26 January 2026

Quarterly (Q3) Incentives December 2025 Report

Business Plan 3 (2025-26)

NESO
National Energy System Operator

Contents

Introduction **3**

Progress against BP3 Performance Objectives **6**

Performance Objectives Summary **7**

Strategic Whole Energy Plans 8

Enhanced Sector Digitalisation and Data Sharing 12

Fit-for-Purpose Markets 15

Secure and Resilient Energy Systems 24

Operating the Electricity System 29

Connections Reform 33

Clean Power 2030 Implementation 37

Separated NESO Systems, Processes and Services 40

Reported Metrics **43**

Summary of Reported Metrics **44**

1. Balancing Costs 45
2. Demand Forecasting 64
3. Wind Generation Forecasting 68
4. Skip Rates 72
5. Carbon intensity of NESO actions 78
6. Security of Supply 80
7. CNI Outages 82
8. Short Notice Changes to Planned Outages 84
9. Zero Carbon Operability Indicator 86
10. Constraints Cost Savings from Collaboration with TOs 92
11. Day-ahead procurement 97
12. Accuracy of Forecasts for Charge Setting - BSUoS 100

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 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.

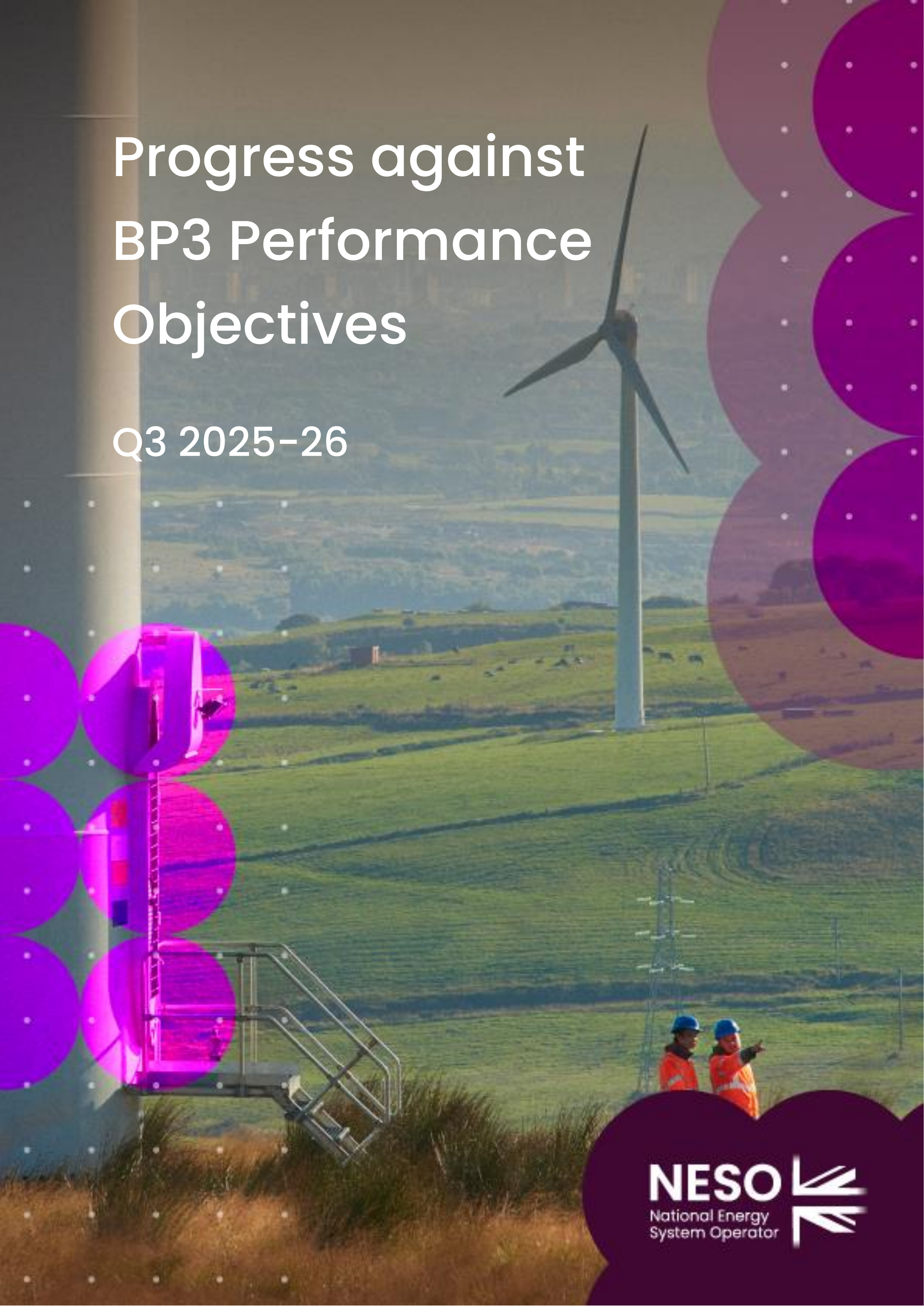
As per the BP3 NESO PAGD, we are required to continue providing quarterly reports directly to Ofgem as part of the CMF throughout BP3. We feel it is also important to share updates with our external stakeholders and industry as part of the framework. Therefore we will include a summary of the CMF update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

Q3 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-Q3 Status	Prior Status (End-Q2)
Strategic Whole Energy Plans	At risk	At risk
Enhanced Sector Digitalisation and Data Sharing	On track / no risk	On track / no risk
Fit-for-Purpose Markets	On track / no risk	At risk
Secure and Resilient Energy Systems	On track / no risk	On track / no risk
Operating the Electricity System	On track / no risk	At risk
Connections Reform	At risk	Significant challenges
Clean Power 2030 Implementation	On track / no risk	On track / no risk
Separated NESO Systems, Processes and Services	On track / no risk	At risk

- ● On track / no risk
- ● At risk
- ● Significant challenges

Performance Objective	Q3 Status	Prior Status (Q2)
Strategic Whole Energy Plans We'll establish our capabilities, and the foundations and methodologies to deliver national and regional strategic whole energy plans.	Amber	Amber

Summary of progress this quarter in delivering this PO outcome
Whilst this Performance Objective remains at amber, it is trending towards green as we are making good progress towards the outcome we committed to with some key activities to take place over the remainder of the period. Some BP3 deliverables have been delayed beyond March 2026 due to external factors, but we have maintained capability-building efforts throughout the BP3 period. The SSEP and RESP methodologies are complete and CSNP is progressing well. We have closely collaborated with DESNZ and Ofgem to set a new timeline for SSEP pathways modelling, aiming for the best outcome by leveraging current team progress. We have successfully completed three key measures by the end of Q3 and the replanning activity of the SSEP pathways modelling and documentation. The key measures completed in Q3 are as follows: 1) Gas Options Advice Document (GOAD) published in December 2025. 2) RESP methodology consultation published in November 2025. 3) Built capability and established regional teams per RESP3 region in December 2025. We continue to manage the intersection of government policy with the output of our modelling and planning which requires careful engagement with stakeholders.

Progress on Success Measures this quarter
Submit the first SSEP pathways document to the UK Energy Secretary by Summer 2026. The original date of December 2025 included in our BP3 plan has been revised following the new timeline announced in December 2025. DESNZ released refreshed energy generation cost data, which is an input to the SSEP. With the release of this new data, NESO and DESNZ took the decision to rerun the SSEP modelling used to ensure our analysis and recommendations are based on the most credible, current and transparent information. As a result, the final SSEP will now be delivered in Autumn 2027, with pathway options submitted for decision by the Secretary of State in summer 2026, with the public consultation on the draft SSEP early 2027.
Publish the Transitional Centralised Strategic Network Plan 2 Refresh Methodology (tCSNP2) report by June 2026 (Initially 31 January 2026). SSEP data validation activity has been decoupled from the tCSNP2 Refresh. The number of new options from Transmission Owners remains higher than expected from the original scope of the refresh. NGET will provide new options information (costs, outages

and Environment & Community appraisals) by end of Jan 2026. This measure remains on track to deliver in June 2026.
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** The methodology will be submitted to Ofgem by 31 January, which is the new date as formally requested and approved by Ofgem. Ofgem decision on the CSNP will be received by 15 April 2026.
Publish the RESP methodology consultation by November 2025. The methodology consultation went live on 17 November as planned. A launch webinar was held with 370 attendees, and deep dive webinars were held in November and December into different methodology topics.
Publish RESP inputs to Electricity Distribution-3 price control as agreed with Ofgem by March 2026. The September consultation closed on 3 November 2025 with strong stakeholder engagement and positive feedback. Analysis of responses is now largely complete, and synthesis outputs are in advanced drafting stages. Final deliverables are expected to be published by end of January 2026.
Publish the Gas Options Advice Document (GOAD) by 31 December 2025. We published the GOAD on 9 December 2025, which was earlier than the target date of 31 December. A post-publication webinar is set to take place in January 2026.
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. Additional engagement workshops are complete with a good relationship with DESNZ. There are no major disturbances to our original concepts and timescales are being aligned with electricity. We now move into developing and socialising 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.

Convene the first quarterly Regional Forum for each region by May 2025, to support transitional RESP and RESP development.

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 NETS 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);
- A new Modification, GSR034 Review of Loss of Infeed Risk for Offshore DC Converters, which addresses one of the defects of GSR030. GSR034 was approved by a special SQSS Panel on 31 October 2025 to proceed straight to Code Administrator Consultation (CAC), and the FMR (Final Modification Report) has since been submitted to Ofgem for their consideration.
- Two new modifications raised at the December 2025 SQSS Panel; GSR035 and GSR036, both relating to System Access Reform (SAR). SAR seeks to reform the transmission outage planning process to better facilitate connections.

We will continue the SQSS review in the BP3 period to ensure the standard is fit for purpose for the latest development.

Evidence how delivery timelines have been optimised for benefits

The outputs for the Strategic Whole Energy Planning Performance Objectives are managed centrally through robust internal governance mechanisms, which have decision making authority, such as the NESO Project Review Board (PRB) and the SEP Portfolio Management Board (PMB).

We also engage closely with DESNZ, Ofgem, and various other stakeholders on a regular basis (e.g. SSEP Committee) to seek input into optimised delivery timelines. A recent example of this collaborative effort is the delay to the SSEP pathways document based on revised modelling data from DESNZ. The programme has been re-baselined through concerted efforts with DESNZ and Ofgem to establish new timelines, which will consequently benefit from using enhanced data to deliver an optimised outcome.

The transitional Centralised Strategic Network Plan 2 (tCSNP2) should be a publication that sets clear signals for industry investment and does not require further refresh;

We are committed to producing the tCSNP2 refresh in alignment with the methodology agreed upon with Ofgem. This will provide clear guidance for investment for Transmission

Owners. Refreshes to the CSNP are determined by external demand (not currently expected).
Progress towards PO not captured by the Success Measure reporting above
No updates for Q3.

Performance Objective	Q3 Status	Prior Status (Q2)
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

We remain on track to deliver our NESO outcome of becoming a digital leader through driving collaborative digitalisation within the whole energy system. This green status is driven by our Data Sharing Infrastructure (DSI) progress, DER/CER re-evaluation and our addressing of stakeholder identified data issues.

During the quarter, we've reached out to stakeholders as part of our now-in-place DSI coordinator leadership structure. We received positive feedback and generated industry interest in participating in its future development.

We've also continued to promote the wider digitalisation agenda in different ways. This included promoting the role of digitalisation in the December Hypercube Energy podcast. In that session, we highlighted the critical importance of digitalisation for effectively managing complex and decentralised energy systems as Great Britain aims for a secure, affordable, and net-zero future. We also highlighted our efforts to transform the energy industry by bridging gaps between power systems engineering and digital delivery. In addition, we shared our ambitious goal for sector-wide data sharing to accelerate safer innovation.

We have begun working on addressing some of the feedback provided in our mid-scheme stakeholder survey as well as other feedback provided through other routes. During this quarter we've focussed on a thorough review of our Data Portal processes specifically looking at areas such as data sharing request responsiveness and data set quality, and we'll continue that focus over the next period.

Finally, we've revisited our DER/CER plans and reprioritised what's important to both ourselves, our other interdependent objectives such as Clean Power 2030 and the wider industry and hope to see significant progress in this area in the coming periods.

Progress on Success Measures this quarter

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

As outlined in Q2, the Sector Digitalisation Plan was published on 1 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.

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 is ongoing. This focusses on two key learnings from the Pilot. Firstly, adoptability which encompasses ensuring lower technical prerequisites, simplicity and a focus on integrations with existing capabilities. Secondly, scalability so that a core capability can be delivered quickly to enable use cases to be built and users can begin to see the benefits of the infrastructure. We have continued to implement our governance structure with our new frameworks now being fully embedded in our programme routines. Supply chain partners are now fully mobilised and participating in our first product increment.
Fully implement the interim Data Sharing Infrastructure (DSI) Coordinator role (subject to consultation outcomes) by the end of 2025. During the quarter, we have recruited our Head of the Data Sharing Infrastructure and the remainder of the team recruitment will be finalised in Q4. On 12 December we ran an industry webinar to around 100 industry stakeholders to present how we are taking on the responsibility to deliver and coordinate the DSI on behalf of the sector. Our feedback score of 4.2/5 demonstrates a good reception from the stakeholders who participated, and more widely we've received positive feedback around our proposed system architecture and legal trust framework. We look to provide value on an ongoing basis, an example of which is our continuing successful collaboration with the National Digital Twin Programme.
Improve the Open Data Portal by increasing the availability of shareable energy data and embedding a more comprehensive data catalogue for greater transparency. During Q3, we have focussed on increasing the amount of open data and improving the functionality of the existing data portal service within the platform. This has been in response to stakeholder feedback around data sharing request responsiveness, rejected requests and transparency, data Point Handling and incomplete or erroneous datasets. Further work will be undertaken during Q4.
Increase distributed energy resources (DER) visibility through improved registration and forecasting. At the end of Q2 we revised the scope of the TIDE project within the BP3 period whilst maintaining the overall goals set out in the original proposal. Immediate focus during this quarter was on: • Developing a conceptual solution to ingest DER/CER information into NESO. • Developing focussed solutions for business areas requiring integration of DER/CER data. • Developing short-term projects and innovation to support the control room to utilise data in future projects.

In the longer term, a TIDE roadmap will be developed to explore a longer term strategy for the implementation of TIDE. This process is already underway and will continue into 2026, with active engagement across the various NESO and external stakeholders to support DER system readiness.
Progress on additional Ofgem expectations
No updates for Q3.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q3.

Performance Objective	Q3 Status	Prior Status (Q2)
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.	Green	Amber

Summary of progress this quarter in delivering this PO outcome

We are now on track to meet the outcome for this Performance Objective. Strong progress across service reforms including continued momentum on auctions, Quick Reserve expansion, and onboarding for Slow Reserve provides a firm foundation for the remainder of the year.

Preparatory work on the Reformed National Pricing (RNP) programme is advancing to plan, and collaboration with DESNZ and Ofgem continues to be constructive as policy design matures.

Early Competition capability is strengthening, with positive regulatory indications supporting readiness for the first qualifying project. With these activities progressing as expected and clear plans in place for Q4, the outturn is forecast to remain positive in achieving stated outcome, with opportunities to consolidate confidence as remaining milestones land.

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%

Q3 Performance:

Constraints: 100% (BP3 target: 100%)

Frequency Response and Reserve: 88.8% (BP3 target: 90%)

Reactive: 4.2% (BP3 target: 5%)

For Q3, 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.

Q3 has seen our activity on RNP ramp up significantly. Specifically on engagement, we have held 23 individual engagement events (either bilateral meetings or workshops) with industry stakeholders across the value chain, getting valuable feedback on all elements of

RNP. This has included consulting our Electricity Markets Advisory Council; a presentation and roundtable at the Scottish Renewables conference; and a workshop with two European TSOs. Once the DESNZ Delivery Plan and our Call for Input are published in Q4, we expect the level of engagement to increase even further.

On Balancing and Dispatch (the NESO-led workstream):

- We have drafted our Call for Input on balancing and dispatch reforms, to be published alongside the DESNZ RNP Delivery Plan. While this was originally planned to be published in 2025, delays to the DESNZ Plan means we will now publish in late-January or early February 2026 (depending on DESNZ).
- We have scoped the analysis needed to be delivered in 2026 to enable a final recommendation and decision to be made on the balancing reforms. This includes Cost Benefit Analyses of the balancing reforms, individually and as a package, as well as assessments on implementation and market impact of the reforms.
- We continue to plan for the implementation of the balancing and dispatch reforms, understanding what it would take for NESO and industry to implement, and the wider impact on industry processes, systems and business models.
- Stakeholder feedback has focused on the 5 proposed balancing reforms – their effectiveness and potential impact on market participants. This has been hugely valuable in shaping our Call for Input drafting.

On Siting and Investment Levers:

- We have been supporting DESNZ, and working with Ofgem, to shape the draft content for the DESNZ Delivery Plan. On policy development, we have focused on creating a risk framework that will enable the RNP programme to understand the scale of risks, and potential mitigations, for each of the packages of levers being proposed.
- We have received stakeholder feedback on the merits of directive vs market-led approaches, and specifically on proposals for network charging reform. We have been bringing this feedback to DESNZ and Ofgem to support their policy development.

On Constraints Management:

- We have established an internal workstream to identify, coordinate and drive forward all NESO initiatives to mitigate constraint volumes and costs. We have supported DESNZ in the drafting of the constraints chapter of the Delivery Plan.

Stakeholders have been speaking to us about ideas for constraint management measures, including prioritising network delivery, forward trading of constraints, and improving transparency of constraint drivers. We are building this feedback into our programme of work, and feeding it back to the wider programme.

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.

Consultations on revised service terms for Dynamic Response, Static FFR and the Demand Flexibility Service (DFS) took place during Q3, and we expect to submit these to Ofgem for formal decisions in Q4. The changes in these services will open up our markets to wider entrants (particularly in SFFR), improve our monitoring and understanding of participants and in the case of the DFS allow us to access demand turn up capability to manage negative margin.

Following our communication last quarter of a delay to the Slow Reserve service, we have published transition plans and are onboarding participants into the new market. We remain on track to deliver Slow Reserve in March 2026.

The reactive mid-term market consultation was published on 9 January 2026 prior to the launch of this market; it invites the market to review the draft documents published on our website and provide any feedback by 4 February 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 (see the final section for an update on demand-side flexibility workstream).

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.

The next Gas Advisory Council (GAC_05) meeting will be held at IGEM House on 29 January 2026, where we will continue to engage effectively with relevant Market Participants.

The GAC has mobilised three NESO-led projects to help inform the Future Market Plan (FMP):

1. Future subsidy support for biomethane post-2030
2. Hydrogen blending at transmission and distribution levels

3. Gas storage – focus here for GAC is feeding into the opening DESNZ consultation Gas system in transition which closes 18 February 2026.

In each of these areas, we are closely aligned with DESNZ to ensure that, while the GAC remains independent, it operates effectively within the DESNZ policy framework.

Regarding the Future Market Plan (FMP), in consultation with relevant Market Participants (GAC), including DESNZ and NESO colleagues, we have identified several key central challenges that are being developed. Each of these will have detailed sub-sections.

1. Consumers and Costs
2. Secure resilient supply
3. Whole system and new vectors
4. European and International Developments
5. Manage gas network changes

Regular bilateral meetings with key stakeholders, both internally across NESO gas teams and externally, have been established to continue to develop these central challenges. The FMP will be published by July 2026.

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 in July 2025, offering an independent view of cross-vector market interactions and opportunities for greater coordination. The summary report has identified three key focus areas with 11 opportunities for improvements.

The team's work is now focusing on gas and energy costs/bills, reflecting themes across the 11 opportunities, to inform other NESO workstreams (e.g. RNP, FMP) rather than further Whole Energy Market Strategy (WEMS)-specific publications.

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 Code Administrator function has continued to progress a higher than usual number of workgroups and Code Modification Panels in Q3. In 2025 a total of 30 CUSC Panels were held, as opposed to the usual 12, to deal with industry demand and increased numbers of modifications, particularly those raised on an urgent basis. As of 31 December 2025, there are currently 44 live modifications across the Codes that we administer.

Several urgent modifications have been approved by the Authority. CMP448, an urgent modification which introduces a Progression Commitment Fee designed to incentivise correct behaviours within the reformed connections queue, was successfully submitted to Ofgem and a decision of approval was received in December 2025. GC0183, which obligates 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, was progressed on an urgent timescale and approved by the Authority in November 2025. CMP447, which sought the removal of designated strategic works from cancellation charges/securitisation was also progressed on an urgent basis and approved by the Authority in January 2026.

We have continued to raise and progress high priority CUSC and Grid Code Modifications, throughout Q3. These urgent modifications have resulted in a high number of workgroups, as well as a sharp increase in the expected number of Code Panels, in particular for CUSC, as mentioned above.

We have continued to work with modification proposers, code panels, and broader industry to ensure that modification proposals are robust and fit for purpose.

We have been working closely with the newly appointed Independent Code Panel Chair since September 2025 and look forward to continuing supporting the new chair in role during 2026. We have also taken over the chairing of CACOP for 2026 and look forward to collaboratively working with other Code Bodies during this tenure.

Finally, we have been proactively engaging with Ofgem and Industry on Energy Code Reform, submitting comprehensive responses to the consultations issued throughout the Q3 period.

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.

Ofgem's consultation on their forward work programme for 2026/27 includes 'Finalise and introduce a pipeline of projects under the Competitively Appointed Transmission Owner (CATO)….'

With the confirmation that the transitional Centralised Strategic Plan refresh is due to be published in June 2026, Network Competition is working closely with the Electricity Network Strategy optimisation team to select the first project and the subsequent pipeline of projects. This will be a key focus through Q4 and throughout 2026.

There was a high level of engagement with potential investors this quarter, including joint presentations from Ofgem/NESO on the CATO model in Japan and South Korea.

Over the period, there has been intensive support to Ofgem to assist with their drafting of the CATO framework licence. Ofgem have confirmed that they are now able to publish the CATO licence for consultation in early 2026. Supporting Ofgem has been invaluable as it has identified what needs to be aligned and updated for the tender processes so that

NESO can run the tender for the first project. For example, the evaluation criteria to be applied to the bids has been reviewed and updated.

Further upskilling was also completed with a Power Systems Engineer and a Planning and Consenting Specialist joining the team.

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 a carefully designed customer readiness programme, including 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 a record high volume of applications for both regimes and during the application window period over 1000 customer queries were answered effectively and in a timely manner.

For CfD Allocation Round 7 (AR7), prequalification assessment and Tier One and Tier Two dispute were completed by December. The auctions are on track to take place in January 2026. For CM 2025, we completed the prequalification assessment and Tier One dispute and published the results on our website in December. We are on track to run the auctions in February and March.

In Q3, we also worked closely with DESNZ to support the development of CM and CfD regulatory changes for CM 2026 and AR8 to ensure that the regimes remain fit for purpose. Some of our suggestions have fed into DESNZ CM and CfD consultations documents.

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

Since the launch of the Clean Flexibility Roadmap (CFR) in July 2025, we consolidated all our actions related to flexibility in our markets in our Enabling Demand Side Flexibility programme. In December 2025, we published an update on progress against all the different workstreams, including delivery of the first CFR actions, publication of DSF volumes in NESO markets and progress in our Routes to Markets project, which is focussed on removing barriers to demand-side flexibility in our markets. The first CFR actions related to the establishment of a NESO team and targets for I&C flexibility in our markets. Additionally, we are also working with the RNP team to ensure that consideration for growing and utilising flexibility is included in the wider market reforms being assessed.

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. In Q3 we spent time reviewing and revising the Market Design Framework (MDF) to ensure that it reflects NESO's new statutory duties as well as ensuring that it is still useful and relevant for the development of new market services. Now that we have the revision approved and rolled out within NESO, we will reflect on our development of market reforms to date against the MDF. We will undertake a full review of our services against the MDF in Q1 2026/27. **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 engaged regularly with Elexon in the lead-up to their publication of the Flexibility Market Rules and the Delivery Plan. We believe that some of our feedback was taken onboard with regard to prioritisation of the different proposed actions. Now that the delivery plan has been published, we will continue to engage with the Market Facilitator through working groups, the advisory board and regular bilateral meetings. **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 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. In addition, we have continued to engage with industry through the C9 Annual Review process. We continue to provide forums for discussion, socialisation and identification of modifications via the Transmission Charging Methodologies Forum and CUSC Issues Standing Group (TCMF and CISG), as well as its counterpart on Grid Code, the Grid Code Development Forum (GCDF). **C9 Annual Review:** The C9 annual review is a process conducted by NESO to ensure that the C9 statements, which are part of the Electricity System Operator Licence, remain current and accurate. This review involves an annual consultation process where we seek industry views on proposed changes to the statements. The review aims to ensure that the statements reflect the latest developments in balancing services and other relevant areas. The Annual C9 Review is underway, and an industry webinar took place on 13 November 2025. An informal consultation launched on 18 November 2025 and closed on 8 December 2025. The industry webinar was well attended, with a peak of around 25 external attendees. The webinar included an overview of the C9 NESO Licence requirement and associated change

process; a summary of the early changes proposed within the C9 informal consultation and detail on how industry can engage with the consultation process. We took questions in the session and subsequently published a Q&A document on our website with responses to all the questions raised.

The informal consultation received responses from three industry participants, all of whom broadly support the majority of the updates to all statements. Comments focussed namely on areas of further clarity on data and use of services, definitions, and increased transparency on the range of tools NESO uses to manage the system. This feedback is being reviewed to inform further changes to the statements, consulted on in the formal consultation, expected to be published on 9 January.

Code Changes – Commercial
We have proactively supported the identification of industry changes and progressed industry change. CMP448, which introduces a Progression Commitment Fee designed to incentivise correct behaviours within the reformed connections queue, was progressed by NESO on an urgent basis following an industry call for input and received a decision from Ofgem to approve the Original Proposal on 8 December 2025. The modification was now successfully implemented into the CUSC on 2 January 2026. Similarly, CMP447, which seeks to remove the remaining strategic TO works from the list of works that new connections need to securitise, was progressed by NESO on an urgent basis following industry engagement. Ofgem approved the original proposal on 7 January 2026.

We continue to seek industry feedback on BSC Modification P462, which aims to reduce consumer costs caused by interactions between CfDs and the Balancing Mechanism that distort bid prices. On 23 December 2025, Elexon issued a mini consultation on the draft Cost Benefit Analysis (CBA) report for P462, prepared by CEPA. This engagement approach allows Workgroup members to review and comment on the CBA ahead of a dedicated discussion. Their input will help shape the modification and ensure industry views are fully considered.

We have been collaborating with Ofgem and DESNZ to develop the scope and associated governance needed to enable timely and efficient connections for demand projects. This programme builds on the TMO4+ reforms, and a range of options to facilitate efficient code changes and targeted demand reforms are being explored.

We undertook a BSC audit in November 2025, covering our role as meter registrant and the associated BSC requirements. The audit conclusion, provided in January 2026, confirmed that no issues were found in the BSC processes tested (FY25/26). Positive feedback was received from both KPMG (the auditor) and Elexon, demonstrating the robustness of our business processes and procedures in ensuring compliance with BSC requirements.

NESO have continued to deliver changes needed for the Market-Wide Half Hourly Settlements (MHHS) programme. NESO delivery has remained on track, with NESO ensuring that we have not been the cause of any delays in the wider MHHS industry programme.

Code Changes – Technical
We have continued to raise and progress high priority technical Code Modifications. In October 2025, Ofgem approved an urgent modification which requires 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. We have recently raised several STC Modifications, including a minor change to due dates for monthly payments to TOs (CM0104) and standardisation of power flow metering polarity (CM0105). In December 2025, we raised two SQSS modifications on System Access Reform, which aligns with the Transmission Acceleration Action Plan aiming to modernise transmission access planning. Our Grid Code Development Forum (GCDF) continues to generate good engagement on potential Grid Code modifications, helping to identify stakeholder impacts at early stages. Technical requirements for large demand were discussed in November 2025; we are setting up an expert group to develop proposals, which begins in late January 2026. We also gave presentations on the transition from Mandatory Frequency Response (MFR) to Dynamic Regulation (DR) at GCDF and TCMF, and are following up with interested stakeholders.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q3.

Performance Objective	Q3 Status	Prior Status (Q2)
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.		
Summary of progress this quarter in delivering this PO outcome		
We remain on track to improve whole energy system emergency preparedness and resilience. This is evidenced through our key contribution to the UK's Energy Resilience Strategy, announced in November 2025, including many of the learnings gathered through our involvement in the North Hyde investigation. The strategy outlines NESO's twelve recommendations on areas such as infrastructure resilience, response, and critical infrastructure protection, ensuring a secure transition to net-zero. We have made notable progress towards meeting the Electricity System Restoration Standard (ESRS) which includes positive acknowledgement from Ofgem that the prioritised activities to achieve the Standard are acceptable, as depicted in the previous Assurance Framework report. The delivery of "95% capability and arrangements to meet new Electricity System Restoration Standard (ESRS) by December 2026" is currently amber due to timeline risks for some deliverables. The Summer Outlook and Summer Readiness reports were successfully published in April 2025 as planned. The Electricity Capacity Report (ECR) was submitted to DESNZ and Ofgem and the report was published at the end of July 2025, in line with BP3 timelines. Following our publication of the Energy Resilience Assessment in July, work continues with DESNZ to agree prioritisation and ownership of the recommendations. Initial activity to draft and deliver the 2026 ERA has also commenced. The Winter Outlook 2025/26 and Winter Readiness and Preparedness reports were successfully delivered in October 2025, in line with agreed timelines. The Gas Security of Supply Assessment was released to Ofgem and DESNZ on 31 October 2025, in line with agreed timescales and published on 26 November 2025, ahead of the deadline of 1 December 2025.		
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. The overall status of the ESRS Programme is Amber, although we are confident to move to Green by February 2026. The current Amber status, and trend towards Green, are underpinned by the following:		

The ESRS team has identified and prioritised effective strategies to reduce the average time needed to restore 60% of electricity demand per region within 24 hours. These focus on the readiness of restoration contributors and their responsibilities to provide an industry wide preparedness. As a result of extensive collaboration with industry stakeholders, these have been agreed with Ofgem, prioritising those needed to achieve the Standard by December 2026, and those that will sustain and enhance compliance to the Standard beyond 2026. Progress continues to be made on additional initiatives with Distribution Network Operators (DNOs) and CUSC parties, including secondary generators, to improve their preparedness for restoration. Legal text has been proposed on Grid Code changes to ensure obligations for Transmission Owners (TOs) and DNOs, with agreements from those parties to the proposals. Although key projects are on track, there remains an inherent risk to providing confidence to Ofgem that the Standard targets can be achieved. We continue to closely monitor the progress we are making to meet the 60% in 24 hours target. We expect positive consultations responses for the Grid Code modifications and the Assurance Framework by the end of February 2026.
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. The Energy Resilience Assessment (ERA) was released in line with the updated deadline in Q2 (see below). The release workshop took place in-person with Ofgem and DESNZ representatives in Wokingham 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 on time in Q2, and this quarter the Winter Outlook 2025/2026 Report was also published in line with expected timelines (9 October 2025).
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 on time in Q2, and this quarter the Winter Readiness and Preparedness 2025/26 Report was submitted in line with expected timelines (31st October 2025). Together, these reports bolstered public confidence, supported market preparedness, and reinforced NESO's reputation for transparent, credible system-resilience planning.
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. The Gas Security of Supply Assessment was released to Ofgem and DESNZ on 31 October 2025, in line with agreed timescales and published on 26 November 2025, ahead of the deadline on 1 December 2025. By conducting this analysis, we were able to identify emerging risks early and, crucially, in time for mitigations to be put in place. Our assessment shows that a combination of measures will likely be required to mitigate those emerging risks and we will work with government, Ofgem and National Gas Transmission to ensure the timely delivery of the most effective options for consumers.
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. We have received positive feedback from the Panel of Technical experts on the 2025 ECR that we published to the agreed timescales 2025 in Report on the NESO Electricity Capacity Report 2025. Initial work on the 2026 ECR report continues.
Deliver the programme to look at the longer-term resilience of our control operations. In January the Project team will seek the O&R (Operations and Resilience) committees' approval to phase the development of the Outline Business Case (OBC) into two phases, with full completion anticipated by June 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. We have completed the first Energy Risk Assessment (ERA) which included both malicious and non-malicious risks. We have discussed various recommendations with Ofgem and DESNZ which will be taken forward for the 2026 ERA. We lead the Sector Threat 360 Community which provides vital insights and connections for those working in threat intelligence roles across the sector. We have issued Hybrid Threat and Insider Threat papers to a cross section of industry and set up workshops to discuss the findings. We also share weekly updates internally. Post event and post-emergency analysis have included the investigation into North Hyde power station and the Technical Assessment into the Iberian event which were both well received by stakeholders. The North Hyde review had a significant system-wide impact on the energy industry. It elevated NESO's authority and reputation, demonstrating its capability as an independent system operator and strengthening confidence across government, regulators and industry. The review drove coordinated resilience actions across NESO, Ofgem and government, creating momentum behind improvements in how the sector prepares for, responds to and mitigates major incidents. Other key reports are also in progress including Storm Darragh and Reactive Power. We have built the capabilities to address Threat Intelligence, Risk Management and Horizon Scanning and assess malicious and non-malicious events. **Provide the Emergency Processes Assessment to Ofgem and DESNZ by 1 December in line with our licence obligation.** The EPA was submitted to Ofgem and DESNZ in November. This first-of-its-kind report focused this year on the emergency processes of the electricity industry in response to an extreme heatwave. Through engagement with industry stakeholders via focus groups, workshops and a survey, we formed a view on current emergency processes and provided recommendations. This report has allowed us to develop our approach and capabilities in partnership with the electricity industry and we will look to include the gas sector and wider stakeholders identified for our 2026 assessment. We will discuss next steps for the findings and recommendations outlined in the report with DESNZ and Ofgem. **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 ECR report has been published and feedback from the Panel of Technical experts has been positive.

The resource adequacy study for the 2030s was published in July. Feedback from Ofgem has been positive including comments that this was a step beyond what is normally expected and praise for NESO exploring new work streams, such as strategic reserve and cap and flow mechanisms, and for providing independent advice to government.
Progress towards PO not captured by the Success Measure reporting above
NESO is establishing itself as a technical expert this area. There is great progress in educating and delivering timely threat advice to the sector. We have reviewed and enhanced the CNI methodology, which was recognised as best practice by the Cabinet Office. We have identified single points of failure in the energy network, leading to a Secretary of State commission to address these vulnerabilities including the scoping and coordinating of this work. In addition to license conditions, we actively support industry forums, leadership in supply chain security strategy, and engagement with international partners such as NATO and the European Commission to share best practice and build global networks. We have developed the Space Weather Industry Protocol and implemented the Grid Code Modification GC0183 to manage severe solar events affecting the electricity grid, requiring generators and interconnectors to notify NESO of their operational status to ensure stability and prevent outages. This initiative, supported by industry and regulators, creates mandatory procedures for operators to share real-time data during space weather warnings, moving beyond voluntary guidelines to ensure system resilience during solar storms.

Performance Objective	Q3 Status	Prior Status (Q2)
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	Green	Amber

Summary of progress this quarter in delivering this PO outcome

We continue to operate the electricity system safely and efficiently and have developed the capability to enable secure zero-carbon operation of the system. We are on track to meet the outcome associated with this Performance Objective.

We identified a window of potential zero-carbon operation during October-December. Although this opportunity did not materialise (due to system operating conditions and the mix of plant delivered by the market), the existence of this window demonstrates that we have developed the capability to manage a single settlement period. Further evidence of this can be seen with increasingly longer periods of low carbon operation – we have succeeded in running at above 90% zero carbon for over 15.5 hours in 2025.

Across the remaining Success Measures linked to this Performance Objective, the Balancing Programme is largely meeting our planned BP3 commitments, and the Dispatch Transparency Programme roadmap is progressing as scheduled, with skip rates decreasing by over 10 percentage points across 2025. Additionally, our balancing costs strategy has delivered savings across key initiatives during BP3 (£445m over the period April-November 2025), and we continue to enhance our understanding and accessibility of costs while actively exploring options for further reduction.

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, as marked by the existence of a potential window of Zero Carbon Operability (ZCO) between October-December 2025. It should be noted that while our ability to operate a ZCO settlement period is no longer dependent on progress to lower inertia through the Frequency Risk and Control Report (FRCR) project, the implementation of a lower minimum inertia level 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 as the information above references and revised our metrics.

In Q3, the highest ZCO period was 96.96% (CP30 definition). Please see the Reported Metrics section of this report for more information related the Zero Carbon Operability and NESO Carbon Intensity metrics. Further evidence of the developed NESO capability to operate for ever increasing periods of low carbon operation were seen in May 2025 – where the electricity transmission system operated at above 90% zero carbon for 15.5 hours and above 85% zero carbon for 33.5 hours. Enabling this level of low carbon operating – leading to ZCO within NESO's operations has been a cumulative build since our original ambition was launched in 2019. Changes to how stability services are used and procured alongside frequency management processes and services have enabled NESO to develop this ability.
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 and explore options to reduce balancing costs. The Balancing Cost Strategy was successfully published on 12 June 2025 along with the Balancing Costs Report. We are also currently working closely with DESNZ and Ofgem to develop a targeted strategy for constraint management and expect to share more information on this later this quarter. Further details on balancing costs are available in the previous Incentives report, including information on delivered balancing cost savings during the BP3 period. Between April-November 2025 we have calculated that NESO has delivered £445m in savings across key balancing cost initiatives. This include £109m from Network Services, £169 from trading actions, and £146m from reduced inertia requirements under FRCR. Further savings have also been delivered through DFS and Balancing Reserve. In Q3, balancing costs totalled £827m. 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. There is a downward trend for skip rates since September with rates at the lowest in December over the whole year, lowering by >10% since the start of 2025. We still see variation in the skip rate across different technology types and validating reasons for this. We continue to progress our root cause analysis work to identify causal factors and have used results of this to shape our initial target proposals, the latter being shared with industry through January 2026 engagement events. Implementation activities continue to plan for Grid Code modification GC0166 (introduction of dynamic parameters for state of energy for limited duration assets) and aligned with industry and EDL/EDT service providers. Implementation of this code modification will allow better utilisation of limited duration assets, particularly in commitment timescales (where long notice units need to be instructed). Development of a methodology for skip rates behind constraints is also on track having shared initial approach with industry and will share more detailed approach at upcoming January forum. Skip rate materiality analysis and associated assurance is complete. Results are being shared with industry through in-person engagements in January.
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. In Q3, in line with our roadmap we have delivered a key digital enabler and have cutover from a resilient platform to high availability and high resilience platform. The National Dispatch Optimisation (NDO) capability has been delivered and now enters a period of operational testing in parallel with the BM Dispatch Advice algorithm. In addition, OBP Instruction capabilities for Wind, and Bulk dispatch from Price Stack in OBP have been delivered. Dynamic Response will be delivered in two releases across Q4. Additional scope including a new Demand Forecast Model within PEF is on track for completion in Q4. Following customer feedback and a comprehensive review of all EDT/EDL sites, the industry and the ENCC requested that the network change should also enhance the resilience of the existing network design. To ensure a smooth transition, we have moved delivery of the EDT/EDL transition from Q4 FY26 to Q1 FY27 to allow time for the necessary network changes, testing and training. We held our November Balancing Programme event where we had 101 attendees, with positive feedback and an overall event score of 8.6 which was our highest score to date. Material for the event can be found here.
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 published our Forecasting Strategy consultation In November, which was slightly delayed due to internal governance. In line with that, we are now targeting the end of March for implementation. We still continue 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. Enhanced features for the wind forecast model have now been developed, and we expect to release them to production in Q4 2025-26. A working next-generation National Demand forecast model is now in place and we anticipate it's release to production in Q4 2025-26. We have also successfully trialled the benefits of consuming commercial forecasts from external vendors and expect to procure a strategic partner in Q1 2026-27. Formal engagement with the Met Office has taken place, with an aim to enhance future weather forecasts that are pertinent to the Electricity Supply Industry, with the objective to improve future energy forecasts.
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 October – December. There were no voltage excursions in October – December.
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 Q3.

Performance Objective	Q3 Status	Prior Status (Q2)
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.	Amber	Red

Summary of progress this quarter in delivering this PO outcome

The overall status of the PO has moved from Red to Amber.

We have delivered and implemented the required activities that drive towards the overall completion of the connections reform performance objective within BP3, although the overall outcome will be delayed as some items have not met the original ambitious timeline. We have successfully published a reformed queue that is smaller and composed of viable projects, aligning with the correct technologies and wider CP30 targets. While we acknowledge that some of the individual success measures will not be met within BP3, we have delivered on reforming the overall queue and will build on this over the next two years.

During the last quarter, Connections Reform has been working on the queue formation phase of the programme. In early December, we achieved a significant milestone by publishing and confirming a new pipeline of deliverable, shovel-ready energy projects that will be prioritised for connection to the electricity networks, unlocking £40 billion in clean investment annually and driving progress towards the government's Clean Power by 2030 target.

In BP3, we estimated that the queue would reduce from 750 GW to approximately 200–250 GW by the end of December 2025. The new queue is now 283 GW of generation and 100 GW of demand.

The queue formation exercise was subject to significant levels of assurance to ensure wider industry confidence in the reformed queue. This has been supported through feedback following the issuing of notifications to customers and the lower than anticipated levels of queries and complaints.

We recognise the impact on the wider industry and that the results of the queue will likely cause disappointment in the short term, noting that this is a once-in-a-generation reform. We are prepared for this and have strengthened our customer handling capability as we continue to work with stakeholders through webinars, Independent Stakeholder Group meetings, the Connections Portal, and Customer Support. This will continue for future windows.

The queue formation, which has now been delivered, was the key element of this performance objective to enable ready and strategically aligned projects to connect in time for 2030. The following phases, led by the transmission owners, will deliver connection offers which will enable projects to connect in a timely and coordinated fashion through the engineering of the networks.

While risks around future connection offer dates persist, particularly for BESS projects, collaborative engagement with Transmission Owners, Ofgem, DESNZ, and wider industry partners continues to drive progress. Through rigorous assurance and review activities, we remain committed to learning from recent experience and ensuring the reforms lay a strong foundation for the future of the energy network.

The Connections Portal continues to be developed in an agile manner to drive improvements and efficiency, and to deliver an improved user experience. We aim to have a much-improved portal for the next window, Horizon 2, which is expected to open between April and July 2026, although this is still to be confirmed.

As the connections queue has been published, the challenges experienced during the submission window have been addressed, key learnings have been made and the timelines for the programme have been revised (see success measure for revised and previous dates).

Progress on Success Measures this quarter

Note: Re-baselined dates have been reflected across the Success Measures with a view of original BP3 date shown in brackets for reference.

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

We have released the results of the queue formation phase. The initial group of protected projects, scheduled for grid connection in 2026 and 2027, have begun to receive formal offers confirming their connection dates. These offers are being issued throughout December and into the early part of the new year. The remaining connection offers are expected to be finalised by the third quarter of next year, providing greater clarity and certainty for all stakeholders involved.

Thousands of projects, ranging from wind and solar farms to battery storage and hydrogen, will learn whether they are included in the 283 GW of generation and storage capacity and 99 GW of transmission-connected demand.

This defined set of deliverable projects will form a new pipeline as the system transitions from a first-come, first-served model to one that prioritises projects ready to meet Great Britain’s energy and economic needs.

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.

We anticipate a high volume of strong customer reactions in relation to the results and have developed a public-facing communications strategy accordingly.

We are also developing a customer handling strategy to minimise reputational risks arising from the potentially high volume of queries and complaints that we may receive.

Customers were notified at the beginning of December of their Gate 1 or Gate 2 status, and whether they are required pre-end 2030 or post-2030 (as determined by strategic alignment to CP30). Our strategy to minimise and respond effectively to complaints centres on providing clarity and transparency regarding the reasons for specific project outcomes within the context of the overall results, for example, by comparing the connection application dates of projects in Gate 2 with those in Gate 1. Feedback from the industry on this process has been positive, particularly regarding query and complaint handling around the queue formation exercise, with timely, complete responses and strong engagement throughout the complaints process.
By September 2026 [was 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. Connections Reform continues to be a significant and complex undertaking, with substantial efforts being made by all stakeholders to address challenges proactively and to deliver robust outcomes. In early December, we successfully published the queue formation outcome, marking a significant milestone that required comprehensive and nuanced handling. The volume of projects moving to Gate 1 is in line with expectations, including unprotected batteries, onshore wind in Scotland, and solar in the south of England (not strategically aligned).
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 is ongoing with DESNZ and we are working to understand what can be delivered ahead of April 2026, which will feed into the integration of the Industrial Strategy. From January 2026, joint governance and project management (DESNZ & Ofgem) will be established as the programme moves into the delivery phase of strategic demand.
Invest further into a fully customer-centric Connections Portal. Issues experienced during the submission window were largely related to data and have now been resolved. As a result of the queue reformation, approximately 1,500 emails have been sent to customers from the portal. Work has commenced to determine how best to optimise the portal to support the next application window. Work and investment continue in developing and building a state-of-the-art portal that incorporates the lessons and insights gained from the submission window and queue reformation stages of the programme.

Progress on additional Ofgem expectations
No updates for Q3.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q3.

Performance Objective	Q3 Status	Prior Status (Q2)
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

We remain on track to deliver our NESO actions in line with the Clean Power 2030 Action Plan as we continue to position ourselves as a credible, independent expert working closely with stakeholders to enable and support wider CP30 delivery.

We've continued to widen our influence by introducing new stakeholder touch points via our stakeholder engagement team and utilising the benefits generated via our new relaunched customer framework. We recognise that our September 2025 survey score highlighted areas of concern from our customers and have begun work to put in place structures that will enable us to respond to our stakeholders needs working cross functionality with our interdependent performance objectives in particular Connections Reform and Sector Digitalisation.

We also continue to develop a wider horizon scanning capability to identify risks and opportunities to track 2030 targets and ultimately our national net zero ambitions.

We've also made great progress on the expectations set out by Ofgem in their final BP3 Final Determinations. Following on from the publication of our LDES methodology in Q2, we've acknowledged customer feedback on a few issues and moved forward with our first set of assessments which should be ready for ranking early in the next period.

We recognise that there are still many risks around wider CP30 delivery, notably sufficient new renewable generation in the coming years, the pace of Network delivery, the future of Connections Reform and the pace of demand side project implementation within the sector as a whole but remain confident that these can be overcome by continuing to work effectively with DESNZ and our other stakeholders across industry and beyond.

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. Following a transitional period during the previous quarter, significant senior engagement with DESNZ through COO and CEO now exists and is working well. There is still some clarification required from a NESO perspective on how both parties wish to engage on an ongoing basis and this will be addressed during the next quarter.
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. A stakeholder lead is now in place and our agreed methodology is now being rolled out in conjunction with the new customer framework. The process of building engagement has begun to take shape through a mixture of new forums and utilising existing working groups such as the SSEP industry group and Markets forum. Utilising our new stakeholder lead, we've also begun to plan more specific interactions which will ramp up as we enter Q4. Finally, we've begun to look at our Customer Survey results and look to address our feedback. The nature of CP30 is complex with numerous interdependencies with other Performance Objectives and our initial efforts have centred on understanding these before we develop a plan in Q4.
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. Following the standing up of the project team in Q2, we have spent Q3 coordinating with Transmission Operators to procure the data required to maximise the value of the plan. During December, we received data which will enable us to move forward to produce the plan during Q4. This was the first time a set of standardised data had been agreed upon and will form the basis of future iterations of this analysis. The coordination is a demonstration of our commitment to acting as a leader within the CP30 space. However, the volume of data received was lower than anticipated and the final plan will therefore not be as robust as it could have been. This will likely impact the speed to which ongoing system access issues can be addressed and resolved. Further iterations of the plan will need to address this going forward.
Publish the updated Operability Strategy Report in December 2025 incorporating the full detail of the Clean Power Action Plan. As reported in the previous period, we 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 was agreed during Q3 and the report is on track to be published in the next 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. As reported previously, the dataset is now fully live and will ultimately feed into the dashboard referred to in the next milestone.
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. During the period, we have continued to develop the dashboard as a proof of concept, and this has now been signed off internally. The complexity and variety of data sources is a risk that has had to be managed during the period although is not considered a significant risk. During Q4, we will look to completing the dashboard and utilising the insight it provides to identify risks and unlock potential opportunities in the CP30 programme.
Progress on additional Ofgem expectations
Long Duration Energy Storage - establishment of capabilities to support cost-benefit analysis work Following on from the publication of our methodology in late September, we received a number of questions and clarification points that we acknowledged when we published our clarification log on 18 November. This contains over 200 points further clarifying or recognising the need to clarify parts of the methodology. We consider the process and output to have been well designed and no significant negative reaction from stakeholders is a justification of that. During this quarter we have run the first batch of 73 applications in the first scenario. This has involved extensive data modelling and optimisation with analysis of the results. This will be combined with other analyses to complete the full CBA which will be released on the 16 January, at which point projects will be ranked. Work on scenario 2 will begin at this point.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q3

Performance Objective	Q3 Status	Prior Status (Q2)
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

We are on track to deliver our outcomes relating to this performance objective.

By the end of BP3, we remain confident of delivering 60% of the services will be exited from NG as part of the TSA with the remaining services on track to exit by Sept 2026. Overall Exit of the TSA will provide a suite of systems and processes that will enhance our capabilities, establish our autonomy and full independence and help us to deliver our customers and wider industry needs in the long term.

We remain on track with our TSA exit plans, and are accelerating progress towards full NESO autonomy with our Security Operations Centre and Security Information and Event Management capabilities continuing to be implemented in the quarter. We've also made great progress in our Network cutover programme, focussing on ensuring our employees are able to continue their work supporting NESOs other priorities uninterrupted. Our Application migration continues at pace, and we've initiated our own ServiceNow platform, a key step in our journey to autonomy. Finally, our Elevate programme continues to move forward in a challenging timescale.

We're also looking at other areas not listed in our success measures. In our BP3 plan, we committed to establishing our Vendor Management Office to enable effective third-party service delivery and performance management and we're making great progress on that journey and will provide a full update in our year end assessment.

Following our mid-scheme survey customer results for this Performance Objective, we're looking at the drivers behind the feedback provided. Where applicable, feedback on the wider role of NESO will be passed on to the relevant NESO directorates for addressing and we will look to focus on any areas relating to our systems and associated processes within this objective in the next quarter.

Progress on Success Measures this quarter

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

As the end of the TSA agreement window approaches, we have focussed on re-baselining our plans during Q3 to make sure we remain on top of any emerging risks. We are on track to deliver the original 60% planned by the end of BP3 and full exit by September 2026.

During the period, considerable strain has been placed on the timeline via the identification of risks and delays for Networks in Foundational Services and the Elevate

Programme However, the risks have been mitigated and minimised via our internal governance and wider project management focus during the period.
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. There have been some minor delays across the Cyber Security plan during the period but these have been mitigated and the NESO requirements for Enhanced Profiling (EP) to achieve parity with National Grid will be met by the end of BP3, with additional advanced profiling completed in Q1 FY27 enabling us to achieve our TSA ambition. The Physical security remains on track for an expected TSA exit in March. This is despite various issues in the quarter, in particular cabling delays which necessitated a critical focus on securing cabling dates and integrator support. In a wider context, we are continuing to develop our organisational capability to support both areas 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** We've made great progress in our Network cutover programme with our Warwick and Wokingham offices transitioning over to the NESO network during the quarter with minimal business interruption. Our C2 and Glasgow office is planned to follow early in Q4 with the focus then moving to the CNI cutover. The delay in network cutover has impacted physical security separation, which is still progressing with the TSA exit expected no later than March. We've also begun our device rollout pilot during December with around 15% of devices now issued, on track to complete 80% by end of Q4. We have done this whilst overcoming several issues earlier in the quarter, notably around DaaS and Managed Print Services which initially were barriers to achieving rollout readiness. Our Application migration continues and is now 65% complete with 85% on track to deliver by the end of BP3. Full migration is now targeted for Q1 FY27 as a result of a delay due to Network cutover issues. This still remains within our overall timescales. We have also initiated our own ServiceNow platform to raise incidents request for devices and apps that have already been migrated to NESO. As we continue to rollout NESO devices, migrate business applications, and launch new corporate applications our users will increasingly use NESO ServiceNow in their day to day. Our focus will now move on launching the NESO Service Desk and new Data Protection controls, alongside increased communications across People, Finance and Procurement on training for new systems and processes.

The NESO Service Desk and Service Now initiatives are important steps in developing our own IT support capabilities and will form the core of our NESO Single Point for Support in the coming years.
Build systems and data for people-related functions, including the implementation of People, Payroll, Finance, and Procurement SaaS platforms. During the quarter we have made steady progress although the overall risk remains high with little or no contingency ahead of the April 2026 Go-Live date. The Elevate (HR and Finance systems) programme successfully completed its system designs, build and functional unit testing across both platforms (Ivalua and Workday) during the period. The majority of cycle 1 testing has been successfully completed during Q3 indicating an acceptable overall quality of platforms and enabling progression to the next stages of testing which will involve focussed activity on critical processes. Additionally, the first productionised capability on Ivalua (procurement platform) has been deployed.
Progress on additional Ofgem expectations
No updates for Q3.
Progress towards PO not captured by the Success Measure reporting above
No updates for Q3.

Reported Metrics

Summary of Reported Metrics

The table below summarises our Reported Metrics for December/Q3 2026:

	Reported Metric	Performance
1	**Balancing Costs**	Dec: **£242m**
2	**Demand Forecasting**	Dec: Forecasting error of **626MW**
3	**Wind Generation Forecasting**	Dec: Forecasting error of **4.39%**
4	**Skip Rates**	Dec: Post System Action (PSA) Offers: **29%** Bids: **37%** Combined: **32%**
5	**Carbon intensity of NESO actions**	Dec: **9.85gCO_2/kWh** of actions taken by NESO
6	**Security of Supply**	Dec: **0** instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. **0** voltage excursion.
7	**CNI Outages**	Dec: **0** planned, **0** unplanned system outages.
8	**Short Notice Changes to Planned Outages**	Q3: (October/November/December) **0** delays or cancellations per 1000 outages due to a NESO process failure.
9	**Zero Carbon Operability Indicator**	Q3: Highest ZCO% of **96.95%** after NESO operational actions, based on the CP30 definition of zero carbon. Using original RIIO-2 definition, the maximum ZCO% was **91.23%.**
10	**Constraints Cost Savings from Collaboration with TOs**	Q3: **£276m**
11	**Day-ahead procurement**	Q3: **94%** balancing services procured at no earlier than the day-ahead stage.
12	**Accuracy of Forecasts for Charge Setting - BSUoS**	Q3: Month ahead BSUoS forecasting accuracy (absolute percentage error) of; October: **11%** November: **6%** December: **7%**

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.

December 2025 performance

Figure: 2025-26 Monthly balancing cost outturn versus benchmark

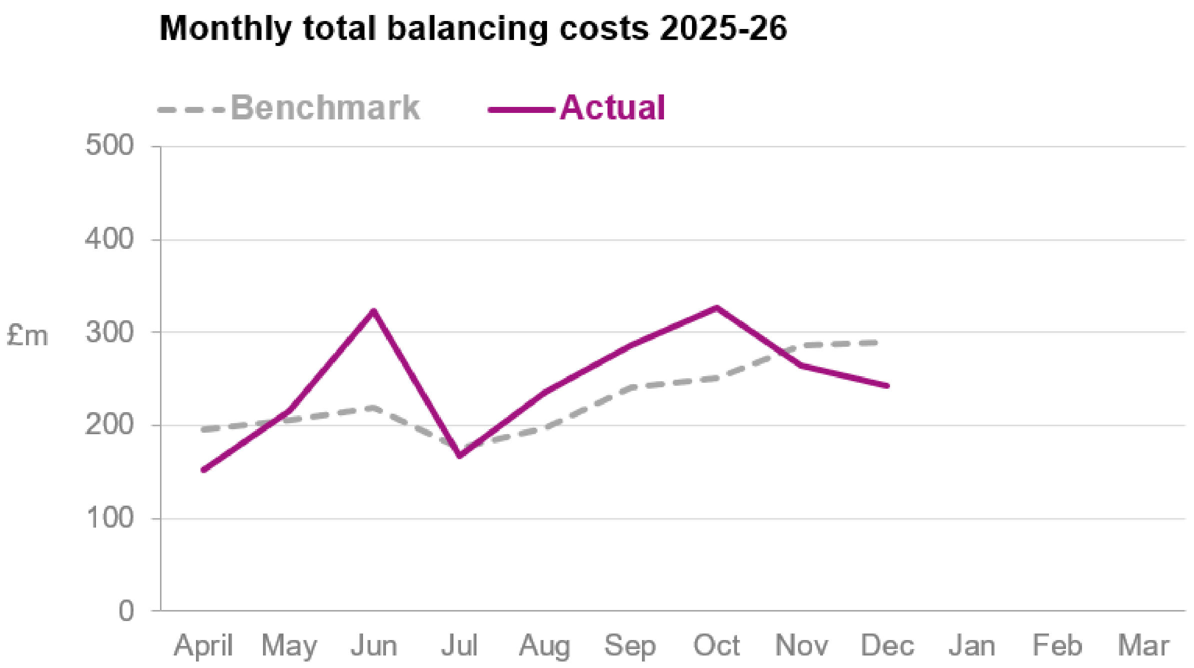


Table: 2025-26 Monthly breakdown of balancing cost benchmark and outturn

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	6.6	7.9	8.3				51.1
Average Day Ahead Baseload (£/MWh)	81	77	73	80	73	72	77	82	75				n/a
Benchmark*	195	206	219	176	197	241	251	286	289				2060
Outturn balancing costs[1]	**152**	**215**	**324**	**167**	**236**	**287**	**326**	**265**	**242**				**2214**

[1] Outturn balancing costs exclude 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

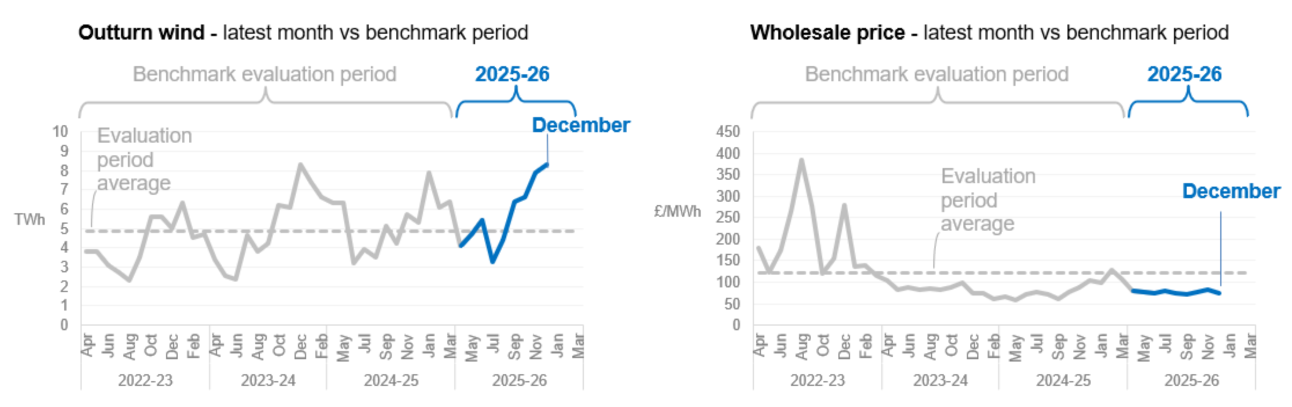
BALANCING COSTS METRIC & PERFORMANCE

This month's benchmark

December's benchmark of £289m is £3m higher than November 2025 and reflects:

- An outturn wind figure of 8.3 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 November 2025's figure (7.9 TWh).
- An average monthly wholesale price (Day Ahead Baseload) that has decreased compared to November 2025 (from £82.0/MWh to £75.4/MWh) and is lower than the same period last year. It falls below the evaluation period average.

Despite the reduction in average monthly wholesale price, an increase in wind outturn has led to a slight increase in the benchmark from November.



Variable	December 2025	November 2025	December 2024
Average Wholesale Price (£/MWh)	**75**	**-7**	**-24**
Total Wind Outturn (TWh)	**8.3**	**+0.4**	**+0.4**
Benchmark (£m)	**289**	**+3**	**-12**

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

Balancing Costs – Overview

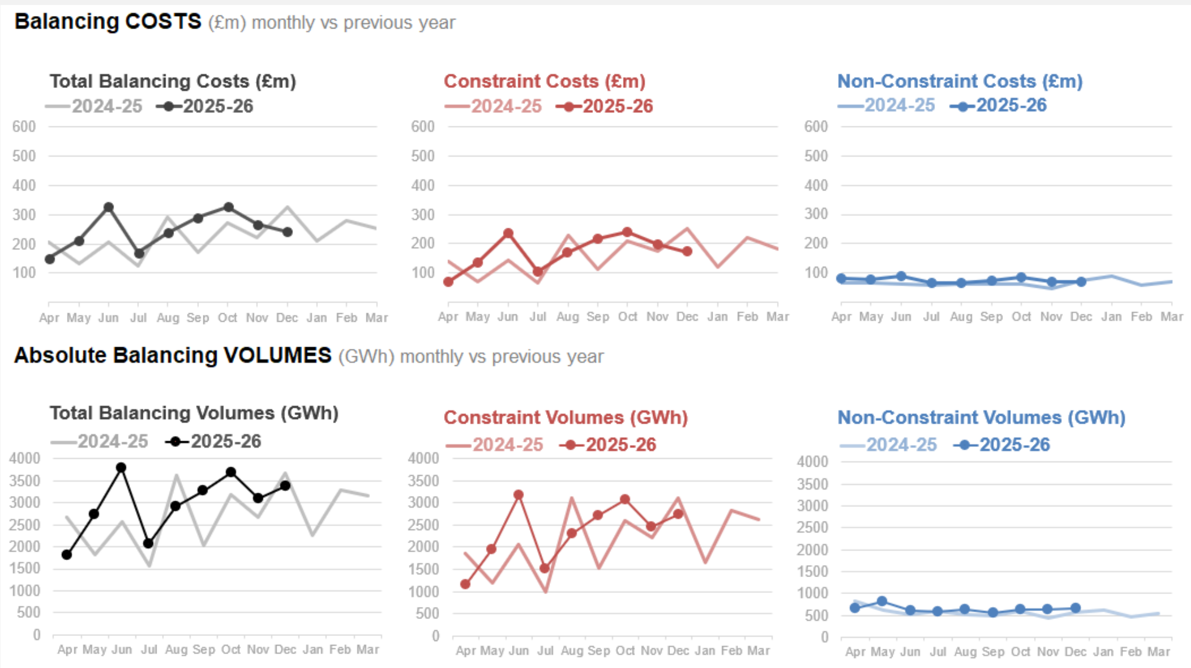
The total balancing cost for December was £241.7m, which is £47m (~16%) below the benchmark.

December saw an increase in wind outturn to 8.3TWh compared to November at 7.9TWh, the highest wind outturn observed so far this year, and the second highest recorded wind outturn. The rise in wind outturn was driven by small increases in outturn for both England & Wales and Scotland. There was one storm during the month, Storm Bram, which led to high wind outturn on the 9 and 10 December, which translated into one of the days of highest wind curtailment on the 10 December. Over the Christmas period, we observed lower balancing costs due to lower wind on the system, reduced outages and reduced demand. Average demand was comparable to November, though slightly higher during daylight hours which allowed for more wind generation to be utilised rather than curtailed, helping to reduce the impact of high wind on overall costs.

Voltage constraint costs have decreased significantly in December partly down to an interconnector returning from full outage along with units self-dispatching, though costs were elevated from December 2024. This is coupled with a slight increase in inertia costs due to an increase in wind outturn.

Non constraint costs have slightly decreased by £1.0m despite a very small increase in the volume of actions compared to November.

Average wholesale prices have decreased by £6.50/MWh in December, largely due to warmer than average temperatures, higher wind outturn and reduced demand in the latter half of the month. The volume weighted average (VWA) price of bids was -£7.2/MWh, which is more expensive than November's price of -£5.4/MWh. This negative bid price reflects that most of the bid actions taken were to curtail wind, with a higher price indicating a higher proportion of bids that were taken for wind curtailment. The VWA price for offers decreased to £106.0/MWh, compared to £132.4/MWh in November, aligning with the fall in wholesale prices.

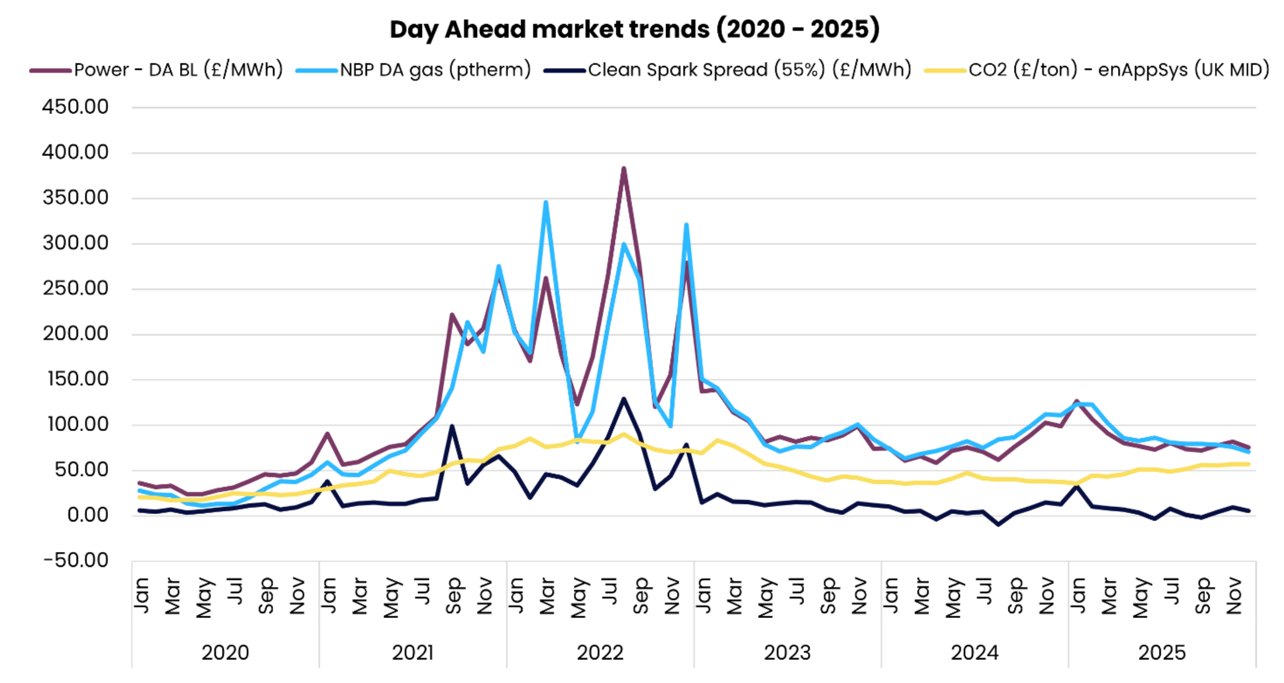


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

Market trends

In December, power and gas prices dropped compared to the previous month, down to £75.37/MWh and 70.93p/therm, with carbon prices also seeing a slight decrease down to £70.89/ton. Market prices were influenced by a variety of factors during December, including warmer than average temperatures, reduced demand over the Christmas period as well as strong wind outturn, especially on the 9 and 10 December due to the effects of Storm Bram.



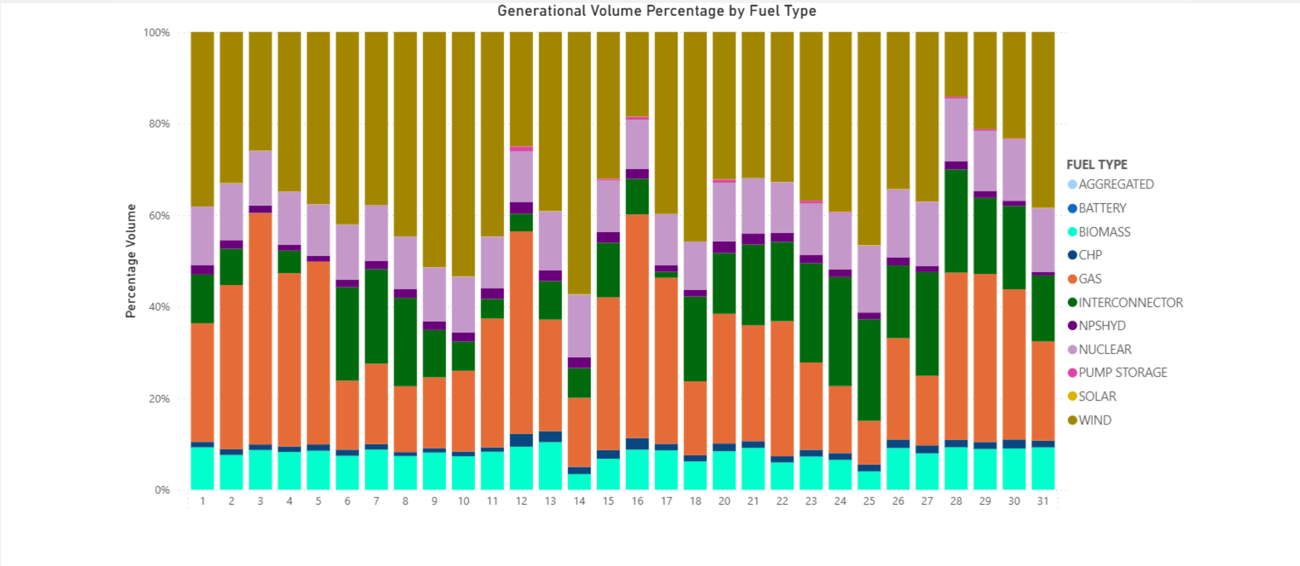
DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Generation Mix

In December, wind was the largest contributor to electricity generation, making up 36% of the total mix, followed by gas, which saw a drop from November down to 28% with interconnectors in third place, rising from 7% in November to 13% in December. This pattern was broadly consistent with November, with wind making up a similar percentage of the generation mix, followed by gas but a higher contribution from interconnection than nuclear.

The chart shows that wind generation was especially strong across the whole month, with only five days where wind generation was less than 25% of the total daily generation, which were the 12, 16, 28, 29 and 30 December.

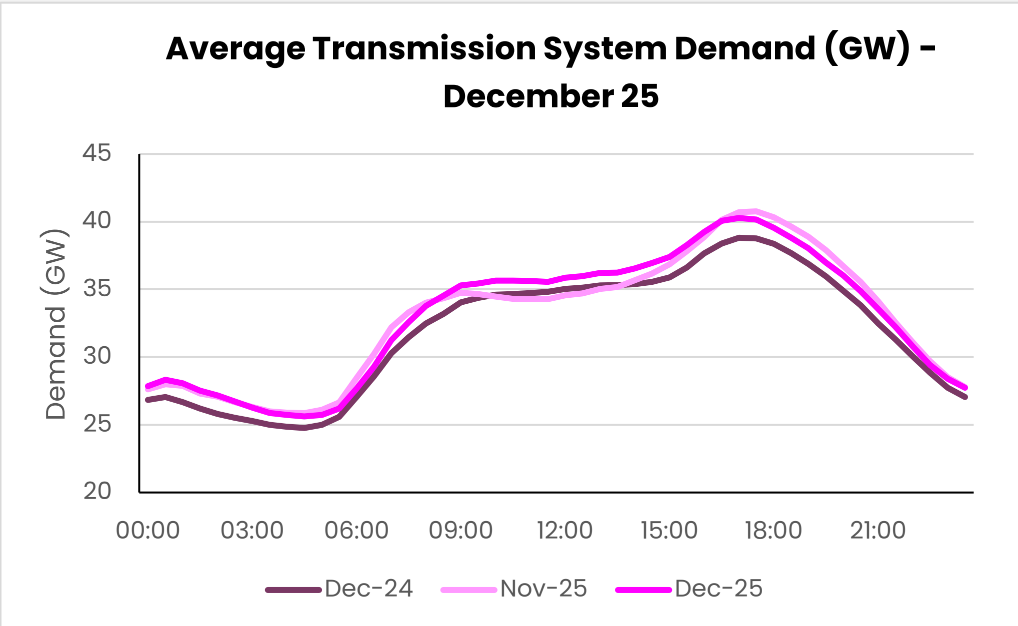
However, we had three days where wind generation was above 50% of total generation which were on the 9, 10 and 14 December, with the highest percentage being on the 14 December at 57%. Also, we saw the highest wind generation recorded in a settlement period on the 5 December at 17:30 with 23,825MW, beating the previous record set in November by over 1GW, despite the 5 December not being the one of the highest days of wind outturn during the month.



*Generation mix includes exports from interconnectors.

Transmission System Demand

In December the average Transmission System Demand (TSD) was in line with November 2025 and slightly elevated on December 2024. This was due to factors including increased hours of darkness, colder weather and lower levels of embedded solar generation. However average TSD during daylight hours was higher than seen in November 2025 and December 2024, despite the warmer than average temperatures seen during the first three weeks of December but was broadly consistent to November in the overnight periods. Economic and market drivers likely also played their part, with lower year-on-year wholesale power prices reducing incentives for demand-side curtailment.

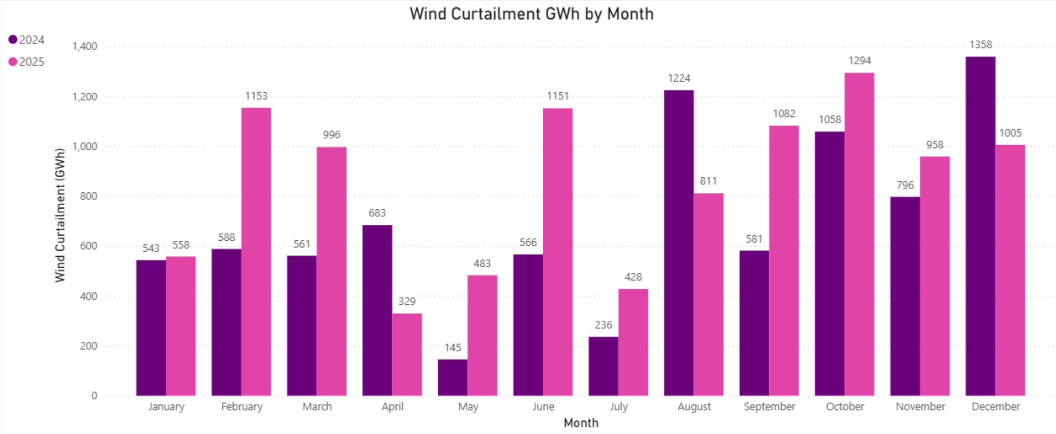


Wind Outturn

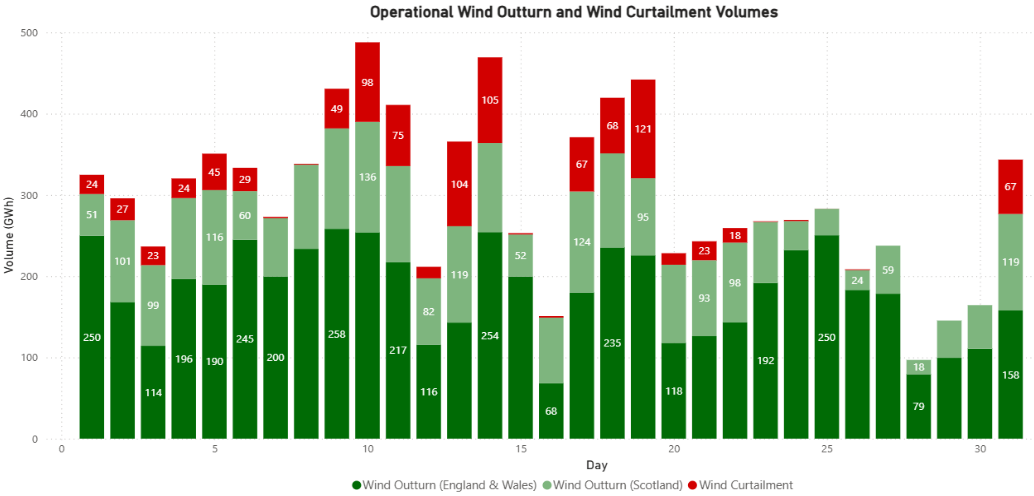
December started off wet and warm with unsettled conditions across the country, leading up to the arrival of Storm Bram on 8 December which heralded strong winds particularly in the western areas of the country. Unsettled conditions continued until 24 December, when temperatures dropped to colder than average.

Overall wind outturn rose from 7.9TWh in November to 8.3 TWh in December (the second highest recorded wind outturn) with a 4.5% increase in England & Wales (from 5.4 TWh to 5.6TWh) and a 3.6% increase in Scotland (from 2.5 TWh to 2.6 TWh) compared to the previous month, giving a 4.1% increase overall.

There was a 4.7% increase in the volume of wind curtailment, which can be associated with a corresponding rise in overall wind outturn. There were variable weather conditions throughout the month, with high wind curtailment mainly being seen in the first half of the month, in contrast to the latter half of December where there were several days over the Christmas period which had very low or no wind curtailment, and reduced outages. The days with the highest volume of wind curtailment were largely in middle of the month; on 19 December (121GWh), 14 December (105GWh), and 13 December (104GWh).



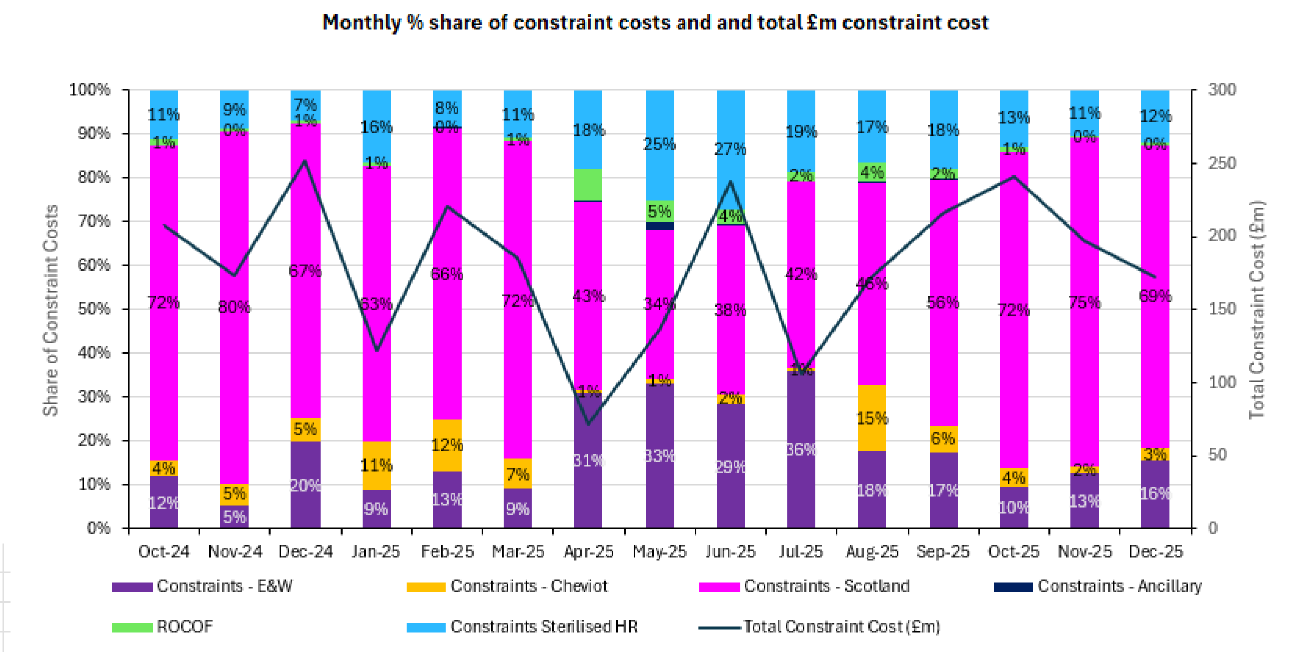
The day with the highest volume of wind curtailment occurred on Friday 19 December with 121 GWh. There was a total wind outturn of 442 GWh on this date, the third-highest outturn of the month. This was also the highest cost day of the month.



Constraints

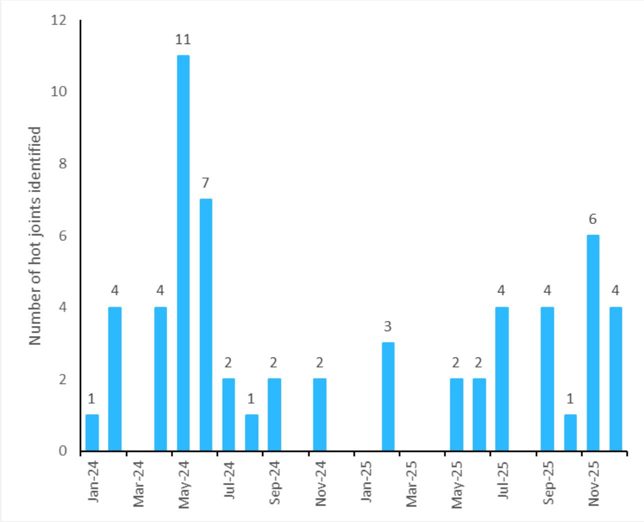
Constraint costs decreased from £196.8m in November to £172.7m in December, a decrease of £24.1m. England and Wales saw a small increase in constraint costs of £2.2m, along with Cheviot which saw a small increase of £1.5m. Most other areas saw a decrease with the most significant being Scotland with a £27.9m reduction in cost compared to November.

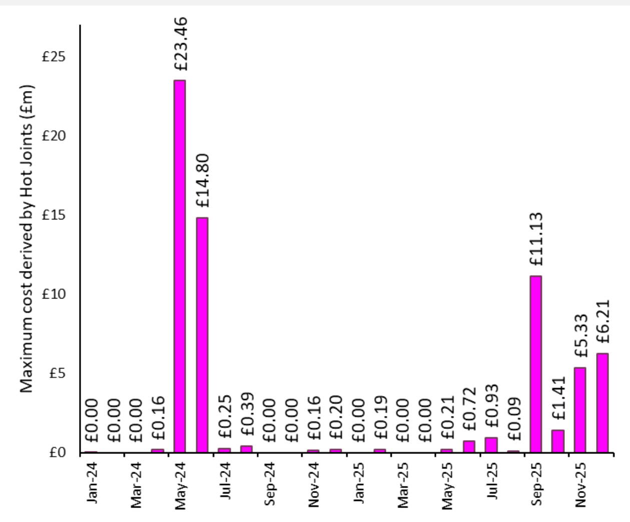
Wind levels across England & Wales and Scotland increased slightly in December corresponding with an increase in wind curtailment. However there was also an increase in demand during the daylight hours, as well as a reduction in power prices and no new planned Scottish outages which helped lower the cost of managing constraints.



Network Availability

Hot joints refer to transmission equipment that tends to overheat during normal operational conditions. Transmission Owners are responsible for notifying NESO of any service reductions associated with this equipment. Hot joints in the system have both operational and economic impacts. In December, four hot joints were identified: two in West-Midlands (Bushbury, Ironbridge), one in East Anglia (Rayleigh) and one on the North-East (Drax). The estimated maximum cost to the system for these hot joints was approximately £6.2 million.





BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): December 2025 vs November 2025

		(a) Nov-25	(b) Dec-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-4.6	0.6	5.1	
	Operating Reserve	5.9	10.6	4.8	
	STOR	4.8	4.5	(0.2)	
	Negative Reserve	1.7	1.1	(0.6)	
	Fast Reserve	15.3	15.8	0.4	
	Response	22.9	19.5	(3.4)	
	Other Reserve	1.6	1.5	(0.2)	
	Reactive	11.9	12.1	0.2	
	Restoration	4.0	4.1	0.1	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	6.5	-0.7	(7.1)	
Constraint Costs	Constraints - E&W	25.0	27.2	2.2	
	Constraints - Cheviot	3.2	4.6	1.5	
	Constraints - Scotland	147.2	119.3	(27.9)	
	Constraints - Ancillary	0.4	0.2	(0.2)	
	ROCOF	0.3	0.7	0.4	
	Constraints Sterilised HR	20.7	20.7	(0.0)	
Totals	Non-Constraint Costs - TOTAL	70.0	69.0	(1.0)	
	Constraint Costs - TOTAL	196.8	172.7	(24.1)	
	Total Balancing Costs	**266.8**	**241.7**	**(25.1)**	

As shown in the totals from the table above, constraint costs decreased by £24.1m and non-constraint costs decreased by £1.0m which results in an overall decrease in costs of £25.1m compared to November 2025.

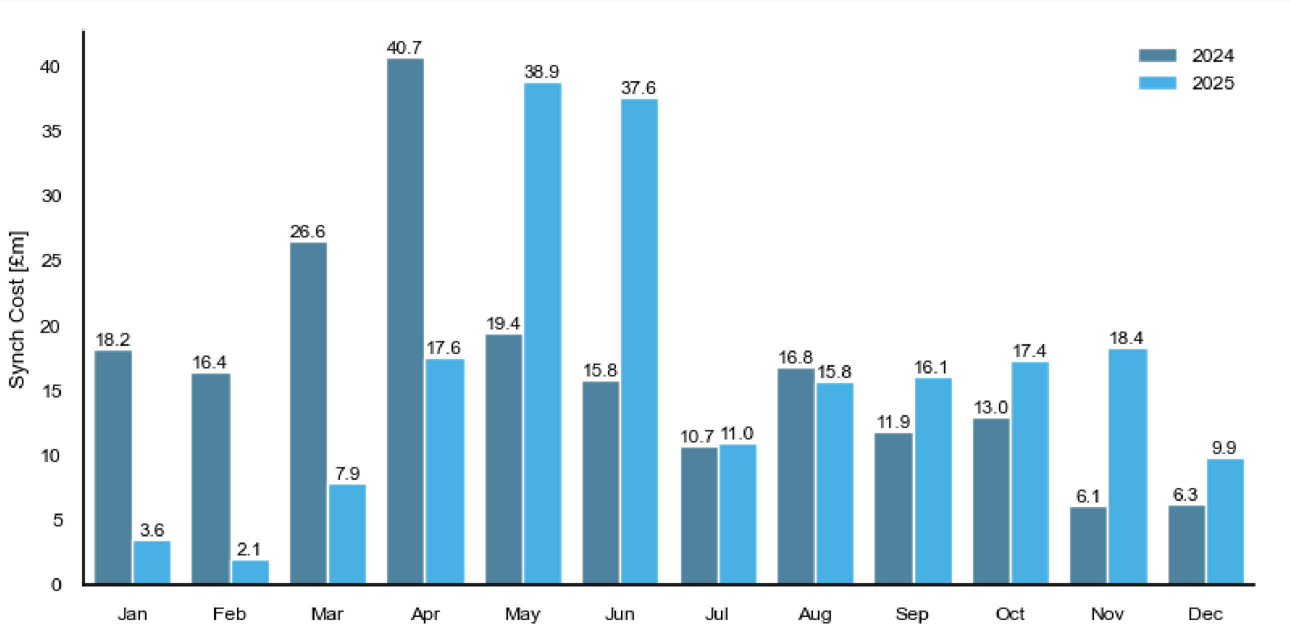
Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: -£26.4m	**Constraints – Scotland & Cheviot: -£59.1m**
Constraint – England & Wales: +£2.2m	**Constraints – England & Wales: -£23.0m**

Constraint Sterilised Headroom: -£0.0m	**Constraints Sterilised Headroom: +£3.5m**
Overall constraint costs decreased by £24.1m, despite an increase of 230GWh in the absolute volume of actions taken. This was partly due to an increase in wind curtailment volumes of 50GWh which was offset by a reduction in power prices. **ROCOF: +£0.4m** The increase in costs can be attributed to a 12GWh increase in absolute volume of inertia procured, because of an increase in wind outturn.	Constraint costs across GB have decreased by £79.5m compared to December 2024, despite an increase in the overall wind outturn. This can be attributed to lower power prices compared to last December, as well as a drop in the absolute volume of actions of 386GWh, including a drop in wind curtailment of 26%. **ROCOF: -£0.7m** Inertia spending has halved compared with December 2024, largely down to a 142GWh reduction in the volume of inertia procured.

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 December, the system synchronisation costs (what it costs to the system, which factors in energy replacement and headroom among others) were £9.9m. This represents a decrease of approximately £8.5m compared to November 2025 and is £3.6m higher than the same period last year (December 2024).

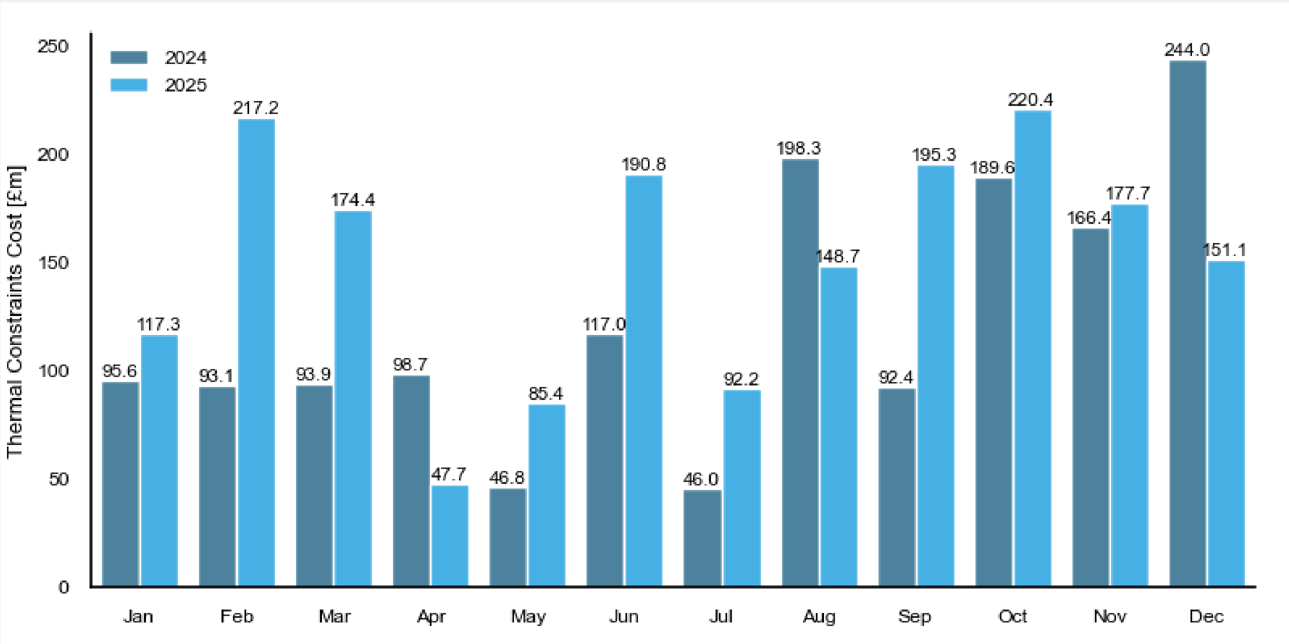


Voltage spending is usually higher overnight: lower demand means that some synchronous units (mostly CCGTs) that usually provide reactive support are not self-dispatched, which forces NESO to procure those services through the Balancing Mechanism.

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. However, the system operational condition and outages in other areas also influence the system spending. An interconnector in the south, along with its Static Synchronous Compensator (STATCOM), came back from full outage in early December which helped lead to a decrease in voltage spending during the month, along with higher demand leading to units self-dispatching as opposed to being procured through the BM.

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

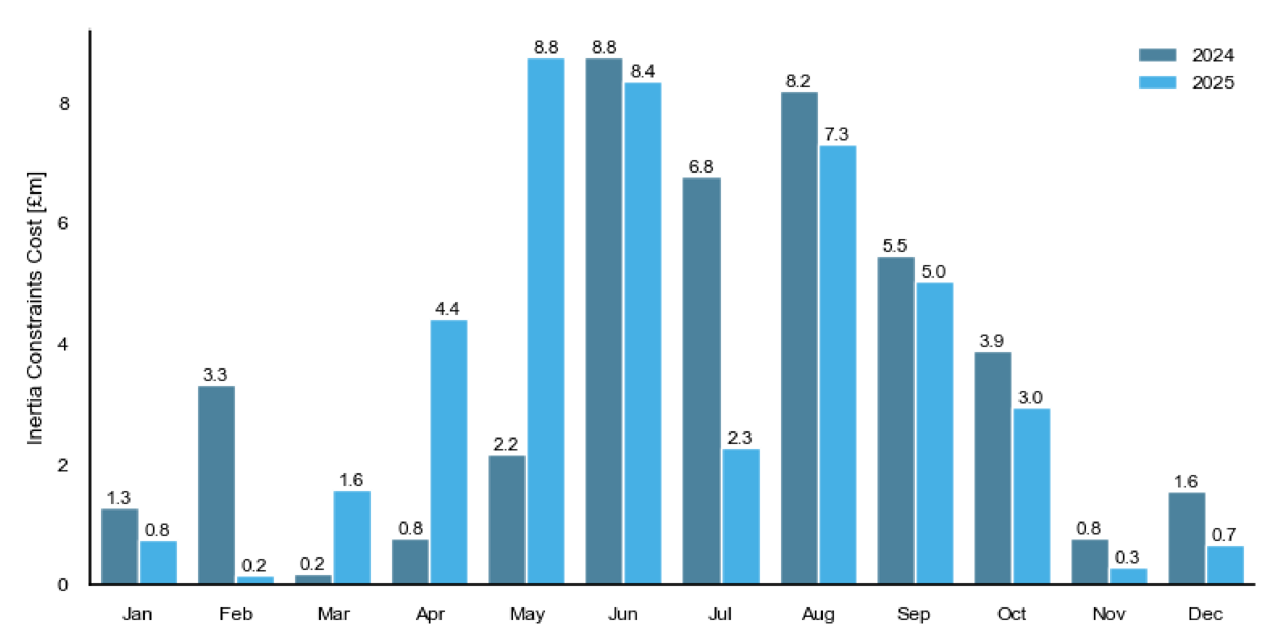
Thermal constraints are linked to operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, often referred to as the B4, B5, and B6 boundaries. The expenditure on thermal constraints 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 December, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £151.1m, reflecting a decrease in costs of over £26.6m compared to the previous month (£177.7m). When compared to the same period last year (£244.0m in December 2024), the cost fell by £92.9m.



December 2025 saw a decrease in thermal constraint costs despite an increase in wind curtailment. Wind curtailment increased from 958GWh in November to 1005GWh in December, which is a 4.7% increase, however this was offset by a reduction in power prices of ~£6.50/MWh.

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 December, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £0.7m, resulting in an increase of £0.4m compared to November 2025 and £0.9m lower than December 2024.



The inertia expenditure rose slightly partly down to the higher wind outturn we saw in December, leading to a higher volume of inertia being procured.

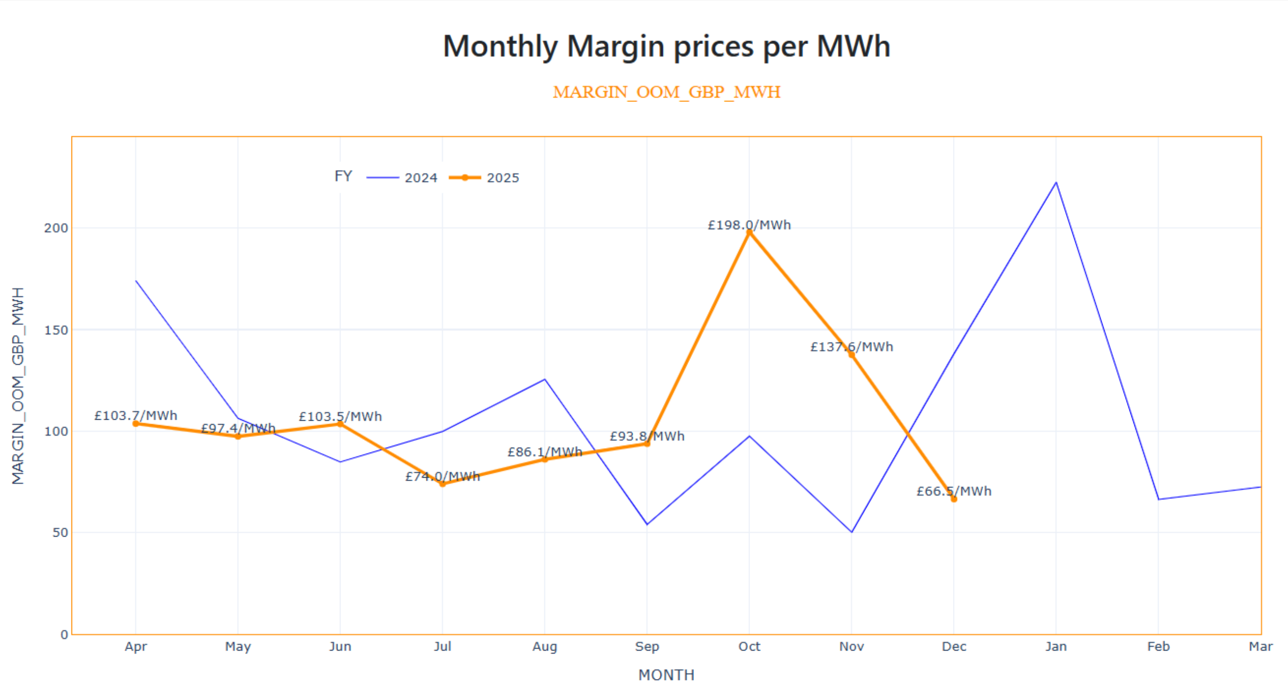
Reactive Costs/Volumes

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£0.2m Reactive costs have increased slightly on last month, due to the high proportion of wind in the generation mix for December.	**+£0.1m** Reactive costs have risen slightly on last year reflecting the increase in wind outturn compared to last December.

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 decreased significantly to £66.5/MWh in December from £137.6/MWh in November 2025, a reduction of over 50%. This trend is the opposite of what we saw last year, with reserve prices rising from £50.1/MWh in November 2024 to £138.1/MWh in December 2024. This is largely down to a reduction in power prices compared with both November 2025 and December 2024, and despite an increase of 345GWh in the absolute volume procured in November.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£4.8m **Fast Reserve: +£0.4m** There was a 343GWh increase in the absolute volume of operating reserve to secure the system compared to November.	**Operating Reserve: +£0.3m** **Fast Reserve: -£0.0m** There was a 55GWh increase in the volume of operating reserve required to secure the system compared to December 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
-£3.4m There was a 10 GWh decrease in the absolute volume of actions compared to November, coupled with average clearing	**+£0.0m** The volume of actions taken for response decreased by 1.5GWh compared to December 2024, coupled with lower

prices for DC, DM, DR services being lower this month than last.	clearing prices in DC and DM but higher prices seen for DR..

Dynamic Services Average Clearing Prices (£/MW): December 2025 vs November 2025

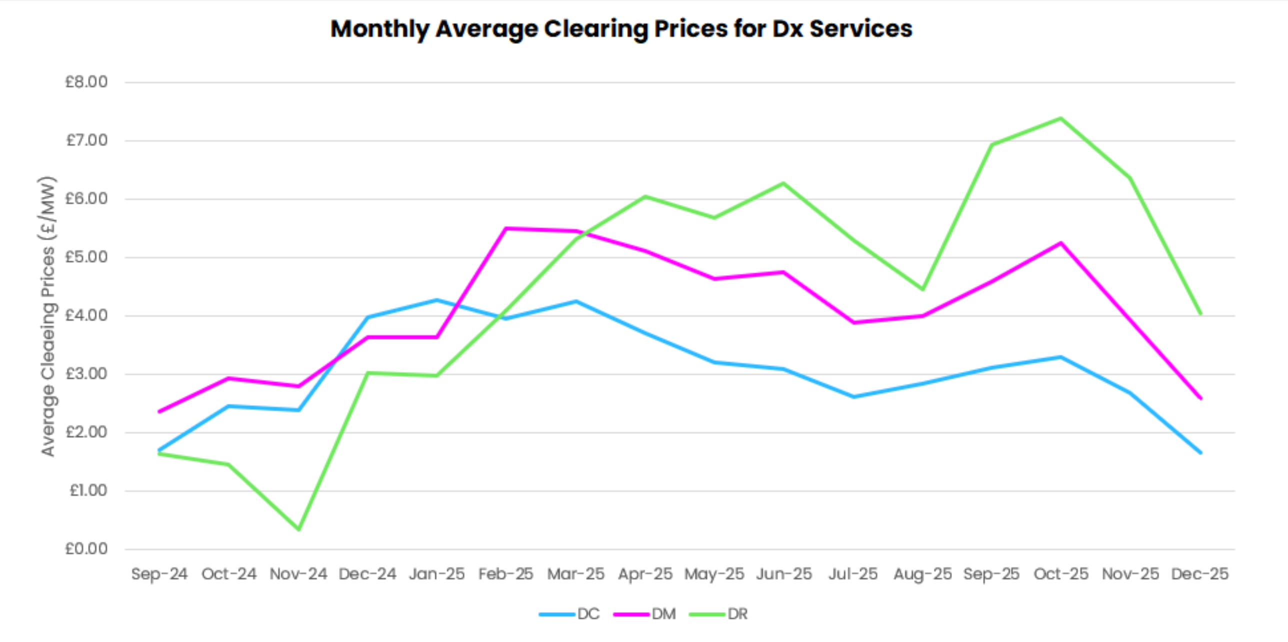
		(a) Dec-25	(b) Nov-25	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Dynamic Services	DC	1.7	2.7	(1.0)	
	DM	2.6	3.9	(1.4)	
	DR	4.0	6.3	(2.3)	

Dynamic Services Average Clearing Prices (£/MW): December 2025 vs December 2024

		(a) Dec-25	(b) Dec-24	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Dynamic Services	DC	1.7	4.0	(2.3)	
	DM	2.6	3.6	(1.0)	
	DR	4.0	3.0	1.0	

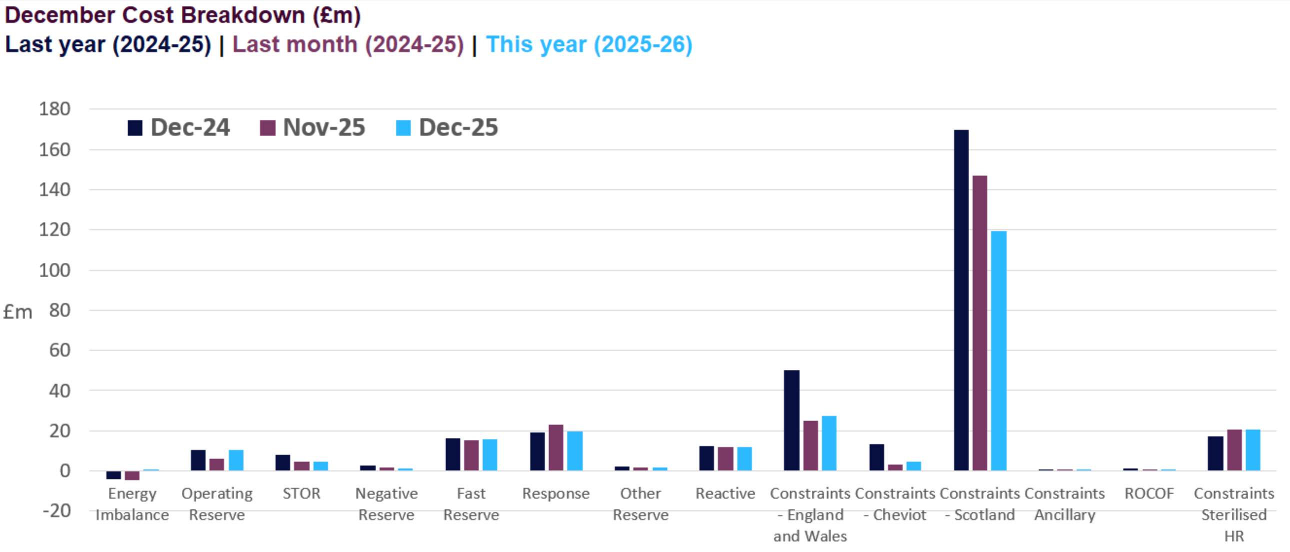
Average clearing prices for Dynamic Containment (DC), Dynamic Moderation (DM), and Dynamic Regulation (DR) decreased in December, continuing the downwards trend that has been seen since October. This decrease has been driven by a combination of mild weather, strong wind outturn and reduced gas prices. Due to the mild weather and stable inertia levels, there has been less wholesale price volatility, allowing assets to bid lower in the response markets and leading to lower clearing prices.

Compared to December last year, both DC and DM have seen reductions in average clearing price, while DR has seen an increase, largely down to increased volumes of procurement since February which has led to higher prices.



Comparison breakdown

The graph below shows the breakdown of monthly balancing costs by category compared to the previous month and the same month in the previous year. 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 lower costs.



COST SAVINGS

Cost Savings – Outage Optimisation

Total savings from outage optimisation amounted to approximately £109m in December 2025. This is an increase of roughly £33.2m relative to November 2025 (£75.8m). The most valuable action was the coordination of outages works between Pelham 400kV, Bramford 400 kV and Norwich Main 400 kV to avoid single circuit risk on Sizewell nuclear power station. The cost saving for this action is estimated in £68.8m.

Cost Savings – Trading

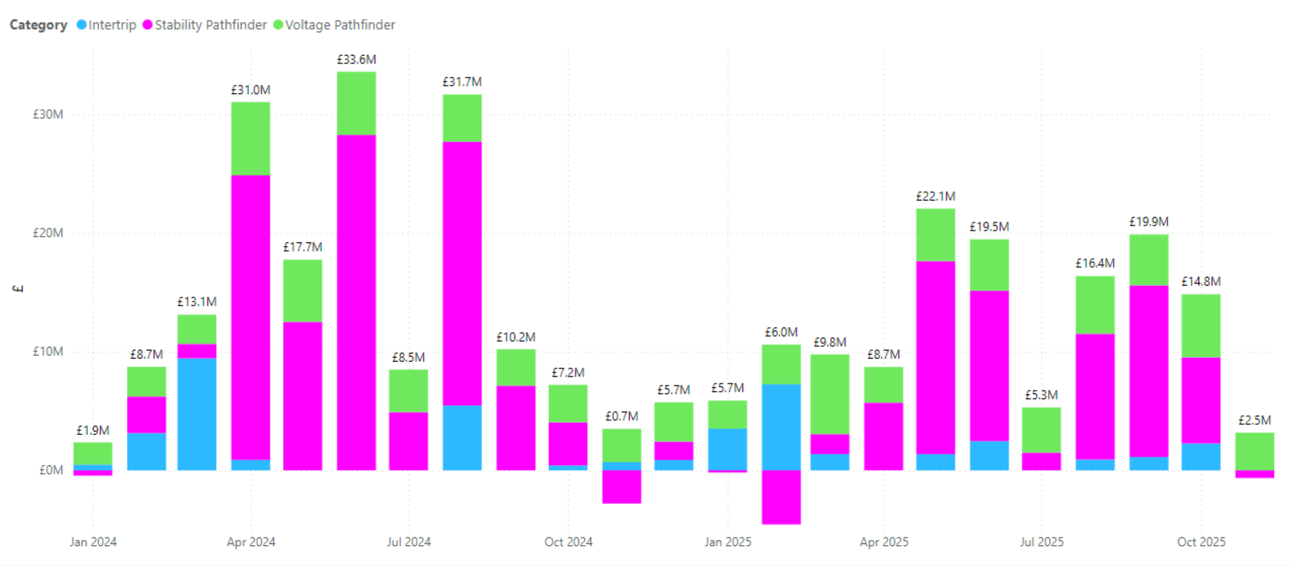
The Trading team were able to make a total saving of £10.7m in December through trading actions as opposed to alternative BM actions, representing a 69% decrease on the previous month. This decrease was largely driven by the reduction in trading activity during in December, particularly regarding margin trades, with interconnectors largely importing throughout the month. Savings made from voltage management remained very similar to that achieved in November. The day with the greatest trading savings was on 24 December at a cost of £2.1m with the greatest component being for downward regulation. The day with the greatest spend on trades was 14 December at a cost of £1.8m, with the greatest component being for voltage control for south England.

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 £109.1 m in savings across 2025/26 to date (April – November 2025). Figures for Stability Pathfinder in September have been amended due to data inaccuracy.

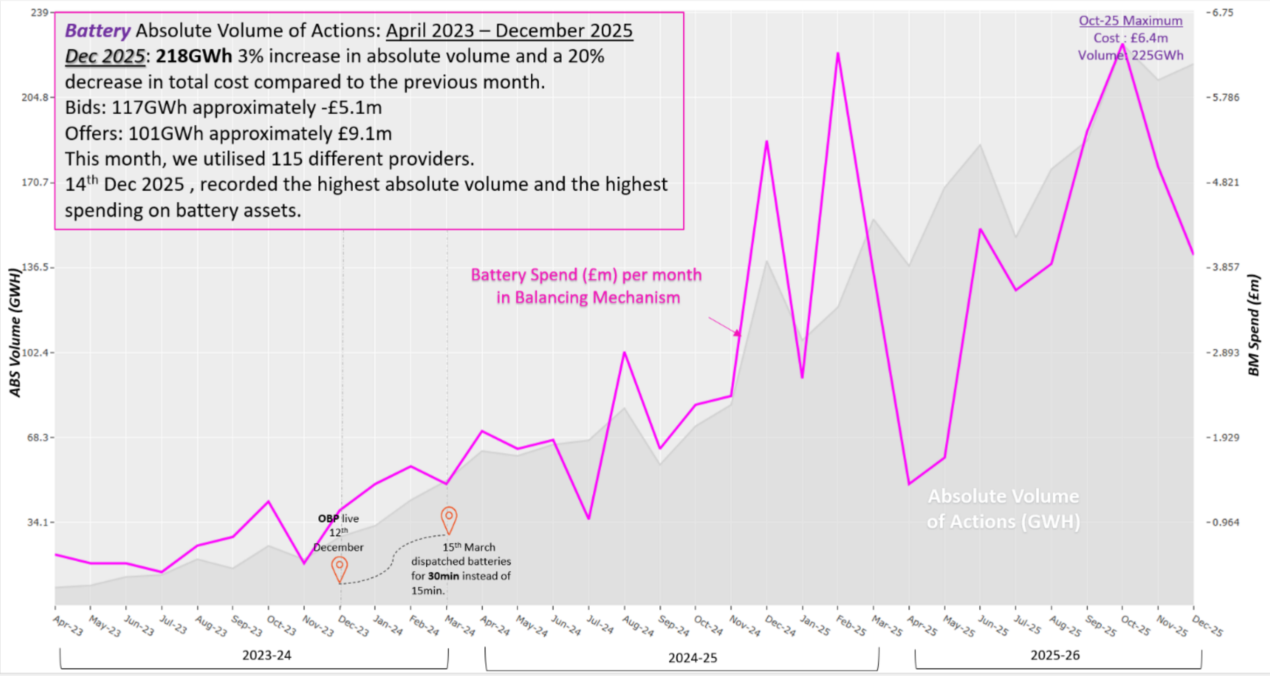
Monthly Savings from Network Services (NS)



NOTABLE EVENTS

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

December 2025



This graph illustrates a clear upward trend in both cost and volume over the observed period from April 2023 through November 2025. Early on, both metrics remain relatively low and stable with minor fluctuations until late 2023 when the first stage of the Open Balancing Platform (OBP), our new platform to support bulk dispatch, went live on 12 December 2023. There is an initial spike followed by continued growth throughout 2024 with periodic dips and peaks—most notably sharp increases around August-September of each year. 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.

Compared to the previous month, December 2025 saw an increase in absolute volume; however, total expenditure declined, reflecting broader market trends.

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 underscores our dedication to enhancing the flexibility of energy provision through battery storage and small Balancing Mechanism Units (BMUs).

DAILY CASE STUDIES

Daily Costs Trends

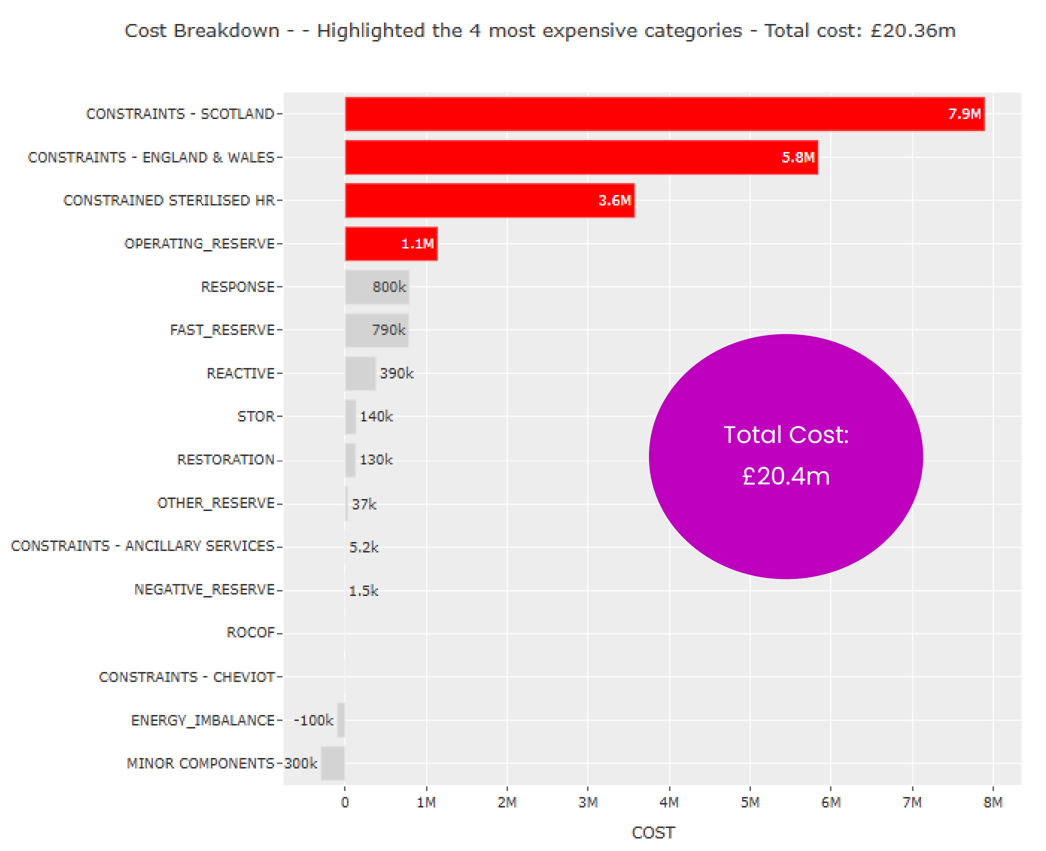
December's balancing costs were £241.7m which was lower by £25.1m than the previous month. This included four days with a total cost above £15m (10, 13, 14, 19), as well as a further five days in December having a cost over £10m (9, 11, 17, 18, 31). The daily average cost decreased from £8.8m to £7.8m, a drop of £1.0m.

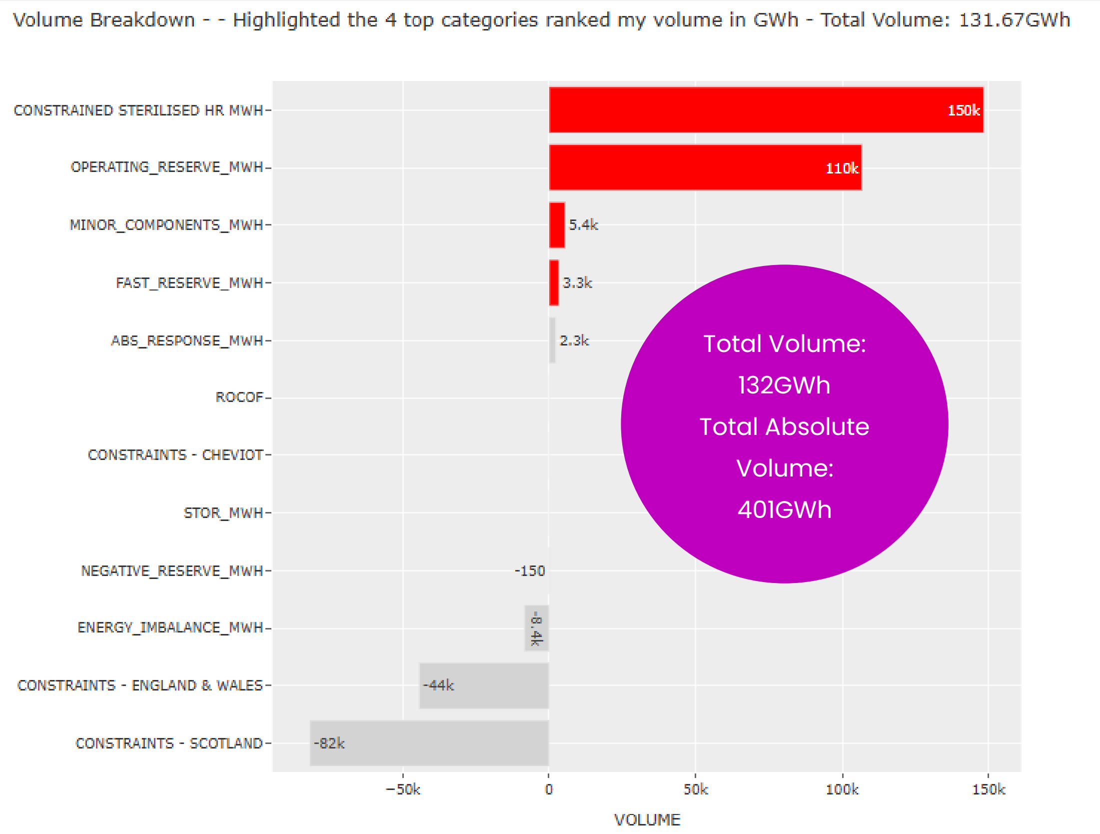
The highest cost day was Friday 19 December, with a total cost of approximately £20.4m, similar to the highest cost day in November. These costs were driven by the highest level of wind curtailment seen during the month, along with outages on the day.

The lowest cost day was Tuesday 23 December with a total cost of approximately £1.6m, followed by 27 December at a cost of £2.2m. The 23 had a low volume of wind curtailment, while the 27 saw no wind being curtailed, while both days had a low absolute volume of actions being taken and a reduction in outage works.

High-Cost Day – 19 December 2025

Breakdown of Cost and Volume





December 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.

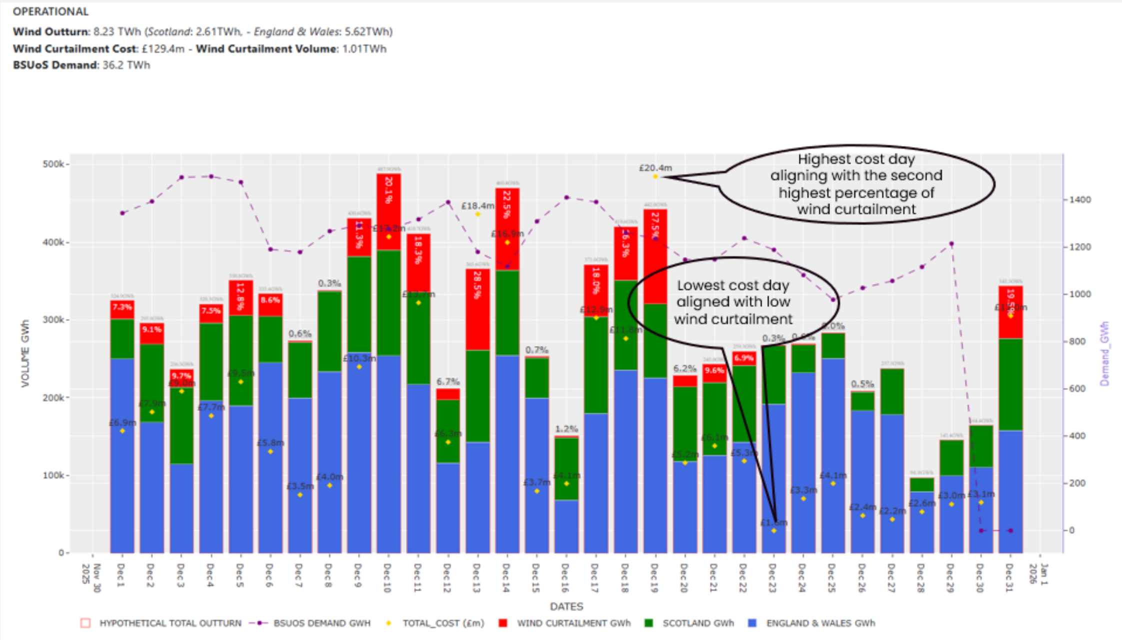
KEY: **Blue bars:** Wind generation in England and Wales

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).

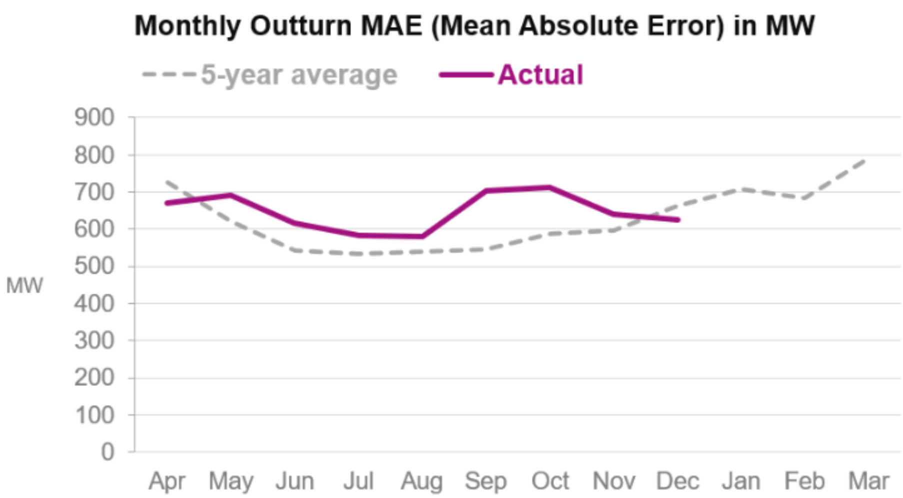
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each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

December 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**	**711**	**641**	**626**			

*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 December 2025 forecasting error averaged 626MW, against the previous 5-year average of 662MW. YTD performance is currently 647MW, vs 5-year average of 594MW.

The weather in December was mostly mild, wet and windy, driven by low pressure systems. The final week was colder than average, driven by arctic air moving south.

Storm Bram brought strong wind gusts, heavy rain and flooding over the worst hit parts of the UK.

The Christmas Holiday period is difficult to forecast due to changing human behaviour and the proximity to where Christmas Day/New Years Day falls in the week. Christmas Day itself is usually benign with an almost identical trajectory year-on-year. Christmas Day also witnessed lengthy "free-energy" offers from numerous electricity retailers, but their effects were minimal.

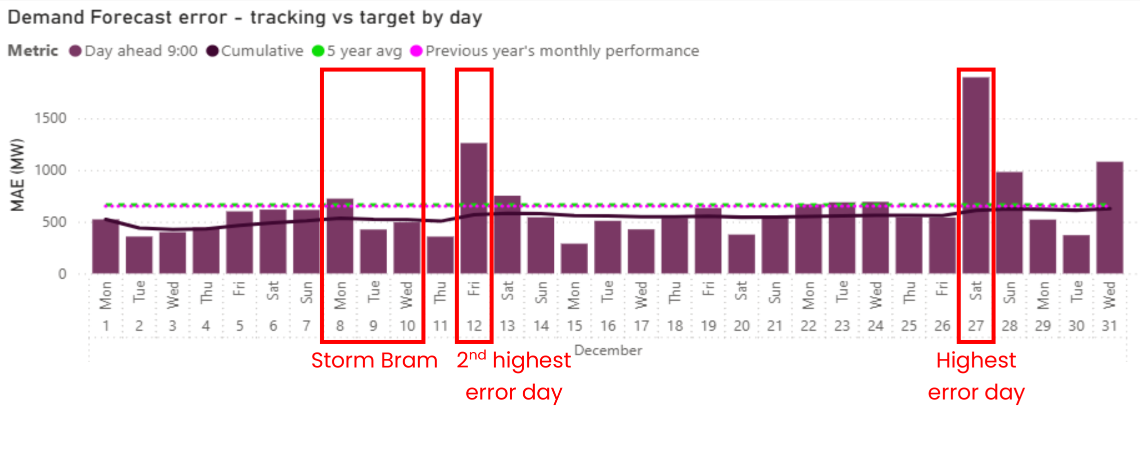
The largest absolute demand error this month was 4.0GW on 27 December, SP32.

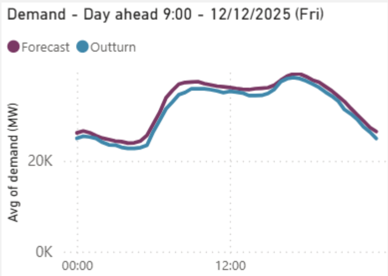
The minimum demand was 19.0GW on 14 December, SP11, while the maximum demand was 42.4GW on 4 December, SP35.

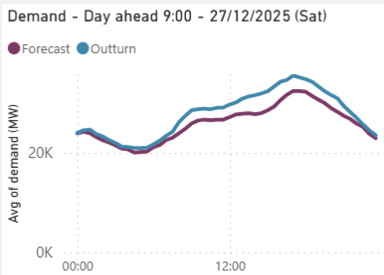
Solar generation peaked at 6.24GW on 3 December.

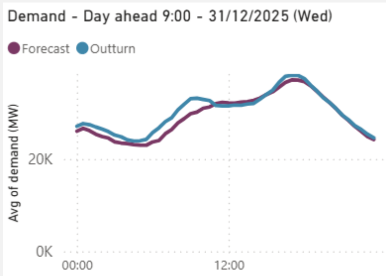
Work continues on rebuilding our national demand forecast models. These will adopt Machine Learning/AI technology and will make use of the latest generation weather data, with an expected release to production in Q1 2026.

Days of Interest:

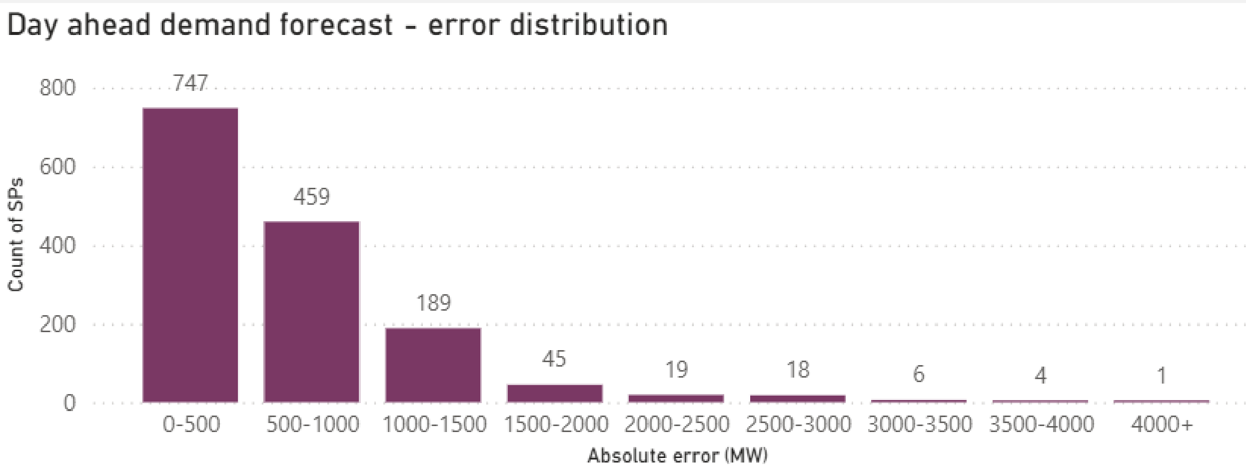




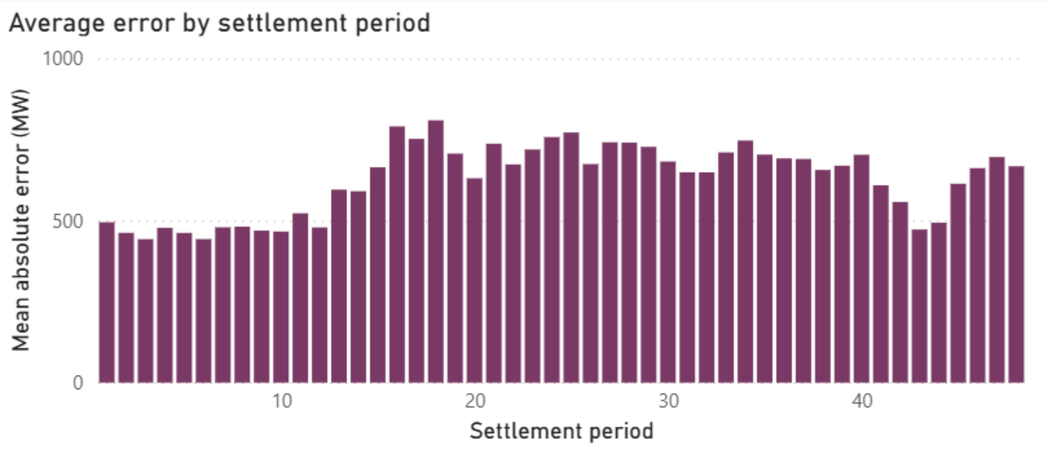




The distribution of settlement periods by error size is shown below:



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



The days with largest MAE were 12, 27 and 31 December.

Day	Error (MAE)	Major causal factors
12	1261	Over forecast across the whole day, including overnight periods
27	1897	Christmas period and cold snap related behaviour changes, and limited profiling options
31	1080	New year period related behaviour changes and limited profiling options

Missed / late publications

There was one late publication on 19 Dec, due to an IT issue with our data portal.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 1, 3, 26, 29, 30 and 31 December, with an accumulated total of 207MWh procured. 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.

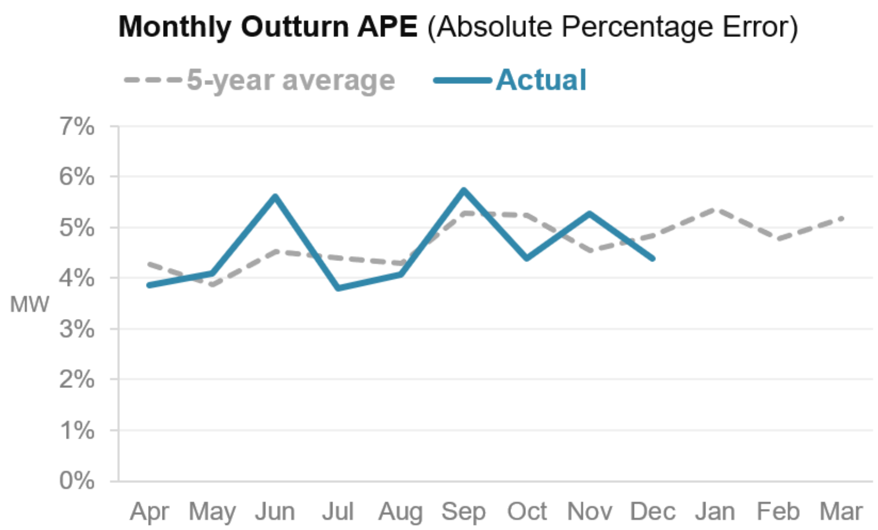
Sites deemed to have withdrawn availability are those that:

- 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.

December 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 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**	**4.06**	**5.74**	**4.38**	**5.27**	**4.39**			

*Ofgem 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 December 2025, BMU wind forecasting error averaged 4.39%, against the 5-year average of 4.84%. YTD performance is currently 4.57%, vs 5-year average of 4.58%.

December was wet and windy, with several low-pressure systems and storm Bram affecting GB. Storm Bram brought wind gusts of up to 84mph, with the northwest being hit hardest.

Larger forecast errors on December 1, 3 and 31 were due to rapidly-changing weather conditions, but the within-day performance improved significantly as the weather forecasts adjusted.

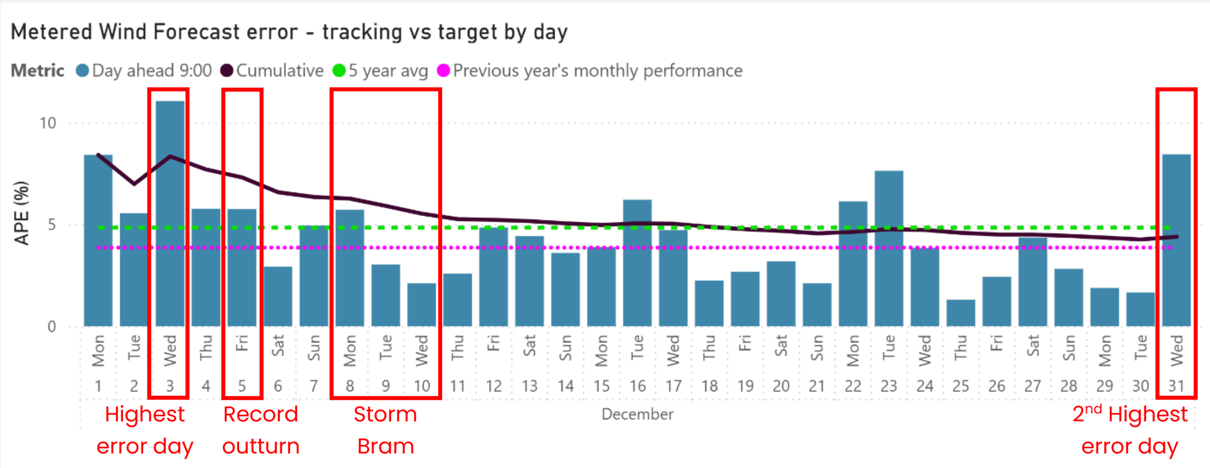
Metric-adjusted wind generation peaked at 17.4GW on 5 December, SP36. This day also observed the latest record for *total* GB wind generation output at 23.8GW.

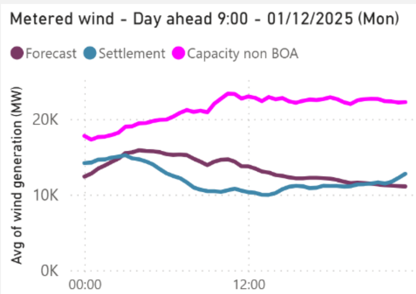
Wind forecast absolute error peaked at 4.3GW on 1 December, SP21.

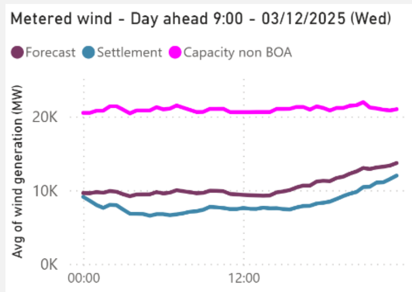
Work continues on our wind generation forecast model upgrades. These make use of additional weather variables (wind direction) and features (blended weather from numerous providers) and we aim to release to production in Q1 2026.

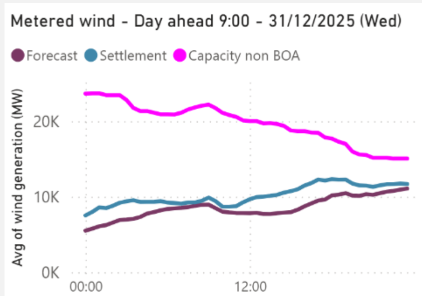
Metric values for previous months have been recalculated with updated settlement outturns and these are reflected in the YTD performance.

Days of Interest:

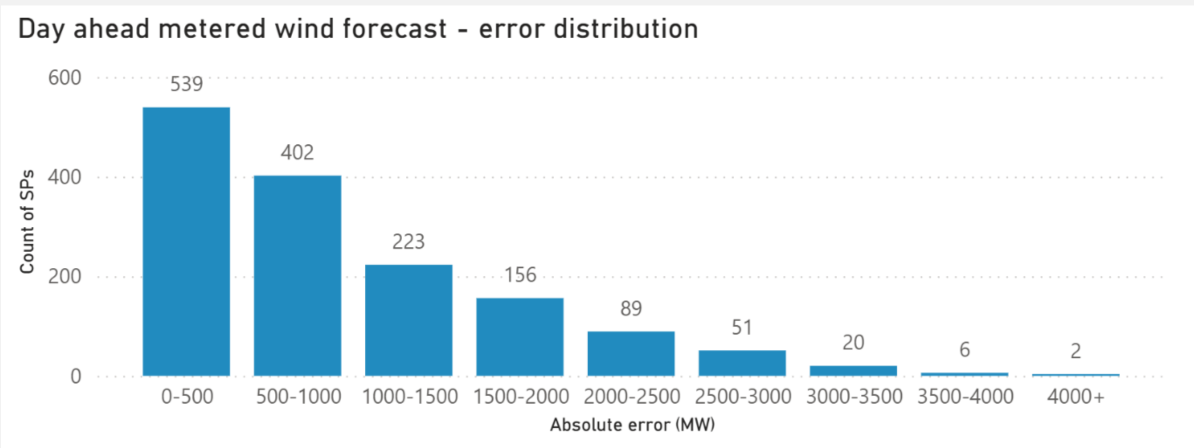








The distribution of settlement periods by error size is summarised below:



Details of largest error

Day	Error (APE)	Major causal factors
1	8.4	Wind speed forecast errors especially at day-ahead stage
3	11.1	Wind speed forecast errors at day-ahead stage
31	8.4	Wind speed forecast errors at day-ahead stage

Missed / late publications

There was 1 late publication on 19 Dec, due to an IT issue with our data portal.

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%	30%	33%	29%			
Bids	43%	42%	47%	46%	39%	42%	40%	35%	37%			
Combined	**42%**	**39%**	**38%**	**42%**	**35%**	**36%**	**34%**	**34%**	**32%**			

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	133	103	113			
Offers – in merit Energy volume	148	205	356	215	279	359	437	309	392			
Offers – All in merit volume (System & Energy)	504	901	1052	529	943	971	1084	878	838			
Bids – Skipped volume	141	148	111	127	122	102	93	108	103			
Bids – in merit Energy volume	336	352	234	277	316	243	234	310	280			
Bids – All in merit volume (System & Energy)	815	995	1576	962	1344	1488	1815	1597	1660			
Combined Bid & Offer – skipped volume	204	219	227	205	208	218	226	211	216			

Supporting information

DECEMBER UPDATES

Demand Side Flexibility (DSF) units

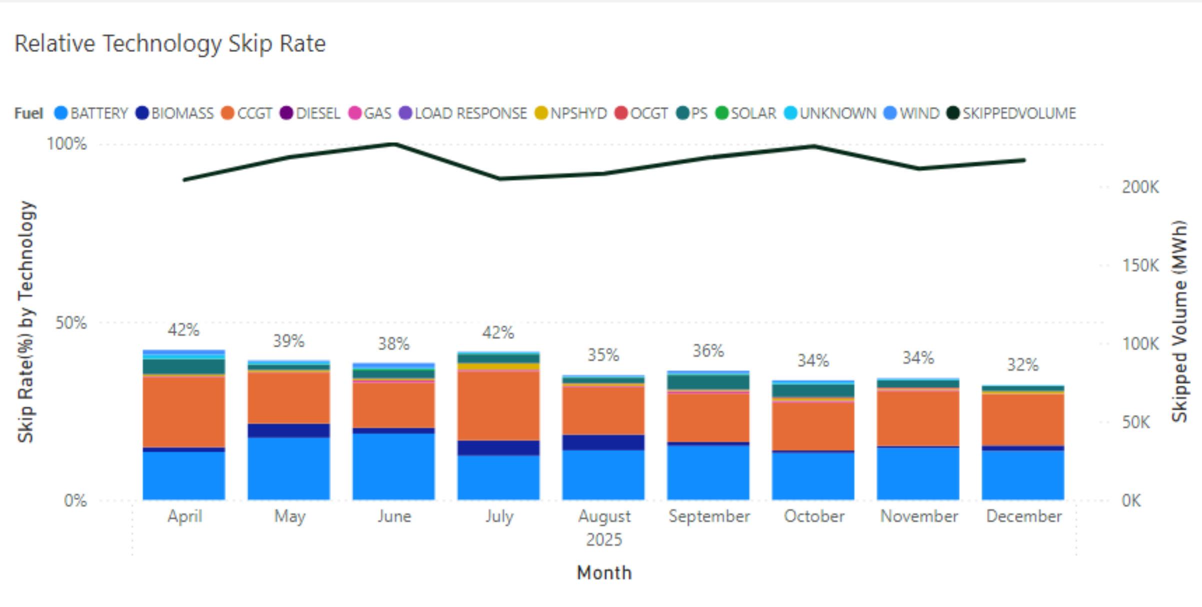
We have published a new dataset showing the skip rate specific to DSF units. This dataset has been incorporated into our external dashboard for ease of use. There are 70 DSF units that have been identified. Of these, 44 are available to dispatch in the BM, and 19 were in-merit at stage 5 at least once over the last year. A summary of this was shared at OTF on 10 December 2025 and is displayed below.

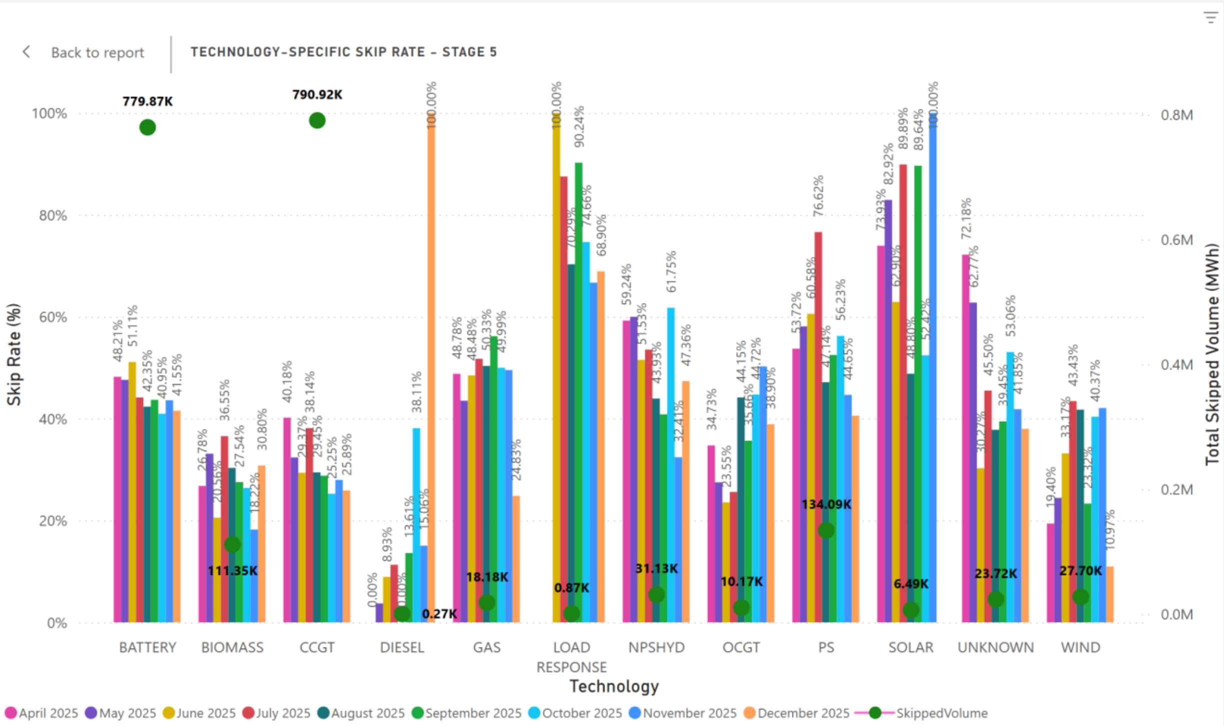
Skips Behind Constraints

Work has continued to develop a methodology to measure skips behind constraints. This method will be shared with industry in January 2026 with the view to agree a method with industry before end of financial year.

Q3 PERFORMANCE – COMBINED BIDS AND OFFERS

The combined bid and offer skip rate has continued to trend downwards during the year and was significantly lower in Q3 compared to Q1 (32-34% in Q3 vs 38-42% in Q1). The combined skip rate decreased in December to the lowest level seen to date (32%).

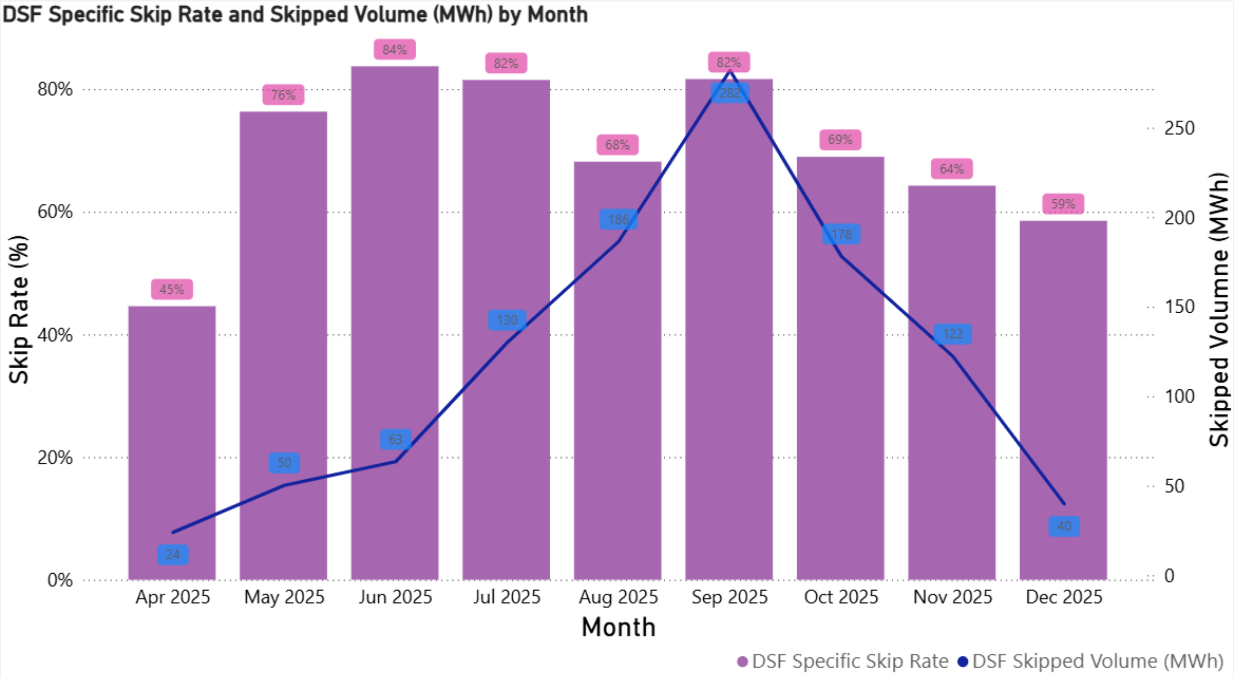




The combined technology specific skip rate has continued to trend down for most technology types since April 2025. This includes Batteries and CCGTs which account for most of the skipped volume. Some technology types see very high or low technology specific skip rates when they have small in merit volumes. For example, in December one Diesel unit was skipped in one half-hour period for 0.68MWh but this resulted in a 100% technology specific skip rate. Similarly solar has a 100% technology specific skip rate in November – this was 30MWh of skipped volume over a 2-hour period on one day.

Note: In the technology specific skip rate graph '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 Flexibility (DSF) units. We have published a dedicated dataset to report skip rates for DSF units and incorporated this into our external dashboard. A summary is provided below.

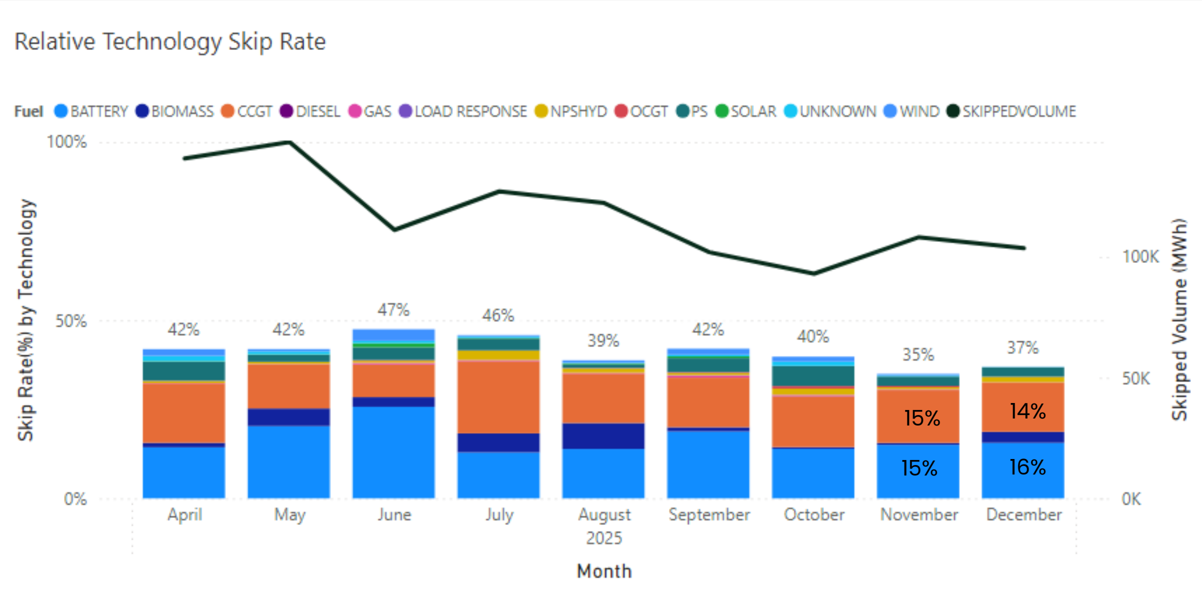
Skip rate for DSF units (combined bid & offer)



DSF skip rate and skipped volume has fluctuated over the year. A high proportion of skipped volume occurs overnight (22:00-02:00). This suggests that these units are more likely to be in merit overnight, but also demand is lower and therefore fewer energy actions are taken.

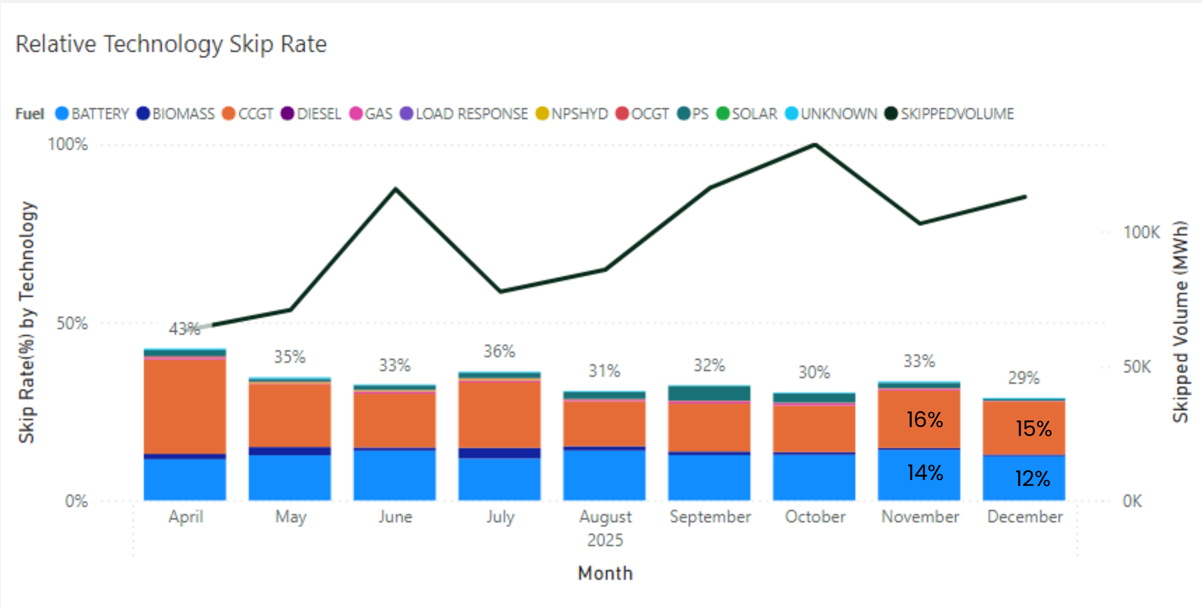
Bids

The Bid skip rate has increased from November (35%) to December (37%), and the skipped volume has decreased from 108GWh to 104GWh. CCGTs accounted for a lower proportion of skipped volume in December (14%) compared to November (15%) and the Technology Specific skip rate for CCGTs has increased from 25% to 31%. Batteries account for a higher proportion of the skip rate in December (16%) compared to November (15%) and the Technology Specific skip rate has decreased from 50% to 42%. This has primarily been driven by an increase in the amount of battery volume that was accepted in merit through the month, with a small reduction in skipped volume and similar accepted in merit volume.



Offers

The Offer skip rate decreased to a new low in December (29%). CCGTs account for a lower proportion of skipped volume in December (15%) than November (16%), and the Technology Specific skip rate has increased from 23% in November to 31% in December. Batteries account for a lower proportion of skipped volume in December (12%) than November (14%), and the Technology Specific skip rate has increased from 39% in November to 41% in December.



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.

December 2025-26 performance

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

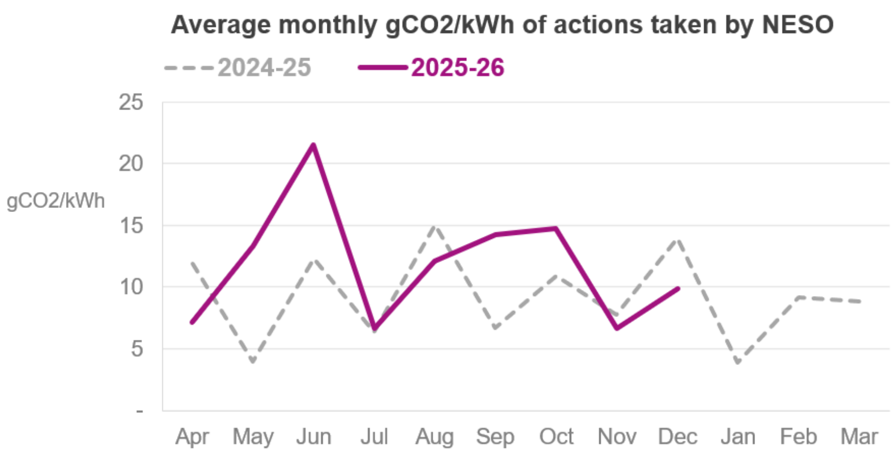


Table: Average monthly gCO2/kWh of actions taken by NESO

	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	14.75	6.68	9.85			

Supporting information

We report the average monthly gCO_2/kWh of actions taken by NESO in line with reporting requirements. Alignment of the ZCO technologies with the CP30 technologies could see biomass and CHP units treated differently in this report, but no change has been made as yet.

In December, the average monthly carbon intensity from NESO actions was 9.85g/CO_2/kWh. This is 3.17 g/CO_2/kWh higher than November, and 1.96/CO_2/kWh lower than the YTD average of 11.81/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 64.90g/CO_2/kWh which took place on 19 December at 05:30. This is 16.18g/CO_2/kWh higher than the highest point in November of 48.72g/CO_2/kWh.

On 19 December wind generation had to be curtailed to manage constraints and manage the system requirements for secure operation.

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 1I).

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.

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

Supporting information

No reportable voltage or frequency excursions during December.

[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.

December 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	0	0	0			
Integrated Energy Management System (IEMS)	0	0	0	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	0	1 outage 150 mins	0			
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0			

Supporting information

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

8. Short Notice Changes to Planned Outages

Performance Objective

N/A

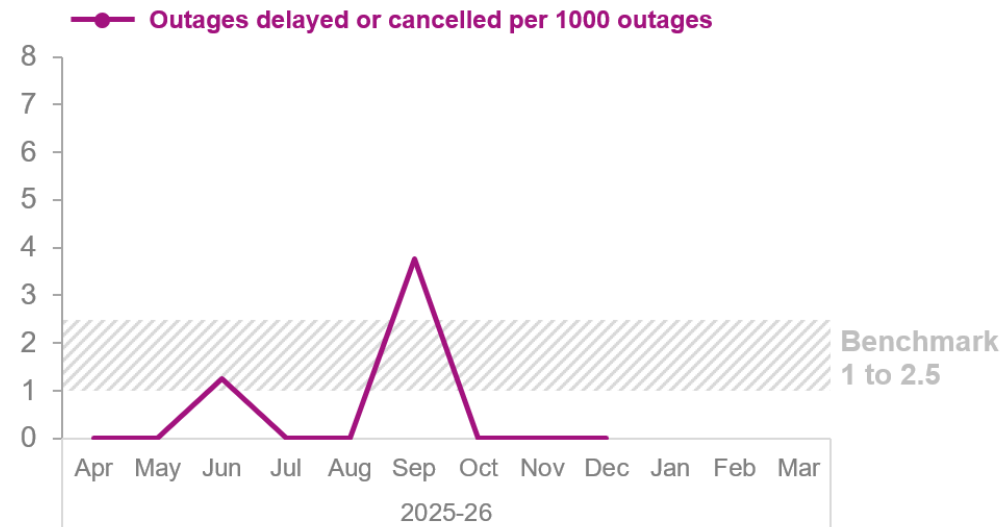
Success Measure

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.

Q3 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	750	758	554				6622
Outages delayed/cancelled due to NESO process failure	0	0	1	0	0	3	0	0	0				4
Number of outages delayed or cancelled per 1000 outages	0	0	1.24	0	0	3.77	0	0	0				0.60

Supporting information

We successfully released 750 outages in October, 758 outages in November and 554 outages in December. Across these three months there were zero delays or cancellations due to a NESO process failure. The year-to-date cumulative number of stoppages or delays per 1000 outages is 0.60.

9. Zero Carbon Operability Indicator

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 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: Q3 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	96.35	99.96	26 Oct SP25	91.23	96.50	26 Oct SP43

Nov	96.95	99.29	1 Nov SP20	90.09	93.65	1 Nov SP19
Dec	95.27	97.56	7 Dec SP42	88.96	94.77	7 Dec SP48
Jan						
Feb						
March						

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

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 aligned** definition of ZCO

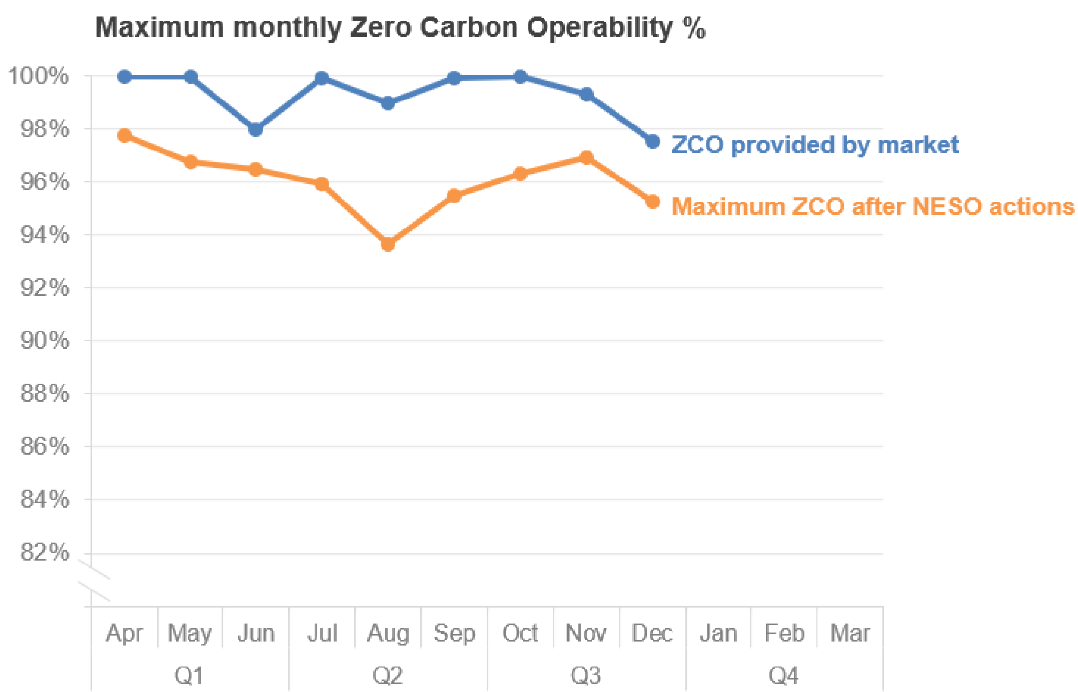


Figure: Q3 2025-26 ZCO by Settlement Period, before and after NESO operational actions

Using **CP30 aligned** definition of ZCO

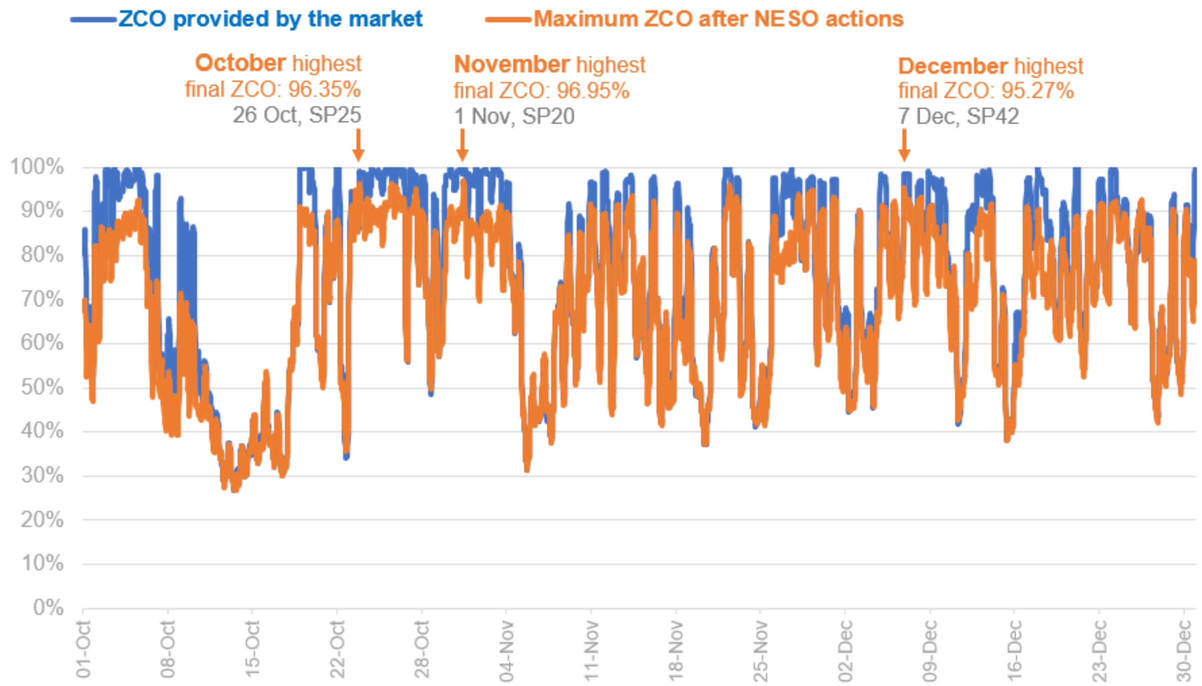


Figure: Maximum monthly ZCO% after NESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred) – two-year view

Using **Original** RIIO-2 definition of ZCO

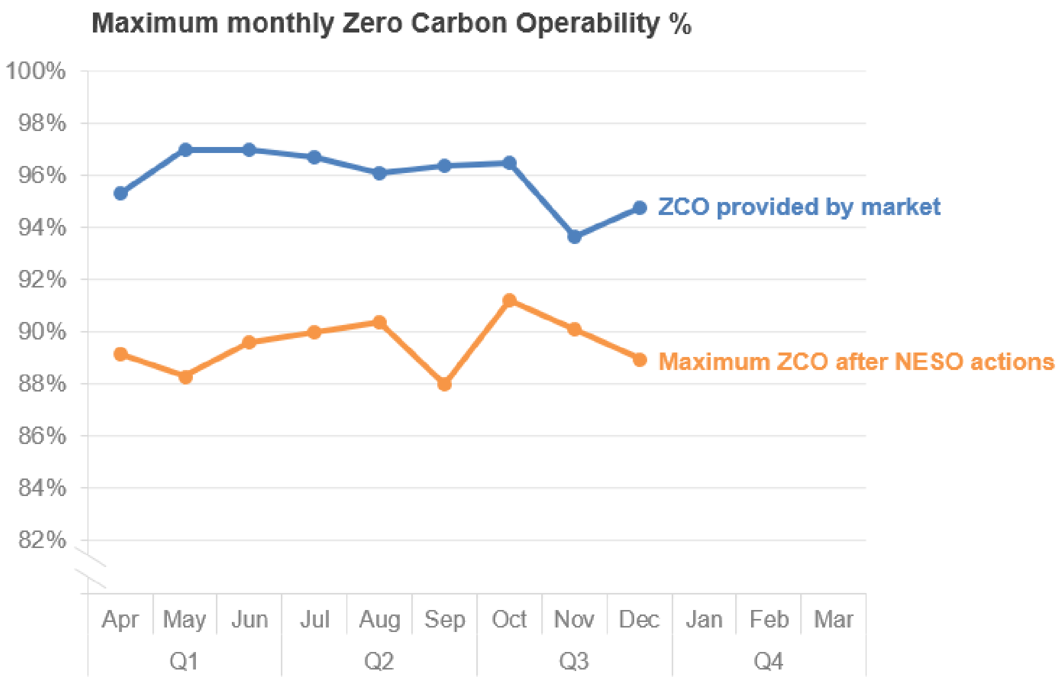
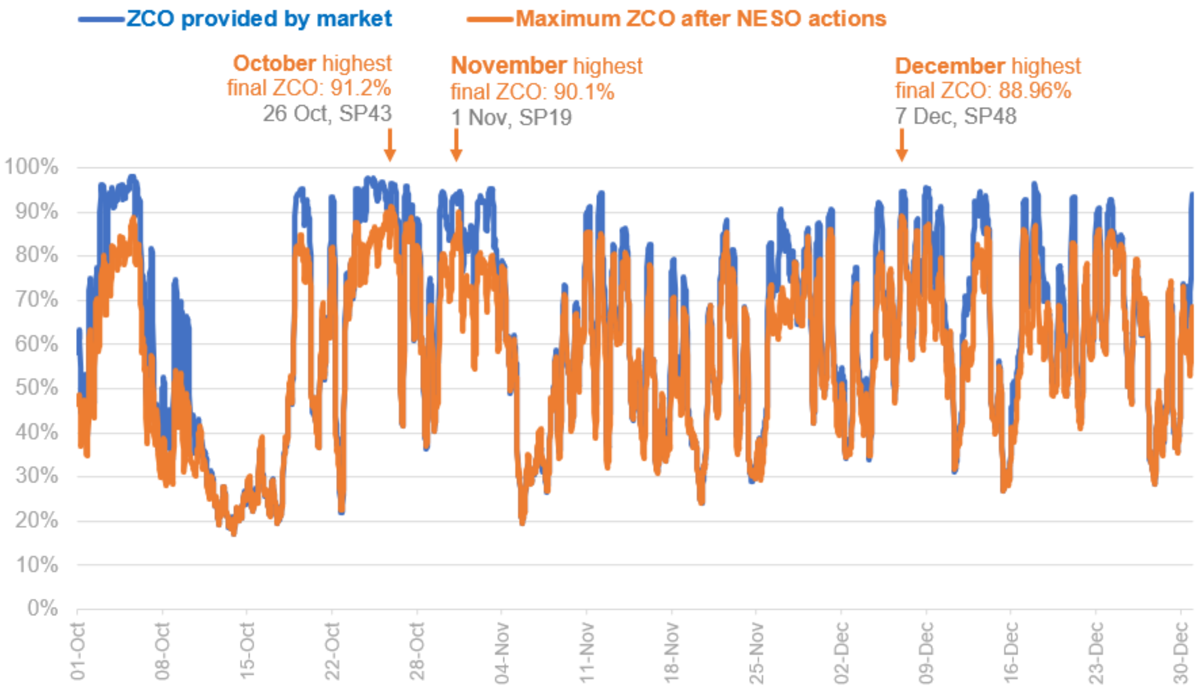


Figure: Q3 2025-26 ZCO by Settlement Period, before and after NESO operational actions

Using **Original** RIIO-2 definition of ZCO



Supporting information

Based on the revised 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 99.9% zero carbon generation. Over 2025 the market has delivered extremely close to 100% zero carbon generation – hitting 100% in the graph above (ZCO definition version) due to rounding, with a small volume of non-zero carbon generation remaining (based on current data).

Highest final ZCO by month vs previous year

Using **Original** RIIO-2 definition of ZCO

Quarter	Month	2024/25	2025/26	Difference
	April	92.2%	89.1%	-3.1%
Q1	May	83.4%	88.3%	+4.9%
	June	86.1%	89.6%	+3.5%
	July	86.7%	90.1%	+3.4%
Q2	August	89.2%	90.4%	+1.2%
	September	84.6%	88.0%	+3.4%
	October	85.1%	91.2%	+6.1%
Q3	November	84.6%	90.1%	+5.5%
	December	**89.4%**	**89.0%**	**-0.4%**
	January	88.7%		
Q4	February	86.6%		

	March	93.5%		

CHP change confirmed on 30 September 2025 (CP30 2025/26 data 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)

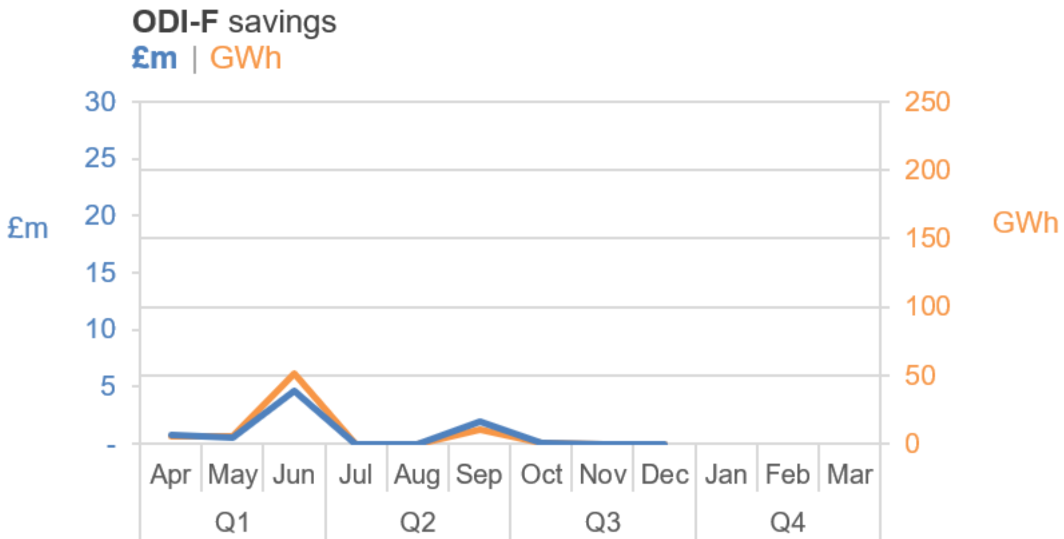


Figure: Estimated £m savings in avoided constraints costs (Other) (Estimated savings in GWh are also shown for context)

*Note **vertical axis scale** differs from the ODI-F graph above.*

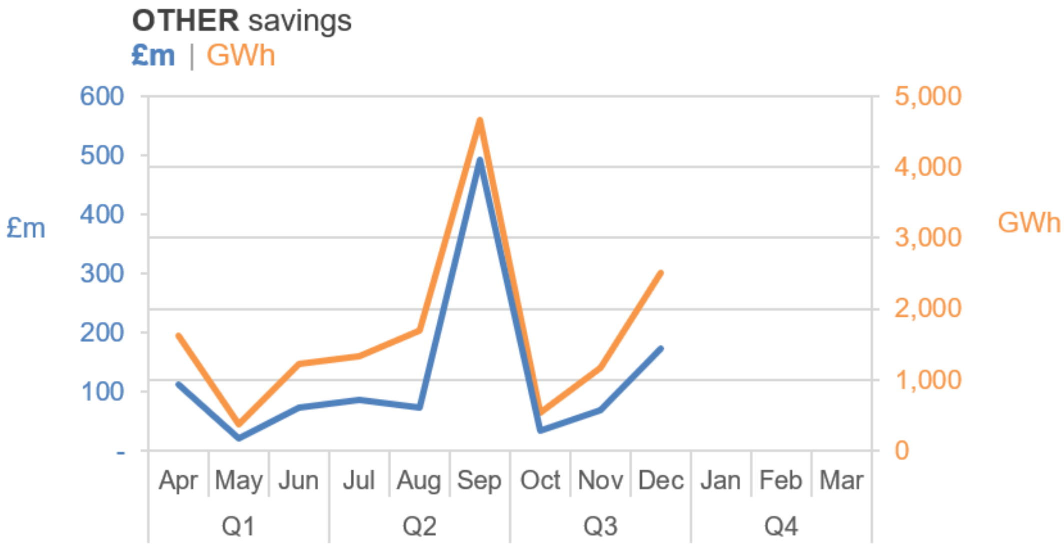


Table: Monthly estimated £m savings in avoided constraints costs (2025-26)

	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	0.06	34.37	0.34	534.60
Nov	0.00	69.83	0.00	1162.60
Dec	0.00	171.97	0.00	2512.20
Jan				
Feb				
Mar				
YTD	**8.03**	**1132.32**	**73.54**	**15134.20**

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 provisions from TO's through STCP 11.4 that provides constraint cost savings this quarter. Some of these provisions are highlighted below:

- In October, National Grid Electricity Transmission (NGET) and Network Access Planning agreed upon enhancements based on static and dynamic weather conditions for two circuits connecting Carrington, Trafford in the North of England through an electrical substation in Cheshire East to Cheddleton, Staffordshire Moorlands. These improvements were implemented to facilitate NGET routine maintenance works on a circuit linking Carrington, Trafford in the North of England to Cheddleton, Staffordshire Moorlands. As a result, these enhancements saved **0.34 GWh** of energy and resulted in an outturn cost of **£0.055 million** for the end consumer.

In Q3 2025-26 financial year, NAP has achieved **£0.055 million** in constraint cost savings through STCP 11-4 with the release of **0.34 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 **88 instances this quarter,** where NESO actions have directly contributed to adding value for end consumers. Additionally, our innovative approaches have successfully facilitated increased generation capacity for connected customers.

Such actions include adjusting outage dates, segmenting outages, minimizing return to service times, acquiring enhanced ratings from Transmission Owners (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 October, NAP received a system access request from National Grid Electricity Transmission (NGET) on a busbar at an electrical substation located in Tresswell, Bassetlaw, Nottinghamshire for 4 weeks, needed to carryout Ad hoc repairs and maintenance on the asset. However, due to this request DRESHEX boundary will be constrained heavily. To minimize the impact, NAP and NGET agreed to reconfigure the substation located in Nottinghamshire to enhance the DRESHEX boundary. This action resulted in saving **174.3 GWh** of energy worth approximately **£13 million**.

- In November, NAP received a system access request from Scottish Power Transmission on the circuit connecting Currie in Edinburgh, Scotland to Grangemouth in Falkirk, Scotland needed for replacement of a Supergrid Transformer. However, due to this request the NKILGRMO boundary will be heavily constrained. To minimize this impact, NAP agreed with SPT to provide enhanced ratings on the circuits connecting Lambhill to Windyhill in the north of Glasgow. This action resulted in saving **66.2 GWh** of energy worth approximately **£5.04 million**.
- In December, NAP received a system access request from SHETL for a circuit connecting Alyth, Scotland to Fife, Scotland as part of the East Coast upgrade works. However, this outage would clash with an already started outage on the parallel circuit connecting Alyth to Fife in Scotland, thereby impacting the boundary B4/B5. To minimize the impact of this outage, NAP proposed to NGET to place the outage for a different date in Mid-December. This action resulted in saving **370 GWh** of energy worth approximately **£27.8 million**.

The customer value opportunities, along with others, collectively amount to an additional **4.2 TWh (approximately £287.9 million)** of generation capacity across Q3 in the 2025/2026 financial year. The surplus capacity would have otherwise been restricted, incurring costs to the end consumer.

The aforementioned STCP 11.4 with customer value opportunities created collectively amount to a **15.2 TWh (approximately £1.1 billion)** of generation capacity year to date for the 2025-26 financial year.

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.

Q3 2025-26 performance

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

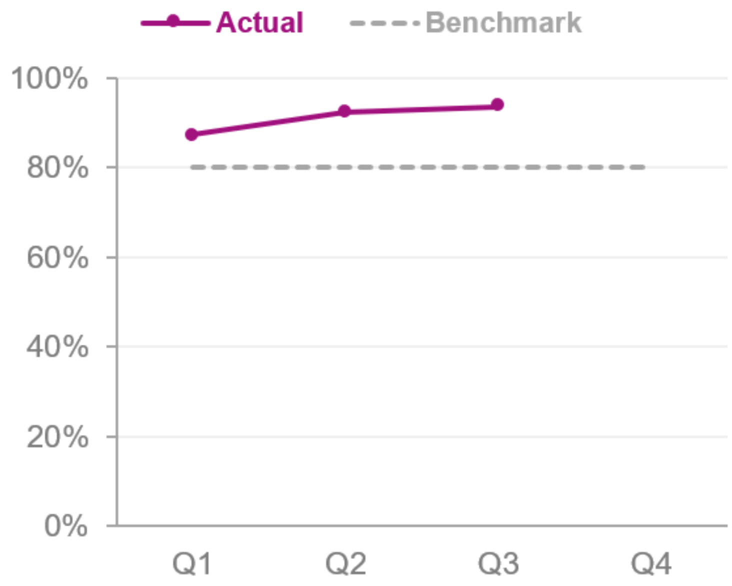


Table: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4	YTD
Volume of balancing services procured (average per procurement period)	MW	5276	5025	4927		
Volume procured no earlier than day-ahead (average per procurement period)	MW	4605	4648	4612		
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	87%	92%	94%		
Benchmark*	%	80%	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	1101		
	DM	MW	294	361	516		
	DR	MW	448	482	488		
	Static FFR	MW	202	198	192		
	STOR	MW	1751	1679	1588		
	BR	MW	10	10	9		
	QR	MW	625	710	718		
	Total	MW	4605	4648	4612		
Non Day-ahead	MFR	MW	671	377	315		
	STOR long-term	MW	N/A	N/A	N/A		
	Total	MW	671	377	315		
All	Grand Total	MW	5276	5025	4927		

Supporting information

In Q3 the percentage of balancing services procured at no earlier than day-ahead has increased to 94%, 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, this along with the increased procured MWs in the Dynamic Moderation service is reflected in the percentage increase 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).

Q3 2025-26 performance

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

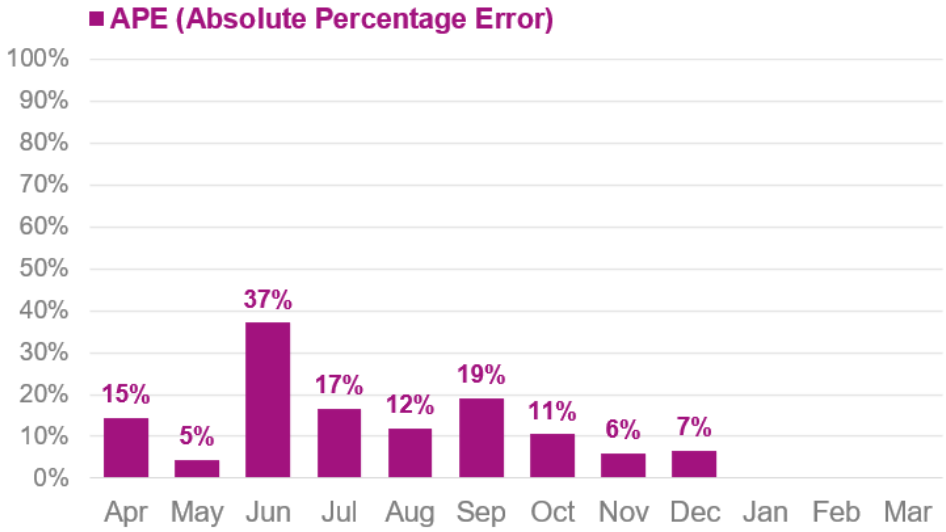


Table: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance - one-year view

	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	18.17	14.57	12.93			
Month-ahead forecast (£ / MWh)	11.15	12.46	13.52	12.51	12.67	13.40	16.45	15.49	14.49			
APE (Absolute Percentage Error)[5]	14.5	4.5	37.1	16.7	12.0	19.2	10.5	5.9	6.6			
Average Monthly APE (by Quarter)		18.7			16.0			7.7				

Supporting information

Q3 Performance:

The average monthly Absolute Percentage Error for Q3 is 7.7%, with actuals being higher than month-ahead forecasts for October.

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 October 2025 forecast.

In October, balancing costs outturned around the 80th percentile of our month-ahead forecast, £49m higher than expected. Constraint costs were the largest component of this difference, £30m higher than forecast. We have found previously that a higher proportion of demand being met by renewable generation tends to correlate with higher constraint costs. We had forecasted 40% of demand to be met by renewables; this outturned at 46%.

Both November and December out-turned below forecast, at the 40th and 35th percentile of the month ahead forecast respectively. In November, constraints outturned £20m below forecast and wholesale market prices were also lower than forecast, outturning at £78/MWh compared to the forecast £83/MWh. For December, constraints were £24m below our month ahead forecast.

The recent out-turns 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 Q3 our average monthly volume forecasting error was 1.2%. The largest variance was in October with volumes out-turning above forecast.

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