23 October 2025

Mid-Year Incentives Report September 2025

Business Plan 3 (2025-26)

NESO
National Energy System Operator

Contents

Introduction

As part of the RIIO-2 price control, we published our third Business Plan (BP3) in January 2025. It sets out our delivery focus for the period April 2025 to March 2026 against eight Performance Objectives. Each Performance Objective is underpinned by a set of Success Measures intended to represent the key deliverables or milestones which, if achieved, demonstrate progress towards the Performance Objective.

Our BP3 Performance Objectives for 2025/26

WHOLE ENERGY

Strategic Whole Energy Plans
NESO will establish the capabilities, foundations and methodologies needed to deliver national and regional strategic whole energy plans.

Enhanced Sector Digitalisation and Data Sharing
NESO will work with the sector to develop an aligned and interoperable digital ecosystem that enables industry digitalisation collaboration utilising innovation, underpinned by transparent data sharing and access.

Fit-for-Purpose Markets
NESO will support the government in making informed decisions on policy and market reform across the whole system. We will also continue to reform our own markets to level the playing field and deliver value to consumers.

Secure and Resilient Energy Systems
NESO will improve whole energy system emergency preparedness and resilience. We will ensure the necessary capabilities and requirements are in place and facilitate industry readiness to meet the Electricity System Restoration Standard.

Separated NESO Systems, Processes and Services
NESO will transition remaining systems, processes and services from National Grid to NESO ownership to enhance our capabilities and establish our autonomy and full independence.

Clean Power 2030 Implementation
NESO will play a pivotal role in securing clean power for Great Britain by 2030 on the path to net zero by 2050. Building on our 2024 advice to government on pathways to a clean, secure, operable and deliverable electricity system, we will move to action and implementation in line with the government's CP30 action plan.

ELECTRICITY

Operating the Electricity System
NESO will transparently operate a safe, reliable and efficient system throughout BP3, while continuing to transform the capabilities of our people, processes and systems to enable secure zero-carbon operation of the system by the end of 2025.

Connections Reform
NESO will drive delivery and implementation of a reformed connections process that enables projects needed for 2030 and beyond to connect in a timely and coordinated manner.

The NESO Performance Arrangements Governance Document (NESO PAGD) for BP3 was published by Ofgem in February 2025. This document sets out the process and criteria for assessing the performance of NESO, and the overarching reporting requirements which form part of the incentives scheme for the BP3 period. Further detailed reporting requirements are also set out in Ofgem's Determinations.

Every month, we report on a set of Reported Metrics. In Business Plan 2 (BP2), these quantitative measures were referred to as Performance Measures (including Performance Metrics and Regularly Reported Evidence). However, for BP3 these have been re-termed to Reported Metrics to reflect the change in the evaluation methodology and adoption of Success Measures. All BP2 measures have been retained for BP3 except for the following as set out in Ofgem's Determinations:

- RRE 1E - Transparency of operational decision making (replaced with new skip rate measure)
- Metric 2Ai – Phase-out of non-competitive balancing services (covered by Success Measure under Fit-for-purpose markets)
- RRE 3X - Timeliness of connection offers
- RRE 3Y - Percentage of 'right first time' connection offers

In several cases our performance against Reported Metrics directly contributes to our Success Measures. In other cases, they apply reputational incentives which are supplementary to Ofgem's public performance assessment. Ofgem will no longer measure our performance against pre-determined benchmarks for the Reported Metrics, however we may still include them as part of our supporting evidence in our reports.

Every quarter, we will provide progress updates for each of the Performance Objectives set out in our BP3 plan. This will include evidence in relation to the Success Measures and where relevant in relation to Ofgem's expectations in their Determinations.

At six months and end of year, we will also publish the results from our Stakeholder Satisfaction Survey and provide an update on how we are delivering Value for Money.

See below a summary of the reporting requirements for our published incentives reports throughout BP3:

Report	Published report content	Dates required by
Monthly	• Reported Metrics	17th working day of the following month
Quarterly	• Reported Metrics • Performance Objectives Progress updates	17th working day of the following month
Six-month and end of year	• Reported Metrics • Performance Objectives Progress updates • Value for Money reporting • Stakeholder survey results	23 October 2025 and 16 May 2026

Following our BP2 submission, Ofgem outlined the requirement for a Cost Monitoring Framework (CMF). The purpose of the CMF is to monitor the delivery and value for money of our IT investments and our exit from the Transitional Services Agreement with National Grid plc.

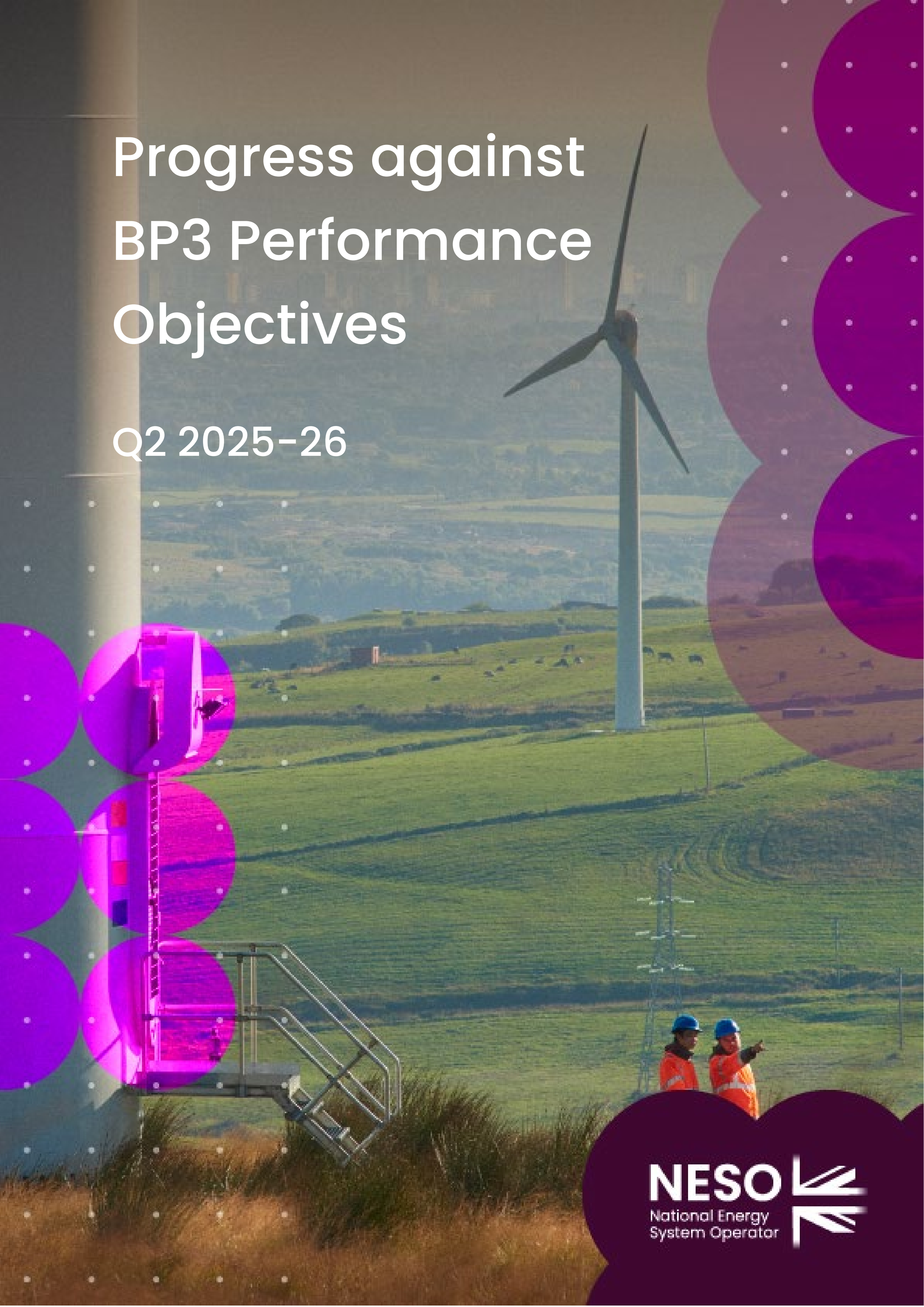
As per the BP3 NESO PAGD, we are required to continue providing quarterly reports directly to Ofgem as part of the CMF throughout BP3. We feel it is also important to share updates with our external stakeholders and industry as part of the framework. Therefore we will include a summary of the CMF update every six months alongside our incentives reporting.

For BP3 we will no longer include a "Notable Events" section in our incentives report – you can stay up to date with our latest news and events on the NESO website or by subscribing to our weekly newsletter.

Please see our incentives website for more information on the scheme and to access our reports.

Progress against BP3 Performance Objectives

Q2 2025-26



NESO
National Energy System Operator

Performance Objectives Summary

We published our third Business Plan (BP3) in January 2025. It sets out our delivery focus for the period April 2025 to March 2026 against eight Performance Objectives. Each Performance Objective is underpinned by a set of Success Measures intended to represent the key deliverables or milestones which, if achieved, demonstrate progress towards the Performance Objective.

Every quarter, we will provide progress updates for each of the Performance Objectives set out in our BP3 plan. This will include evidence in relation to the Success Measures and where relevant in relation to Ofgem's expectations in their Determinations.

The below table shows the status for each Performance Objective as at the end of the quarter. This is followed by more detailed updates for each Performance Objective including progress updates for their associated Success Measures.

Performance Objective	End-Q2 Status	Prior Status (End-Q1)
Strategic Whole Energy Plans	🟡	🟡
Enhanced Sector Digitalisation and Data Sharing	🟢	🟡
Fit-for-Purpose Markets	🟡	🟡
Secure and Resilient Energy Systems	🟢	🟡
Operating the Electricity System	🟡	🟡
Connections Reform	🔴	🔴
Clean Power 2030 Implementation	🟢	🟢
Separated NESO Systems, Processes and Services	🟡	🟡

🟢 On track / no risk

🟡 At risk

🔴 Significant challenges

Performance Objective	Q2 Status	Prior Status (Q1)
Strategic Whole Energy Plans We'll establish our capabilities, and the foundations and methodologies to deliver national and regional strategic whole energy plans.		

Summary of progress this quarter in delivering this PO outcome
The amber rating reflects the inherent complexity of delivering SWEP which is first-of-its-kind, against challenging timelines. We continue to manage the intersection of government policy with the output of our modelling and planning which requires careful engagement with stakeholders. The SSEP pathways document submission is delayed following a formal request from DESNZ. Draft pathways already selected are at risk due to updated data sets published by DESNZ.

Progress on Success Measures this quarter
Submit the first SSEP pathways document to the UK Energy Secretary by the end of 2025. The DESNZ formal request to delay the delivery date for draft pathways has now been received which means the milestone of the end of 2025 cannot be met. We had selected draft pathways by the end of September however there is a risk to these draft pathways as DESNZ have published updated data sets which impact the SSEP inputs. We are now agreeing our approach and the impact on timescales.
Publish the Transitional Centralised Strategic Network Plan 2 Refresh Methodology (tCSNP2) report by 31 January 2026. This is at risk due to interaction with CSNP timescales/scope and dependencies from other programmes. There are ongoing discussions regarding baselined schemes with Transmission Owner's, including EGL5. The approach will be presented to Ofgem and at the Monthly Transmission Owner's (TO) meeting in early October. Ofgem views TCSNP2R as critical for enabling the next round of funding for TO projects so are not prepared to materially change the scope.
Publish the approved strategic energy planning methodologies within the specified timelines: SSEP methodology by May 2025; CSNP methodology by September 2025. **SSEP methodology by May 2025;** The SSEP methodology was published on 15 May 2025 following approval from the Secretary of State for Energy Security and Net Zero and Ofgem. **CSNP methodology by September 2025** Positive progress has been made on the methodology following our consultation, with submission now targeting January 2026, as agreed with Ofgem. The delivery of the first

cycle is challenging due to delays in preceding activities (Connection, SSEP, TCSNP2R). We are working with Ofgem on time and scope proposals ahead of internal agreement.
Publish the RESP methodology consultation by November 2025. This remains on track for November 2025. The approach has been agreed with Ofgem and the framework has been shared.
Publish RESP inputs to Electricity Distribution-3 price control as agreed with Ofgem by March 2026. The September consultation launched successfully and runs until 3 November. Early feedback is positive. Right For Information (RFI) reviews are underway, and final outputs remain on track for January 2026.
Publish the Gas Options Advice Document (GOAD) by 31 December 2025. The project is progressing well despite facing challenges with internal resources and delivery timescales. We are on track with the GOAD and hydrogen network planning, with significant achievements in data acquisition, methodology approval and stakeholder engagement. The GOA Methodology has been published and a webinar was held on 8 October.
Establish hydrogen network planning activities by 30 March 2026, including, where relevant, proposals to extend the 2026 Gas Network Capability Needs Report (GNCNR) to cover hydrogen network requirements. We are progressing well with hydrogen network planning, having published the high-level methodology as part of the whole system CSNP consultation, and will continue to refine the methodology based on stakeholder feedback. This integration demonstrates our commitment to a whole-system approach, optimising energy network infrastructure costs across electricity, gas, and hydrogen. There remains some risk as we await final commitment of dates to help finalise the plan develop the methodology.
Build capability and establish regional teams with at least five full-time equivalents (FTEs) per RESP region by December 2025. Convene the first quarterly Regional Forum for each region by May 2025, to support transitional RESP and RESP development. All 11 nations and regions have now successfully achieved the target of five FTEs ahead of the original deadline set for the end of December 2025. The first conventions took place on 11 April 2025. Total attendance at the first round of quarterly forums was 1,263, and one of the key lessons captured was to enable more stakeholders' input into those forums.

Progress on additional Ofgem expectations
Review of Security and Quality of Supply Standard (SQSS) The NEST SQSS review is an ongoing process. Since we proposed the review plan in RIIO-2 submission, we continued to review and deliver on that plan with: - Five modifications submitted and approved by the Authority (GSR025 EREC P28, GSR026 non-standard voltages, GSR027 Frequency Control, GSR031 CATOs, GSR033 Code Maintenance) - Two workgroups in progress with some elements planned to be submitted to the NETS SQSS panel in October (GSR029 Review of Demand Connection Criteria and GSR030 Offshore DC Connections); - Three other modifications are currently in scoping /prioritisation stage. We will continue the SQSS review in the BP3 period to ensure the standard is fit for purpose for the latest development.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q2.

Performance Objective	Q2 Status	Prior Status (Q1)
Enhanced Sector Digitalisation and Data Sharing By working with the energy sector, we'll develop an aligned and interoperable digital ecosystem driving industry digitalisation collaboration utilising innovation, underpinned by transparent data sharing and access.		

Summary of progress this quarter in delivering this PO outcome

The successful launch of the Digitalisation Plan has helped to engage the wider industry with the required digital journey that is required to hit our CP2030 targets and ultimately our net zero actions. We are also making strides in our data sharing capabilities with a number of process reviews being undertaken in Q2 which should drive future improvements later in the year.

However, we are still behind schedule on the TIDE project. This has demonstrated to us the difficulty of coordinating the complex make up of industry stakeholders that are required to succeed in this objective and more work is required in this area.

Progress on Success Measures this quarter

Publish a sector digitalisation plan study by the end of April 2025.

The Sector Digitalisation Plan was published on 1st September having been developed in collaboration with Ofgem and DESNZ. The plan is the first of its kind and we consider it to have significantly shifted the Digital agenda in the UK energy sector. Stakeholder feedback has been extremely positive.

Sector Digitalisation Plan | National Energy System Operator

Establish Data Sharing Infrastructure (DSI) for the industry, with Minimum Viable Product (MVP) readiness by the end of September 2025.

Following the successful DSI pilot in Q1 the Minimum Viable product phase has been undertaken in Q2.

Procurement for two of the four proposed workstreams is progressing well using our recently developed DD&T Procurement framework. A third workstream is in the process of being initiated. On both workstreams, we are working with stakeholders that we have collaborated successfully with previously.

Fully implement the interim Data Sharing Infrastructure (DSI) Coordinator role (subject to consultation outcomes) by the end of 2025.

The team structure has been finalised and recruitment is well under way. The Head of the Data Sharing Infrastructure has been recruited and starts mid-November. After the completion of the recruitment phase, the next stage will be to develop processes within the team as we embed the infrastructure.

Improve the Open Data Portal by increasing the availability of shareable energy data and embedding a more comprehensive data catalogue for greater transparency. During Q2, we have acted on internal and external feedback and reviewed many of our processes within this area. Process improvements have been implemented to improve timeliness and responsiveness. Timeliness of processing external data sharing requests within SLA has improved by 39 percentage points from last financial year to this (now at 92%). Transparency on decision making has also improved, with a log now available on the NESO website of requests that were subsequently rejected and the reason why. Building on these foundations in Q3 and Q4 is our focus for the rest of the year.
Increase distributed energy resources (DER) visibility through improved registration and forecasting. Positive progress has been made in developing a new standard based on OpenADR to support data sharing for flexibility services across Great Britain. The TIDE programme is still behind schedule. We are working to define the high-level solution blueprint and develop a roadmap during Q3.
Progress on additional Ofgem expectations
No updates for Q2.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q2.

Performance Objective	Q2 Status	Prior Status (Q1)
Fit-for-Purpose Markets We'll support the government in making informed decisions on policy and market reform across the whole system. We will also continue to reform our own markets to level the playing field and deliver value to consumers.		

Summary of progress this quarter in delivering this PO outcome

The performance objective is currently at an amber status with mixed progress against the success measures.

We have made progress to deliver against our Markets Roadmap with the extension of the Quick Reserve service to non-Balancing Mechanism participants and are expecting the approval of changes to the Balancing Reserve service terms and approval of the new Slow Reserve service. However, the Slow Reserve service go live has been delayed until March 2026.

We worked closely with DESNZ and Ofgem on the Clean Flexibility Roadmap and have made progress towards NESOs deliverables within this and our Enabling Demand Side Flexibility actions.

We continue to develop the capability and capacity to run an Early competition tender when the first qualifying project is accepted by Ofgem. We are continuing to work with Ofgem towards the ambition of identifying a suitable first project, and subsequent pipeline of future projects, for delivery through onshore early competition.

We are supporting government with the creation of a delivery plan for a Reformed National Pricing (RNP) wholesale market focussing on delivery of SSEP, enhancing operational efficiency and enhanced constraint management measures.

Progress on Success Measures this quarter

Report the volume of services procured competitively. The proposed targets for BP3 are: Constraints: 100%, Frequency Response and Reserve: 90%, Reactive: 5%

Q2 Performance:

Constraints: 100% (BP3 target: 100%)

Frequency Response and Reserve: 85.1% (BP3 target: 90%)

Reactive: 4.4% (BP3 target: 5%)

For Q2, constraints competitive procurement % was in line with the full-year target (100%). Whilst Frequency Response & Reserve and Reactive were slightly below the full-year targets, the % are an improvement compared to BP2 (82.5% and 3.8% respectively). We expect to continue to see improvement through BP3.

Deliver quality analysis required for the REMA programme to reach a successful conclusion and move into the implementation phase. We will evidence engagement with a broad range of customers and clearly demonstrate how their feedback has been fully considered in our work.

On 10 July 2025 government announced their decision on REMA to retain a single national wholesale price with subsequent reforms to existing arrangements. The NESO REMA Programme has been re-scoping and re-planning accordingly.

We have been establishing a new NESO RNP programme, to stand up formally in October, to focus on:

1. Supporting DESNZ to align and coordinate the different siting and investment levers in the power sector, to ensure the real-world delivery of the Strategic Spatial Energy Plan (SSEP) pathway
2. Enhancing operational efficiency via improvements to balancing and settlement arrangements
3. Bearing down on thermal constraint costs and volumes through enhanced constraint management measures

We have begun to engage industry stakeholders, including the NESO Electricity Markets Advisory Council, on our plans and proposed reform options. Q3 will see this stakeholder engagement ramp up significantly.

Deliver against the Markets Roadmap to be published in April 2025.

- **Improved capability to manage frequency, and a level playing field for response providers.**
- **New and improved procurement processes for ancillary services, such as stability and reactive power.**
- **Deliver the actions needed to support the objectives of our Enabling Demand Side Flexibility report, including the Routes to Market Review (as per the planned timeline).**

The 2025 Electricity Markets Roadmap was successfully published in April 2025, detailing our market design principles and plans for NESO markets.

Good progress has been made in market development work for day ahead reactive power and stability markets, static recovery, the Demand Flexibility Service, locational procurement of response and reserve, and instructible dynamic response.

Quick Reserve Phase 2 to allow non BM units to participate in the service went live in September. We are working with market participants to onboard them. In addition to this we also implemented measures to allow greater data transparency following provider and market feedback.

Since last quarter we have indicated a delay from Q3 delivery of Slow Reserve to Q4 delivery. This was due to additional scheduling requirements being identified before the service could go live. The reactive power mid-term market is being developed ready for its first tender early in 2026. A combined, long-term tender was launched for procurement of both stability and reactive power services; the combination is designed to help providers plan and coordinate which markets they participate in. The actions contained within Enabling Demand Side Flexibility report and Routes to Market Review have been combined into a programme of work with the Clean Flexibility Roadmap actions for markets, which we are now tracking and driving progress.
Publish the first draft Gas Future Markets Plan for consultation and review. We will also lead and set the direction of the Future of Gas Steering Group and Forums which will support in providing a review done with effective industry engagement. We continue to engage Relevant Gas Market Participants via the Gas Advisory Council (GAC), which has prioritised three projects to prioritise as GAC-led initiatives: i) Hydrogen blending, ii) Bio-methane post-Green Gas Subsidy Support scheme, and iii) Natural Gas storage. The official project start dates will be finalised at the next GAC meeting on 22 October 2025. Regular bilateral meetings with key stakeholders have been established, including to ensure clarity around project scope and NESO's role.
Engage with decision-makers and customers across energy vectors to move towards greater whole energy market coordination, collaborating to assess and prioritise our activities. Evidence engagement with a broad range of customers and clearly demonstrate how their feedback has been fully considered in our work to develop proposals in areas where there is benefit from improved whole energy market design coordination. The Whole Energy Market Coordination Summary report was published during July 2025, offering an independent view of cross-vector market interactions and opportunities for greater coordination, the summary report has identified 3 key focus areas with 11 opportunities for improvements. We are currently working on post-publication stakeholder engagement, aiming to identify a number of priorities among the 11 opportunities to be taken forward. In parallel, we are also working to finalise and publish the longer report of the work done to date. Alongside this, we have been working with stakeholders from across industries and vectors in the development of the Demand for Constraints service for the past 18 months. Recently we have set up an expert group to help provide input through the detailed design phase. This group is providing feedback and insight from a range of interested parties, including hydrogen electrolysis developers, data centres, aggregators and industrial manufacturers.

As Code Administrator for the CUSC, Grid Code, STC and SQSS, NESO will ensure that these codes are administered in an independent, fair manner in accordance with CaCOP standards. Positive feedback from our Independent Panel Chair, Panel Members and industry in relation to our performance as Code Administrator. The Connection and Use of System Code (CUSC) and System Operator – Transmission Owner STC (code) modifications for Connection Reform were implemented as per the Authority decision letters, and industry and NESO are actioning the required changes. To complement these Connections Reform changes, we raised a CUSC modification to introduce an additional financial requirement for developers. This mechanism, which can be activated if needed, aims to encourage the removal of unviable projects from the connections queue, thereby improving the efficiency and timeliness of viable project connections. The proposal has now completed the workgroup stage and is currently awaiting Authority approval. We have continued to raise and progress high priority Grid Code Modifications, including a new modification which proposes to obligate Generators and Interconnector Owners to notify NESO of their intended position in the event of severe space weather, therefore ensuring system security in such circumstances. Key Market-wide Half-Hourly Settlement (MHHS) milestones have been delivered in this reporting period. NESO and Elexon delivered successful implementation and testing to ensure the programme milestones could be delivered on time and to budget. Following a thorough recruitment process and the approval of Ofgem, we announced the appointment of the new Independent Chairperson for the Grid Code and Connection and Use of System Code (CUSC) Panels. We have continued to lead on work to develop future CUSC, Grid Code, STC, SQSS and BSC changes, and have collaborated with UK TSOs on further development of the trading arrangements identified within the Trade and Cooperation Agreement.
First Early Competition pre-qualification launched by the end of 2025 and Invitation to Tender launched by the end of March 2026. Deadlines met with sufficient market interest to run an effective procurement event. **As the delivery body, NESO are to be ready through the development of capability and capacity to run a tender for when the first qualifying project is accepted by Ofgem. The requirement to ensure that there is sufficient market interest and that deadlines are met to run the tender remain once the first project is selected.** The plan set out for out Early Competition Success Measure was in line with Ofgem's expectations of ambitious delivery at that time. However, noting Ofgem's decision on Early Competition, there is now a period of uncertainty to the timelines expressed for the first Early Competition BP3 document. Ofgem's revised expectation is for Network Competition is '*To ensure it is ready to deliver against a future identified project with similar project timelines, though further into the*

future. Our expectation is that NESO continues to upskill and prepare for this important competitive procurement activity."

We are continuing to work with Ofgem towards the ambition of identifying a suitable first project, and subsequent pipeline of future projects, for delivery through onshore early competition.

Implement Capacity Market and Contracts for Difference regimes for CP30 and operate the markets effectively.

- **Implement system and process guidance changes required to enable CP30 and wider policy objectives in line with DESNZ and Ofgem consultation decisions ready for the CM and CfD rounds opening summer 2025.**
- **Provide support for CM and CfD customers enabling participation in the schemes through maintaining guidance, offering points of contact and in running industry webinars.**
- **Deliver continuous improvements to CM and CfD systems and processes against prioritised customer enhancements.**

Following carefully designed customer readiness programme incl. comprehensive guidance and videos, launch events and webinars, we successfully opened the Capacity Market 2025 and CfD AR7 and AR7a. All the relevant regulatory changes were implemented in time. We have seen record high volume of applications for both regimes and during the application window period, over 1000 customer queries were answered effectively and timely.

For CfD, application assessment and Tier One Dispute have been completed. Applicants who do not agree with the outcome can raise to Ofgem for final decision. For CM 2025, we will be informing Applicants of their prequalification application results by 11 November 2025.

Progress work to enable the realisation of the demand side flexibility required to achieve CP30, including through NESO markets.

In July 2025, DESNZ published its Clean Flexibility Roadmap. We worked closely with DESNZ and Ofgem on the development of this document, so that when it was published it was already aligned with our planned work in most areas. Since its publication, we have set up internal governance to track the implementation of the roadmap actions, alongside our own programme of work, set out in the Enabling Demand Side Flexibility report and Routes to Market review. We are working on the actions contained within these areas, planning for our next stakeholder update in October 2025. We will also be aligning our reporting with the DESNZ requirements for the Clean Flexibility Roadmap.

Progress on additional Ofgem expectations
Evidence how market reform has resulted in greater market compliance with NESO's Market Design Framework, shown through an update of the 2023 assessment by a competent third party or equivalent. The Market Design Framework (MDF) has been reviewed internally and updated to reflect NESO's new responsibilities and other changes in approach over the past two years. It is being used internally to inform our reactive power market development and a full MDF review of NESO's markets is planned for 2026. **Evidence how NESO has proactively engaged with the Market Facilitator ahead of its launch, such that development of market rules and delivery of benefits is enabled as soon as possible from go-live (and earlier where relevant). NESO should also continue to work with the Open Networks programme, delivering on actions where relevant.** We are engaging regularly with Elexon through face to face deep dive sessions on elements such as the delivery plan to make sure that we're aligned as possible. Through this engagement, we have been able to set up our internal processes and prepare for the launch in December, including the first flexibility market rules. **Evidence how NESO has engaged proactively in the identification of GB rule changes (including relevant industry codes and standards) and has worked to affect change positively to the benefit of the GB consumer.** We have proactively supported the identification of industry changes and progressed industry change in its role of Code Administrator. CMP448, which introduces a Progression Commitment Fee designed to incentivise correct behaviours within the reformed connections queue, was progressed on an urgent basis and has recently received a minded to decision from Ofgem (20 October 2025) supporting its Original Proposal. BSC Modification P462 has been progressed with the aim of reducing consumer costs caused by interactions between CfDs and the Balancing Mechanism distorting bid prices. Some examples of recent Grid Code Mods that NESO has proactively developed and raised include GC0182 on introducing a Metering Polarity Standard into the Grid Code and GC0183 on a Space Weather Industry Protocol. Further to this, we have allocated extra resource to deal with a larger than usual number of urgent modifications in the first half of the 2025/26 financial year. This includes the current live modifications CMP447 and GC0183. This has been particularly prevalent in the CUSC arena, where the number of modifications progressed on an urgent timescale has either directly or indirectly led to 8 Special CUSC Panels being held, which is greater than the number of standard CUSC Panels (6) since April 2025. As part of usual activity, we continue to provide forums for discussion and socialisation and identification of modifications via Transmission Charging Development Forum and CUSC Issues Standing Group (TCMF and CISG), as well as its counterpart on Grid Code, the Grid Code Development Forum (GCDF). We also host informal groups to develop solutions with the input of external stakeholders prior to formally raising a Mod – an example of this

is the Grid Forming Expert Group, which has input from a wide range of external stakeholders. There is currently a large volume of live code modifications across CUSC (22), Grid Code (12), System Operator and Transmission Owner Code (STC) (7 STC and 7 STCPs), the Security and Quality of Supply Standard (2). These numbers, particularly across CUSC and Grid Code, illustrate that NESO are progressing a larger volume of modifications than we have seen in previous years.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q2.

Performance Objective	Q2 Status	Prior Status (Q1)
Secure and Resilient Energy Systems We'll improve whole energy system emergency preparedness and resilience. We will ensure we are on track to have the capabilities and requirements in place and facilitate industry readiness to meet the Electricity System Restoration Standard.	Green	Amber

Summary of progress this quarter in delivering this PO outcome

This Performance Objective is green overall, for this reporting period.

The 2025 Energy Resilience Assessment was released to Ofgem & DESNZ on 25 July 2025, following the approval of an extension to incorporate learnings from the North Hyde investigation. The release was in alignment with the agreed revised timescales. Work has now started with DESNZ to agree prioritisation and ownership of the recommendations made in the 2025 ERA. Initial activity to draft and deliver the 2026 ERA, has also commenced.

For the BP3 reporting period, delivery of 95% capability and arrangements to meet new Electricity System Restoration Standard (ESRS) is at risk, driven by a variety of individual delivery elements off track in the near-term (March 2026) plan. However, we continue to remain on track against meeting the ESRS by December 2026.

The Gas Security of Supply Assessment and the Methodology Statement are on track and progressing through internal governance throughout October 2025. The publication date for both the assessment and the methodology will be aligned to the release date of the upcoming DESNZ consultation.

Progress on Success Measures this quarter

Deliver 95% of capability and arrangements to meet the Electricity System Restoration Standard to restore 100% of Great Britain's electricity demand within five days.

ESRS is off track for this reporting period, driven by certain individual delivery elements in the near-term plan (to March 2026) being off schedule. However, the Programme remains on track, against the December 2026 delivery date for the Restoration Standard.

Our external RDST Supplier & DD&T have agreed a product-led approach following an agile-style methodology. The ESRS and DD&T teams have reviewed the proposal set our external RDST Supplier and have agreed it in principle. The solution proposed will implement a minimum viable product (MVP) by November 2026 with further iterations scheduled over the subsequent 2 years.

ESRS Successes: There are several notable programme successes, for this reporting period: - **Assurance Framework:** An interim report was submitted to Ofgem to communicate progress towards meeting the ESRS targets. - **Week 24 Submissions** completed for 2025 exercise, identifying improved progress to meeting resilience targets (80% by Dec 2026). - **DNO Engagement:** initial engagement with DNOs has been positive to understand their current restoration status, gain support to enable adjustments in block loading intervals to 10 minutes, and investigate opportunities to expand restoration zone sizes. **Progressing Towards Implementing the Restoration Standard:** Current modelling does not achieve the 60% demand restoration within 24 hours. Three additional key actions are being implemented to ensure the standard of restoring 60% demand in 24 hours is met. These actions are being implemented via Ofgem and DNOs. A sensitivity analysis using the ESR probabilistic model was conducted to identify pathways to reduce average 60% demand restoration time. The outcome of this analysis suggests that a significant reduction in restoration time can be realised by: 1. speeding up demand block loading, 2. improving power island stability and 3. expansion of multiple distribution restoration zones.
Produce the first Energy Resilience Assessment by 30 June 2025. We will evidence engagement with a broad range of customers and clearly demonstrate how their feedback has been fully considered in our work. Energy Resilience Assessment (ERA) has been released in line with the updated deadline (see below). The release workshop took place in-person with Ofgem and DESNZ representatives in mid-August. The delivery of this assessment was delayed incorporating learnings from the North Hyde investigation. The final report was published at the end of June 2025. This delay was agreed with Ofgem to ensure governance and factor in the necessary changes. There was an emphasis on the need for consistency between the North Hyde review and the ERA to ensure alignment and avoid conflicting recommendations. The scope for 2026 ERA will be agreed with consideration of DESNZ feedback and prioritisation on how the actions from the 2025 ERA are taken forward. These ongoing conversations will enable the definition of the 2026 ERA scope. A webinar was held after the report was published to engage with stakeholders and collate feedback.
Publish the electricity Summer and Winter Outlook Reports by 30 April 2025 and 31 October 2025. We will evidence collaboration with industry partners, including National Gas, which prepares the *Gas Winter Outlook*, to ensure there are 'no surprises'.

The Summer Outlook Report was submitted in line with expected timelines (30 April 2025). The Winter Outlook 2025/26 Report is scheduled for publication on 9 October 2025. The report Is on track for publication on the agreed date and the team has clear understanding of required steps needing to be completed, before publication. The report is currently progressing through final stages of governance process, with all feedback received early October.
Submit to DESNZ and Ofgem the Summer and Winter Readiness Reports by 30 April 2025 and 31 October 2025. The Summer Readiness Report was submitted in line with expected timelines (30 April 2025). The Winter Readiness and Preparedness 2025/26 Report is currently on track, ahead of the 31 October 2025 deadline. The team are working through intense analysis and report writing phase, making good progress against the baseline plan. An early-view summary has been completed and shared with DESNZ, Ofgem and internally.
Publish the Gas Supply Security Report by 31 October 2025. Recommendations of the *Gas Supply Security Report* will be evidence-based, considering the impact on the whole energy system, and will be adopted by the government and Ofgem. There are two outputs associated with this publication: the methodology statement, and the assessment. Both are on track to meet the deadline 31 October 2025. The publication date for both the assessment and the methodology will be aligned to the release date of the upcoming DESNZ consultation. A publication date for the consultation, is currently being confirmed by DESNZ, with the team working to the 31 October 2025 submission date.
Submit the Electricity Capacity Report to DESNZ by 1 June 2025. Recommendations in the Electricity Capacity Report are adopted by government. DESNZ's Panel of Technical Experts remark positively on the quality of the modelling in their published report. 2025 ECR was released at the end of May 2025 to Ofgem and DESNZ and published online at the end of July 2025, in alignment with agreed timescales. The 2026 ECR report activity is underway. Initial planning conversations with the with Product Owners, with consideration of lessons from last report period, being undertaken.
Deliver the programme to look at the longer-term resilience of our control operations. Following approval of the needs case for Project Juliet, the Strategic Outline Case was endorsed and progress to the Outline Business Case, scheduled for Board review in March 2026. Due to the sensitive nature of this programme, we will not be providing detailed information for security reasons. However, we will work closely with Ofgem to ensure effective outcomes and efficient spending on this project.

Progress on additional Ofgem expectations
Establish the capability to fully meet Parts A, Energy risk and threat advice, and B, Post-event and post-emergency analysis, of our Energy resilience and resilience reporting licence condition obligations. **Provide the Emergency Processes Assessment to Ofgem and DESNZ by 1 December in line with our licence obligation.** **Continue to work on medium-term adequacy modelling, building on the developments made in BP2 including:** - **the Electricity Capacity Report and the annual cycle of development projects to enhance the modelling; and** - **adequacy modelling, including assessment of the 2030s, looking beyond the time horizon set out in CP2030 which now includes a new, dedicated assessment of gas supply security to be produced by 31 October each year.** The additional Ofgem expectations set out as part of the BP3 Final Determination have considered and/or delivered as part of the ongoing activity, undertaken by the teams across the R&EM directorate.
Progress towards PO not captured by the Success Measure reporting above
Various reports are produced by NESO which contribute towards the strategic outcome for this performance objective. During BP3 this has included the investigation into North Hyde power station and the Technical Assessment into the Iberian event.

Performance Objective	Q2 Status	Prior Status (Q1)
Operating the Electricity System Transparently operate a safe, reliable and efficient system throughout BP3, while continuing to transform the capabilities of our people, processes and systems to enable secure zero-carbon operation of the system by the end of 2025		

Summary of progress this quarter in delivering this PO outcome

We continue to operate the electricity system safely and efficiently while progressing towards zero-carbon operation by end-2025.

There is a small window of opportunity across October-December to operate a zero carbon system following the alignment of CP30 with ZCO and the exclusion of CHP's. Ofgem approval on FRCR is pending on minimum inertia levels which impacts on the potential window for ZCO.

The Balancing Cost Strategy and Annual Report was published in June, enhancing transparency, though skip rate reduction remains challenging. Daily publication of detailed skip rate datasets, including new technology-specific metrics, supports future analysis, and methodology development for constraint-driven skips is underway. Overall the Dispatch Transparency Programme roadmap delivery is on track and risks being actively managed.

The Balancing Programme is largely delivering against our planned BP3 commitments. A key milestone, non-BM Quick Reserve has been delivered in Q2 FY26 opening opportunities for flexibility providers. In addition, an enhanced real-time prediction capability has been deployed.

Progress on Success Measures this quarter

By the end of 2025, we will demonstrate our ability to operate the system carbon-free whenever electricity markets provide a zero-carbon solution. We will measure this through reporting against the Zero Carbon Operability Indicator (BP2: RRE 1F) and the Carbon Intensity of NESO Actions (BP2: RRE 1G).

Progress against this success measure has improved. Our ability to operate a Zero Carbon Operability (ZCO) settlement period is no longer dependent on progress to lower inertia through the Frequency Risk and Control Report (FRCR) project although implementation of this will increase the number of ZCO windows available.

Following DESNZ's decision to exclude Combined Heat and Power – Major Power Producers (CHP-MPPs) from the Clean Power Metric we have updated our analysis of the possible ZCO windows.

In Q2, the highest ZCO period was 95.93% (CP30 definition). Please see the Reported Metrics section of this report for more information related the Zero Carbon Operability and NESO Carbon Intensity metrics.

We will further develop and implement initiatives from our Balancing Cost Strategy to demonstrate cost efficiency through the Balancing Cost metric (BP2: Metric 1A). In consultation with industry, we will publish an updated Balancing Cost Strategy by June 2025. Opportunities are continually being identified to enhance understanding and accessibility of balancing costs. The Balancing Cost Strategy was successfully published on 12 June 2025 along with the Balancing Costs Report. Further details are available in the previous Incentives report. In Q2, balancing costs totalled £689m. Please see the Reported Metrics section of this report and previous incentives reports for further updates related to the Balancing Costs metric.
In December 2024, we published a skip rate methodology and delivery plan alongside a continuous skip rate measure on our data portal. We will develop this further into a detailed delivery programme and roadmap ahead of BP3, aligning it with our dispatch strategy. During BP3, we will deliver all commitments within our delivery programme and roadmap to reduce skip rates, providing transparency by continuing to report against the skip rate measure. **Share Platform for Energy Forecasting (PEF) and skip rate data, as well as issuing data associated with other strategic platform energy releases.** **By the end of BP3, deliver a substantial reduction in skip rates with a target of relative parity across technology types.** **Publish timely, accessible and accurate skip rates data using both the existing 5-stage post system action methodology and any updated methodology agreed with industry.** See the Reported Metrics section for updates related to the Skip Rates metric. We are progressing on track against our programme roadmap. Whilst the trend for skip rates currently remains relatively flat, we are progressing our root cause analysis work to identify causal factors. We continue to improve transparency through release of an interactive dashboard to analyse skip rate numbers to differing levels of granularity on top of continued data publication. We are also continuing engagement through webinars, drop-in sessions and the Operational Transparency Forum (OTF). Methodology development for constraint-driven skips is underway but remains in early stages. An engagement plan for defining a skip rate target with industry has been developed and is utilising industry body forums alongside programme run engagement.
In BP3, we will deliver new products and capabilities in accordance with our Balancing Programme, following our industry-agreed roadmap. The Balancing Programme roadmap is largely on track to deliver against our BP3 plan. Non-BM Quick Reserve has been delivered in Q2 FY26 opening opportunities for flexibility providers. In addition, an enhanced Real-Time Prediction capability has been deployed. Progress has been made on several other key milestones including our Fully Resilient OBP, National Dispatch Optimisation & OBP Instruction capabilities which are on track to be

delivered in Q3 FY26. The roadmap is challenging with several further milestones planned for delivery by March 2026.
Continuous improvement in forecasting is vital to ensuring we make informed decisions across all timescales. We will continue to publish our performance in this area through the Demand Forecasting metric (BP2: Metric 1B) and Wind Generation Forecasting metric (BP2: Metric 1C). **Enhanced forecasting capability is key to enabling secure and economic balancing decisions through the energy transition. We will develop and publish our Forecasting Strategy for consultation by October 2025, followed by a corresponding delivery plan by February 2026. We will implement any initiatives specified in our delivery plan that are due within BP3.** See the Reported Metrics section for updates related to the Wind and Demand Forecasting metrics. We have successfully updated our Restoration Demand Forecast capability and also completed our internal-stakeholder engagement development of our Forecasting Strategy. We are continuing to make tactical improvements to our Grid Supply Point (GSP) forecasts used in the Network Access Planning (NAP) & Electricity National Control Centre (ENCC) functions, while also developing the features for their strategic replacement. We have successfully completed our new solar forecast capability, including the integration of an innovative third-party solar forecast which uses satellite imagery. Work has begun to build our next generation National Demand forecast models, while we are also trialling the benefits of consuming commercial forecasts from external vendors. We are largely progressing with the original 1B/1C Improvement Plan, that was presented to Ofgem in early 2025 and both 1B & 1C are where we expect them to be at this present time.
As the electricity system in Great Britain evolves, we will transform the capabilities of our people, processes and systems and continue to deliver economic and efficient real-time operation of the electricity transmission system, as measured through the Security of Supply reporting evidence (BP2: RRE 11). There were no frequency excursions in July – September. There were no voltage excursions in July and August. There was one voltage excursion in September. During the night of Tuesday 9 September 2025, the transmission network in the Pembrokeshire area in South Wales was operated outside of statutory voltage limit outlined in the Electricity Transmission Licence Standard Condition E7 reporting criteria statement. The voltage excursion occurred at Pembroke 400kV and lasted for 16.8 minutes. Please see the Reported Metrics section of this report for further information related to these events.

Progress on additional Ofgem expectations
Progress against additional expectations related to skip rates covered above.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q2.

Performance Objective	Q2 Status	Prior Status (Q1)
Connections Reform Drive delivery and implementation of a reformed connections process that enables projects needed for 2030 and beyond to connect in a timely and coordinated manner.		

Summary of progress this quarter in delivering this PO outcome

In Q2, timelines for the delivery of Connections Reform were extended. The programme demonstrated resilience and diligence in addressing the challenges encountered that have arisen during the quarter.

The evidence submission window originally planned for three weeks was extended due to challenges with the portal and data. Increased efforts are in progress to address and provide assurance for the queue formation, engineering, and offers phases of the programme. The total result of the additional time requests now stands at 5+5+3 weeks which was agreed through joint industry governance and approved by governance in September.

The main risks are programme delays, increased costs, ongoing restoration of previously damaged reputation, and possible legal issues. The risk to timelines must be set in the context of balancing operational delivery, legal and reputational risk.

Progress on Success Measures this quarter

100% of the projects that enter the Gate 2 to Whole Queue process will have connection offers by the end of December 2025.

The evidence submission window closed on 26 August 2025 with 1,815 applications successfully submitted during the window which aligned with our forecast. We delivered on our commitment of not leaving any application behind. The closure of the window was five weeks later than originally planned.

Additional flexibility has been brought into the plan based on the lessons learnt from the challenges during the submission window. Increased focus on data quality, assurance and technical build verification has increased the timeline. Customer feedback, both direct and through trade bodies supported the need for the programme to deliver a high quality output at pace.

The process to reduce and reorder the connections queue, referred to as "Gate 2 to Whole Queue," will commence in October with applicants being updated with their status no later than week commencing 1 December 2025.

The additional time requirements will have an impact downstream on the timelines for the Performance Objective. The current timeline delays all G2TWQ from end of March 2026 to no later than end of Q3 Calendar year 2026.

During the connection reform process, achieve effective customer engagement through transparent and clear communication. **Provide enhanced support for customers via the Connections Reform Hub, hosting industry webinars, and using a range of other communication and outreach channels.** Following on from the issues customers faced with the NESO evidence submission portal, NESO have listened to customers and reflected their feedback to the next phase of delivering connections reform. Customers will be able to see dates that we are committed to delivering by, on the remaining reform timelines, giving them the certainty they need to make investment decisions and move projects forward with confidence. The programme has engaged with trade associations, hosted webinars, updated connections reform guidance, and conducted outreach sessions with trade bodies.
By March 2026 provide revised connection offers aligned with the new methodologies approved by Ofgem. These offers will reflect the technological and locational mix required to deliver a queue of projects capable of supporting the government's Clean Power 2030 Action Plan. Only those who meet specific readiness and strategic alignment criteria will progress beyond Gate 2 and be eligible for a confirmed connection date, with others receiving a provisional Gate 1 offer. The current timeline delays all G2TWQ from end of March 2026 to no later than end of Q3 Calendar year 2026.
By March 2026 design an approach to accelerate strategic demand projects leading to improved connection times. To include identifying and consulting on amendments to connection methodologies to support strategic demand identified by government. Engagement with Ofgem and DESNZ on strategic demand options post Gate 2 process is underway.
Invest further into a fully customer-centric Connections Portal. Work and investment continues in developing and building a state-of-the-art Portal, that incorporates the lessons and learnings gained from the submission window and queue re-formation.
Progress on additional Ofgem expectations
No updates for Q2
Progress towards PO not captured by the Success Measure reporting above
No updates for Q2

Performance Objective	Q2 Status	Prior Status (Q1)
Clean Power 2030 Implementation Play a pivotal role in securing clean power for Great Britain by 2030 on the path to net zero by 2050. Building on our 2024 advice to government on pathways to a clean, secure, operable and deliverable electricity system, we will move to action and implementation in line with the government's CP2030 action plan.	●	●

Summary of progress this quarter in delivering this PO outcome

The Clean Power 2030 implementation remains at status green as we continue to position ourselves as a credible, independent expert to our stakeholders that are part of the wider CP2030 program. This has been achieved by us producing relevant plans and reports on time and to a standard that has generated positive feedback from Ofgem and wider industry stakeholders. We've also begun to widen our influence by introducing new stakeholder touch points via our stakeholder engagement team. We also are developing a wider horizon scanning capability that looks at interdependencies and timelines to keep us on track for our 2030 targets and ultimately our national net zero ambitions.

A number of key milestones have been achieved in the quarter but there are still a wide range of associated interdependencies and external factors that need to be actively managed to stay on track.

During Q2 we have appointed our stakeholder engagement lead, launched our System Access Planning consultation and finalised our first wave of transmission network dashboards.

We've also made great progress on Long Duration Energy Storage, one of our Final Determination actions from Ofgem.

We are still seeing a high degree of interdependencies that need managing such as the Connections Reform portal issues that were experienced through Q2 but have now been resolved. System Access Reform also remains a challenging area that requires close management and alignment to the wider program.

Progress on Success Measures this quarter

Consult upon and publish our comprehensive 2030 NESO delivery plan in April 2025. This will be a clear and concise publication with evidence of collaboration with and alignment to DESNZ Clean Power Team and Mission Control's objectives.

The NESO Clean Power Implementation Plan was delivered in Q1 and is being used as a foundation for the CP30 Delivery Obeya, an internal forum established earlier this year to manage cross-NESO risks and interdependencies.

To support this, the plan is being continually updated through the Obeya process, and the higher-level, externally facing version will be regularly refreshed on our website to ensure our customers stay informed.
Establish ways of working with DESNZ Clean Power Team and Mission Control. We will provide timely responses to reactive requests from DESNZ through Mission Control who are planning to run "policy sprints" which would focus resolving an issue in a short 6-12 week time horizon. The previous meeting formats which were suspended in Q1 have been replaced by a new Tripartite meeting to be recommenced in Q3. Although lower level meetings continue, the suspension of these meetings has caused some risk to the overall control of the programme which should be mitigated as they recommence in Q3.
Produce a stakeholder engagement plan that enables NESO publications to clearly and concisely demonstrate evidence of engagement with a broad range of customers on CP30 and how their feedback has been considered. During Q2 the stakeholder lead has been appointed and the process of building engagement is beginning to take shape through a mixture of new forums and utilising existing working groups. Plans are also being developed to form wider networks by designating leads within other stakeholder organisations and develop our own internal networks.
Develop a strategic approach to System Access Planning with TOs and wider stakeholders by the end of June 2025 with delivery following by the end of March 2026. During Q2, the project team has been fully stood up and work is progressing towards the production of the System Access assessment at the end of Q4. As this initiative involves significant input from Transmission Operators, continued stakeholder engagement is taking place to ensure that the required data is available to maximise the value of the end assessment.
Publish the updated Operability Strategy Report in December 2025 incorporating the full detail of the Clean Power Action Plan. We have requested the report publication date to be moved to March 2026 to make it an annual report and to tie in with the Markets report. This is awaiting agreement from Ofgem. The report is updated on an ongoing basis internally throughout the BP3 period.
Working with DESNZ, Ofgem and TOs, develop and implement by June 2025 a new dashboard system that provides a single version of the truth against which to track progress of transmission network projects required to meet CP30 and, where necessary, facilitates mitigation of project risks. Following the initial release in Q1, some minor amendments were made in early Q2 and the dashboard is now fully live. The focus of work now moves to the milestone below.

Work with stakeholders to produce a set of integrated dashboards to track and review the delivery of the supply side projects required to meet CP30 targets. Development work has continued in Q2 with an expected go live in Q3 as per the timeline outlined in BP3. The complexity and variety of data sources is a risk that has had to be managed during this period. A secondary analysis dashboard is also under development to help us better understand the outputs from the initial build.
Progress on additional Ofgem expectations
Long Duration Energy Storage - establishment of capabilities to support cost-benefit analysis work We have made a good progress in this area and feedback from Ofgem has been positive. This initially consisted of the agreement of the methodology in May for consultation with the final methodology due to be published in the first week of October. Consultation on NESO Assessment Methodology for LDES
Progress towards PO not captured by the Success Measure reporting above
No updates for Q2

Performance Objective	Q2 Status	Prior Status (Q1)
Separated NESO Systems, Processes and Services We'll transition remaining systems, process and services from National Grid to NESO ownership to enhance our capabilities and establish our autonomy and full independence.		

Summary of progress this quarter in delivering this PO outcome

Progress has continued in all areas of the transition. We remain confident about achieving our timescale commitments and we are increasingly being able to define a future state that is not only separated from National Grid but is designed to fit the requirements of the future NESO organisation.

As we move towards the exit date, timescales become tighter and all risks implications are amplified and we continue to work to identify and mitigate as quickly as possible.

Progress on Success Measures this quarter

Exit 60% of services from the Transition Service Agreements (TSA) by the end of March 2026.

Although plans are broadly on track, the foundational service elements are being delayed due to network issues. Q3 is now a critical period in the timelines for network set up and a focus is being placed heavily in this area to mitigate the risk.

Transition physical and cyber security from National Grid. Establishing the strategic Security Operations Centre (SOC), Security Information and Event Management (SIEM), Digital Forensics, and Threat Intelligence capabilities by March 2026.

The Cyber Security transition is progressing well with minor delays in some workstreams although none of these are significantly putting the exit timelines at risk.

Physical security remains at risk due to network cabling delays, with key milestones on track for Q3 and critical actions focused on securing cabling dates and integrator support.

In a wider context, we are continuing to develop our organisational capability in line with our TSA commitments.

Deliver foundational services, including:

- **physical separation of the NESO network from National Grid by December 2025**
- **migration of all users and devices to NESO infrastructure by January 2026**
- **migration of digital platforms and the majority of applications to NESO by March 2026**

The M365 migration delivery for all users, platforms and Sharepoints was completed during the quarter, a significant achievement with little or no business interruption.

The device rollout plan for all employees has begun and the office cutover plans are being developed with a view to implementing in Q3. Resourcing options to assist in the business change process are being finalised.
Build systems and data for people-related functions, including the implementation of People, Payroll, Finance, and Procurement SaaS platforms. During the quarter, the design phase was completed focussing on a philosophy of using the products out of the box with minimal customisation. There have been a number of delays to the project during the quarter for a variety of reasons. This will require significant and close management during Q3 with our planned go live data approaching at speed.
Progress on additional Ofgem expectations
No updates for Q2.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q2.

Stakeholder Evidence

Stakeholder Evidence

Our incentives scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of NESO's plan delivery. To demonstrate performance against this criterion, at the six-month and end-scheme stages we report on our stakeholder satisfaction survey results.

Stakeholder Surveys

NESO commissioned surveys from market research company BMG. These surveys ask our stakeholders to rate NESO's performance based on their experience for each Performance Objective. The survey was targeted at senior managers, decision makers and experts, and includes a wide selection of relevant stakeholders who have had material interactions with NESO's services.

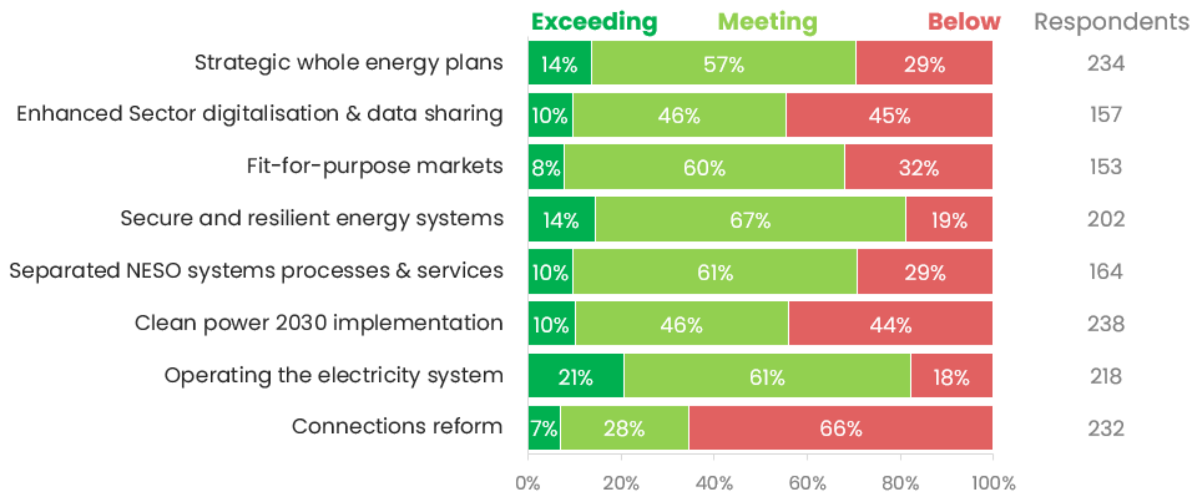
The following questions were asked:

1. **Please tick/highlight the areas where you have experienced/worked with NESO over the last 6 months:**
    a. Strategic Whole Energy Plans
    b. Enhanced Sector Digitalisation and Data Sharing
    c. Fit-for-purpose markets
    d. Secure and Resilient Energy Systems
    e. Separated NESO Systems, Processes and Services
    f. Clean Power 2030 Implementation
    g. Operating the Electricity System
    h. Connections Reform
2. **For each Performance Objective highlighted/ticked** - From your experience of NESO over the last 6 months, how would you rate NESO's performance against your expectations? (below, meeting, exceeding)
3. **For each Performance Objective highlighted/ticked** - What did NESO do to not meet, meet or exceed your expectations in these areas? (Open text)

Survey results by Performance Objective

Overall, we contacted **3,540** stakeholders and received **348** responses from across our representative stakeholder base. Below is a summary of the responses by PO, including the number of stakeholders who responded for each one.

SURVEY QUESTION: **"From your experience of NESO over the last six months, how would you rate NESO's performance against your expectations?"**

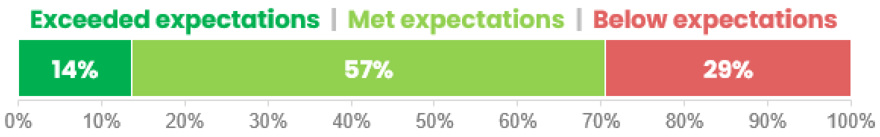


ROUNDING: Percentages are rounded to the nearest whole number, therefore may not sum to 100%.
RESPONDENTS: Note that many stakeholders provided responses for more than one PO.

Summary of stakeholder feedback themes

Below we summarise the key themes from responses to question 3 ('What did NESO do to not meet, meet or exceed your expectations in these areas?') We have categorised the themes by Performance Objective, and by those who evaluated our performance as below, meeting or exceeding expectations.

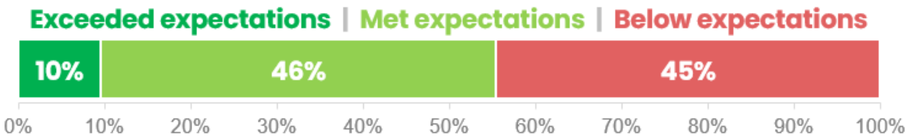
Performance Objective: **Strategic Whole Energy Plans**



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

Category	Key topics and issues raised
Below expectations 69 respondents	**Lack of transparency and engagement:** some responses flagged insufficient sharing of data and limited opportunities for industry input into planning and modelling. **Unrealistic or uncoordinated planning:** some concerns around unclear assumptions, and a lack of integration across energy vectors (e.g., gas and electricity).
Meeting expectations 133 respondents	**Progress on planning and structure:** respondents noted the establishment of strategic plans and improved structure but often described these as “early-stage.” **Need for greater clarity and integration:** there were calls for clearer communication of how different plans fit together and more integration across workstreams and with government.
Exceeding expectations 32 respondents	**Quality and ambition of plans:** respondents praised the quality, ambition, and clarity of NESO’s strategic planning work. **Stakeholder engagement:** positive feedback was given for NESO’s engagement with stakeholders and the breadth of issues considered.

Performance Objective: **Enhanced Sector Digitalisation and Data Sharing**

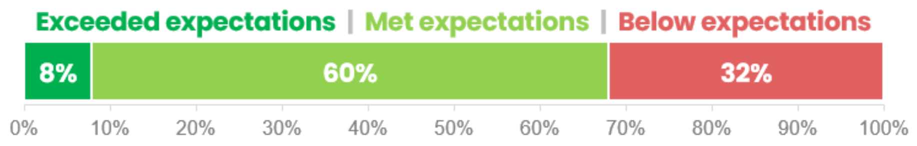


Percentages are rounded to the nearest whole number, therefore may not sum to 100%

Category	Key topics and issues raised
Below expectations	**Limited data sharing and poor digital platforms:** respondents frequently cited inadequate data sharing, slow progress on

70 respondents	digitalisation, and digital tools (such as portals) that are difficult to use or unreliable. **Lack of coordination and clarity:** there were concerns about fragmented systems, unclear responsibilities, and insufficient communication about digital initiatives.
Meeting expectations 72 respondents	**Progress on digitalisation:** some respondents acknowledged improvements in digitalisation and data sharing, but often described these as incremental. **Need for greater transparency and integration:** calls for more open data, better integration of systems, and clearer communication about digital initiatives were common.
Exceeding expectations 15 respondents	**Effective and easy data sharing:** positive feedback was given for specific digital initiatives that improved data sharing.

Performance Objective: **Fit for Purpose Markets**

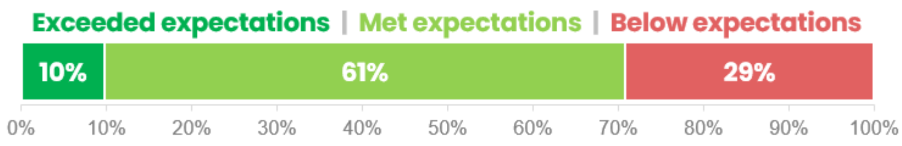


Percentages are rounded to the nearest whole number, therefore may not sum to 100%

Category	Key topics and issues raised
Below expectations 49 respondents	**Slow progress and delays:** respondents frequently mentioned a lack of progress on market reforms, with delays to key programmes (such as Slow Reserve and OBP) and frustration over the pace of change. **Barriers to market access and flexibility:** concerns were raised about markets still being designed for traditional generators, with insufficient support for flexibility, new entrants, or innovative solutions and a lack of gas knowledge.
Meeting expectations 92 respondents	**Markets functioning but could improve:** respondents generally felt that markets are working as intended, but there is room for improvement, especially in terms of consistency and transparency. **Desire for greater competition and clarity:** there were calls for more consistent treatment of resources, clearer market frameworks, and better communication of market changes.

Exceeding expectations 12 respondents	**Proactive market development:** positive feedback was given for NESO's efforts to develop and implement new market mechanisms.

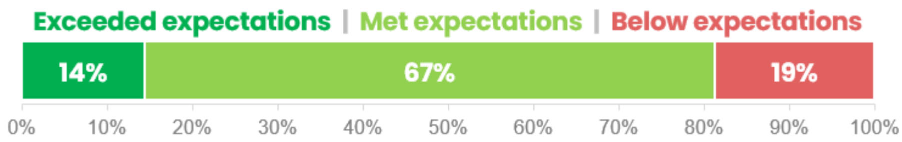
Performance Objective: **Separated NESO Systems, Processes and Services**



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

Category	Key topics and issues raised
Below expectations 48 respondents	**Fragmentation and complexity:** respondents cited confusion and inefficiency due to fragmented systems, unclear processes, and lack of integration across NESO services. **Poor communication and delays:** there were concerns about inconsistent communication, delays in information sharing, and insufficient support during transitions.
Meeting expectations 100 respondents	**Transition managed as expected:** respondents generally felt the transition to separated systems and processes was managed as expected, with some noting stable operations and continuity. **Need for further integration:** some called for more integration, clearer communication, and a single interface to reduce complexity for users.
Exceeding expectations 16 respondents	**Smooth transition and support:** positive feedback was given for a smooth transition.

Performance Objective: **Secure and Resilient Energy Systems**

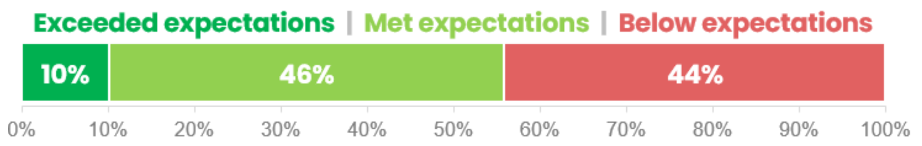


Percentages are rounded to the nearest whole number, therefore may not sum to 100%

Category	Key topics and issues raised

Below expectations 38 respondents	**Lack of clear strategy and communication:** respondents cited unclear or insufficient communication about resilience planning, risk management, and the integration of new technologies. **Slow progress and coordination issues:** concerns were raised about delays and fragmented approaches.
Meeting expectations 135 respondents	**Stable operations and risk management:** respondents generally felt NESO maintains stable and secure system operations, with risk management and contingency planning meeting expectations. **Room for improvement in transparency:** some noted a need for clearer communication about resilience strategies and more visible integration of new technologies.
Exceeding expectations 29 respondents	**Strong performance under pressure:** positive feedback was given for NESO's ability to maintain system security and resilience, even in challenging or changing conditions. **Clear communication and industry engagement**: some respondents highlighted effective engagement and clear communication about resilience planning.

Performance Objective: **Clean Power 2030 Implementation**

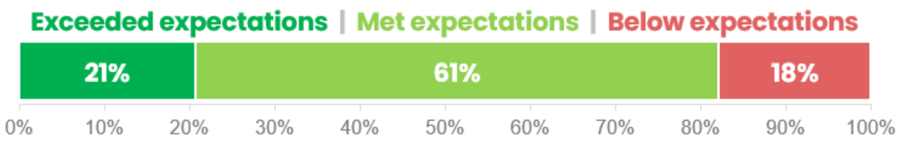


Percentages are rounded to the nearest whole number, therefore may not sum to 100%

Category	Key topics and issues raised
Below expectations 105 respondents	**Delays and unclear processes:** respondents frequently cited delays in connection reform implementation as reducing the viability of delivering cp30 in time. **Insufficient industry engagement:** there were concerns about limited opportunities for industry input, lack of transparency in modelling and assumptions, and inadequate explanation of key decisions.
Meeting expectations 109 respondents	**Timely policy implementation:** some respondents acknowledged NESO's efforts to develop and implement CP2030 policies.

	Need for greater clarity and communication: there were calls for more transparent reporting, clearer communication of progress, and better explanation of how CP2030 aligns with other initiatives.
Exceeding expectations 24 respondents	**Strong leadership and innovation:** positive feedback was given for NESO's leadership in setting clear targets, innovative approaches, and proactive engagement with stakeholders. **Effective communication and support:** some respondents highlighted clear, accessible communication and support as exceeding expectations in this area.

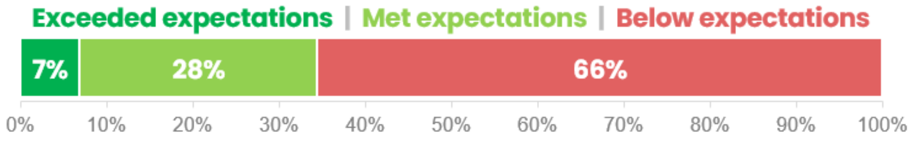
Performance Objective: **Operating the Electricity System**



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

Category	Key topics and issues raised
Below expectations 39 respondents	**Inefficiency:** respondents highlighted high skip rates, the need for improved tools and processes. **Delays and communication issues:** there were concerns about slow processes, unclear decision-making, and insufficient communication.
Meeting expectations 134 respondents	**Reliable system operation:** respondents generally felt that NESO maintains reliable and stable system operations, with processes and risk management meeting industry standards. **Room for process improvement:** some noted that while operations are stable, there is still room for improvement in forecasting, transparency, and responsiveness to operational challenges.
Exceeding expectations 45 respondents	**Strong performance and resilience:** positive feedback was given for NESO's ability to maintain system security, continuity of supply, and robust operational standards, even under challenging conditions. **Clear communication and data sharing:** some respondents highlighted effective communication, clear data provision, and openness to engagement as exceeding expectations.

Performance Objective: **Connections Reform**



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

Category	Key topics and issues raised
Below expectations 152 respondents	**Portal and process failures:** respondents consistently cited major problems with the connections reform portal—describing it as unfit for purpose, poorly tested, and a source of delays and confusion. **Communication and engagement:** there was widespread frustration about poor communication from NESO, including lack of timely updates, unclear guidance, and insufficient engagement with industry stakeholders.
Meeting expectations 64 respondents	**Progress on reform and engagement:** respondents acknowledged NESO's efforts to implement reforms and engage with stakeholders, though often described as work in progress or as expected. **Need for process improvement:** there were calls for further simplification, clearer guidance, and more user-friendly digital tools to support the reform process.
Exceeding expectations 16 respondents	**Taking on the challenge:** a few respondents mention that the methodologies are impressive and form inspiration for other so's.

Value for Money

Executive Summary

Delivering Value for Money for consumers is a fundamental principle that guides NESO's operations and strategic decisions. We are embedding our own Value for Money framework to ensure accountability, drive continuous improvement, and maximise contribution to achieving NESO's strategic objectives, and broader, policy goals, while maintaining public trust through transparency and evidence-based decision-making.

Our framework has been based on the strong foundations of the recognised Value for Money principes of Economy, Efficiency and Effectiveness. The objectives of the framework are:

- To demonstrate NESO is achieving operational efficiency by ensuring excellence and transparency in our operations and business processes.
- To demonstrate NESO is delivering and measuring the impact of our activities to ensure effective outcome delivery to customers, stakeholders and consumers.
- To demonstrate NESO is leading and shaping the energy system through strong and robust strategic alignment.

Assessing Value for Money is a complex task that goes beyond straightforward calculations. It involves careful consideration of different factors, such as benefits, performance and outcomes that are linked to costs, both qualitatively and quantitatively. Value for Money cannot be assessed in isolation and must be considered alongside other business processes for example risk management, internal audits, performance management and corporate strategy.

Our NESO framework defines Value for Money as:

> *"The optimal use of resources to achieve stated objectives, considering all social, economic, and environmental benefits. It involves balancing today's requirements with longer-term opportunities and evaluating the trade-offs between spending and delivering benefits."*

Our framework is further underpinned by three value pillars:

Strategic alignment ensures that our activities are aligned with our mission, vision, and strategic priorities.

Outcome delivery ensures that we are achieving intended outcomes and delivering measurable impacts.

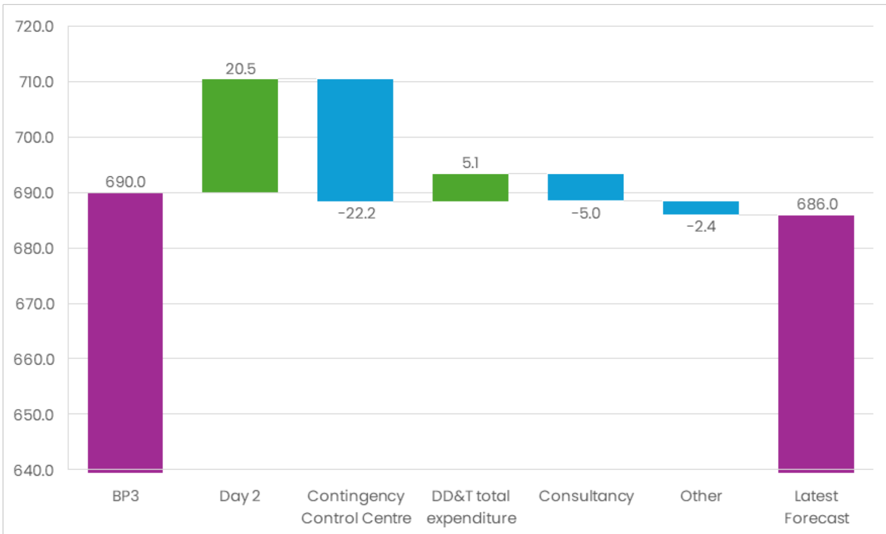
Operational efficiency focuses on ensuring that our resources are used optimally to achieve the best possible outcomes without compromising quality, ensuring that every action we take is cost-effective and contributes to the overall efficiency of the organisation.

Whilst our narrative in this document provides an updated view of the cost out turn for BP3 and explanations where there are cost variances, our delivery of value for consumers is underpinned by our business processes and core values that guide our strategy, business planning, performance management and decision making.

We are continuing to mature our business processes that support delivery of Value for Money. This year we have developed a Value Measurement Framework which will enhance our decision making and internal performance management. It supports scenario analysis and sensitivity testing to guide strategic choices, ensuring that resources are directed toward the most impactful outcomes. By integrating the framework into team-level performance reporting, NESO creates a clear line of sight between individual contributions and organisational value. This promotes accountability, collaboration, and adaptability, reinforcing NESO's commitment to delivering measurable public value while maintaining regulatory confidence through transparent optioneering and cost-benefit justification.

The framework has underpinned our future business plan, but some elements of the framework will be used to further improve current decision making such as the implementation of a new Business Performance Reporting (BPR) framework which tracks and drives progress of our performance objectives, as well as improving our portfolio management through aligning investment delivery to performance objectives to drive our strategic outcomes. As we build these processes, we can share further evidence of how we are delivering Value for Money in the end of scheme report.

Total Cost Overview



Our forecast overall spend for the BP3 period is broadly in line with our BP3 submission.

Our Day 2 project, which will separate our foundational digital and technology services from National Grid and stand up our own back-office systems for finance, people and procurement, will incur higher costs in FY26 than outlined in our BP3 plan. This project is a multi-year programme and underspent by £16m against project sanction in FY25, so those costs are now being incurred in FY26. In total we expect costs to remain in line with the overall sanctioned spend.

We have commenced a programme to look at the longer-term resilience of our control centre operations and the establishment of a new contingency control centre. Given the critical nature of this investment, we are undertaking a further review of the needs case in line with government's official standard for options appraisal and evaluation. This has deferred any significant expenditure on the programme beyond the BP3 period.

Spend on Digital, Data and Technology (DD&T) underpins all our critical roles and activities and accounts for more than half of our total planned spend in FY26. Overall DD&T cost for FY26 is £5.1m higher than the cost wrapper we set in BP3, and we are continuing to prioritise investments and resources with the objective of managing costs in line with our BP3 plan.

Our forecast for consultancy spend has decreased by £5.0m compared to our BP3 plan. In our plan we noted the inclusion of provision to procure consultancy services for reactive discovery work to minimise delays and impacts on broader objectives. To date this provision has not been required and we have reduced our cost forecast accordingly.

Risks to forecast

We are making substantial progress in reforming the grid connections process which will lay the foundations for accelerating the move to a more sustainable energy system and enabling economic growth across Great Britain. This is a complex process which is being undertaken within a limited timeframe and has inevitably presented challenges. Over the summer we experienced issues with our connections portal which resulted in extremely high volumes of customer queries and a delay to the closure of the customer evidence submission window. We deployed additional resources onto the programme to ensure we could resolve all customer queries and successfully process 1,800 applications. We anticipate that costs relating to our connections reform programme will exceed those we set out at the time of our BP3 plan. We are in the process of revising our cost projections and will provide further details on this in the end of scheme report.

Part 1 – Our Roles

Energy Markets

In our Energy Markets role we develop and operate the markets needed for balancing GB's electricity system. We also contribute to the strategy for wholesale markets, act as a code manager and are a market delivery body, across all energy vectors. Our Energy Markets role supports our performance objective for **Fit-for-Purpose Markets**.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	25.6	250	25.6	250	-	-
Investment	31.2		29.1		-2.1	
Energy Markets Total	**56.8**	**250**	**54.7**	**250**	**-2.1**	**-**

Our latest operating cost forecast and FTE requirement for the Energy Markets role is unchanged from our BP3 submission. Our BP3 plan included the resource required to support the government's Review of Electricity Market Arrangements (REMA)programme. Following the announcement in July 2025 that GB would retain a single national wholesale electricity price and reject zonal pricing, the REMA programme was closed. Our resources are now fully focussed on the successor programme: Reformed National Pricing (RNP). We are currently reviewing the scope of work for RNP and whether this can be delivered within existing forecast operating costs.

ID	Investment	BP3	Forecast	Variance to BP3
280	GB and RiE Regulations	4.5	5.2	0.7
320	EMR and CfD Improvements	4.6	4.7	0.1
330	Digitalised Code Management	-	0.1	0.1
400	Single Markets Platform	5.5	5.3	-0.2
420	Auction Capability	1.7	1.6	-0.2
610	Settlements, Charging and Billing	12.9	10.5	-2.3
680	Local Constraints Markets	-	-	-
820	Contracts for Difference	2.0	1.7	-0.3
	Energy Markets Total	**31.2**	**29.1**	**-2.1**

Our total investment forecast has decreased by £2.1m compared to BP3. We are forecasting to spend £10.5m on our STAR (Settlements, Charging & Billing) programme. This will deliver the final milestones for the STAR programme, migrating all existing revenue and settlements services to our new platform, which will be fully hosted on NESO infrastructure, whilst enabling the archiving and decommissioning of legacy applications. We are also delivering enhancements and regulatory driven changes to make billing processes more efficient and remain compliant with our regulatory requirements. We are delivering the full scope we outlined in BP3 at £2.3m lower cost through delivery efficiencies.

Strategic Energy Planning

In our strategic energy planning role, we create integrated, resilient national network plans for GB's electricity, gas and hydrogen networks. We also align regional energy planning through regionalised engagement teams and strategies. Our key focus in 2025/26 is to establish the capabilities, foundations and methodologies needed to deliver national and regional strategic whole energy plans. Our strategic Energy Planning role mainly supports our **Strategic Whole Energy Plans** performance objective.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	54.9	446	53.4	420	-1.5	-26.0
Investment	14.1		9.6		-4.6	
Strategic Energy Planning Total	**69.0**	**446**	**62.9**	**420**	**-6.1**	**-26.0**

Our forecast operating costs for BP3 are £1.5m lower than in our BP3 plan with a reduction of 26 FTEs. In our BP3 plan we made provision for a pool of power systems engineering capability to support additional workload driven by CP30. The planned cost of this resource was attributed to the strategic energy planning role, recognising that this capability could be deployed across NESO. So far, we have managed within our existing resources without drawing on any additional resource and have adjusted our future planned spend accordingly.

Our BP3 plan set out our plans to grow our Regional Energy System Planner (RESP) role. The costs we included were based on a blueprint design which set out a transitional plan delivering an end state capability by 2028. Costs and FTE projections are underpinned by several assumptions. These include a bottom-up assessment of regional complexity to underpin the headcount for regional teams, utilisation of market data for projecting asset costs, and assumptions regarding external contractor requirements associated with design.

The programme of work to deliver our RESP capability is subject to review, challenge and ultimately sanction through our NESO sanctioning committee.

In April 2025 Ofgem published their decision on the RESP consultation, which re-affirmed that our plans were in line with Ofgem's latest thinking. The programme therefore requested (and was granted) approval for FY26 to spend in line with our blueprint design. We have committed to work closely with Ofgem and DESNZ and to share updates to the FY27 design costs and enduring RESP delivery cost as we move through high level design to detailed design and implementation. Our programme plan is building efficiency and best practice into the RESP design through:

- Learning from the methodology consultations undertaken by the SSEP and CSNP teams.
- Working closely with the Future Energy Pathways team on pathway development.

- Using our regional resources to support the RESP development and implementation programme rather than relying on external consultant support.
- Ensuring DD&T investment is aligned across all SEP deliverables for example, geospatial and data.
- Competitively tendering for 3rd party support on RESP.

Our costs and resource requirements will be formally reviewed again at the end of the detailed design phase in December 2025 with any material changes being subject to review and challenge through the sanctioning committee.

ID	Investment	BP3	Forecast	Variance to BP3
340	RDP Implementation and Extension	2.6	0.6	-2.0
650	DER/CER Visibility and Access	-	0.4	0.4
690	GeoSpatial & Location Intelligence	6.0	3.8	-2.2
700	Strategic Energy Planning	5.5	4.7	-0.8
	Strategic Energy Planning Total	**14.1**	**9.6**	**-4.6**

Our investment in Geospatial and Locational Intelligence will deliver an enduring platform for NESO's geospatial and location intelligence capabilities, and full integration with the NESO data platform, delivering advanced spatial analytics, modelling, and visualization. Integration within the data platform will also improve data governance, transparency, and operational efficiency, supporting programs and initiatives across NESO. In our BP3 plan we estimated a cost of £6.0m to deliver this capability. Following an analysis of options, we have selected a solution with a forecast delivery cost of £3.8m, a reduction of £2.2m compared to our BP3 plan.

Our reduction in planned spend on RDPs (-£2.0m) is driven by the de-scoping of two RDPs and a longer timescale (into FY27) for another RDP. The descoping of RDPs is in one case due to finding a more practical existing solution to deliver the original intention, and in the second case a reassessment of consumer benefits which did not make a viable economic solution.

Energy Insights

In our Energy Insights role, we create robust evidence-based insights into emerging energy transition trends, resulting in the development of scenarios, insight and advice for the use of policy makers, industry and NESO itself.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	11.8	102	11.8	102	-	-
Investment	-		-		-	
Energy Insights Total	**11.8**	**102**	**11.8**	**102**	**-**	**-**

Our latest operating cost forecast and FTE requirement for the Energy Insights role is unchanged from our BP3 submission and delivers the planned scope of work.

Security of Supply Modelling

In our Security of Supply modelling role, we enable a reliable and secure energy system through an integrated and co-ordinated approach to provision of expert advice on resource adequacy to government, to ensure our energy demands can be met. Our strategic Security of Supply Modelling role mainly supports our **Secure and Resilient Energy Systems** performance objective.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	3.9	32	3.9	32	-	-
Investment	-		-		-	
Security of Supply Modelling Total	**3.9**	**32**	**3.9**	**32**	**-**	**-**

Our forecast costs and FTE requirement is in line with our BP3 plan and will deliver all the planned modelling capability.

Energy System Resilience

In our Energy System Resilience role, we ensure whole-energy system resilience by understanding risk. We use our trusted voice to develop mitigations working in partnership with government and industry. Our Energy System Resilience role mainly supports our **Secure and Resilient Energy Systems** performance objective.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	10.6	100	10.6	100	-	-
Investment	5.0		5.0		-0.0	
Energy System Resilience Total	**15.6**	**100**	**15.6**	**100**	**-0.0**	**-**

One of our new roles as an independent public body is to identify, analyse and co-ordinate resilience activities across the whole energy system. We have already demonstrated the value that this role provides through two high profile major incidents.

In March 2026, a major outage at North Hyde Substation resulted in power loss for over 70,000 customers and businesses, including the temporary closure of Heathrow Airport. NESO was swiftly commissioned by DESNZ and Ofgem to lead a high-risk, complex review into the incident.

A cross-functional response team was rapidly assembled, delivering both interim and final reports under intense scrutiny and tight deadlines. The review was widely praised, receiving commendations from the CEO of Heathrow Airport, the Expert Panel, and recognition in Parliament and the media.

The investigation involved reviewing nearly 900 pieces of evidence and produced several recommendations aimed at reducing the likelihood and impact of similar events in future. The team demonstrated agility and professionalism, navigating ambiguity and evolving requirements while integrating external expertise and innovating new ways of working.

The insights from the review were so impactful that NESO delayed the publication of its first Energy Resilience Assessment to incorporate the findings. This work not only delivered value for money but also set a new benchmark for NESO's response to urgent national challenges.

In September 2025 we published a technical assessment report into the blackout in Spain and Portugal which occurred in April 2025. Whilst Great Britain has one of the most reliable electricity networks in the world, we know that exploring every opportunity for learning and improvement is essential. Without drawing conclusions or commenting on the Iberian incident, our report examined what lessons can be applied to drive continuous improvement and to see how we can make our system even more resilient.

ID	Investment	BP3	Forecast	Variance to BP3
510	Restoration & Restoration Decision Support Tool	5.0	5.0	-0.0
	Energy System Resilience Total	**5.0**	**5.0**	**-0.0**

This investment will deliver our capability to manage emergency restart of the electricity network in the context of zero carbon operations. We will deliver a decision support tool based on real-time data to deliver a dynamic, feasible restoration plan to Government standards. The tool will support the decision making of the control centre engineers in a national power shutdown scenario on the best restoration route to implement. We remain on track to deliver the first phase of the Restoration Decision Support Tool (RDST) that runs live with the latest network configuration, providing a dynamic decision tree for the best route to Restoration across all seven regions of the UK by the end of BP3.

System Operations

Within our System Operations role we balance Great Britain's electricity system through real-time operations and short-term planning. We anticipate and manage whole energy system interactions and will operate a clean power system in 2030. Our System Operations role supports our **Operating the Electricity System** performance objective.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	49.2	451	49.2	451	-	-
Investment	70.0		77.5		7.5	
System Operations Total	**119.2**	**451**	**126.7**	**451**	**7.5**	**-**

Our latest operating cost forecast and FTE requirement for the System Operations role is unchanged from our BP3 submission.

Within this role we have formed a Systems Access Reform programme. The programme is being designed in collaboration with Transmission Owners (TOs), with the aim to formalise our commitment to Transmission Acceleration actions, build a 6-year system access plan and perform an end-to-end process review to proactively minimise delivery risk for Clean Power 2030 (CP30). Funding for this project was not explicitly recognised in BP3 but has been prioritised within our portfolio delivery for FY26 because of the strategic alignment to CP30 delivery and the wider benefits it will deliver (such as reduced carbon-intensive curtailment events, increased investor confidence in infrastructure delivery and Improved coordination, knowledge sharing, and transparency between NESO, TOs, and industry actors). The estimated costs of the programme for FY26 are £4.7m which we are funding through re-prioritisation of existing budgets.

ID	Investment	BP3	Forecast	Variance to BP3
110	Network Control	11.6	12.1	0.5
120	Interconnectors	1.8	1.9	0.2
130	Inertia Monitoring	0.6	0.2	-0.4
140	ENCC Operator Console	2.6	3.6	1.0
170	Frequency Visibility	3.3	1.5	-1.8
180	Enhanced Balancing Capabilities	18.0	22.8	4.8
190	Workforce & Change Mgmt Tools	0.4	0.5	0.2
200	Future Training Simulator and Tools	-	0.0	0.0
210	Balancing Asset Health	5.3	6.1	0.7
220	Data and Analytics Platform	11.4	6.3	-5.0
240	ENCC Asset Health	3.0	3.2	0.3
260	Forecasting Enhancements	2.9	6.4	3.5
480	Ancillary Services Dispatch	0.9	0.9	0.1
670	Real Time Prediction	3.8	3.3	-0.4
720	Network Service Procurement	1.4	1.4	-0.1
850	System Operations Tech Enablement	3.2	1.9	-1.3
	CNI Optel Refresh Lot 3a	-	5.4	5.4
	System Operations Total	**70.0**	**77.5**	**7.5**

Our spend on the Enhanced Balancing Capability programme is forecast to be £4.8m higher than BP3 plans. This is due to delivery of additional delivery scope for electronic data logging/transfer (EDL/EDT), gateway contingency management and quick reserve and slow reserve services which support new market opportunities.

Spend on our Data and Analytics platform is £5.0m lower than planned in BP3 largely due to resource optimisation efficiencies such as less reliance on external party support.

In the second half of BP3 we plan to bring forward the mobilisation of our Operational Service Agreement (OSA) Exit programme. The OSAs were established to ensure NESO could operate safely and reliably from its first day as an independent organisation, while longer-term systems and processes were developed. They cover critical services such as CNI hosting, networks, control room telephony, metering operations, and contingency arrangements. The OSA programme will provide a structured and well-governed route to exit these agreements with National Grid in a way that maintains resilience and regulatory compliance. Spend in FY26 will deliver a fully costed, assured, and design-ready delivery plan, including confirmed suppliers, technical architectures, and implementation timelines. We have not included a cost forecast for this project because we will fund this through prioritisation of other works within the portfolio to ensure we remain within the overall cost wrapper for DD&T spend in the BP3 period.

The CNI Optel Refresh project (£5.4m) is transitioning our CNI network services which support data exchange for balancing services and frequency control systems, to a new supplier. Changing supplier represents an opportunity to save £19.5m across the 5-year contract period compared to the new contract proposal from the incumbent supplier. Timing of the contract transition has pushed costs into the BP3 period, which was not anticipated when our BP3 plan was published.

Network Operability & Connections

In our Network Operability and Connections role we ensure that Great Britain's electricity system will be operable through identifying operability needs, procuring solutions and delivering engineering services and commercial contracts. We serve customers connecting to and operating on transmission and distribution networks. Our Network Operability and Connections role supports our **Connections Reform** performance objective.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	26.3	254	26.3	254	-	-
Investment	17.4		16.9		-0.4	
Network Operability & Connections Total	**43.6**	**254**	**43.2**	**254**	**-0.4**	**-**

We are not currently reporting a change to the BP3 cost forecast for this role. We have however signalled that we anticipate a cost increase for BP3 with regard to the connections reform programme. We are working through the revised cost forecasts and will provide an update in the end of scheme report.

One of our most significant drivers of consumer value is delivered through network services procurement. An important lever to minimise balancing costs is the design and procurement of new services to balance the system with greater competition at an optimised price. For example, in June 2025 following a competitive tender process, we awarded Constraint Management Intertrip Service (CMIS) contracts to generating assets which will reduce network congestion costs in the East Anglia (EC5) region. We are forecasting a cost for this balancing service of £41.9m which we estimate will deliver a £171m benefit to consumers compared to using alternative actions in the Balancing Mechanism over the course of the life of the service (July 2026 to September 2029).

ID	Investment	BP3	Forecast	Variance to BP3
350	Planning and Outage Data Exchange	2.6	2.7	0.1
360	Offline Network Modelling	3.4	2.4	-1.0
380	Connections Platform	9.6	10.1	0.5
390	Electricity Network Development Tools	1.8	1.8	0.0
	Network Operability & Connections Total	**17.4**	**16.9**	**-0.4**

Investment costs for this role are broadly in line with our BP3 plan.

Facilitating Sector Digitalisation

In our Facilitating Sector Digitalisation role, we co-ordinate the delivery of shared digital infrastructure for, and by, industry. This role supports the delivery of our **Enhanced Sector Digitalisation and Data Sharing** performance objective.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	1.2	12	1.2	12	-	-
Investment	6.0		5.0		-1.0	
Facilitating Sector Digitalisation Total	**7.2**	**12**	**6.2**	**12**	**-1.0**	**-**

Our latest operating cost forecast and FTE requirement for the Facilitating Sector Digitalisation role is unchanged from our BP3 submission.

ID	Investment	BP3	Forecast	Variance to BP3
830	Data Sharing Infrastructure	6.0	5.0	-1.0
	Facilitating Sector Digitalisation Total	**6.0**	**5.0**	**-1.0**

NESO is currently developing and delivering on behalf of industry the Data Sharing Infrastructure (DSI), a multi-year socio-technical programme to enable secure, resilient, and scalable data sharing between any energy sector participants. This investment will begin the delivery of a Minimum Viable Product (MVP) of the DSI. The MVP will expand the technical capability developed during the pilot and will be launched in test mode for trials by network partners. While the DSI is expected to enable multiple use cases, benefits quantification in our outline business case has focused on four of these: Strategic Planning, Flexibility, Smart Tariff Transparency, and Vulnerable Customers.

Role Delivery Support

We directly support the delivery of our core roles through change and data management, driving innovation and building strong customer relationships.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	36.1	484	33.1	484	-3.0	-
Investment	41.0		31.3		-9.7	
Role Delivery Support Total	**77.1**	**484**	**64.4**	**484**	**-12.7**	**-**

Our forecast for consultancy spend has decreased by £3.0m compared to our BP3 plan. In our plan we noted the inclusion of provision to procure consultancy services for reactive discovery work to minimise delays and impacts on broader objectives. To date this provision has not been required and we have reduced our cost forecast accordingly.

ID	Investment	BP3	Forecast	Variance to BP3
250	Digital Engagement Platform	4.5	3.1	-1.4
450	Future Innovation Productionisation	3.4	3.4	-0.0
750	Enterprise Data Management	6.1	5.6	-0.5
770	AI Transformation	8.0	4.3	-3.7
730	Technical Debt/New Priority Initiatives	12.0	15.0	3.0
760	Data Enablement - DAP Usage and Data Quality	7.0	-	-7.0
	Role Delivery Support Total	**41.0**	**31.3**	**-9.7**

Our Digital Engagement Platform (DEP) was delivered in BP2 and provides a single point of secure access to NESO systems and external visualisation of open and subscribed content and data, compliant with data classification policies and standards via the NESO website. In our BP3 plan we outlined the need to continue to enhance DEP to improve the customer experience whilst continuing to support business as usual activities. We have scoped the enhancements which we will deliver in FY26 at a reduced cost of £1.4m compared to BP3.

During FY25 we identified the need to fund some priority initiatives, address technical debt and strengthen technical capability as an independent NESO. We have rolled this forward into our BP3 plan to continue to reduce our technical debt through refreshing assets to minimise technology risk as well as enabling us to have platforms that can co-exist with other investment upgrades.

Our Data Enablement, Data Management and AI transformation projects are new programmes in BP3. We are beginning to scope and deliver projects within these programmes and will sanction future spend where appropriate and whilst maintaining our overall portfolio spend within our BP3 forecast.

Part 2 – Supporting Functions

Corporate Functions

Our corporate functions support NESO to achieve its strategic priorities through strong financial stewardship, developing talent and capability, acquiring and maintaining our properties and managing risk and reputation.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	74.9	456	70.3	434	-4.5	-22.0
Investment	18.3		19.8		1.5	
Corporate Functions Total	**93.2**	**456**	**90.2**	**434**	**-3.0**	**-22.0**

Our forecast operating costs for corporate functions are £4.5m lower than in BP3.

In FY26 we have 22 fewer graduates and apprentices than planned with a lower cost of £0.9m compared to our BP3 plan. Our spend on consultancy for external affairs is forecast to be £2.1m lower than planned due to media training and monitoring being done in-house rather than externally. We have also reclassified £1.5m of property spend as investment rather than operating expense.

Our corporate functions cover areas such as assurance, finance, procurement, legal, property, people and external affairs. Whilst these functions indirectly support the delivery of our strategic outcomes, they ensure delivery of Value for Money through:

Effective procurement: Consultancy is one of our largest areas of spend. To ensure value for money and compliance with procurement best practice we manage our consultancy procurement through a General Management Consultancy (GMC) framework. We run mini competitions through this framework to secure consultancy services through pre-approved suppliers which ensures value for money, compliance and strategic alignment. Running mini competitions rather than making direct awards drives better commercial outcomes. Our data suggest that we achieve an average 18% discount from GMC framework rates.

Engineering Services: Our Engineering Services framework helps enable teams across NESO with resourcing through onshore and offshore options. Whether resources are required for a short period for projects or ongoing support is needed for business-as-usual (BAU) tasks, the framework offers flexibility and caters to varying requirements. For BAU work, offshore teams deliver consistency and uniformity across processes by adhering to clearly defined service level agreements and key performance indicators. These measurable benchmarks ensure that all activities are performed to the same high standard and provide transparent metrics for monitoring performance. The benefit is that NESO teams benefit from predictable outcomes, robust quality assurance, and streamlined operations, which together drive improved efficiency, reliability and value for money. We currently have around 120 offshore FTE supporting across some of our key activities such as network modelling, balancing and revenue services, connections and

EMR. We estimate that this has already delivered a saving of £3.4m in the BP3 period when compared to hiring onshore resources.

ID	Investment	BP3	Forecast	Variance to BP3
800	Digital Change for Enabling Functions	5.0	5.0	-0.0
	Property	13.3	14.9	1.6
	Corporate Functions Total	**18.3**	**19.8**	**1.5**

Most of our investment spend for corporate functions relates to property, where spend after the reclassification of £1.5m of costs from operating expense is in line with BP3. Our property spend covers the upkeep of our main sites as well as the fit out of a newly acquired leasehold property in London, which fulfils the need to expand our office space in London to accommodate our organisational growth and provide adequate space to convene customers and stakeholders. We have balanced the need for adequate space, resilience and security, proximity to government stakeholders and overall long-term cost.

Cyber & Physical Security

We will create a resilient and secure organisation that supports NESO's transition to net zero.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	20.9	78	20.6	78	-0.3	-
Investment	7.5		6.7		-0.8	
Cyber & Physical Security Total	**28.4**	**78**	**27.3**	**78**	**-1.1**	**-**

Our operating cost forecast for Cyber and Physical security remains aligned to our BP3 plan.

ID	Investment	BP3	Forecast	Variance to BP3
	Cyber Security TSA	-	3.6	3.6
780	Security	7.5	3.1	-4.4
	Cyber & Physical Security Total	**7.5**	**6.7**	**-0.8**

Security spend is broadly aligned to our BP3 plan. Some cyber security investment continues to be delivered through the TSA with National Grid.

Digital & Technology Support

We manage the provision of IT service delivery across all NESO functions. We ensure the right digital, data and technology principles, tools, standards and strategies are in place to achieve NESO's objectives.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	83.0	121	100.2	121	17.1	-
Investment	-		-		-	
Digital & Technology Support Total	**83.0**	**121**	**100.2**	**121**	**17.1**	**-**

Our forecast operating costs for Digital and Technology support are £17.1m higher than BP3. This is because our BP3 plan included an efficiency target for total DD&T expenditure, which we aim to deliver through the investment portfolio, rather than through run-the-business activities.

Part 3 – Transformation

Transformation

In this role we deliver transformational activities and programmes that support NESO's strategic priorities. This activity mostly supports our **Separated NESO Systems, Processes and Services** performance objective.

	BP3		Latest Forecast		Variance to BP3	
Spend Category	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**	**Cost (£m)**	**FTE**
Operating Cost	-	97	-	97	-	-
Investment	81.0		78.8		-2.2	
Transformation Total	**81.0**	**97**	**78.8**	**97**	**-2.2**	**-**

All our spend on transformational activities is classified as investment spend.

ID	Investment	BP3	Forecast	Variance to BP3
810	REMA	0.5	-	-0.5
	Contingency Control Centre	25.2	3.1	-22.2
	Separation from National Grid Day 2	55.3	75.8	20.5
	Transformation Total	**81.0**	**78.8**	**-2.2**

Following the government decision in July 2025 to retain a single national wholesale electricity price, we have not progressed the planned REMA discovery work. We will review investment needs as future policy develops.

The creation of a Contingency Control Centre for future needs is part of NESO's broader transformation programme, designed to support its operational independence and strategic capabilities.

Our original cost estimate for FY26 had assumed an earlier delivery date for standing up new contingency arrangements and therefore we had forecast to incur costs of £25.2m. Given the scale and critical importance of this investment we are reviewing the needs case and setting out the strategic context and rationale for this investment. We are adopting the Better Business Case methodology. This approach, based on HM Treasury's Green Book guidance, is the UK Government's official standard for options appraisal and evaluation. It provides a structured framework for developing business cases that assess delivery options in terms of cost, benefits, and overall Value for Money.

The methodology is built around the Five Case Model, which offers a consistent and robust approach for both projects and programmes. Applying this framework will help minimise unnecessary cost and complexity, support informed decision-making, and highlight the non-financial benefits of investment.

We continue to transition our systems, processes and services from National Grid in line with our target to exit TSAs by the end of September 2026. In our BP3 cost annex we set out our plan to separate our data and systems from National Grid at an overall cost of £105m. This programme is delivering benefits earlier than had been set out in our FSO blueprint through streamlining and automating processes, enabling technological advances such as AI, increasing transparency of data to improve decision making and automating controls to manage, monitor and govern compliance and risk. Whilst we are still expecting to deliver the programme within the Board approved cost of £105m, the phasing of spend means that we will spend an additional £20.5m in FY26 (£16m of this relates to an underspend in FY25 which is being carried forward into FY26).

Appendix 1 – Detailed Cost Breakdown

Role/Function	Activity	Cost (£m)	FTE
Energy Markets	Code Administration & Market Frameworks	5	50
	Electricity Market Reform (EMR) Delivery Body	4	50
	Long Term Market Design	6	50
	Market Development & Operations for Electricity System Balancing	7	90
	Market Monitoring	1	10
	Central Costs - Energy Markets	2	<10
	Energy Markets Investment	29	
Energy Markets Total		**55**	**250**
Strategic Energy Planning	Centralised Strategic Network Planning	8	80
	Gas Network Development	2	20
	Network Competition	2	10
	Regional Energy Strategic Planning (RESP)	17	150
	Strategic Spatial Energy Planning (SSEP)	8	50
	Zero Carbon Operation Strategy	8	30
	Central Costs - Strategic Energy Planning	8	80
	Strategic Energy Planning Investment	10	
Strategic Energy Planning Total		**63**	**420**
Energy Insights	Policy Advice	5	50
	Scenario Development	5	50
	Whole Energy Insights	1	<10
	Central Costs - Energy Insights	1	<10
Energy Insights Total		**12**	**100**
Security of Supply Modelling	Energy Security Modelling & Insights	4	30
Security of Supply Modelling Total		**4**	**30**
Energy System Resilience	Electricity System Restoration	5	50
	Emergency Readiness & Response	3	30
	Energy Sector Security	3	20
	Central Costs - Energy System Resilience	0	<10
	Energy System Resilience Investment	5	
Energy System Resilience Total		**16**	**100**
System Operations	Operational Readiness	7	50
	Network Control Programme	2	20
	Balancing Programme	- 0	40
	ENCC Real-time Operations	18	140
	Future ENCC Design	1	30
	Network Access Planning	6	90
	Operational & Performance Insights	7	90
	Central Costs - System Operations	7	10
	System Operations Investment	77	
System Operations Total		**127**	**470**

ROUNDING: FTEs are rounded to the nearest 10 FTE and therefore do not sum to the total FTE, and may not align with figures in the individual tables in the narrative.

Role/Function	Activity	Cost (£m)	FTE
Network Operability & Connections	Connections Strategy	1	10
	Connections Policy & Change	4	30
	Connections Operations	9	80
	Network Operability Modelling	3	30
	Network Operability Services	6	80
	Network Services Procurement & Balancing Services Contracting	4	20
	Central Costs - Network Operability & Connections	0	<10
	Network Operability & Connections Investment	17	
Network Operability & Connections Total		**43**	**250**
Facilitating Sector Digitalisation	Interim Data Sharing Infrastructure (DSI) Coordinator	1	10
	Facilitating Sector Digitalisation Investment	5	
Facilitating Sector Digitalisation Total		**6**	**10**
Role Delivery Support	Customer	4	30
	Data Science & AI	4	40
	Operational Leadership	1	<10
	Innovation	5	50
	Programme Management & Technology Delivery	19	360
	Role Delivery Support Investment	31	
Role Delivery Support Total		**64**	**480**
Corporate Functions	Assurance	3	30
	Corporate Strategy	1	10
	External Affairs	5	40
	Finance & Procurement	22	150
	Legal	6	20
	People	9	70
	Property	13	<10
	Portfolio Management	1	10
	Regulation	2	20
	Graduates	4	80
	Office of the CEO	3	<10
	Corporate Functions Investment	20	
Corporate Functions Total		**90**	**430**
Cyber & Physical Security	Physical & Cyber Security	21	80
	Cyber & Physical Security Investment	7	
Cyber & Physical Security Total		**27**	**80**
Digital & Technology Support Total	Digital & Technology Support Contracts	88	<10
	Digital Strategy & Architecture	6	60
	Functional Excellence	6	60
Digital & Technology Support Total		**100**	**120**
Transformation	Day 2 Transformation	76	90
	Contingency Control Centre	3	10
Transformation Total		**79**	**100**
Grand Total		**686**	**2,836**

ROUNDING: FTEs are rounded to the nearest 10 FTE and therefore do not sum to the total FTE, and may not align with figures in the individual tables in the narrative.

Reported Metrics

Summary of Reported Metrics

The table below summarises our Reported Metrics for September/Q2 2025:

	Reported Metric	Performance
1	**Balancing Costs**	Sep: **£287m**
2	**Demand Forecasting**	Sep: Forecasting error of **702MW**
3	**Wind Generation Forecasting**	Sep: Forecasting error of **5.62%**
4	**Skip Rates**	Sep: Post System Action (PSA) Offers: **32%** Bids: **45%** Combined: **38%**
5	**Carbon intensity of NESO actions**	Sep: **14.22 gCO_2/kWh** of actions taken by NESO
6	**Security of Supply**	Sep: **0** instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. **1** voltage excursion.
7	**CNI Outages**	Sep: **0** planned, **0** unplanned system outages.
8	**Short Notice Changes to Planned Outages**	Q2: (September) **3.77** delays or cancellations per 1000 outages due to a NESO process failure. July & August **0** delays or cancellations per 1000 outages due to a NESO process failure.
9	**Zero Carbon Operability Indicator**	Q2: Highest ZCO% of **95.93%** after NESO operational actions, based on the CP30 definition of zero carbon. Using original RIIO-2 definition, the maximum ZCO% was **90.42%.**
10	**Constraints Cost Savings from Collaboration with TOs**	Q2: **£652m**
11	**Day-ahead procurement**	Q2: **92%** balancing services procured at no earlier than the day-ahead stage.
12	**Accuracy of Forecasts for Charge Setting - BSUoS**	Q2: Month ahead BSUoS forecasting accuracy (absolute percentage error) of; July: **17%** August: **12%** September: **19%**
13	**Balancing services procured in a non-competitive manner**	H1: **£170m** spend on non-competitive services. Volume **40.9 TWH** and **23.5 TVARH**
14	**Future Savings from Operability Solutions**	H1: i) Saved balancing costs: **£171m** ii) Monetised carbon reductions: **£361** iii) Indicative impact on the SZCP limit: See Reported Metric 14 (Future Savings from Operability Solutions) for details

1. Balancing Costs

Performance Objective

Operating the Electricity System

Success Measure

We will further develop and implement initiatives from our Balancing Cost Strategy to demonstrate cost efficiency through the Balancing Cost metric (BP2: Metric 1A). In consultation with industry, we will publish an updated Balancing Cost Strategy by June 2025.

This Reported Metric measures NESO's outturn balancing costs (including Electricity System Restoration costs).

For consistency with previous RIIO-2 incentives reporting, we have included a view of a benchmark based on the BP2 methodology. Note that as per the PAGD, Ofgem will not assess our performance against this metric as below/meets/exceeds, therefore the thresholds have been removed.

When setting up the BP2 benchmark methodology, analysis showed that the two most significant measurable external drivers of monthly balancing costs are wholesale price and outturn wind generation. The BP2 methodology uses the historical relationships between those two drivers and balancing costs:

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

The formulas used for the 2025-26 benchmark are as follows (with Day-Ahead Baseload being the measure of wholesale price):

Non-constraint costs = 62.25 + (Day Ahead baseload x 0.478)
Constraint costs = -33.49 + (Day Ahead baseload x 0.39) + (Outturn wind x 23.51)

Benchmark (Total) = 28.76 + (Day Ahead baseload x 0.87) + (Outturn wind x 23.51)

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

NESO Operational Transparency Forum: We host 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 System Operations panel. Details of how to sign up and recordings of previous meetings are available here.

September 2025 performance

Figure: 2025-26 Monthly balancing cost outturn versus benchmark

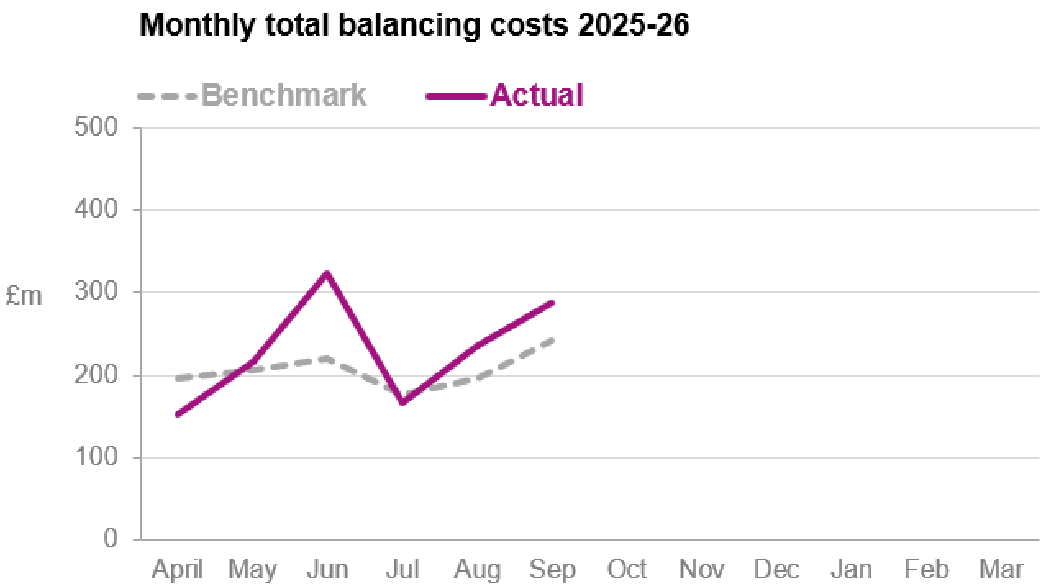


Table: 2025-26 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	4.1	4.7	5.4	3.3	4.4	6.4							28.3
Average Day Ahead Baseload (£/MWh)	81	77	73	80	73	72							n/a
Benchmark*	195	206	219	176	197	241							1235
Outturn balancing costs[1]	**152**	**215**	**324**	**167**	**236**	**287**							**1381**

[1] 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.

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.

*Ofgem no longer use a benchmark to assess our performance against this Metric however, we continue to report this as an indicator against the outturn figure.

Supporting information

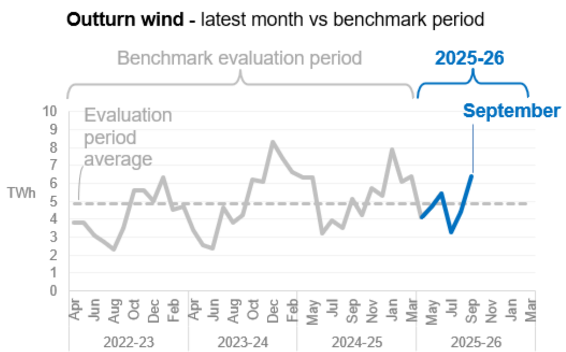
BALANCING COSTS METRIC & PERFORMANCE

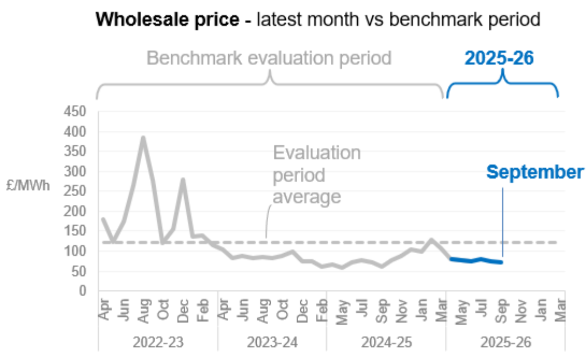
This month's benchmark

The September's benchmark of £241m is £44m higher than August 2025 and reflects:

- An outturn wind figure of 6.4 TWh that is higher than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 5.0 TWh) and is higher than August 2025's figure (4.4 TWh).
- An average monthly wholesale price (Day Ahead Baseload) has decreased slightly compared to August 2025 and is also lower than the same period last year. It also remains lower than the evaluation period average.

The higher wind outturn has caused the increase in September's benchmark compared to August but has been somewhat negated by lower wholesale prices.





Variable	September 2025	August 2025	September 2024
Average Wholesale Price (£/MWh)	**72**	**+1**	**+4**
Total Wind Outturn (TWh)	**6.4**	**-2**	**-2**
Benchmark (£m)	**241**	**-44**	**-47**

*The rows show the outturn measures for this month and difference in the previous month and same month last year.

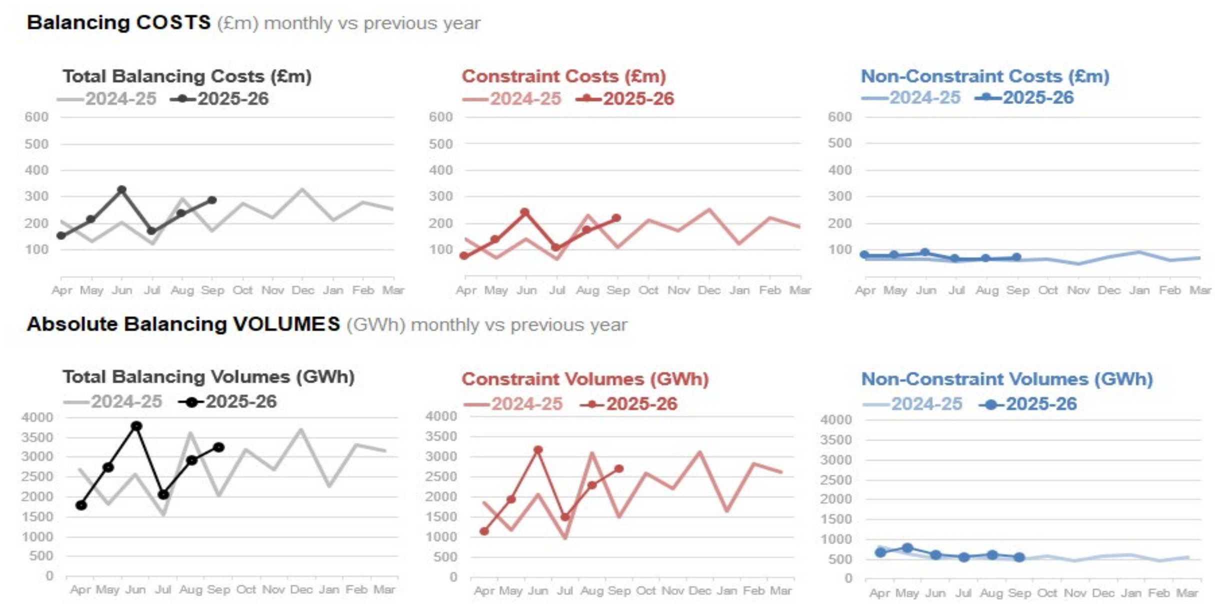
Balancing Costs - Overview

The total balancing cost for September was £286.6m, which is £45.6m (~19%) above the benchmark.

September saw an increase in wind outturn compared to the previous month at 6.4 TWh, compared to 4.4 TWh in August. This has driven a marked increase in constraint costs, with wind curtailment volumes up to 1,082GWh from 811GWh last month. Voltage constraint costs saw a slight increase in September, similar to last month, partly due to continued high wind output displacing synchronous units (mostly CCGTs) that typically provide reactive support. In contrast, stability constraint costs decreased, linked to elevated overnight demand, which kept more synchronous generators online and reduced the need for additional stability services through the Balancing Mechanism. It’s worth noting that overlapping capabilities of synchronous units can sometimes be leveraged to manage both voltage and stability constraints efficiently, helping reduce the need for separate service procurement.

September was wetter than average across much of the UK and, though variable, the overall temperature was slightly below average. Several periods of unsettled weather, including strong wind levels, led to a notable rise in wind curtailment volumes compared to August; there were consequently more high costing days, which together accumulated to higher overall costs for the month

Average wholesale prices decreased by £1/MWh from August 2025 and decreased £4/MWh from September 2024,. The higher wind outturn figure compared to last month and the previous year likely contributed to these lower prices, due to excess renewable supply. The volume weighted average (VWA) price of bids was -£25.2/MWh, which is more expensive than August’s price of -£10.2/MWh, with greater requirement for wind curtailment making Bid prices less competitive. The VWA price for offers has increased slightly from £121.2/MWh to £121.4/MWh. Non-constraint costs increased by £5.15 million compared to August 2025, reflecting an accumulative rise in the costs of restoration, response and minor components since last month.



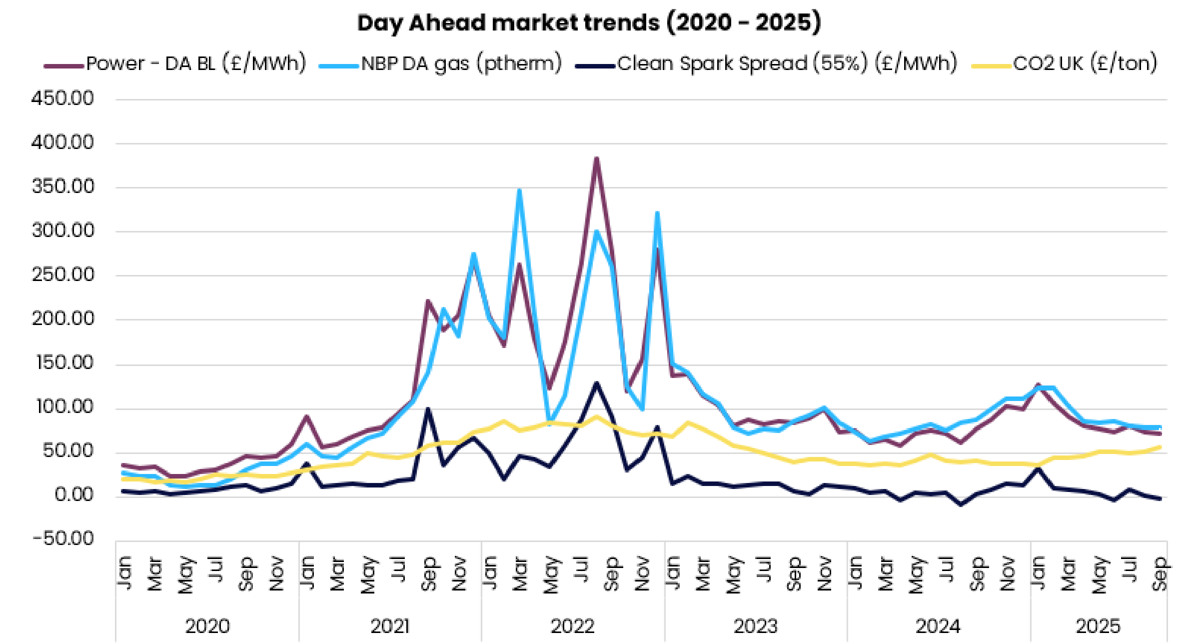
*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

Market trends

In September, gas prices held steady at 79.26p/therm, while CO_2 prices rose sharply to £56.16/ton, the highest level in two years, driven by strong market demand and tightening supply conditions. Power prices in September remained relatively stable at £72.14/MWh, with only a marginal decrease.

The month was shaped by seasonal temperature shifts and variable wind conditions - strong wind in the first half supported lower prices, while reduced wind output and cooler weather in the latter half increased demand for heating and power. Together, these factors led to a decline in the Clean Spark Spread, which fell from £1.26/MWh in August to -£1.67/MWh, reflecting tighter profit margins for gas-fired generation.

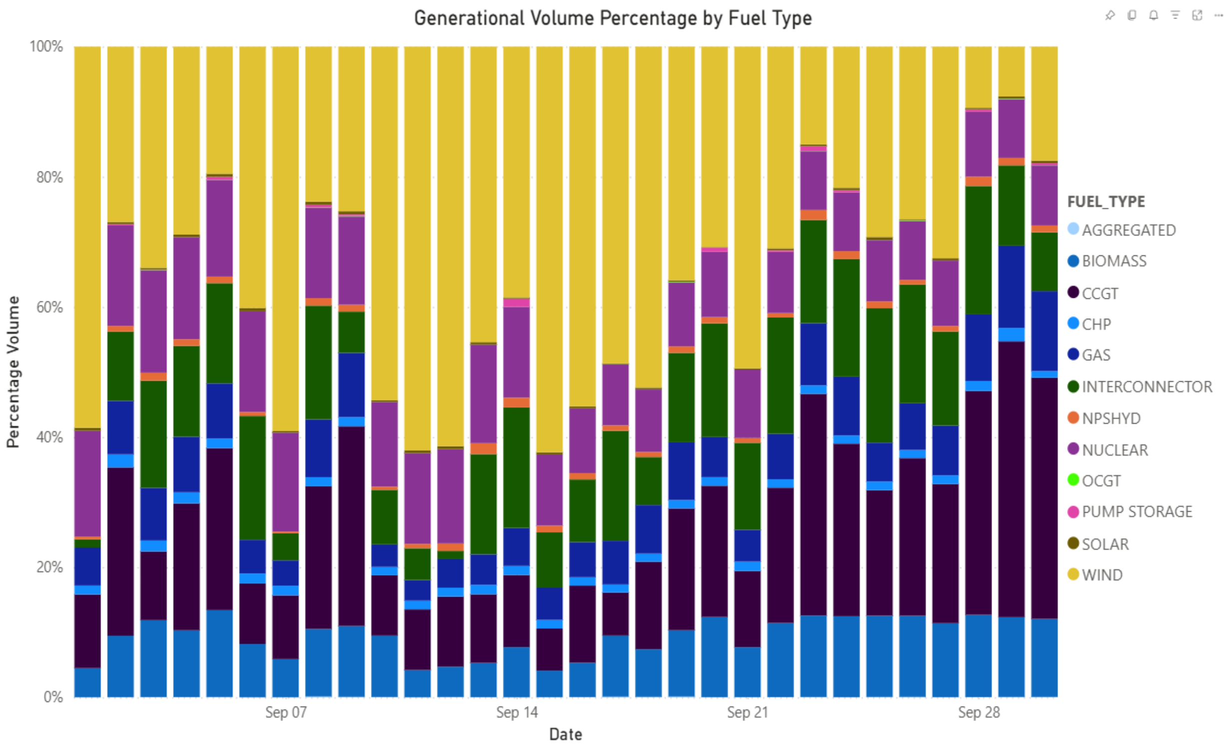


DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Generation Mix

In September, wind made up the largest share of the generation mix at 36%, followed by CCGTs (19%) and Interconnectors (13%). This is consistent with August, where wind also held the largest share of the generation mix. The chart highlights the dominance of wind generation across first three weeks of the month, particularly on the 11th, 12th, and 15th, when wind accounted for approximately 62% of the daily generation mix on each of those days.

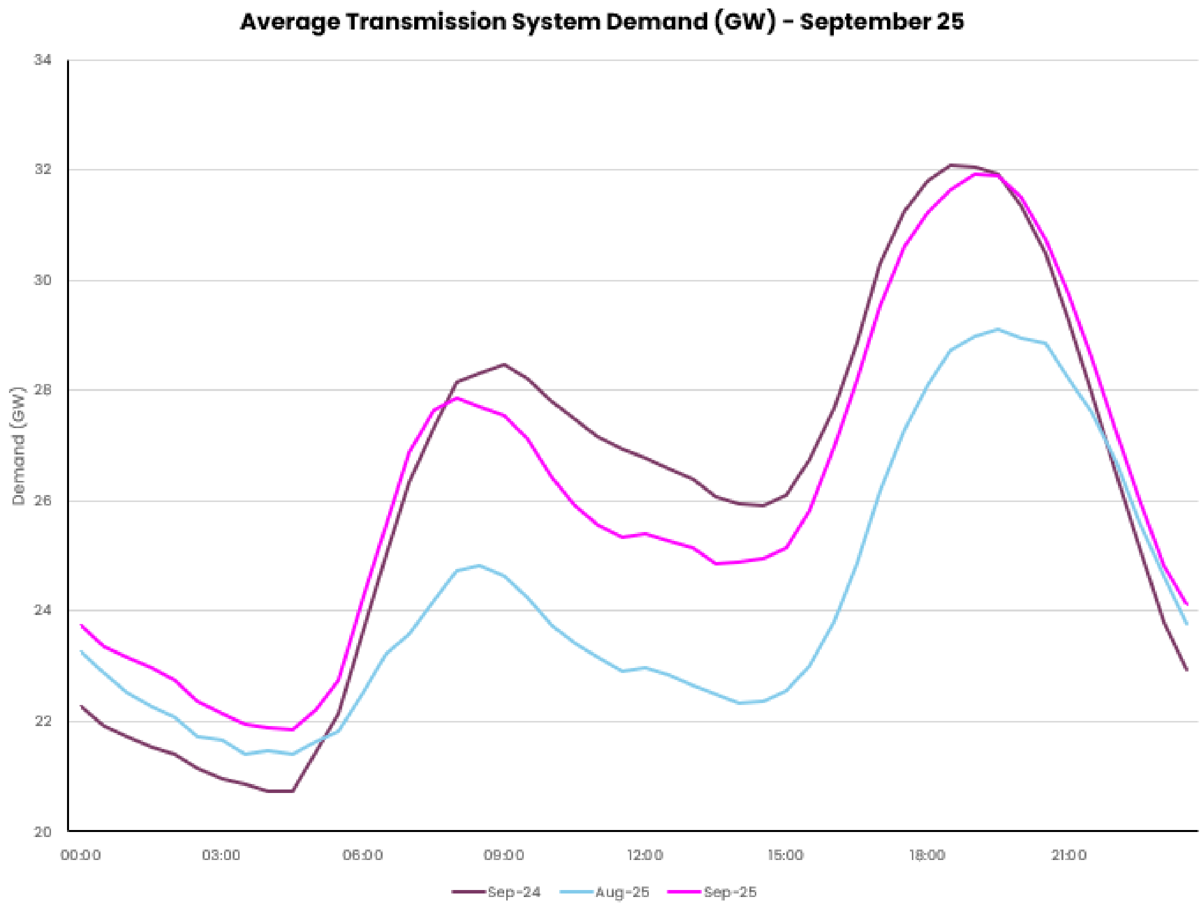
However, in the final week of September, the generation mix shifted. CCGTs and Interconnectors became more dominant, while wind generation dropped to a range of 7–30% on several days. Since wind's share increased compared to August, there was a drop in Interconnector and Nuclear contributions, while all other fuel types remained broadly unchanged.



*Generation mix includes exports from interconnectors.

Transmission System Demand

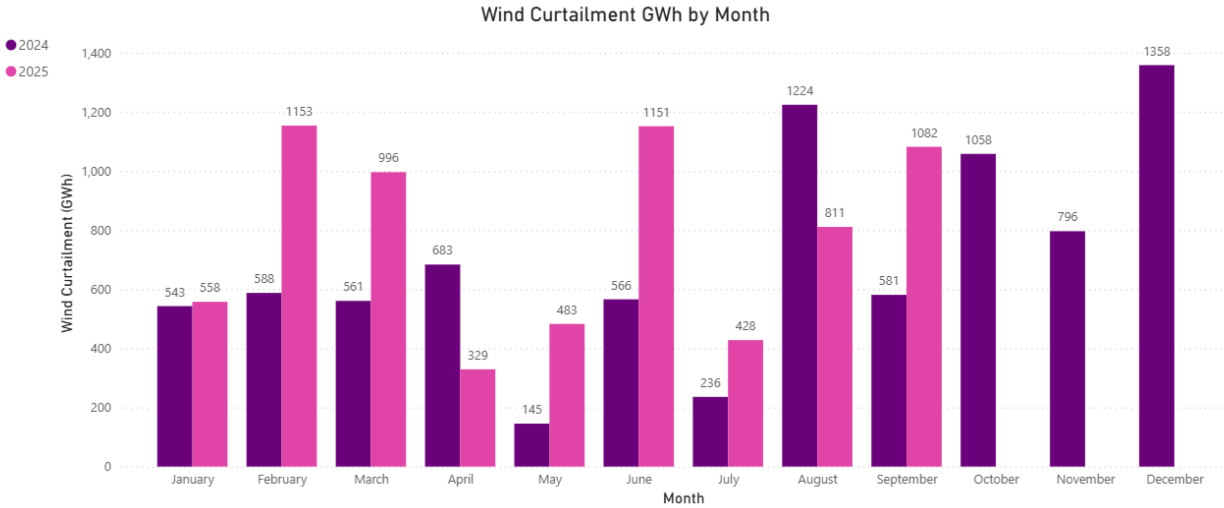
In September the average Transmission System Demand (TSD) was higher than August throughout the whole day, which can be expected due to increased hours of darkness, colder weather, the restarting of the school term and lower levels of embedded solar generation during the daytime. Comparing September 2025 to September 2024, the average TSD was notably lower during the daytime period, with the average TSD between 1.2-1.5GW lower than last year between the hours of 10:00-13:30. However, overnight (20:00-07:30) the average TSD was higher than in September 2024, particularly from midnight until 04:30, when the average TSD was 1.2GW higher than last year. This trend since last year is likely due to more embedded wind and solar generation suppressing the demand during daylight hours (with both more sunshine hours and higher windspeed than September last year) but greater levels of flexible demand e.g. EV smart charging increasing demand overnight since last year.



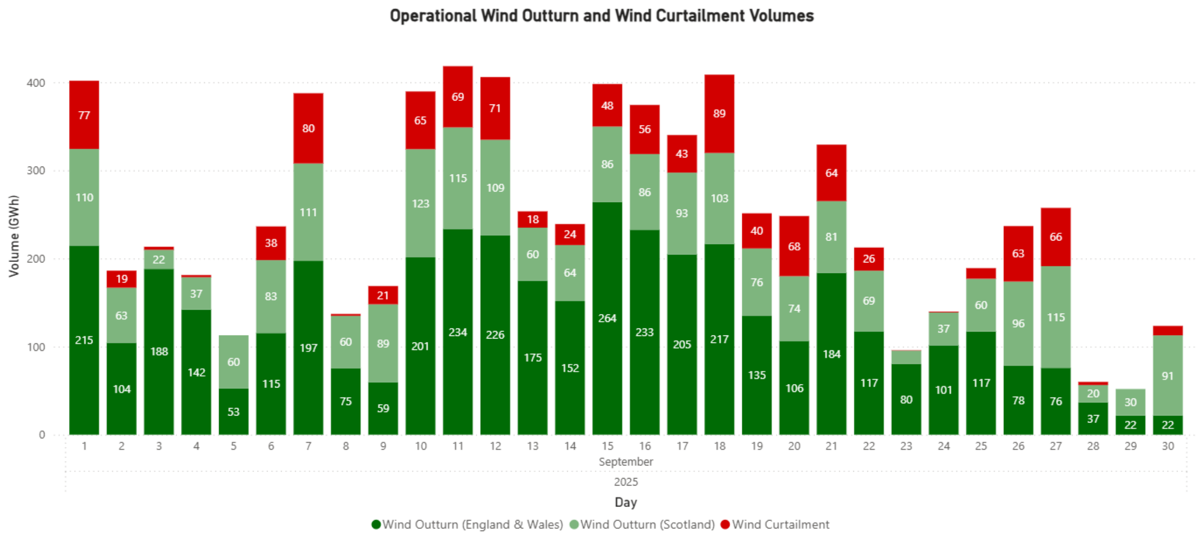
Wind Outturn

September was wetter than average across much of the UK, with rain for most of the first three weeks and periods of strong wind and heavy downpours at several points. While temperatures varied throughout the month, the overall temperature was slightly below average, bringing an end to the above average temperatures of the summer months.

Overall wind outturn rose from 4.4 TWh in August to 6.4 TWh in September, with a 47.5% increase in England & Wales (from 2.8 TWh to 4.13 TWh) and a 37% increase in Scotland (from 1.63 TWh to 2.24 TWh) compared to the previous month, giving a 45% increase overall. This led to an associated 33% increase in the volume of wind curtailment seen since last month. With a 2.05 TWh increase in overall wind outturn compared to September 2024, there was also a significant 86% increase in the volume of wind curtailment in September 2025 compared to September 2024 (from 581GWh to 1,082GWh). With variable weather conditions throughout the month, the highest volume wind curtailment days were spread throughout the month; on 1st September (77GWh), 7th September (80GWh) and 18th September (89GWh).



The day with the highest volume of wind curtailment occurred on Thursday 18th September with 89 GWh. There was a total wind outturn of 409 GWh on this date, the second-highest outturn this month. This was also the overall highest-costing day in September.

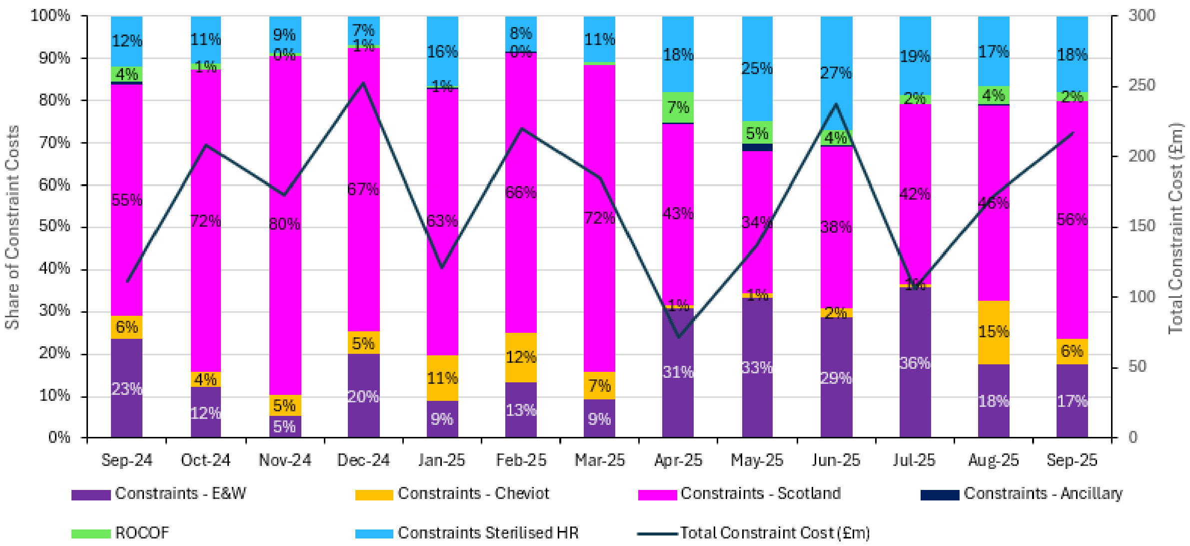


Constraints

Constraint costs increased from £172m in August to £217m in September, an increase of £45m. This increase was mainly due to an increase in Scottish constraint costs (from £80m to £122m). Constraint costs also rose in England & Wales by 25%, but decreased in the Cheviot region this month, following higher than usual Cheviot constraint costs last month.

Wind outturn across England & Wales and Scotland increased in September. This led to a notable rise in wind curtailment volumes compared to August, driven largely by several periods of unsettled weather including strong wind levels.

Monthly % share of constraint costs and total £m constraint cost



BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): September 2025 vs August 2025

		(a) Aug-25	(b) Sep-25	(b) - (a) Variance	decrease ◂▸ increase Variance chart
Non-Constraint Costs	Energy Imbalance	-0.7	-1.1	(0.5)	
	Operating Reserve	10.4	9.6	(0.8)	
	STOR	5.6	6.9	1.2	
	Negative Reserve	0.4	0.6	0.2	
	Fast Reserve	12.4	14.0	1.6	
	Response	20.8	23.2	2.5	
	Other Reserve	0.9	1.4	0.5	
	Reactive	13.0	8.1	(4.9)	
	Restoration	3.4	7.3	3.9	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	-1.4	0.0	1.4	
Constraint Costs	Constraints - E&W	30.5	37.9	7.4	
	Constraints - Cheviot	25.8	13.2	(12.6)	
	Constraints - Scotland	79.5	121.7	42.1	
	Constraints - Ancillary	0.3	0.1	(0.2)	
	ROCOF	7.3	5.0	(2.3)	
	Constraints Sterilised HR	28.6	38.7	10.0	
Totals	Non-Constraint Costs - TOTAL	64.8	70.0	5.1	
	Constraint Costs - TOTAL	172.1	216.6	44.5	
	Total Balancing Costs	**236.9**	**286.6**	**49.7**	

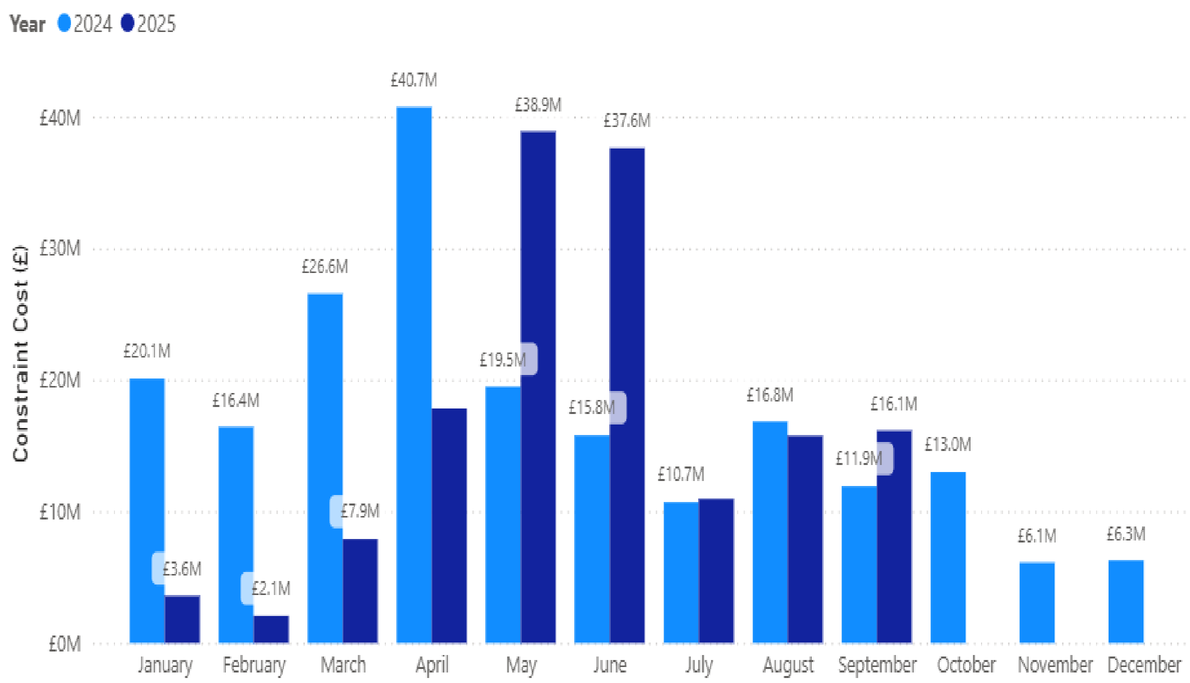
As shown in the totals from the table above, constraint costs increased by £44.5m and non-constraint costs increased by £5.2m which results in an overall increase in costs of £49.7m compared to August 2025.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: +£29.7m **Constraint – England & Wales: +£7.4m** **Constraint Sterilised Headroom: +£10.0m** Overall constraint costs increased in September by £44.5m, which coincided with an increase in the absolute volume of actions taken. This was largely due to a significant increase in wind output, which reached 6.4 TWh in September, compared to 4.4 TWh in August. The higher wind levels led to a rise in thermal constraint costs across the GB. **ROCOF: -£2.3m** As August saw an increase in costs for managing system inertia due to high wind outturn, the drop in costs this month represents a higher system demand compared to the previous month, which leads to more synchronous generators being self-dispatched to meet load, meaning these generators do not need to be dispatched through the BM.	**Constraints – Scotland & Cheviot: +£74.9m** **Constraints – England & Wales: +13.5m** **Constraints Sterilised Headroom: +£18.5m** Constraint costs across the GB have increased by £107 million compared to September 2024, largely driven by a significant rise in wind output and the resulting curtailment and balancing actions. Of note is the particularly sharp increase in Scotland & Cheviot, indicating that constraints were more concentrated the northern part of the country this year. **ROCOF: -£0.5m** There was a slight decrease in inertia spend compared to September 2024. This decrease will be in part due to the higher system demand during overnight periods as compared to the last year September, which leads to more synchronous generators being self-dispatched.

Voltage – Monthly system cost of synchronisation actions for voltage control across 2024 and 2025:

Synchronisation costs are associated with specific actions required to support voltage in the system. These actions involve units that are instructed to provide MVArs and maintain voltages within SQSS limits. It is a highly location-dependent issue, so only a limited set of assets are effective in voltage support. In September, the system synchronisation costs (what it costs to the system, which factors in energy replacement and headroom among others) were £16.1m. This represents an increase of approximately £0.3 million compared to August 2025 and is £4.2 million higher than the same period last year (August 2024).

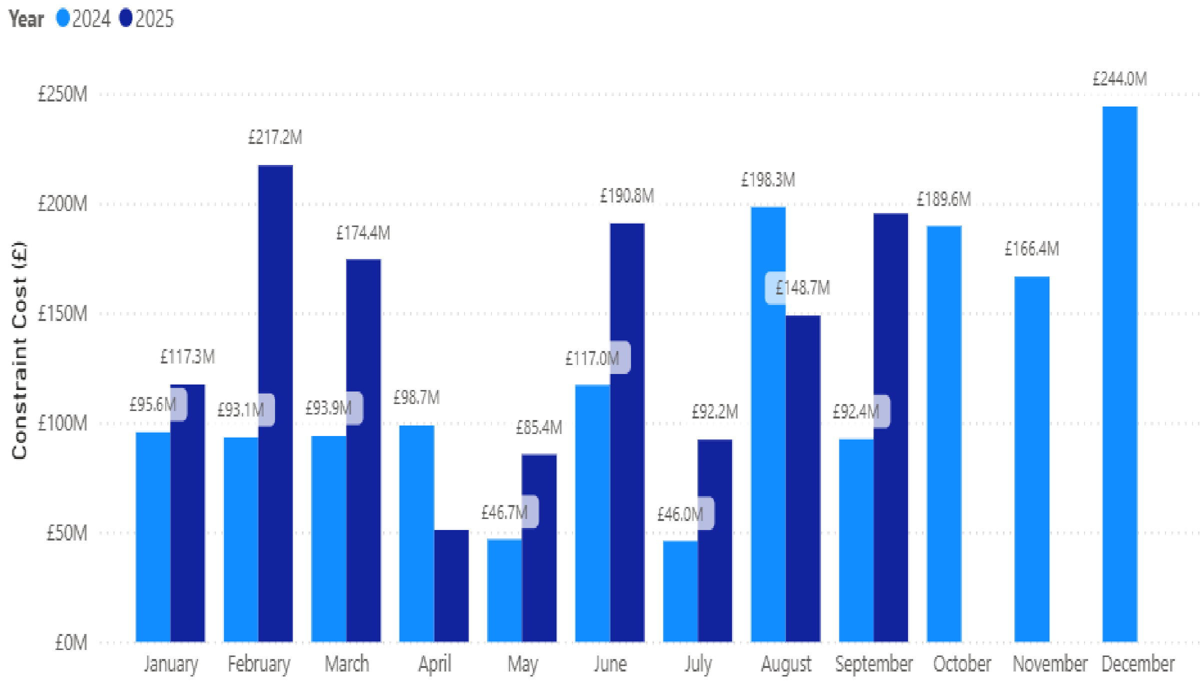


Voltage spending is usually higher overnight: lower demand means that some synchronous units (mostly CCGTs) that usually provide reactive support are not self-dispatched, which forces NESO to procure those services through the Balancing Mechanism.

Most voltage costs arise from the South-West region of Great Britain, where the system relies on Combined Cycle Gas Turbines (CCGTs) for voltage management. A couple of important CCGTs in the region were on planned outage until October, which resulted in a limitation of available resources for voltage control. Despite this, spending in the current month has not been significantly affected.

Thermal – Monthly system cost of actions for thermal management across 2024 and 2025:

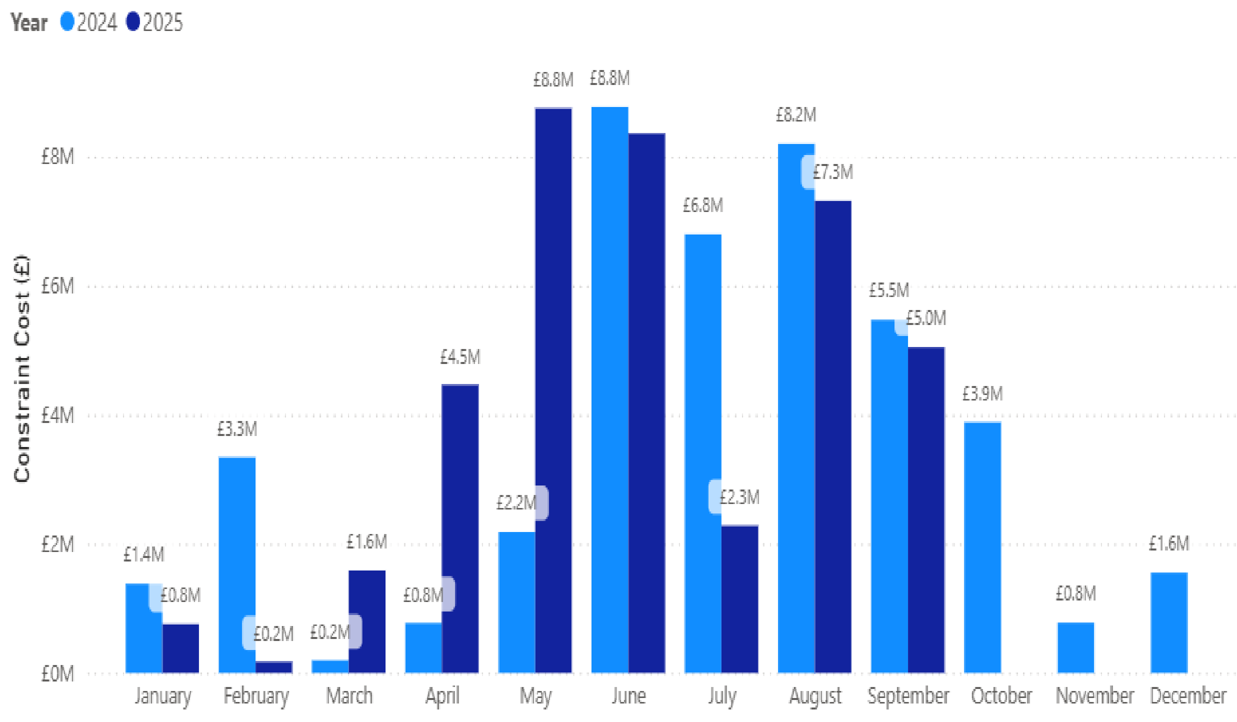
Thermal constraints are linked to operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, often referred to as the B4, B5, and B6 boundaries. The expenditure on thermal constraints is highly correlated with levels of curtailment in Scotland, as well as planned or forced outages in transmission assets that limit the grid's transfer capacity. Thermal constraints constitute the vast majority of the system constraints, accounting for a significant percentage of system actions. In September, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £195.3m, reflecting an increase in costs of over £46m compared to the previous month (£148.7m). When compared to the same period last year (£92.4 million in September 2024), the cost was up by £103 million, a notable year-on-year rise.



September 2025 saw a significant increase in wind curtailment, contributing to the rise in thermal constraint costs. Wind curtailment reached 1.08 TWh, up from 811 GWh in August 2025, indicating a continued upward trend. While September 2024 was in line with seasonal norms, this year's figures reflect an abnormally high wind outturn, especially when compared to previous Septembers over the past few years.

Inertia – Monthly system cost of actions for inertia management across 2024 and 2025:

Inertia refers to the resistance of the system to changes in its rotational speed. Inertia is primarily provided by the rotating mass of large synchronous generators, mainly CCGTs, but also includes hydro, pumped storage, biomass, and Combined Heat and Power (CHPs), among others. The costs associated with inertia tend to be marginal in the system compared to thermal or voltage constraints. In September, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £5m, resulting in a decrease of £2.3m compared to last month (£7.3m) and just £0.5m lower than September 2024.



The inertia expenditure fell in September despite higher wind generation, which made up around 36% of the total generation mix. The drop in inertia cost was linked to higher system demand compared to the previous month, which leads to more synchronous generators being self-dispatched to meet load. The increased presence of synchronous units naturally boosted system inertia, reducing the requirement for NESO to procure additional inertia services through the Balancing Mechanism.

Reactive Costs/Volumes

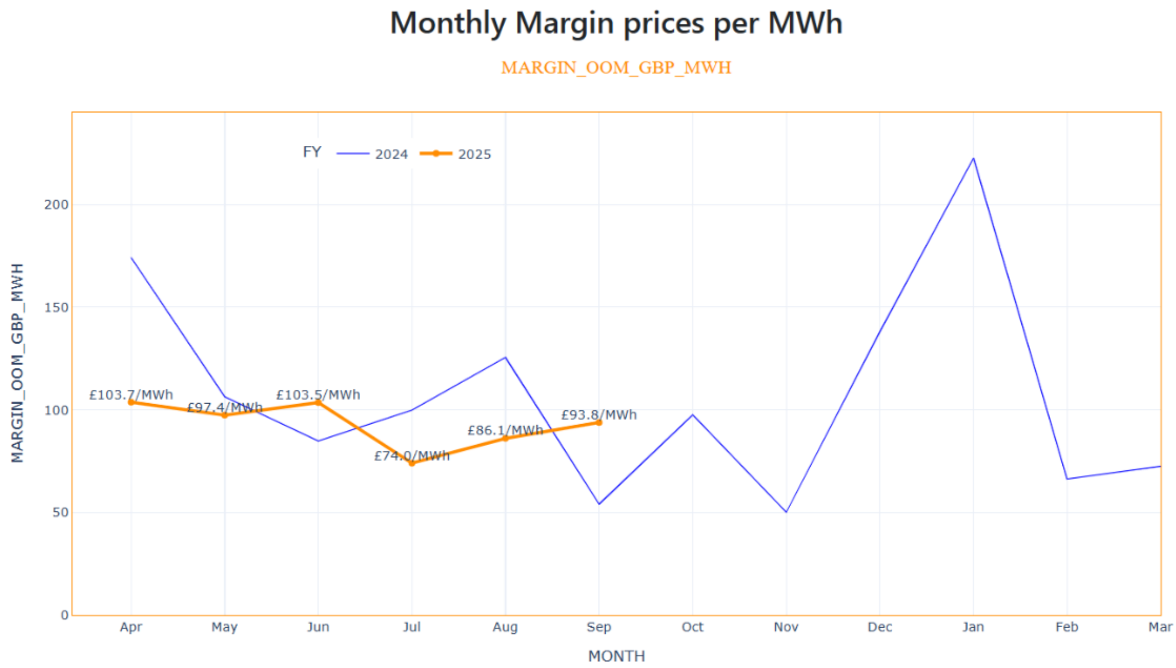
Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£4.9m Reactive costs have fallen on last month reflecting a decrease in power prices compared to August.	**-£3.8m** Reactive costs have fallen on last year reflecting a decrease in power prices compared September 2024.

We have started a Network Innovation Allowance (NIA) project that will review of the Obligatory Reactive Power Service (ORPS) methodology to ensure that the service remains fit for purpose and cost reflective.

Reserve Costs/Volumes

Reserve prices increased to £93.8/MWh in September from £86.1/MWh in July 2025. This is in contrast to the trend last year when prices between August 2024 and September 2024 dropped significantly (£125.5/MWh to £54/MWh). The average price across August and

September combined are actually very similar in 2025 as they were in 2024 (~£90/MWh), representing less month-on-month volatility this year.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: -£0.8m **Fast Reserve: +£1.6m** There was a 17.9 GWh decrease in the absolute volume of operating reserve required to secure the system compared to August.	**Operating Reserve: +£2.8m** **Fast Reserve: -£3.9m** There was a 18.6 GWh increase in the absolute volume of operating reserve required to secure the system compared to September 2024.

We are currently in the process of quantifying the benefits associated with Balancing Reserve, and the results will be shared in the coming months.

Response Costs/Volumes

Our Dynamic Services for response, Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR) continue to benefit from more competitive and more liquid markets and the continued development of the Single Market Platform.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£2.5m	**+£10.1m**

There was a 27.55 GWh decrease in the absolute volume of actions compared to August. However, clearing prices for DC, DM and DR services were all higher this month than last.	The volume of actions taken for response increased 11.57 GWh compared to September 2024. Clearing prices were also higher year-on-year across all Dynamic Services.

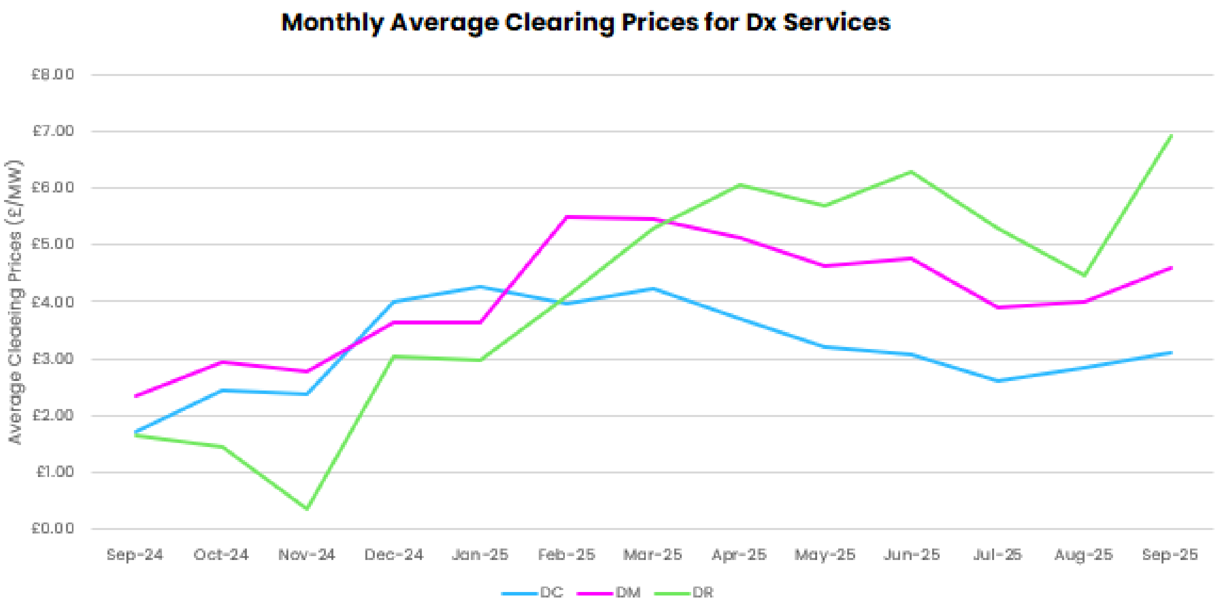
Dynamic Services Average Clearing Prices (£/MW): September 2025 vs August 2025

		(a) Sep-25	(b) Aug-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	3.1	2.8	0.3	
	DM	4.6	4.0	0.6	
	DR	6.9	4.4	2.5	

Dynamic Services Average Clearing Prices: August 2025 vs August 2024

		(a) Sep-25	(b) Sep-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	3.1	1.7	1.4	
	DM	4.6	2.3	2.2	
	DR	6.9	1.6	5.3	

Average clearing prices increased in September for Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR). Dynamic Regulation (DR) had seen a significant reduction on the clearing price In August 2025 (from £5.29/MW in July to £4.45/MW in August). The price has now significantly increased again in September, reaching higher than the July figure had been, to £6.9/MW. All three services also saw an increase in average clearing prices to September last year, corresponding to higher target volumes (pay as clear markets), particularly for DR and DM. There is some seasonality to DC pricing, which is needed less over winter when there is more inertia on the system, meaning higher prices in spring/summer. However, the prices for DC have risen since August, rather than started to fall during the transitional season to winter.

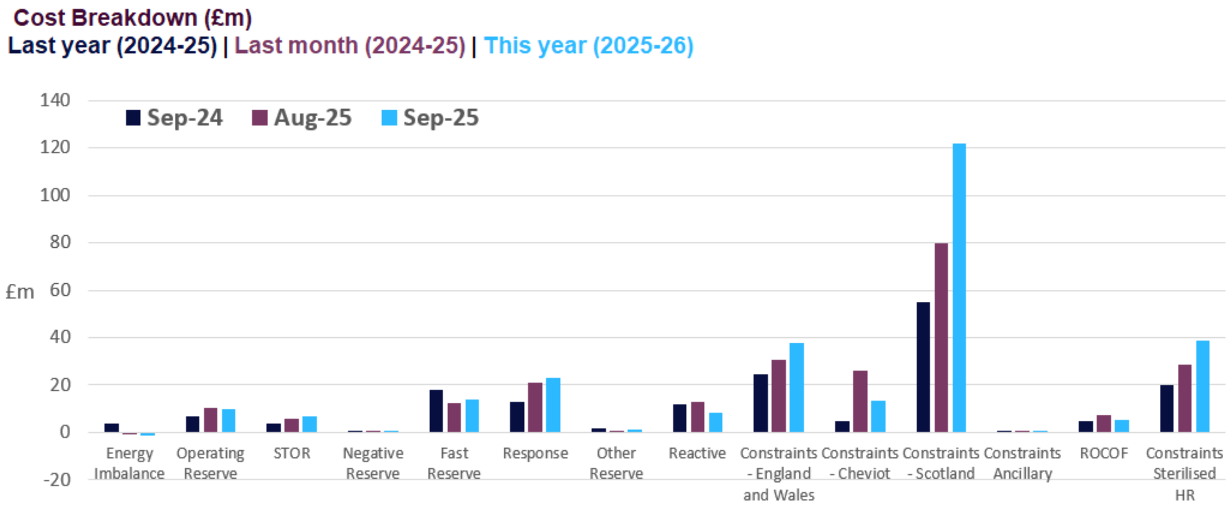


Comparison breakdown

Constraint costs increased by £44.5m compared to the previous month. Higher costs were seen across England & Wales and Scotland, though there was a decrease in Cheviot constraint costs (likely reflecting that the system required constraining further north in Scotland this month). The higher costs are in line with an overall increased wind outturn in September compared to August and, as such, higher volumes of wind curtailment required. Voltage and inertia spending both decreased month-on-month, reflecting the higher system demand which tends to bring more synchronous generation into the market. Total constraint costs almost doubled compared to September last year (from £110.42m to £216.64m), reflecting the fact that wind curtailment volumes almost doubled since last September as well.

Non-constraint costs increased by £5.15 million compared to August 2025, reflecting a rise in the costs of restoration, response and minor components since last month. Thermal constraints are currently the largest component of balancing costs.

We are progressing several initiatives to reduce thermal constraint volumes/costs including the Constraints Collaboration Project and Constraint Management Intertrip Service. Network Service Procurement projects for voltage and stability are also helping to provide solutions for network management at lowest cost.



COST SAVINGS

Cost Savings – Outage Optimisation

Total savings from outage optimisation amounted to approximately £18.7m in September 2025. This is a reduction of roughly £44.1m relative to August 2025 (£62.8m). The most valuable action was reprogramming the planned outage in East Claydon 400 kV substation. The outage will take place after the return of Sundon-Wymondley 400kV circuit. This action avoids a situation where a BMU would have to be run to manage the voltage. The estimated cost savings for this action was roughly £10.4m.

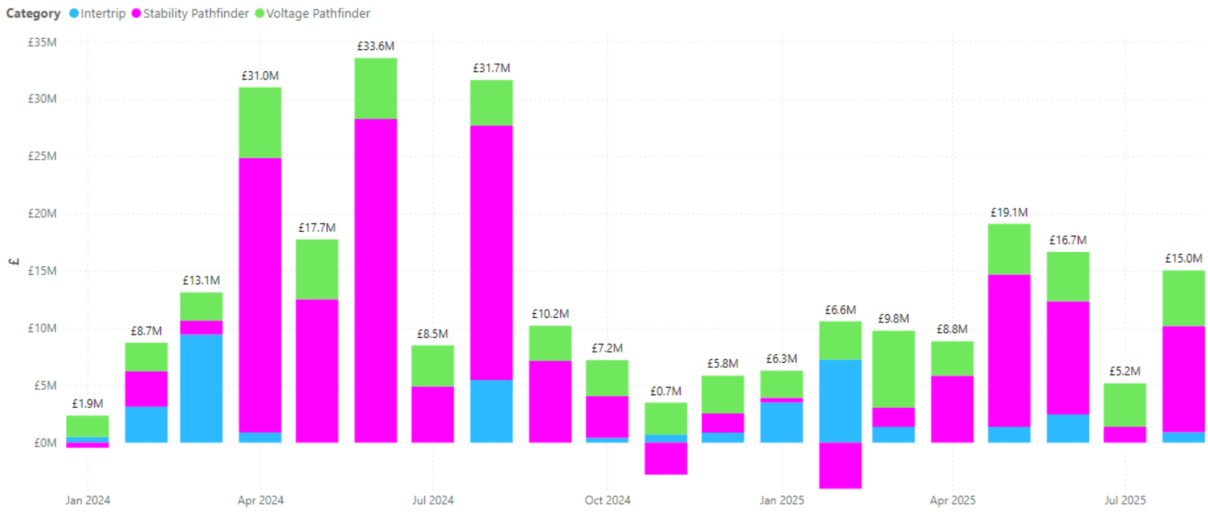
Cost Savings – Trading

The Trading team were able to make a total saving of £26.9m in September through trading actions as opposed to alternative BM actions, representing a 17% increase on the previous month. The increase has been driven by trades to manage constraints, often in the South East. These trades were usually priced against wind bids, with interconnector trades being the more economical option. Trades also occurred for downwards regulation, largely down to the difference in price between GB and Europe, causing interconnectors to be importing. The 16th September saw the greatest trading savings at £3.0m, with the greatest component being for managing constraints in the South East. 15 September saw the greatest spend on trades at £1.1m, with the greatest component being for managing VSCENTRAL.

Cost Savings – Network Services (NS)

We are using Network Services (NS) to implement solutions to operability challenges in the electricity system. This includes the Constraint Management Intertrip Service, and Voltage & Stability pathfinders. We have calculated that the B6 and EC5 Constraint Management Intertrip Services, Voltage Mersey, Voltage Pennines, and Stability Phase 1 have delivered approximately £64.8m in savings across 2025/26 to date (April – August 2025).

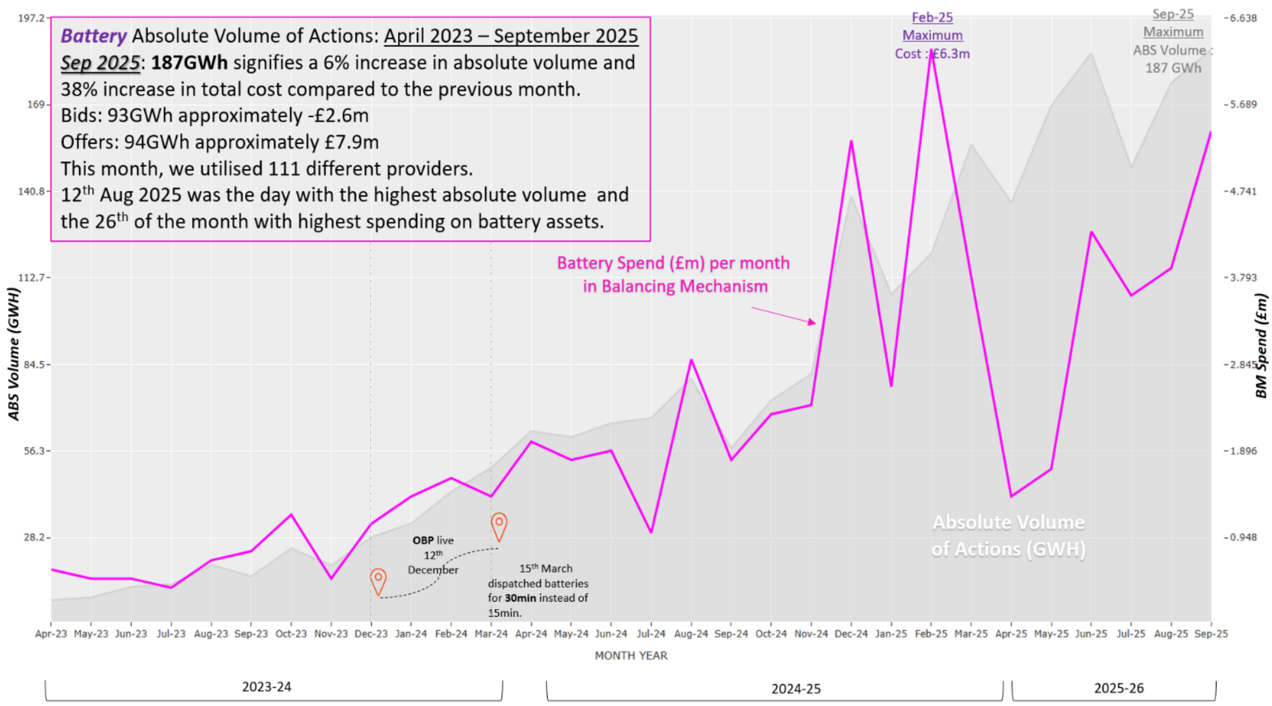
Monthly Savings from Network Services (NS)



NOTABLE EVENTS

Monthly Absolute Volume of actions and spend for Batteries in the BM

September 2025



The first stage of our new platform to support the bulk dispatch of battery storage and small Balancing Mechanism Units (BMUs), the Open Balancing Platform (OBP), went live on 12 December 2023. Since then, our ability to dispatch a greater number of typically smaller

BMUs within a settlement period has increased. This has unlocked greater capability to dispatch batteries in the Balancing Mechanism.

In comparison to the previous month, September 2025 saw both the overall volume of battery actions and the total costs increase. Since April 2025, the absolute volume of battery dispatch has nearly tripled compared to the same period last year and has increased more than fifteenfold since April 2023. This growth highlights our commitment to improving the flexibility of energy provision through battery storage and small Balancing Mechanism Units (BMUs).

DAILY CASE STUDIES

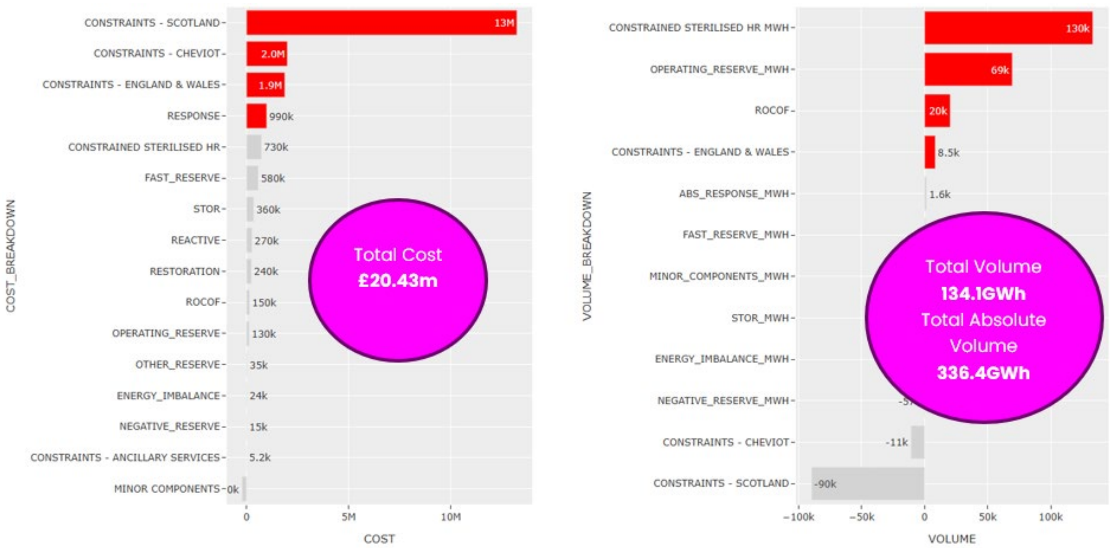
Daily Costs Trends

September's balancing costs were £286.6m. This included two days with a total cost above £15m (18th and 20th September), with the highest cost day of the month being the 18th. By comparison there were six days with a total cost above £15m in August. So, while the total costs have increased across the month in September, the number of especially higher costing days has decreased. There were an additional twelve days with costs above £10m in September (1st, 7th, 10th-12th, 14th-21st, 26th & 27th). In comparison, August only had one day with costs in the £10-15m range. The daily average cost rose by £1.8m, from £7.7m in August to £9.5m in September, which was driven by a larger number of high-cost days spread throughout the month, but most notably in the middle of the month.

The highest cost day was Thursday 18th September, with a total cost of approximately £20.4m. These high costs were driven by high levels of wind curtailment / constraint management in Scotland. The date had the highest level of wind curtailment this month overall.

The lowest cost day was Friday 5th September at a cost of approximately £2m. This was a fairly low wind day (total outturn of 113 GWh) and constraints were generally managed from trades, with very few system actions taken in the BM.

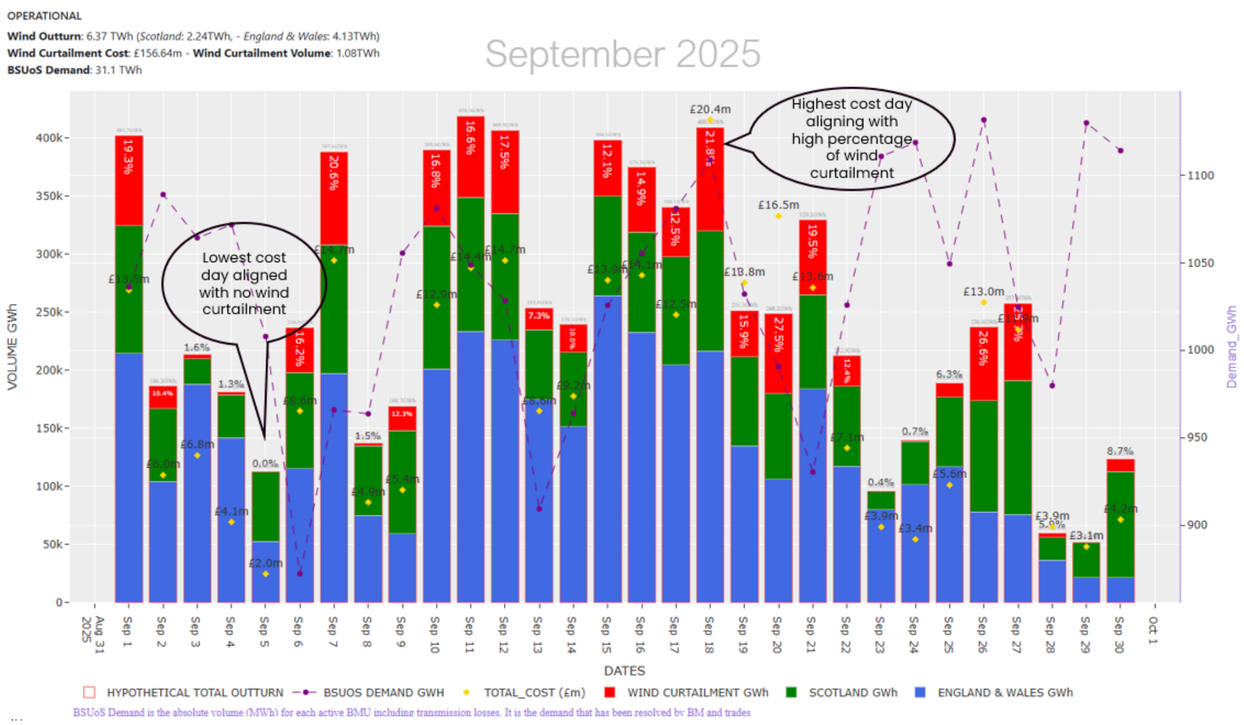
High-Cost Day – 18 Sep 2025



September 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. With this graph we can trace, for example, how wind performance and low demand affect the cost of each day.

KEY: **Blue bars:** Wind generation in England and Wales
Green bars: Wind generation in Scotland
Red bars: Wind curtailment
Purple dotted line: Demand resolved by the BM and trades
Orange diamonds: Daily cost



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 NESO control room actions.

2. Demand Forecasting

Performance Objective

Operating the Electricity System

Success Measure

Continuous improvement in forecasting is vital to ensuring we make informed decisions across all timescales. We will continue to publish our performance in this area through the Demand Forecasting metric (BP2: Metric 1B) and Wind Generation Forecasting metric (BP2: Metric 1C).

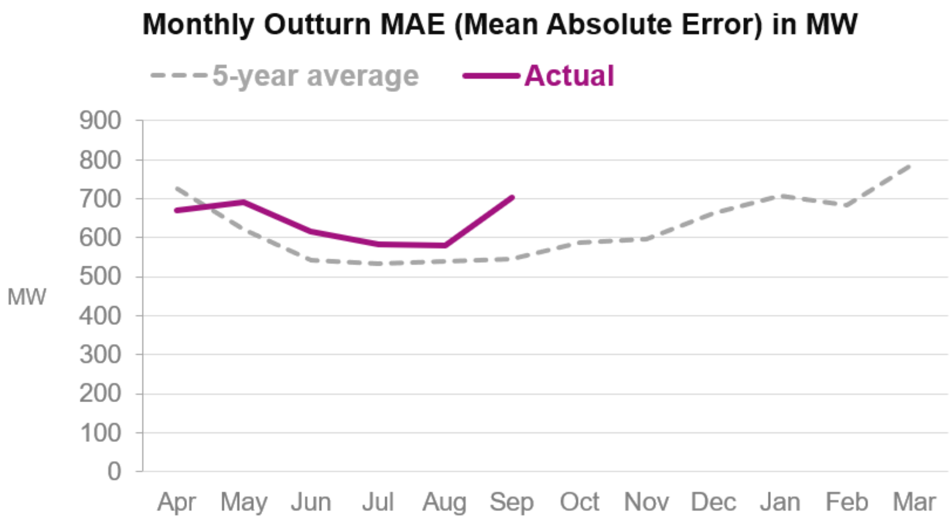
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each half hour period. BMRS is now known as Elexon Insights.

In settlement periods where the Demand Flexibility Service (DFS) is instructed by NESO, this will be retrospectively accounted for in the data used to calculate performance.

In order to provide transparency of our performance, we compare each month's actuals to the previous year, and to the average of the previous 5 years' actuals for the same month.

September 2025-26 performance

Figure: 2025-26 Monthly absolute MW error vs Indicative Benchmark



[2]Demand | BMRS (bmreports.com)

Table: 2025-26 Monthly absolute MW error vs Previous 5-year average

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Previous 5-year Average (MW)	727	620	541	532	538	545	588	596	662	707	684	793
Previous year outturn (MW)	687	610	565	528	596	612	578	591	652	735	758	850
Absolute error (MW)	**671**	**692**	**616**	**584**	**579**	**702**						

*Ofgem will no longer use a benchmark to assess our performance against this Metric however we will continue to report the previous 5-year average and last year's outturn as an indicator.

Supporting information

In September 2025 forecasting error averaged 702MW, which is a 157MW increase on the previous 5-year average of 545MW.

While September usually brings late summer warmth and dry, settled days, this year was different. Except for some very brief periods, the weather was unsettled and variable with frequent wet and windy periods and weekly swings in temperature.

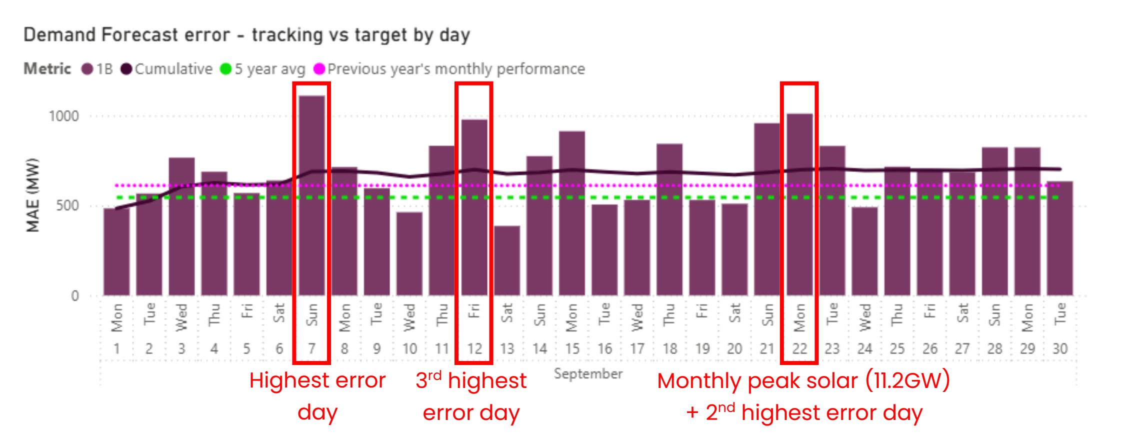
This month has been challenging. While the larger Day-1 errors have been fewer in number, medium-scale errors were more frequent.

Free-energy offerings from retailers continue to be made available at short-notice to consumers. These have typically occurred during weekend daylight periods, but are now being made available during business hours. They do influence the outturn demand profiles, but currently have minimal effect on the daily metric performance; affecting only 1-2 settlement periods.

New solar models have been deployed and are ready for release to production, which should make a nominal improvement to our legacy-system forecasts. Work is underway to build a new suite of demand forecast models.

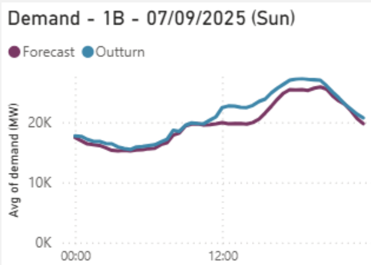
Solar generation peaked at 11.2GW on 22 September.

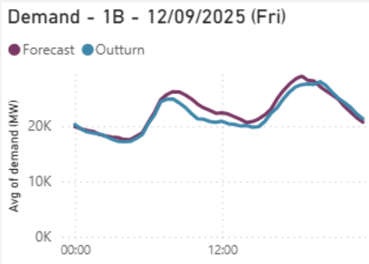
The largest absolute demand error this month was 3.0GW on 21 Sep, SP32.

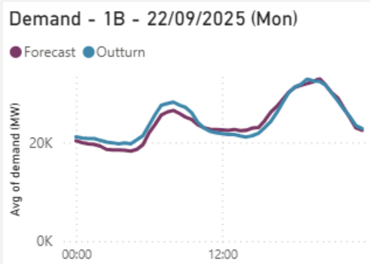


The minimum demand was 15.5GW on 7 Sep, SP10

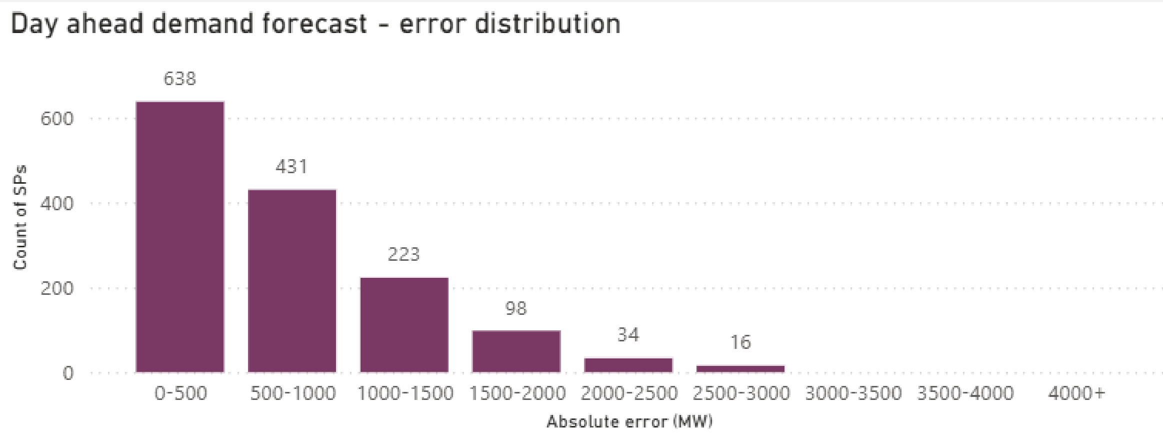
Days of Interest:



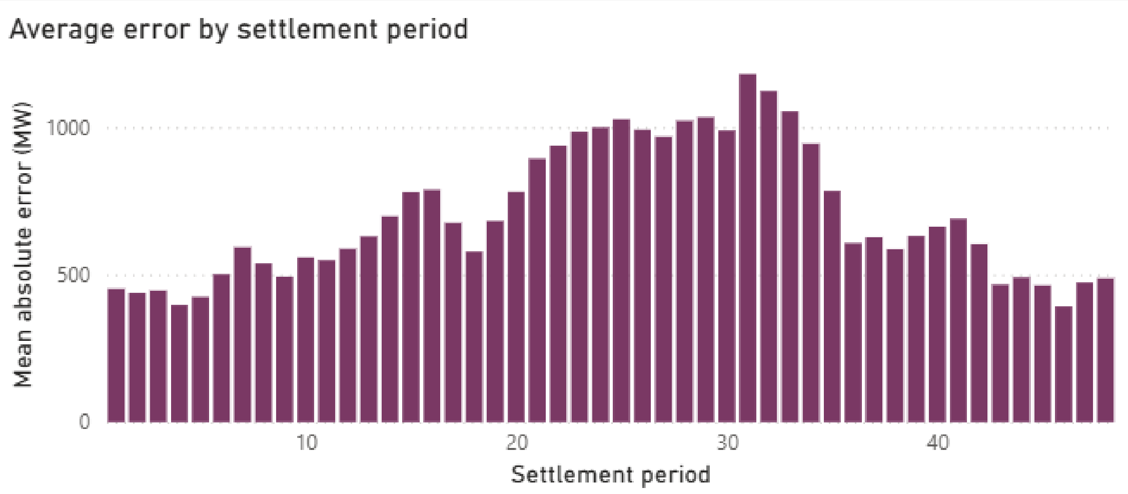




The distribution of settlement periods by error size is shown below:



The distribution of average error by settlement period is shown below:



The days with largest MAE were 7, 12 and 22 September.

Day	Error (MAE)	Major causal factors
7	1111	Solar and wind forecasting errors
22	1011	Solar forecasting and profiling errors, and other factors not captured by our models
12	978	Solar forecasting and profiling errors at day ahead

Missed / late publications

There were no missed/late publications in September.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 1-5, 8, 19, 22-24, 29 and 30 Sep, with an accumulated total of 191MWh delivered. These will nominally affect the national demand outturns but are not included in the day ahead forecast.

3. Wind Generation Forecasting

Performance Objective

Operating the Electricity System

Success Measure

Continuous improvement in forecasting is vital to ensuring we make informed decisions across all timescales. We will continue to publish our performance in this area through the Demand Forecasting metric (BP2: Metric 1B) and Wind Generation Forecasting metric (BP2: Metric 1C).

This Reported Metric measures the average absolute error between day-ahead forecast (between 09:00 and 10:00, as published on NESO data portal) and post-event outturn wind settlement metering (as published on the Elexon insights portal) 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); and
- did not withdraw availability completely between time of forecast and time of metering; for the relevant settlement period. We publish this data on its data portal for transparency purposes.

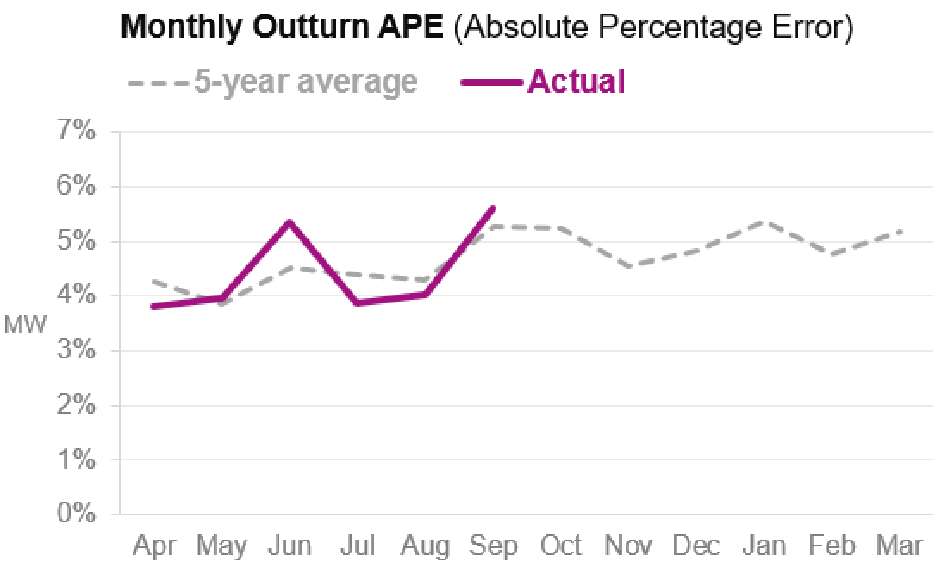
Sites deemed to have withdrawn availability are those that:

- re-declare maximum export limit (MEL) from a positive value day-ahead to zero at real-time; or
- re-declare their physical notification (PN) from a positive value day-ahead to zero at gate closure of the Balancing Mechanism.

In order to provide transparency of our performance, we compare each month's actuals to the previous year, and to the average of the previous 5 years' actuals for the same month.

September 2025-26 performance

Figure: 2025-26 BMU Wind Generation Forecast APE vs Indicative Benchmark



In line with the BP2 methodology reported from the BP2 18-Month Report onwards (published in October 2024), the APE% that we report excludes some of the factors that are outside of our control. This view excludes sites that have redeclared to zero and incorporates Initial Settlement Runs (+16 Working Days).

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Previous 5-year average (%)	4.26	3.87	4.53	4.39	4.3	5.27	5.23	4.55	4.84	5.36	4.78	5.18
Previous year outturn (%)	4.64	3.60	4.72	4.24	4.15	5.04	4.70	3.63	3.86	4.40	3.97	5.20
APE (%)	**3.85**	**4.09**	**5.61**	**3.80**	**4.02**	**5.62**						

*Ofgem will no longer use a benchmark to assess our performance against this Metric however we will continue to report the previous 5-year average and last year outturn as an indicator.

Supporting information

In September 2025, BMU wind forecasting error averaged 5.62%, a 0.35% increase on the 5-year average of 5.27%.

September brought unsettled wind weather conditions, with several frontal systems affecting UK. These bring strong, varied winds and intense gusts, and usually increase windspeed forecasting difficulty.

Three (11, 20 and 28) extraordinary high error days were attributed to poor weather forecasts. Although the quality of these forecasts improved significantly within-day, they were the major cause of the performance fractionally exceeding the historic average this month.

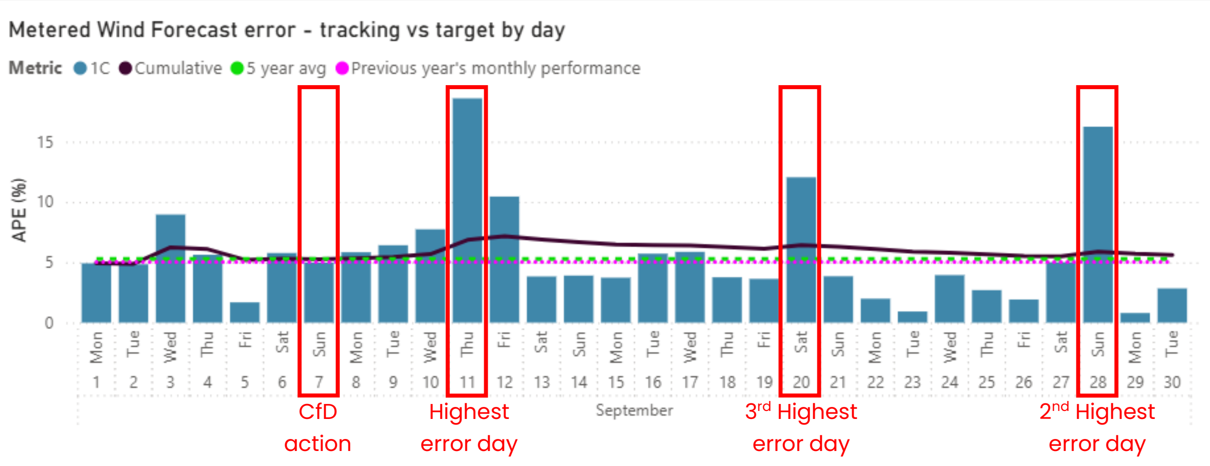
Contracts for Difference (CfD) activity occurred 7 September, with close to 4GW of redeclarations received. These redeclarations are accounted for in the current metric.

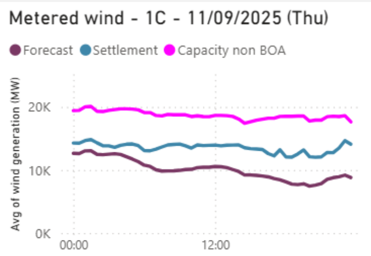
Work has begun on upgrading the wind generation forecast models. This will make use of additional weather variables and functionalities added in the new platform.

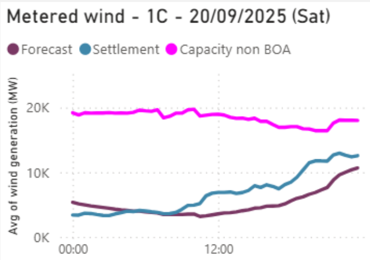
Metric-adjusted wind generation peaked at 15.7GW on 14 September, SP38.
Wind forecast absolute error peaked at 5.6GW on 28 September, SP12.

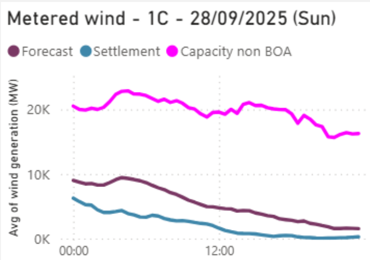
Note: metric performance for August has been recalculated with updated settlement data, which in this case has caused a very minor increase in reported accuracy.

Days of Interest:

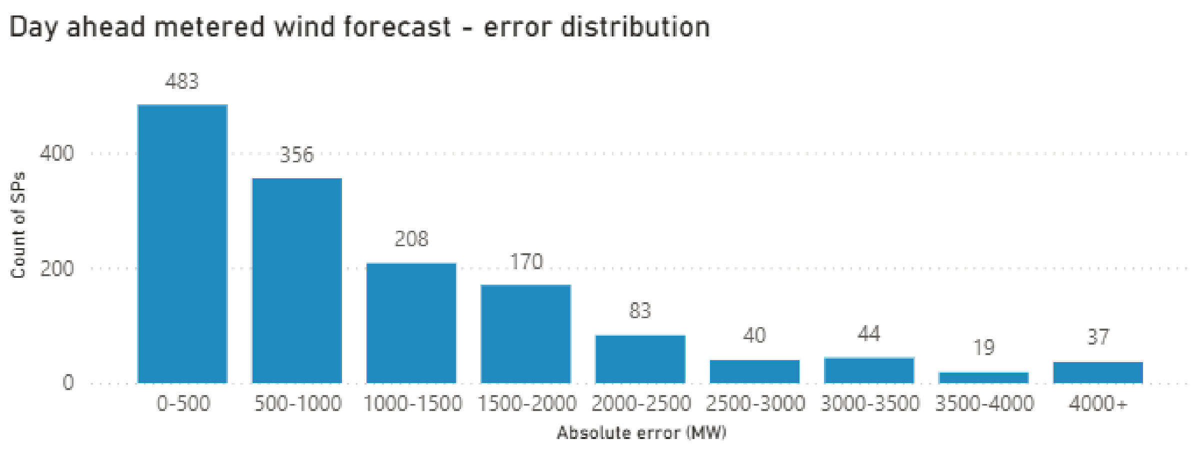








The distribution of settlement periods by error size is summarised below:



Details of largest error

Day	Error (APE)	Major causal factors
11	18.6	Wind speed forecast errors at day-ahead stage
28	16.3	Wind speed forecast errors at day-ahead stage, especially towards end of forecast window
20	12.1	Wind speed forecast errors at day-ahead stage, especially offshore units

Missed / late publications

There were no missed/late publications in September.

4. Skip Rates

Performance Objective

Operating the Electricity System

Related Success Measure

In December 2024, we published a skip rate methodology and delivery plan alongside a continuous skip rate measure on our data portal. We will develop this further into a detailed delivery programme and roadmap ahead of BP3, aligning it with our dispatch strategy. During BP3, we will deliver all commitments within our delivery programme and roadmap to reduce skip rates, providing transparency by continuing to report against the skip rate measure.

By the end of BP3, deliver a substantial reduction in skip rates with a target of relative parity across technology types.

Publish timely, accessible, and accurate skip rates data using both the existing five-stage post system action methodology and any updated methodology agreed with the industry.

Work closely with industry to develop and set an absolute numerical target for skip rates within the BP3 period.

Develop and share a methodology to measure the skip rate of actions taken to manage system constraints.

Share Platform for Energy Forecasting (PEF) and skip rate data, as well as issuing data associated with other strategic platform energy releases.

NESO has an obligation to operate a safe, reliable and efficient system. In consultation with industry, we have developed the All Balancing Mechanism (All BM) skip rate and Post System Action (PSA) skip rate as measures of dispatch efficiency. A skip occurs when a non-economic dispatch decision is made due to the NESO Control Room sending an instruction via BOA (Bid Offer Acceptance) at a higher price than an alternative could have been taken. Some skips are unavoidable due to asset dynamics and transmission limits while others may occur as a result of optimising the lowest cost over the day.

Our goal is to enhance transparency on our dispatch decision making and deliver a substantial reduction in skip rates that results in, as far as is practicable, relative parity across technology types by the end of BP3.

This Reported Metric measures the skip rate for bids and offers based on stage 5 of the Post System Action (PSA) methodology and will also include any updated methodology agreed with industry. More information on the skip rate definition and methodology can be found here.

Table: 2025-26 Monthly % PSA Skip rate Offers and Bids

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Offers	43%	35%	33%	36%	31%	32%						
Bids	45%	43%	51%	47%	40%	45%						
Combined	44%	40%	40%	42%	36%	38%						

Table: 2025-26 Monthly Skip rate Offers and Bids volumes (GWh)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Offers – skipped volume	63	71	116	78	86	116						
Offers – in merit Energy volume	148	205	356	215	279	359						
Offers – All in merit volume (System & Energy)	504	901	1052	529	943	971						
Bids – Skipped volume	150	154	118	130	128	109						
Bids – in merit Energy volume	336	352	234	277	316	243						
Bids – All in merit volume (System & Energy)	815	995	1576	962	1344	1488						
Combined Bid & Offer – skipped volume	213	225	234	208	214	226						

Supporting information

Q2 UPDATES

Reporting and methodology:

The definition of Post System Action (PSA) Skip Rate and the methodology to calculate skip rates were developed with LCP Delta and shared with industry in December 2024. We are currently reporting the PSA skip rate numbers for both bids and offers calculated at stage 5, which represents the actions available to our balancing team within the Control Room in real-time. The different stages within the methodology represent the removal of different types of units that are not accessible to balancing engineers in real-time. The stages are provided to aid transparency around units excluded from the final calculation rather than representing operational stages of the power system. Work is ongoing to add some of the identified limitations of the methodology into the calculation, which are dependent on the availability of data from the Open Balancing Programme (OBP) and currently planned for Q3 FY26.

Additional Metrics:

We have expanded this metric to include the skip rate by technology type, using two calculation methods. The first graph shows the Relative Technology skip rate for the current financial year, which shows how different technology types contribute to the overall skip rate. The second graph show the Technology Specific skip rate for each technology type for the last 3 months. This graph has been updated to include the skipped volume for each technology type as this metric can produce a very high skip rate when there is very low volume. The skipped volume on the Technology Specific graph is the total skipped volume for each technology type over the 3-month period shown. Both calculation methods are based on the PSA skip rate definition.

SEPTEMBER UPDATES

During September work has progressed on identifying potential solutions to reduce skip rates through the delivery of our Dispatch Strategic Review and analysis of the first Root Cause Analysis hypotheses to identify causation.

We are also working on establishing how to measure skips behind thermal constraints.

We held a drop-in session on 23rd September for industry to provide feedback and ask questions about the new skip rate dashboard. Feedback was positive, with participants finding the dashboard insightful and easy to use.

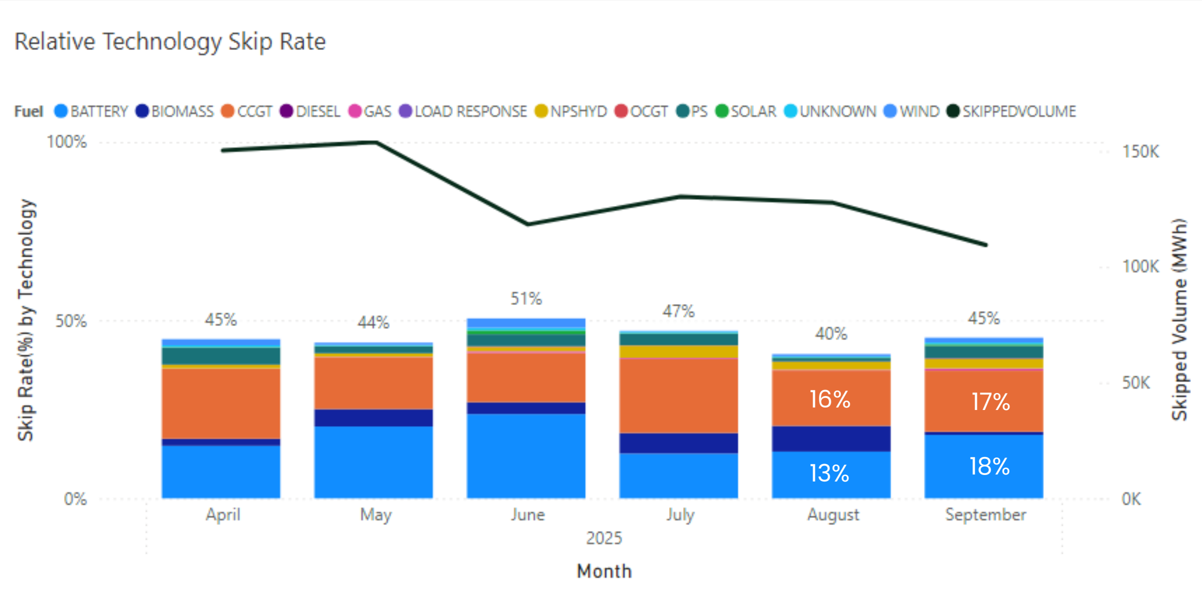
SEPTEMBER PERFORMANCE

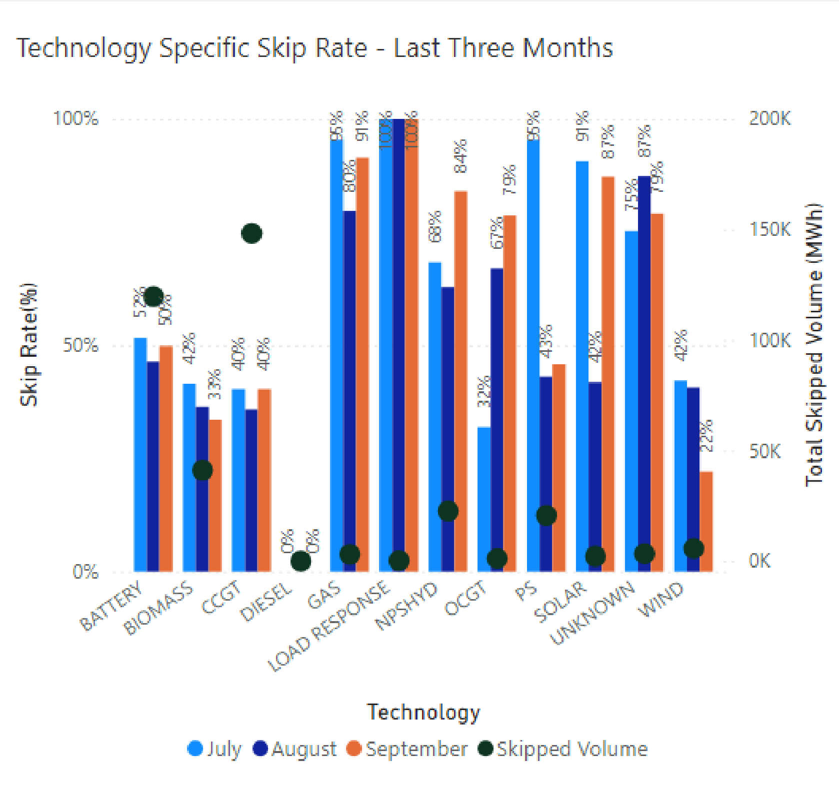
The Offer skip rate has increased slightly from August (31%) to September (32%) but skipped volume has increased due to a higher volume of energy offer actions taken in September. The Bid skip rate has also increased from 40% in August to 45% in September but skipped volume has decreased showing a lower volume of energy bid actions were taken in

September. The combined bid and offer skip rate has increased from 36% in August to 38% in September but this is still lower than all months pre-August.

Bids

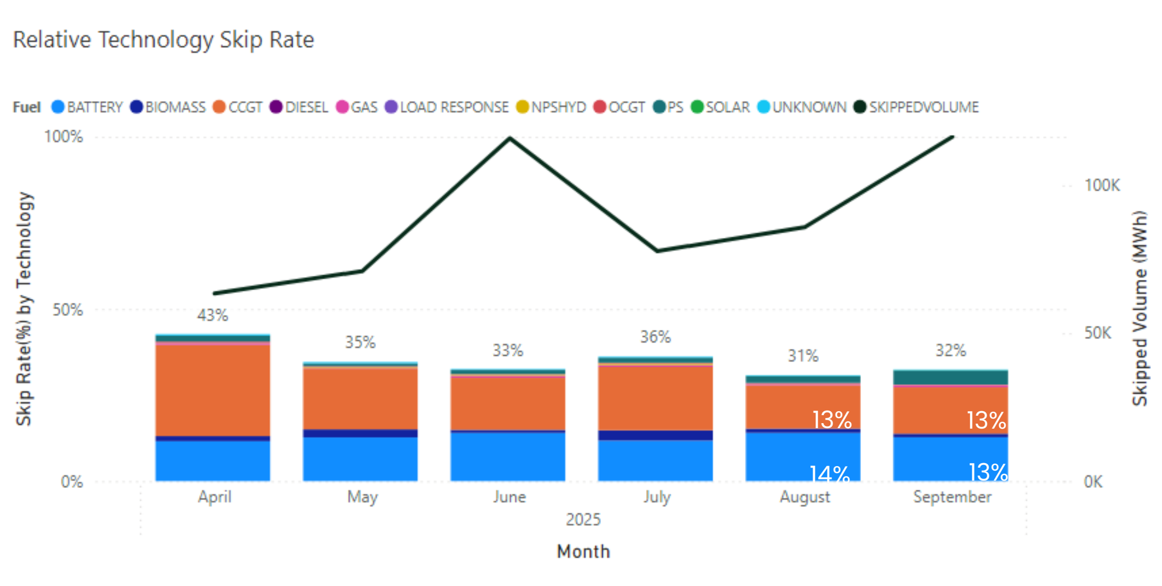
CCGTs accounted for a similar proportion of skipped volume in September (17%) compared to August (16%) and the Technology Specific skip rate for CCGTs has increased from 36% to 40%. Batteries account for a higher proportion of the skip rate in September (18%) compared to August (13%) and the Technology Specific skip rate has increased from 46% to 50%.

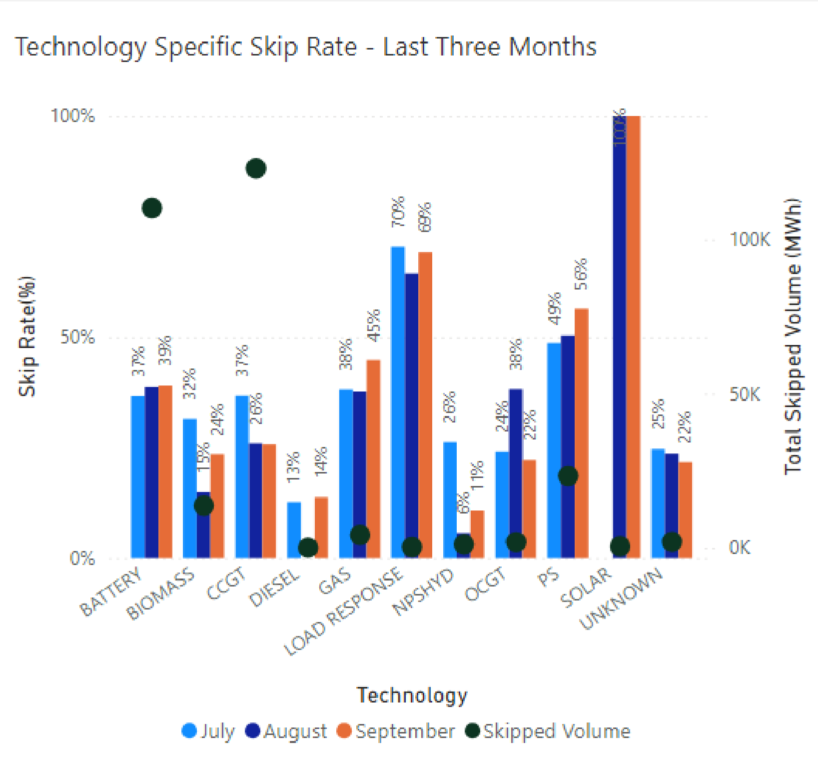




Offers

CCGTs account for the same proportion of skipped volume in September and August (13%), and the Technology Specific skip rate has also remained constant at 26%. Batteries account for a similar proportion of skipped volume in September (13%) and August (14%), and the Technology Specific skip rate also remained constant at 39%.





Note: In these graphs 'Gas' refers to gas reciprocating units, which are typically small, aggregated units. 'Load Response' is based on the fuel type category used by Elexon. These are typically Demand Side Response (DSR) units, however work is ongoing to better define and report on these units.

5. Carbon intensity of NESO actions

Performance Objective

Operating the Electricity System

Success Measure

By the end of 2025, we will demonstrate our ability to operate the system carbon-free whenever electricity markets provide a zero-carbon solution. We will measure this through reporting against the Zero Carbon Operability Indicator (BP2: RRE 1F) and the Carbon Intensity of NESO Actions (BP2: RRE 1G).

This Reported Metric 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 Zero Carbon Operability Indicator (previously RRE 1F) and Carbon intensity of NESO actions (previously RRE 1G) differs.

It is often the case that balancing actions taken by NESO for operability reasons increase the carbon intensity of the generation mix. We provide more information about our operability challenges in the Operability Strategy Report.

September 2025-26 performance

Figure: 2025-26 Average monthly gCO2/kWh of actions taken by NESO (vs 2024-25)

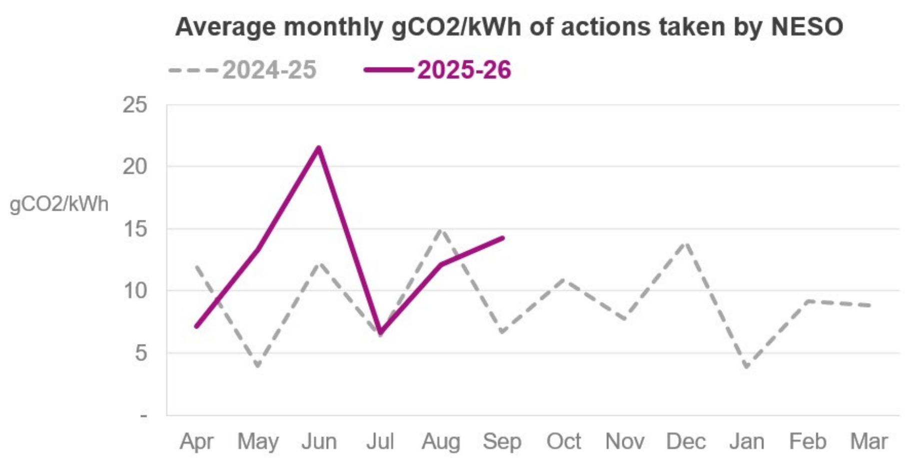


Table: Average monthly gCO2/kWh of actions taken by NESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	7.16	13.36	21.53	6.64	12.11	14.22						

Supporting information

In September we continue to report the average monthly gCO_2/kWh of actions taken by NESO in line with reporting requirements. Alignment of CP30 with ZCO technologies would see the inclusion of biomass and CHP's, which has yet to be reflected in the figures reported above.

In September, the average monthly carbon intensity from NESO actions was 14.22g/CO_2/kWh. This is 2.11g/CO_2/kWh higher than August and 1.71g/CO2/kWh higher than the YTD average of 12.5g/CO_2/kWh.

The maximum difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the BM and the equivalent profile with balancing actions applied was 57.23g/CO_2/kWh which took place on 21 September 2025 at 04:30. This is 8.44g/CO_2/kWh lower than the highest point in August 2025 of 65.67g/CO_2/kWh.

On 21 September NESO intervention was required to manage wind constraints. Wind cutout was forecast with loss volumes of up to 2.5GW at 05:00.

The Q2 average of the average monthly gCO2/kWh of actions taken by NESO was 10.99g/CO_2/kWh per month compared to Q1 average of 14.01g/CO_2/kWh.

Over Q2 we have seen the maximum difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the BM and the equivalent profile with balancing actions applied trending down. In July 2025 the maximum was 76.32g/CO_2/kWh, this decreased to 65.67g/CO_2/kWh in August and to 57.23g/CO_2/kWh in September.

6. Security of Supply

Performance Objective

Operating the Electricity System

Success Measure

As the electricity system in Great Britain evolves, we will transform the capabilities of our people, processes and systems and continue to deliver economic and efficient real-time operation of the electricity transmission system, as measured through the Security of Supply reporting evidence (BP2: RRE 11).

This Reported Metric shows when the frequency of the electricity transmission system deviates more than ± 0.3Hz away from 50 Hz 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 50 Hz 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.

September 2025-26 performance

Table: Frequency and voltage excursions (2025-26)

	2025-26											
	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						
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0						
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	1	0	0	1						

Supporting information

During the night of Tuesday 9 September 2025, the transmission network in the Pembrokeshire area in South Wales was operated outside the permissible voltage range of the Standard of Security and Quality of Supply (SQSS), and the declared rating of the assets owned by National Grid Electricity Transmission (NGET). The voltage excursion occurred at Pembroke 400kV and lasted for more than 15 minutes.

[3] https://www.neso.energy/industry-information/industry-data-and-reports/system-performance-reports

7. CNI Outages

Performance Objective

N/A

Success Measure

N/A

This Reported Metric 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.

September 2025-26 performance

Table: 2025-26 Unplanned CNI System Outages (Number and length of each outage)

Unplanned	2025-26											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	0	0						
Integrated Energy Management System (IEMS)	0	0	0	0	0	0						

Table: 2025-26 Planned CNI System Outages (Number and length of each outage)

Planned	2025-26											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	1 outage 215 mins	1 outage 115 mins	0						
Integrated Energy Management System (IEMS)	0	0	0	0	0	0						

Supporting information

There were no outages, either planned or unplanned, encountered during September 2025.

8. Short Notice Changes to Planned Outages

Performance Objective

N/A

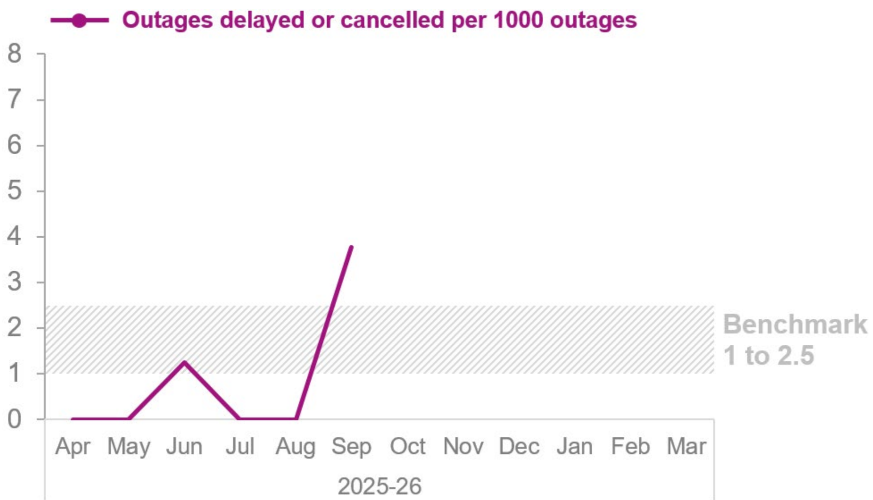
Success Measure

N/A

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

Q2 2025-26 performance

Figure: 2025-26 Number of outages delayed by > 1 hour, or cancelled, per 1000 outages



We have included the BP2 "meeting expectations" benchmark (1 to 2.5) threshold in the graph above for comparability purposes. Note that as per the PAGD, Ofgem will not assess our performance against this metric as below/meets/exceeds.

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	727	750	804	807	676	796							4560
Outages delayed/cancelled due to NESO process failure	0	0	1	0	0	3							4
Number of outages delayed or cancelled per 1000 outages	0	0	1.24	0	0	3.77							0.88

Supporting information

We successfully released 807 outages in July, 676 outages in August and 796 outages in September. Across these three months there were three delays or cancellations due to a NESO process failure that all occurred in September. The number of stoppages or delays per 1000 outages in September was 3.77, while the cumulative number of stoppages or delays per 1000 outages to date is 0.88. The three events are summarised below:

The first delay was caused due to a combination of ongoing outages that put two Grid Supply Points (GSPs) in an abnormal network configuration. Another outage at a nearby substation was requested by the Transmission Owner (TO) and it required a Risk of Trip (RoT) to be declared on the whole substation. This meant the two GSPs could disconnected if a trip occurred. Normally these GSPs would be secure for the single circuit trips, but with the RoT declared on the whole substation it could result in a busbar fault disconnecting both circuits feeding the demand simultaneously. This was not picked up in planning timescales and the NESO Control Room deferred the outage back to the Planning department. The RoT was modified so the whole site would not be at risk and this mitigated against a possible demand disconnection. Consequently, the outage was successfully released and an Operational Learning Note (OLN) is being written to capture proactive actions on scenarios where demand is abnormally fed during a Risk of Trip.

The second delay occurred due to an overlap between a circuit which is routinely switched out for voltage management and a nearby circuit that was requested to be switched out by the Transmission Owner (TO). In the offline studies conducted by the Planning team, the circuit used for voltage management was considered in service and no violations were observed. However, the NESO Control Room required the circuit for voltage management to be switched out to system conditions. As a consequence, operational challenges were observed in the real-time analysis software before the outage was switched out, and consequently this was passed back to the Planning department. An Operational Learning Note (OLN) has been written to capture the sequence of events and how to improve internal coordination between voltage and thermal constraint management.

The third delay occurred due to a voltage violation that was identified by the NESO Control Room in their real-time analysis software before the outage was released. This voltage violation was not observed in the offline analysis conducted by the Planning team. Therefore, the outage was deferred to be investigated further. This is being investigated into the root cause of the discrepancy between the two tools before the outage can be re-planned.

9. Zero Carbon Operability Indicator

Performance Objective

Operating the Electricity System

Success Measure

In December 2024, we published a skip rate methodology and delivery plan alongside a continuous skip rate measure on our data portal. We will develop this further into a detailed delivery programme and roadmap ahead of BP3, aligning it with our dispatch strategy. During BP3, we will deliver all commitments within our delivery programme and roadmap to reduce skip rates, providing transparency by continuing to report against the skip rate measure.

By the end of BP3, deliver a substantial reduction in skip rates with a target of relative parity across technology types.

Publish timely, accessible, and accurate skip rates data using both the existing five-stage post system action methodology and any updated methodology agreed with the industry.

Work closely with industry to develop and set an absolute numerical target for skip rates within the BP3 period.

Develop and share a methodology to measure the skip rate of actions taken to manage system constraints.

Share Platform for Energy Forecasting (PEF) and skip rate data, as well as issuing data associated with other strategic platform energy releases.

This Reported Metric 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 Reported Metric, 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.

In 2019 we began preparing to be capable of operating the GB electricity system, at the transmission level, safely and securely using 100% zero carbon generation when the market provides and wider system conditions allow.

Definition updated to reflect CP30

Following the Government's Clean Power 2030 Action Plan (CPAP) we have updated our definition of zero carbon generation sources to align with the clean power technologies. Within this report we will report performance under our revised ZCO definition, as well as continuing to report the original RIIO 2 definition statistics.

As a result, we now define zero-carbon generation sources as including wind, solar PV, nuclear, hydro, pump storage, batteries, and biomass. CHPs are excluded from the Zero Carbon calculation following DESNZ's Energy Trends publication on 30 September setting out the treatment of CHPs under the Clean Power metric.

The scope of the ambition remains the same i.e., to be capable of operating using 100% zero carbon generation at the transmission level, and **Interconnectors** remain excluded from the ZCO calculations i.e., as neither contributing to or detracting from NESO's ZCO capability.

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

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

Regular reporting on actual ZCO

Every quarter we report the ZCO provided by the market versus the ZCO following NESO 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, biomass, and pumped storage technologies) divided by the total transmission generation. Two figures are calculated: one represents the system conditions before NESO 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 zero carbon generation that the market provided over the month. For example, the maximum zero carbon generation provided by the market in Q2 2023-24 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 ZCO of the month.

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

Table: Q2 maximum zero carbon generation percentage by month (2025-26)

	CP30 aligned definition			**Original** RIIO-2 definition		
Month	**Highest ZCO% in the month** *(after NESO operational actions)*	**Market provided ZCO%** *(during the same day and settlement period)*	**Date / Settlement Period**	**Highest ZCO% in the month** *(after NESO operational actions)*	**Market provided ZCO%** *(during the same day and settlement period)*	**Date / Settlement Period**
April	97.77	99.99	1 April SP32	89.14	95.31	2 April SP33
May	96.76	99.97	29 May SP27	88.30	96.98	29 May SP27
June	96.49	97.96	10 June SP18	89.60	96.96	3 June SP26
July	95.93	99.95	14 July SP31	90.05	96.71	7 July SP28
August	93.68	99.00	30 Aug SP33	90.42	96.14	30 Aug SP34
Sept	95.51	99.92	15 Sep SP19	88.00	96.44	15 Sept SP24
Oct						
Nov						
Dec						
Jan						
Feb						
March						

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

Notification of errors in the BP2 End-Scheme Report

Our BP2 End-Scheme Report contained some errors outlined below:

1. The graph on page 97 of Annex A: Role 1 – Control centre operations showed the market provided 100% zero carbon generation in some settlement periods between 25 March and 31 March. This was incorrect.

   > On further investigation we identified an inaccuracy in the data processing. Specifically, negative data were not being processed correctly, and affected the overall calculation. This has been rectified.

2. The table on page 96 stated that during SP 20 on 30 March 2025 the market provided 99.7% ZCO.

   > This statistic had been input incorrectly due to a manual inputting error. The peak the market delivered was not 99.7%, it was 97.8% ZCO on 29 March 2024 at 19:30.

Figure: Maximum monthly ZCO% after NESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred) – two-year view (using CP30 definition of ZCO)

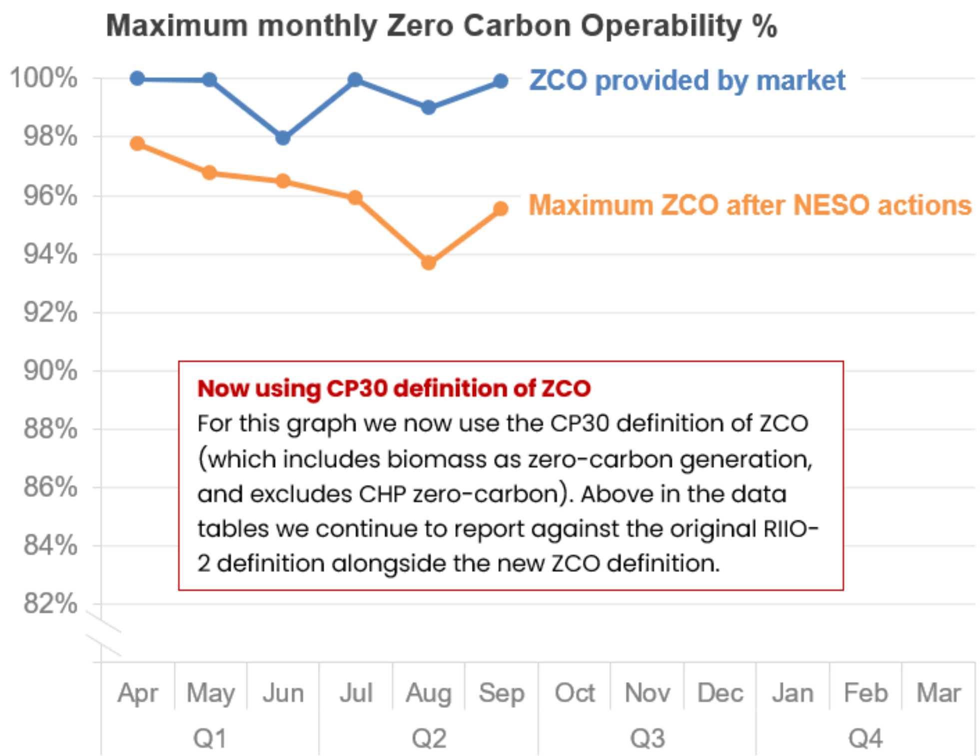
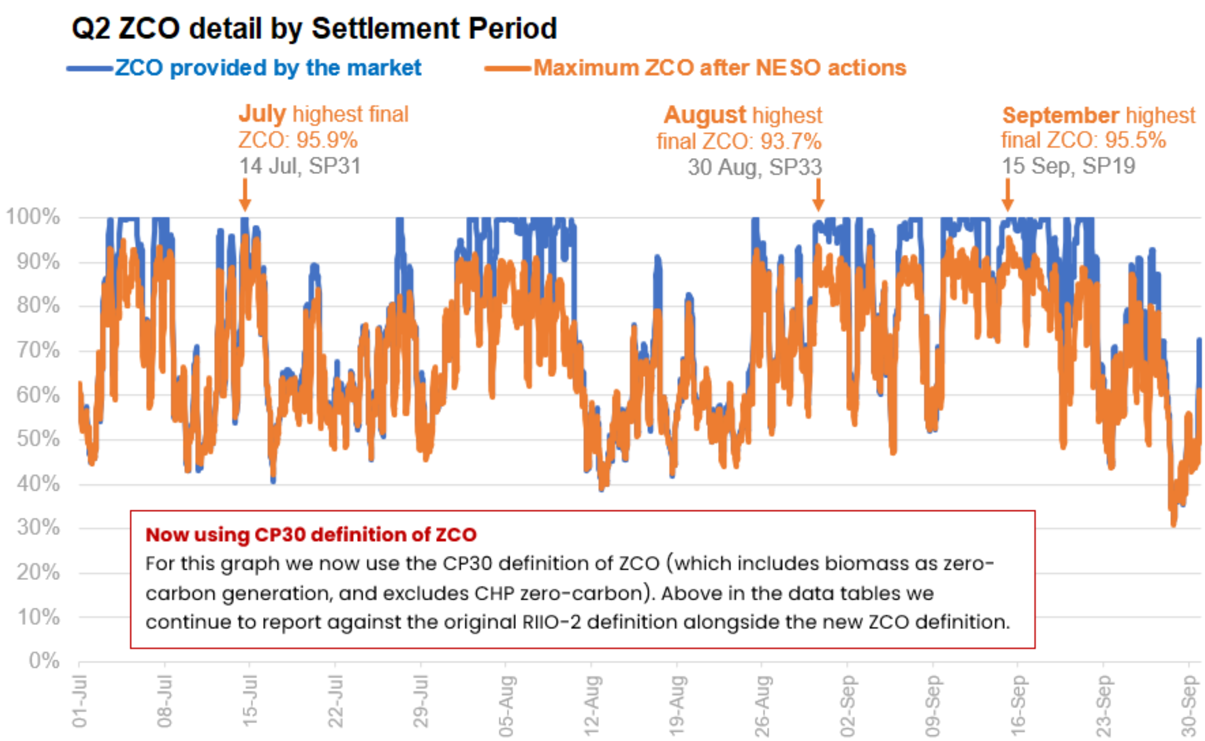


Figure: Q2 2025-26 ZCO by Settlement Period, before and after NESO operational actions (using CP30 definition of ZCO)



Supporting information

Based on the new ZCO definition, the Q1 statistics confirm a new ZCO record of 97.8% that was achieved on 1 April SP32. At this time the market also delivered a record 99.9%.

For Q2, the quarterly average was 95% ZCO with a highest period of 95.93% taking place on 14 July.

On 14 July unconstrained transmission-connected wind output increased slowly to 6GW. The solar output forecast was also expected to peak at 9.4GW.

The alignment of CP30 technologies sees a positive increase towards achieving 100% zero carbon operability. With a 100% zero carbon operability announcement due to be made, once achieved, based on the CP30 metric.

In Q2 2025-26, based on the original RIIO-2 definition the monthly average highest ZCO was 89.5% which is 0.5% higher than last quarter's average of 89% and 1.4% higher than Q4 2024.

Highest final ZCO by month vs previous year (original RIIO-2 definition)

Quarter	Month	2024/25	2025/26	Difference
Q1	April	92.2%	89.1%	-3.1%
	May	83.4%	88.3%	+4.9%
	June	86.1%	89.6%	+3.5%
Q2	July	86.7%	90.1%	+3.4%
	August	89.2%	90.4%	+1.2%
	September	84.6%	88.0%	+3.4%
Q3	October	85.1%		
	November	84.6%		
	December	89.4%		
Q4	January	88.7%		
	February	86.6%		
	March	93.5%		

CHP change confirmed on 30 September 2025 (Energy . 2025/26 contains adjustments not included in 2024/25.

10. Constraints Cost Savings from Collaboration with TOs

Performance Objective

N/A

Success Measure

N/A

The Transmission Operators (TOs) need access to their assets to upgrade, fix and maintain the equipment. TOs request this access from NESO, 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 Reported Metric measures the estimated £m avoided constraints costs through NESO-TO collaboration.

There are two ways NESO can work with the TOs to minimise constraint costs. We will report on both:

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 NESO to help reduce constraint costs according to the STCP 11-4[4] procedures. NESO 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 for this metric.

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

iii. For this metric, 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. NESO 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) – 2025-26

(Estimated savings in GWh are also shown for context)

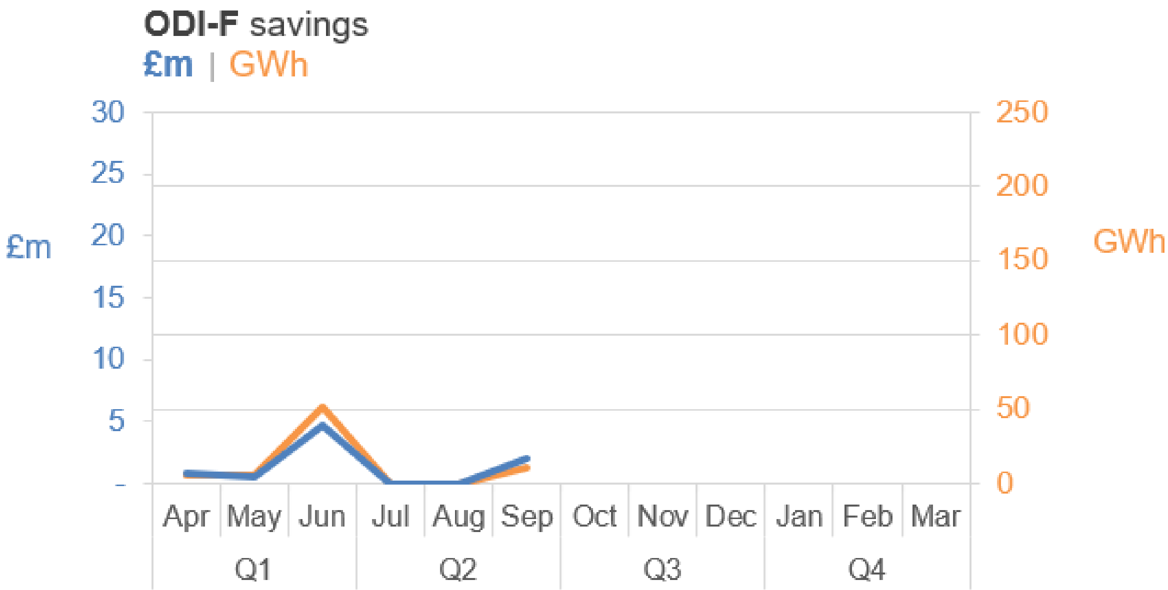


Figure: Estimated £m savings in avoided constraints costs (Other) (Estimated savings in GWh are also shown for context)

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

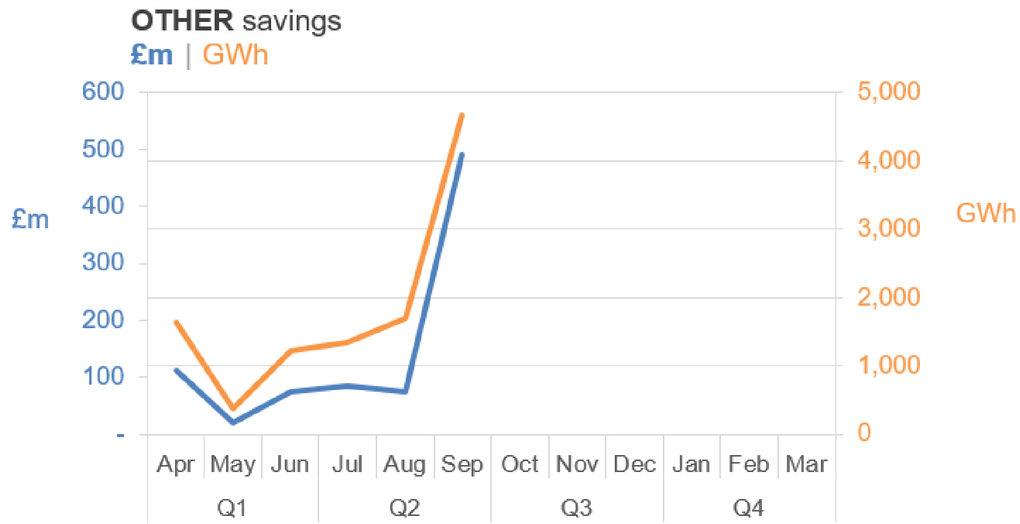


Table: Monthly estimated £m savings in avoided constraints costs (2025-26)

	ODI-F savings	Other savings	ODI-F savings	Other savings
	£m	£m	GWh	GWh
Apr	0.75	111.78	5.78	1,628.50
May	0.56	20.30	5.26	376.00
Jun	4.70	73.70	51.80	1,216.20
Jul	0.00	85.10	0.00	1,341.50
Aug	0.00	73.95	0.00	1,695.80
Sep	1.96	491.32	10.36	4,666.80
Oct				
Nov				
Dec				
Jan				
Feb				
Mar				
YTD	**7.97**	**856.15**	**73.20**	**10,924.80**

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 completed one approved enhanced service provision from TO's through STCP 11.4 that provides constraint cost savings this quarter. This is highlighted below:

- In September, National Grid Electricity Transmission (NGET) and Network Access Planning agreed upon enhancements based on static and dynamic weather conditions for two circuits connecting North Tyneside to Northumberland and South Tyneside. These improvements were implemented to facilitate NGET routine maintenance works on a circuit linking Tyne and Wear County with Northumberland. As a result, these enhancements saved **10.36 GWh** of energy and resulted in an outturn cost saving of **£1.96 million** for the end consumer.

In Q2 2025-26 financial year, NAP has achieved **£1.96 million** in constraint cost savings through STCP 11-4 with the release of **10.36 GWh** of additional capacity. This is because only started and completed enhancements have been reported. There are several ongoing enhancements which will be included in the next quarterly reports once they have successfully completed.

Other Savings (Customer Value Opportunities):

The Network Access Planning team has demonstrated significant progress over the past three months. In collaboration with our stakeholders, Transmission Owners (TOs) and Distribution Network Operators (DNOs), we have identified and documented **62 instances this quarter,** where the actions of the National Energy System Operator (NESO) have directly contributed to adding value for end consumers. Additionally, NESO's innovative approaches have successfully facilitated increased generation capacity for connected customers.

Such actions include adjusting outage dates, segmenting outages, minimising return-to-service times, acquiring enhanced ratings from TOs, re-evaluating system capacity, identifying and facilitating opportunity outages, synchronizing outages with customer maintenance schedules and generator shutdowns, proposing and implementing alternative solutions for prolonged outages that impact customers, among others.

Some examples of these instances include:

- In July, NAP received a system access request from National Grid Electricity Transmission (NGET) on the circuits connecting Sundon in Bedfordshire to Wymondley in North Hertfordshire District for for months, needed to replace a faulty circuit breaker at Wymondley 400kV Substation. However, due to this request boundary B9 and LE1 will be constrained heavily. To minimize the impact, NAP and NGET agreed to reconfigure the Pelham substation located in Buntinford, Hertfordshire to enhance the B9 and LE1 boundary. This action resulted in saving **252 GWh** of energy worth approximately **£18.9 million**.

- In August, NAP received a system access request from National Grid Electricity Transmission (NGET) on the Main Bus bar section 2 at East Claydon Substation in Aylesbury Vale, England. This was needed carry out refurbishment works on a Shunt Reactor connected to the Main bus bar, this request will alter the configuration of East Claydon substation. Also, there was an already planned outage on the circuits connecting Sundon in Bedfordshire to Wymondley in North Hertfordshire District. Due to this additional request, there will be a requirement to run additional synchronous machines to maintain the voltage within SQSS standards. NAP and NGET agreed to replan the Main Bus bar outage to after return of the Sundon to Wymondley 400kV circuit. This action resulted in saving **576 GWh** of energy worth approximately **£20.8 million**.
- In September, NAP worked extensively with SSEN-T to accelerate the ongoing East Coast Onshore 400kV Upgrade (ECUP) programme on the circuits connecting Kintore in Aberdeenshire to Kincardine in Falkirk, Scotland within the current year which will deliver the ECUP programme 6 months earlier. The new completion date is March 2027 as against the original plan of November 2027. This action resulted in saving **2.13 TWh** of energy worth approximately **£320 million**.

The customer value opportunities, along with others, collectively amount to an additional **7.7 TWh (approximately £650 million)** of generation capacity across Q2 in the 2025/2026 financial year. The surplus capacity would have otherwise been restricted, incurring costs to the end consumer.

The £/MWh figure for savings is calculated per outage. Savings for conventional generation are calculated using £36 per MWh, while renewable generation uses £75 per MWh. Where a full commercial cost-benefit analysis is available, those 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.

11. Day-ahead procurement

Performance Objective

N/A

Success Measure

N/A

This Reported 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 NESO and may be revised if new products are introduced.

For consistency with previous RIIO-2 incentives reporting, we have included a view of a benchmark set based on expected product expirations, and expectations for new procurement volumes. Note that as per the PAGD, Ofgem will not assess our performance against this metric as below/meets/exceeds, therefore the thresholds have been removed.

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

Whilst NESO 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, Quick reserve and Balancing Reserve
Non-day-ahead:	Mandatory Frequency Response only. Previously, this also included Long Term STOR, however since April 2025, this service is no longer procured.

Services newly introduced during BP2 should only be included in this metric if they displace those procured earlier than day-ahead. This is the reason why Balancing Reserve figures are not included in the Volume details by service table in page 61.

Q2 2025-26 performance

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

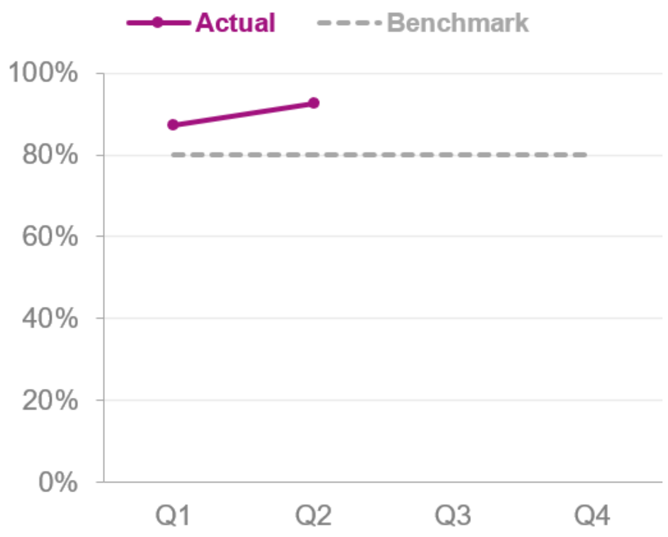


Table: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4	YTD
Volume of balancing services procured (average per procurement period)	MW	5276	5025			
Volume procured no earlier than day-ahead (average per procurement period)	MW	4605	4648			
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	87%	92%			
Benchmark*	%	80%	80%			

*We have reviewed performance data and will maintain the benchmark of 80% used in BP2. Note that as per the PAGD, Ofgem will not assess our performance against this metric as below/meets/exceeds expectations.

Volume details by service

Type	Service	Unit	Q1	Q2	Q3	Q4	YTD
Day-ahead	DC	MW	1275	1218			
	DM	MW	294	361			
	DR	MW	448	482			
	Static FFR	MW	202	198			
	STOR	MW	1751	1679			
	BR	MW	10	10			
	QR	MW	625	710			
	Total	MW	4605	4648			
Non Day-ahead	MFR	MW	671	377			
	STOR long-term	MW	N/A	N/A			
	Total	MW	671	377			
All	Grand Total	MW	5276	5025			

Supporting information

In Q2 the percentage of balancing services procured at no earlier than day-ahead has increased to 92%, against the benchmark of 80%.

With the growth in Response and Reserve competitive markets, we can procure more of our requirements at day-ahead so have less reliance on non-day ahead procured services. As Quick Reserve has matured, we have seen a steady rise to more competitively procured day-ahead volumes being utilised, reflected in the percentage increase as mentioned above.

12. Accuracy of Forecasts for Charge Setting - BSUoS

Performance Objective

N/A

Success Measure

N/A

This Reported Metric 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. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) are forecast for six-monthly tariffs and set 9 months ahead of the chargeable tariff period. For 2025/26, Fixed Tariff 5 (April 25 – September 25) was published in June 2024. Fixed Tariff 6 (October 25 – March 2026) was published in December 2024.

We continue to forecast balancing costs monthly and measure our performance against this forecast. 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).

Q2 2025-26 performance

Figure: 2025-26 Monthly BSUoS forecasting performance (Absolute Percentage Error)

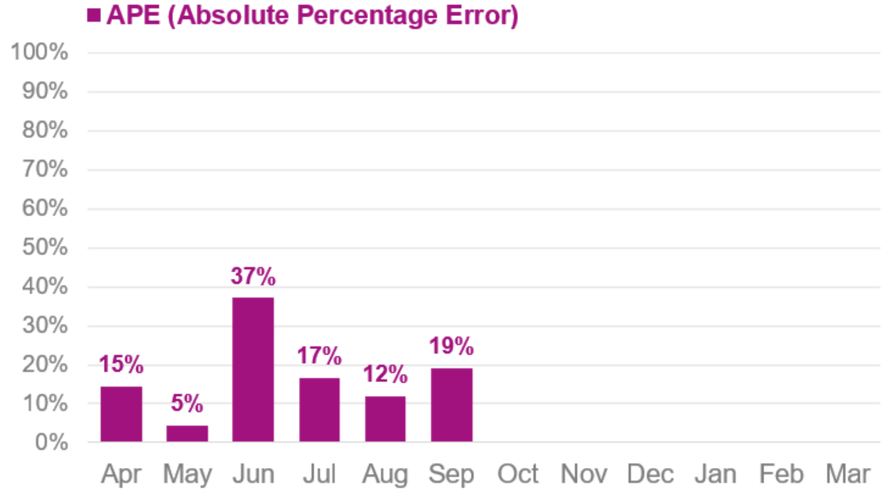


Table: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	9.53	13.02	18.54	10.43	14.19	15.97						
Month-ahead forecast (£ / MWh)	11.15	12.46	13.52	12.51	12.67	13.40						
APE (Absolute Percentage Error) [5]	14.5	4.5	37.1	16.7	12.0	19.2						
Average Monthly APE (by Quarter)	18.7			16.0								

Supporting information

Q2 Performance:

The average monthly Absolute Percentage Error for Q2 is 16.0%, with actuals being higher than month-ahead forecasts for both August and September.

The BSUoS forecast is probabilistic and tries to find patterns in recent history. It also uses two key drivers in forecasting expected costs; wholesale market prices and the proportion of demand met by renewables.

[5] 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.

Costs:

Total balancing costs across the quarter outturned above our month ahead forecast across the quarter, with the largest variance from our June 2025 forecast.

In July, balancing costs outturned around below the 30th percentile of our month ahead forecast, with lower than forecast constraint costs being the largest driver, outturning 20% lower than our forecast.

In August, balancing costs outturned at the 70th percentile of our month ahead forecast, £32m, above forecast. The proportion of demand met by renewables over August was 44%, compared to a month ahead forecast of 24%. We have found previously that a higher proportion of renewables tends to correlate to higher constraint costs, which outturned 32% higher than the August forecast.

September balancing costs outturned at the 80th percentile of our month ahead forecast, as high levels of wind generation resulted in 52% of demand being met by renewable generation, compared to a forecast of 38%.

The recent outturns will impact on our future forecasts through our persistence model, which uses previous forecasting errors to adjust the near term of our forecasts. We are also continuing to monitor the performance of the balancing cost forecast, and the distribution of the outturn percentiles compared to forecast.

Volumes:

Chargeable BSUoS volume is forecast using a linear regression model based on the National Demand forecast, and historic actual BSUoS volumes.

Across Q2 our average monthly volume forecasting error was 2.8%. The largest variance was in July with volumes outturning above forecast.

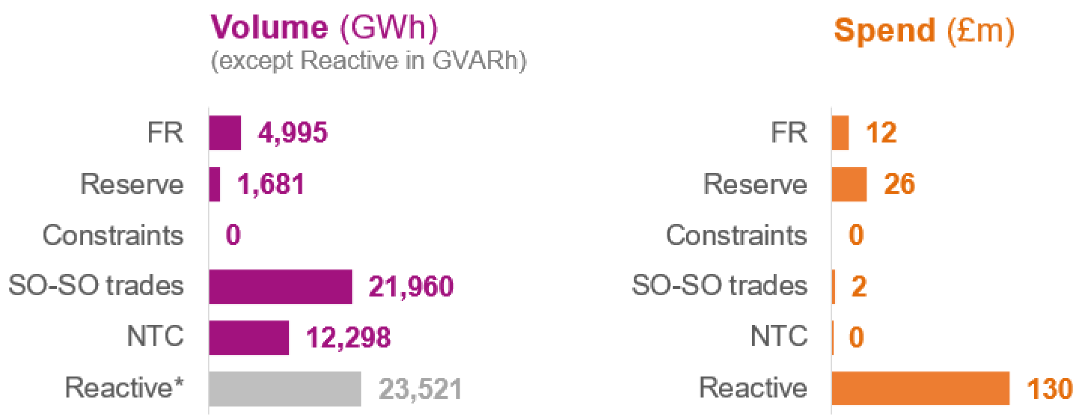
13. Balancing services procured in a non-competitive manner

This Reported Metric 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 2024, 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.

H1 2025-26 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	H1	H2	Full Year
VOLUME	Frequency Response****	GWh	4,995		
	Reserve****	GWh	1,681		
	Constraints***	GWh	0		
	SO-SO trades	GWh	21,960		

	Net Transfer Capacity (NTC)	GWh	12,298		
	Total Volume in GWH	GWh	**40,934**		
	Reactive (in GVARh)	GVARh	23,521		
SPEND	Frequency Response	£m	12		
	Reserve	£m	26		
	Constraints	£m	0		
	SO-SO trades *	£m	2		
	Net Transfer Capacity (NTC)**	£m	0.15		
	Reactive	£m	130		
	Total spend	£m	**170**		

*SO-SO trades, trade volumes and costs for services provided to NESO by another country's system operator have been included. Services provided by NESO 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 actively considering alternatives to the current MFR service to reduce this volume in the future and have continued to engage with stakeholders on this.

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 2025 and 2026.

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.

Constraints

No non-competitive constraint contracts have been used.

SO-SO Trades

Historically SO-SO Trades were available to us across the IFA and IFA2, Nemo Link, EWIC and Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 and Nemo Link, the current required notice period is longer than the hourly gates provide, and so we can no longer use this service.

EWIC, Greenlink & 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.

SO-SO trades are also available with Energinet via the Viking Link Interconnector.

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 2023, 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.

14. Future Savings from Operability Solutions

April 2025 to September 2025 Performance

This Reported Metric outlines the forecast medium to long term benefits from new operability measures including:

- Saved balancing costs
- Monetised carbon reductions
- Any indicative impact on the SZCP limit

In each report we show projects concluded in the BP3 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 BP3.

H1 2025-26 performance

i. Saved balancing costs

Table: Forecast balancing costs savings for operability measures concluding in BP3 so far

Operability Solution projects	LATEST VIEW Mid-Scheme 25-26 View: Forecast Savings £m	PREVIOUS VIEW End-Scheme 24-25 View: Forecast Savings £m
Constraints Management Intertrip Service (CMIS) EC5 Enduring (July 26 – Sept 29)	**171**	**-**
TOTAL	**171**	**-**

The method to calculate the costs savings for CMIS is 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.

Supporting information

Constraints Management Intertrip Service (CMIS) EC5 Enduring – (July 26 – Sept 29)

The tender for the enduring service has concluded and the estimated savings from these contracts is £171m. The service will make use of the upgraded intertrip scheme which will have an enhanced trip speed of 200 milliseconds, allowing the scheme to be used for increased operational conditions, thereby delivering increased savings.

In the BP3 End of Scheme report, we will include benefits for the ongoing Mid-term (Y-1) Stability Market Year 2 tender that will conclude by the end of 2025 for delivery from October 2026.

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. These prices are also those used in our RIIO-2 Business Plan 2 Cost-Benefit Analysis – Annex 2. The prices are weighted for the calendar year in which the services are contracted to deliver.

Table: Constraints Management Intertrip Service (CMIS) EC5 Enduring – (July 2026 to September 2029)

Constraint Management Intertrip Service EC5 Enduring	Unit	Feb 24 – Mar 25
CCGT generation output avoided in GWh	GWh	3,392
Carbon intensity for Gas (Combined Cycle) from NESO Carbon Intensity Forecast Methodology	gCO2/kWh	394
CO_2 in tonnes	tCO_2	1,336,448
Carbon price (BP2)	£/tCO_2e	270
Savings	**£m**	**361**

Supporting information

To calculate the monetised value of carbon savings, we have used the prices from BEIS' 'Valuation of greenhouse gas emissions: for policy appraisal and evaluation' policy paper. The prices have been weighted for the calendar year in which the services are contracted to deliver.

Constraints Management Intertrip Service (CMIS) EC5 Enduring – (July 26 – Sept 29)

The enduring service will contract with new generators to connect the East Anglia tripping scheme with an enhanced trip speed of 200 milliseconds, allowing the scheme to be used for increased operational conditions.

iii. Any indicative impact on the SZCP limit

As outlined in our Operability Strategy Report 2025, we updated the Zero Carbon Operation methodology to reflect the clean power technologies as set out in the Clean Power Action Plan. Under this methodology, the record for zero carbon operation was 95.2% on 15 April 2024 (The methodology has since been further updated to exclude CHPs, as outlined in the Zero Carbon Operability Indicator Reported Metric.)

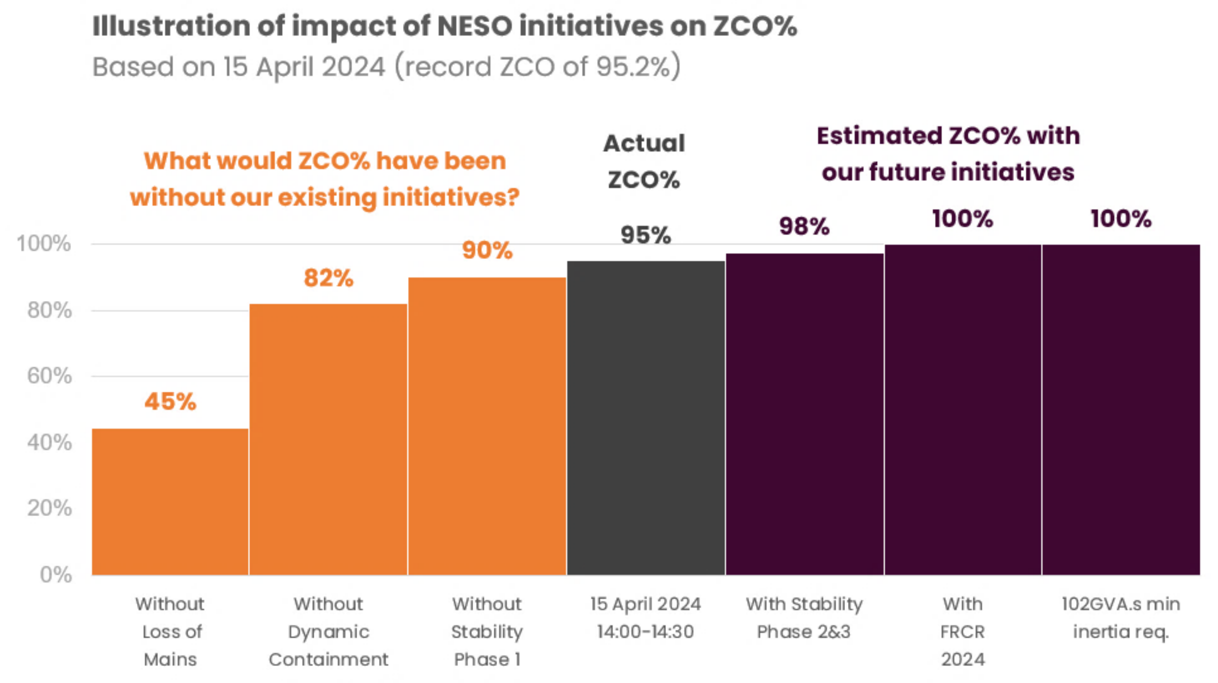
The below graph shows how much lower the ZCO% would have been on 15 April 2024 without the delivery of Stability Phase 1, Dynamic Containment and the Loss of Mains change programme. Each programme is assessed independently rather than cumulatively.

- **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 90%.
- **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 11 units at 250MW each, reducing the ZCO% to 82%.
- **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 285GVA.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 140GVA.s, so an additional 48 units would have been needed to deliver 130GVA.s at 250MW each. This would have reduced the ZCO% to 45%.

The graph then shows how our future projects will help close the ZCO gap to 100% by 2025.

- **FRCR 2024** was approved on 27 September 2024, which was to maintain the minimum inertia requirement from FRCR 2023 at 120GVA.s. Therefore FRCR 2023 and 2024 would reduce the minimum inertia requirement from the 140GVA.s on 15 April 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 100%.
- **102GVA.s min inertia req.** FRCR 2025 proposed the minimum inertia requirement should be reduced to 102GVA.s. This is the minimum inertia level we have been aiming for as part of enabling a zero carbon electricity system. Ofgem led an industry consultation on the FRCR 2025 proposals, which closed on 12 September 2025. We are awaiting the decision (13 Oct 2025). Reducing the minimum inertia to 102GVA.s means more periods with a zero carbon generation mix will be operable. Compared to 15 April

2024, this would have reduced the number of carbon emitting units by ten. As there were less than ten carbon emitting units on the system, the ZCO% is 100%.



Note: The calculations make assumptions about the contribution to system needs on 15 April 2024, 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 15 April 2024 to be zero carbon, there are further projects which will enable zero carbon on other days too.

There are four reactors being delivered in early 2026 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 generators (1250MW).

Looking beyond 2025, our voltage tender for 2026 ("Voltage 2026") has procured enough reactive power to remove another three generators (750MW). First contracts start service provision in late 2025, with final contracts starting service provision at the end of 2027.

And further ahead, through the "Long-term 2029 tender", our first bundled procurement of stability, voltage and restoration services, NESO are seeking additional services for delivery in 2029. This tender covers all of Great Britain and offers providers the option to bid on one or more of these services using the same asset. Stability and Voltage services must be able to be provided at 0MW, therefore enabling the electricity system to get ever closer to Clean Power in 2030. This tender process is ongoing and due to complete in 2026.

We're currently working through implementation for a mid-term reactive market with a view to launching it when a requirement for mid-term procurement is identified. This will complement our mid-term stability market, providing us with a platform for procuring voltage and stability services closer to operational timescales, accessing additional capabilities from existing assets.

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