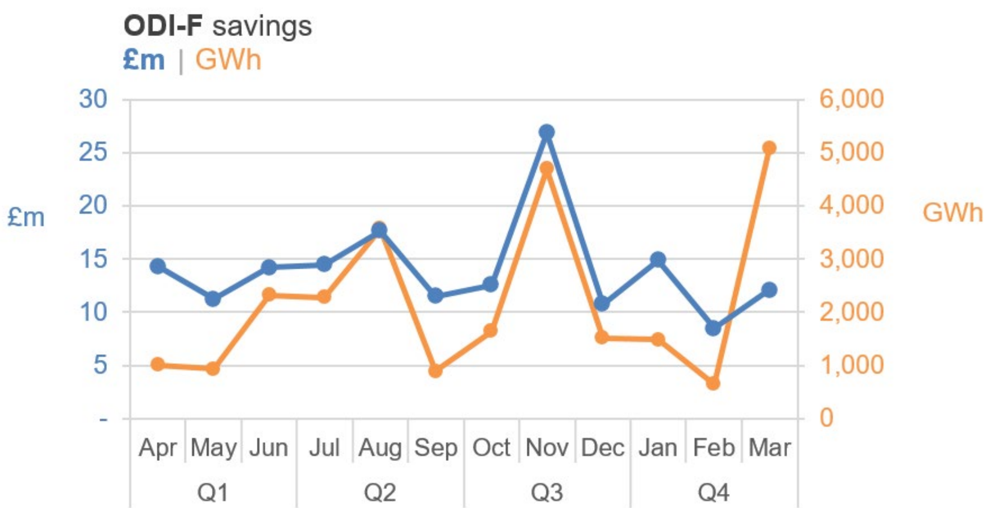
This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

There are two ways the ESO can work with the TOs to minimise constraint costs. We will report on both for RRE 1H:

1. ODI-F savings: Actions taken through the System Operator: Transmission Owner (SO:TO) Optimisation ODI-F
    i. Output Delivery Incentives (ODIs) are incentives that form part of the TOs' RIIO-2 framework. They are designed to encourage licensees to deliver outputs and service quality that consumers and wider stakeholders want to see. These ODIs may be financial (ODI-F) or reputational (ODI-R).
    ii. One of these ODIs, the SO:TO Optimisation ODI-F, is a new two-year trial incentive to encourage the Electricity Transmission Owners (TOs) to provide solutions to the ESO to help reduce constraint costs according to the STCP 11-4[9] procedures. The ESO must assess the eligibility of the solutions that the TOs put forward in line with STCP 11-4, and must deliver the solutions in order for them to be included as part of the SO:TO Optimisation ODI-F and this RRE 1H.
    iii. For RRE 1H, where constraint savings are delivered through the SO:TO Optimisation ODI-F, the savings are calculated in line with the methodology for that incentive.
2. Other savings: Actions taken separate from the SO-TO Optimisation ODI-F
    i. The ESO also carries out other activities to optimise outages. In these cases, the assumptions used for estimating savings will be stated in the supporting information.

Figure: Estimated £m savings in avoided constraints costs (ODI-F) – 2023-24

(Estimated savings in GWh are also shown for context)



[9] The STCP 11-4 'Enhanced Service Provision' procedure describes the processes associated with the ESO buying a service from a TO where this service will have been identified as having a positive impact in assisting the ESO in minimising costs on the GB Transmission network.

Figure: Estimated £m savings in avoided constraints costs (Other) – two-year view

(Estimated savings in GWh are also shown for context)

*Note **vertical axes scales** differ from the ODI-F graph above.*

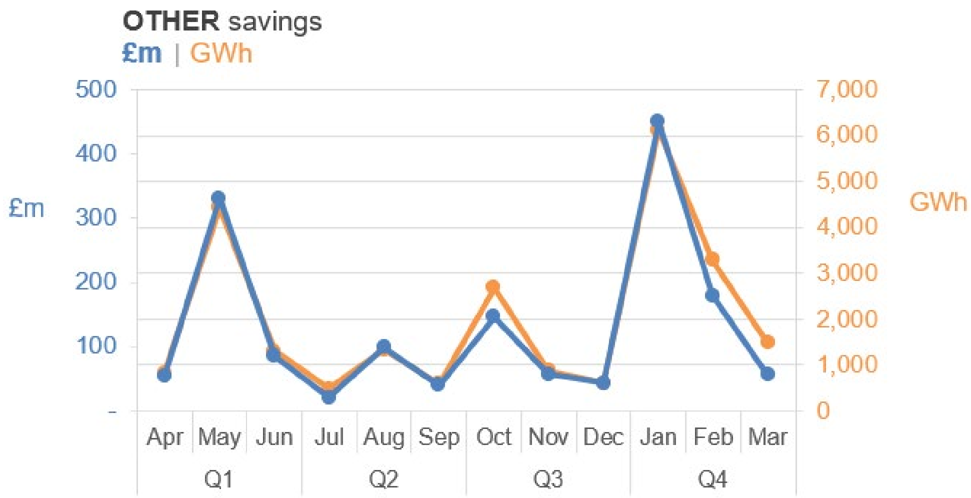


Table: Monthly estimated £m savings in avoided constraints costs (2023-24)

	ODI-F savings	**Other** savings	**ODI-F** savings	**Other** savings
	£m	£m	GWh	GWh
Apr	14.3	53.4	1011.5	827.6
May	11.2	331.4	940.3	4425.4
Jun	14.2	84.9	2323.0	1309.9
Jul	14.5	21.5	2279.0	486.3
Aug	17.7	99.1	3570.0	1345.3
Sep	11.5	40.5	893.9	593.1
Oct	12.5	146.6	1643.5	2688.3
Nov	26.9	57.2	4689.6	883.5
Dec	10.8	44.0	1517.8	602.4
Jan	14.9	449.5	1488.6	6125.3
Feb	8.5	179.3	649.3	3290.3
Mar	12.1	56.0	5077.2	1479.0
YTD	**169.1**	**1563.4**	**26083.7**	**24056.4**

Note that figures from previous quarters may change as some savings are updated retrospectively with costs that were not available at the time that the activities were carried out.

Prices of £36 per MWh are used for conventional generation and £75 per MWh for renewable generation.

Supporting information

ODI-F (STCP 11-4) Constraint Cost Savings

The Network Access Planning (NAP) team has progressed and approved 5 enhanced service provisions from TO's through STCP 11.4 that provide constraint cost savings for Q4 this year. Some of these provisions are highlighted below:

In January, SPT and NAP agreed an enhancement on Hunterston East – Neilston 400kV 1 circuit to facilitate an outage on Hunterston East – Neilston 400kV 2 circuit, to enable the safe removal of the redundant section of the gantry shared with the Hunterston East – Neilston 400kV 1 circuit. This enhancement yielded a saving of **0.84 TWh** circa **£6.4 million** to the end consumer.

In March, a weather-based rating enhancement was agreed on Padiham - Penwortham 400kV circuit, to facilitate a planned outage on Carrington – Penwortham 400kV overhead line that connects Penwortham, Lancashire to Carrington, Greater Manchester. With this enhancement in place, a total of saving **0.8 TWh** and **£1.8 million** to the end consumer was achieved for the duration of the outage.

Still in March, a system access request for the Hawthorn Pit – Norton - Offerton 275kV circuit for carrying maintenance to remove arcing horn pokers from the circuit. To deliver this outage successfully, an enhancement on Hawthorn Pit – West Boldon 275kV circuit was put in place to increase the operational capability of this circuit thus realizing a saving of **0.23 TWh** and **£0.82 million**.

Across 2023-24, NAP team has progressed and approved 32 enhanced service provisions which have realised approximately **£154.4 million** of constraint cost savings through STCP 11.4 from **23.8 TWh** of extra capacity released.

Please note that the figures for previous quarters have also been updated following overall updates as at the end of 2023-24. There were two specific enhancements which were utilised for the entire year and these were; West Link Run Back scheme and the Kintore – Tealing 275kV outage bypass. Therefore, these enhancements have been distributed across the 12 months.

Financial savings have also been accurately calculated across 2023-24 for the outturn costs. No forecast savings are included in the data for this section. TWh outturn savings are proportionally calculated from the forecast GWh values and the actual outturn cost savings.

Other Savings (Customer Value Opportunities (CVO)):

The Network Access Planning team has made good progress over the last three months. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded **69 instances this quarter, and 215 instances in the past 12 months,** where the ESO's actions directly resulted in adding value to the end consumers and its innovative ways of working facilitated increased generation capacity to the connected customers.

Such actions are taken to optimise transfers on the network to maximise capacity across constraint boundaries and include: moving outage dates, splitting/separating outages, reducing return to service times, obtaining enhanced ratings from TOs, re-evaluating system capacity, identifying and facilitating opportunity outages, aligning outages with customer maintenance and generator shutdowns, proposing, and facilitating alternative solutions for long outages that impact customer, and many more.

Some examples of these instances include:

In January, ESO received a system access request from SPT on the Elvanfoot-Moffat circuit for two weeks needed as a proximity outage. However, there was already a planned outage on Elvanfoot-Gretna circuit for synchronous compensator works. Therefore, ESO took the assessment and resolved that these outages cannot overlap, because overlapping them would require the B6 boundary to be held at 0MW. This action equated to a saving of **1.5 TWh** and approximately **£113.4 million** to the end consumer.

In January, SHET had a planned/granted system access on Kintore – Fettersso XS1 275kV circuit for re-insulation and re-conductoring works. As a consequence of this outage, the SSE North – South flows would be dropping by approximately 500MW. To mitigate this drop, an operational capability limit was realized on the Kintore – Fettersso XS2 275kV circuit. This action in turn saved an approximate of **0.79 TWh** and **£59.8 million** to the end customer.

In March, ESO received two system access requests from NGET on Cottam – West Burton 400kV for proximity and Keadby – West Burton 2 400kV circuits, for overhead line refurbishment works. This combination of outages would reduce the capability to export power around Keadby and West Burton, and therefore to mitigate this issue, West Burton 400kV substation configuration was rearranged, and this increased the constraint limit by 1200MW, for 22 days of the outages duration which equated to **0.63 TWh** and **£22.8 million** savings.

This section of the report includes actions tracked up to the end of 2023-24. There was an upsurge of CVOs in January mainly due to a disproportionate amount of value opportunities from rapid increase in outages as the new plan year begins and therefore there are more opportunities to optimise the plan.

The above and many more customer value opportunities represent a total of **24.1 TWh (approximately £1.56 billion)** of extra generation capacity across the 2023-24, which would have otherwise been constrained at a cost to the end consumer.

The £/MWh figure for savings is calculated per outage. £50 per MWh is used for savings on conventional generation, £75 per MWh is used for renewable generation. Where full commercial cost benefit analysis assessment is available these figures are used instead. Due to the high price per MWh in fully costed CVOs and the increase in renewable generation on the network, the average price per MWh is approximately £65.

RRE 1I Security of Supply

April 2023 to March 2024 Performance

This Regularly Reported Evidence (RRE) shows when the frequency of the electricity transmission system deviates more than ± 0.3Hz away from 50Hz for more than 60 seconds, and where voltages are outside statutory limits. On a monthly basis we report instances where:

- The frequency is more than ± 0.5Hz away from 50Hz for more than 60 seconds
- The frequency was 0.3Hz - 0.5Hz away from 50Hz for more than 60 seconds
- There is a voltage excursion outside statutory limits. For nominal voltages of 132kV and above, a voltage excursion is defined as the voltage being more than 10% away from the nominal voltage for more than 15 minutes, although a stricter limit of 5% is applied for where voltages exceed 400kV.

For context, the **Frequency Risk and Control Report** defines the appropriate balance between cost and risk, and sets out tabulated risks of frequency deviation as below, where 'f' represents frequency:

Deviation (Hz)	Duration	Likelihood
$f > 50.5$	Any	1-in-1100 years
$49.2 \leq f < 49.5$	up to 60 seconds	2 times per year
$48.8 < f < 49.2$	Any	1-in-22 years
$47.75 < f \leq 48.8$	Any	1-in-270 years

At the end of the year, we will report on frequency deviations with respect to the above limits and communicate any plans for future changes to the methodology.

March 2023-24 performance

Table: Frequency and voltage excursions (2023-24)

	2023-24											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz for over 60 seconds)	0	0	0	0	0	0	0	0	0	0	0	0
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0	0	0	1	0	0	1
Voltage Excursions defined as per Transmission Performance Report[10]	0	0	0	0	0	0	0	0	0	0	0	0

Supporting information

March Performance

There were no reportable voltage or frequency excursions in March. There was one instance where frequency was 0.3 – 0.5Hz away from 50Hz for over 60 seconds, as follows:

On 11 March 2024 @09:56, Viking Link interconnector tripped while importing 1400MW from Denmark. The frequency dropped to 49.634Hz but returned to operational limits, 49.8Hz by 09:58.

[10] https://www.nationalgrideso.com/research-publications/transmission-performance-reports

April 2023 – March 2024 performance

During the 2023-24, there was no reportable voltage or frequency excursions as per Transmission Performance report criteria.

There were three instances where frequency deviations are over 0.3Hz for more than 60 seconds but returned to operational limits 0.2Hz within 5 minutes. System margins stayed healthy and system security remained under control of Frequency Risk and Control Report (FRCR) 2023.

RRE 1J CNI Outages

April 2023 to March 2024 Performance

This Regularly Reported Evidence (RRE) shows the number and length of planned and unplanned outages to Critical National Infrastructure (CNI) IT systems.

The term 'outage' is defined as the total loss of a system, which means the entire operational system is unavailable to all internal and external users.

March 2023-24 performance

Table: 2023-24 Unplanned CNI System Outages (Number and length of each outage)

	2023-24											
Unplanned	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Balancing Mechanism (BM)	0	0	0	0	0	0	0	0	0	0	0	0
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0	0

Table: 2023-24 Planned CNI System Outages (Number and length of each outage)

	2023-24											
Planned	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Balancing Mechanism (BM)	0	0	1 outage (185 mins)	0	0	1 outage (265 mins)	1 outage (145 mins)	1 outage (170 mins)	0	1 outage (203 mins)	0	1 outage (190 mins)
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0	0

Supporting information

April 2023 – March 2024 performance

From April 2023 to March 2024, there were six planned CNI system outages. For more information on these planned outages see previous reports on our website. There were no other planned or unplanned outages during this period.

March performance

In March 2024, there was one planned CNI system outage. The outage was to carry out regular maintenance activities on the BM production systems, and impacted the key BM Suite components used for scheduling and dispatch of generation.

This change took place on 12 March, and was planned in advance, in collaboration with our control rooms to ensure it did not introduce a conflict with other known periods of high activity. Notifications are posted to the industry, via BMRA, at 7 days prior and 1 day prior.

On the day of the outage, our control rooms are again consulted to confirm that conditions remain suitable to proceed with the change or, if required, whether the change must be rescheduled.

Additionally, on the day, notifications are posted to the industry, via BMRA, when the outage is due to start, and when it is complete.

There were no other planned outages during March.

There were no unplanned outages during March.

Role 2
Market developments and transactions

ESO

B.1 Plan Delivery for Role 2

Deliverable progress

For Role 2, the RIIO-2 Delivery Schedule received an ambition grading of 4/5, providing us with an ex-ante expectation of Ofgem's assessment of plan delivery if these deliverables are met. The ESORI guidance states that "the Performance Panel should consider that the ESO has outperformed the Plan Delivery criterion if the ESO has successfully delivered the key components of a 4- or 5-graded delivery schedule".

See below an overview of key plan delivery topics for Role 2 over the first 12 months of the Business Plan 2 period.

Net Zero Market Reform (NZMR)

Position at end of BP1:

Feedback from Ofgem and the Performance Panel for our performance in BP1 was very positive. NZMR showed our ability to act at pace and act responsively to emerging system issues. We have endeavoured to build on this positive feedback in BP2 and continue to drive the debate forward in Review of Electricity Market Arrangements (REMA).

How have we progressed our work in BP2 (since 1 April 2023)?

In the first year of BP2, the NZMR programme has evolved significantly. We have undertaken an in-depth review of investment policy, to complement our earlier work on operational market design. Together, these analyses complete the holistic review of market design and policy that we set out to achieve at the start of the programme. The NZMR programme of work has been consistently at the forefront of the GB market reform public debate.

Since completing the NZMR analysis, we have been brought into REMA as a formal delivery partner alongside DESNZ and Ofgem. This outcome reflects our objective to be a 'trusted partner' to government and demonstrates the quality of work that the NZMR programme delivered. Going forward, our NZMR work will be integrated into our REMA delivery.

Our work on investment:

Completion of the Investment Policy aspects of market reform has been a major focus area. In early 2023, we published Baringa's detailed investment policy options analysis, which we had commissioned. We accompanied this analysis with our own view on the study's findings. Through the first half of 2023, we conducted our own in-depth analysis, building on the Baringa study. Ahead of publication, we shared our final conclusions with stakeholders through a webinar which attracted over 400 participants and included an extensive live Q&A session. From spring through the remainder of 2023, we worked very closely with DESNZ, supporting officials in developing the case for change to reform the Contracts for Difference (CfD) scheme and to analyse different options in preparation for the second REMA consultation. While this delayed the publication of our final report (intended for summer 2023), it provided the opportunity for deeper analysis and coordination with the REMA process. We published our final report in December 2023, ahead of the publication of the second REMA consultation.

We worked closely with DESNZ during 2023 and formally joined the REMA programme in January 2024. We now also undertake an advisory role in the Future Renewables Investment (FRI) working group – one of several REMA working groups. On the back of the deeper analysis conducted through 2023, the FRI group has progressed at pace since its initiation in January 2024.

Our contribution to the FRI workstream since January 2024 has been primarily on the case for change element, i.e., understanding the evidence base to support reform of the current CfD. We have also been working with DESNZ on assessing the merits of a deemed generation CfD versus a capacity based CfD.

Wholesale market and dispatch reform:

Throughout 2023, we supported Ofgem in their analysis of locational pricing (including nodal and zonal pricing). This included providing input on the feasibility of different options and technical expertise on the impact of locational pricing on our within-day balancing processes.

In BP2, we committed to assessing how different market design options in REMA interact with operational challenges posed by net zero. We have established a significant body of work focusing on wholesale and balancing market processes in 'operational' timeframes. In keeping with NZMR's scope, this work looks beyond ESO-owned balancing activities and at the broader wholesale market context.

We have:

1. Developed a 'Case for Change' that current scheduling and dispatch arrangements are not working as intended.

   We are currently part way through engaging with stakeholders on our 'Case for Change' to existing Scheduling and Dispatch arrangements. This analysis identified three intersecting challenges facing GB balancing arrangements:

   a. Absence of incentives
   b. Imperfect visibility and access
   c. Inter-temporal issues

   In addition to workshops with DESNZ and Ofgem, we held an in-person workshop with key market participants and institutional actors such as power exchanges. Comments from attendees suggested that they broadly agreed with our identification of issues in current scheduling and dispatch processes, although there was disagreement as to the scale of the issues and the impact on different parties. We will continue to hold similar workshops in spring 2024. The feedback we get from this engagement is informing our ongoing assessment in the REMA programme. We continue to gain valuable input on how we engage on potential reforms from the ESO Markets Advisory Council.

2. Established an innovation project looking at the topic of 'co-optimisation', including the potential consumer and system benefits out to 2035 and implementation considerations.

   This project has assessed the arguments for and against more co-optimised procurement of energy, transmission and reserve in the context of GB's evolving asset mix. The project is still being completed but combines an extensive report outlining the theory of co-optimisation with excellent forward-looking modelling of intraday market processes. The modelling has underlined the critical role of energy-limited assets to GB's future balancing arrangements and the value that could be derived from co-optimised management of energy and reserve towards the end of this decade.

   We are now planning to share our findings from phase 1 of this project with industry stakeholders to get their feedback before a potential phase 2.

3. Undertaken significant internal analysis on different dispatch models and the circumstances under which they would be appropriate for GB. This work will be the foundation for the assessment of dispatch options we are undertaking to support DESNZ' REMA programme.

   To support DESNZ' decision on whether to retain Self Dispatch or move to Central Dispatch, we have explored international arrangements and the emerging needs of GB's future system. On the basis that there is no clear existing template that GB could adopt, we have developed our own framework for assessing the various 'building blocks' of dispatch mechanism options and are building possible models 'bottom-up' for evaluation in REMA. A key line of research is the impact of different arrangements on cross-border trading. This work is again feeding into DESNZ and Ofgem's parallel analysis of other reforms in REMA.

Our work on operability:

In BP2, our operability-related work for REMA has been focused largely on the issue of thermal constraints. The first REMA consultation, and our wider stakeholder engagement, uncovered suggestions from industry as to how thermal constraints could be tackled in the short- to medium-term period between now and when REMA delivers fundamental market reforms. We have worked with industry and with internal colleagues to understand these proposals in more detail and whether they would be appropriate solutions.

However, we wanted to get a much fuller and more comprehensive view of industry’s ideas and provide an open opportunity to co-create solutions. So, in January 2024, we launched our Constraints Collaboration Project to ask industry for market-based solutions to thermal constraints that could deliver value in up to five years’ time. A total of 30 responses were received, primarily from developers and generators, but public body and academics were also represented. The solutions can be categorised into three main themes:

1. Constraints management markets
2. Using flexible assets to reduce the flow over boundaries
3. Increasing how much can flow over boundaries

We are discussing these solutions with industry to get feedback from as many experts as possible, and to hear how they could be improved upon or further developed. We are currently assessing the solutions at a high level against our Market Design Framework. This will enable us to narrow the options down to a shortlist for detailed assessment. We will then proceed with design and implementation stages if options are deemed to be of significant consumer value.

Market Reform

(including market development processes and Enduring Auction Capability (EAC))

Key developments in market reform include the launch of the EAC enhancement of the new dynamic Frequency Response products with the associated phasing out of legacy products, and progress on designs for Reactive power markets.

EAC

The EAC is a RIIO-2 deliverable, designed to deliver co-optimised procurement for our day-ahead frequency response and reserve products. The EAC platform enables us to procure Dynamic Containment, Dynamic Regulation and Dynamic Moderation response services.

We partnered with NSIDE and SOOPs to facilitate the design, build and implementation of the new EAC platform. It includes several new features such as co-optimisation, splitting/stacking, a new sell order design, an advanced clearing algorithm, overholding and the capability for market participants to offer negative pricing. The inaugural auction, held in November 2023, saw active participation from all 23 existing dynamic response service providers, signalling strong support and endorsement from key stakeholders.

The EAC platform launched on 19 October 2023, with the platform becoming open for bid submissions.

The first live auction on the EAC platform took place on 2 November 2023. Offers were received on a total of 109 units from 23 participants utilising the new market design features available to them on the EAC platform.

The launch of the platform followed Ofgem’s publication of its Decision to approve the Enduring Auction Capability. Prior to the launch of the EAC platform, market participants participated in a series of trials from September to mid-October. This helped ensure a smooth transition and allowed providers to test new features and functionalities. The project's development involved extensive collaboration with stakeholders, addressing service providers needs across 30 one-to-one sessions, three industry webinars, 15 EAC drop-in sessions, 16 trial auctions and two comprehensive industry questionnaires and market explainer guidance published online.

The EAC has delivered a substantial price step change, with all Dynamic Response markets moving across in a single day to deliver savings for the consumer estimated at £86.5m per year (see CBA Build the future balancing service markets (A4) for detailed calculation). This substantial decrease demonstrates the efficiency and effectiveness of the new auction platform in procuring ancillary services.

As previously reported, the EAC project delivery timeline was revised due to several factors. The implementation of a Prior Information Notice (PIN) and a Prequalification Questionnaire (PQQ) to ensure compliance with Utilities Contracts Regulation 2016 extended the project timeline. Delays were encountered in capturing and approving functional requirements due to limited subject matter expertise and critical strategic considerations. The project team also spent time collaborating with IT Security and Tech Risk teams to align non-functional requirements and Baseline Security Requirements. Resource churn in the initial stages caused further delays.

The lessons learned from this program include early engagement with regulatory processes, management of SME availability, improvement of the strategic decision-making process, and enhanced collaboration with IT Security and Risk teams.

The second version of EAC involves the introduction of a new reserve service, Balancing Reserve (BR) which went live in March 2024. The BR service enables us to move to day-ahead procurement of the energy reserves we need and respond to system demand in real time, rather than the current on-the-day system. This service capitalises on the new market design, the Power Matching Algorithm, the robust infrastructure, and other components of the co-optimised EAC Auction, which were consulted on with industry.

This will also pave the way for additional Quick and Slow Reserve services to also be added to the platform. A revised phased implementation plan for Quick and Slow Reserve was proposed in line with the delivery of our strategic IT platforms. The first phase is expected to go live with a Quick Reserve BM only service at the end of summer 2024 followed by a non-BM service in summer 2025.

We have now also completed our proposed Service and Procurement Design for Quick Reserve (phase 1), which was shared at our last industry webinar. Invitations for one-to-one sessions have also been extended to industry for further engagement on our proposed design.

Further Frequency Response Reform

In addition to the transition to co-optimised auctions, further enhancements to the operational usage of the dynamic frequency response products were implemented. Key changes included enhanced visibility and control of the new products for the control room. These changes enabled us to increase procurement of the more competitive day-ahead dynamic services and phase out the legacy product Dynamic Fast Frequency Response (DFFR) as well as reduce usage of Mandatory Frequency Response (MFR).

Reactive power market design

Between October 2021 and March 2022, we were allocated Network Innovation Allowance (NIA) funding to develop and propose potential solutions to reform reactive power services in partnership with AFRY. The project proposed an initial market framework design that would meet system voltage requirements whilst maximising participation from potential providers. The initial market design comprised of three markets running over different timescales: long-term (year -4), mid-term (year -1), and short-term (day-ahead). During 2023 there was further work to assess the impact of these markets in unlocking future consumer benefits and identify the order of priority for implementation.

Work on the long-term market is complete and we plan to launch the first tender when the right opportunity presents itself. Implementing the long-term market will drive locational investment and enable greater competition in the delivery of reactive power service provision. The earliest year there may be a requirement to be covered by the long-term market is 2029. This is subject to a firm requirement being identified and the long-term market being selected by us as the preferred delivery route.

Further assessment is required on the consumer benefit and impact that a mid-term reactive market could provide by procuring reactive power closer to the delivery year. There are some design questions to be further analysed before progressing with a mid-term market, so we’re continuing to review the value and impact with industry.

On the short-term market, further analysis is required to determine the value of a day-ahead service. This work will also consider the output from the review of the Obligatory Reactive Power Service (ORPS). Prior to the introduction of a short-term market, work continues with the roll out of Commercial Services Agreements (CSAs), providing a way that generators can receive payment for their additional reactive power capability beyond their mandatory obligations.

Review of Market Development Processes

We are taking steps to ensure that our submissions are accurate, contain no unavoidable errors and that there is better alignment between Ofgem and ESO in terms of direction, development and delivery of new products and services. We are also taking steps to ensure that there are no unintended consequences through having multiple live consultations or necessary changes to text that then may cause later issues with development or approval of products. This will work alongside our thorough review of the Article 18 mapping activity under the

Electricity Balancing Regulation to allow all stakeholders to clearly understand how changes to any relevant terms and are considered.

In addition, we recognise that understanding of the requirements of TSO's under the legislation is not always clear to all of our stakeholders and we are taking steps to ensure that these are well understood assisting all parties with progressing change effectively to our products and services.

Demand Flexibility Service (not in BP2 plan)

Following the success of DFS in 2022-23 we made further progress in 2023-24 in terms of engagement and participation, service design, and testing.

Increased engagement

In June 2023 we launched a consultation to seek industry feedback on our proposed terms and conditions of the revised DFS, in accordance with the requirements of EBR Article 18. Over eight hours of workshops and webinars were held before the consultation launch, covering feedback from Winter 2022-23, the role of DFS, and obtaining industry feedback. There were more than 100 participants for each of the sessions and this, along with feedback from a Call to Input, helped shape the design and proposals for DFS moving forward, leading into the EBR Article 18 Consultation.

The EBR Article 18 Consultation received widespread interest with responses from 32 providers and over 100 pages of feedback submitted to Ofgem.

DFS was presented at several industry forums, and numerous one-to-one calls took place to keep industry up to date with information and any service developments. There is also a dedicated mailing list for DFS with 3,987 subscribers, to help improvements in communication and engagement.

We saw an increase in numbers of registered participants, with 48 this year compared to 31 during the previous winter. The total number of individual participants this winter, measured in Meter Point Administration Numbers (MPANs - unique identifiers for individual meters) has now reached over 2.4 million, which represents an increase of 50% compared to the previous winter, and over 3.6GWh delivered.

It is also worth noting that improvements in forecasts, bids and settlement files have all been a product of enhanced engagement. Any information provided via internal teams was fed back to providers and allowed us to communicate changes required moving forward.

Service Design for Winter 2023-24

Following engagement with industry, we prioritised a number of process changes for Winter 2023-24. We shared these via an industry webinar on 27 April 2024.

The main priorities for the development of DFS were:

- Removal of the domestic in-day adjustment for the baseline methodology
- Retain existing metering requirements if appropriate
- Apply Applicable Balancing Services Volume Data (ABSVD) to Half-Hourly (HH) settled volume (I&C and Domestic MPANs signed up to provide DFS with supplier) but continue to investigate changes that could be made to the process
- Set the ownership for duplicated MPANs as the latest sign-up
- Identify what is possible for automating elements of provider interactions including:
    1. Bid submission process
    2. MPAN check process
- Guaranteed Acceptance Price (GAP) & price discovery
- Event opt-in

We managed to incorporate the majority of these into the service design. With regards to keeping the existing metering requirements, there was a step change around this rule for Winter 2023-24, further details of which are provided below. Greater automation was provided via an API, whilst keeping the remaining process in place so that there were multiple options available for registered participants. We implemented MPAN rules and daily MPAN duplication checks, plus an option for providers to apply an 'Opt-out' approach. We also removed the within-day adjustment from domestic participants' baselines to counter opportunities to 'game' the service. The rules around the application of ABSVD remained, but there was a change to the profile class in which these related.

The main change to these requirements was allowing sub or asset meters to participate in this edition of DFS. Initially, the plan was to keep the same rules as the previous winter. However, our stakeholders informed us that they would like us to re-consider our position on this and remove barriers for additional participating volume. We used a series of deep dives, one-to-ones, and industry forums to find a solution that allowed sub or asset meters to participate.

This winter, we introduced two further procurement lead times adding to the existing day-ahead route:

- Day-Ahead – 14:30
- In-Day (morning) – 09:00
- In-Day (lunchtime) – 12:00

The aim was to bring procurement closer to real-time, allowing us to understand the impact different lead times had on the volume of flexibility available. Although initially provider forecasts were poor, this was understandable as parties adapted to the new service terms. Forecasts improved as further tests were conducted with volume stabilising at around 450MW for day-ahead and circa 350MW for within-day dispatch.

All changes were detailed in the *Participation Guidance Document* we produced for this winter.

Regarding the Guaranteed Acceptance Price (GAP) and price discovery for this winter, test events took place which incorporated both. The first six test events, all conducted by 31 December 2023, were underpinned by a GAP of £3,000. To better understand the prices at which consumers and service participants are willing to reduce demand, we introduced the concept of competitive tests i.e., tests where the GAP = £0/MWh. To date we have carried out seven competitive tests looking at various facets of the service and accepted prices have ranged from £150/MWh to £ 2500/MWh.

Distributed Flexibility

In 2023 we established a new team working closely with our industry colleagues to develop our first Flexibility Market Strategy to unlock the potential of distributed flexibility. We have defined our vision, desired outcomes for 2028, and identified six workstreams to help us achieve the outcomes and develop a roadmap of actions. Our proposal has been tested with various industry colleagues via the Markets Forum, industry workshops and bilateral conversations.

Looking ahead, we are committed to deepening the collaboration with industry, focusing on identifying and prioritising the blockers and pain points to enhance accessibility of our flexibility markets for distributed resources. Facilitating ESO-DSO market stacking to optimise the use of distributed assets will be another focus area. Additionally, we are dedicated to supporting the design and implementation of the Market Facilitator and various industry wide transformational programmes. A Call for Input on our Flexibility Market Strategy will be launched in May 2024 to make our engagement more effective and inclusive.

EMR (BAU and Portal)

CfD

The CfD scheme is the government's main mechanism for supporting new low carbon electricity generation projects in Great Britain. As the Electricity Market Reform Delivery Body (EMR DB), we are responsible for the prequalification, disputes and auction processes of the CfD scheme.

Allocation Round 5 (AR5) (2023)

On 8 September 2023, we published the CfD AR5 results. A total of 95 projects were successful, representing ~3.7 GW at a cost of ~£228m (2012 price) ~£294m (current price). This included geothermal projects (three projects) being awarded CfD contracts for the first time, record numbers of tidal stream projects (11 projects), and significant quantities of new solar and onshore wind generation.

As EMR DB, we are proud that the prequalification, dispute and auction processes went smoothly. A record low number of disputes were raised to Ofgem, who upheld our decision. This is the result of enhanced customer service and effective partnership with DESNZ and Ofgem. The quality of how we administered the AR5 process was also reflected in our customer satisfaction survey results, with a score of 8.64/10 received from 44 respondents.

Following closure of AR5, we engaged closely with DESNZ to identify learnings from the first annual round.

Allocation Round 6 (AR6)

In preparation for AR6, which opened for applications in April 2024, we have supported DESNZ with developing changes to the Allocation Framework. This support has included a significant proposal to allow offshore wind projects that reduced their capacity (known as a permitted reduction) to enter the balance of their capacity into AR6.

We have also undertaken activities to prepare stakeholders and ourselves for the start of AR6, including:

- Holding an AR6 introductory webinar, which was designed to introduce stakeholders to delivery partners, the process and the AR6 Framework. We had over 200 attendees and received a feedback score of 4.5 out of 5.
- Holding an ESO Applicant Readiness webinar, designed to give more detail on the application and auction processes, which was attended by 65 people. 30 questions were proposed for the Q&A section, indicating potential applicants wanted further information, and we published responses to all questions.
- Moving AR6 Guidance onto new, clearer templates, updated in line with AR6 Framework, simplified where possible and tailored for those new to the CfD process (in response to the AR5 customer satisfaction survey feedback).

Capacity Market (CM)

The CM was a key outcome of the government's EMR programme and continues to be the main mechanism for ensuring security of supply into the future. The CM is technology neutral and procures capacity through two Auctions – the T-1 and the T-4. The EMR DB is responsible for the prequalification, disputes, auction and ongoing agreement management processes of the CM scheme.

Auctions 2023-24

We assessed over 1,000 applications during the prequalification process over summer 2023 and rejected approximately 5% for failing to meet all the prequalification requirements. The most common reasons for rejection were misunderstanding of new regulatory requirements or failing to provide sufficient information by applicants under the CM Rules. During the Tier 1 disputes process, the EMR DB was able to prequalify most applicants who had previously been rejected, following receipt of information or correction of errors to make the applications compliant. Three applicants raised Tier 2 disputes with Ofgem. Ofgem upheld the EMR DB's decision on two of the disputes and overturned one. The EMR DB is working with Ofgem on a change to clarify the intent of the Rules associated with the overturned rejection.

On 20 February 2024, the EMR DB ran the T-1 Auction and on 27 February 2024, the T-4 Auction, securing 7.6 GW and 42.8 GW respectively. DEZNZ have published the Auction Monitor Reports for both auctions, confirming that they were run in accordance with the CM Rules and Regulations.

Policy and regulatory changes

The EMR DB is an active participant of the CM Advisory Group (CMAG), which is an impartial expert group established by Ofgem to develop, assess, and recommend changes to the CM Rules. Bringing our insight and expertise, we contribute considerably to the discussions, provide challenge and undertaking impact assessments to ensure Ofgem has sufficient information to reach decisions on proposals.

In addition to operational change proposals, we have identified a number of more significant changes while administering the CM. We are working closely with delivery partners, including through meetings under DESNZ's governance, to consider these against overarching CM principles.

Finally, we have been supporting DESNZ in shaping the detailed design and implementation of the proposals on the CM Rules which were consulted on with the industry late last year. These proposed changes are designed to align to the net zero ambition as well as to improve efficiency of operation of the regime.

EMR Portal

The new EMR Portal was originally planned to be delivered by the end of the BP1 period, however delivery was delayed due to internal and external factors. These factors were discussed with Ofgem and customers in early 2023 with clear support for delivery of the full CM processes into 2024-25 (see Portal Update February 2023 for details).

Following on from this engagement, the EMR DB worked with Ofgem to agree new baseline milestones which were approved in October 2023. The updated schedule included one milestone for delivery in 2023-24 updating the existing portal to enable ongoing compliance with regulatory changes required for Prequalification 2023. Overall delivery milestones were updated to reflect implementation of the new portal in Q1 2024-25, with milestones associated with continuous improvement from Q2 through to Q4.

In parallel to the milestone updates, an independent audit was commissioned by Ofgem on the overall delivery of the new portal. This was undertaken by PWC in November 2023 and included an overview of the new portal architecture, lessons learnt during the project, customer engagement approach and a detailed response to specific concerns raised on governance and risk management. PWC were satisfied with the evidence provided on the project. A deep dive was arranged with the Ofgem ESO Regulation team to provide further details on the new portal delivery, provide a demonstration of the portal look and feel, and an overview of how customer requirements have been integrated into the overall design.

The first stage of the new portal implementation was delivered in January 2024, which has enabled customers to register their companies and users as a prerequisite to migrating existing system data for the full go-live in Q1 2024-25. A full customer familiarisation window was run between 20 March and 16 April 2024 with 66 customers representing over 300 individual companies participating during the window. Customers took part in a full end-to-end validation of the new portal processes and functionalities to build confidence in using the portal. This included running processes related to migrated agreements from the current portal prior to operational use. It also helped us to identify and fix issues raised by customers before the system goes live and to incorporate customers' feedback into our future improvement plans.

Review of Market Development Processes

We are taking steps to ensure that our submissions are accurate, contain no unavoidable errors and that there is better alignment between Ofgem and ESO in terms of direction, development and delivery of new products and services. We are also taking steps to ensure that there are no unintended consequences through having multiple live consultations or necessary changes to text that then may cause later issues with development or approval of products. This will work alongside our thorough review of the Article 18 mapping activity under the Electricity Balancing Regulation to allow all stakeholders to clearly understand how changes to any relevant term's and conditions are considered.

In addition, we recognise that understanding of the requirements of TSO's under the legislation is not always clear to all of our stakeholders and we are taking steps to ensure that these are well understood assisting all parties with progressing change effectively to our products and services.

Settlements and Revenue (STAR)

The Settlements, Charging and Billing investment continues to deliver against an agile delivery roadmap.

For Charging and Billing, STAR has successfully delivered on its 2023-24 Ofgem revenue commitments. Enhancements and additional mandatory scope (driven by DESNZ and HMRC) have also been delivered. The exception is 'Reconciliation functions' which has been deferred to 2024-25 to deliver value in alignment with annual business processes.

For Settlements, the programme has delivered the highly complex suite of dynamic services (Containment, Moderation and Regulation) for Firm Frequency Response (FFR) on STAR and is yet to deliver Mandatory Frequency Response (MFR) in order to complete its Frequency Response milestone, delaying business value generation from 2023-24 to Q1 2024-25. This delay is primarily due to assurance of FFR payments and remediation of performance issues on the platform.

Settlements operates in a highly dynamic environment where market-driven changes play a significant role. We take account of these factors when reviewing the roadmap and when reprioritising the transition of existing ancillary services to STAR. They also impact our assessment of new services like MFR Batteries and a new set of Reserve services (Quick, Slow, and Fast), which were not initially anticipated during the sanctioning process.

To mitigate any further risk to this investment, the programme is reprioritising the STAR roadmap based on business value, delivery efficiency and market direction. There is a sustained need for programme resources to deliver on remaining BP2 commitments and initiate work early to meet 2025-26 milestones.

Single Markets Platform (SMP)

SMP is linked directly to nine BP2 milestones and progress on these is shared below. However, looking at the performance of SMP through the lens of BP2 milestone delivery in isolation significantly underestimates what has been achieved and the value that the platform has delivered. This is because SMP operates as a genuinely agile project that adheres to a fixed budget and seeks to deliver value through releases developed and delivered on a monthly basis. Within the context of assessing value, the SMP team has a strong understanding of what should be on our backlog but we don't assume that we have all of the answers. As a result, we engage continuously with our user base to refine and prioritise what we develop. This approach also recognises that milestones written at the start of 2022 may not remain appropriate as time progresses and the project develops. We seek to ensure that we actively manage our development backlog against the following four pillars of delivery:

1. Delivering user functionality that enhances our user experience (external and internal)
2. Addition of appropriate balancing services onto SMP
3. Integration with other ESO systems that are being developed across the user journey
4. Engagement with the DSO / Flexibility community

We begin each year with a plan of what will be included within each release. We then retain the flexibility to adapt this plan by bringing features forward, pushing others back or adding / removing them altogether. We make these decisions based on other timetables that are out of our control, tactical requirements or an updated prioritisation review taken in conjunction with our external and internal users. To ensure that we co-create our feature backlog we consider feedback from our users in the 'Show and Listen' webinars, as well as in fortnightly drop-in surgeries and in direct conversations. These allow us to demonstrate upcoming features, take the opportunity to playback ideas that we have had and ask what functionality our users would like to see on SMP in the future. This means we can focus on functionality that adds greater value to our users as well as descope / adjust our strategy as appropriate. Additionally, ideas for new features only get surfaced as we develop SMP and as our users' experience of the product increases. In the first year of BP2, SMP has delivered, or is developing, many features and integrations that we expected to develop. We've also developed at least five features that were triggered by external user feedback, and at least four that came from our internal users.

At the Mid-Scheme stage two are complete, three are on track and four are delayed. The delayed milestones fall into the following categories:

- Two were due in year one but are recoverable during the BP2 period. These have been delayed due to timetable challenges outside of SMP's control.
- Two are due in year two but are not likely to be delivered in their entirety as the wider industry works together to determine how ESO and DSO markets should best integrate over time. Additionally, since the inception of BP2 other ESO projects, such as the DER Visibility project and the Virtual Energy System, are actively addressing these subjects.

In support of the ambition to integrate more closely with DSO / Flexibility markets, the SMP team have also led on the development of a proof of concept with a DSO (UKPN) and Electralink to demonstrate how MPAN data could be matched to determine potential risks of conflict between DSO and ESO commitments. This proof of concept was run in Q4 2023-24 and is seeking to inform how greater levels of visibility and interaction between

DSO flexibility markets and ESO balancing markets can be facilitated in the future. We believe that the design of this proof of concept is wider than the original BP2 milestone and therefore adds greater value to what was initially envisioned. It will also support wider industry work in this space alongside parallel ESO projects focusing on DER visibility.

EU and cross-border activity

Cross-Border strategy and REMA work

In 2023, we delivered the Future of Interconnectors (FIC) innovation project. This project was designed to provide a better understanding of how interconnectors' behaviour may evolve as we transition to a net zero system and how they could contribute to the key dimensions of system operation: adequacy, flexibility and operability.

An extensive range of qualitative and quantitative analysis was done on each of these areas. This led to the identification of the key challenges and barriers that would need solving to maximise interconnectors' full capabilities and value. The project completion report will be published in due course and the interim report is available on the ENA website.

Based on the evidence provided by the FIC and the issues it highlighted, we developed a cross-border case for change shared with Ofgem and DESNZ in September 2023. This included a prioritisation exercise to shortlist the key issues that should be focused on first, based on the assessment of each issue's urgency and its potential contribution to GB's energy trilemma.

One of the priority issues highlighted by the case for change is the fact that the scheduling of interconnector flows does not account for system constraints. Since the case for change was presented, REMA has significantly emphasised the need to investigate this and the efficiency of cross-border trading. Understanding the impact of major REMA reforms on cross-border trading has now become the priority area of work for the team. This does not mean that we have lost sight of the other cross-border case for change identified issues, and we will be developing the most critical in parallel in the second year of BP2.

Strategic engagement with the EU

We said we would ensure that UK/ EU TSO cooperation channels will be fully opened and functioning well by end of Q1 2023-24, however the framework that will allow UK TSO / ENTSO-E re-engagement to start is awaiting approval by the European Commission and DESNZ. The Trade and Cooperation (TCA) Working Arrangements Memorandum of Understanding will allow joint EU/ GB cooperation groups to be established and its approval is expected by early Q2 2024-25. In the interim we initiated informal engagement between ENTSO-E and EU TSOs in key areas including North Sea Cooperation (including Offshore and MPIs), interconnector ramping limits, operational harmonisation and IC flow control tools.

We have established and are chairs of the UK TSO TCA Coordination group, to ensure there is a venue for all classes of UK TSO to agree single positions for the negotiation of TCA topics with the EU.

Adequacy

We delivered the 2023 Electricity Capacity Report to DESNZ by 1 June 2023 in line with our regulatory obligations. The report was also published in July and set out our recommendations on the target capacity for the T-1 and T-4 capacity market auctions for delivery in 2024-25 and 2027-28 respectively. Our recommendations were supported by DESNZ's Panel of Technical Experts (PTE) who scrutinise our modelling, and accepted by DESNZ. The PTE were positive about our 'open and constructive' engagement in their published report. We also reported on how we had advanced our modelling through development projects undertaken in 2022-23. Most notably, this included changes in our approach to modelling non-delivery risk. The PTE said: 'We congratulate National Grid ESO in its implementation and consider it to be an important step forward.'

We have also undertaken a set of development projects since the 2023 *Electricity Capacity Report* to improve the modelling ahead of the 2024 report. They included building on the implementation of non-delivery to set out a vision of the future capacity procurement process, in response to recommendation 79 of the PTE report. It also included modelling to explore potential changes to de-rating factors for storage technologies. An industry webinar was held on 9 April to present our findings and launch a consultation with industry stakeholders on our recommendations.

In December 2022, we published our first study assessing resource adequacy in the 2030s. This was undertaken in collaboration with AFRY. We engaged with stakeholders in spring 2023 via in-person and online round-table discussions, as well as bilateral meetings. We published our next steps in July 2023, setting out that we would publish a follow-up study by September 2024 with our new in-house Net Zero Adequacy Modelling team. We also committed to producing some spotlights on key areas of focus, which we expect to publish in spring 2024. To support this work, we sought expressions of interest in joining an expert group. We have convened this group to challenge and help us develop the assumptions and methods for the next study.

Codes and Charging

Transmission Network Use of System (TNUOS) Reform:

The strategic changes being delivered for TNUOS reform have been incorporated into the Ofgem led TNUOS Task Force. We played a significant and active role in the Task Force, through chairing and managing third party analysis being conducted by Frontier. The complexity of strategic change in this area has taken significantly longer than expected. As a result, most of the BP2 TNUOS Reform commitments relating to Settlements and Revenue (STAR) have been delayed.

To date, two live modifications have resulted from the Task Force. The first is CMP424 ‘Amendments to Scaling Factors used for Year Round TNUoS Charges’. This seeks to introduce a mechanism which sets a lower limit on the variable generation scaling factors used for the purpose of year-round background tariff calculation. This is to address a defect in current methodology. If not addressed, we expect this error to calculate negative scaling factors within the next few years. CMP424 is currently at the workgroup consultation phase.

The second modification is CMP423 ‘Generation Weighted Reference Node’. This seeks to move from demand-weighted reference node calculations to a generation-weighted reference node calculation. CMP423 is currently in the workgroup phase and has held one workgroup to date. Analysis is still being completed to define the impact on tariffs of changing how the reference node is calculated.

Offshore Coordination and Network Planning Review:

The Offshore Coordination Code Modification Sub-Group, ‘TNUoS Charging Arrangements’, was established to support the development of changes to the TNUoS charging methodology within section 14 of the Connection and Use of System Code (CUSC) related to the Offshore Transmission Network Review (OTNR). This was prior to changes being formally proposed via the standard industry governance process. The overall focus of the sub-group was to consider, discuss and provide input into the development of methodology changes. This aims to support creating a set of code modifications with a level of user support to facilitate offshore coordination. The sub-group closed in September 2023.

There are currently two live CUSC Modifications that have been raised due to the OTNR sub-group:

- CMP419 ‘Generation Zoning Methodology Review’. This seeks to review the existing generation zoning methodology to incorporate offshore assets connected as part of the Holistic Network Design (HND). This is to enable the wider tariff to be applied to offshore generators. It also seeks to revisit the issue of zoning, further to the expectations set out as part of the authority decision on modifications CMP324 and CMP325. This modification is still in the workgroup phase.
- CMP426 ‘TNUoS charges for transmission circuits identified for the HND as onshore transmission. This seeks to consider the cost recovery for circuits classified as boundary reinforcement within the HND. In turn, this ensures that consideration is given to the purpose and functions of those circuits when determining the appropriate TNUoS tariff and users the costs are recovered from. This modification is currently at the workgroup phase.

Emergency Restoration Standard:

In October 2021 Department for Business, Energy & Industrial Strategy (BEIS) issued a direction in accordance with Special Condition 2.2 of the ESO's Transmission Licence, the Electricity System Restoration Standard (ESRS) which is set at the following:

- 60% of electricity demand being restored within 24 hours in all regions;
- 100% of electricity demand being restored within 5 days nationally.

The purpose of this direction fulfils the following:

a) Ensure and maintain an electricity restoration capability; and
b) Ensure and maintain the restoration timeframe
c) Replace the definition of "Black Start" with "Electricity System Restoration"

The actual standard needs to be in place by 31 December 2026. However, the code requirements to achieve this need to be in place as soon as possible to allow companies to prepare. The code submissions to Ofgem were sent in Q2 of 2023-24 and approved by Ofgem in Q4 2023-24.

We have led on and developed the Grid Code (GC0156), STC (CM089/CM091) and STCP (PM0128/PM0132) changes. We also advised on the Security and Quality of Supply Standard (SQSS) changes for the ESRS team.

The Restoration Standard is a licence requirement that will bring the following benefits:

i) Enable us to meet the requirements of the Electricity System Restoration Standard (a key Government initiative).
ii) Provide assurance and additional robustness to the wider industry to ensure all parties can play their part in meeting the requirements of the ESRS.
iii) Enable the system to recover more quickly from a total or partial system shutdown.
iv) Embed Distributed Re-Start (a world first) into the codes as business as usual.
v) Enable low carbon technologies to contribute to System Restoration where traditionally they have not been able to.
vi) Increase competition and now enable smaller Generators (including embedded) to participate in restoration where traditionally they would not have had the opportunity to do so.
vii) Replace the old Black Start arrangements which were heavily dependent upon older Large Transmission Connected carbon-based Generation Plants which are retiring.

Market-Wide Half-Hourly Project:

The Market-Wide Half-Hourly Settlement (MHHS) Programme will deliver a faster and more accurate electricity settlement process by introducing site specific reconciliation using half-hourly meter readings. The programme is industry-led and we are one of the programme participants.

Delivery of MHHS will be a key enabler of the smart and flexible energy system required to support the country's transition to Net Zero. In Ofgem's *Final Impact Assessment*, it was estimated that MHHS will deliver net benefits to GB energy consumers of between £1.5bn and £4.5bn by 2045.

The Baselined MHHS Implementation Timetable was updated in June 2023 following extensive industry consultation and approval by Ofgem of revised Level One Milestones. The revised timetable is a delay to the original delivery dates, moving completion from October 2025 to December 2026 and MHHS migration start from November 2024 to April 2025. However, it was recognised from the outset that a re-baselining activity would be required at this stage.

Under the MHHS Programme, the design was approved in October 2023 and industry code drafting has progressed. We have participated in various groups under MHHS governance. We have actively responded to consultations, reviews, and impact assessments to support delivery of different stages of MHHS.

We have raised two CUSC Modifications, CMP430 and CMP431 'Adjustments to TNUoS Charging from 2025 to support the MHHS Programme' (Charging and Non-Charging). The CUSC changes have been descoped from the Settlement Reform Significant Code Review (SCR) process, but they will still require implementation for the start of MHHS migration in April 2025.

We have completed internal discovery work, and activities relating to design, testing and implementation are on track for our involvement in Systems Integration Testing in September 2024.

Additional Ad-Hoc Code Change:

Under the code change framework, we regularly resource and progress ad-hoc code changes that were not in our Business Plan. Below we provide details of a few of these.

CUSC Issues Steering Group (CISG) sub-group on connections strategic change and impact to the CUSC

In July 2023, we held our first CISG sub-group on connections strategic change and impact to the Connections and Use of System Code (CUSC). Representatives from the CUSC panel suggested that there would be value in additional and specific CUSC commercial sessions to understand our proposed changes to the connections process and new policy. The primary focus was centred on discussing the Connections Five Point Plan. We successfully ran the sub-group with representatives from the industry from July – December. The scope of the subgroup was to:

- Provide clarity on the horizon of strategic connection change.
- Signpost to more medium term-change, such as Connections Reform.
- Focus immediate discussions on Connections Five Point Plan initiatives, including our new policy for battery storage connections.
- Break down our line of thinking with regards to implementation of these initiatives.
- Provide opportunity to deep dive on those change initiatives of interests.

CMP376 - Queue management

On 13 November 2023, Ofgem approved CMP376 – Inclusion of Queue Management. Ofgem's decision can be found here.

CMP376 implements the queue management process into CUSC including the introduction of a right for us as System Operator to terminate contracted projects which are not progressing against agreed milestones. This is a positive move as it will reduce the connections queue, allowing more parties to connect. This is a major milestone for broader Connections workstreams.

A total of 11 solutions were presented to Ofgem to decide on. Workgroup Alternative CUSC Modification 7 (WACM) was approved, which means that the Queue Management process will now apply to:

- New connecters entering into agreements from the Implementation Date of CMP376.
- Those with an existing connection contract or, an offer to connect where the Completion Date is two years or more from the Implementation Date of CMP376.
- Parties with a connection contract where the Completion Date is on or before the date two years from the CMP376 Implementation Date where the ESO has reason to believe that the User's project is not progressing in accordance with, nor is reasonably aligned to, the Construction Programme in the agreement, and the User is unable to demonstrate such progression to the reasonable satisfaction of ourselves.

CMP330/374/414 - Contestability

CUSC modification proposal CMP414 enacts the solution derived as part of the CMP330 / CMP374 Workgroup to allow developers to build connection assets further than the existing 2 km boundary. It also provides a comprehensive review of contestability. This will oblige Transmission Owners (TOs) to offer terms to developers for adoption of these assets and providing amendments to the Connection Application process. There is also an ongoing consequential STC Modification CM079, which was submitted to Ofgem in December as part of the suite of modifications for Ofgem to decide on.

These modifications, if approved (current expected date is May 2024) should:

- Promote competition in network development to deliver more cost-effective solutions.
- Allow developers who want to connect to the transmission system to build more of their assets than they can currently.

CMP427 – Connections Letter of Authority (LoA)

We raised this CUSC modification on an urgent basis in December 2023. On 15 March 2024, Ofgem approved modification CMP427 "Update to the Transmission Connection Application Process for Onshore Applicants". Ofgem selected our Original Proposal. This modification places an obligation on all applications to connect to the Transmission Network to provide a Letter of Authority. The modification establishes who owns the land on which the connection takes place, and that they are aware of the application. The modification will take effect from 28 March 2024.

In their joint *Connections Action Plan (November 2023)*, DESNZ and Ofgem placed an obligation on us to raise a modification to introduce a Letter of Authority. This was to be submitted to Ofgem for decision by the end of Q1 2024. This modification prevents speculative applications without landowner authority from entering the queue. It also improves the credentials of an application and the likelihood of the project progressing.

Our original proposal was approved. The proposal introduces two templates for Letters of Authority which are to prove that a landowner is in discussions with the developer. The second template is applicable for instances where the developer owns the land.

A guidance note was published ahead of the modification going live on 28 March, supported by a review session and webinar. The thinking around the "LoA v2" Modification will continue over the coming weeks.

P462 - The removal of subsidies from bid prices in the Balancing Mechanism (BM)

We raised modification P462 in November 2023 to address structural issues regarding the interaction between the BM and support mechanism arrangements. Generation units that hold a support mechanism need to price recover an expected subsidy within their bid prices. This prevents them from pricing on equal terms with units that do not hold support mechanisms. This interaction leads to actions being taken in bid price order, rather than consumer cost order. The result leads to excess consumer costs and a lack of competition at the lower end of the bid stack. In turn, this translates into clustering behaviours showing further uneconomic consumer outcomes.

The solution seeks to amend the Balancing and Settlement Code (BSC) to make a BM Unit whole for any lost support mechanism value by changing the BM Unit cash flow formula. Currently, the support mechanism is included implicitly within the bid price. The proposed solution seeks to pay the lost support mechanism explicitly to remove the need for its inclusion within the bid price.

The desired outcome is to reduce costs to the end consumer. We can achieve this by reflecting consumer costs in the wider BM merit order and reducing out of overall merit order transactions. Further benefits may be anticipated from limiting the imbalance price volatility. Limiting the imbalance volatility could reduce the imbalance risk premium that is built into units' pricing, improving market efficiency. In addition, allowing all units to compete based on marginal costs without the distortion of subsidies could create a more efficient BM and may reduce the tendency for clustering behaviours. The change will look to ensure that the subsidised unit receives the payment it was due had they generated. The change should remove the current interaction that creates excess consumer cost from taking actions in bid price merit order which are not in consumer merit order. It will also offer benefits as the change will make the interaction transparent. It should lead to improvement in transparency of costs for both BM prices and subsidies.

GC0137 - Grid Forming

Grid Code Modification GC0137 introduced a non-mandatory technical specification for Grid Forming. Additional guidance was required to show how compliance could be proven. A Grid Forming best practice group was set up which brought together industry from across the world. The group's aim was to debate best practices and recommend future Grid Code changes. As a result, we have delivered the *GB Grid Forming Best Practice Guide.* The guide provides guidance on appropriate studies that should be carried out to prove compliance with the Grid Code. It also discusses different modes of operations and recommends future Grid Code changes. The document has been well received by industry. We have already raised Grid Code modification GC0163 to remove the virtual impedance restriction which was a recommendation from the best practice group. We start the next round of Grid Forming Grid Code Modifications once that has completed. This is so we can determine acceptable performance requirements such as phase jump and withstand modes. The work carried out by the group is world leading and we have had good engagement with Transmission System Operators (TSOs) internationally. If we can have an international agreement on how to achieve Grid Forming, manufacturers will be able to produce Grid Forming equipment that is compliant across the world, reducing development costs.

GC0117 -Harmonisation of GB Small, Medium and Large Power Station thresholds

GC0117 is a modification raised by SSE to harmonise the Small, Medium and Large Power Station thresholds across Great Britain. The original proposal is to move the large threshold to 10 MW (with BM participation mandatory for Large Power Stations), with the medium threshold removed. We support this option as the Cost Benefit Analysis (CBA) conducted shows significant benefits. For example, increased visibility and control of embedded generation down to this threshold regarding cost price stack in the BM. There will also be improved demand forecasting and constraint management.

We do not support the alternative proposal which would move the current England and Wales thresholds into Scotland. The CBA shows significant increases in balancing costs over time due to the large thresholds being increased which will result in less visibility and BM participation in Scotland over time. The change would not be retrospective. It would only relate to generators who apply for a connection agreement after the modification has been approved (if approved). In addition, it would only be applicable for generators who will be signing contracts for their main plant and apparatus after 1 June 2027. The modification has now completed its workgroup phase. It is now at Code Administrator Consultation which is due to close on 26 March. It is expected that the Final Modification Report will be with Ofgem around May/June this year.

Winter programme work, GC0161, GC0162

Operating Code 6 (OC6) is one of the tools that enables us to reduce demand on the National Electricity Transmission System (NETS) to either avoid or relieve operating problems. It is designed to be used at no or short notice. Due to tighter winter margins, there was an increased focus on the tools we use to reduce demand to ensure the system remains balanced in the event of a supply shortfall. Under OC6 there was no protection afforded to critical sites or the ability to rota demand disconnections if the demand reduction were to last for a prolonged period. Modification GC0161 removed the Grid Code barrier to protecting sites on the Electricity Supply Emergency Code (ESEC) Protected Sites List for Demand. This applies to demand control instructions to reduce demand by up to 20% only. GC0162 extends the ability to protect critical sites for 20-40% demand disconnection. GC0161 and GC0162 were both urgent modifications and were implemented following Ofgem approval in December 2023. These changes enable the Distribution Network Operators (DNOs) to do the right thing by protecting critical sites without being non-compliant with the Grid Code.

GC0154 – Interconnector ramp rates

We raised Grid Code modification GC1054 to add interconnector ramp rates into the Grid Code. The aim was to ensure full compliance to System Operator Guidelines (SOGL) Article 119. It also sought to solve operational challenges with the increasing number of interconnectors and fast ramp rates.

There were multiple workgroups to discuss this code change and a CBA was completed by Baringa (on behalf of the workgroup). Another CBA was completed by consultants AFRY (commissioned by the Interconnectors). The final modification report was sent to Ofgem at the end of 2023 and a decision was made in March 2024. The recommended solution for implementation now addresses the full compliance to SOGL Article 119.

Additional non-code change deliverables

Digitisation of Codes:

The Digitalised Whole System Grid Code (DWSGC) project is progressing broadly to plan. The simplification elements of the project were significantly descoped in 2022-23 due to industry prioritisation and resource limitations. We proposed Grid Code modification GC0164 in October 2023 which showcases how a section of the Grid Code (OC2) could be simplified. There are competing industry viewpoints around the trade-off between simplification and providing legal certainty. The hope is that by raising GC0164 it can set a precedent on the answer to that challenge.

Regarding the digitisation of the code, we followed a fair and transparent procurement process to identify a vendor to deliver the project. The scope of the project focuses on making the code more interactive and simplifying user experience. We also sought to deliver a significant step change in the code governance and management process. The intention is to remove as much manual intervention as possible. The minimal viable product was due at the end of March 2024 but has been delayed until May 2024. This is due to some back-end IT issues identified via the new vendor. We are still confident of delivering an implemented solution on time for Q4 2024-25.

Whole System Electricity Framework Reform:

This deliverable meets and exceeds the expectations within Activity 2c in the Roles and Principles guidance document by allowing us to anticipate future necessary reforms across the electricity frameworks. This enables participation by multiple parties and removes potential blockers for innovators and new business models as we move to a net zero system. This is a new team set up within Market Frameworks. Whilst we have resourced the team adequately to succeed, the onboarding process took slightly longer than expected resulting in a detailed workplan that was due in Q4 2023-24 being pushed into Q1 2024-25. Work has already begun on assessment of some of the areas that will be set out in the detailed workplan, based on priorities in other areas of BP2.

European Frameworks:

Trading and Cooperation Agreement (TCA)

There are several workstreams under the TCA including interim and enduring Cross-Border Balancing (CBB) and Capacity Calculation and Allocation at various timeframes (Forwards, Day-Ahead, Intraday). The BP2 deliverable on enduring CBB (‘UK position on enduring balancing options agreed with all relevant parties’) was successfully completed in 2023; a CBA of CBB options was completed by Compass Lexecon and results were shared with industry in October 2023. The project recommended that none of the alternative CBB options are progressed. Internal next steps are underway, including monitoring market developments that may require a refresh of the analysis. We also must consider the amendment of the Grid Code as part of the move to simplify it and take out references to TERRE/MARI, which no longer apply to GB. An interim CBB arrangement is on hold due to limited appetite from relevant EU TSOs.

Progress on the Day-Ahead Capacity Calculation (DACC) methodology is delayed due to no engagement from EU TSOs, and limited appetite from UK TSOs to progress it any further without EU TSO input. External stakeholders will require a definitive steer from the Specialised Committee of Energy (SCE) to commit resources to further DACC work. The focus of the SCE steer during 2023 was in relation to Multi Region Loose Volume Coupling (MRLVC), which is the Day-Ahead Capacity Allocation mechanism mandated in the TCA. A working group, which we were party to, responded to technical questions from the SCE on MRLVC and its implementation. The next direction from the SCE is anticipated following an SCE meeting in November 2023. It will likely focus on further work on MRLVC. In the meantime, we previously coordinated work among UK TSOs on the development of potential DACC options.

EU Engagement

We have made good progress on the BP2 deliverable of achieving a step-change in ESO and EU TSO relationships. Developments in this area over the last year include:

- Initiation of the ISA (Inter Synchronous Area) EU Harmonisation meetings for discussion with our connected TSOs on the most pressing cross-border issues. These are monthly meetings that provide a forum for us to raise issues of concern and interest and understand concerns and developments from connected EU TSOs.

- The first bilateral meeting in Dublin between ESO and EirGrid took place in November 2023, following the UK-Ireland MOU on energy transition. A subsequent online meeting took place this month.
- Recent EU-UK TSO cooperation on MRLVC technical questions (February - June 2023).
- We attended the ninth annual energy cross-border trading and balancing market forum in Berlin and an Offshore Wind Transmission conference in February 2024.
- We responded to an ACER consultation on proposed changes to the European Network Codes Requirements for Generators (RfG) and Demand Connection Code (DCC) 2.0.

C28 derogation and NTCs

Our control room and other European TSOs use Net Transfer Capacity (NTC). We utilise this when we need to restrict the import or export capacity of interconnectors to maintain the security of supply. As we cannot procure NTCs using market-based procedures, we are required to apply to Ofgem for a derogation against Condition C28.4(h)(i) of our transmission licence. Our previous derogation was for a six-month period and expired on 30 September 2023. In August 2023 we submitted a request to Ofgem to extend this derogation. This was following a programme of work over summer 2023 to address comments in Ofgem's previous C28 decision letter. The work included running a consultation on the NTC Commercial Compensation Methodology. We also undertook data analysis on the historic use of NTCs, internal development on ways to minimise the use of NTCs and stakeholder engagement events and workshops.

In their decision published on 28 September 2023, Ofgem granted us a derogation against C28 for NTCs until 30 September 2026. They also approved our revised NTC Commercial Consultation Methodology, which applied from 1 October 2023. This provides our control room with the certainty that they can use this vital tool as required for system security over the coming years.

We are monitoring the use of NTCs and ways to minimise them and improve transparency. We use an internal governance forum and will provide regular updates to Ofgem during the derogation period. This includes monitoring progress against several items Ofgem identified in their decision letter for further work.

Interconnector Framework

In October 2023, we published a Request For Input (RFI) to hear from industry on the development of an Interconnector Framework. We asked industry to consider questions to help shape the potential scope of a framework and highlight issues under current arrangements. The RFI received multiple submissions from a variety of stakeholders. We gathered useful insight into industry's opinions on the creation of a framework and initial thoughts on potential scope of the framework.

On 29 February 2024, we hosted an industry session to give an overview of the RFI responses and provide a further opportunity for discussion with a wide range of stakeholders.

The session covered the following topics:

- Industry’s view on the key opportunities of creating an interconnector framework.
- Industry’s view of current uncertainties relating to the creation of an interconnector framework.
- Industry's views on the key complexities when considering the scope of the framework.
- Industry's suggestions for what a framework could look like.
- Time for continued discussion on the key themes identified.
- Overview of next steps for the workstream.

As we saw in the RFI some stakeholders continued to express strong support for the creation and implementation of a framework. Others have reservations as to whether it is required and do not feel there is a clear case for change. We will continue to engage with the industry through a series of events over the coming months. The intention of this engagement is to refine the case for change and potential scope of any framework. The outcomes of this engagement and future sessions are fundamental in establishing a scope for the framework. We will then consult industry and establish key gaps where industry feels we should provide a viewpoint.

Competitively Appointed Transmission Operator (CATO)

To introduce the concept of CATOs into the Grid Code, STC(P), SQSS and CUSC, a suite of modifications was required. The modifications are needed to enable Onshore Network Competition for the design, build and ownership of Onshore Transmission assets which will augment the three pre-existing TOs. We took this approach to extend existing relevant Onshore TO provisions as far as appropriate, reflecting Ofgem's expected licencing regime. One of the STC modifications and one STCP modification introduce a connections process for accession of a CATO to the NETS.

As the UK works towards achieving Net Zero, the NETS requires transforming to cater for the expansion in renewable sources of energy. Introduction of the concept of CATOs to the relevant industry codes ensures the safe, secure, and coordinated operation of the NETS. It will establish both the obligations of CATOs and those entities interacting with CATO assets. The first phase of the Early Competition procurement process (the pre-tender) is set to commence in Q3 2024. Following the completion of a competitive tender, a CATO will be awarded a Transmission Licence and categorised as an Onshore Transmission Owner. As a Licensed TO, CATOs will be subject to broadly the same obligations and frameworks as other Onshore Transmission Owners. This will help facilitate a level playing field.

The Technical and Commercial Codes Teams have supplied continuous practical support to the Early Competition Team leading the CATO project. We provided code change expertise in the form of identifying the appropriate approach and which areas of the codes require legal text changes. We are leading the process for taking the project through the code change process on time. Workstreams include raising defects and proposal forms, contributing to work groups, making legal text changes, involving relevant internal and external Subject Matter Experts (SMEs), our legal team as appropriate, and attending all workgroups and workshops).

Our Technical Codes team has engaged with the Code Governance team throughout. We have managed timelines to get the modifications ready to get Ofgem approval in time for the first phase of the Early Competition procurement process in late 2024. The Final Modification Reports for two STC Modifications are now with Ofgem. We are on target to submit the remainder by late May 2024 for an Ofgem decision when they have the full set.

Improvement to code processes

We identified several issues in relation to the drafting of our code documents. As a result, we carried out an initial piece of work that considered our internal Code Administration processes and the management of Modification implementations. This work led to several process changes. We also sought external legal support to undertake an audit of both the CUSC and the Grid Code.

We have identified no impacts to our customers or stakeholders as a result of the drafting issues. We are continuing to further review our internal processes and are fully committed to putting in place enhancements to the existing control framework.

Deliverable Status

Our BP2 RIIO-2 deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables, with commentary including explanations for all delayed milestones.

The statuses are defined as follows:

On track	For a milestone date in the future: we're on track deliver it on time
Complete	Milestone has been delivered
Delayed – consumer benefits	Delayed or de-prioritised to maximise consumer benefits
Delayed – external reasons	Delayed due to factors outside our control (e.g., BREXIT, Covid, Ofgem)
Delayed – internal reasons	Delayed due to factors within our control and/or that we're accountable for
Continuous activity	For certain activities with ongoing delivery (e.g., OTF)
Milestone no longer valid	Removed from Delivery Schedule as no longer required (agreed with Ofgem)

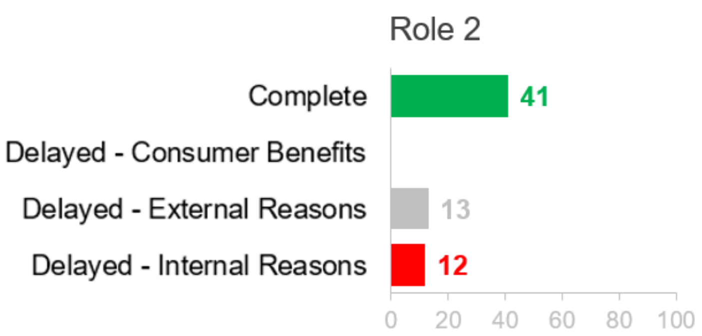
Statuses of 'on track' or 'continuous activity' are not shown as they can only apply to milestones not yet due for completion.

Role 2 - Progress of our deliverables

For Role 2 (Market development and transactions), the latest BP2 RIIO-2 deliverables tracker lists **38 deliverables** in total, which is made up of **133 milestones**.

- **66** of these milestones were due to be completed by March 2024 or earlier
- Of those:
    - **0** are delayed in order to deliver an improved outcome for consumers
    - **13** are delayed due to reasons outside the ESO's control
- Of the remaining 53**:**
    - **41** (77%) are now complete
    - **12** (23%) are delayed due to ESO related delays

The results for the **66** milestones due to be completed by March 2024 or earlier are illustrated below:



Role 2 – Milestone status by deliverable

For milestones due by March 2024 or earlier

Ref	Deliverable name (shortened)	Complete	Delayed... Consumer Benefits	Delayed... External reasons	Delayed... Internal reasons
D13.5.3	Enhance our energy modelling to reflect stakeholde...	1			
D15.8.1	Develop policy areas to accelerate whole electrici...	3			
D15.8.3	Enabling whole electricity system operational serv...			1	3
D21.1	Cross-border strategy development	1			
D21.1.1	Strategic Engagement with EU			1	
D21.2.1	Continued facilitation of EU driven code changes i...	2			2
D21.2.2	Implementation of the TCA	1		2	
D4.1.1	Frequency management strategy				1
D4.2.1	Regular and specific metrics and publications acro...	1			
D4.3.3	New reserve products - development and introductio...				1
D4.3.6	Future developments to frequency response services	2			
D4.4.1	A market platform through which market participant...	1			2
D4.4.2	Common standards, including interoperable systems,...	2			
D4.5.3	Reforming markets to facilitate future growth of D...	1			
D4.5.4	Facilitating market access for Distributed Flexibi...	1			
D4.5.5	Ensure co-ordination of markets across the whole e...				1
D4.6.1	Development of competitive approaches to procureme...	1			
D4.6.2	Development of competitive approaches to procureme...	1			
D4.6.4	Local Constraints Market reform	1			
D5.1.1	Continuation of Electricity Market Reform (EMR) De...	4			
D5.1.2	Continuation of EMR Delivery Body obligations:We ...	2			
D5.2	Developing the EMR platform	1			
D5.3	Use of enhanced modelling and more granular data s...	2			
D5.4	Building our long-term security of supply modellin...	2			
D6.1	Continued facilitation of industry changes to the ...	1			
D6.1.1	Enable major net zero programmes - Offshore Coordi...			1	
D6.1.2	Enable major net zero programmes - Onshore Competi...			1	
D6.1.3	Enable zero carbon operation - System Restoration	2			
D6.1.4	Enable zero carbon operation - Stability	1			
D6.1.5	Lead charging reform	1			
D6.1.6	Support Market Wide Half Hourly Settlement			1	
D6.3	Continued managing, collecting and disbursing char...	2			
D6.3.1	Market half-hourly settlement	1		1	1
D6.3.2	TNUoS reform			4	
D6.4	Change from a code administrator to a code manager...			1	
D6.5	Develop a single technical code for distribution a...	1			
D6.8	Implementation of digital solutions	1			
D6.9	Whole electricity system framework assessment	1			1
	TOTAL - Role 2	**41**	-	**13**	**12**

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 2. Some of these projects are funded as part of the RIIO-2 price control, and are therefore eligible for consideration as part of the RIIO-2 incentive scheme. The references in the table below provide links to additional information about each project

Innovation Project Name	Description	Progress update	Deliverables supported	Status	Funding
Dynamic Reserve Setting[11]	**Use AI and machine learning to set reserve levels dynamically, day-ahead.**	**Following the extension of the original project to allow the development of a proof-of-concept model, the project has now been delivered and is being trialled in the control room and is currently awaiting control engineer sign off and IT productionisation before full implementation (also mentioned under Role 1).**	**D4.1** **D4.3.3 (BP1)**	**Delivery**	**RIIO-2**
Exploring the economic benefits of co-optimising procurement of energy, response and reserve[12]	The project is looking at the potential benefits of co-optimising the procurement of energy and ancillary services like reserve and response. The benefits arise from removing the imperfect opportunity cost estimation under sequential procurement which leads to inefficient allocation of resources and higher prices.	The qualitative report is final and articulates the benefits of co-optimisation, looks at why it would be useful in the future GB regime and highlights international comparisons and successes. The second report is draft final, and provides the underpinning economic theory and building blocks to think about the design choices for co-optimisation and three specific key areas of consideration around bidding product design, locational considerations, and reserve scarcity pricing. The ongoing work is on a qualitative assessment of the benefits, looking at the potential cost saving and improvements in market signals by moving to co-optimisation, and how the dynamics / behaviours change in a zonal market	D20.1	Delivery	RIIO-2

[11] Probabilistic Machine Learning Solution for Dynamic Reserve Setting | ENA Innovation Portal (energynetworks.org)

[12] Exploring the Economic Benefits of Co-optimising Procurement of Energy, Response and Reserve https://smarter.energynetworks.org/projects/nia2_ngeso053/

		rather than a national market. We've already seen some really interesting insights into behaviours and allocation of resources, with more to come. We're planning to use the output as part of our engagement with industry on REMA options and to inform future, more detailed work on how this could be implemented in GB.			
Stability Market Design[13]	Aims to create a number of options for the delivery of a short-term stability market for the UK, assess these options, and provide a recommendation.	Phase 2 of the Stability Market Design Network Innovation Allowance (NIA) project has now completed. The project recommended 3 discrete markets – Long-term (Y-4), Mid-term (Y-1), and Short-term (D-1) – to procure stability services in an effective way. For each of these markets, fundamental questions on eligibility and contract structure have been answered, and there is a core recommendation to launch the Y-1 Mid-term market as a priority. This is to harness additional inertia capability from existing units, to provide an enduring route to market for existing assets currently contracted under the Pathfinder framework, and to build investor confidence that stability services will be procured on a regular basis. The plan for launching the Y-1 market was set out in the 2023 Markets Roadmap publication and we have since resourced the project team internally to deliver the Y-1 market. This is now at the Invitation to Tender stage where we are accepting bids for the first delivery year. In parallel to initiating the delivery of the Y-1 stability market in 2023,	D4.5.1 (BP1 reference)	Completed	RIIO-2

[13] Stability Market Design https://smarter.energynetworks.org/projects/nia2_ngeso005/

		we are completing further process mapping and system impact assessments to establish achievable plans for developing the short-term stability market and a regular framework for initiating new-build procurement in the long-term, if required.			
Crowdflex (SIF)[14]	Crowdflex is a multi-year SIF project designed to realise the potential that domestic flexibility can play in addressing decarbonisation by developing a model to explore how domestic flexibility can be used in network operations, improving coordination across the network and reducing stress on the system.	The project went through Discovery and Alpha phases in 2023 and was awarded funding for the Beta phase, which is now underway. In March 2024, the first stage gate was held to determine progress to the next stage. This next stage involves running the first set of trials between May and July with electricity supplier customers and testing the first iteration of the model. The design of the trials and the model will subsequently be refined based on the learnings obtained. Following that, the next round of trials and model refinement will begin.	(No directly linked deliverable)	Delivery	RIIO-2

[14] Crowdflex Beta https://smarter.energynetworks.org/projects/10070764/

B.2 Stakeholder Evidence for Role 2

The ESO incentive scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of the ESO's plan delivery. To demonstrate performance against this criterion, every six months we report on our stakeholder satisfaction survey results.

Stakeholder surveys

The ESO has commissioned surveys from market research company BMG. These surveys measure satisfaction for each ESO role and are carried out on a six-monthly basis. The survey is targeted at senior managers, decision makers and experts, and includes a wide selection of relevant stakeholders who have had material interactions with the ESO's services. In total we contacted 1496 stakeholders, across all 3 roles.

Role 2

For Role 2, the following question was asked:

> "One of the ESO Roles is focused on Market Development and Transactions, which includes key activities such as Market Design, Balancing Services, Electricity Market Reform (EMR) and Industry Codes and Charging. Overall, from your experience in these areas over the last 6 months, how would you rate ESO's performance?"

Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

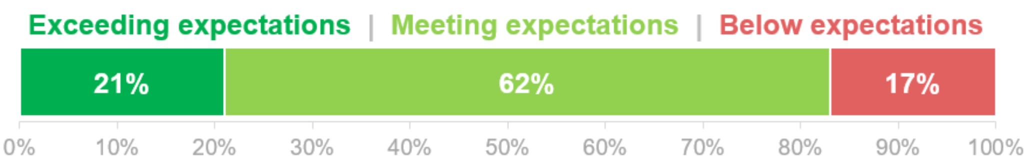
1. If they rated the ESO as below expectations, they were asked what the ESO needed to do to meet their expectations.
2. If they rated the ESO as meeting expectations, they were asked what the ESO needed to do to exceed their expectations.
3. If they rated the ESO as exceeding expectations, they were asked what the ESO did that exceeded their expectations.

For Role 2, we contacted **418** stakeholders, and received **100** responses to this question, which were distributed as follows:

- **21%** exceeding expectations
- **62%** meeting expectations
- **17%** below expectations

(Percentages rounded to the nearest whole number)

Stakeholder survey - **Role 2**



Percentages are rounded to the nearest whole number, therefore may not sum to 100%

	Summary of stakeholder feedback for Role 2
"Exceeding Expectations" **21** stakeholders scored us as "exceeding expectations". Feedback on what we'd done to exceed stakeholder expectations in Role 2 included:	➢ **Good communication and engagement with stakeholders –** Effective communication and engagement reoccur within the responses. The coder's working group, responses to queries, publishing of updates, and communications around the Open Balancing Platform (OBP) quarterly balancing sessions and weekly Operational Transparency Forum (OTF), are all flagged as examples of our effective delivery of communications and engagement. ➢ **Collaboration and support to stakeholders** – Several responses commend our collaboration and support to stakeholders. For example, the Electricity Markets Reform (EMR) is said to be "very well run" and as an organisation, we are collaborative in sharing and learning with stakeholders. Other comments say we design markets with end consumers in mind, offer support to market participants and provided access to subject matter experts. ➢ **Proactive in long term planning** – One stakeholder commented that "ESO are proactive in their thinking about long-term issues in the energy sector, something we found less evident before the ESO became independent". ➢ One stakeholder stated they had "low expectations for the electricity industry to get things done in a timely and coordinated way. The ESO have made real progress with new and existing markets in the last 12 months, and I am impressed with the iterative, almost entrepreneurial mindset that is being shown. They are engaging very well with industry including the smaller generators and new energy storage operators and they are implementing ideas and improvements to systems relatively quickly".

"Meeting Expectations" **62** stakeholders scored us as "meeting expectations". Feedback on what we need to do to exceed stakeholder expectations in Role 2 included:	➢ **Enable participation in markets** – Some stakeholders feel we can enable participation across markets by incentivising suppliers/aggregators with low flexibility volume to be able to participate in most of the Demand Flexibility Service (DFS) events, and by removing barriers to access. ➢ **Enhance visibility** – Improvement to the visibility of material, slides, webinars, and documents was a recurring theme on some responses. One responder commented that while the website works better, they feel we could improve visibility and transparency of documents by clearly highlighting live service terms, and procurement documents should be on the website with actual document titles and versions used in the title. ➢ **Expand delivery of services** – Several stakeholders want more progress in modernising, developing, deploying, and improving services such as balancing services and other legacy IT systems. One stakeholder urged us to "ensure that the Balancing Programme progresses without delay". ➢ **Improvements to communications** – There were requests for more frequent updates, more proactive communications regarding updates to markets, upcoming services, and updates to codes. One expressed a need for more clarity on strategy. ➢ Some responses indicated that while they believe we are exceeding expectations in some instances, e.g. Markets Forum, our performance for new services needs to improve. In addition, some commended us on providing clearer communications, improved customer focus and more engagement with industry.
"Below Expectations" **17** stakeholders scored us as "below expectations". Feedback on what we need to do to meet stakeholder expectations in Role 2 included:	➢ **Faster delivery across markets** – Several responders say we need to provide faster delivery across markets noting the following; delays in delivering new services like Quick and Slow Reserve, improvements to despatch regarding battery energy storage, and significant delays between the tender award and sending a final version of the contract. ➢ **Encourage participation in markets** – Some responses suggest that we do not do enough to encourage competition and new services. We are asked to expand participation in markets by removing barriers to access and "embrace genuine level playing field for all i.e. new and existing parties". ➢ **Improve engagement with stakeholders** - Frustration at engagement is a theme within these responses. Some suggest code change proposals would benefit from collaboration within the industry, such as technical experts. One felt workshops and user engagement felt like "box-ticking exercises" and was one-way engagement with "poor presentations". ➢ **Provide more clarity** – A key theme from the survey responses was the want for increased clarity on our market roadmap, constantly changing to temporary auctions, and messages about where/how markets are going are not very clear ("sometimes sent around with little time to digest").

Addressing stakeholder feedback in BP2

Effective engagement with stakeholders has been instrumental to the progress of our Role 2 business activities and projects across the first year of BP2. In the following section, we outline how we have addressed stakeholder feedback gathered via stakeholder surveys and regular project/business activity stakeholder engagement to improve our activities across Markets.

❶ Shaping the future of Demand Flexibility Service with our stakeholders

We launched the Demand Flexibility Service (DFS) as part of a range of winter 2022 contingency measures against a backdrop of geopolitical uncertainty and a shortage of gas supplies across Europe. DFS allowed households and businesses to earn pounds, points, or prizes for shifting electricity usage outside of peak demand hours and allowed us to manage supply through periods when margins were tight.

To shape the future of the DFS going into Winter 2023-24, we engaged with over one hundred stakeholders through workshops, webinars, deep dives, 1-2-1s and industry forums. These engagements aimed to gather industry feedback from DFS Winter 2022-23. Some of the responses suggested valuable improvements to the DFS service design for Winter 2023-24. As a result of the feedback, we were able to able to implement;

- Greater automation for users by the introduction of an Application Programming Interface (API).
- Providers can offer their end consumers the new option of “opt-out” of DFS.
- The ability for providers to participate in this edition of DFS with both sub (asset) meters and boundary meters.
- Two new within-in-day procurement windows and the removal of the within-day adjustment.

To gain an insight into Stakeholder’s experience of DFS, we commissioned the Centre for Sustainable Energy using Network Innovation Allowance funding to evaluate how households responded, and the benefits and challenges they experienced. The report was published in July 2023 and can be accessed here.

❷ Working with our stakeholders to enhance our Frequency Response services through proactive engagement

We actively sought stakeholder feedback to inform our decisions and enhance our Frequency Response services across the first year of BP2. We used a range of engagement to connect with and learn from our stakeholders including:

- **Frequency Response Webinars -** hundreds of stakeholders attended our Frequency Response webinars to discuss technical and policy changes and develop a shared understanding with our stakeholders about any challenge they may be faced with to action such changes from their end. We’ve then handled this information to shape discussions at 1-2-1s and our in-person roadshows, to co-create solutions to such pain points.

- **Roadshows in London and Edinburgh -** to seek input and answer questions on Frequency Response reform. Having reprioritised the Reserve reform in April 2023, the Ancillary Service Reforms (ASR Reserve team) used these sessions to provide further clarification of our decision to align with new systems delivery and seek direct 1-2-1 feedback from service providers on all aspects of the project delivery.

- **Ramp Rate Workshop & Detailed 1-2-1s –** our engagement indicates customers have found ramp restrictions to be a reoccurring pain point. To understand the issue and develop an effective solution, we have engaged via a virtual workshop and subsequent in-depth 1-2-1s with some of our providers. The input from stakeholders will be a key component of the policy decision that will be made in Spring 2024 before our 2024 Response consultation.

- **Optional 1-2-1s related to the Release 2 Consultation** - we received ten stakeholder responses to our 2023 Response Release 2 consultation. Each responder was offered a 1-2-1 session with the Frequency Response team to allow us to gain a deeper insight into their responses and provide clarification on changes we had made in the consultation. Five parties requested a 1-2-1, each enabling an open discussion around the consultation and developing our mutual understanding of the challenges that had arisen. These valuable interactions shaped the changes that were then incorporated into our Service Terms and supporting documents and guidance which are accessible here.

❸ Delivering improved functionality to Single Markets Platform (SMP) at pace through stakeholder engagement

Single Markets Platform (SMP) is an agile project developed to support a seamless and consistent user experience in facilitating participation in our balancing service markets. Stakeholder engagement is central to the evolution of SMP, as it allows us to actively re-prioritise our backlog based on user feedback or significant changes within the industry.

We communicate how we manage our backlog through our monthly Show and Listen engagement events with users and wider interested industry stakeholders. To get maximum buy-in and interest from our stakeholders, the Show and Listen schedule is shared with the industry near the end of the preceding year so interested parties can plan their attendance.

The agenda is shared in advance of each webinar with a mural board available to show relevant material and capture feedback; mural boards are then published on our SMP webpage as a permanent record of what was discussed and can be viewed here.

This engagement allows us to be transparent about how we prioritise our backlog, helps us course-correct our future, demonstrates functionality that is soon to be released, and co-creates our future plans to ensure that SMP continually delivers value to our users.

The Show and Listen stakeholder feedback is enriched by the feedback generated in fortnightly drop-in surgeries, 1-2-1 stakeholder meetings, or communicated through the relationship with the balancing services account management team.

We have delivered or scheduled the following features in the first half of BP2: The development of a pre-qualification dashboard, onboarding checklist, user management system enhancements, and map integrations.

Each feature has been derived from and informed by our external user engagement and stakeholder feedback. The features are over and above what we had originally planned or worked up internally.

❹ Improvements to our Markets Forum events following stakeholder feedback

We hold four Markets Forum events per year. We use these events as specific milestones to engage with a wide range of industry stakeholders. At the events, we aim to reflect on the priorities of the energy industry and how our role, and in turn our project delivery within Markets, is positioned to deliver against these roles.

On the back of stakeholder feedback about accessibility to our forums and the time commitment required to attend in person, we have agreed to deliver our events in the following format: two pre-recorded events and two in-person events annually. The in-person events will be rotated between London, Glasgow, and Cardiff, and will also be live-streamed, enabling more stakeholders to participate in our forums.

To improve our Markets Forum, we requested suggestions from our stakeholders on how else we can improve our events. They said they would like to see the following incorporated into future sessions:

1. Overview of escalation routes
2. Share project deep dives and next steps
3. Share transparency of market priorities
4. Visibility of Market policy decisions
5. Delivery of both virtual and in-person events
6. Sharing of details of key contacts
7. Regular updates to be shared on the market roadmap.

On the back of this feedback, we have committed to providing a greater cadence of market events with clear content while ensuring we are available, transparent, and consistent in our messaging across the industry. To that end, there is a large variety of published content including webinars and Q&A sessions our users can access on our website here.

❺ Developing Enduring Auction Capability with collaboration from industry

The Enduring Auction Capability (EAC) is designed to deliver co-optimised procurement for our day-ahead Frequency Response and Reserve products. It is envisioned that this method of procurement will allow us to meet our needs most efficiently while enabling providers to participate in multiple markets.

Stakeholder engagement has been instrumental in delivering an optimised EAC platform for our users. To get the stakeholder input needed, the project team held three webinars and over thirty 1-2-1s with the industry to gather their input and feedback on the project. The feedback received from the industry resulted in several changes such as changes to the penalty arrangements and planned improvements to the auction platform features.

Our EAC consultation run, and we consulted stakeholders on the proposed changes to performance monitoring for frequency response to accommodate stacked services. The feedback informed changes including:

1. Modifying our proposed minimum settlement adjustment methodology to a fixed settlement adjustment for poor performance when the market clearing price is negative.
2. Amending the wording of our Service Terms to make our formulae and Energy Management document easier to read. The amended documents are available here.

❻ Increased transparency on Operational Metering through our Power Responsive Programme

Operational Metering (OM) is used in the Balancing Mechanism (BM) and Ancillary Services markets to provide visibility of asset output in real-time to the control room. These parameters influence the volume, quality and time lag for which data should be submitted by the market participant to us.

The Power Responsive programme is a stakeholder-led team that engages through events, steering group meetings, and projects to remove barriers to market entry for demand-side flexibility.

Within the Power Responsive Working Group, stakeholders queried the timeframe to make changes to access to operational metering measurement standards, our justification for the timescale of changes. To address this feedback, we've increased the regularity of working group meetings and ensured that our relevant representatives and Subject Matter Experts (SMEs) attend to provide clarity and context behind the steps we are taking.

Stakeholders at the Power Responsive Working Group also flagged what they perceive to be a low-risk tolerance when testing if we can apply proportional standards to enable participation within markets. Following constructive discussions with our stakeholders, we have updated our trial participation parameters which should enable more providers to take part and made the relaxed standards enduring rather than time-limited to encourage investment in the sector. In parallel to this, we have committed to an external review of our operational metering standards to ensure that we make decisions using fair, neutral, and thorough research and analysis.

Transparency around our decision-making with regards to OM was queried. The reason for this is the Power Responsive and our representatives attending events were often not the front-facing stakeholder teams. So, we have started to invite more senior SMEs to attend these events and explain the reasoning behind some of our decisions.

❼ Developing solutions to thermal constraints in collaboration with industry

Following consistent stakeholder feedback, we are improving how we co-create with the industry when we develop market reforms, especially early in the process (i.e. at the ideation stage). One of our biggest challenges concerning balancing costs is the issue of locational thermal constraints on the transmission system. Therefore, in January 2024, we launched our Constraints Collaboration Project to ask industry for market-based solutions to thermal constraints that could deliver value in the next five years. We received 30 responses from stakeholders and are crowdsourcing feedback on these ideas from the market, we are working to assess the ideas against our Market Design Framework to help determine which ideas to progress to implementation.

This is a new approach to co-creation within balancing costs, and while the initiative is still very much in progress, early feedback from the industry has been very positive. If it continues to be successful, we will adopt this approach more systematically to tackle other strategic operability and market design challenges that we are facing.

B.3 Metric Performance for Role 2

Table: Summary of metrics for Role 2

Metric			Unit	Full year 2023-24 Benchmark	Full year 2023-24 Actual	Mid-scheme status
2Ai	Phase-out of non-competitive balancing services	FR & Reserve	%	25%	22%	Exceeding expectations
		Reactive	%	90%	97%	Below expectations
		Constraints	%	65%	62%	Exceeding expectations
2X	Day-ahead procurement		%	55%	69%	Exceeding expectations

Metric 2Ai Phase-out of non-competitive balancing services

April 2023 – March 2024 Performance

This metric measures the percentage of services procured by the ESO that are procured on a non-competitive basis. For the purpose of this metric, we consider a 'non-competitive' service to be either a bilateral contract or a service with significant barriers to entry. It excludes SO-SO trades, which are trades made between system operators of connected countries. These are used to determine the direction of electricity flow over interconnectors. The volumes reported in this metric are those delivered within the time period.

There are benchmarks for the following categories: Frequency Response (FR) and Reserve, Reactive Power, and Constraints.

Benchmarks are set based on the ESO's current and projected procurement for each of these services:

Category	Benchmark	Assumptions applied in BP2 benchmark
FR and Reserve	Year 1: 25% Year 2: 20%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for the benchmark • Reserve will continue to be procured competitively until the implementation of new reserve services
Reactive power	Year 1: 90% Year 2: 90%	• Historical data was analysed from the previous reporting period (BP1) and no uplift applied for the benchmark • Competitive procurement of Reactive Power through Market mechanisms will be understood later in 2024 – through the Reactive Power Market Reform. • There will continue to be specific regional requirements, and these will be procured through market mechanisms where feasible.
Constraints	Year 1: 65% Year 2: 55%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for the benchmark • B6 Commercial Intertrip service was the first Constraint service to be delivered competitively. More will be delivered through market mechanisms in BP2, such as Constraint Management Intertrip Service (EC5 CMIS) and Local Constraint Market (LCM).

The non-competitive percentage is calculated on a volume basis, which is measured in MWs, with the exception of Reactive Power which is measured in MVAr.

These expectations are set for the current suite of products and may be revised if new products are introduced.

Category	Services procured competitively	Services procured non-competitively
Frequency Response	• FFR (Firm Frequency Response) Secondary, High and Static • Dynamic Containment Low and High • Dynamic Moderation Low and High • Dynamic Regulation Low and High	• Mandatory Frequency Response (Primary, Secondary and High) • Fast Start
Reserve	• Day-Ahead STOR (Short Term Operating Reserve)	• Long Term STOR • Optional Fast Reserve • Super SEL (Stable Export Limit) (Footroom)
Reactive Power	• Mersey Reactive Power Pathfinder • Pennines Pathfinder	• Reactive • Mandatory Reactive Lead & Lag • Stability Reactive Lead & Lag • Reactive Sync Comp, Comp Lead and Comp Lag • Inertia (Stability)
Constraints	• B6 Intertrip	• Strike Price

Overall performance – All services

Q4 2023-24 performance

Figure: Percentage of volume procured non-competitively vs benchmark

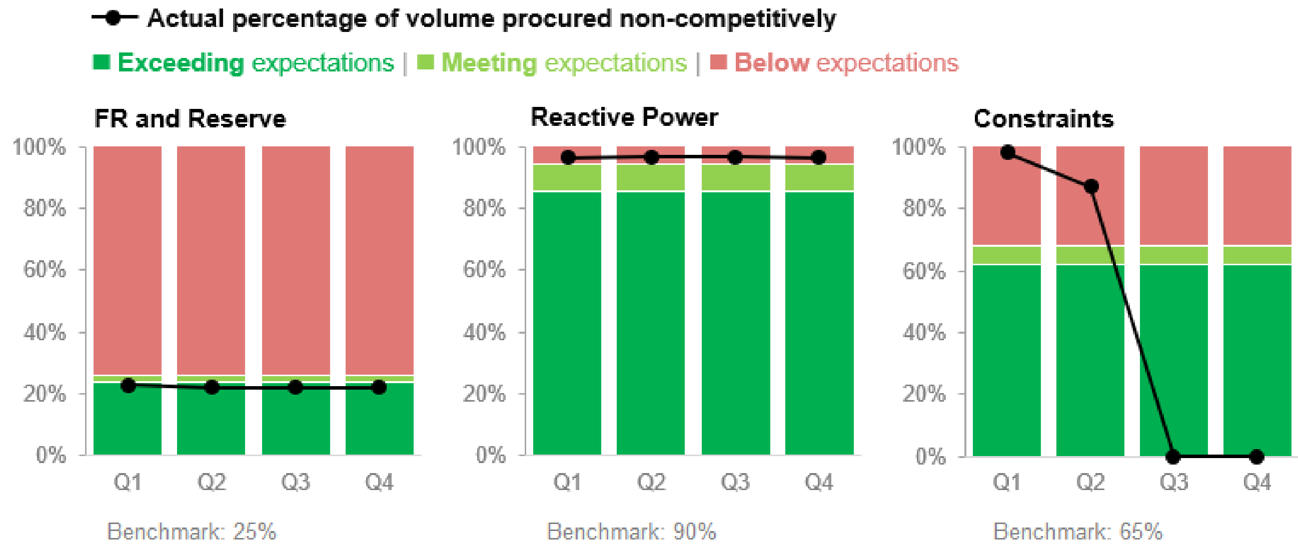
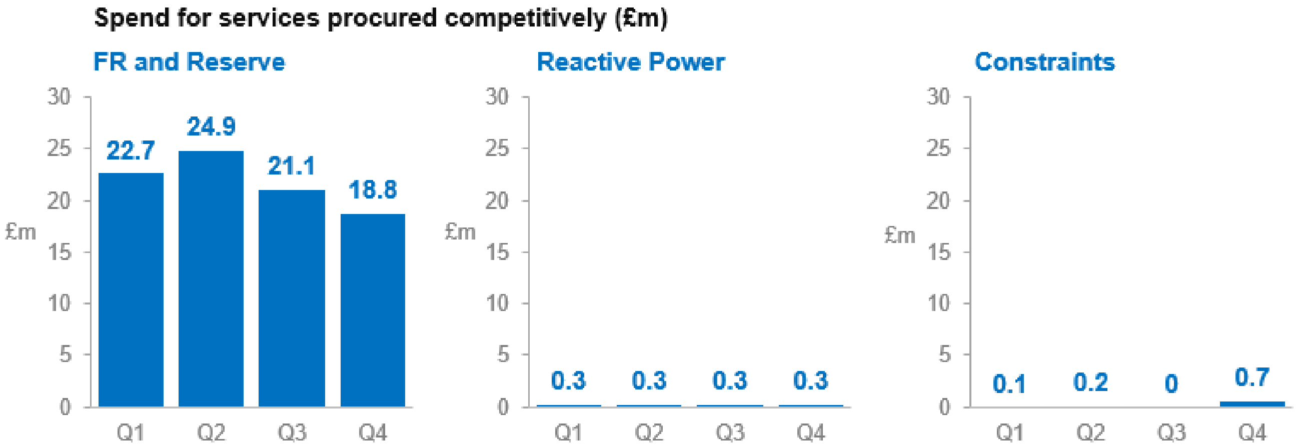


Figure: Quarterly competitive spend by service



SO-SO trades made during Q4

Historically SO-SO Trades were available to us across the IFA & IFA2, Nemo Link, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & Nemo Link, the current required notice period is longer than the hourly gates provide, and so we can no longer use this service. EWIC & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. We do not trade via third Parties and therefore only have access to CBB.

Trades for Q1 totalled £0.06m consisting of 2 trades on Moyle interconnector.

Trades for Q2 totalled £0.2m consisting of 3 trades, 2 on the Moyle Interconnector and one on the IFA-1 Interconnector.

Trades for Q3 totalled £0m consisting of 0 trades on 0 interconnector/s.

Trades for Q4 totalled £0m consisting of 0 trades on 0 interconnector/s.

1. Frequency Response and Reserve

Q4 2023-24 performance

Table: Frequency Response and Reserve percentage of services procured on a non-competitive basis, and spend.

Frequency Response & Reserve		Unit	Q1	Q2	Q3	Q4	Full Year
Volume	Total volume procured	GWh	13,715	15,638	14,558	14,772	58,683
	Volume procured non-competitively	GWh	3,159	3,476	3,221	3,248	13,104
	Percentage of volume procured non-competitively	%	**23%**	**22%**	**22%**	**22%**	**22%**
	Year 1 benchmark	%	25%	25%	25%	25%	25%
	Status	n/a	●	●	●	●	●
Spend	Total spend	£m	47.1	52.4	41.3	31.5	172.3
	Spend for volume procured competitively	£m	24.4	27.5	20.2	12.6	84.7
	Spend for volume procured non-competitively	£m	22.7	24.9	21.1	18.8	87.5

Performance benchmarks:

- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5% or more higher than the annual procurement benchmark

The benchmark for Year 2 is 20%

Supporting information

In Q4, 22% of Frequency Response and Reserve volume was procured non-competitively compared to the benchmark of 25%, and therefore meeting expectations.

With the growth in response and reserve competitive markets we are able to procure more of our requirements at the day-ahead so have less reliance on non-competitive procured services. As more reserve services are introduced to day-ahead procurement we expect to see further reductions in the Frequency Response and Reserve volumes that are procured non-competitively. For Long Term STOR, we remain committed to the legacy ~ 400MW volume of contracts which expire in April 2025. This volume will then be replaced by volumes procured at day-ahead through the new reserve products.

For detail on Q1, Q2 & Q3 please see our previous reports on our website.

2. Reactive Power

Q4 2023-24 performance

Table: Reactive Power percentage of services procured on a non-competitive basis, and spend.

Reactive Power		Unit	Q1	Q2	Q3	Q4	Full Year
Volume	Total volume procured	GVARh	15,680	16,097	15,486	14,721	61,984
	Volume procured non-competitively	GVARh	15,126	15,567	14,956	14,197	59,846
	Percentage of volume procured non-competitively	%	96%	97%	97%	96%	97%
	Year 1 benchmark	%	90%	90%	90%	90%	90%
	Status	n/a	●	●	●	●	●
Spend*	Total spend	£m	76.7	68.2	69.8	60.9	275.6
	Spend for volume procured competitively	£m	76.4	67.9	69.5	60.6	274.4
	Spend for volume procured non-competitively	£m	0.3	0.3	0.3	0.3	1.2

*Rounding: Spend figures in £m are rounded to the nearest 1 decimal place, therefore Total spend may differ slightly from the sum of competitive and non-competitive spend.

Performance benchmarks:
- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5% or more higher than the annual procurement benchmark

The benchmark for Year 2 remains at 90%

Supporting information

In Q4, 97% of Reactive Power volume was procured non-competitively compared to the benchmark of 90% and therefore below expectations. The benchmark was established late in the BP1 period, on the expectation that by BP2 we would have a Reactive Market in place. The development of that market was postponed in 2022 and has restarted in May 2023. This remains unchanged from Q2.

The Reactive Power service is delivered primarily by providers who have Mandatory Service Agreements and are typically connected to the Transmission Network. These providers would also be in the Balancing Mechanism (BM).

The long-term Mersey Pathfinder awarded two contracts to meet a need in this region: the Peak Gen shunt reactor service went live in Q1 2022-23 and the Zenobe Battery live in Q4 2022-23. In January 2022 we also awarded contracts to meet reactive needs in the Pennines region that are due to commence in 2024-25 which will decrease the percentage of reactive power services procured and utilised through non-competitive means. The Pennines solutions delivered by NGET are expected to come online in 2024-25 with potentially the first one in Q1 2024-25.

Reactive market is being established based on initial market design from NIA project in 2022. We have completed our work on the long-term reactive power market and plan to launch the first tender when the right opportunity presents itself. Implementing the long-term market will drive locational investment and enable greater competition in the delivery of reactive power service provision. 2029 is the earliest year for which there may be a requirement to be covered by the long-term market, subject to a firm requirement being identified and the long-term (Y-4) market being selected by ESO as the preferred delivery route.

We are continuing to assess the consumer benefit impact that a mid-term (Y-1) and short-term (D-1) can deliver.

For detail on Q1, Q2 & Q3 please see our previous reports on our website.

3. Constraints

Q4 2023-24 performance

Table: Constraints percentage of services procured on a non-competitive basis and spend.

Constraints		Unit	Q1	Q2	Q3	Q4	Full Year
Volume	Total volume procured	GWh	158	116	7	134	415
	Volume procured non-competitively	GWh	155	101	0	0	256
	Percentage of volume procured non-competitively	%	98%	87%	0%	0%	62%
	Year 1 benchmark	%	65%	65%	65%	65%	65%
	Status	n/a	🔴	🔴	🟢	🟢	🟢
Spend	Total spend	£m	4.9	1.0	0.1	0.7	6.7
	Spend for volume procured competitively	£m	0.1	0.2	0	0.7	5.6
	Spend for volume procured non-competitively	£m	4.8	0.8	0	0	0.9

Data Issue: The original Q2 figures reported in our Q3 report excluded spend and volume on the B6 intertrip service due to a data processing error. This has now been corrected, changing the percentage procured non-competitively from 100% to 87%, with no change to the performance status.

Performance benchmarks:

- 🟢 **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- 🟢 **Meeting expectations:** within ±5% of the annual procurement benchmark
- 🔴 **Below expectations:** 5 or more higher than the annual procurement benchmark

The benchmark for Year 2 is 55%

Supporting information

In Q4, the intertrip service has been utilised more frequently than the first two quarters across the B6 due to several outage conditions and the higher wind throughout the period. The control room experienced outages on circuits in the B6 region which reduced boundary limits thereby increasing the need to arm units. Additionally, when the NSL interconnector was importing from Norway, this had an impact on power flows in the region, again increasing the need to arm units. The EC5 service is now live however was not utilised in Q4.

There is a significant change in performance between the first two quarters of the year, and the last two quarters. This is because there were no strike price contracts for delivering any constraint services in Q3 and Q4. It is not unusual to not need any strike price contracts during the autumn and winter seasons as demand is greater and generation availability is more certain. Therefore it is likely that we could see similar in Q3 and Q4 next year.

For detail on Q1, Q2 & Q3 please see our previous reports on our website.

Metric 2X Day-ahead procurement

April 2023 – March 2024 Performance

This metric measures the percentage of balancing services procured at no earlier than the day-ahead stage, i.e. those procured at day-ahead or closer to real time. We report on total contracted volumes (mandatory and tendered) in megawatts (MWs). Expectations are set for all relevant services that are currently procured by the ESO and may be revised if new products are introduced.

Benchmarks are set based on expected product expirations, and expectations for new procurement volumes:

Note that in line with the terms of a derogation from the requirements of Article 6(9) of the Electricity Regulation, the ESO is required to procure at least 30% of services no earlier than day-ahead stage

Whilst the ESO set out the daily requirements for day-ahead procurement, when these requirements are not met through competitive day-ahead tendering the outstanding requirement could be met through other means such as bi lateral agreements and mandatory markets.

The following services are included in the figures for this metric:

Day-ahead: Short-Term Operating Reserve (STOR), Dynamic Containment, Dynamic Moderation, Dynamic Regulation, Static Firm Frequency Response

Non-day-ahead: Firm Frequency Response Monthly, Mandatory Frequency Response, Long Term STOR

Services newly introduced during BP2 should only be included in this metric if they displace those procured earlier than day-ahead.

Q4 2023-24 performance

Figure: Quarterly percentage of balancing services procured at no earlier than day-ahead

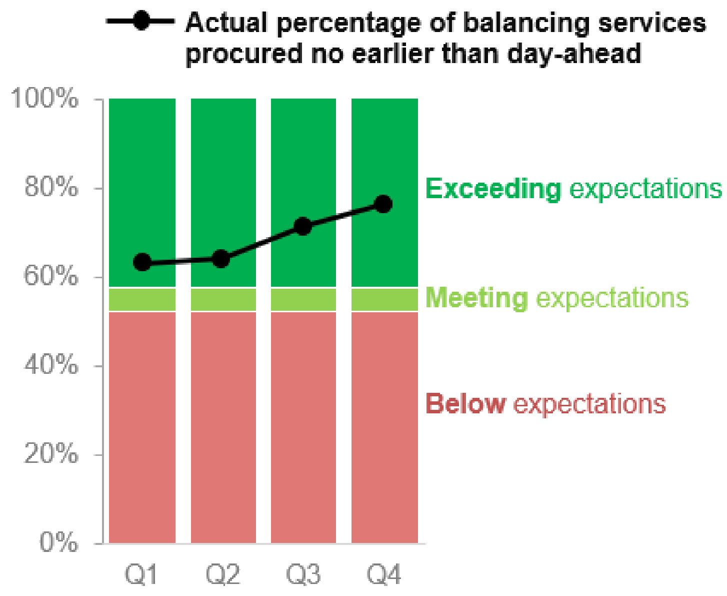


Table: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4	Full Year
Total volume of balancing services procured	MW	12,486	13,213	12,259	12,148	50,106
Volume procured no earlier than day-ahead	MW	7,893	8,463	8,751	9,281	34,388
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	63%	64%	71%	76%	69%
Benchmark	%	55%	55%	55%	55%	55%
Status	n/a	●	●	●	●	●

Performance benchmarks:

- **Exceeding expectations:** 5% or more higher than annual day-ahead procurement benchmark
- **Meeting expectations:** within ±5% of the annual day-ahead procurement benchmark
- **Below expectations:** 5% or more lower than the annual day-ahead procurement benchmark

For year 2, the benchmark increases to 80%

Supporting information

In Q4, 76% of balancing services volume was procured no earlier than day-ahead, compared to the benchmark of 55%, and therefore exceeding expectations.

The exceeding expectations performance for day-ahead procurement of services is due to several factors across the markets. Over the past 12 months the response and reserve markets have matured, resulting in greater market liquidity and greater competition. Reducing volumes in non-day-ahead service such as Dynamic Firm Frequency response which was phased out with last delivery of the service in November 2023 and these volumes are going into services procured at day-ahead.

Going forward we would expect to see this performance increase as legacy services are fully phased out and new services go live.

For detail on Q1, Q2 & Q3 please see our previous reports on our website.

B.4 Quality of Outputs for Role 2

The fourth evaluation criterion for the ESO incentive scheme is Quality of Outputs, where the Performance Panel will consider the actual benefits the ESO has realised from delivering its Business Plan, or any outputs additional to the Business Plan.

At the time of publishing our original RIIO-2 Business Plan in December 2019, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the RIIO-2 Business Plan. The relevant CBAs for Role 2 are:

- Build the future balancing service and wholesale markets (A4)
- Transform access to the Capacity Market (CM) (A5)
- Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 (A6.5)
- Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges (A6.6).

In this section, we provide a progress update for each of the activities for which we originally provided a CBA, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence (RRE), and describing any sensitivity factors which would impact on the delivery of the stated benefit. Deliverable activity statuses reflect the delivery of RIIO-2 milestones and do not recognise either work completed prior to April 2021 nor progress made towards yet to be completed milestones.

We also provide a specific case study on **Balancing Reserve**, which was not covered by the original CBA document.

The Panel will also consider the ESO's RREs as part of the Quality of Outputs criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the Electricity System Operator Reporting and Incentives (ESORI) guidance. For Role 2, the items of RRE reported at mid-year are:

- 2B. Diversity of Service Providers
- 2E. Accuracy of Forecasts for Charge Setting – BSUoS

CBA: Build the future balancing service markets (A4)

BP2 Mid-Scheme view of gross benefits compared to BP2

We now estimate gross benefits of £279m over the RIIO-2 period, which is an increase of £180m compared to the BP2 figure of £99m.

		Estimated gross benefits during RIIO-2 (£m)		
Area		**BP2 Plan view**	**Latest forecast view**	**Variance**
1.	More liquid response and reserve market	72	209	**+137**
2.	Buying the optimal volume of response	27	70	**+43**
Total		**99**	**279**	**+180**

As we set out further below, the original BP2 benefits figures for this CBA were created based on high level assumptions. For the Mid-Scheme view we have taken a new approach based on the calculated benefit of a number of individual market changes we have made.

The updated calculation shows higher benefits than estimated at BP2, due to the transition to the Enduring Auction Capability (EAC) auction platform. This has features such as co-optimisation of auction products, splitting of bids across multiple products and negative price clearing. The combination of these with an increase in market liquidity has greatly reduced the cost of procuring frequency response.

Summary of progress in 2023-24

We have made a number of beneficial changes to our reserve and response markets so far under RIIO-2. We have transitioned to a new set of frequency response products that we are able to procure at a day-ahead stage and will provide high quality grid stability into the future.

One of the most impactful changes made has been the transition to the EAC auction platform in November 2023. Prior to this, participants could only bid into a single product market with their unit per EFA block, meaning that if they were unsuccessful, that capacity could not be utilised in any of the other product markets. The EAC platform allows participants to bid all or part of their unit into multiple product markets for the same EFA block. These combinations of units and bids are then run through a co-optimisation algorithm to ensure the best overall result for bidders and the ESO. This has created many more opportunities for providers to offer their services and in turn has created more opportunities for us to fulfil our frequency response requirements. Since the introduction of the EAC platform, the number of units bidding into these markets has increased steadily, brought about by the flexibility that the platform provides.

Prior to the launch of the EAC auction platform, the development and launch of the new frequency response products suite provided many benefits over the legacy products they have been replacing.

Dynamic Containment was launched as a day-ahead auction product that is procured day-ahead in EFA block and has separate product categories for high or low frequency response (Dynamic Containment High and Dynamic Containment Low). Dynamic containment ensures that we can secure the largest loss and has replaced other post-fault frequency response products.

Dynamic Regulation and Moderation have also been launched and provide constant grid stabilisation.

Progress has also been made on transitioning some of our other markets into day-ahead procurement. Both Static Firm Frequency Response (sFFR) and Short Term Operating Reserve (STOR) are now procured in day-ahead auctions, a change from the month-ahead auctions that they used to be procured in. Procuring closer to real time enables providers a better view over the markets and alternative revenue streams, and they are not locked into month-long contracts.

Please note we have provided a separate consumer benefit case study on Balancing Reserve, which is out of the scope of this CBA.

Combined status by milestone for relevant deliverables (Activity A4)

Status	Count	%
Complete	**11**	31%
On track	**11**	31%
Delayed – Consumer Benefit	**-**	-
Delayed – External Reasons	**3**	8%
Delayed - Internal Reasons	**4**	11%
Continuous activity	**7**	19%
Total	**36**	**100%**

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Supporting evidence

Type	Measure	Rationale and status
Qualitative evidence	-	The expansion and development of the new frequency response product suite has enabled us to secure larger loss volumes than it ever has previously. This materialised during high frequency oscillation events on the network during July 2023. We were able to run a secure network during this period of instability as there was access to higher levels of Dynamic Containment through a liquid day-ahead response market. During this time, we secured a record 1576 MW Dynamic Containment Low in one EFA block. The new services suite is also allowing us to develop towards a system capable of running in lower-carbon, lower-inertia conditions. The minimum inertia level at which the grid will run has been lowered from 140 GVA.s to 130 GVA.s. This reflects increased confidence in the new products and their ability to be procured.
Metric	2X Percentage of balancing services procured at no earlier than day-ahead	End of 2023-24 view: exceeding expectations with 69% of balancing services procured at no earlier than day-ahead, compared to the benchmark of 55%. Procuring closer to real time enables providers a better view over the markets and alternative revenue streams, and they are not locked into month-long contracts. This also allows us to buy more optimal volumes of response and reserve due to more accurate forecasts.

Metric	2Ai Phase-out of non-competitive balancing services	End of 2023-24 view: • Frequency Response and Reserve are exceeding expectations (22% procured non-competitively vs benchmark of 25%) • Reactive Power is below expectations (97% procured non-competitively vs benchmark of 90%) • Constraints is meeting expectations (62% procured non-competitively vs benchmark of 65%) The greater volume of reserve and response that are exposed to competitive markets should enable us to fulfil more of our system security obligations at a lower price.

Detail: Calculation of monetary benefit

The original BP2 benefits figures for this CBA were created based on high level assumptions as set out below. For the Mid-Scheme view we have taken a new approach based on the calculated benefit of a number of individual market changes we have made. Below we set out the original BP2 calculation, followed by our new Mid-Scheme calculation.

1. More liquid response and reserve market

BP2 approach:

Assumptions	BP2 Plan view
(a) Value of the response and reserve market per year	£479 million. This is not a forecast of future response and reserve spend, it is the value of the response and response market today used for estimation of consumer benefits.
(b) Percentage saving in the response and reserve markets	Our actions deliver a 5% saving in the response and reserve markets based on evidence from early trials, as evidenced in the 2019 - 21 Forward Plan (page 111) and from subsequent market changes.
(c) Number of years of benefits	Three. Benefits delivered from year three of RIIO-2, allowing two years for implementation.
Calculation	£479m (a) x 5% (b) x 3 (c)
Gross benefits	£72m

Mid-Scheme approach

Assumptions	Latest forecast view
Volume-weighted cost of buying response on the EAC platform compared to the previous EPEX platform	The benefit calculation compares the weighted volume cost of procuring frequency response services in the following two periods: • The five months after the move to the EAC platform (November 2023 – March 2024) • The same five-month period a year earlier (November 2022 – March 2023) on the previous auction platform (EPEX) This benefit was calculated to be £86.5m / year for 2 years and 5 months
Calculation	£86.5m / year * 2 years and 5 months
Gross benefits	£209m

2. Buying the optimal volume of response

BP2 approach:

Assumptions	BP2 Plan view
(a) Value of the response market per year	£179 million. This is not a forecast of future response spend. It is the value of the response market today used for the estimation of consumer benefits.
(b) Percentage saving in the response markets	Our actions deliver a 5% saving in the response and reserve markets based on evidence from early trials, as evidenced in the 2019 - 21 Forward Plan (page 111) and from subsequent market changes.
(c) Number of years of benefits	Three. Benefits delivered from year three of RIIO-2, allowing two years for implementation.
Calculation	£179m (a) x 5% (b) x 3 (c)
Gross benefits	£26.8m

Mid-Scheme approach

Assumptions	Latest forecast view
(x) Volume weighted cost of procuring static FFR in a day-ahead auction compared to the month-ahead auction	Benefit based on a comparison of the volume-weighted cost of procuring static FFR at a day-ahead basis in the following time periods: • The 12 months before the service began being procured (April 2022 – March 2023) • The first 12 months in which the service was procured (April 2023 – March 2024) This was calculated to be £5.2m (£1.3 million/year for four years).
(y) Volume weighted cost of procuring post-fault frequency response as dynamic containment	Benefit based on the decrease in costs (volume weighted) of procuring Dynamic Containment Low in the period November 2021 to October 2022 and November 2022 to October 2023. This was calculated to be £49.9m (£12.5m for four years).
(z) Volume weighted cost of procuring pre-fault frequency response as dynamic regulation and moderation compared to legacy products	Benefit based on comparison of procuring pre-fault frequency response through legacy Dynamic Firm Frequency Response service (dFFR) and through Dynamic Moderation and Dynamic Regulation. Comparison is based on the final 10 month period immediately prior to dFFR being phased out (January 2023 to October 2023). The benefit was calculated to be £15m (£5 million/year for three years).
Gross benefit	£70.1m
Calculation	£5.2m (x) + £49.9m (y) + £15m (z)

CBA: Transform access to the Capacity Market and Contracts for Difference (A5)

BP2 Mid-Scheme view of gross benefits compared to BP2

We now estimate gross benefits of £192.4m over the RIIO-2 period, which is an increase of £117.7m compared to the BP2 figure of £74.7m.

	Estimated gross benefits during RIIO-2 (£m)		
Area	**BP2 Plan view**	**Latest forecast view**	**Variance**
1. Enhanced Modelling Capability	68.2	186.5	+118.3
2. Reduced Barriers to Entry and Cost of Participation	6.5	5.9	-0.6
Total	**74.7**	**192.4**	**117.7**

*Figures are rounded to the nearest £0.1m, therefore small differences may arise in totals.

For Enhanced Modelling Capability, the only assumption that has changed since BP2 is the clearing price, which has been updated with actuals for 2022-23 and 2023-24. This has increased the benefit by £118.3m.

For Reduced Barriers to Entry and Cost of Participation, the benefit has reduced from £6.5m to £5.9m to reflect the EMR Portal go-live being delayed until Q1 2024-25.

Summary of progress in 2023-24

1. Enhanced Modelling Capability

We have met all of the milestones for enhanced modelling capability in this period. This includes delivery of the annual Electricity Capacity Report to DESNZ and a set of development projects that seek to improve the modelling each year. Development projects have been completed in line with a well-established joint-prioritisation process involving DESNZ and Ofgem. Details of the development projects are reported each year in the Electricity Capacity Report. The development projects have sought to enhance our modelling capability such that it remains robust for a changing electricity system. This enhanced capability has underpinned our recommendations on the required capacity to secure – recommendations that have continued to withstand scrutiny from DESNZ' Panel of Technical Experts and be accepted by DESNZ.

2. Reduced Barriers to Entry and Cost of Participation

The EMR Portal is the key enabler for both the ESO and the Capacity Market participants to comply with the Capacity Market Rules and Regulations. The new system is expected to deliver efficiency for all parties involved through its more user-friendly, agile and modernised functionalities and design logics.

We have achieved all the milestones against the new baselined delivery plan which was supported by the industry and Ofgem. It is on track to go live from May 2024 as such the benefits are expected to deliver from 2024-25 onwards with about £3m per annum.

Combined status by milestone for relevant deliverables
(Activity A5)

Status	Count	%
Complete	**7**	29%
On track	**17**	71%
Delayed – Consumer Benefit	**-**	-
Delayed – External Reasons	**-**	-
Delayed - Internal Reasons	**-**	-

Continuous activity	-	-
Total	**24**	**100%**

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Supporting evidence

1. Enhanced Modelling Capability

Type	Measure	Rationale and status
Qualitative evidence	n/a	The enhanced modelling capability has underpinned our recommendations on the required capacity to secure through the Capacity Market. Our recommendations have withstood scrutiny from DESNZ' Panel of Technical Experts (PTE), who have supported our recommendations that were accepted by DESNZ. The PTE have reported on our "open and constructive process of engagement"[15] and have found "no conflict of interest concern"[16] in us producing our recommendations.
RRE	RRE 2D Demand Forecasting Accuracy	We have made improvements to our input data and analytical tools, leading to more accurate forecasting of demand than would otherwise be the case. These improvements are described in the narrative for RRE 2D. However, even with improved modelling, it is still possible for events outside of our control to impact on our demand forecasting accuracy, as described in RRE 2D. Delivery year 2023-24: Absolute percentage error of 4.1% for T-1 (below expectations), and 0.1% for T-4 (exceeding expectations).

2. Reduced Barriers to Entry and Cost of Participation

Type	Measure	Rationale and status
Qualitative evidence	Customer Satisfaction Survey	We are intending to run a customer satisfaction survey after the new EMR Portal has gone live to validate the expected efficiency delivered for the participants and to gain insight of their overall experience with the Portal.

Detail: Calculation of monetary benefit

1. Enhanced Modelling Capability

Assumptions	BP2 Plan view	Latest forecast view
(a) Clearing price of the Capacity Market	£17.045/kW per year based on the average of six T-4 auctions held to date.	2022-23: £63.500/kW (Actual) 2023-24: £65.000/kW (Actual) 2024-25 and 2025-26: £28.984/kW per year (Forecast

[15] Panel of Technical Experts: Report on the National Grid ESO Electricity Capacity Report 2023 (publishing.service.gov.uk) paragraph 12

[16] Panel of Technical Experts: Report on the National Grid ESO Electricity Capacity Report 2023 (publishing.service.gov.uk) paragraph 23

		based on the average of nine T-4 auctions held to date)
(b) Annual consumer savings as a result of our actions.	The equivalent of purchasing an additional 1 GW of capacity.	No change to high level assumption
(c) Number of years of benefits during RIIO-2	Benefits delivered from year two of RIIO-2, therefore four years of benefit. This allows a year for implementation of this activity, given auction timings, when improved analysis will feed into recommendations to procure capacity.	Modelling improvements delivered in year one of BP2, therefore four years of benefit still applies.
Calculation	= 17.045 (a) x 1,000,000 (b) x 4 (c)	= (63.500 + 65.000 + 28.984 + 28.984) (a) x 1,000,000 (b)
Gross benefits	£68.2m	£186.5 m

2. Reduced Barriers to Entry and Cost of Participation

Assumptions	BP2 Plan view	Latest forecast view
(a) Number of companies on CM register	1,122. The approximate number of companies registered on the EMR portal.	1,537 (updated number of registered companies)
(b) Percentage of registered companies that interact with the Capacity Market	50%. We have assumed that around 50% of registered companies are active at either T1 or T4 auctions, based on historical observations.	No change
(c) Number of weeks of FTE weeks of time that our actions save for each Capacity Market company	2 FTE weeks. We have assumed that Capacity Market companies' FTE requirements mirror our own	No change
(d) Cost of one FTE week	£1,923. Based on one FTE at £100,000 divided by 52.	No change
(e) Number of years of benefits during RIIO-2	Benefits delivered from year three of RIIO-2, therefore three years of benefit. This allows a year for implementation of the activity, given auction timings.	Reduced from three years' benefit to two, to reflect the delayed go live of the EMR Portal, with full functional go-live in Q1 2024-25.
Calculation	= 1,122 (a) x 50% (b) x 2 (c) x £1.923 (d) x 3 (e)	= 1,537 (a) x 50% (b) x 2 (c) x £1.923 (d) x 2 (e)
Gross benefits	£6.5m	£5.9m

CBA: Work with all stakeholders to create a fully digitalised, Whole System Technical Code by 2025 (A6.5), Digitalisation of Codes (A6.8)

BP2 Mid-Scheme view of gross benefits compared to BP2

In BP2 we estimated gross benefits of £40 million over RIIO-2. For this Mid-Scheme update, we have not updated the BP2 gross benefits calculation, but instead provide an update on progress along with qualitative evidence of the benefits that A6.5 and A6.8 will deliver.

		Estimated gross benefits during RIIO-2 (£m)	
Area		**BP2 Plan view**	**Latest view**
A6.5	Reducing Barriers to Entry through Digitalising the Grid Code	40	We have provided a written update for Mid-Scheme. The current view is still consistent with the original high level assumptions.
A6.8	Digitalisation of codes*	0	
Total		**40**	

*Note regarding A6.8 benefits: A6.8 is a new sub-activity for BP2; however, it does not generate new tangible benefits, as the benefits were already accounted for at BP1. The original A6.5 sub-activity has now been split into two sub-activities A6.5 and A6.8 where A6.5 is focused on consolidation of code and A6.8 on digitalisation of codes. Splitting the original sub-activity improves governance and control of the project to deliver best value for consumers. The expected split of benefits is 80% digitalisation and 20% consolidation.

Although split into two sub-activities A6.5 and A6.8 benefits are accounted for in a combined CBA because it is difficult to demonstrate distinct benefits for each sub-activity. It is anticipated that ongoing work will continue to gather data from across industry to identify and inform the benefits associated with individual workstreams, in turn informing separate cost benefit analysis for A6.5 and A6.8 in BP3.

Summary of progress in 2023-24

The Digitalisation project is at the Minimum viable project phase of the process and went live in April 2024 here. We have consulted with stakeholders through a steering group and workshops to discuss and decide on the scope of the project and the wants and needs of a digital code. From these discussions we then chose a partner to work with us to create the vision we had for the digital Grid Code. The benefits needed to be for the end user as well as benefits within the ESO for useability.

The original benefit case was to reduce customer resource spent on asking queries and reduced need for dedicated legal teams reducing barriers to entry. We also wanted the new digitised format to allow customers to search through the code, and generative AI will allow customers to easily find sections of the code which are relevant to them reducing time spent searching through code.

In turn this would reduce the number of queries we received providing us with more improved stakeholder satisfaction scores.

Once we had discussed the options and art of the possible with the IT team (IBM) we soon found the benefits to us as an organisation would prove invaluable too.

The digitisation of the code ultimately results in the reduction of risk of errors to codes used by industry as an improved workflow with reduced areas for human error has been introduced.

This will result in a reduced workload for Code Governance and elimination of need for multiple offline documents and lengthy review processes. Digitisation of codes improves the ability to update – especially when drafting multiple changes from different mods coincidingly.

Combined status by milestone for relevant deliverables
(Activities A6.5 and A6.8)

Status	Count	%
Complete	2	50%
On track	2	50%
Delayed – Consumer Benefit	-	-
Delayed – External Reasons	-	-
Delayed - Internal Reasons	-	-
Continuous activity	-	-
Total	**4**	**100%**

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Calculation of monetary benefit

The original business plan benefits case was conducted at a very high level, due to the nature of the benefits being industry time saved spread across multiple companies, so it is almost impossible to calculate a meaningful number.

Therefore, for this Mid-Scheme update we haven't updated the benefits calculation. However, we believe the known benefits are still consistent with the original proposal but are still very much anecdotal based on customer feedback.

CBA: Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges (A6.6) and Fixed BSUoS tariff setting (A6.7)

BP2 Mid-Scheme view of gross benefits compared to BP2

We now estimate an NPV of £68m over the five-year RIIO-2 period, which is in line with the original BP2 figure of £68m.

		NPV over the five-year RIIO-2 period (£m)		
Area		**BP2 Plan view**	**Latest forecast view**	**Variance**
A6.6	Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges	68	68	-
A6.7	Fixed BSUoS tariff setting	-	-	-
Total		**68**	**68**	**-**

Note regarding A6.7 benefits:

- During the BP1 period we worked with industry to deliver a programme of BSUoS reform which resulted in code modifications and a change to our licence. This activity was completed before the BP2 period. A new sub-activity A6.7 was then created to look at the long-term delivery of the recommendation from the BSUoS taskforce. The benefits of A6.7 are already accounted for in the original A6.6 benefits case, so A6.7 has no additional financial benefits.

Note regarding NPV benefits:

- In BP2 we quoted NPV benefits rather than gross benefits. Ofgem commissioned analysis by independent consultants, Frontier Economics and LCP to support their assessment of the code modification proposals for BSUoS reform. The analysis included an 18-year NPV for CUSC modifications CMP308, which removed charges from generation and CMP361/CMP362, which introduced an ex ante fixed BSUoS tariff. Unfortunately, different methodologies were used and hence it is not possible to easily combine the impacts to obtain a NPV of both modifications that reflects the total benefits of BSUoS reform. Therefore, for the BP2 benefits assessment we focussed on the CMP308 NPV using the Consumer Transformation FES as a basis, recognising that this gives a conservative estimate of the total NPV. To obtain an estimate of the NPV across the RIIO-2 period, we annuitised the benefits from the analysis commissioned by Ofgem. This gave an estimated NPV of £68 million over the 5 five-year RIIO-2 period and £167 million over 10-years.

Industry, Ofgem and the ESO agreed that the introduction of fixed BSUoS for final demand would result in a reduction of risk premia. With BSUoS costs of £2.9bn in 2023-24, even a very conservative estimate of 1% reduction in suppliers' risk premia would provide a £29m consumer benefit for the first year of operation alone. Therefore, we can assume that we are on track to deliver the overall benefits, with two years of the RIIO-2 period remaining after 2023-24.

Following implementation of CMP308 and CMP361/361, we raised another modification CMP408 (followed by CMP415 for the non-charging elements) to reduce cashflow risk, and the resulting risk of a tariff reset. These modifications have been submitted to Ofgem for approval and are awaiting clarity on the Working Capital Facility.

This benefit cannot be tracked as it relies on reduced risk premia from suppliers which is not data that is available to the ESO. There is no indication to suggest that the benefits have not been realised, so until there is evidence to suggest otherwise, we are comfortable that we are on track to deliver £68m.

Summary of progress in 2023-24	Fixed BSUoS was implemented in April 2023. Fixed Tariff 1 (April 2023 – September 2023) and Fixed Tariff 2 (October 2023 – March 2024) have concluded. Fixed Tariffs 3 and 4 have been set, and Fixed Tariff 5 is due to be set by the end of June 2024. To date, no tariff resets have been required.

The cash position at the end of Fixed Tariff 1 was £350m. As of Mid-Scheme (18 April 2024), we are forecasting the end of cash position for Fixed Tariff 2 at £845m, Fixed Tariff 3 at £451m and Fixed Tariff 4 at £426m.

The positive cash position is in line with suppliers reducing their risk premia as this reduces the risk of a tariff reset. It should be noted that the large cash position at the end of Fixed Tariff 2 is due to reducing wholesale costs following the Tariff being set 9 months in advance. As stated in the section above, CMP408 and CMP415 are currently with Ofgem for a decision which would reduce the notice period, and therefore enable more accurate Tariffs to be set than is available presently.

Combined status by milestone for relevant deliverables
(D6.7 only (Enhanced delivery of the recommendation from the BSUoS taskforce around reducing the volatility of BSUoS forecasting). D6.6 was 100% complete at the end of the BP1 period)

Status	Count	%
Complete	**-**	-
On track	**-**	-
Delayed – Consumer Benefit	**-**	-
Delayed – External Reasons	**-**	-
Delayed - Internal Reasons	**-**	-
Continuous activity	**1**	100%
Total	**1**	**100%**

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Supporting evidence

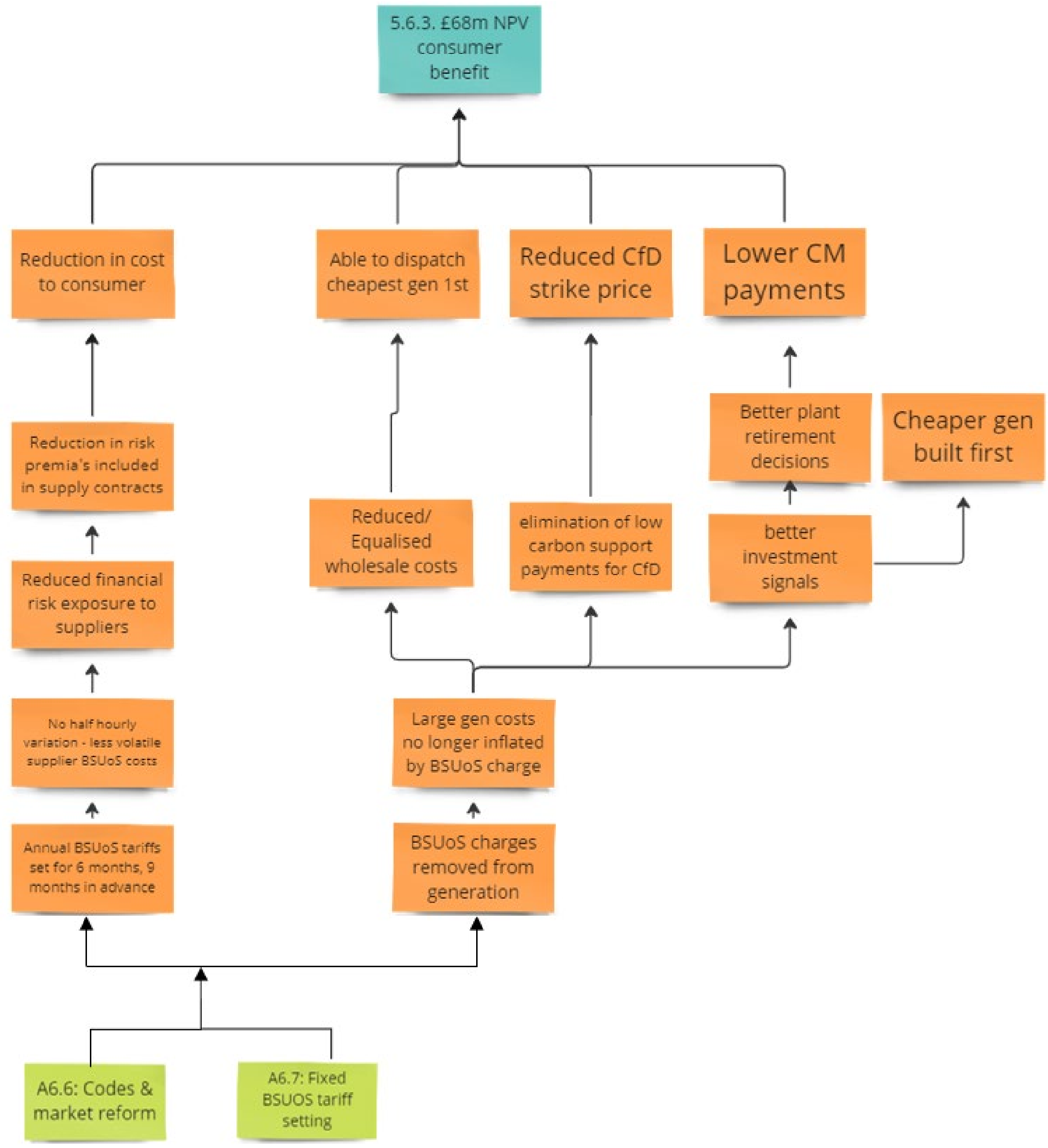
As the original benefits figure was based on a high level calculation (shown further below), here we present a range of further evidence to demonstrate our performance in relation to delivering the benefits.

A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges.
(The benefits of A6.7 are already accounted for in the original A6.6 benefits case, so A6.7 has no additional financial benefits.)

Type	Measure	Rationale and status
Qualitative evidence	-	Below this table we have included the process that we use to understand where the benefits derive from. This has helped to drive the indicators below to help us understand if we are on track or not.
Performance Indicator	No. times reset in period / once fixed	Zero within Fixed Tariff 1 (Apr 23 – Sep 23) and Fixed Tariff 2 (Oct 23 – Mar 24). No tariff resets would maximise the benefit.
Performance Indicator	Forecast cash position	Fixed Tariff1: £350m, FT2 £798m, FT3: £338m, FT4: £360m A positive cash position is indicative of benefit being delivered.

RRE 2E	BSUoS month ahead forecast % error	Average month ahead forecast error (Absolute Percentage Error) of 22% for 2023-24. A small error shows the accuracy of the BSUoS forecasting methodology. Ideally this would be close to zero, as prolonged forecasting error may increase the risk of under-recovery and a tariff reset.
Performance Indicator	Forecast Revenue vs Cost report	Weekly published report shows at daily granularity the current and forecast cash position for Fixed Tariffs. (available here under 'Current BSUoS Data') This ensures that industry can inform their forward contracts and pricing, by identifying potential impacts on future fixed tariffs, and early indication of any risk of tariff rest.
Performance Indicator	Communicating new tariffs by deadline (current 9 month ahead)	All tariffs have been published on time. This ensures that industry can use the information released in tariffs in their own contracts and pricing.
Performance Indicator	Communicating draft tariffs by deadline (current 18 month ahead)	All draft tariffs have been published on time. This ensures that industry can use this information to inform their forward contracts and pricing.

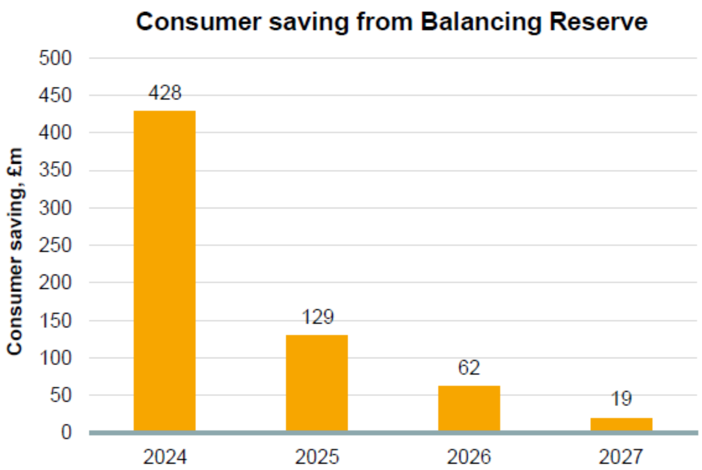
Flow chart: How benefits result from activities A6.6 and A6.7



Detail: Calculation of monetary benefit	For consistency with the original BP2 benefits case, below we have also updated the high level calculation produced by Frontier Economics and LCP. **A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges.** (The benefits of A6.7 are already accounted for in the original A6.6 benefits case, so A6.7 has no additional financial benefits.)

Assumptions	BP2 Plan view	Latest forecast view
Code modification proposals for BSUoS reform	BP2 focussed on the CMP308 NPV using the Consumer Transformation FES as a basis, recognising that this gives a conservative estimate of the total NPV. To obtain an estimate of the NPV across the RIIO-2 period, we have annuitised the benefits from the analysis commissioned by Ofgem.	These modifications have now been implemented. We are currently waiting on a decision from CM408 and CMP415 to make amendments to the notice and fixed period and undergoing workgroups for CMP420.
BSUoS price setting	If we did not undertake A6.6 and A6.7, the BSUoS arrangements would remain unchanged and the BSUoS price would continue to be set after balancing actions are taken.	No change from BP2 view
Benefits methodology:	Our five-year NPV estimate is now based on analysis commissioned by Ofgem for CMP308.	No change from BP2 view
Implementation date for BSUoS reform	We assume benefits begin from April 2023, the estimated implementation date of BSUoS reform.	Implemented in April 2023 as assumed.
ESO will finance any new arrangements	Taking on the additional cost of managing the risk premia will require financing for us to manage this risk.	The working capital facility is currently still in place.
Risk premia	Frontier Economics and LCP risk premia assumption	Even a very conservative estimate of a 1% reduction in risk premia would result in £29m of benefit in the first year alone (2023-24), with two more years of RIIO-2 remaining.
Benefit over the five-year RIIO-2 period (£m)	£68m (RIIO-2 NPV)	More than or equal to £68m

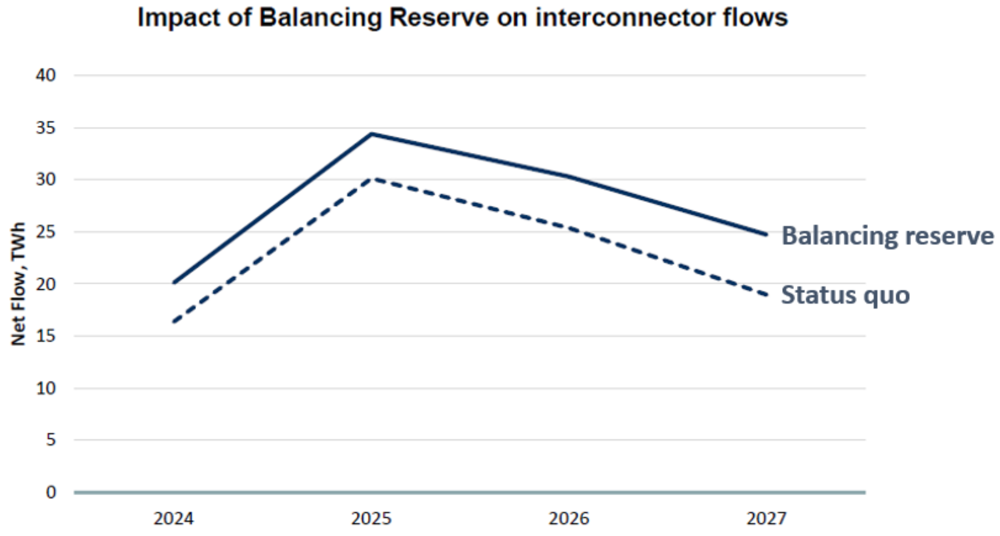
Consumer benefit case study for Role 2 Balancing Reserve

Activity	Balancing Reserve (BR)
Role	Role 2
Key RIIO-2 Deliverables	Activity A4 - Building the future Balancing Services markets
Is the consumer benefit mainly this year or in future years?	The BR market launched on 12 March 2024 for contracts to be delivered from 23:00 that evening. As of the time of writing (31 March 2024) there have been nineteen successful auctions. The key benefits of the BR service come from reducing the need to take costly margin actions either through the Balancing Mechanism (BM) or via trading to adjust interconnector positions. **Positive Balancing Reserve (PBR) or Upwards Margin** We typically see the most expensive actions for upwards margin (a need which can be met by the Positive Balancing Reserve service) during the winter months. This is because demand and energy prices are both typically higher and this pressure feeds through into the prices we face for energy in the BM. We should expect that in Winter 2024-25 we will see the benefits of avoided BM actions mounting. During Summer 2024-25 we will look to grow the market, monitoring liquidity and increase the sophistication of our procurement strategy to better realise the benefits available in winter. **Negative Balancing Reserve (NBR) or Downwards Margin** Negative Reserve (also known as downwards margin) can be accessed at zero cost from any units scheduled to run at full load. During higher demand periods we are usually able to access downwards margin at very low cost. However, when the system is lightly loaded, we may need to run units for voltage or inertia at their lowest possible level and find ourselves short of space to reduce unit output if required. It is in these periods, usually in summer overnight periods, that we believe there will be the most value in Negative Reserve.
Calculation of monetary benefit to consumers	A Cost Benefit Analysis produced by LCP Delta of the Positive Balancing Reserve market suggests the introduction of the market could deliver a potential consumer saving of £639m across the next four years under the base case. 

	Total consumer savings reduce in the later years of the analysis as energy prices are assumed to fall. However, the balancing costs savings would remain as we shift to buying reserve capacity directly rather than bundled with energy which is always lower cost.
Assumptions made in calculating monetary benefit	• Assumes full participation from all BM units at their cost of offering the service – based on the first few days of the auction not every single BM unit is participating. We are particularly hoping to see greater participation from CCGTs in the auction in the future who could, under the right conditions, have a competitive cost of provision. • Assumes the full positive reserve requirement is secured in the BM (although sometimes that comes at zero cost). • Assumes that the entire demand volume pays the Day-Ahead (DA) wholesale market price for energy. In reality large volumes are traded in the forward markets and the costs are different to the DA clearing prices on the power exchanges. • Assumes that the units contracted for BR are always replaced in the wholesale market – based on the first few auctions some units are winning capacity contracts that were not planning to run and therefore removing their volume from the wholesale market would not have had a material impact on wholesale prices.
How benefit is realised in the consumer bill	As a reduction in the costs incurred to access reserve capacity which reduces the total BSUoS bill. This benefit passes through suppliers to impact end consumers' bills.
Non-monetary benefits	**Balancing Reserve (BR) introduces our first firm negative reserve market; learnings from which will help us to prepare procurement strategies for a decarbonised energy system.** The Negative Balancing Reserve market is our first firm negative reserve market. We and the market will be able to learn about how the market functions and the capability to predict the value of negative reserve at day-ahead. This will help us to build a procurement strategy to secure access to negative reserve at the best cost for end consumers. This is especially important in a changing energy system where periods of low transmission demand due to high embedded renewables become increasingly relevant operational challenges. Buying turn down capability through a firm market could provide a key part of our procurement strategy in the future. **Sharper and more accurate market signalling will deliver better market outcomes reducing the requirement for ESO intervention.** The GB market is interconnected with neighbouring regions. Our largest volume border, France, offers 4GW of import/export interconnector capacity across IFA, IFA2 and Eleclink. GB has historically been unusual in securing the majority of reserve capacity in or close to real time via instructions through the BM to hold or maintain margin on identified units. The introduction of the BR market will allow the GB power market and interconnector positions to better reflect both GB reserve capacity and GB demand alongside the existing signals sent by the French yearly and daily procurement of reserve capacity. Bringing our procurement into temporal alignment with our neighbours should enable more optimal interconnector positions to be delivered by the market without requiring ESO trading intervention.

This will have the effect of sharpening market signals and enabling emerging technology groups like consumer flexibility to respond, potentially providing better value options than are available to us in real time.

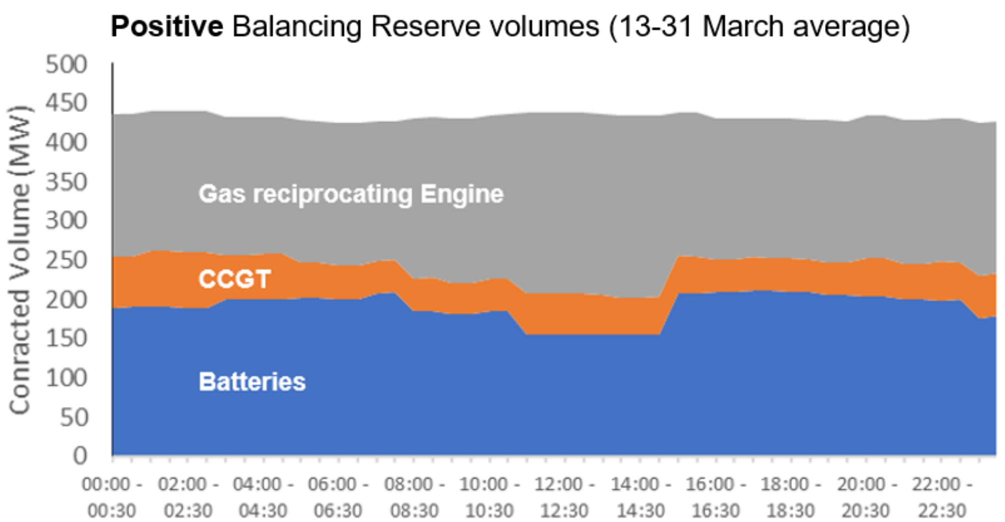
This chart shows that under the introduction of the BR market we would expect interconnector flows to be importing more to GB than without the market signal. This reflects a more optimal position as we are currently trading back the interconnectors to achieve this outcome in real time. If better interconnector positions can be found by the market the end consumer will benefit from a reduced need to trade closer to real time.

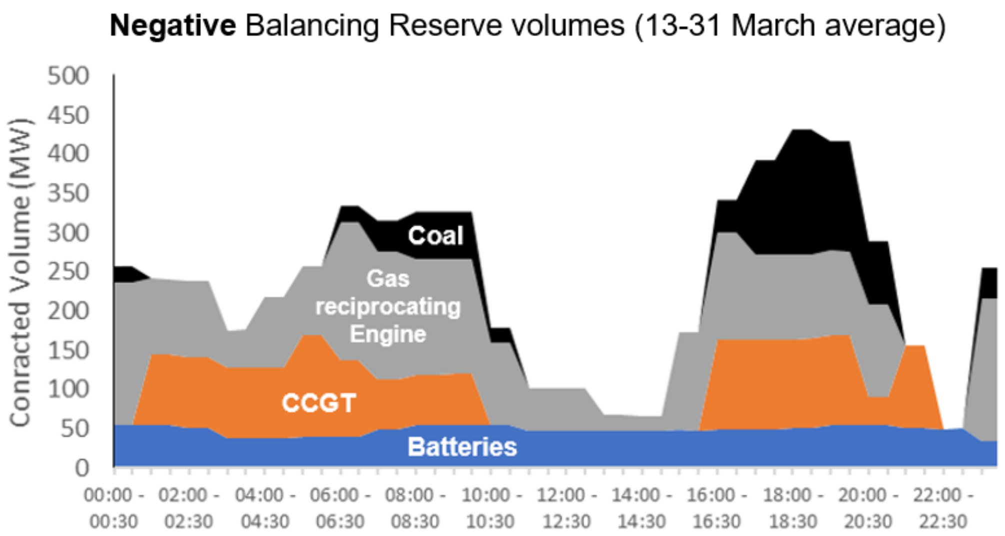


New market options for non-traditional reserve providers will accelerate progress in using new technologies to meet our balancing needs

The BR market is open to all BM participating units. From the first few days of auction we have seen volume being won by batteries and small gas engines which have not traditionally been utilised for reserve.

The introduction of a pay-as-clear auction will allow participating units to demonstrate their cost effectiveness compared to traditional providers leading to reserve being held on the most optimal units.





Assumptions made in calculating non-monetary benefit	1. Market participants are aware of the BR market and provide their feedback to us to enable learnings. 2. Units enter the BR market with prices that reflect their costs (including opportunity cost) of providing the service rather than engaging in bidding behaviour designed to increase prices – our experience from the first few auctions has suggested that our considered buy orders and smaller volume targets have avoided benefitting "hockey stick bids" and other attempts to influence the clearing price. This is a positive outcome as we don't want to reward market participants which seek to influence the clearing price via unreflective bid prices.

Regularly Reported Evidence

Table: Summary of RREs for Role 2

Most RREs don't have performance benchmarks, with the exception of 2D which is reported annually.

2023-24

RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
2Aii	Balancing services procured in a non-competitive manner	n/a	Q1: Spend: £96m Volume: 19 TWH and 15 TVARH			Q2: Spend: £86m Volume 17 TWH and 16 TVARH			Q3: Spend: £83m Volume 18 TWH and 15 TVARH			Q4: Spend: £73m Volume 17 TWH and 14 TVARH		
2B	Diversity of service providers	n/a	See 2B section below for details											
2D	RRE 2D EMR Demand Forecasting Accuracy	%	T-1 forecast accuracy of 4.1%: ● below expectations T-4 forecast accuracy of 0.9%: ● exceeding expectations											
2E	Accuracy of Forecasts for Charge Setting (TNUoS)	%	Actual total TNUoS revenue for 2023-24 is within 2% of the budget											
	Accuracy of Forecasts for Charge Setting (BSUoS)	%	18%	68%	43%	29%	7%	11%	36%	0%	1%	13%	40%	10%

RRE 2Aii Balancing services procured in a non-competitive manner

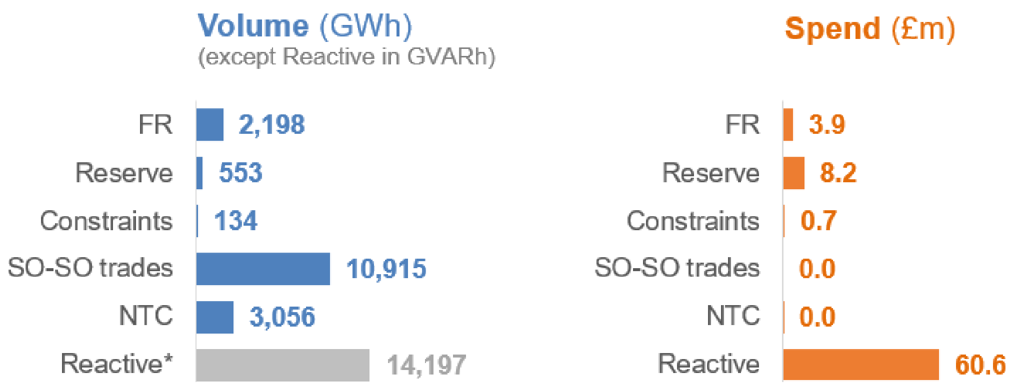
April 2023 – March 2024 Performance

This Regularly Reported Evidence (RRE) measures the volume and spend for non-competitive services for contracts. For the purpose of this metric, we have included volumes where the decision to instruct non-competitive services is made after 31 March 2023, even if the contract terms were signed before (e.g. Mandatory Frequency Response). Figures are reported in GWh/GVARh for the contracted month, which is calculated as the contracted volume in MW multiplied by the number of contracted hours.

Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded. However, all SO-SO trades and NTC application, as well as any other non-competitively procured services with contract award after this date, are included.

Q4 2023-24 performance

Figure: Volume and spend for non-competitive services for contracts



*Reactive volume is measured in GVARh and is not directly comparable to the other services measured in GWh but is included in the graph with this caveat.

Table: Volume and spend for non-competitive services

	Service	Unit	Q1	Q2	Q3	Q4	Full Year
VOLUME	Frequency Response****	GWh	1,917	2,172	2,138	2,198	8,425
	Reserve****	GWh	714	737	567	553	2,571
	Constraints***	GWh	158	101	7	134	400
	SO-SO trades	GWh	10,920	11,040	11,045	10,915	43,920
	Net Transfer Capacity (NTC)	GWh	5,242	3,091	4,565	3,056	15,954
	Total Volume in GWH	GWh	**18,951**	**17,141**	**18,322**	**16,856**	**71,270**
	Reactive (in GVARh)	GVARh	15,156	15,567	14,956	14,197	59,876
SPEND	Frequency Response	£m	4.0	4.6	4.4	3.9	16.9
	Reserve -	£m	10.6	11.9	9.3	8.2	40.0
	Constraints	£m	4.8	1.0	0.1	0.7	6.5
	SO-SO trades *	£m	0.1	0.2	0.0	0.0	0.3
	Net Transfer Capacity (NTC)**	£m	0.0	0.0	0.0	0.0	0.0
	Reactive	£m	76.4	67.9	69.5	60.6	274.4
	Total spend	£m	**95.8**	**85.6**	**83.3**	**73.3**	**338.1**

*SO-SO trades, trade volumes and costs for services provided to the ESO by another country's system operator have been included. Services provided by ESO to another country's System Operator are excluded.

**NTC cost was updated for Q1 to show payments to provider only – this logic to be used going forward

***For Q2 - Super SEL category has moved from Constraints to Reserve

****Total non-competitive procurement for Frequency Response and Reserve in RRE 2Aii will not align with volume stated in Metric 2Ai. This is because Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded from RRE 2Aii as per the agreed methodology.

Supporting information

Frequency Response

The volume of non-competitive services procured in Frequency Response is Mandatory Frequency Response (MFR). MFR is used as an element of our response holding that can be instructed within operational timescales. We are considering alternatives to MFR to reduce this volume in future.

Reserve

This volume of non-competitive Reserve is made up of the intra-day Optional Fast Reserve product, where prices for the service can be updated by providers per Settlement Period close to real-time. The Optional Fast Reserve product will be phased out with the introduction of the new day-ahead procured reserve products as they are introduced through 2024 and 2025.

Optional Fast Reserve is used for short-term frequency management outside contracted fast reserve windows e.g., periods where wind may have dropped unexpectedly or demand has increased more than anticipated. Note that day-ahead procured STOR is to replace the largest loss and thus utilisation should always be quite low.

Super SEL, which is now included as a Reserve service, is an active but optional contract that a number of generators can provide as a backup to other solutions. Super SEL has not been utilised since early 2022 and so we have reported 0GWh in this metric to reflect utilisation. We have previously reported the contract values and not actual utilisation.

Constraints

There were multiple arming instructions throughout Q4 due to high wind and congestion on the network.

Additionally, one optional Transmission Constraint Service for voltage control (through a Strike price option) contract was procured for the Southern region for services in December Q3. In December, no instructions were given as there were more economic options in the Balancing Mechanism.

SO-SO Trades

Historically SO-SO Trades were available to us across the IFA & IFA2, Nemo Link, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & Nemo Link, the current required notice period is longer than the hourly gates provide, we can no longer use this service.

EWIC & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. The ESO does not trade via 3rd Parties and therefore only has access to CBB.

Net Transfer Capacity (NTC)

A capacity management process is used to ensure secure system operation for both Interconnectors and onshore TSOs. This process can result in the reduction in capacity through the application of a Net Transfer Capacity (NTC) and this reduction is defined as a non-frequency ancillary service.

Standard Licence Condition C28 requires that we procure non-frequency balancing services using market-based procedures. NTC is not procured through market-based procedures and therefore requires a derogation from this requirement. The procurement of NTC cannot be market-based due to technical parameters and the fact that alternative actions are not sufficient or economically efficient.

On 28 September, Ofgem granted us a derogation against C28 for NTCs until 30 September 2026. This follows a request we sent to Ofgem to extend this derogation in August. They also approved our revised NTC Commercial Consultation Methodology, which applies from 1 October 2023. This gives our Control Room certainty that they can use this vital tool when required for system security over the coming years.

NTCs are our only way of guaranteeing system security in real time. As a result, they are as near to real-time calculated values as the market structure allows. Any restrictions are based on the forecast system conditions for that particular real-time period and are reflective of the limits of GB system security.

RRE 2B Diversity of Service Providers

April 2023 – March 2024 Performance

This Regularly Reported Evidence (RRE) measures the diversity of technologies that provide services to the ESO in each of the markets covered by performance metric 2A (Competitive procurement). We report on total contracted volumes (mandatory and tendered) in megawatts (MWs) or megavolt amperes of reactive power (MVARs).

There are four services we report on:

- Frequency Response (MFR, sFFR, dFFR, DC, DM, DR, FFR Auction, EFR)
- Reserve (STOR, Fast Reserve)
- Reactive
- Constraints

Data on Restoration services is not included in this report due to the sensitive nature of the information, which will be provided to Ofgem separately.

Methodology

<table>
<tr><th colspan="2">Product</th><th>Methodology</th></tr>
<tr><td rowspan="8">Frequency Response</td><td>Mandatory Frequency Response (MFR)</td><td>We report on contracted volumes for every unit. Figures only apply to a single day, not the whole month. For example, a 20MW MFR contract is only recorded as 20MW in the report, not as 600 MW (20MW x 30days).</td></tr>
<tr><td>Static Firm Frequency Response (sFFR)</td><td rowspan="2">We report on the highest volume for each unit that has contracted for a particular service block for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Dynamic Firm Frequency Response (dFFR)</td></tr>
<tr><td>Dynamic Containment (DC)</td><td rowspan="3">We report on the highest volume for each unit that has been contracted for a particular Electricity Forward Assessment (EFA) block for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Dynamic Moderation (DM)</td></tr>
<tr><td>Dynamic Regulation (DR)</td></tr>
<tr><td>Enhanced Frequency Response (EFR)</td><td>We report on contracted MW. This will not change from month to month unless a contract ends.</td></tr>
<tr style="display:none"><td></td><td></td></tr>
<tr><td rowspan="5">Reserve</td><td>Short Term Operating Reserve (STOR)</td><td>We report on the highest volume for each unit that has been contracted for a particular service window for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Super SEL (Footroom)</td><td>We report on contracted volumes for all contracts that are live for any part of the month.</td></tr>
<tr><td>Fast Reserve</td><td>We report on contracted volumes. We record the highest available volume for each unit for each month. Available volumes can change throughout the month for a unit. For example, a unit can be available at 60MW for 29 days in a month, and at 70MW for 1 day of the same month.</td></tr>
<tr><td>Quick Reserve</td><td rowspan="2">We report on the highest volume for each unit that has been contracted for a particular service window for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Slow Reserve</td></tr>
<tr><td rowspan="2">Reactive</td><td>Mandatory Reactive</td><td rowspan="2">We report on contracted volumes for every unit. Figures only apply to a single day and not the whole month. For</td></tr>
<tr><td>Stability Reactive</td></tr>
</table>

	Synchronous Compensation	example, a 20MW Reactive contract is only recorded as 20MW in the report, not as 600MW (20MW x 30days).
	Mersey & Pennine Pathfinder	
Constraints	Strike Price	We report on contracted volumes for all contracts that are live for any part of the month. Some are live for the whole month whereas others are live for part of the month. The highest available volume on a specific day for each unit for the relevant month is captured. The sum of those values is what we present in the monthly report.
	B6 Intertrip	

Firm Frequency Response Auction – this service is excluded as it ended in 2021-22.

Figure: Total contracted volumes by service type for Q4

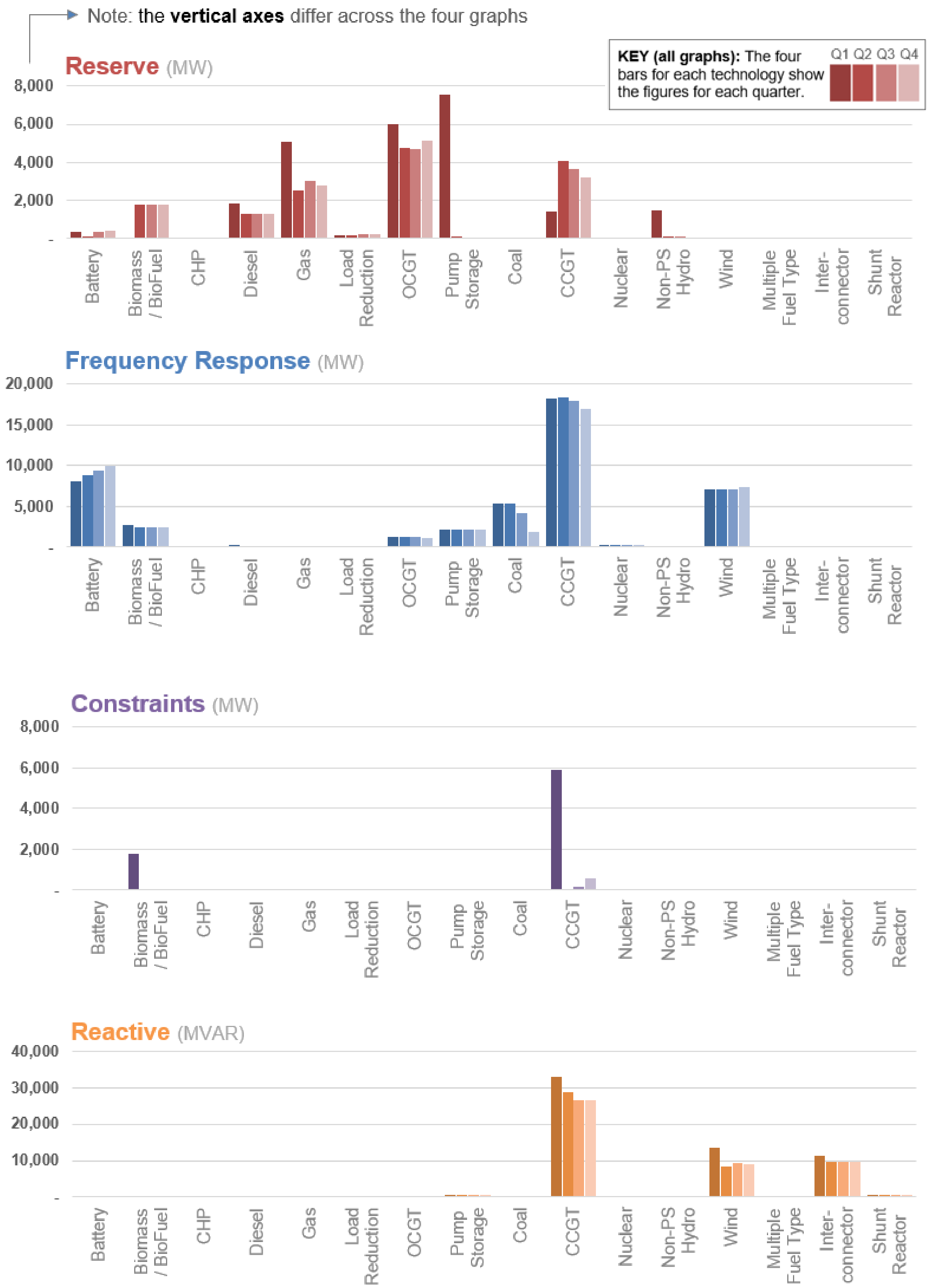


Table: Monthly contracted volumes provided to the ESO by service type

Reserve

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Q1	Q2	Q3	Q4
Total	8,017	8,022	8,022	5,038	5,105	4,793	5,009	5,029	5,184	5,360	4,947	4,663	24,062	14,936	15,222	14,970
Battery	134	134	134	40	24	88	135	105	125	133	109	210	401	152	365	452
Biomass/BioFuel	19	19	19	595	595	595	595	595	595	595	595	595	58	1,785	1,785	1,785
CHP	-	-	-	-	-	-	-	-	-				-	-	-	-
Diesel	628	627	627	426	421	423	424	427	432	432	435	432	1,882	1,270	1,283	1,299
Gas	1,690	1,691	1,691	910	831	773	1,023	1,034	984	948	922	940	5,073	2,514	3,041	2,810
Load Reduction	70	70	70	54	55	52	69	87	101	100	86	86	210	161	257	272
OCGT	2,001	2,003	2,003	1,497	1,762	1,485	1,535	1,562	1,578	1,875	1,830	1,430	6,008	4,744	4,675	5,135
Pump Storage	2,516	2,519	2,519	100	-	-	-	-	-				7,554	100	-	-
Coal	-	-	-	-	-	-	-	-	-				-	-	-	-
CCGT	465	466	466	1,416	1,417	1,227	1,228	1,219	1,219	1,277	970	970	1,397	4,060	3,666	3,217
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	490	490	490	-	-	150	-	-	150	-	-	-	1,470	150	150	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	3	3	3	-	-	-	-	-	-	-	-	-	9	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Frequency Response

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Q1	Q2	Q3	Q4
Total	15,161	15,436	15,203	15,501	15,324	15,467	15,451	15,673	14,057	14,173	14,195	14,454	45,800	46,292	45,181	42,822
Battery	2,596	2,767	2,695	3,017	2,820	2,956	2,960	3,162	3,254	3,368	3,390	3,298	8,058	8,793	9,376	10,056
Biomass/BioFuel	957	937	837	837	837	837	817	837	837	837	837	837	2,731	2,511	2,491	2,511
CHP	-	-	-	-	-	-	-	-	-				-	-	-	-
Diesel	112	112	56	36	56	56	56	56	54	56	56	56	280	148	166	168
Gas	-	-	-	-	-	-	-	-	-				-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-				-	-	-	-
OCGT	443	443	443	443	443	443	443	443	362	362	362	362	1,329	1,329	1,248	1,086
Pump Storage	728	728	728	728	728	728	728	728	728	728	728	728	2,184	2,184	2,184	2,184
Coal	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	650	650	650	650	5,346	5,346	4,214	1,950
CCGT	6,024	6,148	6,148	6,148	6,148	6,155	6,155	6,155	5,662	5,662	5,662	5,662	18,320	18,451	17,972	16,986
Nuclear	92	92	92	92	92	92	92	92	92	92	92	92	276	276	276	276
Non-PS Hydro	70	70	70	70	70	70	70	70	70	70	70	70	210	210	210	210
Wind	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,694	7,029	7,029	7,029	7,380
Multiple Fuel Type	14	14	9	5	5	5	5	5	5	5	5	5	37	15	15	15
Interconnector	-	-	-	-	-	-	-	-	-				-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-				-	-	-	-

Constraints

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Q1	Q2	Q3	Q4
Total	2,300	3,605	1,795	-	-	-	-	-	200	200	200	200	7,700	-	200	600
Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass/BioFuel	595	595	595	-	-	-	-	-	-	-	-	-	1,785	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pump Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	1,705	3,010	1,200	-	-	-	-	-	200	200	200	200	5,915	-	200	600
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Reactive

MVARs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Q1	Q2	Q3	Q4
Total	19,921	19,921	19,921	16,174	16,174	16,174	15,702	15,839	15,747	15,702	15,702	15,702	59,763	48,522	47,288	47,106
Battery	32	32	32	16	16	16	49	65	49	49	49	49	96	48	163	147
Biomass / BioFuel	-	-	-	-	-	-	-	-	-				-	-	-	-
CHP	-	-	-	-	-	-	-	-	-				-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-				-	-	-	-
Gas	-	-	-	-	-	-	-	-	-				-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-				-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-				-	-	-	-
Pump Storage	235	235	235	235	235	235	235	235	235	235	235	235	705	705	705	705
Coal	-	-	-	-	-	-	-	-	-				-	-	-	-
CCGT	11,021	11,021	11,021	9,579	9,579	9,579	8,832	8,832	8,832	8,832	8,832	8,832	33,063	28,737	26,496	26,496
Nuclear	-	-	-	-	-	-	-	-	-				-	-	-	-
Non-PS Hydro	93	93	93	72	72	72	72	72	72	72	72	72	279	216	216	216
Wind	4,573	4,573	4,573	2,813	2,813	2,813	3,055	3,176	3,100	3,055	3,055	3,055	13,719	8,439	9,331	9,165
Multiple Fuel Type	-	-	-	-	-	-	-	-	-				-	-	-	-
Interconnector	3,767	3,767	3,767	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	11,301	9,777	9,777	9,777
Shunt Reactor	200	200	200	200	200	200	200	200	200	200	200	200	600	600	600	600

Supporting information

The commentary below is similar to previous reports as the diversity of providers that provide balancing services didn't change significantly through BP1 and is not expected to change much in BP2 unless otherwise stated.

Frequency Response

Frequency services are delivered by providers who have a Mandatory Services Agreement (MSA) or who are awarded contracts through a competitive tendering process (which includes the daily auctions). Mandatory Frequency Response is primarily provided by providers with MSA registered transmission connected Units. For frequency response procured through competitive tendering the unit base is a mix of BM and Non-BM, primarily distribution connected, however we are starting to also see transmission connected storage assets that are providing frequency services. There is a continued growth in MWs from batteries providing tendered frequency services, with this asset type now making up the vast majority of the MWs provided by frequency services procured through competitive tendering. Static FRR has seen the generation mix diversify further since moving to day-ahead procurement with increased DER, Domestic and Battery assets now regularly participating in the service

Reserve

Procurement volumes and technology mix in Q4 remain consistent with historical STOR data however- Within the quarter, STOR had its first multiple Electric Vehicle charging Unit submitted for availability, winning several contracts in the later stages of the quarter. Achieving a milestone for technology agnostic approach for a legacy service.

Reactive

The reactive power service is delivered primarily by providers who have Mandatory Service Agreements and are typically connected to the Transmission Network. These providers would also be in the BM. The launch of the Voltage Pathfinders (now called Network Services Procurement – NSP) has seen the delivery of a new shunt reactor service that went live in Q1 2022-23 which has further diversified the type of providers. In January 2022 we also awarded contracts to meet reactive needs from an offshore windfarm in the Pennines region due to commence in 2025-26.

Constraints

Constraint costs occur when we pay generators to constrain their output due to network capacity limitations and typically for them to increase or decrease MWs on the system. Historically, this service has been limited to the providers that are connected to the transmission network and by requiring providers to change their MW generation levels. The Constraint Management Pathfinder reduces the actions required by the ENCC to manage the constraint across the B6 and EC5 boundary.

RRE 2D EMR Demand Forecasting Accuracy

April 2023 – March 2024 Performance

This Regularly Reported Evidence (RRE) measures the accuracy of the ESO's peak national demand forecast. This forecasting is done as part of the ESO's role as Electricity Market Reform (EMR) Delivery Body (DB). We aim to optimise the volume of capacity procured in the Capacity Market during RIIO-2 through more accurate forecasts of peak demand, which are used by the Secretary of State to determine the volume of capacity to procure.

The RRE measures the absolute percentage difference between our forecast and outturn of peak National Demand [17]. For outturn peak National Demand, we used Peak Average Cold Spell (ACS) i.e., peak weather corrected National Demand, as this is the most effective measurable proxy. This percentage gives a value greater than, or equal to, zero, and indicates how accurate the peak demand forecasts are. The closer to zero the percentage, the more accurate the forecast.

Over forecasting leads to unnecessary capacity being procured, which increases the cost to consumers. Under forecasting leads to either more capacity needing to be procured later (potentially at a greater cost) or risks security of supply.

All forecasts that outturn post 1 April 2023 will be assessed against this measure.

For 2023-24, the accuracy of two forecasts will be measured as follows:

- The T-1 forecast made in 2022-23, for delivery in 2023-24
- The T-4 forecast made in 2019-20, for delivery in 2023-24

Forecast accuracy is the absolute difference between forecast ACS Peak National Demand and outturn ACS Peak National Demand, given as a percentage of the outturn ACS Peak National Demand.

Table: One-year view of peak demand forecast accuracy

Auction	Forecast made in	Delivery Year	Forecast	Actual	Forecast accuracy	Status
T-1	2022-23	2023-24	45.2 GW	43.4 GW	4.1%	●
T-4	2019-20	2023-24	43.0 GW	43.4 GW	0.9%	●

Performance benchmarks (2023-24)	T-1	T-4
● **Exceeding expectations**	<2%	<4%
● **Meeting expectations**	2%	4%
● **Below expectations**	>2%	>4%

[17] National Demand as defined in the Grid Code

Supporting information

2023-24 performance

- Our 2019-20 peak demand forecast accuracy for T-4 exceeded expectations
- Our 2022-23 peak demand forecast accuracy for T-1 is below expectations

Our long-term demand forecasting analysis feeds into a range of processes, including the Future Energy Scenarios (FES) and the Electricity Ten Year Statement (ETYS), as well as Electricity Market Reform (EMR).

Since 2018-19 (the first year of making forecasts included in this report), we have pursued a number of initiatives which have led to improvements in our long-term demand forecasting process.

These have included increasing the quality and quantity of our stakeholder engagement, continuously improving the quality of input data available for demand forecasting, and employing cutting-edge techniques in the analysis of large data sets to identify uncertainty and degrees of correlation between historic drivers of demand. With the continued roll out of the latest analytical tools, more data and insight is accessible to the wider team earlier in the process, allowing for a more critical analysis of the factors that will shape our demands. The incremental reduction of forecasting error is a testament to this work. Further detail on these improvements is provided in the table below.

However, our forecasting processes are not without some vulnerabilities. We retrospectively review our core baseline data (which is provided externally) early in the forecasting process. Typically, historic changes are rare, so we are not immediately aware of the cascading effect of these changes until modelling activities are further advanced. The projection of peak demands is sensitive to the accuracy of the most recent historic supply and demand data used in our forecast. As such, small changes in recent historic data (for example, historic revisions in sector demand of Energy Trends 5.5 between 2022 and 2023 datasets) did disproportionately affect the earlier years of our forecasting. This is particularity evident in the 2022-23 T-1 peak demand forecast. Additionally, weather methodologies used to normalise electricity demands to average weather conditions continue to be a known vulnerability.

Improvement / vulnerability	Category	Description
Improvement	**Stakeholder engagement**	• Stakeholder engagement happened earlier in the process, allowing more time for the team to act on the feedback and insights gained before starting the modelling • We held a stakeholder event much earlier in the FES process, called “Topic Table Talks”, which enabled a more diverse range of stakeholders to discuss pertinent topics with the ESO’s analysts • We met with approximately 50 new organisations for our FES 2024 bilateral engagement, compared to FES 2023

Improvement	**Input data quality**	• We used a wider range of data providers to estimate load factors for distributed generation and behind-the-meter generation • Our improved stakeholder engagement provided better insight to inform our assumptions about the uptake of new technology such as district heat, engagement in industrial DSR and viability of hydrogen • We have continued to keep abreast of new industry developments, for example the electrification of oil and gas platforms resulting from the North Sea Transition Deal recommendations, allowing us to add new datasets for future years • We have added new subject matter knowledge to our team, leading to improved modelling of distributed generation and demand side response.
Improvement	**Analytical tools**	• We have rolled out new models for Lighting and Appliances, which are capable of analysing and processing much larger product-based data sets • We are working on a suite of other model improvements, which will allow our analysts to focus their time on more value-added activities, as well as forming part of the ESO's overall digitalisation strategy • We have rolled out the use of the PowerBI tool across the team, allowing us to have more frequent, targeted and clear conversations with our stakeholders to test assumptions and outputs for constituent components of demand before overall peak demand is finalised • We have carried out more in-depth correlation analysis between economic factors such as GVA/GDP and energy demand in energy intensive industries. We found a reducing level of correlation between these two factors, and as such have begun a revision of our modelling methodology to incorporate additional drivers of energy demand. • In line with feedback from the Panel of Technical Experts, we have made continued improvements to our stochastic modelling in order to better understand uncertainties in our forecasting • We have continued our ongoing improvement activities to reduce risks of errors through the deployment of cloud technologies for storing, accessing, and managing data.
Vulnerability	**Historical data**	• There is a risk that normalising demand for an average year may hide subtle changes and nuances in demand as a result of the development of new behaviours for newly deployed technologies, such as those that move heating demand from gas to electricity. • Peak forecasting is an estimation based on the analysis of multiple sector-based historical data sets. These represent the most known state of demand in any given sector, but perfect knowledge of historic demand is not possible.

	• Historical revisions in externally-provided data sets will change the scale and trajectory of demand, especially in the first 5 years of the forecast. • Updates to underlying sector demand used in both FES23 and FES24 for the historic year 2021, had a knock-on effect in the estimation of peak demand for these sectors. This led to the 2023 underlying demand forecast being revised downward by ~0.6GW. • The removal of Triads left a lot of uncertainty as to what level of peak shaving should be expected in subsequent years. Levels of peak shaving were greater than anticipated, showing a ~1.4GW decrease in transmission system peak in FES24 T-1.

RRE 2E Accuracy of Forecasts for Charge Setting – TNUoS and BSUoS

April 2023 – March 2024 Performance

This Regularly Reported Evidence (RRE) shows the accuracy of Transmission Network Use of System (TNUoS) and Balancing Services Use of System (BSUoS) forecasts used to set industry charges against the actual outturn charges.

1. Accuracy of forecasts for charge setting - TNUoS (reported annually)

The TNUoS tariff setting methodology describes how much of the total required revenue should be collected from Suppliers and Generators, which requires a wide range of tariffs to be calculated. These tariffs aim to reflect the costs of how, when and where Suppliers and Generators use the transmission system. Final TNUoS tariffs are set by 31 January for the next charging year commencing 1 April, and out-turn revenue is known by the end of April following the charging year.

Customer type	Liable for	Detail
Suppliers	TNUoS Demand charges	The Non Half-Hourly (NHH) demand tariff is charged for consumption between 4pm-7pm for every day of the charging year, and the Half-Hourly (HH) demand tariffs are applied to import or export over Triads (the three periods of highest net GB system demand). The TDR demand charges is based on site counts or unmetered supply volume per day as provided by the DNOs (except for TRN1 to TRN4 bands which are determined by the ESO).
Generators	TNUoS Generation charges	All Generators are liable for the Wider TNUoS Generation tariff. They may also be required to pay onshore local circuit and onshore local substations tariffs depending on where they connect to the transmission system. Offshore local tariffs are also created following asset transfer of the offshore transmission system, which are then charged to offshore generators.

The charging bases used to calculate TNUoS tariffs are the inputs that can be responsible for significant variance between budget and actual TNUoS revenue. The TDR demand tariffs require an assumed demand charging base for each of the 22 charging bands. The locational demand tariffs require an assumed demand charging base for each of the 14 demand zones and for each type of demand (NHH, HH gross demand and HH embedded export). The generation charging base is the best view of the amount of Transmission Entry Capacity (TEC) contracted by Generators for the charging year.

Table: Forecast vs. outturn TNUoS Performance

TNUoS Charging	Forecast £m	Actual £m	Variance £m	Variance %
NHH Demand	65	61	-4	-5.8%
HH Demand	19	14	-5	-25.1%
TDR Demand	3,388	3,368	-20	-0.6%
Generation	944	885	-59	-6.2%
TOTAL	**4,416**	**4,328**	**-88**	-2.0%

For each charge type, the **Forecast** is what we aim to collect for each tariff and **Actual** is how much we collected.

Actuals are based on the final available settlement metering.

Figures rounded to the nearest £m, therefore totals may differ slightly from the sum of the four components.

Supporting information

Several events can impact out-turn TNUoS revenue once TNUoS tariffs have been set 14 months earlier. For 2022-23, the most obvious recent impact on TNUoS demand has been the continuing impact of the war in Ukraine which has resulted in lower overall demand due to pressure on energy prices. A mild winter has continued the reduction. Generation revenue may be impacted by unforeseen delays to stations connecting to the transmission system or delays in the transfer of an offshore transmission system.

TNUoS charge	Explanation of variance
TDR Demand	This is the first year of TDR demand and we have seen a considerably large amount of data refinement from customers and DNOs with large drops in site count data within the first 6 months. This reduction has largely been the removal of non-final demand and de-energised sites as customers have queried data with their DNOs. A charging base of 11.7bn site count days was assumed at tariff setting compared to 11.65bn site count days outturn (-0.75%) with revenue down £20m at outturn (-0.6%). Of note there has been a large decrease in the high value EHV4 band (£-28m) as customers have sought to have them re-banded by DNOs. LV4 also experienced an increase (+£19m). This correction of data prompted by suppliers was not anticipated whilst setting the tariffs. It is expected based on the prior 6 months that TDR site counts are now stabilising.
NHH Demand	A charging base of 24.23TWh was assumed at tariff setting for 2023-24, in line with the 24.96TWh 2022-23 charging base. Actual 2023-24 out-turn NHH demand is 9.1% lower at 22.7TWh, likely due to a mild winter combined with the cost-of-living crisis affecting domestic usage.
HH Demand	**HH Gross Demand:** A 2023-24 charging base of 18.46GW was assumed at tariff setting. This compares with actual out-turn at 18.54GW, a 0.4% increase on expectations, resulting in revenue from the HH Gross Demand tariff of £38.72m (0.64% over budget). It is expected that the distribution of actual demand by location varies slightly to our assumptions at tariff setting. **HH Embedded Export** A charging base of 7.63GW was assumed at tariff setting, which compares with actual out-turn at 7.69GW (0.9% above expectation). The level of embedded exports is not necessarily driven by demand and therefore not impacted by events such as Covid-19, rather it is influenced by a range of other factors including wind availability. Out-turn credits paid for 2023-24 exports (£24.5m) were 26% higher than budget at tariff setting (£19.4m).
Generation	The amount of Transmission Entry Capacity (TEC) assumed at 2023-24 tariff setting was 75.8GW compared to actual TEC invoiced of 72.5GW. The delay of asset transfer for several offshore transmission systems means that offshore tariffs could not be introduced and charged to offshore Generators as early as anticipated when Final tariffs were set leading to a reduction of £52m. Combined with a lower than expected number of new connections, this means that in 2023-24 overall TNUoS Generation revenue is 6.2% less than budget (compared to 4.8% less than budget for 2022-23).

2. Accuracy of forecasts for charge setting - BSUoS (reported monthly)

April 2023 – March 2024 Performance

This Regularly Reported Evidence (RRE) shows the accuracy of Balancing Services Use of System (BSUoS) forecasts used to set industry charges against the actual outturn charges.

The BSUoS charge (£/MWh) is now based upon a fixed tariff that was published in January 2023. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) were forecast for the year ahead, and two 6-month tariffs were set to cover the 2023-24 charging year.

We continue to forecast balancing costs monthly and measure our performance against this forecast as it remains an important metric to support the fixed tariff methodology, by being the main component of the fixed BSUoS tariff. The BSUoS cost forecast (costs rather than what is charged against the fixed tariff) is probabilistic and therefore produces percentile values. The published forecast for each month is based on the central value of the BSUoS cost forecast (50th percentile). If the outturn BSUoS costs are below the 50th percentile of the cost forecast, then the actual costs for that month would be lower than the forecast predicted, provided the actual volume is at or above the estimate (and vice versa).

March 2023-24 performance

Figure: 2023-24 Monthly BSUoS forecasting performance (Absolute Percentage Error)

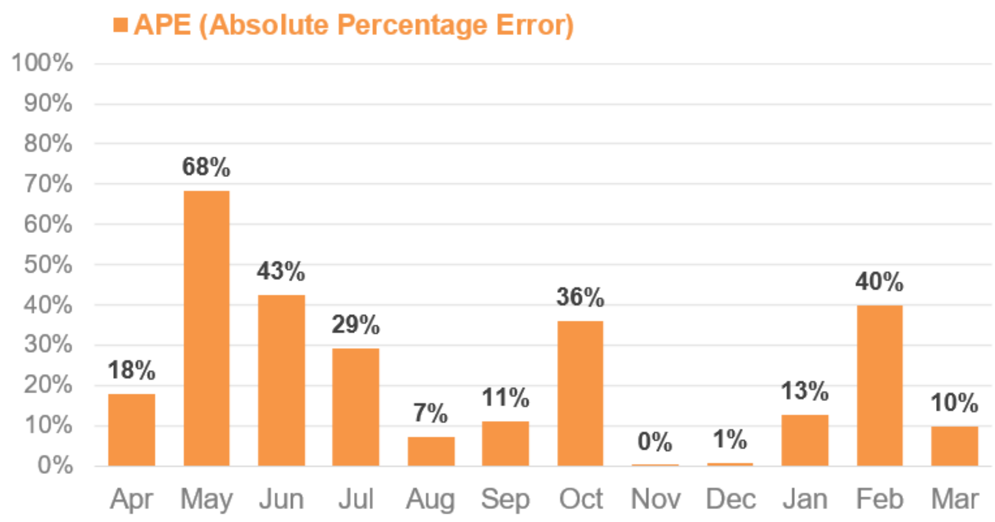


Table: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	10.8	8.2	7.5	13.7	10.4	12.8	16.5	10.5	10.6	8.9	11.9	9.6
Month-ahead forecast (£ / MWh)	12.7	13.8	10.8	9.7	9.7	11.4	10.6	10.5	10.6	10.0	8.5	10.5
APE (Absolute Percentage Error)[18]	**18.0**	**68.4**	**42.5**	**29.1**	**7.2**	**11.0**	**36.0**	**0.0**	**0.7**	**12.7**	**39.9**	**9.8**

[18] Monthly APE% figures may change with updated settlements data at the end of each month. Therefore, subsequent settlement runs may impact the end of year outturn.

Supporting information

Overall performance:

The 2023-24 charging year is the first year that BSUoS has been based on a six-monthly fixed tariff. Tariffs are set 9 months in advance of the tariff period, however we continue to monitor our monthly BSUoS forecast performance as this supports fixed BSUoS methodology.

Two key drivers of our BSUoS forecasting are wholesale electricity prices and the renewable proportion of demand met by renewable generation. Therefore, although our average monthly APE has decreased since last year (22% vs 34%), changes in these drivers can result in higher percentage errors.

This is most clearly seen in May, which saw a 30% decrease in wholesale energy prices between our forecast at the beginning of March, and May outturn and June, which saw a 28% decrease in the proportion of demand met by renewables between our forecast at the beginning of May and June outturn.

2023-24 is also the first charging year where BSUoS has been charged on final demand only. Therefore, improvements have been made in our forecasting methodology of BSUoS volume. The BSUoS chargeable volume was forecast using a simple linear regression using the ESO national demand data as the explanatory variable. Once sufficient data was available, we have updated the methodology used to estimate the linear regression by using actual BSUoS settlement data.

In late 2023, an innovation project was concluded, which had set out to investigate whether Machine Learning techniques could be employed to improve our forecast of balancing costs. Of all the variables tested, the ones with the best predictive power for forecasting the components of balancing costs were found to be the ones used within our forecasting model; renewable generation as a proportion of demand and wholesale electricity prices. However, it was found an alternative modelling package provided a theoretical improvement in accuracy compared to the existing model, and therefore this will be taken forward within the 2024-25 charging year.

March Performance:

Actuals out-turned below forecast for March, with an absolute percentage error of 9.8.

March costs:

March costs were around the 40th percentile of the forecast produced at the beginning of February. There was an 8% decrease in the average wholesale electricity price between the February forecast for March (£66/MWh) and March outturn (£61/MWh). Constraint costs also decreased by 5% between the February forecast for March and March outturn.

March volumes:

March actual volume was above the February forecast. This small variance could be due to weather and temperature fluctuations.

Forecast for March made at the start of February: 23.8TWh

Outturn volume for March: 24.3TWh

Role 3
System insight, planning and network development

ESO

C.1 Plan Delivery for Role 3

Deliverable progress

For Role 3, the RIIO-2 Delivery Schedule received an ambition grading of 4/5, providing us with an ex-ante expectation of Ofgem's assessment of plan delivery if these deliverables are met. The ESORI guidance states that the "Performance Panel should consider that the ESO has outperformed the Plan Delivery criterion if the ESO has successfully delivered the key components of a 4- or 5-graded delivery schedule".

See below an overview of key plan delivery topics for Role 3 over the first 12 months of the Business Plan 2 period:

Connections

Summary

The connections landscape has changed significantly over the last year. At the time of writing, the queue to connect to the transmission system stands at over 530 GW. This is more than double the size of the queue a year ago. If it continues to grow at the current rate, it could reach over 800 GW by the end of 2024 – over four times what is needed to meet the 2050 targets. This means that recent connection applications are joining the end of a long queue, triggering significant transmission reinforcements. Therefore, applicants are receiving much later connection dates than we or they would wish (now into the late 2030s for new applications).

The work we are undertaking through our Five Point Plan and wider work with Distribution Network Operators (DNOs) is beginning to yield results for projects due to connect before 2030. This offers potentially accelerated connection dates for up to 40 GW of storage and embedded projects. A further c.40 GW of other viable generation projects are estimated to receive accelerated connection dates by Autumn 2024.

The size of the queue and latency of seeing initiatives deliver positive outcomes to connections dates means further action is required. The scale of the challenge and need for cross-industry reform beyond what we deliver alone has been recognised by Ofgem and DESNZ. This led to the publication of the Ofgem/DESNZ Connections Action Plan (CAP) in November 2023 and the establishment of the Connections Delivery Board (CDB) in December 2023. Ofgem chaired the CDB with representation from network companies and a cross-section of customers to bring industry and government policymakers together. We have played a strong leadership role at the CDB. We recently suggested a range of recommendations to go further and faster on more fundamental reforms to the connections process that will take effect from January 2025.

We recognise this period of substantial change has been challenging for our customers. In addition to changing and improving our processes, we are committed to improving the service that customers receive from us.

Below we provide further information on the range of initiatives we have progressed within the first year of BP2 to address challenges and deliver better outcomes for customers and consumers.

Facilitating development of the customer connections portal

In the ever-changing and fast-paced world of connections, the efficiency of processing applications plays a vital role in our success. The traditional manual process of stakeholders applying for a connection to the transmission network in Great Britain was historically arduous and time consuming. It was generally an unpleasant experience for both customers applying to the ESO and for our staff attempting to process customer applications. This process is now a completely different experience for our customers and internal users. The user experience has been significantly improved, evidenced by the feedback we have received from customers.

The Connections Portal has been live for almost 12 months and has processed approximately 2,500 pre-applications and licenced applications combined. Previously this would have been unimaginable. With use of a backend Customer Relationship Management (CRM) system, the Connections Portal allows customers to apply for their connection in a timely manner with an intuitive application process and user interface. The CRM includes the technical details of the assets they wish to connect to on the transmission network. It also facilitates the selection of the specific connection site customers wish to connect to. The Connections Portal allows customers to view and manage their connection projects once they have moved past the application stage. This enables customers to submit any necessary modification applications. More importantly, it permits customers to view, respond to and manage their queue management milestones following the recent introduction of CMP 376 (Queue Management). An upcoming development of the Connections Portal will enable customers to provide details like a Letter of Authority for land.

Development of the Connections Portal has been customer focused, responsive and fast-paced. The queue management feature is just one of many functionalities added to increase the quality of the overall user experience. Development has included functionalities such as supporting the two-step offer process, managing agreement to vary offers and enabling DNOs to manage modification notices (all within the Connections Portal). The next feature for development and deployment to the Connections Portal is Consultant Access. This functionality will allow consultants and developer companies alike to manage who has access to their application and project data. It is designed to ensure that developer companies can manage their third-party consultants with greater ease and flexibility. Consultant users will also benefit from the improved interface and useability upgrades.

The Connections Portal has improved transparency between industry customers and us through the query management functionality with 1,232 queries submitted to date. Whilst this is a high volume of queries, the average query closure time is just four days. This is quicker than the service level agreement that we generally work to for customer queries. The Connections Portal has helped improve relationships between industry customers and us. We regularly undertake stakeholder sessions in the build up to (and shortly after) large functionality releases. The sessions enable us to consult customers on changes, requests to be heard and functionality demonstrations to be given. The success of these sessions has culminated in an overall average Connections Portal feedback score of four out of five. We consider this a significant achievement considering the infancy of the platform and the ever-changing nature of the industry.

Overall, the Connections Portal has been a resounding success. The connections process has moved into the digital world and is now more accessible to those wishing to connect. This is clearly evidenced by the 862 currently active users of the platform. The Connections Portal will continue to develop to the needs of the industry including in relation to connections reform. We will continually strive to deliver improvements to best serve those wishing to connect to the electricity transmission network.

Improvements to the connections process

Ofgem noted in their End of BP1 Decision on ESO Performance that our performance on connections had fallen short of expectations. There was a view that we should have been more proactive in addressing emerging (at the time) issues related to connections. Separately, there were several key areas where further improvements were deemed necessary as follows:

- A concise summary was requested to outline the expected outcomes and delivery timelines of the Five Point Plan.
- Thorough consideration of battery energy storage assets and distribution customers was advised to ensure impactful solutions were devised by the ESO.
- To see increased engagement with stakeholders to gain insights into their experiences with the connection application process.

We have taken this feedback on board and taken positive action in our BP2 performance for year one. We will consider this and other future stakeholder feedback as we continue to listen and act in year two of BP2. We believe we have met or surpassed the expectations outlined in our original ESO RIIO-2 Business Plan and delivery milestones, published in August 2022. This is aside from the one exception which we expanded upon earlier regarding the two-step process. Because of our performance to date, we have recently agreed on new and challenging proposed BP2 milestones. This is because we met and exceeded our milestones and expectations, and incorporated feedback from the industry and customers.

The following summarises what we have done over the past 12 months and our planned delivery for the next 12 months. Full details are provided in the BP2 RIIO-2 deliverable tracker, broken down by deliverable area and milestones per quarter, as revised due to our outperformance in some areas. Our activities can be broadly categorised into two categories. Shorter-term tactical actions are to improve the connections process and its outcomes where possible. This includes working within the existing industry frameworks via our Five-Point Plan and working with the Electricity Network Association (ENA) on its three-point plan. Medium to longer-term reforms are aimed to fundamentally redesign industry frameworks, via our connections reform project.

Five Point Plan

The Five Point Plan was launched in February 2023. Some areas of our Five Point Plan have encountered challenges. Overall, we have delivered more tactical changes and positive outputs under this plan than anticipated.

The impacts of the implementation of the Five Point Plan have been estimated to bring circa 150 GWs of benefits in the future. These benefits will be delivered because of:

- A combination of accelerated non-firm offers for storage projects.
- Accelerated firm agreements through the adoption of the revised modelling assumptions.
- Removal of stalled projects as part of the new queue management approach.
- Removal of projects from the queue as part of the Transmission Entry Capacity (TEC) amnesty project.

We continue to deliver on the Five Point Plan initiatives, and we provide an update on each of these areas as follows.

Queue Management

In November 2023 Ofgem approved code modification CMP376 to implement the queue management process into the Connection and Use of System Code. This includes the introduction of a right for the ESO to terminate contracted projects which are not progressing against agreed milestones. This decision was welcomed by us and industry as a whole to remove projects that are not progressing and in turn reduce the size of the queue.

The CAP estimated that this ESO-led initiative will result in 80 GW of capacity removal from the queue where projects fail in line with agreed milestones.

In the coming months, we will share the outcome of the CMP376 six month notice to industry. This will illustrate the number of projects seeking to delay connection dates. It will also demonstrate the number of projects which agree to have milestones added to their contract based on their existing connection date. We will also be able to quantify the initial impact of CMP376 implementation.

Accelerated Storage

Working with National Grid Electricity Transmission (NGET), the first batch of non-firm storage connection offers have been made to battery projects within England and Wales. The first tranche of offers covers 10 GW of capacity, spread across 21 different projects. We will look to build on this through the release of subsequent tranches of offers, currently estimated as another 10 GW. We are also working with the Scottish Transmission Owners (TOs) to introduce non-firm storage connection offers in Scotland. We expect customers to start to receive these offers from July 2024 onwards.

TEC Amnesty, Construction Planning Assumptions (CPAs) and Transmission Works Review

Following the TEC Amnesty project, 4.1 GW of projects were removed from the transmission queue. This project allowed customer projects that were not progressing to leave the queue without incurring cancellation charges. It also enabled us to remove stalled projects quicker.

By revising our CPAs to reflect the attrition rates that only 30-40% of projects that are contracted go on to connect, up to 46 GW of projects could benefit from an accelerated connection date. The wider Transmission Works Review will continue to see if works can be removed from contracts and therefore in turn have developer securities reduced. The revised CPAs fed into the two-step offer process.

However, as we mentioned with respect to the two-step offer process, this is the one area within our deliverables/milestones where performance fell below expectations, albeit for justifiable and explainable reasons. We set out further information as follows:

Two-Step Offer Process

From March 2023 all applicants to join the transmission system in England and Wales followed a new two-step process. The objective of this was to reduce uncertainty and provide better connection dates for customers when they were receiving their second step offer. However, during this time, the connections queue grew at a fast pace, as described in the summary section. This ongoing increase in projects meant over 150 GW of new connections spread over 500 contracts which was double the original estimate for the two-step process. As a result, it was clear the original objectives were not met. Around 60% of customers were given a later connection date.

We recognised this would not be acceptable to our customers. Therefore, we worked with NGET on a different assessment methodology. The new methodology considered wider system enabling works to align with the outcome of the Transitional Centralised Strategic Network Plan.

This change to our original offer process aimed to improve second step customer connection dates overall. 60% of customers received a better or aligned date to their first step offer and (currently to date). 40% will receive a date beyond their first step offer and we are continuing to work on improving this with stakeholders. To improve on this, we started sending second step offer letters out in February 2024, with the commitment all second step offers would be issued by the end of May 2024.

We acknowledge this aspect of the Five Point Plan faced challenges, and consequently we have needed to change our approach. We considered the needs of our customers and took bold and decisive action to mitigate the impacts of the underlying causes of the challenges. In addition, we ensured that there was clear and timely communication with impacted stakeholders.

Energy Networks Association (ENA) Three-Step Plan

In addition to the above, we are working closely with the ENA, helping to accelerate connections for distributed connected customers. In April 2023, the ENA published a three-step plan to support customers connecting to the distribution network:

- Reforming the distribution network connections queue, promoting mature projects that are closer to delivery above those that may be ‘blocking’ the queue.
- Changing how transmission and distribution networks coordinate connections, improving their interactivity.
- Greater flexibility for storage customers through new contractual options.

This work complements what we are doing at the transmission level. The work has had significant success speeding up customers connecting to the distribution networks. For example, we have been working closely with the TOs and DNOs to manage connections in operational timescales within agreed technical limits at each grid supply point. This is being rolled out with a phased approach across Great Britain. The first tranche brings forward the connection offer dates for potentially over 30 GW of distributed projects. This is across ~72 Grid Supply Points (GSPs), accelerating ~800 projects by an average of ~6 years. The first of these projects energised on 12 March 2024 demonstrates the success of this initiative.

We are currently working on the next phase, due to complete later this year. This accelerates a further 80 GSPs and we have an aspiration to roll out to the whole of Great Britain.

Connections Reform

We have taken on board feedback advocating for proactivity and accelerated pace. For example, we successfully completed Phase 2 of our Connections Reform Project well ahead of schedule. We advanced the completion date of this phase from July 2024 to December 2023, with the publication of our Final Recommendations Report. In April 2024 we also published our intention to go further and faster on our reform proposals. In addition, we submitted associated code modification proposals to allow ‘go live’ of a fundamentally reformed process leading to a significantly reduced and reordered connections queue, from January 2025. Subject to Ofgem agreement of our code modification proposals, we are therefore on track to implement the reformed connections process in January 2025. This is sooner than the anticipated completion date of September 2026, as was originally foreseen within our RIIO-2 BP2 Business Plan.

We achieved this enhanced delivery through substantive stakeholder engagement to inform our views. Extensive collaboration and well-planned engagement took place with our stakeholders via a design workstream and newly created external governance groups. The stakeholder feedback culminated in a formal consultation on our initial recommendations in Spring 2023.

Over 100 organisations (many of which attended our design workstream workshops to identify and challenge potential reform options) dedicated considerable time to help us shape our proposals. We now have over 1000 subscribers to our distribution list following this stakeholder engagement. We also received circa 80 formal responses to our consultation.

Within our Final Recommendations Report in December 2023, we set out how and where we had addressed stakeholder feedback. We also provided a more detailed question-by-question summary of responses within an Annex. Most stakeholders agreed the options presented in our consultation were a reasonable range of reform options, showing the success of the earlier industry engagement. Furthermore, there was majority industry support for our key initial recommendations.

As a noteworthy milestone, in March 2024 Ofgem formally approved the first of our major reform recommendations to introduce a Letter of Authority entry requirement for new applications. As requested by the CAP, we raised a code modification to enact this change in December 2023 under an urgent process. This was undertaken considerably faster than average timescales.

The reformed connections process us and industry have designed and recommended directly targets issues we both share regarding connections. The benefits of the reformed process will include:

- Significantly reducing the time to connect by moving to a first ready first connected approach, as well as via introduction of a range of other improvements (e.g., network modelling tools).
- Savings driven from co-ordinated development of the electricity transmission network, in alignment with Centralised Strategic Network Planning in a way which balances the needs of new connections and the need to deliver energy security in a net zero electricity system.
- Introducing efficiencies to the connections process, and better managing interfaces with other organisations and processes.

We are now in Phase 3 of the Connections Reform Project. We have a new external governance and engagement structure that is providing views from across the industry to shape the reformed process.

We have also been supporting and delivering on our range of CAP Actions in a robust and timely fashion. We will continue this over the coming months to ensure CAP milestones are met and we deliver better outcomes for customers and consumers. We consider that a successful outcome will be significant progress in 2025 towards the longer-term CAP goal of connection offer dates being within six months of the connection date requested by developers.

Regional Energy Strategic Planner (not in BP2 plan)

In November 2023, Ofgem gave NESO the role of delivery body for the new Regional Energy Strategic Planners (RESPs). The RESPs are being established following the recognition that delivering net-zero will involve accelerated decarbonisation and decentralisation of energy supply and demand as well as significant involvement of local communities. Effective regional energy planning, providing alignment across all energy vectors and with national plans, will be pivotal in this transformation.

We are building a new team to deliver the RESP role. It is therefore very early days for the setting up of the RESP capability within the ESO. Since November 2023 we have focussed on the following:

- Building relationships with key stakeholders.
- Getting involved with and supporting existing RESP related innovation projects.
- Setting up our own RESP innovation project.
- Starting to recruit a team that will lead the RESP development and implementation following Ofgem's RESP design process and consultation.
- Participating in Ofgem workshops and meetings on RESP policy design.

There were no deliverables expected from us for RESP in 2023-24.

Network Services Procurement

There are three BP2 milestones for Networks Services Procurement (previously called Pathfinders) all relating to the Constraint Management Intertrip Service.

We stated that by Q3 2023-24 we would run a tender in the EC5 region (East Anglia) and carry out a tender for year three of the B6 service (Anglo-Scottish boundary). There is a separate milestone for the go-live of the B6 year two service which has a completion date of Q3 2024-25.

The delivery of both milestones for Q3 2023-24 is delayed. For the EC5 service this is due to stakeholder feedback on allowing maximum participation from a range of possible solutions i.e.**,** DNO connected and offshore assets, to increase competition and achieve best value for consumers. The tender is now planned to take place from May 2024 and conclude in August 2024. However, the service will still commence from April 2025 which, despite the delay to carrying out the tender, remains the same start date for the service. Between August 2024 and April 2025, service providers along with NGET will connect the contracted generators to the intertripping scheme.

In the meantime, we delivered an interim tender to contract with parties that are already connected to the intertripping scheme to allow a service to be in place before April 2025. These contracts have been in place since February 2024 and will be replaced by the new contracts from April 2025. Additionally, we have instructed NGET to begin works on the scheme ahead of the tender concluding to minimise risk of any further delays.

For the B6 year 3 (Oct 2025 – Sept 2026) tender, in order to deliver best value for the consumer and ensure the next B6 tender is delivering in the right place at the right time, we took the decision to review the requirements against the tCSNP2 outcomes. This delayed us meeting the planned BP2 milestone. As an alternative, we have exercised the extension option under the year two contracts (Oct 2024 – Sept 2025) to ensure an intertrip service will remain in place until September 2026 whilst we consider our strategy for future intertrip tenders.

The go-live of the B6 year 2 service is on track to commence from Q3 2024-25.

In addition to the above milestones, we launched a tender for Voltage 2026 in December 2023 for the procurement of long-term reactive power capability in two regions in England – London and North England. This builds on previous voltage pathfinder tenders that have been carried out in the Mersey and Pennines regions and is an evolution of how ESO procure network services. At tender launch, the requirement set was 200 MVAr in each region, though following review of studies with NGET, the requirement in the North was increased to 400 MVAr enabling greater competition for our needs.

We also launched a tender in December 2023 for the new annual Stability Y-1 market which seeks to contract for inertia capability between 2025 and 2026. This is an evolution from the ad-hoc long-term tenders that have previously been carried out under the stability pathfinder projects, as we aim to provide greater clarity and certainty to the market on our approach to procuring stability services. Following tender launch, we informed the market in February 2024 with updated information on the target requirement ensuing additional analysis that we had carried out. This was to ensure that tenderers have a transparent view of what we aim to procure to inform the submission of their bids.

As part of the tender launches, we carried out webinars with industry to provide detailed information on certain aspects of the services such as technical requirements, contract terms, assessment methodology etc. These were well received with the Voltage Webinars scoring on average 4.3 out of 5 and the Stability Y-1 webinars averaging 3.5 out of 5.

Future Energy Scenarios (FES)

We published our Future Energy Scenarios with the launch event taking place across the week commencing 10 July 2023 at the Science Museum in London. Over 2,200 stakeholders joined us during the week across the live event and the deep dive webinars. We received a further 3,188 views of the launch stream, live or on catch-up. We shared key messages and key insights from our analysis, and webinars provided the next level of detail from the main report. We made changes to the website to make it easier for stakeholders to read and absorb the content. We have made several modelling enhancements in alignment with feedback we have been receiving from our stakeholders and the customers of FES.

Alongside the launch, we published our interactive regional maps, enabling stakeholders to explore the geographical differences in our 2023 scenarios.

In line with Ofgem decisions on the Centralised Strategic Network Plan (CSNP) consultation, we have developed a new framework for FES 2024. We tested the new framework with stakeholders at our dedicated framework workshop and Topic Table Talks event, to gain insight on their opinions.

We have implemented new capacity expansion and dispatch models for our electricity supply analysis.

For FES 2024 we have engaged with 2,627 stakeholders across all our events (including the 2023 launch) representing a total of 561 organisations across our nine stakeholder categories. We have gained valuable insight from the engagement which has provided input into our FES 2024 scenarios which will be published on 24 June 2024.

Offshore Coordination

In the past year we have completed the offshore ScotWind Holistic Network Design Follow Up Exercise (HNDFUE) which was an integral part of the '<u>Beyond 2030: A national blueprint for a decarbonised electricity system in Great Britain</u>' report published in March 2024. The report sets out the network requirements to facilitate Government targets and connection of a further 21 GW of offshore wind, on top of the Holistic Network Design (HND). The tCSNP2 (Transitional Centralised Strategic Network Plan 2) was published in March 2024.

We also made progress in facilitating the delivery of the transmission infrastructure recommended in the HND. To support the delivery of network in our recommended network designs, we have developed and implemented an impact assessment process. As part of the Detailed Network Design (DND) phase, developers, and TOs have identified changes to the original HND. Since we have implemented this process, we have completed two impact assessments for the HND. Since the publication of the tCSNP2, we have extended the process to incorporate HNDFUE developers.

In March 2023 the Crown Estate Scotland (CES) announced the winners of their Innovation Targeted Oil and Gas (INTOG) leasing round, providing exclusivity agreements to 13 developers. Through a change control request, six development sites have been included in our HNDFUE Terms of Reference (ToR). We have completed our Initial Strategic Options Appraisal process (ISOA) which has determined our six draft shortlisted designs. We will continue into our Final Strategic Options Appraisal Process to come to a recommended design in Summer 2024.

The HNDFUE is considering 3 X 1.5 GW Project Development Areas (PDAs) in the Celtic Sea. For the first time, will make a design recommendation ahead of The Crown Estate awarding the Round 5 seabed leases in 2025. We have refined 21 design options to a shortlist of seven designs. We shared these with our Celtic Sea Working Group, our newly formed Celtic Sea Community Working Group and interested developers at our in-person developer workshop in November 2023. We established the Celtic Sea Community Working Group to bring together interested council officers to advise on possible community impacts of proposed designs in the Celtic Sea to inform the community design appraisal. We are now conducting the final strategic options appraisal process to reach the recommended design ahead of The Crown Estate's invitation to tender in August 2024.

Throughout the BP2 period we have been engaging with developers across all our workstreams; ScotWind, Celtic Sea and INTOG. Our engagement to date has incorporated individual developer sessions, webinars and workshops hosted in both Glasgow and Bristol to ensure developers are kept up to date of project progress. For ScotWind there have been 13 project wide events and 120 individual developer discussions. We have also held many Central Design Group (CDG) sessions which is part of our Terms of Reference for the HNDFUE. Since April last year, we have held six sessions to gain insight and feedback from members including TOs, Ofgem, DESNZ, environmental, community and developer representation.

Network Competition

We originally set out to complete the implementation of Early Competition by Q4 2023-24. This is a joint activity with Ofgem, who own key parts of the process. Due to other priorities, Ofgem were unable to begin their elements until Q3 2023-24. Therefore, revised timeframes for the project were agreed with Ofgem and DESNZ. The target is now to launch the first competition by the end of 2024. This is on track to be achieved.

We have progressed our elements of the project, including submitting updated proposals to Ofgem by end September, as per agreed timeframes. We also responded to Ofgem's recent proposed changes to network planning processes, adapting the early competition model accordingly.

Alongside this we published a detailed stakeholder 'You Said, We Did' report, which documents the feedback received during our extensive stakeholder engagement, and our response to that feedback.

During Q3 and Q4 we have worked closely with Ofgem to support their deliverables and to ensure our own deliverables meet their needs. We have also established a joint governance forum with Ofgem and DESNZ, reflecting the joint nature of the project.

As per agreed timeframes, we have begun the process to identify the first projects for competition. Our Beyond 2030 publication includes a list of projects that meet the competition criteria. Stakeholder communications on this process are underway.

Zero Carbon Operations (ZCO) and Distributed Energy Resource (DER) visibility

Zero Carbon Operations

Over the last year we have made significant progress towards being able to operate a zero carbon system in 2025. In nine out of the twelve months of 2023-24, we operated a system with higher penetrations of zero carbon generation than the same month of the previous two recorded years. This was accomplished in a record-breaking year for zero carbon generation. The highest ever solar and wind power output was achieved, alongside the lowest fossil fuel generation and carbon intensity.

System operation was made possible in these conditions following the further delivery of our new response and reserve suite, reducing our need to run carbon-emitting generation. After sub-synchronous oscillations were experienced in Scotland, we delayed implementing the Frequency Risk and Control Report (FRCR) 2023 recommendation to reduce the minimum inertia requirement whilst we engaged with multiple industry parties to investigate the event. Implementation of FRCR 2023 was delayed further following the multiple generation losses and network trips on 22 December 2023. The benefits of our frequency strategy are evidenced in detail in our Role 1 case study on the events of 22 December 2023. We have now implemented stage one of the FRCR 2023 recommendation to reduce the minimum inertia requirement. This has generally removed the need to run three carbon emitting generators.

Elsewhere, we have set in motion ways to further reduce reliance on carbon-emitting generation by launching our mid-term stability market. This will enable us to access more inertia provision from zero carbon sources from October 2025. We have also engaged with TOs to prioritise and accelerate the return of reactive compensation assets and deliver new assets to reduce the need to run carbon emitting generation for voltage reasons.

We can now accommodate greater flows on the transmission network, reducing the need to constrain off zero carbon generation. We've done this through developing and expanding our Constraint Management Intertrip Service (see Network Services Procurement section) and launching the MW Dispatch platform under the Regional Development Programmes (see RDPs section).

ZCO BP2 milestones:

- The Operability Strategy Report was published on time accompanied by an industry webinar. The webinar was well received, with attendees scoring the content usefulness at four out of five, and 90% saying that they learnt something new. The report continues to be popular with over 500 downloads and the webinar recording watched nearly 100 times.
- We continue to support stakeholders in implementing new technology developments. Over the last year we have initiated a Constraints Collaboration Project. This is developing market solutions to constraints with industry, which can deliver short-term benefits. We have also been working with DESNZ and industry stakeholders to develop standards for electric vehicles and other energy smart appliances that will ensure they can provide flexibility to the electricity system whilst not creating excessive security risks.

DER Visibility

In June 2022, we published our Operational Visibility of DER paper explaining the potential consumer benefits of DER visibility, which we quantified as up to £150m per annum. This figure was expected to be an underestimate, with significant industry benefit in addition to this.

In September 2023, we launched a programme to drive delivery in ESO and with industry, the DER Visibility Programme. The programme will deliver an industry transformation covering ESO Business changes, ESO Data & Systems changes and Industry changes (DNOs, TOs, Market Participants, Market Platforms). We will lead the programme, which will require industry collaboration to be a success.

The Programme Delivery is planned in five phases as part of an indicative roadmap:

Phase	***Status***	***Phase and dates***	***Objective***
1	Complete	Vision & Strategy Roadmap (Aug-Dec 2023)	To define a whole-system Vision & Strategy Roadmap
2	In progress	Whole system roadmap and impact assessment (Initial period Jan-Apr 2024, extended to Sep 2024)	To secure industry buy-in to vision and strategic roadmap and understand whole-system impact (Business & Technology)
3	Not started	Design & Deliver Priority DER Visibility Use cases (Sep 24 to Mar 25)	To design and deliver the business and technology changes needed to deliver priority use cases associated with DER Visibility and begin to realise benefits
4	Not started	Achieving DER & CER visibility (Apr 25 – Dec 26)	To deliver business and technology changes needed to deliver all DER Visibility, priority Consumer Energy Resources (CER) visibility and priority DER & CER access use cases
5	Not started	Achieving DER & CER Access (Jan 27 – Dec 28)	To deliver business and technology changes needed to deliver remaining CER visibility and DER & CER access use cases

The outputs of Phase 2 will validate and confirm the exact scope and timing of these phases.

Status on current delivery:

Distributed Energy Resources (DER) Visibility Phase One update:

- The programme has successfully collaborated with industry (DNOs, the Energy Networks Associations' Open Networks Project (ONP), the Association for Decentralised Energy (ADE)) and Ofgem and DESNZ to draft a vision, design principles and an indicative roadmap for achieving DER visibility. This has been underpinned by capturing and prioritising approximately 200 industry use cases which are enabled by around 100 industry data points, through a series of industry workshops.

Phase 2 update:

- Phase 2 of the programme has commenced, aiming to agree the vision, design principles, priority use cases, data points and the roadmap for their delivery with industry. This will be achieved through delivery of ESO and DNO business and technology impact assessments, a whole system benefits case and a policy impact assessment to finalise the roadmap. To date, we have agreed the vision, design principles and outputs of Phase 1 with industry. We have also agreed to integrate our industry engagement with the Open Networks Programme due to mutual alignment, benefit, and efficiencies. Our business capability impact assessment is being finalised and we have made good progress with delivery of three innovation projects (DERIVE, Cascade & Fractal Flow) along with a series of other wave 0 demonstrators. Our Digital, Data and Technology (DD&T) Discovery kicked off on 25 March 2024, delayed by 2.5 months from 15 January. Expected timescales have increased from the three months planned initially to 13 months. The associated Ofgem milestone to begin DD&T Discovery (by December 2023) was delayed but has since been completed. TheBP2 milestone to complete Discovery (by March 2024) will be delayed. The programme has been replanned to extend Phase 2 to complete at the end of September 2024. Change requests will be made as appropriate for BP2 milestones.

Regional Development Programmes (RDPs)

RDPs look across the whole electricity system landscape to resolve problems in key regional areas of the network in need of development. We committed to continuing RDP development and delivering Generation Export Management system (GEMS) and RDPs 1 – 6 by end of 2024.

We have made positive progress on a number of the RDPs we committed to deliver during this period, particularly in the following areas:

N-3 Intertripping – we have delivered an Intertripping solution providing network protection. The solution will protect in specific network depletion scenarios across the UK Power Networks (UKPN), National Grid Electricity Distribution (NGED) and Scottish and Southern Electricity Networks (SSEN) DNO areas. This solution is now operational across all three regions. It allows us to permit providers to continue to generate during outage scenarios in certain network areas rather than enforcing them to cease generation in anticipation of a potential but very rare N-3 fault / network depletion scenario.

We have delivered a MW Dispatch Minimum Viable Product (MVP) solution in both NGED and UKPN DNO areas. The MVP is a key enabler for allowing more volume as well as quicker DER connections in these areas by giving our Control Room teams a way to manage pre fault thermal constraints by having visibility and control of the DER output in these areas. These RDPs have involved the development of a whole new infrastructure for cross ESO / DNO communications and data sharing. This includes brand new Inter Control Centre Protocol (ICC) links and new Web Service Application Program Interfaces (APIs). In addition, we have a bespoke Multi-Protocol Label Switching (MPLS) link with NGED. This has allowed us to implement a multi organisation set of co-ordinated processes that share appropriate data, provide a whole system view, and facilitate better, more informed cross-party decisions.

We plan to build on these MVP deliveries in NGED and UKPN DNO areas by evolving the solutions in our next RDPs. The aim is to remove any MVP manual processes and align the solutions and processes across both NGED and UKPN wherever possible. This should provide a blueprint for a wider rollout of a MW Dispatch solution to further DNOs as and when required.

Whilst there have been many successes in the RDP area, some of the RDPs have not progressed as initially planned. This is due to a mix of internal and external reasons. The rationale, impact and recovery plan is highlighted in our response to Ofgem's six month feedback.

We highlighted the ongoing risk with the delivery of complex, cross-organisational projects. For example, the risk of change to the overall delivery plan as a result of unforeseen factors like dependencies on third-party actions. We provided a 'best view' forecast of RDP development and delivery but recognise system requirements can change and the number of active RDPs in the BP2 period is subject to variation.

As detailed, we are looking for opportunities to scale up RDP solutions where possible and deploy them across GB moving forward. MW dispatch and its enhancements (RDPs 1- 4) has the potential to be scaled up to a GB wide solution based on the need case. For example, after a change of direction with GEMS, we are initiating

RDP 6, which would be a MW dispatch solution, with Scottish Power Distribution (SPD). Also, we are enabling GSP technical limit[19] via RDP 5 which is a GB wide solution.

RDPs are 'trial-by-doing' initiatives with our TO and DNO partners and are delivered through an agile delivery framework. As such it was challenging to predict the full scope and outcome at the time of the original BP2 submission. The RDPs remain challenging to deliver, with multiple parties across disparate systems needing to prioritise and work together. The challenges and what we are doing to overcome them in delivering RDPs are listed below:

- The way we set up business plans and regulatory incentives across the industry doesn't always ensure that we have directly reciprocal strategic plans across all involved stakeholders in this area. A mechanism that would achieve this in sufficient detail would assist in the delivery of these complex cross-organisational initiatives.
- As Ofgem noted, the RDPs always look for opportunities to deliver best value and rationalise the treatment across DNO areas. We recognised the need to carefully coordinate with the fast-changing connection landscape and priorities. For example, some of the RDPs were on hold for some time while our five point plan and the ENA's three-step plan were taking shape to allow us to gauge and understand how the ongoing RDP delivery programme may best support these key initiatives.
- We have worked with ENA initiatives closely and helped to develop the GSP technical limit proposal. It should be noted that the GSP technical limits considered a number of RDP learnings such as the Appendix G process and real-time data links. This collaboration will allow us to rationalise the treatment across DNO areas and should deliver best value.
- Some of the RDPs that were on hold are now covered by the Grid Supply Point (GSP) technical limit proposal. It is now envisaged that we will be able to recover some of the lost time by way of delivering a consistent solution across multiple DNO areas in parallel.
- Delivering the GSP technical limits via RDPs contribute to Role 3 by way of working across the whole electricity system. This is to coordinate markets and remove blockers to allow increasing volumes of distributed energy resources to connect and participate in our markets.

The GEMS delivery did not make progress as initially expected in 2023-24. Below we highlight the key points on why this is the case. We also state what we are doing to move forward and the implications of the project delay.

- Our project partner and their third-party supplier could no longer move forward with the original GEMS design. This is due to having encountered several impassable technical issues, cyber security concerns and concerns over the implications for a transmission company of full compliance with Balancing and Settlement Code (BSC) (BM dispatch rules).
- We evaluated other options with our project partner. After discussions with the Open Balancing Programme (OBP) it was determined that given the slower rate of new generation connections, the needs case for securing this network now aligned with the roadmap and timescales of the OBP delivery schedule.
- The OBP has already delivered 'bulk dispatch' functionality which we can use to automate generation dispatch to a certain extent. This added to our confidence that the adoption of OBP will deliver benefits and will not have any negative impact on generation connection or system operation.
- The new proposed way forward (as below) will deliver a more streamlined, lower risk and scalable solution for the consumer. In addition to this, it will provide consistency in approach GB wide, whilst not impeding new connections in this part of Southwest Scotland.
  - The TO will continue to deliver works to upgrade the transmission network as always intended to make it a radial network and implement the Super Grid Transformer (SGT) automatic protection scheme at Kilmarnock South 400 kV substation.
  - We will take over the full scope of the automatic boundary monitoring and dispatch functionality as part of the OBP activities. Already delivered bulk-dispatch functionality will cover the short-term

[19] GSP Technical Limits is the process being rolled out by DNOs, TOs and ESO as part of the ENA's 3-point plan. This is to allow distribution schemes to connect on a non-firm basis before large scale transmission reinforcement work has finished.

needs case. Additional capabilities to manage nested constraints and fully automate dispatch will be delivered over the coming years.

- The requirements for GEMS on the distribution network will revert to a MW-Dispatch like project, mimicking the developments underway with NGED and UKPN DNOs in England.

Centralised Strategic Network Plan (CSNP)

The CSNP will be the new long-term planning framework for network investment. We have been working closely with Ofgem on the development of the new arrangements through their Electricity Transmission Network Planning Review (ENTRP). In December 2023, Ofgem published their decision on the framework for the Future System Operator's Centralised Strategic Network Plan (CSNP) which built on the concepts and proposals discussed between the two organisations.

We recognise that close collaboration is an important aspect for the successful delivery of the new framework. On that basis weekly meetings have been established to provide opportunity to discuss framework development and agree next steps.

In the latter half of 2023-24 the focus has been on the following:

- The development of CSNP Methodology (led by ourselves) and the CSNP Guidelines (led by Ofgem) and how to ensure alignment between the two governance documents; and
- The alignment between the new strategy spatial plans (CSNP, Strategic Spatial Energy Plan (SSEP) and Regional Energy Strategic Planner (RESP)), Future Energy Scenarios (FES) and the Connection Reforms, given the interaction and dependencies between the different initiatives.

These will continue to be focal points of engagement and delivery throughout 2024-25, as the CSNP framework is finalised. The CSNP framework and supporting methodology will build on the concepts and learning from the transition CSNPs (tCSNP1 and tCSNP2) which have incorporated key principles of the new CSNP framework.

Strategic Spatial Energy Plan (not in BP2 plan)

The Transmission Acceleration Action Plan was published in August 2023, and was the Government's response to the Electricity Networks Commissioner's report on accelerating electricity transmission network build. A key action was for the Government and ourselves to develop a Strategic Spatial Energy Plan (SSEP) to bridge the gap between government policy and Network Development Plans.

We are setting up our team to deliver and support DESNZ ahead of their official commission to us. The commission will instruct us to develop the SSEP in line with the Commissioner's recommendations. The work we have begun in developing the SSEP was not forecast in our original BP2 submission.

Deliverable Status

Our BP2 RIIO-2 deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables, with commentary including explanations for all delayed milestones.

The statuses are defined as follows:

On track	For a milestone date in the future: we're on track deliver it on time
Complete	Milestone has been delivered
Delayed – consumer benefits	Delayed or de-prioritised to maximise consumer benefits
Delayed – external reasons	Delayed due to factors outside our control (e.g., BREXIT, Covid, Ofgem)
Delayed – internal reasons	Delayed due to factors within our control and/or that we're accountable for
Continuous activity	For certain activities with ongoing delivery (e.g., OTF)
Milestone no longer valid	Removed from Delivery Schedule as no longer required (agreed with Ofgem)

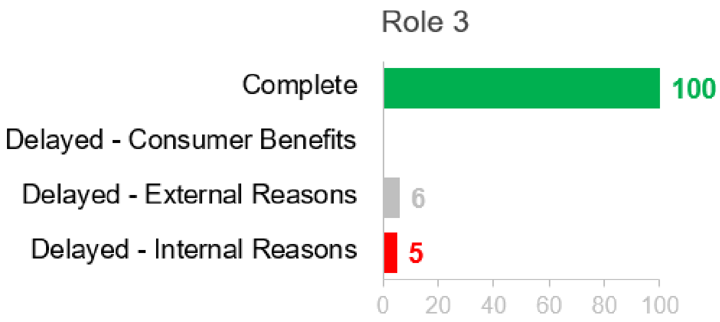
Statuses of 'on track' or 'continuous activity' are not shown as they can only apply to milestones not yet due for completion.

Role 3 - Progress of our deliverables

For Role 3 (System insight, planning and network development), the latest BP2 RIIO-2 deliverables tracker lists **52 deliverables** in total, which is made up of **228 milestones**.

- **111** of these milestones were due to be completed by September 2023
- Of those:
  - **0** are delayed in order to deliver an improved outcome for consumers
  - **6** are delayed due to reasons outside the ESO's control
- Of the remaining **105**:
  - **100** (95%) are now complete
  - **5** (5%) are delayed due to ESO related delays

The results for the **111** milestones due to be completed by March 2024 or earlier are illustrated below:



Role 3 – Milestone status by deliverable

For milestones due by March 2024 or earlier

Ref	Deliverable name (shortened)	Complete	Delayed... Consumer Benefits	Delayed... External reasons	Delayed... Internal reasons
D11.1	Improved identification of when is the most econom...	1			
D11.2	Improved identification of network needs	1			
D11.3	Improved assessment of voltage requirements, and a...	1			
D11.4	Improved assessment of stability requirements acro...	1			
D12.2	Potential solutions identified and direction estab...	1			
D12.3	Key changes to SQSS made or in progress	1			
D13.1	Published Future Energy Scenarios (FES), Winter Ou...	3			
D13.2.1	Provide whole system regional insights	2			
D13.3	Shared insights on future energy expectations and ...	4			
D13.4	Bridging the Gap - produce evidence-based recommen...	1			
D14.3.1	Establish dedicated Distributed Energy Resource (D...	2			
D14.3.3	Whole electricity system connection seminars on an...	4			
D14.3.4	Improving Systems and Data	4			
D14.3.6	Proposing future policy and code improvements	1			
D14.4.1	Implement first phase of the ESO connections porta...	2			
D14.4.2	Phase 2 of the connections portal concluded	4			
D14.5.1	Five Point Plan	2			
D14.5.2	Connections Reform Phase 2	3			
D14.5.3	Connections Action Plan - ESO delivery	2			
D14.5.4	Connections Reform Phase 3	3			
D15.1.1	System Operability Framework (SOF) documentation t...	4			
D15.1.2	Innovation projects developing new operability sol...	1			
D15.11.2	Forward Plan 2020-21 RDP - Generation Export Manag...				
D15.4.1	Data transfers between network organisations in ac...	1			
D15.4.2	Technical modelling for use across the ESO – ongoi...	4			
D15.4.3	Automation of data exchange mechanism and preparat...	1			
D15.5.2	RDP2 of RIIO-2 (MW dispatch, South East, UKPN)	1			
D15.5.3	RDP3 of RIIO-2 (wider rollout & enhancements, WPD)	1		1	
D15.5.4	RDP4 of RIIO-2 (wider roll out & enhancements UKPN...	1		1	
D15.5.5	Deliver GB rollout of functionality developed thro...	2			
D15.5.6	RDP5 of RIIO-2	1			1
D15.5.7	RDP6 of RIIO-2	1			1
D15.6.2	Further Grid Code modification implementation (ari...	1			
D15.6.7	Deeper Outage Planning go live in Offline Network ...	1			
D15.6.8	Development & ongoing maintenance of EMT Capabilit...	3			
D15.6.9	Co-simulation analysis innovation project	2			
D15.7.1	Commence System State Targeted Monitoring and Cont...			1	
D15.8.2	Enabling whole electricity flexibility service pro...	3			1
D16.1.1	Year ahead regional outage programmes developed in...	1			
D16.1.2	Detailed week and day ahead operational documentat...	1			
D16.2.1	Great Britain (GB) wide NAP process goes live incl...	4			
D16.3.3	Finalise new processes in readiness for approval o...	1			
D16.3.4	Deeper access planning go-live – frameworks, proce...	1			
D16.4.1	Scoping exercise concluded for delivery of enhance...	2			
D16.4.2	Delivery of enhancements to outage notifications, ...	1			
D16.5.1	Agreed future platform for any automation and crea...	4			
D16.5.2	Scope future automation development	4			
D7.1	Electricity Ten Year Statement (ETYS)	2			
D7.2	NOA Annual Report	3			
D7.3	Large Onshore Transmission Projects (LOTI) (previo...	4			
D8.1	Rollout of Network Services Procurement (NPS) appr...				2
D8.4	Early Competition	1		3	
	TOTAL - Role 3	**100**	-	**6**	**5**

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 3. Some of these projects are funded as part of the RIIO-2 price control and are therefore eligible for consideration as part of the RIIO-2 incentive scheme. The references in the table below provide links to additional information about each project.

Innovation Project Name	Description	Progress Update	Deliverables Supported	Status	Funding
Stability Requirements Calculation Toward Net-Zero (STARTZ)[20]	This project will review the current methods of calculating system stability needs and implement automation and machine learning to calculate system stability needs for the GB network at a granular level.	Following an initial delay due to data confidentiality issues the project is now back on track and due to complete a few months later than anticipated. Work Package 1 (WP1) has completed which conducted a review of the current methods used for calculating system stability, the report for WP1 has been reviewed and a final version is being prepared for publication. A paper has also been submitted to CIGRE (Conseil International des Grands Réseaux Electriques; Council on Large Electric Systems) 2024 based on the findings from WP1.	D11.4	Delivery	RIIO-2
Strength to Connect[21]	Developing a new method to measure grid strength as an alternative to short circuit level.	The "Strength to Connect" project is on track to complete in June 2024. The project's initial phase (WP1) involved a comprehensive review and reclassification of system strength metrics into two categories: small-signal and large-signal. These categories were based on their distinct behaviours. The newly defined metric classifications provide a method for evaluating the resilience of the system's voltage to different types of disturbances: minor ones that can lead to voltage fluctuations, harmonic interactions (small signal), and major ones (large signal) that	D15.2.1, D15.3.1	Delivery	RIIO-2

[20] Stability Requirements Calculation Toward Net-Zero (STARTZ)

[21] Strength to Connect

		can result in voltage drops and protection mal-operation. This differentiation allows the ESO to more accurately determine if the integration of new devices might compromise system stability or pinpoint vulnerabilities within the system. The advancements achieved in WP1 have already aided several academics and industry professionals in gaining a deeper understanding of how to assess system strength effectively. The project's second phase (WP2) focuses on developing a metric to gauge system strength in scenarios of significant disturbances and assessing the best ways to apply these new metrics.			
Consumer Building Blocks[22]	This project created a set of industry-standard consumer archetypes in conjunction with the other network companies.	The Consumer Building Blocks Project completed in July 2023 and produced a set of industry-standard consumer archetypes that are now being used as part of the FES modelling process. The archetypes have helped understand the types of consumers and the characteristics that drive their behaviour, what this means for their consumption, appetite for change, adoption rates of technology and ability/propensity to engage with time of use tariffs. Relevant stakeholders and project partners from external organisations have also received training on how to interpret the archetypes, how to apply them and how to keep them up to date. As a next step we are now looking to improve the archetypes	D13.2.1	Completed	RIIO-2

[22] Consumer Building Blocks

		by incorporating further data from the first Demand Flexibility Service.			
Automated Sub Synchronous Oscillation Identification [23]	Ability to investigate a wider pool of future scenarios for potential Sub-Synchronous Oscillation (SSO) threats and develop an advanced tool useful for both planning and connections studies for ESO, TO and customers.	The SSO Identification project is on track to be completed in May 2024. To date the project has completed a literature review on the theoretical background of SSO phenomena and a report detailing the developed python tools and a user guide on how to use them appropriately. The Beta versions of the SSO identification tool covering the impedance scan, stability analysis and the Grey Box implementation were delivered and are being tested. For wider dissemination purposes, a technical paper was submitted and accepted for the CIGRE Paris Session 2024.	D15.6.8	Delivery	RIIO-2
Data Driven Power System Model Development for Control Interaction Studies (D3) [24]	Developing new black box models which can be shared with external companies to alleviate the risks of control interactions between existing and new power electronic equipment.	The D3 project, completed in February 2024, explored how power systems that rely heavily on Inverter-Based Resources (IBRs) respond to changes in frequency. This work is particularly valuable for future projects that examine how different parts of a power system interact and how to keep the system stable. It offers insights into several key areas, including ensuring the power network works as it should, evaluating how new customers can connect to the network, investigating issues after they happen, and helping with the planning and design of the network. This project introduced a cutting-edge method that		Completed	RIIO-2

[23] Automated Sub Synchronous Oscillation Identification

[24] Data Driven Power System Model Development for Control Interaction Studies (D3)

		relies on analysing large amounts of data to study the stability of power systems. This approach is beneficial for projects that need to understand the system's behaviour based on a wide range of data, like detailed records from different operational scenarios. The project has produced several tools and methods, including a testing system and models in the PSCAD/EMTDC environment, a module for testing and measuring harmonics, which is suitable for devices powered by electronics, and a toolbox for analysing stability based on impedance, which helps identify potential risks of interaction between different parts of the system. Additionally, it developed a technique for simplifying models, making it easier to balance the system's accuracy with the need to process data efficiently. This simplified model-building approach is designed to work well under various operating conditions, ensuring that studies on system stability can be both accurate and manageable.			
RealSim: Real-Time Phasor-EMT Simulations[25]	Investigating when and where to use phasor mode and EMT mode simulations for a given system condition and provide real-time simulation of the grid in that region for system stability & security and identification of stability risks.	Following the project kick-off in July '23 a 'sliced' model developed in the PSCAD analysis package was shared. An electromagnetic transient (EMT) network build for analysis in PSCAD has now been developed. ESO has tested and validated this model against our Power Factory Model which yielded good results. Therefore, work package 1 (WP1) has been completed	D15.6.8, D15.6.9	Delivery	RIIO-2

[25] RealSim: Real-Time Phasor-EMT Simulations

		and a technical report has been delivered. WP2 has now commenced and the developed model is being replicated in the OPAL-RTs Hypersym environment, to be later tested and validated for real-time simulation.			
Powering Wales Renewably[26]	Through delivery of a digital twin of the whole Welsh transmission and distribution system combined with other datasets, PWR will provide a digital common interface to accelerate the integration of renewable generation and decarbonised demand into the electricity system.	Currently reaching the end of Alpha Phase. PWR Alpha is designed to address three substantive problems: 1. The lack of visibility, and a common understanding by stakeholders, of the whole electricity system network challenges. 2. Flexibility is not yet treated as a whole system resource nor fully coordinated between transmission and distribution. 3. Local area energy plans, network development plans, and the connections queue, lack alignment, leading to potential synergies being hard to identify. A pilot system has been deployed with key functional advancement such as the ability to correlate separate datasets against an intelligent connected network model.	(No directly linked deliverable)	Reaching end of Delivery. Moving towards Beta application	SIF Round 2
Probabilistic Pathways for Energy System Planning (SIF Discovery)	This project will develop an enhanced end-to-end network planning methodology for the whole energy system. We will explore applying advanced computational tech niques, such as artificial intelligence and probabilistic	Discovery phase kicked off in early March ‘24. Project now progressing through a series of workshops to capture the business modelling processes, from FES to network planning and network assessment. The aim is to develop and refine an end-to-end process map for how the enhanced methodology is integrated.	D13.1, D13.2	Delivery	SIF Round 3

[26] Powering Wales Renewably – Alpha
https://smarter.energynetworks.org/projects/10078792/https://smarter.energynetworks.org/projects/10078792/

	modelling, to capture risk and un certainty within future energy pathways, enable rapid iterative network needs analyses, risk-based network options assessments, and deliver optimised planning decisions.	

C.2 Stakeholder Evidence for Role 3

The ESO incentive scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of the ESO's plan delivery. To demonstrate performance against this criterion, every six months we report on our stakeholder satisfaction survey results.

Stakeholder surveys

The ESO has commissioned surveys from market research company BMG. These surveys measure satisfaction for each ESO role, and are carried out on a six-monthly basis. The survey is targeted at senior managers, decision makers and experts, and includes a wide selection of relevant stakeholders who have had material interactions with the ESO's services. In total we contacted 1496 stakeholders, across all 3 roles.

Role 3

For Role 3, the following question was asked:

> "One of the ESO Roles is focused on system insight, planning and network development, which includes key activities such as Connections and Network access planning, Strategy and Insight (e.g. FES) and long-term Network development. Overall, from your experience in these areas over the last 6 months, how would you rate ESO's performance?"

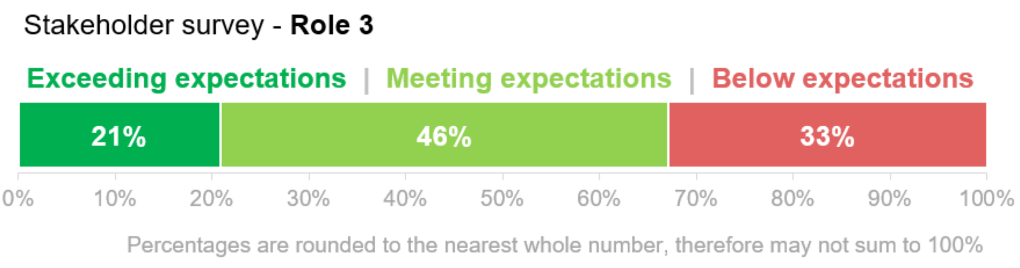
Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

- If they rated the ESO as below expectations, they were asked what the ESO needed to do to meet their expectations.
- If they rated the ESO as meeting expectations, they were asked what the ESO needed to do to exceed their expectations.
- If they rated the ESO as exceeding expectations, they were asked what the ESO did that exceeded their expectations.

For Role 3, we contacted **807** stakeholders, and received **134** responses to this question, which were distributed as follows:

- **21%** exceeding expectations
- **46%** meeting expectations
- **33%** below expectations

(Percentages rounded to the nearest whole number)



	Summary of stakeholder feedback for Role 3
"Exceeding Expectations" **28** stakeholders scored us as "Exceeding expectations". Feedback on what we did that exceeded their expectations included:	• **Good communication, engagement and subject knowledge –** The majority of stakeholders said our communication and engagement has been very good. Stakeholders also found us knowledgeable. Some specifically commented on our willingness to take on industry suggestions, providing knowledge over a large portfolio of projects, and being very clear and precise in communications. • **Good response times to queries –** Some stakeholders have seen improvements in our responsiveness to queries in the past year. • **Process improvements with Connections Reform –** Stakeholders found we have improved our connections process since last year. Comments include processing vast volumes of applications, providing clear and precise communications and providing helpful information and data to help customer interests. One noted that our overhaul of the queue system is going well, while another stated they are pleased by our willingness to engage and consider industry suggestions. • **The FES team continues to impress –** Stakeholders pointed out the FES team are trying extremely hard to provide relevant information and are really open to feedback. Some feel the team have been instrumental in shaping a resilient and sustainable energy future, demonstrating an exceptional ability to anticipate and prepare for future energy demands and challenges.
"Meeting Expectations" **62** stakeholders scored us as "meeting expectations". Feedback on what it would take for us to be exceeding expectations for them included:	• **Clarity and transparency –** Stakeholders mentioned the need for greater clarity on timescales, investment decisions, criteria applied and information accessibility. They also emphasized the importance of transparent assumptions, data usage and conclusions in reports and planning processes. • **Collaboration and coordination –** Stakeholders highlighted the importance of coordination, consistent invitations to meetings, effective communication between team, the need for better engagement, tailored initiatives and proactive strategies. • **Process improvement –** Stakeholders mentioned the need for efficiency in communications, timely responses to queries, and streamlining processes. They also called for innovative approaches, adaptability, and clear guidance in the network planning space. • **Resource allocation –** Some stakeholders mentioned the need for additional staff or resources to address workload and respond faster to industry changes.

"Below Expectations" **44** stakeholders scored us as "below expectations". Feedback on what we needed to do to meet their expectations included:	• **Collaboration and engagement –** Stakeholders emphasized the need for closer collaboration with developers, understanding their issues, and actively engaging with them. • **Planning and responsiveness –** Stakeholders expressed dissatisfaction with poor planning, lack of visibility, and a need for timely responses. They called for more proactive thinking, flexibility, and the ability to adapt to changing circumstances. • **Transparency and communication –** Stakeholders highlighted the importance of transparent decision-making, better communication of information, and improved documentation. They sought clarity, accuracy, and openness in interactions with us. • **Meeting commitments and improvement –** Concerns were expressed about our ability to meet deadlines, deliver on commitments, and improve various processes. We need better resource allocation, adherence to agreed timescales, and continuous improvement in operations.

Addressing stakeholder feedback in BP2

Effective engagement with our stakeholders across the first term of BP2 has been crucial for us to facilitate the effective delivery of our business activities and projects across system insight, planning and network development. In the following section, we outline how we have addressed stakeholder feedback gathered via stakeholder surveys and regular project/business activity stakeholder engagement to improve our activities.

❶ Co-creating solutions and products that are more inclusive to all market participants via Connections Reform

The Connections Reform project has been delivered in conjunction with input from our customers and stakeholders. We have worked collaboratively with them to tackle the challenges currently facing our connections customers within the Connections application process.

Across the first year of BP2 we have engaged with our stakeholders in various forms including;

- Five in-person events
- Monthly webinars to provide regular updates and encourage stakeholder interactions regarding Connections Reform
- Bespoke online events showcasing progress on reform, the connections portal and our Five Point Plan
- Regular newsletters to our stakeholders and customers.

Insights from these interactions have moulded the Connections Reform Consultation held in June 2023 which received 80 detailed responses from industry. The consultation feedback has shaped our proposals for delivering an enhanced Connections experience. The full connections reform report is accessible here.

Based on the feedback received from consultation, we received significant support for the use of Target Model Option 4 (TMO4), which was our initially recommended connections process model within our June consultation. Some of this support was conditional on making some refinements or improvements to the model in several areas. We will be working with industry and other key stakeholders during Phase 3 to develop the detailed design of the new reformed connections process based on our final recommendations.

We launched the Stakeholder Connections Process Advisory Group in January 2024, with an independent chair, to enable industry to steer the detailed design and code modifications within the parameters set out in our final recommendations. This advisory group also reports to the Connections Delivery Board being established by Ofgem and the Government.

❷ Using stakeholder feedback to deliver greater coordination with industry partners via engagement on Network Access Planning

Our Network Access Planning engineers are responsible for assessing, co-ordinating and sanctioning the planned release of assets from the National Electricity Transmission System (NETS) for maintenance and commissioning of new connections and equipment.

To ensure our stakeholders are kept in the loop regarding all things Operating Code 2 (OC2), operational planning and data provision of the Grid Code, we held a face-to-face event called the OC2 Forum in Birmingham in March 2024.

At this interactive event, we were able to address feedback from our stakeholders across the year and demonstrate the improvements we had made across Network Planning as a result. For example:

- Stakeholders had stressed the need for more National Planners and voltage engineers. Over the past twelve months, we recruited four more.
- We created a specific Year Ahead (YA) team to lead our proactive planning to support us in resolving queries before the end of the year.
- Colleagues from our Connections team were at the event to offer guidance to attendees on more specialist queries.
- More consistency was requested from our service/delivery across teams; therefore, we standardised this by implementing numerous automations on the network.
- Transmission Owners (TOs) requested greater access to support from National Teams, therefore we created shared spaces to help.

❸ Delivering greater transparency of how we plan our activities and make decisions via our implementation of Early Competition

Stakeholder feedback has been central to the development of the early competition model during the first year of BP2.

Building on previous engagement undertaken during the evolution of the Early Competition Plan (ECP), we have maintained our commitment to engaging in an open and transparent manner. We have proactively sought feedback on key topics and listened to stakeholders who have shared their views on the areas that matter to them. During the early competition implementation phase, we held six webinars providing both general updates on our progress, as well as providing the opportunity to ask questions or give feedback. We have spoken to 38 organisations across different sectors who have provided insight and robust challenges on our proposals across 54 in-depth discussions.

We received a range of stakeholder feedback and evolved our project to incorporate that feedback. For example:

- We have adjusted the post-preliminary works costs assessment (PPWCA) cap to 40%. This protects consumers from an open-ended obligation to absorb cost increases, protects the Procurement Body from legal challenge, and ensures that bidders are appropriately incentivised to assess and manage risk.
- Revising our revenue period for bidders to a 35-year term, rather than the 45 years previously proposed.
- The development of a clear, transparent connections process, which is currently passing through the Code Modification process.

The full ‘you said, we did’ record of stakeholder feedback on Early Competition can be found here.

The adaptations of the Early Competition model to fit the Centralised Strategic Network Plan (CSNP) and the recommendations set out were communicated to stakeholders in our webinar in December 2023.

❹ Improved comms and engagement via our Centralised Strategic Network Plan Engagement Programme

To support our Beyond 2030 Report we developed a new set of external governance forums with the Transmission Owners (TOs), Ofgem, the Department for Energy and Net Zero (DESNZ) and Devolved Governments. The purpose of these forums was to seek stakeholder endorsement on proposed network recommendations which included reinforcements such as subsea cables, overhead lines and circuit upgrades. We established three forums hosting executive and senior level representation from these stakeholder organisations for each round of governance, which we undertook twice, once to show our initial findings and then another round to present the final recommendations.

Previous comparable governance includes the Network Options Assessment Committee. This expanded external governance has allowed us to coordinate with our key stakeholders and make significant pivots in some of our network recommendations-based decisions and agreements made in these forums. This included seeking a commitment from the TOs to aid us with significant reanalysis of network options to realise large cost savings and environmental benefit. This was a result of feedback that we’d received in other stakeholder forums from our Environmental Stakeholders.

This significantly changed our network recommendations off the West Coast of Britain, leading to a more streamlined network design.

The transitional Centralised Strategic Network Plan (TCSNP2) will be recommending approximately £58bn of network investment throughout the 2030's. This governance has enabled us to ensure these recommendations are providing good value to the consumer as more refinement of the network design has taken place as a result.

C.3 Metric Performance for Role 3

There are no metrics for Role 3.

C.4 Quality of Outputs for Role 3

The fourth evaluation criterion for the ESO incentive scheme is Quality of Outputs, where the Performance Panel will consider the actual benefits the ESO has realised from delivering its Business Plan, or any outputs additional to the Business Plan.

At the time of publishing our original RIIO-2 Business Plan in December 2019, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the RIIO-2 Business Plan. The relevant CBAs for Role 3 are:

- Network Options Assessment (NOA) enhancements (A7-A11)
- Taking a whole electricity system approach to connections (A14)
- Taking a whole electricity system approach to promote zero carbon operability (A15)
- Delivering consumer benefits from improved network access planning (A16)

In this section, we provide a progress update for each of the activities for which we originally provided a Cost-Benefit Analysis, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence, and describing any sensitivity factors which would impact on the delivery of the stated benefit. Deliverable activity statuses reflect the delivery of RIIO-2 milestones and do not recognise either work completed prior to April 2021 nor progress made towards yet to be completed milestones.

The Panel will also consider the ESO's Regularly Reported Evidence (RRE) as part of the Quality of Outputs criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the ESORI guidance. For Role 3, the items of RRE reported in our mid-year 2021-22 report are:

- 3A. Future Savings from Operability Solutions
- 3B. Consumer Value from the NOA
- 3C. Diversity of Technologies Considered in NOA

CBA: Network Options Assessment (NOA) enhancements (A7-A11)

BP2 Mid-Scheme view of gross benefits compared to BP2

In BP2 we estimated gross benefits of £929 million over RIIO-2. Due to the significant changes to the NOA process this year, including the implementation of three additional design criteria, we do not believe this CBA appropriately reflects our performance, so we have provided a qualitative evaluation for this Mid-Scheme update.

Further information on the benefits of projects being delivered under Network Services Procurement (formerly Pathfinders) is reported in CBA A15 -Taking a whole electricity system approach to promote zero carbon operability.

	Estimated gross benefits during RIIO-2 (£m)	
Area	**BP2 Plan view**	**Latest view**
1. Facilitate competition by embedding Network Services Procurement (Pathfinder) projects into the NOA	564	We have provided a written update for Mid-Scheme.
2. Extend NOA approach to all connection's wider works	148	
3. Extending NOA to end of life asset replacement decisions	118	
4. Network Options Assessment	69	
5. Support decision making for investment at the distribution level	30	
Total	**929**	

We have undertaken extensive development of the NOA process over the past 12 months, resulting in a coordinated offshore and onshore plan called 'Beyond 2030'. This plan supersedes the NOA while continuing its history of excellent economic analysis, across multiple FES scenarios. Additionally, the Beyond 2030 analysis considers four equally weighted design criteria for the first time for onshore reinforcements: economic and efficient; environmental impact; community impact; and deliverability and operability. In order to implement these improvements, other potential opportunities were reprioritised. This primarily includes the embedding of asset replacement decisions within the NOA and the extension of NOA to all connection's wider works. Due to the significant changes to the NOA process this year, we do not believe this CBA appropriately reflects our performance.

Summary of progress in 2023-24

Developments to NOA (Beyond 2030)

The Beyond 2030 report and it's supporting publications present the next set of recommended investments for GB in the most accessible way to date, allowing significantly more engagement to take place with the wider community and politicians. Additionally, this year's onshore assessment is the first to consider four design criteria (economic and efficient; environmental impact; community impact; and deliverability and operability) and four scenarios simultaneously. Integrating these criteria and the offshore coordination of ScotWind into this assessment required significant resource to manage effectively. This resulted in the reprioritisation away from the embedding of asset replacement decisions within the NOA and the extension of NOA to all connections wider works.

Facilitate competition by embedding Network Services Procurement (Pathfinder) projects into the NOA

The Voltage 2026 tender was launched in December 2023 for the procurement of long term reactive power capability in two regions in England. This builds on previous voltage pathfinder tenders that have been carried out in the Mersey and Pennines regions and is an evolution of how ESO procure network services.

We also launched a tender in December 2023 for the new annual Stability Y-1 market which seeks to contract for inertia capability between 2025 and 2026. This is a marked difference to the ad-hoc long term tenders that have previously been carried out under the stability pathfinder projects, as we aim to provide greater clarity and certainty to the market on our approach to procuring stability services.

For constraint management services, we enacted the one-year extension option from the current B6 Anglo-Scottish intertrip contracts which ensures that the current service will be in place until September 2026. New 'interim' contracts were also awarded to units in the East Anglia region for an intertrip service between February 2024 and March 2025.

The tenders and contracts aim to procure network services to enable the operation of a zero-carbon network while delivering savings for consumers.

DNO engagement (DNOA)

Whilst we have not directly supported decision making for investment at the decision level within NOA, we have supported the Distribution networks through two alternative pathways. The first of these is the multiple consultations we have conducted with UKPN over the past year. Within these, we have shared valuable insight with UKPN about how our NOA process is run, along with its inputs and outputs. Additionally, we offered feedback on their DNOA proposal and methodology.

Secondly, we have conducted a cost benefit analysis supporting DNO investment with relation to renewable generation connections at a DNO level. This analysis was for NGED, considering an active network management scheme (ANM) against accelerating reinforcement works at Rugeley 132kV Substation. This analysis found that the active network management scheme was the superior choice, saving between 30-40% of the cost.

Extend NOA approach to all connection's wider works

To enable the extensive process development required for the "Beyond 2030" analysis, the extension of the NOA process to capture all connection's wider works had to be delayed. We plan to capture this within the Centralised Strategic Network Plan (CSNP). As a result, the reduction in benefits should be mitigated, particularly as our current assessment targets 2030 and later, which will be within CSNP scope.

Extending NOA to end of life asset replacement decisions

To enable the extensive process development required for the "Beyond 2030" analysis, the extension of the NOA process to incorporate end of life asset replacement decisions works had to be delayed. Ofgem's CSNP decision document states that this will continue to be the responsibility of the TOs and is therefore out of scope for CSNP. There may be some exceptions to this which will be informed by the CSNP, when interactions with the wider network are relevant. As the TOs conduct end of life asset replacement decisions as part of their standard asset management, the benefit lost should not be severe. Where exceptions arise, they should be captured within CSNP, mitigating the benefit loss.

Rollout of Network Services Procurement (NPS) approach and optimise assessment and communication of future needs

Under this deliverable (D8.1), there are three milestones relating to the constraints management intertrip service.

'Constraint Management Pathfinder B6 year 2 service start date' is on track to commence delivery from October 2024 and to continue delivering the cost and carbon savings delivered by previous constraint contracts.

'Constraint Management Pathfinder B6 year 3 tender' is delayed for internal reasons as we review the updated studies for future constraint requirements and the design of this service.

We do not anticipate any negative impact on benefits as we have enacted the extension option on current contracts to ensure the constraint service remains in place until 2026.

‘EC5 tender run’ is also delayed for internal reasons as we reviewed the design of the service to consider a range of possible solutions. However, the service is still due to commence from April 2025 once the current ‘interim’ contracts end.

Early Competition

Four milestones are delayed as outputs require regulator input. Revised timeframes have been agreed with Ofgem and DESNZ.

Combined status by milestone for relevant deliverables (Activities A7, A8 and A11)

Status	Count	%
Complete	14	48%
On track	9	31%
Delayed – Consumer Benefit	-	-
Delayed – External Reasons	4	14%
Delayed – Internal Reasons	2	7%
Continuous activity	-	-
Total	**28**	**100%**

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Supporting evidence

Type	Measure	Rationale and status
Lead indicator	“New” NOA reinforcement opportunities identified by the ESO	During the NOA analysis in 2023-24, the ESO identified key areas of GB which required reinforcement beyond the options submitted by the TOs. Following this, we instigated the development of 12 new onshore options and recommended a new design of the west coast offshore HVDC link, now known as WCD4. The economic benefit of these options being instigated one year earlier is between £70 and £300 million depending on the FES scenario.

Detail: Calculation of monetary benefit

As mentioned in the introduction, due to the significant changes to the NOA process this year, including the implementation of three additional design criteria, we do not believe this CBA appropriately reflects our performance, so we have provided a qualitative evaluation instead.

CBA: Take a whole electricity system approach to connections (A14)

BP2 Mid-Scheme view of gross benefits compared to BP2

In BP2 we estimated gross benefits of £23.6 million over RIIO-2. For this Mid-Scheme update, we have not updated the BP2 gross benefits calculation, but instead provide an update on progress along with quantitative and qualitative evidence of the benefits that A14 will deliver.

	Estimated gross benefits during RIIO-2 (£m)	
Area	**BP2 plan view**	**Latest view**
1. Efficiency Savings	22.6	We have provided a written update for Mid-Scheme, with revised measures of success to reflect the current position.
2. Customer Service Improvement	1.0	
Total	**23.6**	

Since October 2022, the Transmission connections queue has grown by more than 275GW and has been growing at an average of over 20GW per month for the last 12 months. The Distribution connections queue has also continued to grow, and at the current rate of growth, the total queue (across transmission and distribution) is likely to exceed 800GW by the end of 2024. This is over four times the installed capacity we anticipate needing by 2050.

The policy landscape has also evolved with the Powering Up Britain Energy Security Plan, the Energy Commissioners Report on Accelerating Electricity Transmission Network Deployment, Government's Transmission Acceleration Action Plan and Ofgem and Government's Connections Action Plan.

We brought forward plans to launch a Connections Reform programme in BP2 and completed Phase 1 within BP1.

Given all of the above, the original BP2 CBA for connections no longer reflects the most appropriate success measures, nor the scale and pace of connections change being delivered.

Therefore, as agreed with Ofgem, we have replaced our existing CBA and instead provide different measures of success to enable a clearer and more accurate data-driven performance narrative.

We have set agreed objectives with milestones, where we are closely able to monitor our performance, ensuring they remain an appropriate indicator of progress towards our goals of meeting customers' needs and enabling a timely transition to net zero.

We expect that the data we have started to record and report upon for our revised CBA (as below) will allow us to see the tangible benefits of the delivery of our accompanying actions/milestones in relation to improved customer service and improved connection dates, more in line with the expectations and requirements of customers seeking to connect to or use the transmission system.

See below key deliverables outlined in our BP2 amended Milestones document, along with an update against what we originally stated we would do.

Summary of progress in 2023-24

Deliverable	Detail	Update
Five Point Plan	To improve connections timescales through a number of tactical initiatives, ahead of the wider reform project.	Capacity has been released via these initiatives, including terminated projects via the TEC amnesty and capacity made available for accelerated connection dates for storage projects on a non-firm basis. With the approval of CMP376 to implement the queue management approach in November 2023, and through the 6-month notice to industry which

		will be shared in the coming months, we will be able to quantify the initial impact of this. The Connections Action Plan (CAP) estimates that in time this will result in capacity removed from the queue. The two-step offer process was amended, to align with other successes within this plan and a revised deadline has been given of May 2024.
Connections Reform Phase 2	Lead a detailed definition and mapping exercise based around feedback from industry parties and on their experience with the connections process set out within our Case for Change (Phase 1).	The initial recommendations consultation was published in June 2023, with findings reviewed and next steps shared at the external Steering Group. Phase 2 was completed with the final recommendations published in December 2023, which also demonstrated the level of engagement with DNOs, TOs, customers, the Department for Energy Security and Net Zero and Ofgem.
Connections Action Plan (CAP)	Develop additional options for improvements to connections, identified within Reform Phase 2 (above). To engage stakeholders and present recommendations to the Connections Delivery Board (CDB).	ESO change delivery was mobilised to reflect new CAP actions, which we are delivering efficiently . Within this, the voluntary Letter of Authority (LoA) was launched after we raised an urgent LoA code modification which was recently approved by Ofgem and is now being implemented – this was the first of our implemented reform final recommendations. Our TMO4+ ('Apply Gate 2 to Whole Queue') proposal to go further and faster to improve connections was recently submitted to the CDB where we received a steer to continue to develop this proposal and we will be raising urgent code modifications in April 2024 with the aim to go-live in January 2025.
Connections Reform Phase 3	Implementation Phase: 12–24-month process anticipated in BP2	An indicative implementation plan was published, within the Reform consultation document and an updated plan within the final recommendations. Both anticipate much quicker implementation than set out within BP2 i.e. January 2025 (Brought forward from September 2026). Reform detailed design and implementation began following publication of the Reform Phase 2 final recommendations in December 2023.
Establish dedicated Distributed Energy Resource (DER) account	Continuously deliver on the use of DER, learn lessons and	We have worked with DNOs directly, and collectively through the Strategic Connections Group, to develop technical limits at Grid Supply Points and issued revised Bilateral Connection Agreements to DNOs that enable accelerated connection offers to be offered to Distributed

management function	implement improvements.	Energy Resources (DER) where network capabilities allow.
Whole electricity system connection seminars on an ongoing basis	Ongoing seminars	We have continued to provide a regular series of both online and in person customer connections Forums and Seminars.

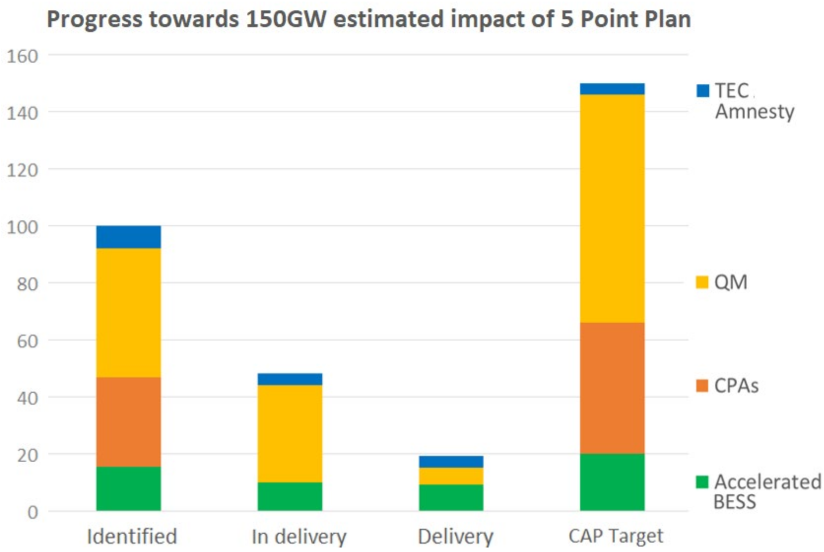
Combined status by milestone for relevant deliverables (Activity A14)

Status	Count	%
Complete	**27**	55%
On track	**19**	39%
Delayed – Consumer Benefit	**-**	-
Delayed – External Reasons	**-**	-
Delayed - Internal Reasons	**-**	-
Continuous activity	**3**	6%
Total	**49**	100%

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Supporting evidence

Type	Evidence
Performance Against Business Plan 2 (BP2) Deliverables	We have estimated that Transmission and Distribution projects in the transmission queue and waiting to connect could reach 800GW by the end of 2024 without further intervention, and until recently (through actions within our 5-Point Plan) customers continued to get later and later connection dates. Therefore, aligned to the ambition within the Connections Action Plan, our goal is to reduce the average transmission connection dates for viable, net zero aligned projects to no more than six months beyond the date requested by the customer. Currently, this stands at 46 months, with the GB connections queue growing rapidly. With the delivery of our BP2 milestones, we will demonstrate the improvements in this area through tangible outputs across queue management, acceleration of viable applications and tactical initiatives, as well as through our reformed connections process once live.
5 Point Plan	The graph below shows our progress through the delivery pipeline for achieving the benefits from the 5 Point Plan **Definitions used in graph below:** Measures Identified: Connection projects identified by network operators that have potential to qualify for detailed review

		In delivery: Revised connection agreements in progress Delivered: Revised offers issued <u>Activities in the 5-Point Plan</u> Accelerated BESS (Battery Electrical Storage System): Enabling storage projects to connect earlier on a non-firm basis CPAs (two-parts of 5 Point Plan): Construction Planning Assumptions, using revised modelling assumptions QM (Queue Management): Adoption of QM milestones TEC Amnesty: Transmission Entry Capacity is the opportunity for developers to return TEC that they no longer intend to use.  *CAP target: The CAP target identified 150 GW estimated impact of the 5 Point Plan, however in April 2024 Ofgem noted that the CAP was likely to deliver 100 GW of benefit.* **Performance**: TEC Amnesty: The TEC Amnesty is now closed, and 7.9 GW of projects expressed interest in participating, of which 4.1 GW were implemented as anticipated. QM: CUSC modification CMP376 was approved in November 2023, beginning a six-month notice period for projects in the queue to either request a delayed connection date, or have QM milestones applied to their current date. This puts us in a good position to robustly monitor project delivery against contracted milestones. Currently, 13.9 GW of projects are seeking to delay their connection. In addition, for projects connecting before 2026, 21 GW of projects are seeking to delay their connection. Together this comes to 34.9 GW 'in delivery'. CPAs: Following an expression of interest exercise in Q1 2023-24, TOs have reviewed projects that are seeking an accelerated connection date and have identified 31.5 GW of projects where this may be possible. Detailed network studies are now underway to confirm which projects can be accelerated. We have agreed with TOs and Ofgem that accelerated offers will be issued by October 2024. Accelerated BESS: 9.3 GW of accelerated non-firm offers have been issued in the first phase to 20 projects in England and Wales. A second phase across GB is in development.

	RRE 3X - Timeliness of Connection Offers	In 2023-24, of the 1578 offers issued, 1569 offers were made within 3 months (more than 99%) and 9 were issued after more than 3 months.
	RRE 3Y - Percentage of 'right first time' connection offers	95% of connection offers were right first time in 2023-24.

CBA: Taking a whole energy system approach to promote zero carbon operability (A15)

BP2 Mid-Scheme view of gross benefits compared to BP2

In BP2 we estimated gross benefits of £1,430.5 million over RIIO-2. For this Mid-Scheme update, we have not updated all of the BP2 gross benefits calculations as follows:

- For 'Whole system operability NOA-type assessment' we have updated the gross benefits, which have decreased from £1,303m in BP2 to £1,002m. This change is due to reduction in some of the previously forecasted benefits that would be delivered through Stability Phase 2, as some of these projects may be delayed from their initially contracted start date. This is however offset by the inclusion of other initiatives that will deliver benefits throughout the RIIO-2 period.
- For RDPs, as they are an enabler for more renewable generation to connect to otherwise congested and constrained areas of the network, we believe a better measure of the benefits is the MW volume connected and contracted. Therefore, we have provided our latest view of MW benefits for Mid-Scheme.
- For DER visibility savings, we have provided a written update.

	Estimated gross benefits during RIIO-2 (£m)		
Area	**BP2 Plan view**	**Latest forecast view**	**Variance**
1. Whole system operability NOA-type assessment (TOTAL)	1,303	1,002	-301
• Stability Phase 1	n/a	107	+107
• Stability Phase 2	1,303	525	-778
• Voltage Mersey	n/a	50	+50
• Voltage Pennines	n/a	3	+3
• Constraints B6	n/a	244	+244
• Constraints EC5	n/a	73	+73
2. RDP Carbon Saving	67	Estimate of MW benefits provided below	Estimate of MW benefits provided below
3. RDP Asset Savings	39	Estimate of MW benefits provided below	Estimate of MW benefits provided below
4. DER Visibility Savings	23	Written update provided for Mid-Scheme (see below)	
Total	**1,431**	**N/A**	**N/A**

Summary of progress in 2023-24

1. NOA

- A tender was launched in December 2023 for the Voltage 2026 service which seeks to identify potential solutions to meet reactive power requirements in two regions in England from 2026 onwards. Following engagement with NGET, we increased the requirement in the North Region
- We also launched a tender in December 2023 for the new Stability Y-1 market which is focused on securing stability services between 2025 and 2026. This tender will conclude by Q4 2024.

- We enacted the one-year extension option from the B6 year 2 contracts in June 2023 which ensures that the current service will be in place until September 2026. This will continue to deliver cost and carbon savings as reported in the table above compared to alternative options for managing constraints.
- In summer 2024, we will be tendering for an enduring constraint intertrip service in the East Anglia region to help alleviate constraints. This is for a service starting from April 2025, though as some generators in the area are already connected to the tripping scheme, we carried out a tender in late 2023 for these generators to offer an interim service to help deliver some of the benefits sooner. This interim service commenced in February 2024 and will run to March 2025, where the enduring service will take over.

2. RDPs

- MW dispatch and N-3 intertripping projects were delivered. These were delayed due to external reasons. However, there was no significant impact on benefit due to delayed connection background.
- The GEMS delivery did not make much progress in 2023-24. It was decided to close the project with agreement from Ofgem and SPT. The functionalities delivered by the Open Balancing Programme (OBP) will cover the short-term needs case. Given the slower rate of new generation connections, the needs case for securing this network now aligns with the roadmap and timescales of the OBP's additional capabilities. No impact on benefit is expected as a result of this change.

3. DER Visibility

- In September 2023, we launched a programme to drive delivery internally and with industry, the DER Visibility Programme. The programme will deliver an industry transformation covering ESO Business changes, ESO Data & Systems changes and Industry changes (DNOs, TOs, Market Participants, Market Platforms). We will lead the programme, which will require industry collaboration to be a success.
- To date, we have successfully collaborated with industry (DNOs, the Energy Networks Associations' Open Networks Project (ONP), the Association for Decentralised Energy (ADE)), Ofgem and DESNZ to agree a vision, design principles and an indicative roadmap for achieving DER visibility. This has been underpinned by capturing and prioritising approximately 200 industry use cases which are enabled by around 100 industry data points, through a series of industry workshops. Our Business Capability Impact Assessment of these use cases is being finalised and we have kicked off the ESO Technology Impact Assessment. We have agreed to integrate our industry engagement with the Open Networks Programme due to mutual alignment, benefit and efficiencies. This will be our route for coordinating equivalent DNO impact assessments.
- We have completed detailed benefits logic mapping for the programme and secured a benefits partner to conduct a robust modelled benefits assessment of the captured use cases. This will be followed by a detailed study of the proposed solutions to these use cases agreed with industry which will allow us to show what benefit will be delivered when throughout delivery of the programme.

Combined status by milestone for relevant activities (A15 activities, plus deliverable D8.1)

Status	Count	%
Complete	**32**	35%
On track	**34**	37%
Delayed – Consumer Benefit	**0**	0%
Delayed – External Reasons	**4**	4%
Delayed – Internal Reasons	**9**	10%
Milestone no longer valid	**4**	4%
Continuous activity	**9**	10%
Total	**92**	100%

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Supporting evidence

1. NOA

Type	Measure	Rationale and status
Reduction in Constraint Cost	£102m savings vs alternative actions	Savings in constraint costs achieved between April 2022 and February 2024 from the use of the B6 intertrip service compared to curtailing generators in the Balancing Mechanism. Over the same time period, constraint spend on the B6 boundary was £225m, so the intertrip service has helped save around a third of what would otherwise have been spent.
Reduction in constraint volume	400GWh	Savings in avoided wind curtailment achieved between April 2022 and February 2024 from the use of the B6 intertrip service compared to curtailing generators in the Balancing Mechanism. Over the same time period, the curtailment that did take place to manage the B6 boundary was 1.1TWh, indicating that the intertrip scheme reduced the volume of constrained energy by roughly 30%.
Reduction in Voltage management cost	£38m savings vs alternative actions	Savings in voltage management costs achieved between April 2022 and February 2024 from the use of the Mersey voltage compared to running Rocksavage in the Balancing Mechanism.
Inertia from zero carbon assets	12.3 GVA.s	Total inertia capability from Stability Phase 1 units which are now operational as of 31 March 2024.

2. RDPs

Type	Measure	Rationale and status
Qualitative evidence	MW volume connected	We believe the MW volume enabled to connect and contract is a more tangible and transparent way of measuring the RDP benefits. This means we can track on a monthly basis using DNO’s Appendix G submissions. See calculation of monetary benefit section below.

3. DER Visibility

Type	Measure	Rationale and status
Qualitative evidence	-	We have completed detailed benefits logic mapping for the programme and secured a benefits partner to conduct a robust modelled benefits assessment of the captured use cases. This will be followed by a detailed study of the proposed solutions to these use cases agreed with industry. This will allow us to show what benefit will be delivered throughout delivery of the programme.

Detail: Calculation of monetary benefit

1. Whole system operability NOA-type assessment

Stability Phase 1	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	The forecasted benefits of the Phase 1 service were calculated to be up to £128m over 6 years between 2020 to 2026. The service has been delivering since 2020, and therefore the benefits shown above, reflect the 5 years of delivery during the RIIO-2 period. For the BP2 End-Scheme Report we aim to calculate the benefit of the Phase 1 contracts against outturn BM counterfactual costs to better reflect what would have been incurred in the BM to access the inertia provided by the Phase 1 units.
Stability Phase 2	£1,303m between April 2024 and March 2026 based on the Balancing Mechanism (BM) cost of satisfying the Short Circuit Level.	In the table above, the forecasted benefits of Phase 2 has been revised down as some of these projects may be delayed from their initially contracted start date, thereby reducing the duration they will be in service during the RIIO-2 period.
Voltage Mersey	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	The £50m savings included in the first table is based on the forecasted savings of approximately £12.5m per year when compared to actions that would have to be taken in the BM to manage any voltage needs in the region from commencement of contracts in April 2022 until the end of the RIIO-2 period. The £12.5m annual saving was calculated at the point of contract award against known counterfactuals at the time. For the BP2 end-scheme report, we aim to calculate the benefit of the Mersey contracts against outturn BM

		counterfactual costs to better reflect what would have been incurred in the BM.
Voltage Pennines	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	The £3m savings is calculated by comparing the forecasted annual spend on the 200Mvar reactor from Mersey against the forecasted annual spend for a similar sized asset that will deliver for Pennines. This is then uplifted as 700Mvar has been contracted for Pennines, resulting in the £3m savings estimated between April 2024 to March 2026. This approach to compare the spend on reactors between Mersey and Pennines has been taken as there are no direct BM counterfactuals for any voltage needs in Pennines.
Constraints B6	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	The £244m benefit included in the first table is calculated based on realised savings from April 2022 to March 2024 of £102m and forecasted savings of £142m between April 2024 to March 2026. Savings are based on the cost to arm units to the intertrip versus the cost that would have been incurred in the Balancing Mechanism to curtail these units.
Constraints EC5	No estimate for savings were provided at the start of the RIIO-2 or BP2 periods.	The £73m benefit included in the first table is calculated based on realised savings from April 2022 to March 2024 of £0 and forecasted savings of £73m between April 2024 to March 2026. Savings are based on the cost to arm units to the intertrip versus the cost that would have been incurred in the Balancing Mechanism to curtail these units.

2. RDP Carbon Saving

Assumptions	BP2 Plan view	Latest forecast view
(a) Carbon intensity in grams of CO_2 per kilowatt hour (gCO2/kWh)	FES 2021 Steady Progression. Figures vary between 86 and 112 gCO2/kWh over the five years of RIIO-2.	Please refer 2(b) below
(b) Carbon generation reduction (GWh)	RDP 2 provided 278 MW of network access for renewable generation. Assuming this continues with an estimated load factor of 40% gives 974 GWh per year (278/1000*0.4*365*24 = 974)	The RDPs being delivered are an enabler for more renewable generation to connect to otherwise congested and constrained areas of the network. As such for this Mid-Scheme update, we believe a better measure of the benefits is the MW volume connected and contracted. Current planned connection volumes are as follows: NGED area: Up to end of 2023: 1373MW

		2024 and beyond: 2813MW (inc. the 2023 figure) UKPN area (as at Jan 2024): Up to end of 2023: 257MW 2024 and beyond: 1343MW (inc. the 2023 figure)
(c) Carbon price pounds per tonne of CO_2 equivalent (£/tCO2e)	Figures vary between 248 and 264 £/tCO2e over the five years of RIIO-2. Source: UK Government Policy Paper: Valuation of greenhouse gas emission 2 September 2021	As mentioned above we believe MW volume enabled to connect and contracted to connect is more tangible and transparent way of measuring the RDP benefits. For figures of MW volume please refer 2(b) above
RDPs completed	Zero for 2021-22 and 2022-23 One for 2023-24, 2024-25, 2025-26	As at March 2024, we have delivered 3 x RDPs (N-3 across 3 DNOs and a MVP MWD solution across both NGED and UKPN areas). Throughout 2024 and by 2025, we intend to deliver a further 3 MWD RDP which will provide an enhanced and scalable NGED and UKPN MWD solution as well as an ‘all DNO’ GSP Technical Limits RDP and a MWD type solution within the SPEN DNO area.
Calculation	CO_2 saved (Tonnes) (a)* x 974 (b) = average of 90,205 per year *(a) varies by year Benefits = CO_2 saved x carbon price (c) x RDPs completed	As mentioned above we believe MW volume enabled to connect and contracted to connect is more tangible and transparent way of measuring the RDP benefits. For figures of MW volume please refer 2(b) above
Gross benefits	Total £66.5m 2021-22: - 2022-23: - 2023-24: 22.2m 2024-25: 22.3m 2025-26: 22.0m	As mentioned above we believe MW volume enabled to connect and contracted to connect is more tangible and transparent way of measuring the RDP benefits. For figures of MW volume please refer 2(b) above

3. RDP Asset Saving

Assumptions	BP2 Plan view	Latest forecast view
(a) RDP's completed	We have committed to a minimum of three inflight RDPs annually during the RIIO-2 period, depending on system needs. Based on experience, these will take approximately two years to complete. Assumption phasing as follows: 2021-22: - 2022-23: 1 2023-24: - 2024-25: 1 2025-26: 1 Total: 3 RDPs	Following a delay in our early RDPs we have started to make better progress on delivery as we have gone through FY 2023 and move into FY 2024. The following phasing applies for either deliveries completed or planned: 2021-22: - (Actual) 2022-23: 2 (Actual) 2023-24: 1 (Actual) 2024-25: 2 (Forecast) 2025-26: 2 (Forecast) Total: 7 RDPs (inc. N-3)
(b) Value of RDP avoided asset build	Based on RIIO-1 avoided asset build of £12.9m per RDP. This is a net value with costs accounted for	Reflecting on our original Benefits Assumptions, we believe that the quicker and increased volume of DER Connections is a more tangible benefit assessment – these figures are included further up the table under 2b.
Calculation	3 (a) x £12.9 (b)	As above
Gross benefits	£38.7m	As above

4. DER Visibility Savings

Assumptions	BP2 Plan view	Latest forecast view
(a) Forecast operability costs per year	2021-22: £0 2022-23: £746m 2023-24: £660m 2024-25: £848m 2025-26: £1,458m Based the DER Visibility Benefits Assessment Master	The DER Visibility programme kicked off in September 2023 to turn the broad goals in BP2 into a clearly scoped and deliverable cross-industry programme. As part of Phase 1 of the programme (Sep – Dec 2023), it was agreed that more a robust, modelled approach was required to quantify the benefit of DER Visibility for ESO and for the wider industry. This will build on the original BP2 benefits assessment which was assumption-based and looked
(b) Reduction in constraint costs from DER Visibility	Greater visibility improves market access for smaller distributed participants and therefore liquidity. We are proposing a conservative reduction of 1% in unit costs for constraints.	

(c) Improved forecasting	Calculation: Annual constraint cost (£m) * (percentage improvement of forecasting, assumed to be 10% for this calculation based the most conservative view from ‘Steady Progression’ scenarios in the DER Visibility Benefits Assessment Master) * (% non-visible distribution connected generation). This gives £8.11m.	solely at transmission level benefit. As part of Phase 2 (kicked off in January 2024), we have completed detailed benefits logic mapping and secured a benefits partner to conduct the assessment based on the full suite of use cases captured in Phase 1. This assessment is expected to complete by end of June 2024. This initial study will be followed by a detailed study of the proposed solutions to these use cases that will be agreed with industry as part of Phase 2 of the programme. This second study will allow us to update our benefits realisation plan to show what benefit will be delivered when throughout delivery of the programme.
(d) Number of years of benefit	One, as we do not expect the visibility savings to be realised until 2025-26.	
Other	There are other consumer benefits of DER Visibility which are difficult to quantify at this stage, therefore we expect this CBA to present a conservative view of its benefits.	
Calculation	(£1,458m (a) x 1% (b)) + £8.11m (c)	
Gross benefits	£22.7m	

CBA: Delivering consumer benefits from improved network access planning (A16)

BP2 Mid-Scheme view of gross benefits compared to BP2

We now estimate gross benefits of £224m over the RIIO-2 period, which is a decrease of £60m compared to the BP2 figure of £284m.

	Estimated gross benefits during RIIO-2 (£m)		
Area	**BP2 Plan view**	**Latest forecast view**	**Variance**
Expanding NAP to England and Wales	284	224	-21%
Total	**284**	**224**	**-21%**

The main driver of the decrease is the lower outturn of the actual England & Wales constraint costs against the forecast. However, a lower outturn constraint cost is beneficial for the end consumer and we introduced the Constraint 5-Point Plan in 2021 to help reduce overall constraint costs.

Summary of progress in 2023-24

As part of our Planning and Outage Data Exchange programme we have continued to deliver a series of ongoing enhancements to our eNAMS system. We've delivered 10 releases in total up to the end of March 2024. These have allowed us to make continual efficiency and functionality improvements to our internal and third party TO outage planning processes.

The programme has also delivered a scoping document which details the further activity we will undertake to improve our outage planning processes. This will incorporate a full ESO existing process review, collaborative sessions with an engaged DNO to propose a series of optimal to be processes which will then be progressed via the ENA for wider visibility, and subsequent implementation by end of March 2025.

The programme also, as a third workstream, is working to understand the impacts and implications on any deliverables and also to build into any future process design of proposed GC0139 changes currently under review / discussion prior to regulatory approval.

Combined status by milestone for relevant deliverables (Activity A16)

Status	Count	%
Complete	**19**	50%
On track	**19**	50%
Delayed – Consumer Benefit	**-**	-
Delayed – External Reasons	**-**	-
Delayed - Internal Reasons	**-**	-
Continuous activity	**-**	-
Total	**38**	100%

For detailed commentary on all of the above milestones, please see the RIIO-2 deliverables tracker.

Supporting evidence

Type	Measure	Rationale and status
Qualitative evidence	-	The NAP policy process is firmly embedded within the ESO and all three onshore TOs. There are four elements to this being a success and we have shown that having an auditable process of tracking outage change and cost savings have been successful. We have seen a steady rate of all of the above activities since expanding the NAP process across England and Wales. 1) STCP 11-4 which is a facility which allows us to procure an enhanced service from a TO reduce cost. 2) STCP 11-3 which is a process that allows us to postpone outages where a planning step has been missed or where there is consumer benefit. 3) The NAP TO Justification process that allows us to assess the TO versus ESO cost of major outages in current year. 4) The CVO (customer and consumer value opportunities) process whereby we track the positive changes made to an outage plan or optimisations made.
Regularly Reported Evidence	RRE 1H Constraints Cost Savings from Collaboration with TOs	2023-24: Q1: £509m Q2: £205m Q3: £298m Q4: £720m These figures show that the expansion of the NAP policy and the CVO process had driven successful collaboration between the ESO and TO with regards to reducing constraint costs.

Our other outage optimisation activities are recorded as Customer Value Opportunities (CVO), which represent the savings made by optimising the requests for system access and efficiently planning the topography of the system. The CVO metric is used to indicate the associated costs for outages that affects specific boundaries' capabilities and their impact on demand security. Network Access Planners determine the associated costs whilst assessing these outage requests.

CVOs are released by negotiation with the TOs to ensure that outages are nested. This means that, for the purpose of managing a constraint, a Balancing Mechanism (BM) spend is only required once for an outage combination. They are also released through the co-ordination of transmission outages with generation shutdowns. There are more examples of the 'types' of initiatives that can result in consumer savings but the aforementioned are the most common. They are pertinent to A16.1 and although not directly related to the expansion of the Network Access Planning (NAP) policy or progression of A16.2 and A16.3, they evidence the heightened awareness of the commercial aspect of what we do in NAP. This heightened awareness and tracking/reporting as part of A16.1 has been largely driven by the expansion of the policy to E&W.

CVO savings for England and Wales:

- 2021-22: £1,135m
- 2022-23: £921m
- 2023-24: £315m

The table below show three of the outages from 2023-24 that were some of the highest CVOs.

S/N	Outage	Description	Saving
1	Norwich Main 400/132kV SGT2	Cross connection installed to remove Sheringham Shoal restriction during the NORM SGT2 replacement outage	£36.4m
2	High Marnham - Stoke Bardolph 400kV Circuit High Marnham QB2	Coordinated two outages to happen at the same time by agreeing with DNO to move all demand out of STOB. That allows under a single outage to fix hot joints across both circuits reducing our exposure to FLOWSTH constraint.	£16.2m
3	Ironbridge - Legacy 2 400kv Circuit. Legacy 400kV Quad Booster 3.	NGET had requested to extend the outage duration of Ironbridge – Legacy 2 400kV circuit in August 2023 for maintenance works, but this extension would have clashed with Cellarhead – Macclesfield 400kV circuit outage between 26-31 August 2023. NAP and NGET agreed to prioritise the CELL-MACC outage and to avoid this overlap, only the WSE on the IRON-LEGA-2 circuit was done, moved the other works to a later date when the outage can be secured.	£27.0m

Detail: Calculation of monetary benefit

Expanding NAP to England and Wales

Assumptions	BP2 Plan view	Latest forecast view
(a) Estimated England and Wales constraint costs	Total £2,466m based on NOA modelling 2021-22: £351m 2022-23: £464m 2023-24: £322m 2024-25: £453m 2025-26: £876m	England and Wales constraint costs. 2021-22: £190m (Actual) 2022-23: £436m (Actual) 2023-24: £275m (Actual) 2024-25: £357m (NOA forecast reduced by 21% based on the sum of the first 3 years' actuals being 21% lower than the first 3 years' NOA forecast)) 2025-26: £692m (NOA forecast reduced by 21% based on the sum of the first 3 years' actuals being 21% lower than the first 3 years' NOA forecast) Wholesale gas prices dramatically increased in the Autumn of 2021, following Russia's invasion of Ukraine. The wholesale gas price did not lower until the summer of 2023. This had a direct impact on the cost of replacement energy and constraint costs. This can be seen with the high cost for 2022-23.
(b) Forecast reduction in	11.5% based on benefits from NAP in Scotland.	11.5%. Original assumption is still valid.

constraint costs	This assumption is based on observed results from Scotland and power system knowledge that system complexity is approximately the same between Scotland and England and Wales, allowing benefits to be extrapolated across from Scotland. 2018/19 benefits in Scotland were forecast to be between £16 million and £36.7 million, equivalent to between a 7% and 16% reduction in costs. We have used the mid-range estimate of an 11.5% reduction in costs.	
Calculation	£2,466m (a) x 11.5% (b)	£1,950m (a) x 11.5% (b)
Gross benefits	£284m Phasing: 2021-22: £40m 2022-23: £53m 2023-24: £37m 2024-25: £52m 2025-26: £101m	£224m Phasing: 2021-22: £22m 2022-23: £50m 2023-24: £32m 2024-25: £41m 2025-26: £80m

Regularly Reported Evidence

Table: Summary of RREs for Role 3

Role 3 RREs don't have performance benchmarks.

RRE	Measure	BP2 outturn			
3A Future savings from Operability Solutions	i) Saved balancing costs:	£68m (Constraints Management Pathfinder B6 extension) £11m (Constraints Management Intertrip Service EC5 Interim)			
	ii) Saved infrastructure costs:	£47m (Constraints Management Pathfinder B6 extension) £49m (Constraints Management Intertrip Service EC5 Interim)			
	iii) Indicative impact on the SZCP limit:	See Report			
3X Timeliness of Connection Offers *Number of offers made (from clock-start date):*	Within 3 Months	Q1: 357	Q2: 369	Q3: 501	Q4: 342
	Longer than 3 Months	Q1: 0	Q2: 6	Q3: 1	Q4: 2
3Y Percentage of ‘right first time’ connection offers		Q1: 93%	Q2: 95%	Q3: 95%	Q4: 96%

RRE 3A Future savings from Operability Solutions

April 2023 to March 2024 Performance

This Regularly Reported Evidence (RRE) outlines the forecast medium to long term benefits from new operability measures including:

i. Saved balancing costs
ii. Monetised carbon reductions
iii. Any indicative impact on the SZCP limit

In each report we show projects concluded in the BP2 period so far, with estimated benefits up to the end of contracts. In the narrative we also call out what upcoming projects are likely to be included in subsequent reports during BP2.

i. Saved balancing costs

Table: Forecast balancing costs savings for operability measures concluding in BP2 so far

Operability Solution projects	LATEST VIEW Mid-Scheme View: Forecast Savings (£m)	PREVIOUS VIEW Mid-Year View: Forecast Savings (£m)
Constraints Management Pathfinder (CMP) B6 extension (October 2025 to September 2026)	68	45
Constraints Management Intertrip Service (CMIS) EC5 Interim (February 2024 to March 2025)	11	N/A
TOTAL*	79	45

* The method to calculate the costs savings it to compare the forecast constraint costs had the contracts not been entered into against those with the contracts being in place. The model we use forecasts constraints across the whole of GB, rather than on a specific boundary.

In future BP2 incentive reports, we will include the forecast savings of further operability measures as they are completed.

These future projects may include:

- Implementation of the FRCR policy on minimum inertia requirements
- The first Stability Y-1 tender which is expected to conclude in September 2024 for service delivery between October 2025 and September 2026
- Voltage 2026 tender which is expected to conclude in September 2024
- EC5 Enduring tender that will conclude in Q3 2024-25.

The expected completion dates for the above projects are subject to change and further updates will be provided in future BP2 reports.

Supporting information

Constraints Management Pathfinder (CMP) B6 – Extension of contracts to September 2026

The CMP service has completed two rounds of tenders, awarding annual contracts for delivery between October 2023 and September 2025. However, as some of the contracted units were already connected to the intertripping scheme, we requested that these units commence their service from April 2022, bringing forward the cost and carbon savings as reported in the BP1 end-scheme report.

We intended to revise how the CMP service is procured, from annual tenders with year-long contracts to a one-off tender with longer term agreements. To allow ourselves time to update the commercial, contractual, and technical aspects of the service, we enacted the one-year extension option from the B6 year 2 contracts in Q2 2023-24 which ensures that the current service will be in place until September 2026. This will continue to deliver cost and carbon savings as reported in section compared to alternative options for managing constraints.

Constraints Management Intertrip Service (CMIS) EC5 Interim – (February 2024 to March 2025)

As part of the NOA 2021-22 Refresh, it recommended proceeding with commercial solutions CS07 and CS08 to manage constraints in the East Anglia region from 2025 until network reinforcement works are complete.

Since early 2023, we have been developing a commercial intertrip service to contract with generators in the region to be connected to the East Anglia Operational Tripping Scheme (EAOTS). A tender will be carried out in Summer 2024, with contract award in Q3 2024-25, for services to start from April 2025. In parallel to the tender process, National Grid Electricity Transmission (NGET) will be carrying out upgrade works to facilitate more generators to connect, as well as reducing the time to trip generators in the event of a fault.

A number of generators are already connected to the EAOTS as part of their connection agreement and so we took the decision to carry out a tender with these parties to agree commercial contracts for a service to start in advance of April, with the aim to deliver savings sooner. Several generators have been contracted and the service commenced in February 2024 with the forecasted savings to March 2025 shown in the table above.

ii. Monetised carbon reductions

The carbon prices used in the tables below are taken from the BEIS publication ‘valuing greenhouse gas emission in policy appraisal’ [27]. These prices are also those used in our RIIO-2 Business Plan 2 Cost-Benefit Analysis – Annex 2 [28]. The prices are weighted for the calendar year in which the services are contracted to deliver.

Table: Constraints Management Pathfinder (CMP) B6 extension

Constraint Management Pathfinder B6	Unit	Oct 2025 – Sept 26
CCGT generation output avoided in GWh	GWh	450
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394
CO_2 in tonnes	tCO2	177,300
Carbon price (BP2)	£/tCO_2e	263
Savings	**£m**	**47**

[27] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal

[28] https://www.nationalgrideso.com/document/266121/download

Table: Constraints Management Intertrip Service (CMIS) EC5 Interim – (February 2024 to March 2025)

Constraint Management Intertrip Service EC5 Interim	Unit	Feb 2024 – Mar 2025
CCGT generation output avoided in GWh	GWh	488
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394
CO_2 in tonnes	tCO_2	192,272
Carbon price (BP2)	£/tCO_2e	257
Savings	**£m**	**49**

Supporting information

Constraints Management Pathfinder (CMP) B6 extension

The Constraint Management Pathfinder B6 contracts are a contractual arrangement where generators in Scotland are contracted to provide an intertrip service to alleviate system constraints. This allows more renewable generation to be exported which would otherwise have been curtailed. The service has been in use since April 2022 with the table above showing forecasted savings for the contract delivery period of October 2025 to September 2026. To calculate the monetised value of carbon savings, we have used the 2025 Central Series price from BEIS' 'Valuation of greenhouse gas emissions: for policy appraisal and evaluation' policy paper.

The constraint service is estimated to deliver savings of:

- Avoided generation from CCGTs: 450GWh
- Avoided CO2: 177k Tonnes
- **£ Savings: £47m**

This is an increase in savings from the £33m reported in mid-year report due to an increase in forecast of the GWH of avoided curtailment from the use of the intertrip service.

Constraints Management Intertrip Service (CMIS) EC5 Interim

The CMIS EC5 contracts make use of generators that are already connected to the EAOTS to be able to be armed to alleviate system constraints. This allows more renewable generation to be exported which would otherwise have been curtailed. The service has been in place since February 2024 with the table above showing forecast savings for the contract delivery period March 2025. To calculate the monetised value of carbon savings, we have used the 2024 Central Series price from BEIS' 'Valuation of greenhouse gas emissions: for policy appraisal and evaluation' policy paper.

The constraint service is estimated to deliver savings of:

- Avoided generation from CCGTs: 488GWh
- Avoided CO2: 192k Tonnes

£ Savings: £49m

iii. Any indicative impact on the SZCP limit

The record as at the end of the first year of BP2 for Zero Carbon Operation was 91.3% on 28 December 2023 between 14:30-15:00 and Carbon Intensity was 28g CO2/kWh. There were nine carbon emitting generators on the system at the time.

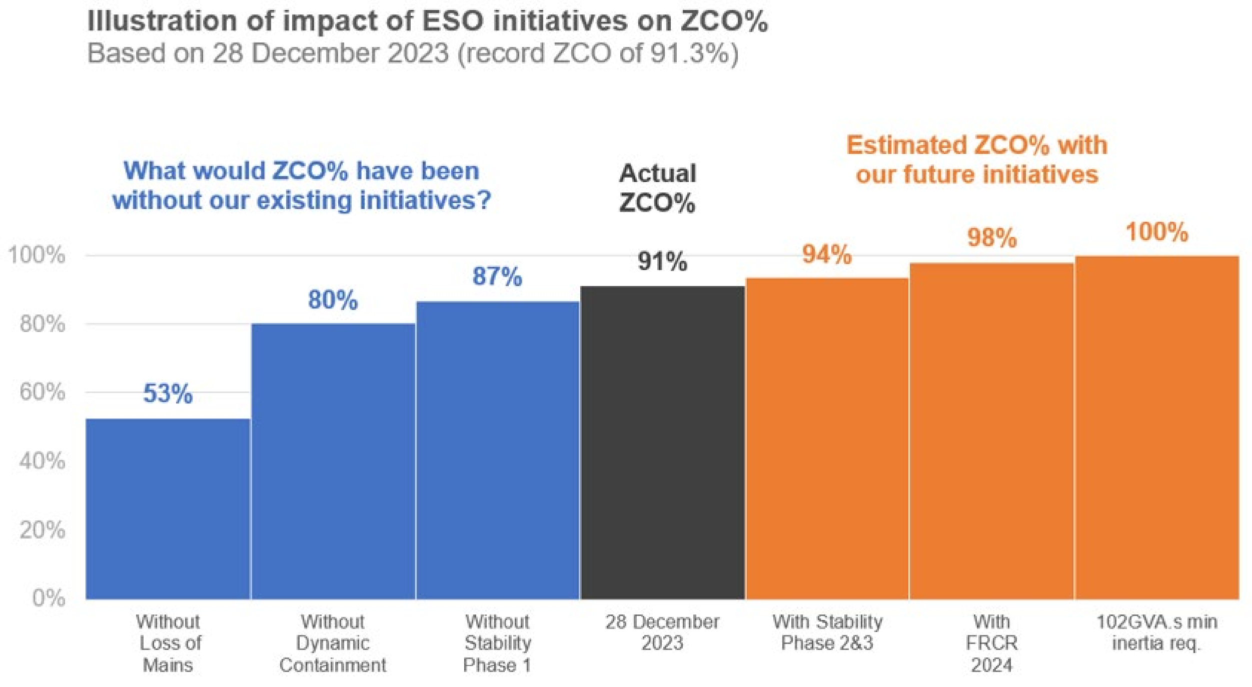
The below graph shows how much lower the ZCO% would have been on 28 December without the delivery of Stability Phase 1, Dynamic Containment and the Loss of Mains change programme. Each programme is assessed independently rather than cumulatively.

- **Stability Phase 1** delivered 12.5GVA.s of inertia, reducing the need for four units at 1000MW. Without Phase 1 the ZCO% would have been 87%.

1. **Dynamic Containment (DC)** has significantly reduced the need to hold legacy frequency response products. Without DC, an additional 2,500MW of headroom would have been required on synchronous carbon emitting generation. This equates to 10 units at 250MW each, reducing the ZCO% to 80%.
2. **The Loss of Mains change programme** has reduced the potential volume of embedded generation susceptible to trip following a frequency change faster than 0.125Hz/s. Had we not completed the programme, we would have required 280GVA.s of inertia to prevent the largest single generation loss causing frequency to change faster than 0.125Hz/s, leading to further generation loss. The system was expected to have 153GVA.s, so an additional 43 units would have been needed to deliver 130GVA.s at 250MW each. This would have reduced the ZCO% to 53%.

The graph then shows how our future projects will help close the ZCO gap to 100% by 2025.

- **FRCR 2024** is out for consultation to maintain the minimum inertia requirement at 120GVA.s (proposed by FRCR 2023 but not yet implemented). Therefore FRCR 2024 would reduce the minimum inertia requirement from the 140GVA.s on 28 December to 120GVA.s. This has the effect of needing approximately six less carbon emitting generators. This would increase the Zero Carbon MW by 1500MW and the ZCO% to 98%.
- **102GVA.s min inertia req.** As outlined in our Operability Strategy Report, we are aiming to reduce the minimum inertia requirement to 102GVA.s by 2025. This means more periods with a zero carbon generation mix will be operable. Compared to 28 December 2023, this could reduce the number of carbon emitting units by ten. This would effectively increase the Zero Carbon MW by another 3000MW and the ZCO% to 105%. As this isn't possible, the calculation is capped to 100%.



NB - The calculations make assumptions about the contribution to system needs on 28 December 2023, taken from FRCR. Each synchronous generator provides 3GVA.s of inertia, operating at a minimum output (Stable Export Limit – SEL) of 250MW with a maximum available output of 500MW.

Whilst this exercise shows that future projects will enable a day like 28 December to be zero carbon, there are further projects which will enable zero carbon on other days too.

There are four reactors being delivered by April 2025 which are for economic reasons, effectively removing the need for a further four generators (1000MW).

Stability Phase 3 bought 17.1GVA.s which, once delivered, removes the need for five units (1250MW).

Looking beyond 2025, our voltage tender for 2026 will procure enough reactive power to remove another two units (500MW).

RRE 3X Timeliness of Connection Offers

This Regularly Reported Evidence (RRE) reports on the number of connection offers made within 3 months of clock start date, and the number of connection offers made that took longer than 3 months.

We provide this information separately for the England and Wales area, the Scotland area and by Transmission Owner (TO) area:

- England and Wales: National Grid Electricity Transmission (NGET)
- Central and Southern Scotland: SP Transmission (SPT)
- North of Scotland: Scottish & Southern Electricity Networks (SHET)

In year 1 (2023-24), in England and Wales, while the two-step offer process is running, we will report:

- The number of standard offers issued within 3 months.
- For two-step offers, the number of (one-step) offers issued within 3 months.
- the number of two-step offers issued within nine months, after counter signature of the step one offer;
- and the number of any connection offers that took longer than the above timeframes.

We also report on the scale of the connection queue in terms of GW and time from offer acceptance to connection date. We include a breakdown of assets in the connection queue by size, technology type, and TO area.

Please note these figures are consistent with the Connections monthly data submission provided to Ofgem.

Table: Quarterly connection offers by time taken

Area	Connection offers issued:	Q1	Q2	Q3	Q4	Total
NGET (England and Wales)	(Standard offer) Within 3 months	162	28	30	21	**241**
	(One-step) Within 3 months	23	154	285	5	**467**
	(Two-step) Within 9 months*	0	0	0	143	**143**
	Longer than the above timeframes	0	0	0	0	**0**
	Total	**185**	**182**	**315**	**169**	**851**
SPT (Scotland)	(Standard offer) Within 3 months	77	104	83	71	**335**
	Longer than 3 months	0	4	1	0	**5**
	Total	**77**	**104**	**84**	**71**	**336**
SHET (Scotland)	(Standard offer) Within 3 months	95	89	103	102	**389**
	Longer than 3 months	0	2	0	2	**4**
	Total	**95**	**89**	**103**	**104**	**391**
TOTAL	Within 3 months	**357**	**369**	**501**	**342**	**1569**
	Longer than 3 months	**0**	**6**	**1**	**2**	**9**
	Total	**357**	**375**	**502**	**344**	**1578**

* after counter-signature of the step one offer

Figure: Connections queue in MW split by time from offer acceptance to connection: Q1 (30 June 2023) vs Q2 (30 Sep 2023) vs Q3 (31 December 2023) vs Q4 (31 March 2024)

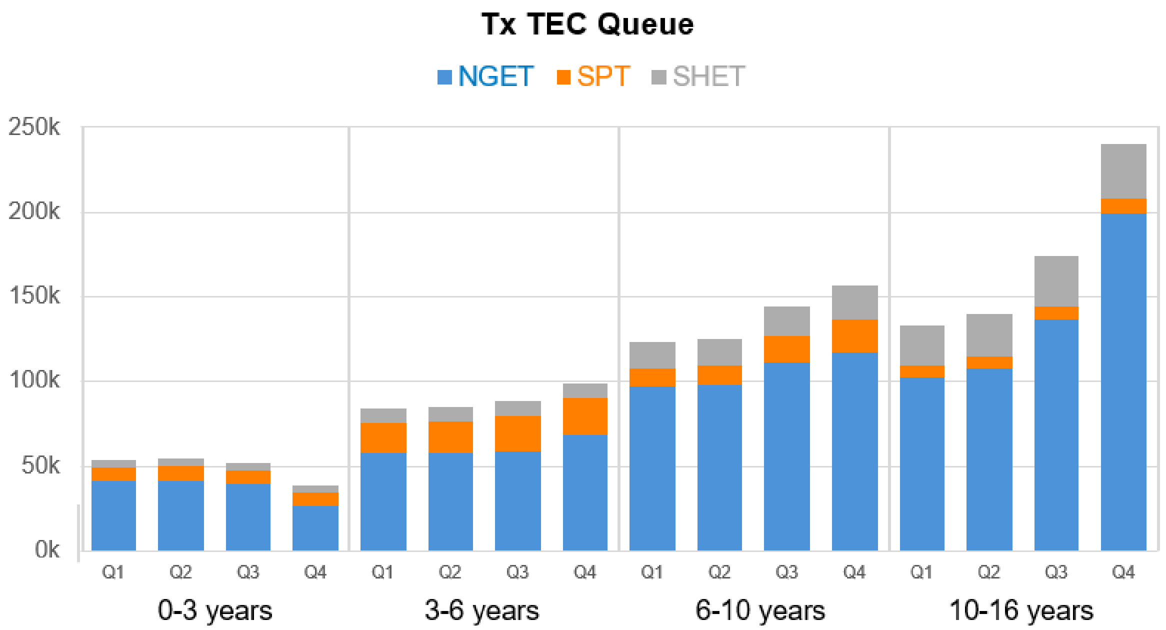
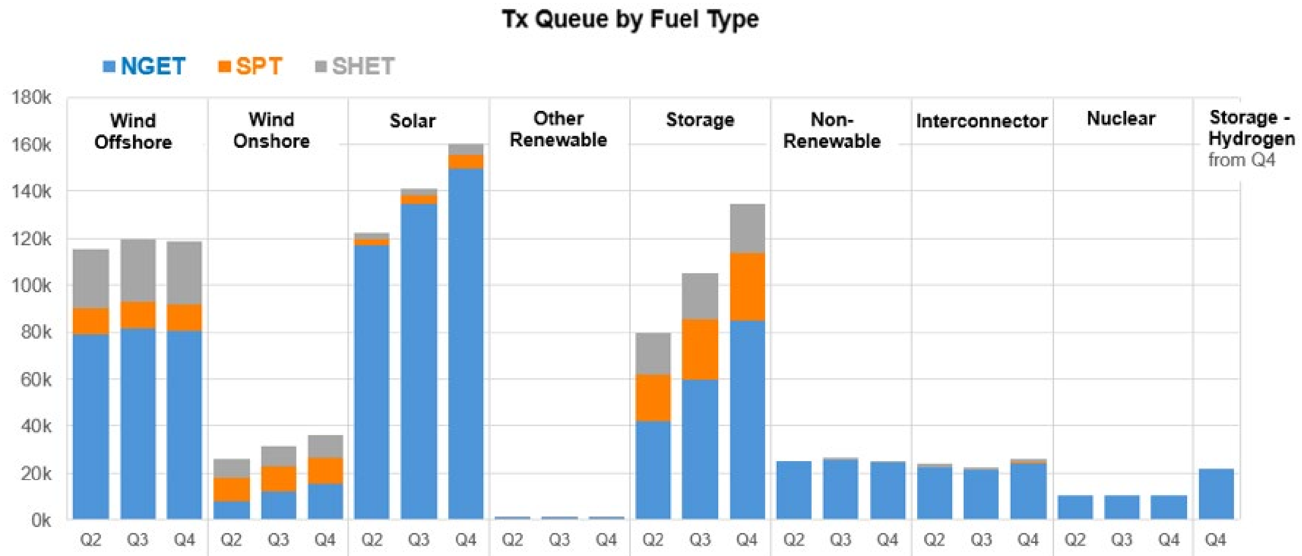


Table: Connections queue in MW split by time from offer acceptance to connection

Host TO	Unit	0-3 years	3-6 Years	6-10 Years	10-16 Years	Total
NGET	MW	26,513	68,716	117,390	199,062	**411,680**
SPT	MW	7,688	21,679	19,493	9,120	**57,980**
SHET	MW	4,105	8,389	19,422	32,265	**64,182**
Total	MW	**38,306**	**98,784**	**156,306**	**240,446**	**533,842**

Figure: Connections queue in MW by technology type (31 March 2024)



Note: Since the Q1 report, the fuel type classifications have changed in line with other regulatory reporting. Therefore, we are unable to show the change at technology level compared to Q1. From Q3 onwards we have been able to show change compared to the previous quarter.

Figure: Connections queue in MW by technology type (31 Mar 2024)

Host TO	NGET	SPT	SHET	Total
Wind Offshore	80,642	11,356	26,468	**118,466**
Wind Onshore	15,493	11,175	9,367	**36,035**
Solar	149,547	5,969	4,688	**160,204**
Other Renewables	733	-	327	**1,060**
Storage	84,858	28,751	21,021	**134,630**
Non-Renewable	24,324	-	910	**25,234**
Interconnector	23,804	730	1,400	**25,934**
Nuclear	10,680	-	-	**10,680**
Storage - Hydrogen	21,600	-	-	**21,600**
TOTAL	**411,680**	**57,980**	**64,182**	**533,842**

Supporting information

Timeliness of connection offers

Application volumes continue to increase in comparison with 2022-23 and this is reflected in the number of offers being sent out across all three TOs.

Two offers were sent outside of CUSC timescales in Q4, this was due to a late clock start on a BELLA agreement and affected both the Customer and DNO Offers - an extension was requested from Ofgem. Further to this, an extension has been granted by Ofgem for all Offers received between 27th November 2023 and 29 February 2024 potentially affecting 330 applications, the effect on timeliness of these offers will be seen at the end of Q1 2024-25.

Connections queue

The Connections queue continues to increase, moving from 457GW at the start of Q4 to 534GW at the end of the quarter. The vast majority of this increase is due to new connection applications from battery storage developers. A large increase in connection dates for the 6-10 year and 10-16 year periods can be seen, which is in line with average connection timescales of 10 years in E&W and 7 years in Scotland.

CUSC modification CMP376 (Inclusion of Queue Management process within the CUSC) was approved and implemented in November 2023. This introduces queue management milestones into connection contracts and allows the ESO to terminate contracted projects which are not progressing against agreed milestones. This is a significant step towards being able to reduce the size of the overall queue and remove stalled projects. Our connections reform proposals (to go live from January 2025) will go further and faster towards reducing the overall queue by removing stalled projects.

RRE 3Y Percentage of 'right first time' connection offers

This RRE measures the % of connection offers made which did not need reissuing. For those that needed reissuing, we break these down by reason.

We include details of the number of connection offers made for the England and Wales area, and the Scotland area, in addition to by TO area. During the period where the 2-step offer process is in place, we will report this separately for step 1 and step 2 offers.

Table: Quarterly % of 'right first time' connection offers

Area	Connection offers	Q1	Q2	Q3	Q4	Total
NGET	Total Step 1 offers signed	1	72	224	197	494
	Number right first time	1	70	222	193	486
	Percentage right first time	**100%**	**99%**	**99%**	**98%**	**98%**
	Total Full / Step 2 offers signed	222	147	38	41	448
	Number right first time	182	121	28	31	362
	Percentage right first time	**95%**	**93%**	**92%**	**90%**	**93%**
SPT	Total connection offers signed	50	48	65	58	221
	Number right first time	38	42	55	55	190
	Percentage right first time	**88%**	**98%**	**97%**	**95%**	**94%**
SHET	Total connection offers signed	46	63	52	65	226
	Number right first time	36	48	36	61	181
	Percentage right first time	**91%**	**95%**	**90%**	**94%**	**93%**
TOTAL	Total connection offers signed	319	330	379	361	1389
	Number right first time	257	281	341	321	1200
	Percentage right first time	**93%**	**95%**	**95%**	**96%**	**95%**

Table: Connection offer that needed reissuing by reason

Area	One-step connection offers	Q1	Q2	Q3	Q4	Total
NGET	Customer driven	18	14	6	6	44
	ESO driven	12	11	4	8	35
	TO driven	24	13	5	7	49
	Total	**40***	**28***	**12***	**14***	**94***
SPT	Customer driven	6	5	7	5	23
	ESO driven	6	1	2	3	12
	TO driven	3	4	2	5	14
	Total	**12***	**6***	**10***	**10***	**38***
SHET	Customer driven	4	7	11	14	35
	ESO driven	4	3	5	4	16
	TO driven	4	7	6	2	20
	Total	**10***	**15***	**16***	**16***	**57***
TOTAL	Customer driven	28	26	24	25	103
	ESO driven	22	15	11	15	63
	TO driven	31	25	13	14	83
	Total	**62***	**49***	**38***	**40***	**189***

* Please note that re-offers can be driven by more than one factor. Therefore, the totals can be lower than the sum of the figures for each reason.

Supporting information

Numbers of re-offers are spread across the TOs relative to the number of offers signed within the period, and the drivers for the re-offers are fairly evenly distributed with ESO driven re-offers coming in a little lower than the others.

There are a variety of reasons leading to an offer being re-issued such as amendments to appendices, charging statements and offer documents following post-offer discussions.

The number of ESO driven re-offers directly affects our performance percentage, which is calculated by looking at the number of offers right first time not due to an ESO re-offer. Re-issued offers and the reasons for them are continuously reviewed.

Overall performance has improved over each quarter resulting in a 95% Right First Time for the year.

Quality of Outputs (Roles Guidance Criteria)

All roles

ESO

Quality of Outputs (Roles Guidance Criteria)

In this section, we provide evidence against the Quality of Outputs criteria which have been integrated into the Ofgem Roles Guidance document for BP2. These criteria are not role-specific and include:

- Publications
- Stakeholder Engagement
- Submissions to the Authority
- Proactivity
- Data and Information
- ESO Policy

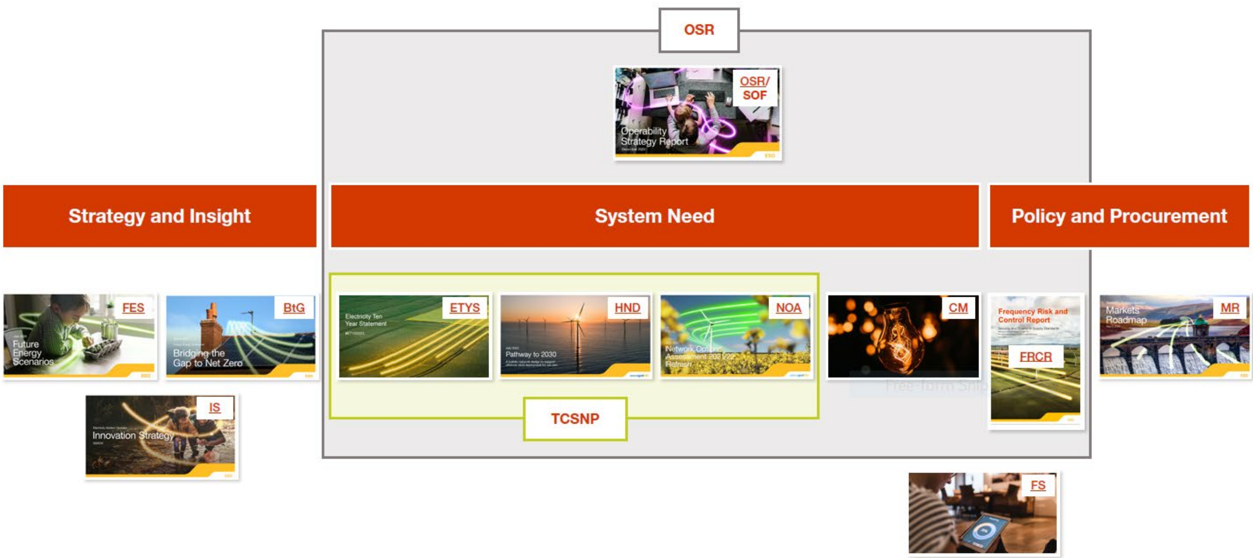
These criteria cover a wide range of ESO activities, and to ensure reporting is proportionate, we have provided targeted evidence below across a selection of the above criteria. There is also further evidence across other areas of this report. Alongside our reporting we regularly engage with Ofgem to discuss performance in these areas.

Publications

Each year, we publish a wide range of reports that provide energy insight and analysis, as well as information about how we're shaping the future of energy in the UK. All our reports are found on their respective pages on the ESO website, and can also all be easily searched and accessed on our dedicated Research and Publications webpage.

Our publications vary in content and level of detail dependent on the target audience, however, are consistent in approach such that stakeholders can easily navigate through them.

The visual below shows how some of our key publications sit alongside one another in terms of purpose. This visual is included in many of our publications so our stakeholders are able to understand the purpose of each publication and decide which may be of interest to them. We've also included a table of links to some of our publications from the last 12 months.



Publication (click for link)	Summary	Date of latest publication
Future Energy Scenarios (FES)	Future Energy Scenarios (FES) represent a range of different, credible ways to decarbonise our energy system as we strive towards the 2050 target.	July 2023
Innovation Strategy (IS)	Our ESO Innovation Strategy document sets out our innovation priorities for the next year.	April 2023
Operability Strategy Report (OSR)	The report outlines our strategy for meeting operability challenges as we progress to operating the electricity system at zero carbon.	December 2023
Electricity Ten Year Statement (ETYS)	The Electricity Ten Year Statement outlines our view of the National Electricity Transmission System over the next ten to twenty years.	August 2023
Beyond 2030	The Beyond 2030 report builds on the Holistic Network Design, further mapping the way to a clean, secure energy future.	March 2024
Markets Roadmap (MR)	The roadmap sets out our market design objectives, principles and plans to reform and evolve our markets.	March 2024

Across our publications we constantly strive to make improvements by learning from experience and seeking feedback from our stakeholders. See below a case study example of where we have made improvements to a publication this year.

Publications Case Study – Markets Roadmap (published March 2024)

The Markets Roadmap in 2024 is the fourth iteration of this publication, which is intended to outline how and why we are reforming the ancillary service and balancing markets we operate.

Customer feedback is crucial to the Markets Roadmap, both in terms of the structure and content of the report, but also to drive the market reforms that the Roadmap outlines.

Some of the improvements to the report this year include:

- An executive summary which illustrates how we see our markets evolving out to 2030, and the potential scenarios beyond 2030 as wider market reform decisions (REMA) will significantly impact our own market design.
- A change to the structure of the report so that the Markets Roadmap is easily comparable to the Operability Strategy Report (OSR). This is important because new markets are designed in response to the system operability needs contained with the OSR.
- A section on revenue stacking, clearly showing where there are opportunities to combine the provision of services, increasing the opportunities for revenue. While this is currently not possible for all services or across DSO services, we have committed to expanding revenue stacking and indicated where we are focusing our efforts.
- In response to previous feedback that the delivery plans contained in early publications were very quickly out of date, we've removed them from this year's roadmap and replaced them with a monthly update on the webpage. This means that up-to-date information about plans for the delivery of reforms and new services can easily be found, along with explanations for any changes. This change was introduced at the Operational Transparency Forum and is regularly promoted there to remind stakeholders.

Previously, we launched the Markets Roadmap with a specific webinar and Q&A session. However, in response to feedback, we launched the latest version at the 2024 Spring Markets Forum, followed by a live Q&A session, giving stakeholders the time to digest the material before asking questions.

Stakeholder Engagement

Stakeholder engagement is critical across all our activities. Engaging with and having representation from the full range of stakeholders across the energy landscape, ensures we maximise the level of insight, collaboration and debate and drives the best possible outcome for all involved.

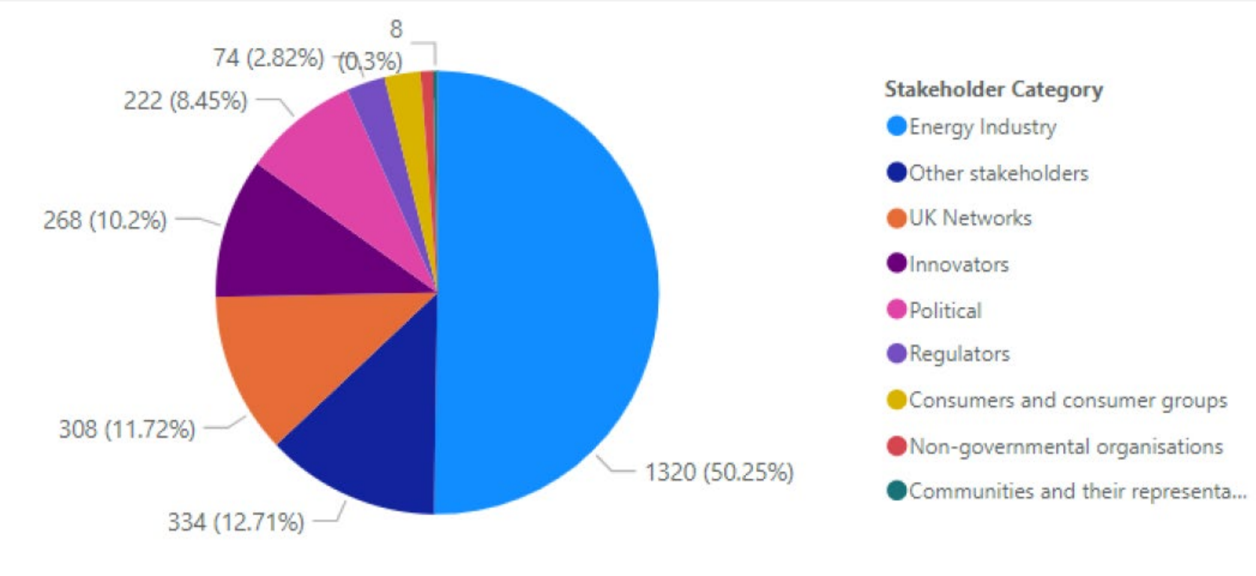
For this criteria, we have chosen to demonstrate how we engage with our stakeholders using a specific case study. However, there are many examples of engagement in other sections of this report, particularly in our Plan Delivery and Stakeholder Evidence chapters.

Stakeholder Engagement Case Study – Future Energy Scenarios (FES) 2024

Engaging with our stakeholders and planning for FES 2024 began in the summer after the publication of FES 2023. We took the opportunity to review the stakeholders we had engaged with as part of the FES 2023 planning process and, recognising the importance of continuing to seek out both a broad range of views and fresh perspectives, identified new organisations for FES 2024.

For FES 2024 we have engaged with 2,627 stakeholders across all our events (including the 2023 launch) representing a total of 561 organisations. To ensure we maximise the breadth of stakeholder engagement, we engage with all nine stakeholder categories identified for FES, with organisations across sectors including motor manufacturing, home building associations, universities, energy suppliers, trade bodies and more.

FES Engagement – Stakeholder Category % Mix



FES Engagement – Stakeholder Sub-Category Breakdown

Sub-category	Total	Sub-category	Total	Sub-category	Total
Industry bodies & experts including consultancies and trade bodies	407	Regulatory bodies	74	Interconnectors	17
Generators (including Big 6)	241	Small businesses	66	Other including media	17
National Grid ESO	221	Large businesses	65	Other non-governmental organisations	17
Gas and electricity transmission companies	193	Small renewables	58	Transmission directly connected demand	14
Manufacturers and technologists	168	Offshore gas companies	45	Small generators	10
UK government bodies	165	Gas distribution networks	39	Environmental groups	7
Energy suppliers	119	General public/individual responses	39	Environmentalists	7
Storage and flexibility	112	European TSO	37	Local campaign groups and advocacy groups	6
Academics, universities and schools	103	Local authorities	37	Other UK networks including water and communications	4
Infrastructure providers	96	Consumer groups and charities	30	Shippers	3
Distribution network operators	82	European and international networks	23	Terminal operators	3
Finance and investment community	80	Devolved administrations	20	Impacted local communities and residents	2

We use a range of methods to ensure we offer all stakeholders the opportunity to get involved and share insight with us. These methods are outlined in our strategy and include online meetings, in-person workshops and consultations, as well as our email and social media platforms. During our events we ask our stakeholders a range of questions from targeted and specific, to broader open-ended questions, all designed to encourage discussion and foster debate.

The list below outlines the key engagement activities we have conducted for FES 2024 so far, ranging from full-day, multi-stakeholder engagement sessions, to strategic bilateral meetings:

- The **FES 2023 launch** saw over 5.3k stakeholders attend or watch our launch events on catch-up. We hosted an in-person event at the Science Museum in London, followed by four webinars looking closely at each of the FES chapters from the main document.
- The **FES 2024 Call for Evidence** took place in September 2023, promoted via ESO social media and FES platforms. This online engagement provided new and existing stakeholders the opportunity to contribute to the future of energy.
- The **FES 2024 framework workshop** took place during September 2023 in London, giving stakeholders early sight of the draft FES 2024 framework and pathways. Feedback received was taken forward to further refine the new framework.
- **FES 2024 bilateral meetings** began in August 2023 and will continue until early spring. These 1:1 meetings with key organisations form an important element of the engagement cycle and production of FES.
- **FES 2024 Topic Table Talk Day** took place at the end of November 2023 in London. This in person event attracted 80 stakeholders representing a wide range of energy industry organisations.
- We hosted two **Network Forum** meetings during the second half of 2023, the latter one in October.

The table below shows how the number of stakeholders we are engaging with is increasing year-on-year as we continuously improve and evolve our strategy:

Engagement event:	2023 for FES 2024	2022 for FES 2023	2021 for FES 2022
FES launch event (in-person and webinars)	2,203 stakeholders	1,365 stakeholders	428 stakeholders
FES launch stream and catch-up	3,188 stakeholders	1,984 stakeholders	142 stakeholders
FES framework workshop	34 stakeholders	n/a	n/a
Call for Evidence	35 stakeholders	61 stakeholders	46 stakeholders
Topic Table Talks	81 stakeholders	63 stakeholders	n/a
All other FES engagement	83 organisations	76 organisations	95 organisations

As part our engagement, and to ensure we are always meeting stakeholder needs, we regularly conduct stakeholder satisfaction surveys following events. See below the satisfaction scores from some of our 2024 events/engagement:

Engagement event:	Average score (out of 10)
Bilateral engagement	8.75
FES launch	8.32
FES Framework Workshop	8.37
Topic Table Talks	8.37

Proactivity

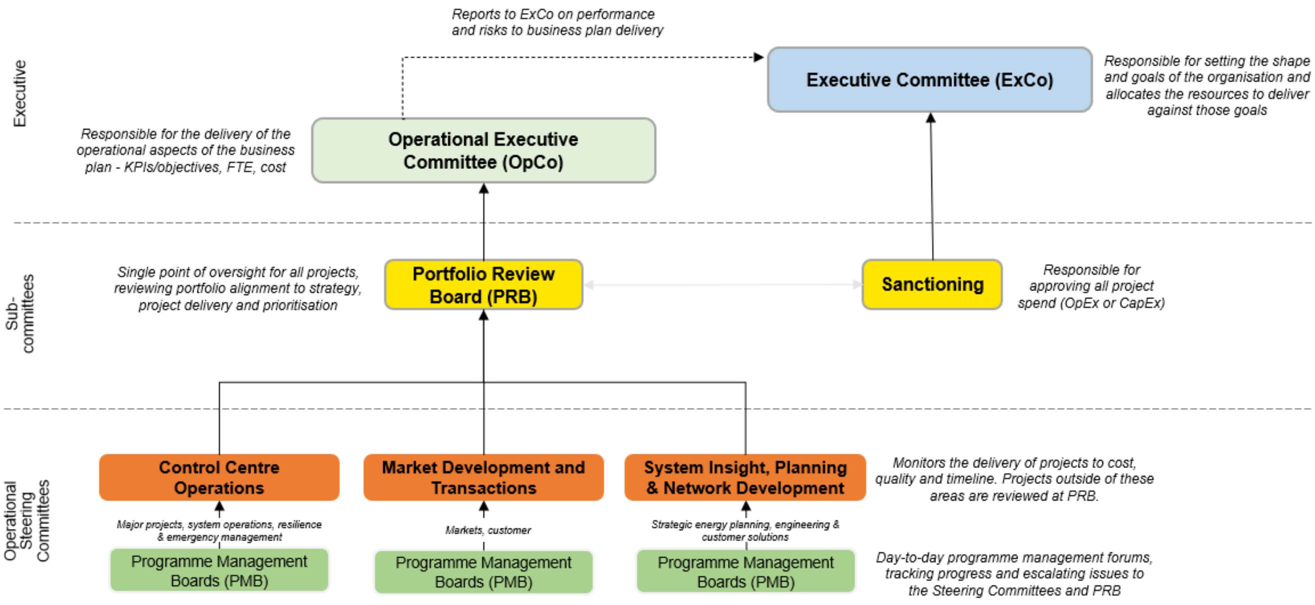
This section sets out how we proactively manage the RIIO-2 BP2 delivery plan. To maximise delivery and consumer benefits and mitigate risk, the Portfolio PMO team monitors delivery through regular plan testing and assessments which also enable a flexible approach to delivery.

Knowledge of current and future risks

Knowledge of current and future risks to our delivery of the Business Plan is reviewed on a monthly basis and updated to the Role Operational Steering Committee. Any risks are escalated to the Portfolio Review Board (PRB) and on to the Operational Executive Committee where necessary (see “Governance Landscape” below).

These escalation governance forums can help remove blockers and get delivery back on track. In addition to flagging risk of delay, delivery confidence is also assessed and monitored monthly. Delivery Confidence is driven by internal and external dependencies and risks such as resourcing, and reliance on external parties which are out of our control. Where appropriate and where possible, mitigating actions will be put in place to bring any forecast risks and delays back on track.

Governance Landscape



Proactive plan testing

Proactive plan testing is undertaken monthly to capture any in-month changes. A more comprehensive test is undertaken quarterly, including the update of all current and future delivery milestones along with updated progress and commentary on progress. This ensures all system data is current and up to date. This process is clearly embedded into our Workfront Programme and Project Management tool (PPM) which Project Managers, Programme Managers and Project Sponsors are familiar with and update commentary regularly.

Continual re-assessment of plans to maximise value to consumers

Continual re-assessment also takes place as part of the monthly and quarterly updates so that customer value can be monitored, and deliverables amended if appropriate to maximise customer value. In these cases, a milestone can be flagged with a status of ‘Delayed – Consumer Benefit’. This status is relevant when more consumer benefit can be realised by delaying an activity.

We have developed a prioritisation approach based on a set of principles as shown in the diagram below. This prioritisation decision support framework will allow us to dynamically respond to external or internal environmental changes to the baselined business plan, help support our narrative behind any deviations to the plan and identify any support requirements in the interim.

Prioritisation Framework

Flexible approach to delivery

Through regular and proactive assessments as documented above, we are able to get early sight of delivery items that could deliver greater value for consumers if a different delivery approach is adopted.

This approach has recently been evidenced through the removal of Generation Export Management Scheme (GEMS) milestones from the BP2 delivery schedule. The value expected from this activity is now being delivered through another activity within the business plan (Open Balancing Platform).

Data and Information

This section provides evidence around how we ensure that data and information is easy to find, accessible and consistent in messaging.

Navigation and accessibility of ESO data

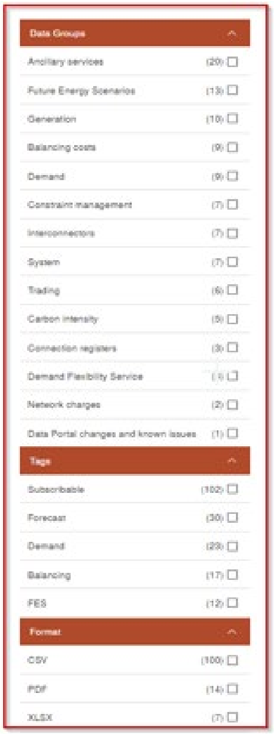
The Data Portal has enabled a transformation of our customers experience by:

- Providing a central repository of published data
- Greatly improving search capabilities
- Using a standard metadata format that allows us to provide detailed descriptions along with easy access to our data
- Providing different ways to consume our data.

The Data Portal provides powerful and logical search capabilities that make it faster and easier to navigate and find our data. All our datasets are available in an accessible format (machine readable) and can be consumed through an application programming interface (API).

See below screenshots below from the Data Portal which show how users are able to easily navigate. Please visit our Data Portal here.

1. Users can search for data using a search bar or via the relevant group/category from the home page. There are other methods by which data can be located, e.g., via tags or format.



2. Users can also search and navigate using popular/new/updated datasets categories

Popular Datasets	New Datasets	Updated Datasets
Non-BM ancillary service dispatch platform (ASDP) instructions The ESO publishes non-BM instruction data from our ASDP system. This data is published in near real-time…	**Ancillary Services Important Industry Notifications** The dataset contains the latest update on important ancillary services procurement changes. Please…	**Balancing Services Contract Enactment** National Grid ESO procures…
NemoLink - NGESO's Net Transfer Capacity These are the values submitted by NGESO to the interconnector capacity calculation processes which…	**EAC-BR Mock Auction Results** A set of auction results views which present the outcome of daily Enduring Auction Capability (EAC) -…	**Upcoming trades** This dataset displays all upcoming electricity trades due to be delivered. To meet our forecast…
Demand Flexibility Service 2023/24 National Grid ESO are again launching the Demand Flexibility Service (DFS) for Winter 2023/24. The…	**Wind BOA Volumes** This dataset contains the volumes of all BOAs taken on wind BMUs that are used in our incentive wind…	**Historic generation mix and carbon intensity** The carbon intensity of electricity measures how much carbon dioxide emissions are produced per kilowatt…
Transmission Entry Capacity (TEC) register A list of projects that hold contracts for Transmission Entry Capacity (TEC) with us. These include…	**Viking Link - NGESO's Net Transfer Capacity** These are the values submitted by NGESO to the interconnector capacity calculation processes which…	**Interconnector Requirement and Auction Summary Data** National Grid ESO (NGESO) trades on interconnectors to adjust the flow of electricity into or out of…
Enduring Auction Capability (EAC) auction results The current suite of response services (DC, DM, and DR) are now being procured via the EAC platform.	**Enduring Auction Capability (EAC) auction results** The current suite of response services (DC, DM, and DR) are now being procured via the EAC platform.	**Weekly operational planning margin requirement (OPMR)** OPMR is the amount of generation exceeding the demand forecast needed to meet our reserve requirement…

3. Data is provided to users in a variety of accessible formats

4. Formats can be consumed manually using a download link or programmatically consumed via an API

Withholding of data

To date, we have not identified any datasets where the open data triage process has identified the need for data to be withheld from industry.

We have put in place an open data triage process that presumes data is open whilst managing sensitivities including data privacy, security, legislation and regulatory obligations, negative commercial impacts, and negative public interest. The process has a requirement to record any reason or mitigation technique that has been applied to make the data open, which will also be published alongside the data.

We are currently reviewing the process to ensure the correct management of the security sensitivity in line with the DESNZ, NPSA, and Ofgem guidance following discussions that data available, in conjunction with other open data from other industry participants, could be a national security threat to the UK.

Consistency of messaging

We hold an online Operational Transparency Forum (OTF) that is held weekly with our stakeholders to ensure that messaging to our customers and stakeholders regarding our activities is consistent. Generic questions are carried over to the next meeting if they have not been answered in the session and so all stakeholders can hear the answer at the same time.

The slides and recordings are also published after the event on our public website here.

We make sure there is consistency of messaging across other areas of the business in the following ways:

- The Customer Team's relationship managers act as a central contact to communicate messages to customers and can be used by stakeholders and customers as a feedback route.
- The Customer Service Triage Team answers customer queries and is building a knowledge base to provide consistent messaging.
- Our Corporate Communication Team also publish official information on projects and initiatives on our website and social media channels.
- We arrange events to increase engagement on relevant topics.

ESO Policy

We design and develop balancing services and operational policies that impact the electricity industry and its stakeholders. To demonstrate how we consider impacts of policy on stakeholders and ensure that policy delivers an optimal output for consumers, we have chosen to include a case study below.

ESO Policy Case Study – Winter Operation Policies

In preparation for Winter 2023-24, a comprehensive review of required contingency arrangements, activities and operational policies was carried out to ensure a suitable level of resource was available over the winter period. This coupled with learnings from the previous year, resulted in the creation of a Day-Ahead Strategy (DAS) team who were responsible for providing day-ahead insights and decisions for contingency arrangements, such as the use of the Demand Flexibility Service (DFS).

This case study is a good example of how we manage key decisions, mobilise necessary resources and engage key stakeholders and customers in agreeing policy.

Case Study Background

As part of winter preparations, operational risks and mitigating actions were tracked through an internal weekly winter forum. At this forum it was highlighted that a team would have to take ownership of the application of DFS and liaise with key stakeholders to ensure the product be properly applied in respect of Order of Actions.

A voluntary Day-Ahead Strategy (DAS) team was stood up in the interim before a permanent team would be recruited and trained. The creation of the DAS team was agreed and signed off via our internal governance structure in August 2023. This was based on the GAP analysis and the consideration that no existing team met the necessary requirements. This follows the precedent set within Winter 2022-23.

We have an internal governance structure in place to ensure that decisions on policy are approved at the appropriate accountability level. This structure utilises a RAPID (Recommend, Agree, Perform, Input, Decision) process. This process produces recommendations for decision at the appropriate governance level based on input and agreement from stakeholders and identifies those that will need to perform actions due to the decision.

DFS affected a wide range of stakeholders, which includes the control room, customers, Ofgem and DESNZ. Consideration of DFS and how its application affected each of these stakeholders was of critical importance to Winter 2023-24 preparations and communicated externally through System Warning Messages on the BMRS and via the OTF.

Policy decisions and communication to stakeholders

As part of the preparation for Winter 2023-24, significant internal preparation and training was undertaken of the voluntary Day-Ahead Strategy Team, ENCC and Network Access Planning (NAP) teams. This training was focused on preparing internal teams for Winter 2023-24, changes made since last winter, the tools available to manage the grid and information on key decisions which effect external customers.

Changes to ESO policy affecting external stakeholders are communicated through multiple channels, including the weekly OTF. The updates to our Winter Operations Policy were presented to Stakeholders during the OTF on 18 October 2023, including the updated Order of Actions and the changes that came about from the Electricity Shortfall and Prioritisation Review that was led by DESNZ.

Winter order actions

The 2022-23 Order of Actions were reviewed in respect of the upcoming Winter (2023-24). Removal of Winter Contingency Contracts (WCC) and consideration to services which would replace the volume were made. Services, such as the use of back-up diesel generators were followed up in discussions with both DESNZ and Ofgem. The services were worked through with stakeholders but were ruled out due to either legislation barriers or lead times to develop and enact the service. The Order of Actions were drafted and confirmed within policy papers, in dialogue with DESNZ in relation to security of supply and ensuring adequacy for the upcoming Winter. DESNZ collaboration included Weekly Winter preparation sessions, where key risks and mitigations were monitored.

Once agreed, the policy was communicated to DNOs through the Winter Liaison meeting on 25 October 2023, and wider industry participants through the OTF on 18 October 2023. We answered questions about our Winter Operations live at the forum.

Activation of DFS

The approach for DFS Activation, and the relevant policies were trained out across the relevant teams.

Assessments were standardised, using learnings from Winter 2022-23 and with the service trigger level considered as margin requirements not being met (i.e. Generation – (Demand + reserve requirements)).

These assessments were made both within-day, and at the day-ahead stage as DFS Winter 2023-24 enabled within-day activation.

Included in the assessment criteria – Wind, Generation, Reserve, Demand, Constraints and Interconnector forecasts. This approach was agreed via internal governance channels and adopted throughout the winter.

Outcome

With the standing up of a voluntary Day-Ahead Strategy team we were able to mobilise a trained set of individuals to liaise with key stakeholders to confirm the Winter Order of Actions, assessment criteria and interconnector assumptions. Through engagement in several forums, we were able to conduct a timely review of the policy and communicate key changes in our activities.

We also provided a timely reminder of actions available to us over the winter period.

This proactive management, and communication of our policies in advance of, and through the Winter period is an example of how we continue to design and develop the necessary tools for continued safe operations, maintaining security of supply.

Value for Money

All roles

ESO

Value for Money

Under the ESO incentive arrangements for RIIO-2, the ESO must report on its outturn and forecast costs for each role against cost benchmarks. As the reporting for the Value for Money criterion relates to all 3 roles, we have brought this together in one section rather than providing a separate Value for Money chapter for each role. All figures in this section are in 2018-19 prices.

It is important to note that the Regulatory Reporting Pack (RRP) remains the formal cost report for the ESO. The final cost outturn for 2023-24 will be submitted in the next RRP cycle in July 2024.

The reported spend for the 2023-24 reporting year has been reviewed as part of our normal monthly management review process but has not been formally audited or been subject to the formal governance process for submission that would normally be used for RRP reporting. The ESO uses the methodology, as set out in the ESORI guidance, to allocate costs to each role.

In February 2024 we moved to a new organisational structure[29] to support the transition to NESO. Our forecasts for 2024-25 are based on the new structure and incorporate the additional costs we expect to incur for new roles as well as the transition from National Grid shared services to standalone functions. These additional costs were not included in our BP2 submission but were estimated in the National Grid Plc and National Grid ESO Separation Blueprint submitted to Ofgem in December 2022 and amended for our updated estimates in March 2023 as our plans for our Enterprise Resource Planning (ERP) solution were revised. We have therefore agreed with Ofgem that we will measure our latest forecast against the combined BP2 plan and the view of indicative additional costs taken from the Separation Blueprint. Any references to the BP2 plan within this document refer to this combined view and not the original plan submitted to Ofgem in 2022. We have not provided any forecasts for roles that were agreed subsequent to the Separation Blueprint, such as new roles in Strategic Energy Planning, since our estimates are at this early stage uncertain and subject to further review, challenge and approval through our internal governance. The restatement of 2024-25 directly attributable ESO opex costs can be found in appendix 1.

Our forecast costs for Digital, Data and Technology (DD&T) investment are based on our latest approved internal forecast. Note that the forecast costs provided in the CMF annex are costs that have been sanctioned through internal governance rather than latest forecast.

The following table sets out our forecast spend for the BP2 period (2023-24 to 2024-25), compared to our original BP2 plan. For a more detailed breakdown, please see the Cost Benchmark Summary Table at the end of this chapter.

		Role 1	Role 2	Role 3	**Total**
Original BP2 plan	(£m)	325.8	184.6	171.9	**682.3**
2023-24 Spend	(£m)	129.4	80.9	70.9	**281.2**
2024-25 Forecast	(£m)	183.9	103.8	95.1	**382.8**
Total 2023-25 Forecast	(£m)	313.3	184.7	166.0	**663.9**
Deviation from BP2 plan	(£m)	-12.5	0.1	-5.9	**-18.4**
Deviation from BP2 plan	%	**-3.9%**	**0.0%**	**-3.4%**	**-2.7%**

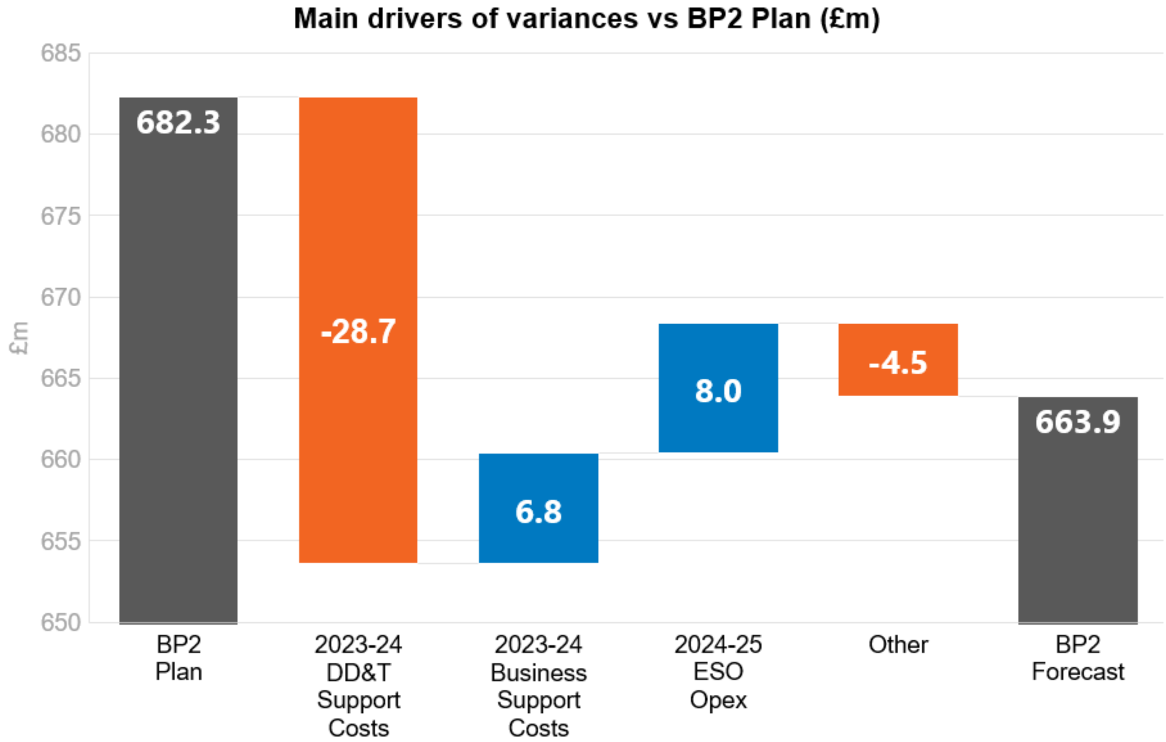
The figures in this table are made up of both directly and indirectly attributable costs.
See 'Cost Benchmark Summary' table at the end of this section for full breakdown of costs

Total forecast spend for the BP2 period is £663.9m, £18.4m lower than the £682.3m presented in our BP2 plan. Within our BP2 plan our non-transformational activities were tasked with a 1% compound cost efficiency

[29] Our new organisational design in preparation for the National Energy System Operator

from the start of the RIIO-2 period to further drive value for money. Overall, there is a total of £3.3m efficiency built into the BP2 plan at activity level.

The following chart shows a high-level view of the main drivers contributing to the variances against the BP2 plan. Further detail is provided on these drivers on a role-by-role basis within this report.



Our **DD&T support costs** for 2023-24 are **£28.7m lower** than our BP2 plan. As in BP1 our DD&T support costs continue to run significantly below our plan due to delays in BP1 in DD&T project delivery (investment underspend of £25.5m in BP1) and therefore a delay in incremental run costs resulting from investment commissioning.

Our **Business Support Costs** (BSC) for 2023-24 (excluding DD&T) are forecast to be **£6.8m higher** than our BP2 plan. As agreed with Ofgem we did not update these costs in our BP2 plan, so the planned costs remain at levels forecast in our RIIO-2 business plan. Our cost out turn is however consistent with levels of spend in the BP1 period.

Our directly attributable **ESO opex** spend of £78.3.m in the first year of BP2 has been slightly below our BP2 plan across all three roles. Our costs have increased year on year by £5.7m with a 206 increase in FTE as our roles continue to evolve. We continue to deliver efficiency savings whilst also choosing to invest in other areas which drive additional benefits such as our customer service operating model and our demand flexibility products. Our forecast spend of £99.6m for 2024-25 is **£8.0m higher** than our BP2 plan and a further year-on-year increase of £21.3m which includes additional roles as outlined in our separation blueprint.

Costs across **other** categories of spend are **£4.5m lower** than our BP2 plan with overall forecast costs of £663.9m over the full plan period.

Directly Attributable Costs (By Role)

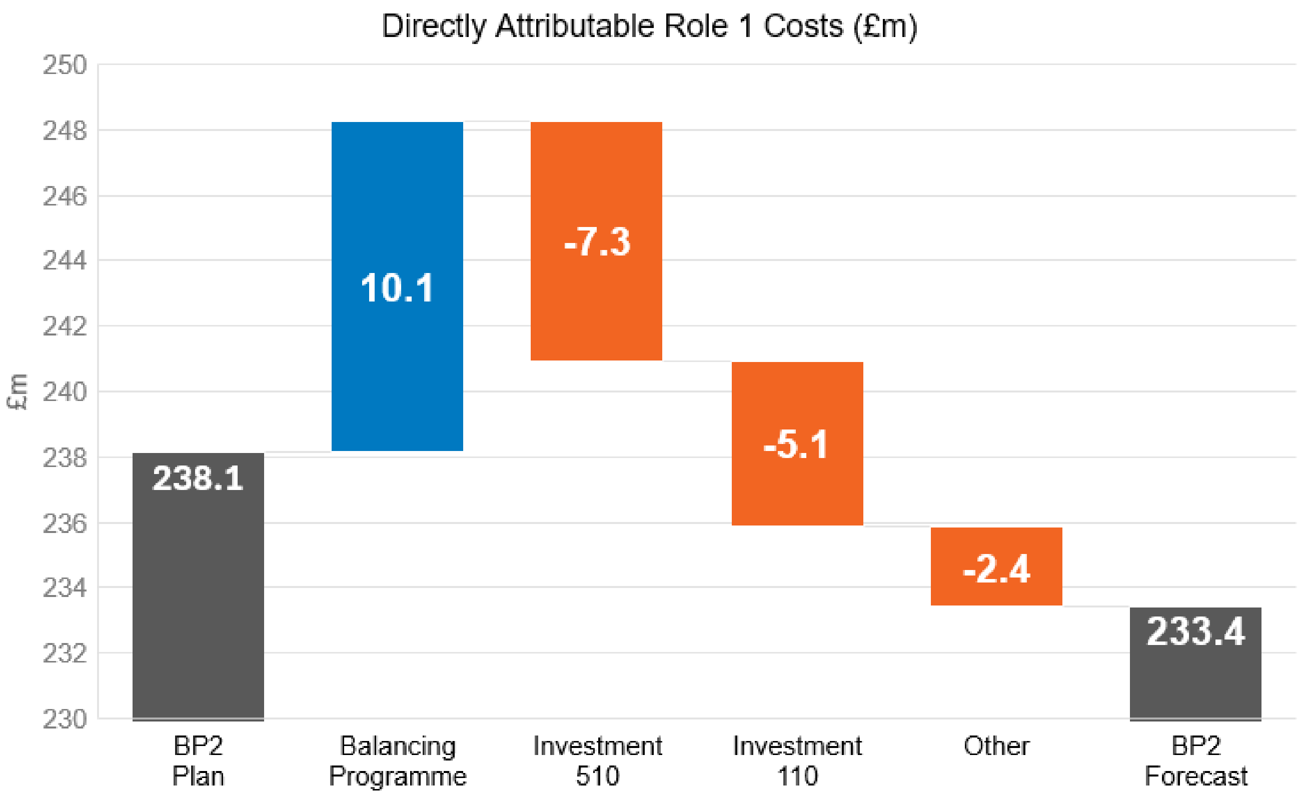
Directly Attributable costs are reported below on a role by role basis. Please note that indirectly attributable costs [30] are summarised in the next section.

Role 1 (Control centre operations) expenditure

For Role 1, we are forecast to spend **£4.8m** less than the BP2 plan, having delivered 80% of the milestones in our plan delivery schedule in 2023-24 (excluding milestones that are no longer valid, delayed for reasons outside of ESO's control, and delayed for consumer benefit).

Category	Costs directly attributable to Role 1 activities	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	vs BP2 Plan (£m)
ESO Opex	ESO Opex	73.0	33.3	41.6	74.9	1.9
Capex	DD&T and other Capex	141.4	58.6	84.6	143.2	1.8
BSC	IT Project Opex	23.7	6.2	9.1	15.3	(8.4)
Total Directly Attributable to Role 1		**238.1**	**98.1**	**135.3**	**233.4**	**(4.8)**

Below we set out the high-level activities driving the variances across Role 1:



**Investment 110 – Network Control*
**Investment 510 – Restoration and Restoration Decision Support Tool*

[30] Indirectly attributable costs relate to costs for teams that work across the ESO business supporting the activities within the three roles, and the costs for National Grid shared services

Directly Attributable ESO Opex[31]

2023-24

Activity	2023-24 BP2 Plan (£m)	2023-24 Spend (£m)	Variance (£m)	2023-24 Milestones: On track/ complete	2023-24 Milestones: Delayed
A1 - Control Centre architecture and systems	29.4	26.8	(2.5)	29	10
A2 - Control Centre training and simulation	1.0	1.0	(0.0)	12	6
A3 - Restoration	1.3	1.4	0.2	8	-
A17 - Transparency and open data	0.9	0.9	0.0	2	-
A18 - Market monitoring*	0.7	0.6	(0.1)	-	-
Centrally Allocated Costs	0.2	2.5	2.2	-	-
New Activities	0.0	0.0	0.0	-	-
Role 1 Total	**33.5**	**33.3**	**(0.2)**	**51**	**16**

**3 Milestones relating to Activity A18 – Market Monitoring are ongoing for the entire BP2 period but no milestones were due for completion in 2023-24*

A1 – Control Centre architecture and systems

The underspend in Activity A1 is mainly due to two factors. Firstly, amounts paid to CORESO (Coordination of Electricity System Operators). CORESO facilitates cooperation between 9 electricity transmission system operators across Europe, with a mission to proactively help Transmission System Operators to ensure security of supply on a European regional basis. Annual spend is approved by the CORESO board and the ESO pays for its share. Costs in 2023-24 were £0.8m less than forecast in BP2. This includes an adjustment for 2022-23 where final costs reconciled by CORESO were less than charged to shareholders.

Secondly, amounts recharged to National Grid Electricity Transmission for updates to the shared iEMS system were £0.7m higher than assumed in our BP2 plan. Following separation from NGET in 2019 ESO recharge NGET under a service agreement for services provided relating to this shared system until such time as each party operates its own separate capability (ESO RIIO-2 investment of £50.0m in Network Control system).

9 out of the 10 delayed milestones in Activity A1 relate to DD&T investments where further information can be found in the Role 1 Plan Delivery section and Cost Monitoring Framework Annex.

A2 – Control Centre training and simulation

Activity A2 spend is in line with BP2, however four milestones relating to the development and delivery of training are delayed. Where milestones are delayed resource has been re-utilised to cover the additional work to recruit and train new Control Room staff who are predominantly from overseas. There has been a considerable financial cost and delay in candidates starting training. In most cases there has been an additional need to provide more training in specific GB topics. This has resulted in an extension in the time to train but has not compromised the quality of training. They have also helped to deliver Control Training Unit (CTU) improvements. With the initial roll out of the Open Balancing Platform we have been able to use the CTU to train the Control Room shift teams on the tools. This has resulted in a good uptake of the new tools and an increase in the dispatch of battery generation.

The remaining 2 delayed milestones in Activity A2 relate to DD&T investments where further information can be found in the Role 1 Plan Delivery section and Cost Monitoring Framework Annex.

[31] Directly attributable opex refers to the operating costs that the ESO incurs to deliver its outputs under its three roles.

A3 – Restoration

Activity A3 is on track with all milestones and spend for 2023-24 is broadly in line with the BP2 plan.

A17 – Transparency and open data

Activity A17 is on track with all milestones and spend for 2023-24 is in line with those presented in the BP2 plan.

A18 – Market Monitoring

Activity A18 is on track with all milestones which are ongoing for the entire BP2 period, and have also achieved a £0.1m cost efficiency outside of the targets built into the BP2 plan. In addition to the core monitoring duty deliverables the team has published a second Winter Review for 2022-23, focused on balancing costs. A webinar was held with interested stakeholders to discuss the findings and examine the data that fed into the report which was well received.

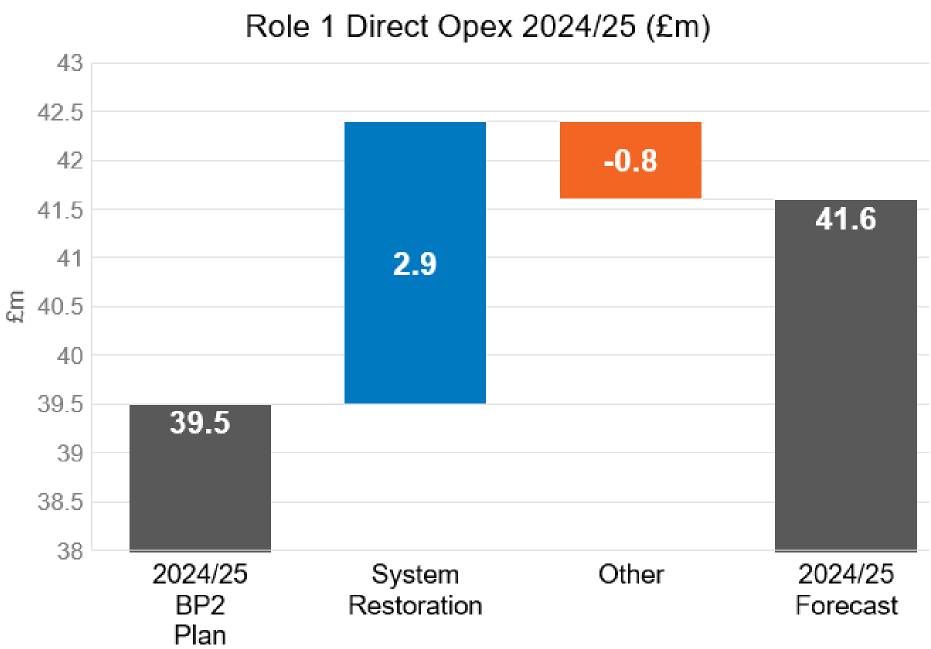
Centrally Allocated Costs (Role 1)

In addition to the cost efficiency targets for each activity, each role was tasked with further efficiency savings as "stretch targets". Although in the BP2 plan these cost reductions were reported across activities, they were high-level targets allocated to each role. To allow true value for money for each activity to be assessed we are reporting progress against these stretch targets separately.

The overspend relating to Role 1 Centrally Allocated Costs is primarily due to the stretch targets not being achieved. Our current view is that the reduction in FTE required to meet these targets is not compatible within Role 1 where resource is required to manage the provision of critical support for the ENCC and increasing operational complexity.

2024-25

In 2024-25 we are forecast to spend £2.1m over the BP2 plan for Role 1 direct opex costs with the key drivers highlighted below:



<u>System Restoration £2.9m</u>

The key driver relates to our System Restoration team and includes the cost of external energy and emergency response training for 75 FTE not originally accounted for within the plan, and an adjustment for costs to account for increased overtime due to slower than anticipated recruitment into roles within the Control Centre. £0.3m of this relates to the extra resource of Restoration Engineers required to undertake additional assurance activities as required by the licence, facilitating the increased number of tender participants, and providing internal and external training. This was not accounted for within the original FSO design.

Directly Attributable ESO Capex and BSC[32]

For Role 1 directly attributable ESO capex and BSC we forecast to spend £6.7m less than the plan across the two year BP2 period.

ID	Investment Name	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)	RIIO-2 Spend as per BP2 (£m)	RIIO-2 Forecast (£m)	RIIO2 Higher/ (Lower) (£m)
110	Network Control	36.4	10.5	20.8	31.3	(5.1)	58.1	52.9	(5.3)
120	Interconnectors	4.3	1.4	1.3	2.7	(1.6)	10.9	7.1	(3.9)
130	Emergent Technology and System Management	3.9	0.4	1.8	2.3	(1.6)	8.7	6.5	(2.2)
140	ENCC Operator Console	2.8	0.3	1.9	2.2	(0.5)	5.5	4.5	(1.0)
170	Frequency Visibility	4.0	0.7	3.2	3.9	(0.1)	6.8	5.9	(0.9)
180	Enhancing Balancing Capabilities	39.8	26.7	22.8	49.6	9.7	102.8	101.5	(1.3)
190	Workforce and Change Management Tools	2.0	0.1	0.3	0.3	(1.7)	3.8	0.8	(3.0)
200	Future Training Simulator and Tools	4.4	0.0	4.5	4.5	0.1	7.3	7.4	0.1
210	Balancing Asset Health	10.1	5.4	4.8	10.2	0.1	27.5	28.1	0.5
220	Data Analytics Platform	15.1	7.7	6.4	14.1	(1.1)	29.9	32.2	2.3
240	ENCC Asset Health	5.8	2.5	2.8	5.3	(0.5)	14.2	12.2	(2.0)
250	Digital Engagement Platform	3.9	4.8	2.6	7.4	3.5	11.4	12.2	0.9
260	Forecasting Enhancements	6.1	1.9	3.6	5.5	(0.7)	13.4	12.6	(0.8)
450	Future Innovation Productionisation	4.0	0.0	4.1	4.1	0.1	6.6	6.7	0.1
480	Ancillary Services Dispatch	2.4	1.8	1.6	3.4	1.0	8.5	8.5	(0.0)
510	Restoration and Restoration Decision Support Tool	17.5	0.5	9.7	10.2	(7.3)	24.9	18.6	(6.3)
670	Real Time Predictions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Wokingham ENCC*	2.7	0.0	1.5	1.5	(1.1)	4.9	2.0	(2.9)
	Inertia Monitoring Modulator*	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6
	Total	**165.1**	**64.8**	**93.7**	**158.5**	**(6.7)**	**345.3**	**320.2**	**(25.1)**

**Investments outside of DD&T Portfolio referenced in CMF Appendix*

Network Control (110), Balancing Programme (180, 210, 260, 480) and Digital Engagement Platform (250) have been selected as case studies to be discussed within the Value for Money report. For details relating to other Role 1 investments please refer to the Cost Monitoring Framework Annex.

Network Control (110)

The Network Control investment continues to deliver against the re-baselined roadmap aligned to the pivot to GridOS, a decision made in Q2 2023-24. These roadmap changes do not impact on the scope and value presented in BP1 and BP2 but add the benefit of early access to a more modular design and future proofing of the system, removing the need for another large-scale project in subsequent years. In addition, the Network Control Management System (NCMS) product will deliver the Wide Area Monitoring System (WAMS) capabilities at no additional cost. This presents a saving as this scope was previously captured under investment 170 (Frequency Visibility).

We have reviewed our delivery plan against the opportunity to pivot to GridOS and aligned our timeline with our supplier platform roll-out strategy. This has moved our go-live date from April 2025 to October 2025 but has not resulted in any increase of costs for the BP2 period.

In 2023-24 we delivered against our re-baselined GridOS pivot scope. In order to avoid incurring regret spend exploring detailed options for the alignment to GridOS, we have moved the requirements for our

[32] Directly attributable ESO capex and BSC (Business Support Cost) expenditure refers to capex and opex costs relating to ESO investments that can be mapped to specific roles.

NCMS tertiary resilience options into 2024-25, this has led to a rephasing of £1.6m of spend from 2023-24 to 2024-25.

Based on the current plan to migrate to GridOS platform, the cutover with NGET SCADA delivery and our management of our CNI data centres dependencies and resourcing challenges with our supplier, we intend on mitigating our current risks and deliver the full RIIO-2 planned scope and value with a potential underspend of £5.3m across the 5 year RIIO-2 period.

Balancing Programme (180, 210, 260, 480)

Enhancing Balancing Capabilities (180)

The Enhanced Balancing Capability investment continues to deliver against our BP2 commitments. We have delivered Open Balancing Platform Release 1 into the Control room in December 2023 as per the planned date but we delivered additional functionality for battery zone.

The Balancing Transformation programme follows the agile delivery methodology and so the delivery plan is regularly re-prioritised based on feedback from users and industry. We currently do not see this impacting overall delivery of BP2 milestones but the order of delivery of those milestones is regularly revised based on user and industry feedback.

During the Foundation and Blueprint phase (BP1) it was recognised that building the basic blocks of OBP OpenShift platform, establishing agile DevSecOps ways of working before growing teams in BP2 will allow us accelerated development of our product milestones. As a result, the £9.7m overspend in the BP2 period is re-phasing of costs from the BP1 period. For the RIIO-2 period we remain on track to deliver within the projected costs.

Balancing Asset Health (210)

The Balancing Asset Health investment continues to remain on track to deliver against our BP2 commitments in line with our BP2 cost projections.

During 2023-24 period, we implemented hardware upgrades to the balancing mechanism infrastructure targeted at improving performance, we are also continuously enhancing performance in each release through code optimisation, to ensure the systems robust operation until the transition to the Open Balancing Platform is complete. For our EBS project we remain on track to migrate all operational functionality to alternative systems or processes and enable retirement of the system.

Forecasting Enhancements (260)

The Forecasting Enhancements investment continues to deliver against our BP2 commitments, at a lower cost than our BP2 cost projections. In addition to our BP2 roadmap, we have expanded our scope to deliver changes for the Local Constraints Market (LCM), which was achieved via an additional release, and enabled forecasting features for the implementation of LCM. In 2023-24, we have had three releases. (1) Strategic Cloud Platform Foundation (2) Grid Supply Point (GSP) forecast (3) Forecasting features for enabling LCM.

During an extended planning phase for the Wind forecast product, we conducted an internal review of our roadmap. It was evident that operating in a complex multi-platform legacy environment poses significant operational and business risks. To address this, we have decided that further enhancement of forecasting products on legacy platforms would only increase technical debt and risk. As a mitigation measure, we have accelerated our retirement plans by migrating forecasting products to the Strategic Platform for Energy Forecasting (PEF) at an earlier stage. Consequently, the delivery of the Wind forecast product has been rescheduled from Q4 2023-24 to Q2 2024-25. Given delays in mobilising WIND (R5) due to prioritisation of LCM release, we will mobilise a second squad at no extra cost to accelerate our legacy platform retirement plans, which is now aligned to our replanned roadmap.

Although there has been a focus on other priority work, i.e LCM and a delayed start to Wind (R5) we intend to deliver the full scope and value of our BP2 commitments within the RIIO-2 period and will remain within our BP2 cost projections.

Ancillary Services Dispatch (480)

The Ancillary Services Dispatch investment continues to deliver against our BP2 commitments. In 2023-24 we have delivered 4 releases. These consist of changes to support Roles 2 and 3 for projects such as enhancements to Dynamic Response Services (Ancillary Services Reform Programme) and delivery of the Megawatt Dispatch Service (Regional Development Programme). The Megawatt Dispatch Service is a new constraints service which will unlock more network capacity, reduce constraint costs and open up new revenue streams for market participants.

Of the four releases in 2023-24, release 14a was an additional high priority release for the Dynamic Response service to enable increased situational awareness for the control room without any cost impact for this programme. As part of the release cycle we have made asset health improvements such as archiving data tables, optimising queries, and middleware authorisation updates. We have also introduced improvements based on control room feedback to the Short Term Operating Reserve and Fast Reserve services, as per our BP2 plan.

Through consultation with the Ancillary Services Reform Programme and the Open Balancing Platform we have agreed to defer the implementation of quick and slow reserve from ASDP to the Open Balancing Platform to avoid regret spend, technical debt and delays to other ASDP deliverables. ASDP capabilities will be migrated to the Open Balancing Platform in 2025-26, we are finalising our plans to achieve this, which will include implementing a change freeze on ASDP later this year.

The £1.0m overspend in the BP2 period is due to re-phasing of costs from the BP1 period. For the RIIO-2 period we remain on track to deliver the full scope broadly within the projected costs.

Digital Engagement Platform (250)

The Digital Engagement Platform (DEP) investment is on track to deliver by 2024-25, which is ahead of the originally proposed delivery timescales. The shift from moving delivery from 2025-26 to 2024-25 was made possible by moving to an upfront delivery model, standing up an additional development team, and the development of reusable component parts.

The only exception with our current roadmap for delivery is DEP/Data Analytics Platform (DAP) Integration which will extend out to Q1 2025-26 due to changes in the DAP roadmap. Although there is no direct cost impact to rescheduling the DEP/DAP work itself, additional scope is in the process of being identified to utilise the time that rescheduling DEP/DAP integration has created. This new scope will have a cost impact, which is yet to be determined but will not exceed £0.3m.

DEP delivery has successfully provided single sign on and integrations to dependent programmes to provide enhanced and frictionless customer experience for portal users such as SMP, ENAMS and Connections. In addition, it has successfully enabled external customers and stakeholders to access ESO data and services in an intuitive, predictable, personalised and seamless manner. It has also integrated with the new Digitalised Code Management platform (digitalisation of the Grid Code) to enhance the end-user experience and support navigation.

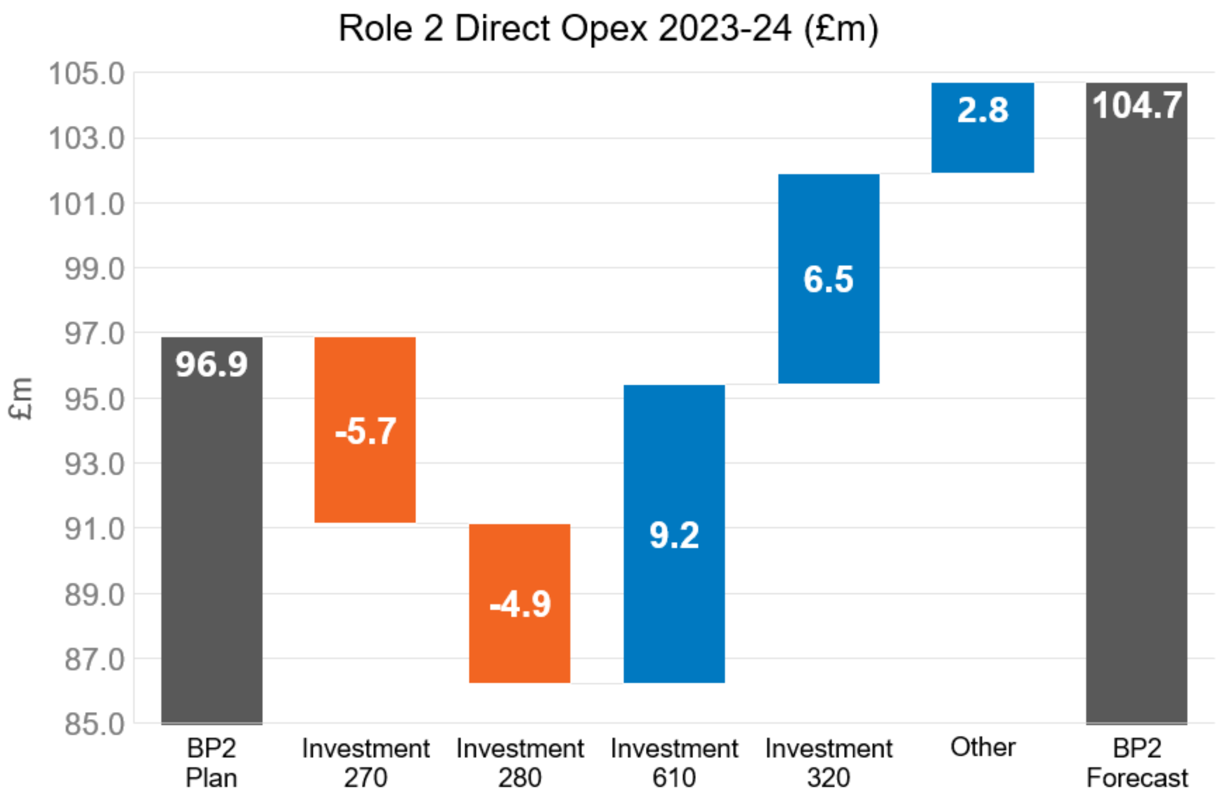
Over and above our BP2 plan, DEP has delivered additional enhancements such as security enhancements to allow for MFA via email and SMS to meet all users needs, FSO rebranding and the creation of a Design System-Kit of assets (reusable component parts; headers, footers etc) to support other areas of ESO with their own rebranding activities.

Role 2 (Market development and transactions) expenditure

For Role 2, we forecast to spend **£7.8m more** than the BP2 plan, having delivered 77% of the milestones in our plan delivery schedule in 2023-24 (excluding milestones that are no longer valid, delayed for reasons outside of ESO's control, and delayed for consumer benefit).

Category	Costs directly attributable to Role 2 activities	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	vs BP2 Plan (£m)
ESO Opex	ESO Opex	40.5	17.5	23.6	41.1	0.6
Capex	DD&T and other Capex	43.4	26.0	26.0	52.0	8.6
BSC	IT Project Opex	13.0	6.1	5.6	11.6	(1.4)
Total Directly Attributable to Role 2		**96.9**	**49.6**	**55.1**	**104.7**	**7.8**

Below we set out the high-level activities driving the variances across Role 2:



**Investment 270 – Role in Europe*
**Investment 280 -GB Regulations*
**Investment 320 – EMR and CfD Improvements*
**Investment 610 -Settlements, Charging and Billing*

Directly Attributable ESO Opex
2023-24

Activity	2023-24 BP2 Plan (£m)	2023-24 Spend (£m)	Variance (£m)	2023-24 Milestones On track/ complete	2023-24 Milestones Delayed
A4 - Building the future balancing services market	6.5	5.6	(0.8)	11	5
A5 - Transform access to the capacity markets	3.8	3.7	(0.1)	11	-
A6 - Develop code and charging arrangements that are fit for the future	7.3	5.5	(1.8)	11	11
A20 - Net zero market reform	0.5	0.4	(0.1)	-	-
A21 - Role in Europe	0.4	0.4	(0.0)	4	5
Centrally Allocated Costs	0.4	1.3	0.8	-	-
New Activities	0.0	0.6	0.6	-	-
Role 2 Total	**18.9**	**17.5**	**(1.4)**	**37**	**21**

**1 Milestone relating to Activity A20 – Net zero market reform is ongoing for the entire BP2 period but no milestones were due for completion in 2023-24*

A4 – Building the future balancing services market
The underspend against BP2 for Activity A4 is primarily due to delays in recruitment for most of the year. Although resources remained overstretched during this time period, only two non-DD&T related milestones are delayed.

The remaining three delayed milestones in Activity A2 relate to DD&T investments where further information can be found in the Role 2 Plan Delivery section and Cost Monitoring Framework Annex.

A5 – Transform access to the capacity markets
Spend and activity milestones broadly in line with BP2 and include an achievement greater than the efficiency target built into the BP2 plan.

A6 – Develop code and charging arrangements that are fit for the future
The underspend against BP2 for Activity A6 is primarily due to delays in recruitment for most of the year. Although, most milestones are on track resource remained overstretched during this time period. There are plans in place to bring recruitment in line with BP2 targets.

57% of the delayed milestones are linked to DD&T-related change being triggered by the outputs of the TNUoS taskforce as part of investment (280) GB Regulation Changes. The changes from the taskforce are currently going through multiple industry governance channels, after which the necessary IT changes can be scheduled.

A20 – Net zero market reform (NZMR)
The NZMR programme has evolved significantly over the first year of BP2, as highlighted in the Role 2 Plan Delivery section of this report. We continue to be a trusted partner to DESNZ and Ofgem since we have been brought into REMA. Spend and activity milestones remain broadly in line with BP2 including achievement of the efficiency target.

A21 – Role in Europe
Spend on Activity A21 is in line with BP2 and includes achievement of the efficiency target. One of the milestones delayed for internal reasons is due to re-prioritisation of resource to work on the Demand Flexibility Service (DFS) derogation. This derogation allowed for the reintroduction of the DFS after its success in Winter 2022-23, and for further progress to be made with the service. We have seen growth in the DFS with 49 registered participants, an increase of 18 from 2022-23. Steps are in place to ensure completion of the delayed milestone within BP2 timelines.

Centrally Allocated Costs (Role 2)

In addition to the cost efficiency targets for each activity, each role was tasked with further efficiency savings as "stretch targets". Although in the BP2 plan these cost reductions were reported across activities, they were high-level targets allocated to each role. To allow true value for money for each activity to be assessed we are reporting progress against these stretch targets separately.

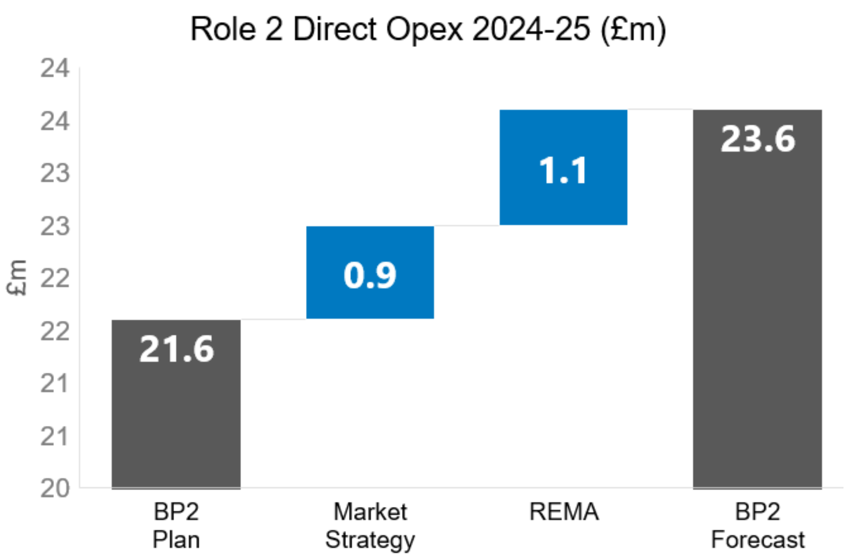
Although, all Role 2 activities have underspent against the BP2 plan, it has been difficult to assess how much of this is due to delays in recruitment or achievement of stretch efficiency targets. Now that recruitment targets are broadly in line with anticipated need, we expect to be able to assess over the remaining BP2 period if the stretch efficiency targets for Role 2 have been achieved.

New Activities

Our Flexibility Markets Strategy (in relation to BP2 milestone D4.5.3 'Develop an ESO Strategy to facilitate the growth of Distributed Flexibility') has progressed significantly since our BP2 submission so we have chosen to report this as a new activity. The growth of flexibility, especially demand side flexibility is essential to the ESO's 2035 mission of achieving a decarbonised, reliable, affordable, and fair electricity system. Our Flexibility Markets Strategy is an ESO-wide strategic programme which aims to explore the low-regret actions to unlock flexibility in the mid-term before enduring market arrangements delivered by REMA. It outlines our vision for flexibility, key outcomes and associated activities needed in the next five years to unlock the flexibility required for achieving a net zero electricity system. We are progressing this strategy in collaboration with industry and will launch a six-week call for input to gather feedback on our plans ahead of finalising our roadmap this Autumn.

2024-25

In 2024-25 we forecast to spend £2.0m over the BP2 plan for Role 2 directly attributable costs.



Market Strategy £0.9m

This increase relates to additional consultancy required to bridge capability gaps for Gas Market Strategy & Whole Energy Market Strategy. These are two brand new teams that have been created for NESO, subsequently we need additional support for skills and knowledge from external experts in industry whilst our internal teams build their own capabilities.

REMA £1.1m

This additional spend relates an additional 21 FTE required to stand up a formal REMA (Review of Electricity Market Arrangements) programme team, building on the Net Zero Market Reform and Role in Europe activities within BP2. REMA is undertaking a once-in-a-generation review of the electricity market and policy arrangements in GB, with the aim of reforming them to be fit for a net zero electricity system by 2035. Officially launched via its first consultation in 2022, is now entering its decision-making phase and is being stood up as a Major Government Project. NESO has (as of Jan 24) joined the REMA programme as an official Delivery Partner to DESNZ, alongside Ofgem.

Directly Attributable ESO Capex and BSC

For Role 2 directly attributable ESO capex and BSC we forecast to spend £7.2m more than the plan across the two year BP2 period.

ID	Investment Name	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)	RIIO-2 Spend as per BP2 (£m)	RIIO-2 Forecast (£m)	RIIO2 Higher/ (Lower) (£m)
270	Role in Europe	9.4	0.7	3.0	3.7	(5.7)	22.3	10.1	(12.2)
280	GB Regulations	8.7	2.0	1.8	3.8	(4.9)	19.4	11.3	(8.1)
320	EMR and CfD Improvements	7.4	9.0	4.9	13.9	6.5	21.3	29.5	8.2
330	Digitalised Code Management	2.5	1.2	1.5	2.7	0.2	2.7	2.7	0.1
400	Single Markets Platform	14.5	5.8	7.8	13.7	(0.8)	34.9	32.2	(2.6)
420	Auction Platform	4.2	2.7	1.4	4.2	(0.0)	8.9	7.9	(1.1)
610	Settlements, Charging and Billing	9.8	9.1	9.9	19.0	9.2	33.5	41.7	8.2
670	Local Constraints Market*	0.0	1.5	1.2	2.7	2.7	0.0	2.7	2.7
	Total	**56.4**	**32.1**	**31.6**	**63.6**	**7.2**	**143.0**	**138.2**	**(4.8)**

**Investments outside of DD&T Portfolio referenced in CMF Appendix*

EMR and CfD Improvements (320) and Settlements, Charging and Billing (610) have been selected as case studies to be discussed within the Value for Money report. For details relating to other Role 2 investments please refer to the Cost Monitoring Framework Annex.

EMR and CfD Improvements (320)

Following industry consultation and Ofgem deep dives in January 2023 a rebaselined plan was agreed, moving the launch of new EMR portal from Q1 2023-24 to Q1 2024-25. This was the preferred option, agreed by all stakeholders. This decision was made due to the improved understanding of the business requirement and the complexities of EMR regulations. This meant that more time and resources were needed to complete sufficient development to demonstrate the full end to end process to users before go live, which was a pre-requisite set out in the BP2 plan.

The new delivery plan included a resource ramp up to multiple development squads to deliver the required number of features and regulatory changes due in Q2 2025 alongside continued support of the legacy portal including regulatory changes due in 2023-24. These changes have resulted in the £8.2m increase in spend for the RIIO-2 period, as they were not included in the original BP2 estimates.

EMR has delivered the feature roadmap as committed in the new delivery plan for 2023-24 and accelerated delivery of Q1 2024-25 features in Q3 and Q4 2023-24. This has given more time for internal and external end to end testing to derisk operational go live.

Registration Go Live was delivered in January 2024 as per the rebaselined plan. Since then, we have had 265 new companies registered (688 in total). We have completed end to end testing internally and given access to approx. 80 industry partners from 20th March 2024 to perform familiarisation and testing and initial feedback has been positive. We are on track to deliver operational go live in Q1 2024-25 in line with the agreed replan.

Settlements, Charging and Billing (610)

The Settlement's, Charging and Billing (STAR) investment can be viewed from two perspectives: revenue and settlements. From a revenue perspective STAR has successfully delivered on its 2023-24 commitments and managed to deliver additional mandatory scope and enhancements (e.g. DESNZ and HMRC changes).

On the settlement front, the highly complex suite of dynamic services are technically live, however invoicing from STAR has been delayed, primarily due to the following factors; 1) Assurance of FFR payments and 2) Remediation of performance issues on the platform. A targeted resolution plan, including performance remediation on the platform is in place and tracked.

It is critical to prioritise the implementation of this plan before implementing subsequent settlements releases to mitigate any further blockers. This decision has resulted in the delay in the completion of the complete Frequency Response delivery milestone, postponing its value generation from 2023-24 to Q1 2024-25.

Settlements operates in a highly dynamic environment of market-driven changes. These will factor into the review of the Roadmap and reprioritisation of transitioning existing ancillary services to STAR as well as the potential inclusion of new services such as MFR Batteries, and a new set of Reserve services (Quick, Slow and Fast) which were not anticipated at the time of producing the BP2 plan.

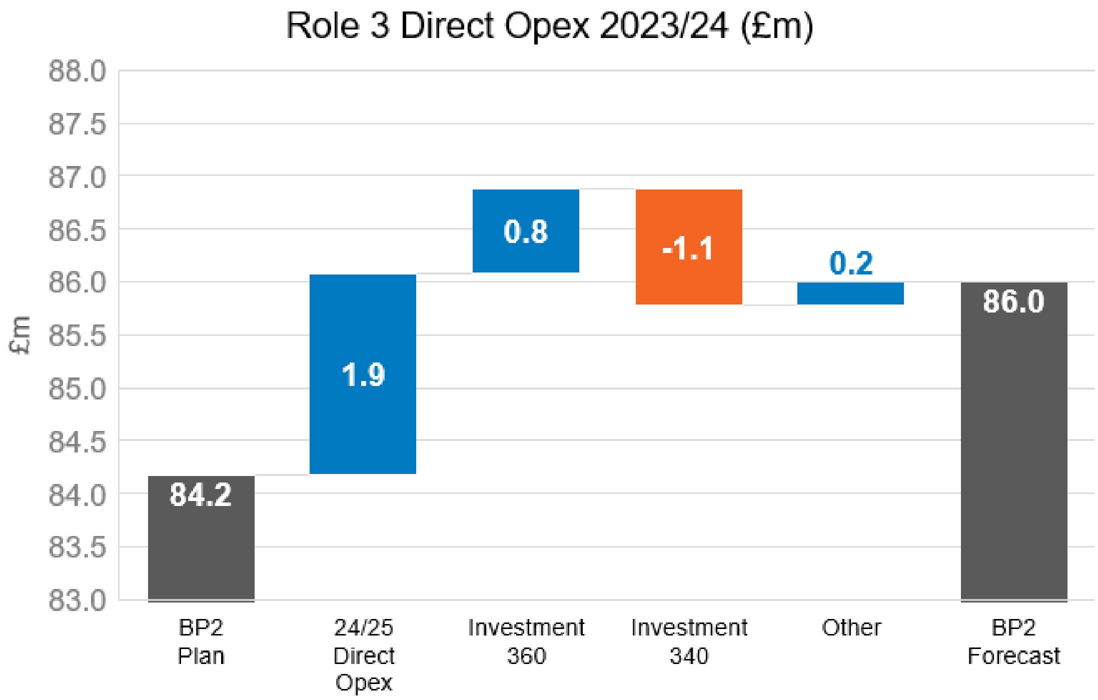
To mitigate any further risk to this investment, the programme is reprioritising the STAR roadmap based on business value, delivery efficiency and market direction and will require a sustained need for programme resources to deliver on remaining BP2 commitments and initiate work early to meet 2025-26 milestones.

Role 3 (System insight, planning and network development) expenditure

For Role 3, we forecast to spend **£1.8m more** than the BP2 plan, having delivered 95% of the milestones in our plan delivery schedule in 2023-24 (excluding milestones that are no longer valid, delayed for reasons outside of ESO's control, and delayed for consumer benefit).

Category	Costs directly attributable to Role 3 activities	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
ESO Opex	ESO Opex	60.4	27.5	34.5	62.0	1.6
Capex	DD&T and other Capex	20.2	10.8	10.2	21.0	0.8
BSC	IT Project Opex	3.5	1.3	1.7	3.0	(0.5)
Total Directly Attributable to Role 3		**84.2**	**39.6**	**46.4**	**86.0**	**1.8**

Below we set out the high-level activities driving the variances across Role 3:



** Investment 340 – RDP Implementation and Extension*
**Investment 360 – Offline Network Modelling*

Directly Attributable ESO Opex

Activity	2023-24 BP2 Plan (£m)	2023-24 Spend (£m)	Variance (£m)	2023-24 Milestones On track/ complete	2023-24 Milestones Delayed
A7 - Network Development	2.4	2.8	0.4	9	-
A8 - Enable all solution types to compete to meet transmission needs	1.7	1.4	(0.3)	1	5
A9 - Extend NOA approach to end of life asset replacement decisions and connections wider works	0.2	0.0	(0.2)	-	-
A10 - Support decision making for investment at distribution level	0.1	0.0	(0.1)	-	-
A12 - SQSS Review	0.4	0.5	0.1	2	-
A13 - Leading the Debate	3.7	3.3	(0.5)	10	-
A14 - Take a whole electricity system approach to connections	5.1	2.2	(2.9)	27	-
A15 - Take a whole energy system approach to promote zero carbon operability	5.6	5.3	(0.2)	31	10
A16 - Delivering consumer benefits from improved network access planning	4.9	4.7	(0.2)	19	-
A22 - Network Planning Review /Offshore Coordination	3.2	3.8	0.6	-	-
Centrally Allocated Costs	0.6	2.3	1.7	-	-
New Activities	0.0	1.2	1.2	-	-
Role 3 Total	**27.8**	**27.5**	**(0.3)**	**99**	**15**

**2 Milestones relating to Activity A22 – Network planning review / Offshore coordination are ongoing for the entire BP2 period but no milestones were due for completion in 2023-24*

2023-24

A7 – Network Development

The overspend of £0.4m for Activity A7 is predominantly due to additional resource required as part of work to publish the second Transitional Centralised Strategic Network Plan (TCSNP2). Within our BP2 plan, we set out costs at a high-level based on an expectation of the work that would be required. During the process of producing the tCSNP2 it was identified that more governance activities and extensive stakeholder engagement between the ESO, Ofgem, Government and GB's Transmission Owners would be needed ahead of publication. This required extra resource was not originally accounted for in the BP2 plan.

Publication of the tCSNP2 (Beyond 2030) report took place in March 2024. We proposed a £58 billion investment in the electricity grid to meet the growing and decarbonising demand for electricity in Great Britain by 2035. The Beyond 2030 report has had over 30 write ups in national, regional and trade press and has seen support from many key stakeholders and thought leaders.

A8 – Enable all solution types to compete to meet transmission needs

The underspend of £0.3m in Activity A8 is a result of delays in the Early Competition project. This was delayed for a period of time as a result of Ofgem's need to focus their resources on delivery of the Accelerated Strategic Transmission Investment (ASTI) suite of projects, work which started in summer 2022 and was completed by August 2023. During this period the ESO continued to work with stakeholders and experts to develop and refine the Early Competition model, culminating in our Early Competition Implementation Update (ECI-update) which was sent to Ofgem in September 2023 and formally published to the industry in February 2024. This document represented our final proposals on how we believe Early Competition should be implemented by Ofgem through tender regulations and licence changes.

In November 2023 DESNZ reiterated their commitment to introducing competition and stated their goal of launching a competition by the end of 2024 in their response to the Winser report on delivery of transmission investment. The ESO is now focused on supporting Ofgem to develop the necessary tender regulations and licence changes required to implement Early Competition in line with the DESNZ timetable.

A9 – Extend NOA approach to end of life asset replacement decisions and connections wider works

No spend reported against A9 as deliverables were completed in BP1 or merged into A22.

A10 – Support decision making for investment at distribution level

No spend reported against A10 as deliverables were completed in BP1.

A12 – SQSS Review

Spend and activity milestones in line with BP2.

A13 – Leading the Debate

The £0.5m underspend against BP2 for Activity A13 is primarily due to delays in recruitment. Challenges in filling vacancies have meant that the teams have been operating below forecasted headcount through the year. Despite the reduced team capacity all milestones have been achieved, however there has been less availability to cover new projects and develop future work, and less investment in training. There are plans in place to bring recruitment in line with BP2 targets. There has also been reduced spend on modelling development as the Future Energy Scenarios reporting cycle changes from yearly to every three years.

Cost efficiencies outside of the targets within the BP2 plan have been achieved by delivering more events remotely which has been well received by stakeholders. Also, further costs have also been reduced through reviewing and renegotiating subscription contracts.

A14 – Take a whole electricity system approach to electricity

Reduced spending of £2.9m is attributed to several factors. Firstly, slower recruitment in the Customer Contract Management teams due to market conditions resulted in the team reaching their headcount target two quarters later than planned. Currently, available resource has been overstretched trying to ensure all milestones are met. Recruitment is now in line with BP2 targets and we therefore expect people costs for this activity going forwards to be in line with the BP2 plan.

Secondly, due to a higher volume there has been an increase in time spent on connection applications. This has resulted in a increased proportion of costs being allocated to connection applications than initially estimated in our BP2 submission.

A15 – Take a whole energy system approach to promote zero carbon operability

There are three drivers of underspend against the BP2 plan. Firstly, a negotiated saving of £0.3m was achieved on the Accenture offshore support contract for the offline modelling team.

Secondly, there was an increased transfer out of costs from the Offline Modelling team due to additional time spent on investments (390) NOA Enhancements and (360) Offline Network Modelling to develop more product features to meet multiple planning and operational needs. This is to ensure achievement of deliverable A15.6 which is to ‘Deliver major upgrades to our offline modelling tools’, which will allow us to model a more complex system".

Thirdly, the Whole Energy System and Zero Carbon Operability team experienced lower than expected headcount due to a restructuring that occurred in Q2, which delayed some recruitment and contributed to delays for deliverables A15.7 and A15.8. There are plans in place to recruit extra resource, and although milestones are slightly delayed, they are still planned to be delivered within the BP2 period.

These underspends are offset by costs on work to define scope, and complete impact assessments on change requirements for IT systems as part of the Distributed Energy Resources (DER) visibility. These were not included in the high-level initial cost forecast provided in the original BP2 submission.

A16 – Delivering consumer benefits from improved network access planning

The underspend against the BP2 plan for Activity A16 is due to the higher than expected attrition rate within the Network Access Planning team. However, a significant proportion of those who left have remained within the ESO and now work in the Electricity National Control Centre where these individuals bring with them the skills and experience gained from working in the Network Access Planning team.

Although all deliverables within the BP2 plan remain on track, this team have daily deliverables to meet where current resource is overstretched due to the lower FTE count. Once all recruitment gaps have been filled, we expect to be on track against the costs stated in the BP2 plan. There are plans to start future recruitment earlier than expected to prepare for anticipated staff turnover, as recruitment and training can take a significant length of time.

A22 – Network Planning Review / Offshore Co-ordination

Due to the early stage of maturity and ongoing uncertainty of both projects, no milestones were set out in BP2 within the deliverables for this activity and costings were set out at a high level. The overspend in Activity A22 against the BP2 plan is due to increased consultancy spend in two areas.

Firstly, to ensure progress in facilitating the delivery of the transmission infrastructure recommended in the Holistic Network Design (HND), additional external consultants required to deliver outside BP2 requirements.

Secondly, in order to complete the offshore ScotWind Holistic Network Design Follow Up Exercise (HNDFUE) which was an integral part of the 'Beyond 2030' report published in March 2024, external consultants with specialist skills such as environmental study and project management experts were brought in to support activities.

Centrally Allocated Costs (Role 3)

In addition to the cost efficiency targets for each activity, each role was tasked with further efficiency savings as "stretch targets". Although in the BP2 plan these cost reductions were reported across activities, they were high-level targets allocated to each role. To allow true value for money for each activity to be assessed we are reporting progress against these stretch targets separately.

Efficiencies have been achieved across activities A13 and A15 of approximately £0.5m through the renegotiation of contracts for additional support and subscriptions.

New Activities

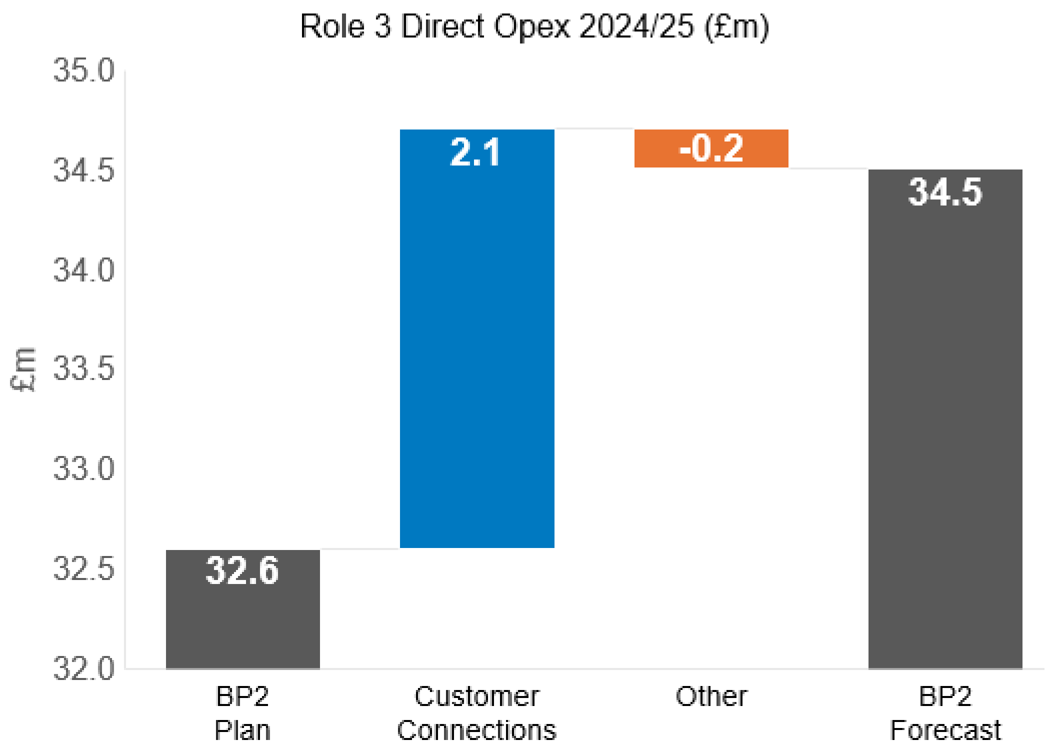
<u>Strategic Spatial Energy Planning</u>

In August 2023, the Electricity Network Commissioner's report recommended that a Strategic Spatial Energy Plan (SSEP) be the foundation for future network planning - bridging the gap between Government policy and Network Development Plans. The vision included identifying the location of generation and high-level network needs, and that it would be on a whole system basis. Following this recommendation, the government have set out plans to commission the ESO to develop the SSEP.

Costings for producing the SSEP were not considered within the BP2 plan or FSO blueprint, as both were published prior to the Electricity Network Commissioner's report. It was recognised within the report that the ESO would require additional resource to prepare the SSEP. The costs incurred in 2023-24 relate to mobilisation of the team and energy modelling.

2024-25

In 2024-25 we are forecast to spend £1.9m over the BP2 plan for Role 3 directly attributable costs.



£2.1m relates to the Customer Connections team. £1.2m of this increase is due to a forecast lower transfer of costs out to application fees charged to connections customers compared to the BP2 plan. There was an estimated total of 1,700 applications for 2023-24. For 2024-25 a similar number of applications are anticipated, however we expect the amount of resource required to process applications to reduce due to increased efficiency. This will allow the team to focus their efforts on other initiatives. £0.6m is required for consultancy to enable the transition to Enduring Reform and to implement Connection Reform and support the Connection Action Plan, using deep expertise to codify changes to the frameworks in CUSC, STC, and Licences. The reliance on consultancy will reduce over time as the team develops the capability required. £0.3m is required for Accenture offshore support for transactional level tasks to reduce the Customer Account Managers' workload so more focus can be spent on value adding tasks such as building/maintaining customer relationships.

Directly Attributable ESO Capex and BSC

For Role 2 directly attributable ESO capex and BSC we forecast to spend broadly in line with the BP2 plan across the two year period.

ID	Investment Name	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)	RIIO-2 Spend as per BP2 (£m)	RIIO-2 Forecast (£m)	RIIO2 Higher/ (Lower) (£m)
340	RDP Implementation and Extension	7.7	3.3	3.2	6.5	(1.1)	17.1	12.3	(4.8)
350	Planning & Outage Data Exchange	3.3	1.1	1.9	2.9	(0.3)	8.4	8.2	(0.2)
360	Offline Network Modelling	3.5	1.6	2.7	4.3	0.8	8.1	8.4	0.3
380	Connections Platform	3.0	1.9	1.7	3.7	0.6	7.0	7.6	0.6
390	NOA Enhancements	6.0	4.0	2.3	6.3	0.3	9.3	8.9	(0.4)
500	Enhanced Frequency Control	0.2	0.2	0.1	0.2	0.0	1.2	1.2	0.0
650	Accelerating Whole Electricity Flexibility	0.1	0.0	0.0	0.0	(0.1)	0.1	0.1	(0.0)
	Total	**23.8**	**12.1**	**11.9**	**24.0**	**0.2**	**51.3**	**46.7**	**(4.6)**

RDP Implementation and Extension (340)

In line with the BP2 timeline, the Regional Development Programme has delivered technical and business go live for RDP1 NGED benefiting eight DER sites. There are a further 48 DER sites (just over 1GW) scheduled to connect before the end of 2025.

N-3 Intertripping has also been delivered and is live for SSEN and NGED, delivering Intertrip services that are systems which automatically curtail DERs post fault. It will allow DERs to ensure energy generation and continued operability of the network until a real system fault happens. In addition to an increase of network capacity benefiting consumers, the N-3 intertripping solution will allow connection of more renewable generation into the DNO network.

A decision was reached in February 2024 with Scottish Power Transmission (SPT) and ESO to close the Generation Export Management system (GEMS) project, and use an alternative solution within the Open Balancing Platform (OBP) instead which requires no further DD&T involvement. The OBP have already delivered ‘bulk dispatch’ functionality which we can use to automate generation dispatch to a certain extent. This added to our confidence that the adoption of OBP will deliver benefits and will not have any negative impact on generation connection or system operation. Due to this, our current forecast for the RIIO2 period is £4.8m less than the BP2 plan costings.

The scope for RDP 3 and 4 has been revisited from the original IT Annex scope and will be focussed on enhancements for MW Dispatch with NGED and UKPN, to ensure we can provide a scalable and enduring MWD solution which will provide benefit by facilitating more volume and quicker DER Connections in our particularly congested Network areas – this is a key problem area for ESO and Industry.

Indirectly Attributable Costs (All roles)

Our assessment for value for money is not only based on costs which are directly driven by activities within a particular role. Some activities support all roles equally and a summary of these costs and our forecast against the BP2 plan is given below.

Activity	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
Supporting Operational Costs	21.8	8.7	15.6	24.2	2.5
Property Capex	10.7	1.7	9.3	11.0	0.3
Indirect IT & Telecoms and Other Capex	21.4	11.0	7.8	18.8	(2.6)
Total Business Support Costs	182.0	59.4	99.8	159.2	(22.8)
IT & Telecoms Indirect	*134.4*	*36.2*	*65.5*	*101.8*	*(32.6)*
Property Management	*12.7*	*8.4*	*5.8*	*14.3*	*1.6*
HR & Non-Operational Training	*8.9*	*2.7*	*8.8*	*11.5*	*2.6*
Finance, Audit & Regulation	*11.4*	*5.5*	*8.4*	*13.9*	*2.5*
Procurement	*2.9*	*0.6*	*1.4*	*2.0*	*(0.9)*
Insurance	*2.6*	*0.5*	*1.9*	*2.4*	*(0.3)*
CEO & Group Management	*9.1*	*5.4*	*8.0*	*13.4*	*4.3*
Total Indirectly Attributable Costs	**235.9**	**80.8**	**132.5**	**213.3**	**(22.7)**

Please note that, as agreed with Ofgem, there was no update to the BP2 plan for costs which are allocated by National Grid to its regulated entities where services or projects are shared across the National Grid group. Therefore for capex, business support (excluding IT & telecoms), and other price control costs all values for BP2 are based on RIIO-2 final determinations. IT & telecoms business support costs were revised in our BP2 submission only to reflect the expected incremental support costs driven by our DD&T investment portfolio.

Supporting Operational Costs

2023-24

There are several teams that work across the ESO business rather than being dedicated to one of the Roles. They carry out activities that we refer to as "cross-cutting". These teams are Business Change, Innovation, Assurance, and Regulation and Customer & Stakeholder.

Activity	2023-24 BP2 Plan (£m)	2023-24 Spend (£m)	Variance (£m)
Innovation	2.0	2.1	0.1
Customer & Stakeholder	1.4	1.9	0.5
Regulation	1.6	1.0	(0.6)
Business Change	1.3	1.1	(0.2)
Assurance	1.6	1.6	(0.0)
Centrally Allocated Costs	0.2	0.9	0.8
Cross Cutting Total	**8.2**	**8.7**	**0.5**

Innovation

Spend broadly in line with BP2.

Customer & Stakeholder

Customer & Stakeholder	2023-24 BP2 Plan (£m)	2023-24 Spend (£m)	Variance (£m)
Opex	1.4	1.9	0.5
Capex*	0.0	0.2	0.2
Total Spend	**1.4**	**2.1**	**0.7**

**Non-DD&T Investment. Included within Indirect Capex total as not directly linked to a specific Role.*

The overspend of £0.7m against BP2 within Customer & Stakeholder relates to work undertaken to implement our new Customer Services Operating Model. This includes £0.2m capex spend not included within the BP2 submission.

In order to achieve our Trusted Partner ambition, a focus on delivering a shift to digital and improved customer experience is required. Following internal and external engagement, we have introduced a new Customer Services Operating Model. This will transform the approach to query and relationship management by establishing a triage team.

The model seeks to enhance the customer experience by addressing inconsistent service, and key customer pain points such as first-time resolution, timely responses/responsiveness and the need for self-serve solutions. The chosen model sets us up for a future increase in query volume, customer self-serve digital first experience and supporting the NESO as we take on new brand values. Delivery of this model aims to reduce our cost to serve queries, improves customer pain points and in doing so would improve our customer satisfaction scores. This will improve our customer experience strategy, saving 3,400 business hours a year, enabling 3,000 repeatable queries to be dealt with by the triage team, and reducing the average closure time of queries.

There is future work on the Digital Engagement Platform (DEP) to improve digital customer experience through a help centre and co-ordinated query management across other platforms. As a result there is awareness and alignment with other DEP impacting projects where query management is being digitalised.

Regulation

The underspend against the BP2 plan in year is largely due to an FTE efficiency being achieved within the team, and lower than forecast non-people spend relating to projected BP3 and future strategy work. Starting work on future business planning has been delayed outside of the usual expected timelines given the transition to NESO in 2024. Discussions are currently taking place with Ofgem around a future business planning and performance framework.

Business Change

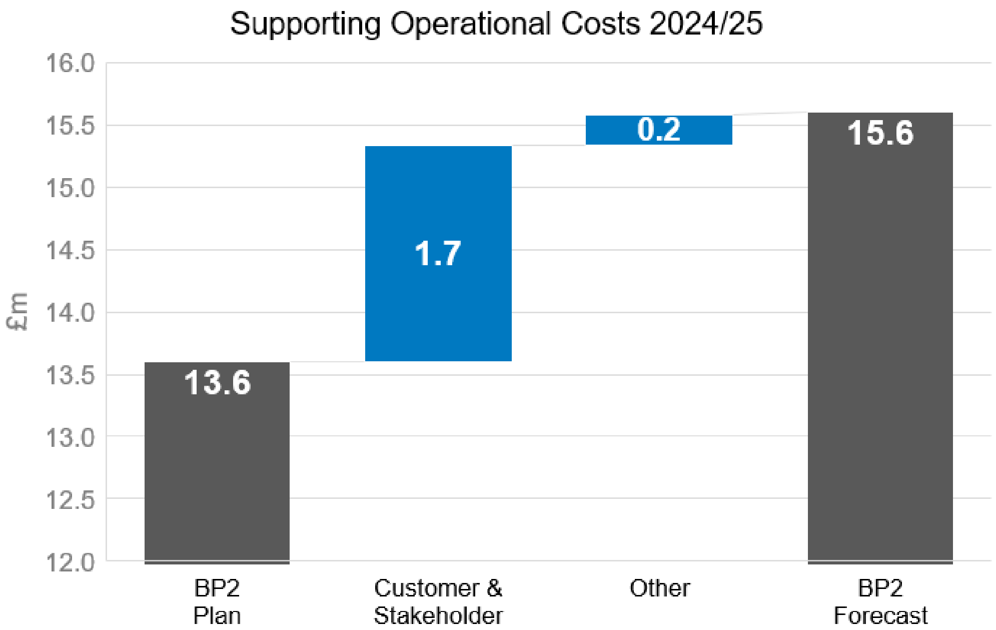
Spend broadly in line with BP2.

Assurance

Spend broadly in line with BP2.

2024-25

In 2024-25 we are forecast to spend £2.0m over the BP2 plan for Supporting Operational Costs.



**Please note any differences between values displayed in the chart and referenced in the text are due to rounding to 1dp*

Customer & Stakeholder £1.7m

£1.3m driven by the introduction of the Customer Service Operating Model project to transform the approach to query and relationship management. £0.4m relates to the establishment of a focused Customer function within NESO.

Property Capex

Property capex relates to spend on ESO occupied properties. This is primarily spending on the Wokingham site but also covers enhancements for the contingency control centre and our share of capex required for the portion of National Grid UK's Warwick head office that houses the ESO.

Activity	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
Property Capex	10.7	1.7	9.3	11.0	0.3

Spend in 2023-24 is £3.0m below the BP2 plan largely due to the timing of spend as outlined below. However, we remain in line across the entire BP2 period.

All ESO sites had planned sustainability projects focusing on energy efficiencies, including the installation of EV charging points and upgrading internal/external lighting to LED. The tenders submitted by suppliers for these works were substantially in excess of expected costs. Following this a decision has been made for the works to be relaunched with a reduced scope to ensure the best value is achieved.

In our BP2 plan we incorporated costs to support the property refurbishment in Wokingham, which was last refurbished around 2014-15 and is now in need of work to bring the working environment to a modern standard which supports current working practices. A decision was made to delay the refurbishment to combine with the programme for increasing office capacity, where we are currently in the process of appointing design consultants for the next phase of design. By amalgamating these works it will let us make best use of the structural steelwork within the atrium and allows for consideration around timings to ensure the least amount of disruption to the site as possible.

IT & Telecoms and Other Capex

Activity	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
Indirect IT & Telecoms and Other Capex	21.4	11.0	7.8	18.8	-2.6*

**£0.2m relates to Customer and Stakeholder Operating Model*

IT & Telecoms capex relate to shared National Grid costs relating to Business Services systems, Hosting, IT Operations and Tooling, Infrastructure, Enterprise Data Networks and End User Computing.

Spend in 2023-24 was in line with BP2 plan. The £2.6m overall underspend forecast versus BP2 is driven by a reduction in 2024-25 planned spend in shared projects with National Grid following the ESO divestment.

Other Business Support Costs

Business Support Costs cover services that are shared across all the National Grid group businesses under a single function for several key support services. These include IT support, property management, human resources (HR), procurement, corporate affairs, legal and finance.

Each National Grid group business pays a fair share of the costs of these functions, through the unified cost allocation methodology (UCAM) approach agreed with Ofgem. These allocations are submitted to Ofgem every year as part of the regulatory reporting pack (RRP) process, which includes a description of and reasons for any allocation methodologies that have changed.

IT & Telecoms Indirect

Activity	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
IT & Telecoms Indirect	134.4	36.2	65.5	101.8	-32.6

IT and telecoms costs are forecast to be £32.6m lower than the BP2 planned spend, driven by current year spend which is £28.8m under the BP2 plan (£65m). The £36.2m current year spend is consistent with the prior year and represents both a delay in the incremental operational costs from project delivery, as well as efforts to offset the incremental costs that do materialise with efficiency savings where possible. There have also been significant cost savings achieved in the current year through securing volume discounts with major suppliers. Spend is expected to increase next year as major BP2 milestones are achieved and as IT headcount is increased to take on new FSO roles and responsibilities.

Property Management

Activity	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
Property Management	12.7	8.4	5.8	14.3	1.6

The forecast £1.6m overspend for the BP2 period mainly relates to property rental costs. At the time of our BP2 submission we were exploring the possibility of acquiring our own office space in London. Since then we have acquired office space in London and signed a further lease for office space in Glasgow, which became operational in January this year. This allows us to have a presence closer to our customers and stakeholders and also serves to widen the geographical area for attracting talent into our organisation.

HR & Non Operational Training

Activity	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
HR & Non-Operational Training	8.9	2.7	8.8	11.5	2.6

2023-24 spend is broadly in line with BP2. £2.3m relates to 2024-25 and is driven by incremental costs for establishing a HR/People function, and higher dis-synergies than expected for stand-alone contracts.

Finance, Audit & Regulation

Activity	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
Finance, Audit & Regulation	11.4	5.5	8.4	13.9	2.5

The £2.3m increase in spend for 2023-24 against the BP2 plan is in line with prior year costs as reported in BP1. 2024-25 remains broadly in line with the BP2 plan, and includes the costs of establishing a stand-alone CFO function for what previously was a shared service provided by National Grid. .

Procurement

Activity	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
Procurement	2.9	0.6	1.4	2.0	-0.9

2023-24 spend is broadly in line with BP2. Costs for 2024-25 are expected to increase as we establish our own stand-alone Procurement function outside of National Grid's shared services. Our current forecast for 2024-25 remains below the forecast within our updated BP2 plan.

Insurance

Activity	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
Insurance	2.6	0.5	1.9	2.4	-0.3

Insurance costs in 2023-24 are largely in line with prior year costs and £0.3m lower than our BP2 forecast. Whilst part of the National Grid group we benefit from the use of a group owned captive insurance company to underwrite insurable risks of our business operations. Costs are expected to increase in 2024-25 as we develop a replacement insurance programme which will be a direct market placement. Despite this we expect additional costs to be slightly below those forecast in our updated BP2 plan.

CEO & Group Management

Activity	BP2 Plan (£m)	2023-24 Spend (£m)	2024-25 Forecast (£m)	Total 2023-25 Forecast (£m)	Variance vs BP2 Plan (£m)
CEO & Group Management	9.1	5.4	8.0	13.4	4.3

The £2m increase in spend for 2023-24 against the BP2 plan is in line with prior year spend as reported in BP1.

£1.3m of the 2024-25 increase mainly relates to ring-fenced legal costs which may arise through the Connections Reform process where customers who have faced termination as a result of their connection project failing to reach agreed milestones (CMP376) may launch legal challenges against the original decision.

Other Price Control Costs

Other price control costs mainly relate to cyber security costs monitored under the PCD obligations and are forecast to be broadly in line with our BP2 plan. This portfolio is being delivered as a five-year plan across the National Grid group businesses and progress is reported separately to Ofgem under the PCD obligations.

	Funding Category	BP2 Plan £m	2023/24 Spend £m	2024/25 Forecast £m	2023/25 Forecast £m	Variance £m
TOTAL	Total Role 1 Costs	325.8	129.4	183.9	313.3	(12.5)
	Total Role 2 Costs	184.6	80.9	103.8	184.7	0.1
	Total Role 3 Costs	171.9	70.9	95.1	166.0	(5.9)
	Total Price Control Costs	**682.3**	**281.2**	**382.8**	**663.9**	**(18.4)**
Role 1	ESO Opex	73.0	33.3	41.6	74.8	1.8
	Capex	141.4	58.6	84.6	143.2	1.8
	BSC	23.7	6.2	9.1	15.3	(8.4)
	Total Directly Attributable to Role 1	**238.1**	**98.1**	**135.3**	**233.3**	**(4.8)**
	ESO Opex	7.3	2.9	5.2	8.1	0.8
	Capex	10.7	4.3	5.7	9.9	(0.8)
	BSC	60.7	19.8	33.3	53.1	(7.6)
	Other Price Control Costs	9.0	4.4	4.5	8.9	(0.2)
	Total Indirectly Attributable to Role 1	**87.7**	**31.3**	**48.7**	**80.0**	**(7.7)**
Role 2	ESO Opex	40.5	17.5	23.6	41.1	0.6
	Capex	43.4	26.0	26.0	52.0	8.6
	BSC	13.0	6.1	5.6	11.7	(1.3)
	Total Directly Attributable to Role 2	**96.9**	**49.6**	**55.1**	**104.8**	**7.8**
	ESO Opex	7.3	2.9	5.2	8.1	0.8
	Capex	10.7	4.3	5.7	9.9	(0.8)
	BSC	60.7	19.8	33.3	53.1	(7.6)
	Other Price Control Costs	9.0	4.4	4.5	8.9	(0.2)
	Total Indirectly Attributable to Role 2	**87.7**	**31.3**	**48.7**	**80.0**	**(7.7)**
Role 3	ESO Opex	60.4	27.5	34.5	62.0	1.6
	Capex	20.2	10.8	10.2	21.0	0.8
	BSC	3.5	1.3	1.7	3.0	(0.5)
	Total Directly Attributable to Role 3	**84.2**	**39.6**	**46.4**	**86.0**	**1.8**
	ESO Opex	7.3	2.9	5.2	8.1	0.8
	Capex	10.7	4.3	5.7	9.9	(0.8)
	BSC	60.7	19.8	33.3	53.1	(7.6)
	Other Price Control Costs	9.0	4.4	4.5	8.9	(0.2)
	Total Indirectly Attributable to Role 3	**87.7**	**31.3**	**48.7**	**80.0**	**(7.7)**

Appendix 1

Below represents the updated view of the BP2 plan when including the indicative RtB costs taken from the Separation Blueprint: