Public

NESO RIIO2 Business Plan 2 (2023-25)

January 2025 Incentives Report

25 February 2025

Contents

Introduction

As part of the RIIO-2 price control, we submitted a second Business Plan to Ofgem in August 2022. It sets out our proposed activities, deliverables, and investments for years three and four of RIIO-2 (2023-2025) as we respond to the rapidly changing external environment.

The Business Plan 2 Delivery Schedule sets out in more detail what we will deliver, along with associated milestones and outputs, for the "Business Plan 2" period.

Ofgem, as part of its Final Determinations for the RIIO-2 price control, set out that we would be subject to an evaluative incentive framework, assessing our performance in delivering the Business Plan.

An updated guidance was published in September 2024 called NESO Performance Arrangements Governance (NESO PAG) Document. It sets out the process and criteria for assessing the performance of NESO, and the reporting requirements which form part of the incentives scheme for the remainder of the BP2 period. Every month, we report on a set of monthly performance measures; Performance Metrics (which have benchmarks) and Regularly Reported Evidence items (which do not have benchmarks). This report is published on the 17 working day of each month, covering the preceding month.

Every quarter, we report on a larger set of performance measures. Our eighteen-month report was similar to our usual quarterly report with the addition of providing an update on our progress against our Delivery Schedule in the RIIO-2 deliverables tracker.

Our end of scheme report will be more detailed, covering all of the criteria used to assess our performance.

Following our Business Plan 2 (BP2) submission, Ofgem outlined the requirement for a Cost Monitoring Framework (CMF). The objective of the CMF is to provide visibility of our BP2 Digital, Data and Technology (DD&T) delivery progress and cost management, and the value being delivered across the BP2 DD&T investment portfolio. As per the NESO PAG guidance, we are required to provide quarterly reports directly to Ofgem as part of the CMF. We feel it is important to share updates with our external stakeholders and industry as part of the framework. So, we'll be including a summary of the CMF update every six months alongside our incentives reporting.

Please see our website for more information.

Summary of Notable Events

In January we successfully delivered the following notable events and publications. We provide further detail on each of these under the role sections:

- On 30 January, we welcomed 106 customers to our Balancing Programme 'Beyond 2025' webinar. The programme aims to align our future balancing and forecasting transformation roadmap with customer expectations, support a decarbonised energy system, and deliver consumer value. We shared insights from our capabilities survey, highlighting the most important balancing and forecasting capabilities identified by the industry, divided into Enhanced Dispatch, Whole System and Flexibility, and Data and Transparency.

- On 31 January, we published the TNUoS Tariffs for the 2025/26 charging year, effective from 1 April. To help customers understand the Final Tariffs and answer questions, we hosted a webinar on 13 February with over 60 attendees. Alongside the TNUoS Tariffs, we released the Annual Load Factors (ALFs) for 2025/26 and a timetable for the 2026/27 tariff publications. The Initial Forecast of the 2026/27 TNUoS Tariffs will be published in April 2025. We are engaging with the industry and Ofgem to ensure the timetable meets industry needs, especially for the CfD AR7. All these documents can be found online here.

- On 29 January, the "Unlocking the potential of demand side flexibility" webinar was held. This webinar aimed to promote the two reports we published before Christmas, Enabling Demand Side Flexibility in NESO markets report and Route to Market Review Stage 2 report, and provide industry stakeholders the opportunity for clarifications and questions. We saw more than 140 attendees joined this event.

- On 22 January, we held a Response Reform Webinar to address key challenges in Frequency Response Services, focusing on Mandatory Frequency Response (MFR) and Static Reform. We discussed issues, potential solutions, and service design ideas. Additionally, we covered reforms to Dynamic Response Services, including Locational Procurement, automated penalties, and future consultations. Post-webinar, we conducted 1-2-1s with industry stakeholders for detailed discussions, aiming for a collaborative process.

- In January, CrowdFlex successfully completed its first year of large-scale domestic flexibility trials. CrowdFlex is a NESO-led project exploring domestic flexibility for grid management. In its beta phase, it has completed the first year of trials, testing recruitment messages and building flexibility models. Surveys with 3,600 participants revealed insights, detailed in a published report. Ongoing 2025 trials will focus on deeper research, varied messaging, and targeting low-income, vulnerable customers, and different customer archetypes.

- In January, we launched the beta phase of the Powering Wales Renewably innovation project. The Powering Wales Renewably project is creating a digital twin of Wales' energy system, including electricity and gas networks. NESO, in partnership with network operators, the Welsh Government, and CGI, has launched the beta phase. The project aims to address challenges like locating new assets, speeding up connections, and using flexibility locally. Increased visibility will enhance coordination and renewable connections. Data sharing on a single platform is crucial, setting a blueprint for other regions and improving energy system awareness.

- In January, Connections hosted two webinars. The first webinar, on the Connections Application Pause, covered key changes during the pause period beginning on 15 January and upcoming timelines. The second webinar, on Connections Reform Final Proposals, provided an overview of the final reform proposals for codes and methodologies, consultation responses, and key changes made as a result. Each event received significant sector engagement, with over 700 attendees and lots of questions during the Q&A section.

- On 28 January, we published the 2024 Electricity Ten Year Statement (ETYS). This annual report outlines future requirements and investments needed for GB's National Electricity Transmission System (NETS) to achieve zero-carbon goals. Based on Future Energy Scenarios (FES) 2024 and Clean Power 2030 Pathways, we highlight future transmission needs and NETS' capabilities. This year's ETYS identifies emerging voltage issues and the need for accelerated network reinforcement to reduce costs during the clean power transition. As NETS operation becomes more complex, the upcoming Centralised Strategic Network Plan (CSNP) will address broader system requirements and provide a year-round perspective.

- On 17 January, we launched the invitation to tender (ITT) for the second round of the Mid-Term (Y-1) Stability Market, seeking stability services from October 2026 to September 2027. Last year, we awarded 5 contracts for 5 GVA.s of inertia for 2025-2026, expected to save consumers £47.3m. This year, we aim to procure 15 GVA.s of inertia with a technology-agnostic approach, anticipating significant savings and supporting Clean Power 2030 goals. More information on the Mid-Term (Y-1) Stability Market can be found here.

NESO Notable Events

NESO launches Data Sharing Infrastructure pilot

As part of NESO's Virtual Energy System, we have launched the pilot phase of the Data Sharing Infrastructure (DSI) following DESNZ's response to the Digital Spine Feasibility Study. This includes delivering the pilot and Minimum Viable Product (MVP), and leading the collaboration with industry partners. In November, we met with Ofgem and network partners and received very positive feedback on the initiative.

The DSI builds on the recommendations for a digitalised net zero energy system and the digital spine feasibility study to enable trusted, secure, resilient and scalable data sharing between energy sector participants.

The DSI is designed to reduce the socio-technical barriers to data sharing, consisting of two main components:

- **Data Preparation Node (DPN):** A containerised software application that prepares and presents data in a standardised format for use across organisations.

- **Data Sharing Mechanism (DSM):** A coordination and control layer that governs secure and trusted data exchange.

We're excited that we've introduced such innovative components designed to solve a critical problem in the energy sector. These will enable data to flow seamlessly across organisations while maintaining security and trust. Our pilot phase will initially demonstrate this with electricity outage planning, showing how data sharing can streamline processes and support operational decision-making.

If you have any questions about DSI, please email VirtualES@nationalenergyso.com

Summary of Metrics and RREs

The table below summarises our Metrics and Regularly Reported Evidence (RRE) for January 2025.

Metric/RRE		Performance	Status
Metric 1A	**Balancing Costs**	£212m vs benchmark of £282m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 735MW vs indicative benchmark of 669MW	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 4.54% vs indicative benchmark of 5.44%	●
RRE 1E	**Transparency of Operational Decision Making**	91.4% of actions taken in merit order or driven by an electrical parameter	N/A
RRE 1G	**Carbon intensity of NESO actions**	3.91gCO_2/kWh of actions taken by the NESO	N/A
RRE 1I	**Security of Supply**	0 instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	0 planned and 0 unplanned system outages	N/A

Below expectations ● **Meeting expectations** ● **Exceeding expectations** ●

We welcome feedback on our performance reporting to box.soincentives.electricity@uk.nationalenergyso.com

Carole Hook
Head of Regulation

Role 1

(Control Centre operations)

Metric 1A Balancing cost management

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

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

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

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

Non-constraint costs = 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.

January 2024-25 performance

Figure: 2024-25 Monthly balancing cost outturn versus benchmark

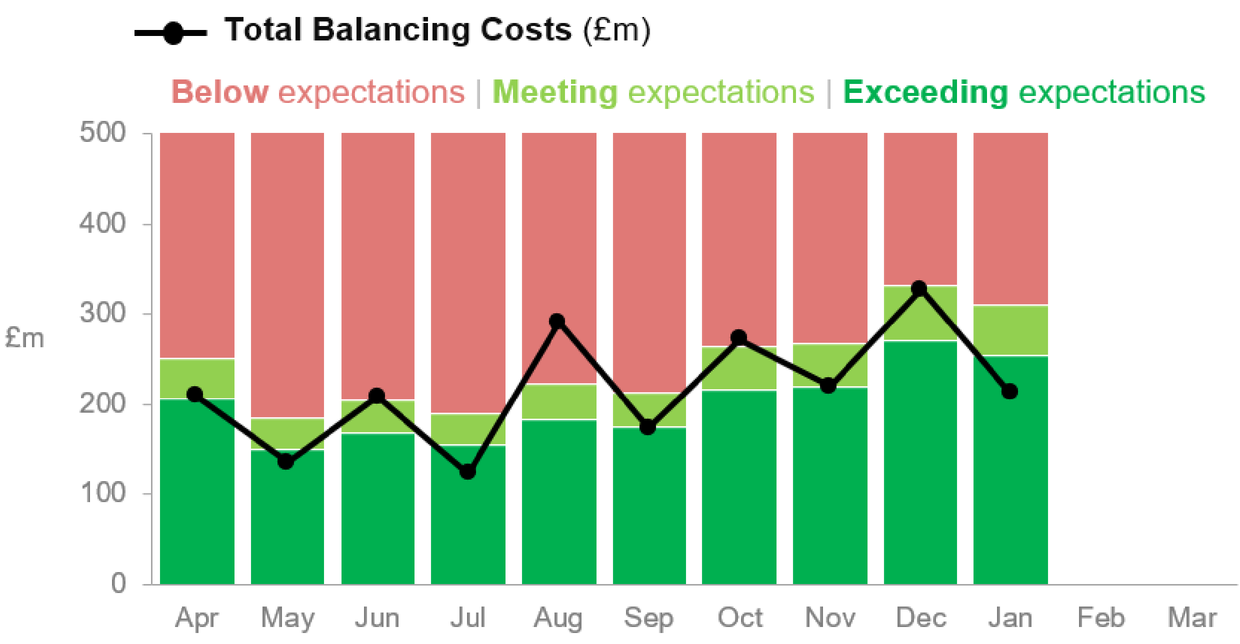


Table: 2024-25 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	6.3	3.2	3.9	3.5	5.1	4.2	5.7	5.3	7.9	6.1			50.4
Average Day Ahead Baseload (£/MWh)	59	72	76	71	62	76	88	103	99	127			n/a
Benchmark	228	167	187	173	203	194	239	243	301	282			2215
Outturn balancing costs[1]	**209**	**135**	**208**	**123**	**291**	**173**	**272**	**220**	**327**	**212**			**2170**
Status	●	●	●	●	●	●	●	●	●	●			●

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

Performance benchmarks:

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

Supporting information

BALANCING COSTS METRIC & PERFORMANCE

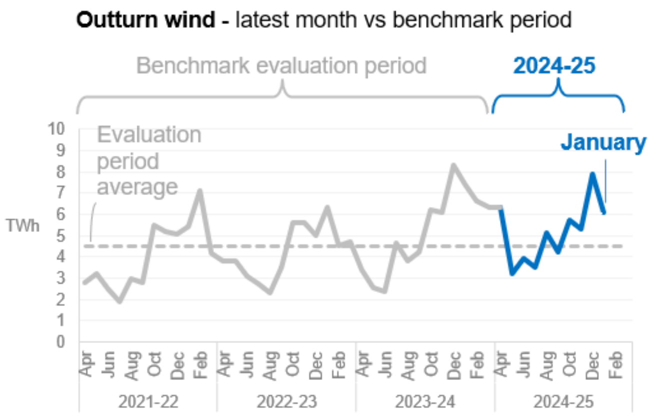
This month's benchmark

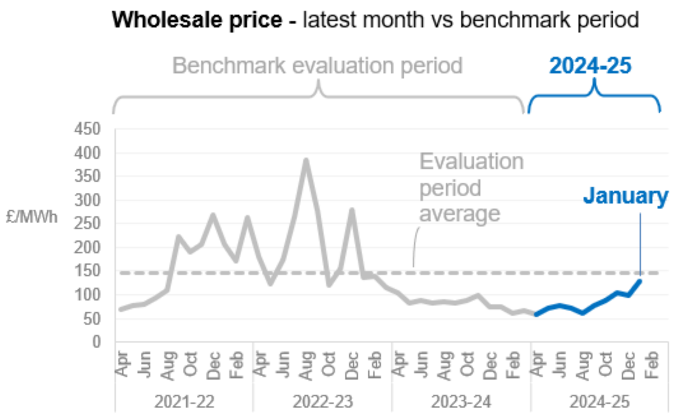
The January benchmark of £282m is £17m lower than December 2024 and reflects:

- An **outturn wind** figure of 6.1 TWh that is higher than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 4.5 TWh) but is lower than last month's figure (7.9 TWh).
- An average monthly **wholesale price** (Day Ahead Baseload) that has increased compared to December and marks a record high so far in 2024-25. However, it remains lower than the evaluation period average.

The decrease in wind outturn contributed to the decrease in the overall benchmark compared to last month but this was somewhat offset by the higher wholesale price.

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





Variable	January 2025	December 2024	January 2024
Average Wholesale Price (£/MWh)	127	-28	-52
Total Wind Outturn (TWh)	6.1	+2.6	+2.1
Benchmark (£m)	282	+37	+12
Performance	●	●	●

*The first three rows show the outturn measures for this month and difference in the previous month and same month last year, while the bottom row outlines outturn performance for each month.

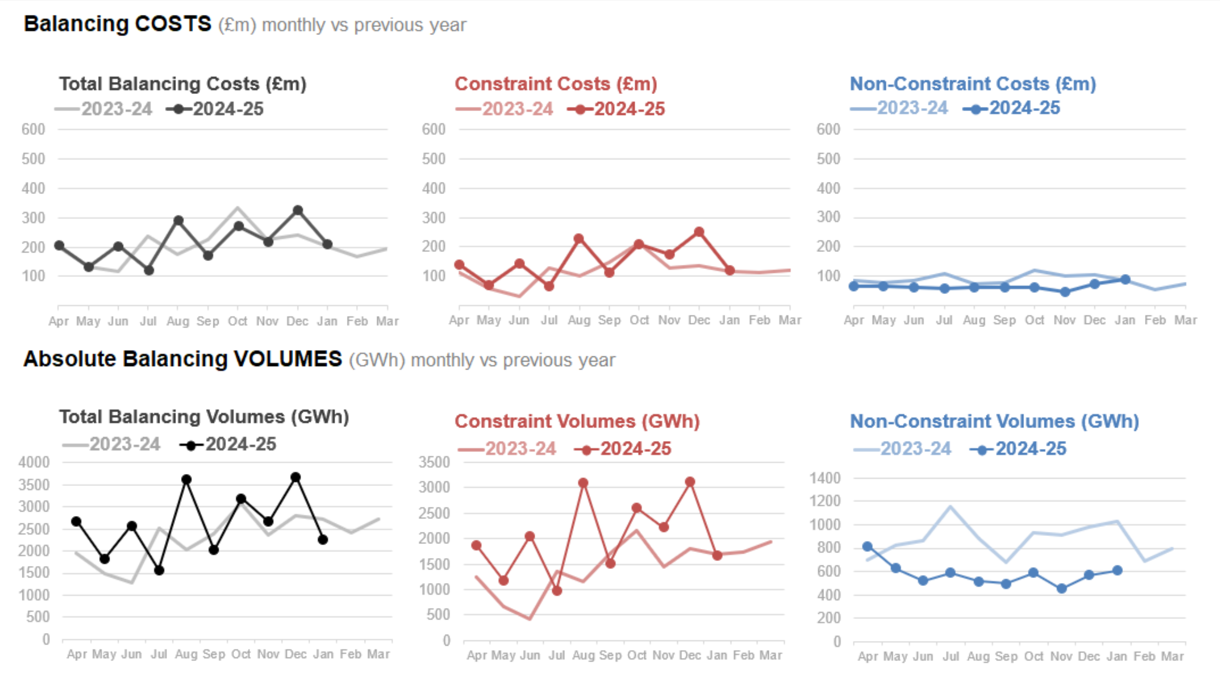
Balancing Costs - Overview

The total balancing costs for January were £212m, which is £70m (25%) below the benchmark of £282m, and therefore performance is exceeding expectations.

Very low temperatures, high demand and weather warnings in place across large parts of the country early in the month led to tight margins that required actions to increase available generation. As a result, 8 January was the highest cost day of the month with the largest spend on this day linked to operating reserve. An Electricity Margin Notice (EMN) was issued at 20:30 on 7 January showing a shortfall of 1,700 MW. A Capacity Margin Notice (CMN) was also automatically generated at 12:01 on 8 January showing a shortfall for the half-hour starting 16:30. The CMN was automatically cancelled at 12:32, as the shortfall had been overcome. The EMN was then cancelled at 16:15. The Demand Flexibility Service (DFS) auction was activated in the morning and secured 92 MW – 184 MW of demand turn down between 16:00 and 19:00 and action was taken to ensure that the full Viking Interconnector capability of 1,400 MW was made available from 14:00. NESO additionally took actions ahead of time on 7th to improve margin, reduce risk, and lower costs on 8th, including actions to return domestic and European transmission lines to service. All operational system and balancing requirements were subsequently met.

Later in the month higher costs were linked to constraint management. Storm Éowyn additionally brought windy weather to northwestern parts of the UK on the 24th, pushing up costs on this day. However, overall constraint costs fell by £130.3m compared to the previous month, falling £39.4m in England Wales and £92.8m in Scotland respectively.

Average wholesale power prices were up £27.6/MWh compared to December 2024 and £52.1/MWh compared to January 2024. The volume weighted average price for bids reduced £32.7/MWh compared to last month (from -£131.2/MWh to -£98.5/MWh), and the volume weighted average price for offers increased by £28.7/MWh (from +£129.5/MWh to +£158.2/MWh), in line with the monthly increase in average wholesale price. Non-constraint volumes have decreased by 373 GWh but costs were £16.5m higher compared to December.

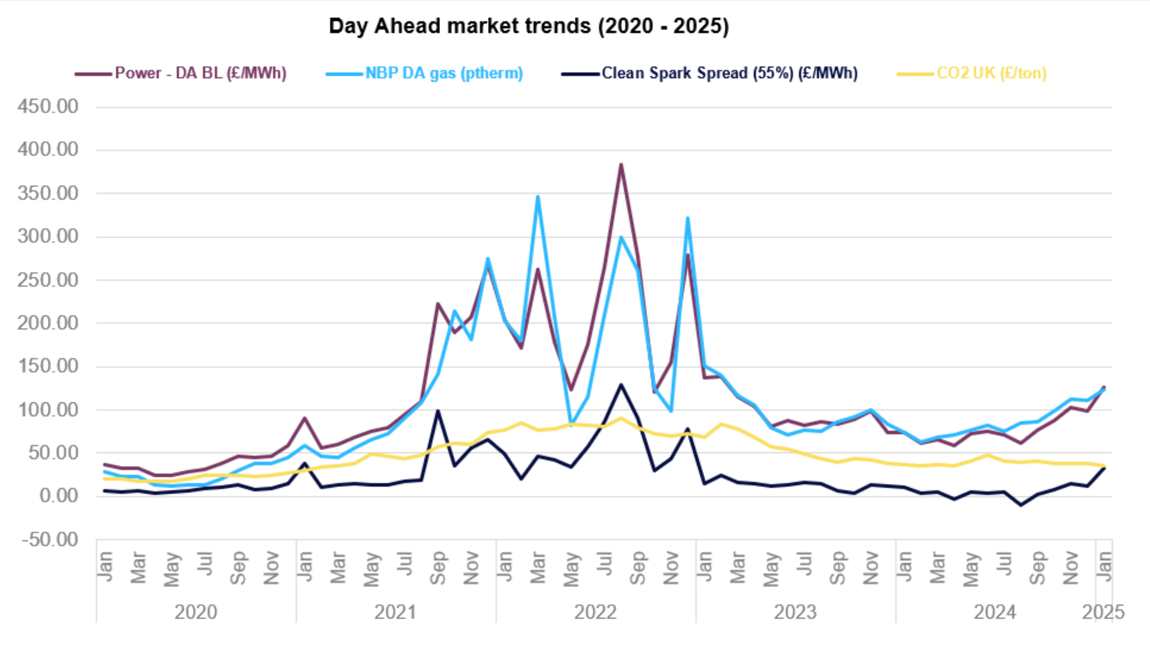


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

Market trends

Power and gas prices increased on last month, with a subsequent increase in the Clean Spark Spread Price and a slight drop in the CO_2 price. Power and gas prices are also higher compared to the same time last year, while the CO_2 price is lower. Higher prices are linked to higher demand and below average temperatures in January driving up gas for heating demand and subsequently power prices. Lower wind early in the month also contributed to tighter system margins and geopolitical developments remain influential on prices, including the end of Russian gas pipeline supplies across Ukraine to the EU on 31 December 2024.



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

Wind Outturn

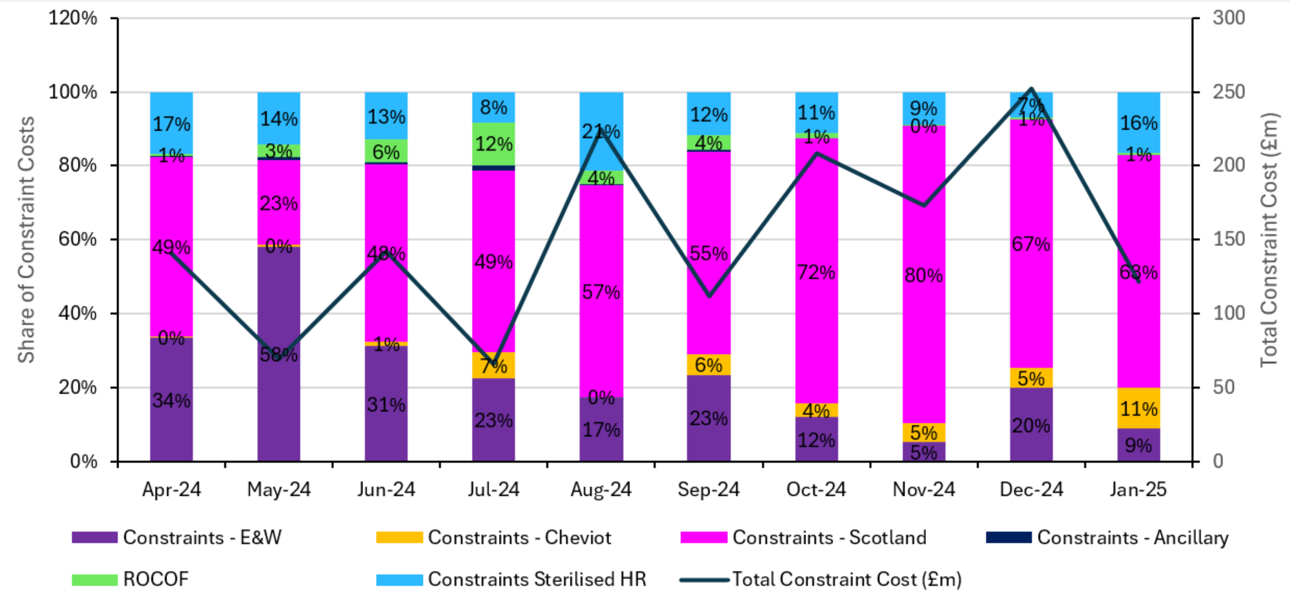
January saw mixed conditions with storms bringing particularly unsettled weather in the second half of the month. Storm Éowyn brought windy weather to northwestern parts of the UK and red warnings for wind on the 24th. Storm Hermina then followed shortly after bringing heavy rain and strong winds to southern England and Wales.

Overall wind outturn decreased from 7.9 TWh in December to 6.1 TWh in January, with a 39% and 21% decrease in England & Wales and Scotland respectively, giving a 33% decrease overall. Wind outturn was also down 28% on January last year. The volume of wind curtailment fell to 0.53TWh in January compared to 1.36TWh in December and 0.55TWh in January 2024.

The highest wind curtailment for the month was seen on 13 January at 386 GWh, representing 21% of the outturn. Reflecting active constraints at the Scottish boundaries.

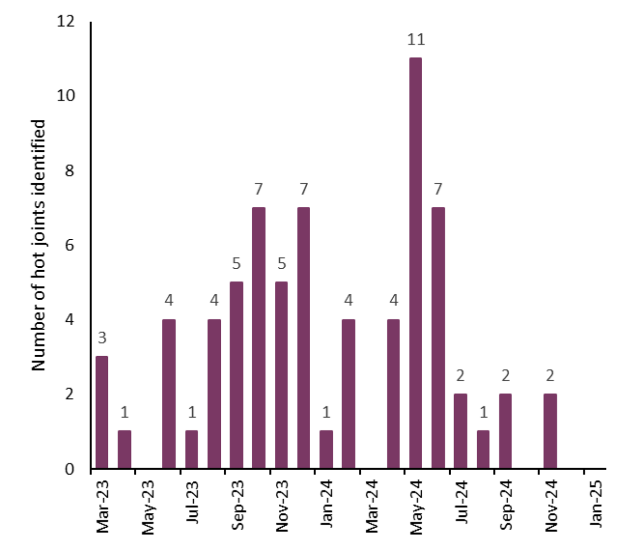
Constraints

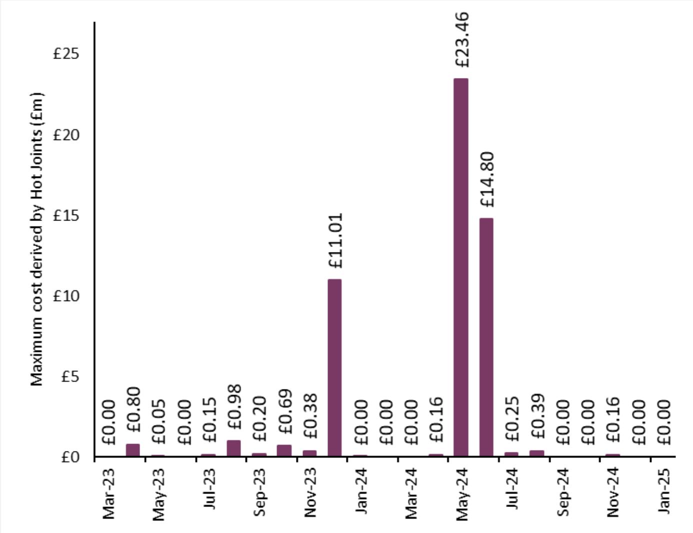
Constraint costs in January decreased by £130.3m compared to December 2024. Costs fell across all constraint components. Despite this decrease Scottish constraints remained £13m higher than January 2024. Lower constraint costs were linked to a reduction in wind outturn and network constraints. It is anticipated that Scottish constraints will continue to represent a significant portion of the costs in 2025 due to various outages aimed at enhancing the transfer capacity of Scottish boundaries.



Network Availability

We continue to monitor the occurrence of hot joints in the system and their potential cost impact. No hot joints were identified in January.





BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): January 2025 vs December 2024

		(a) Dec-24	(b) Jan-25	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Non-Constraint Costs	Energy Imbalance	-4.1	-3.9	0.1	
	Operating Reserve	10.4	25.2	14.9	
	STOR	9.9	11.8	1.9	
	Negative Reserve	2.7	1.2	(1.6)	
	Fast Reserve	15.8	18.1	2.3	
	Response	19.5	20.3	0.8	
	Other Reserve	1.9	1.8	(0.1)	
	Reactive	12.0	11.4	(0.6)	
	Restoration	3.3	3.6	0.3	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	3.8	0.4	(3.4)	
Constraint Costs	Constraints - E&W	50.2	10.8	(39.4)	
	Constraints - Cheviot	13.5	13.4	(0.1)	
	Constraints - Scotland	169.6	76.7	(92.8)	
	Constraints - Ancillary	0.4	0.2	(0.2)	
	ROCOF	1.4	0.7	(0.7)	
	Constraints Sterilised HR	17.2	20.0	2.8	
Totals	Non-Constraint Costs - TOTAL	75.2	89.8	14.6	
	Constraint Costs - TOTAL	252.2	121.8	(130.4)	
	Total Balancing Costs	**327.4**	**211.6**	**(115.8)**	

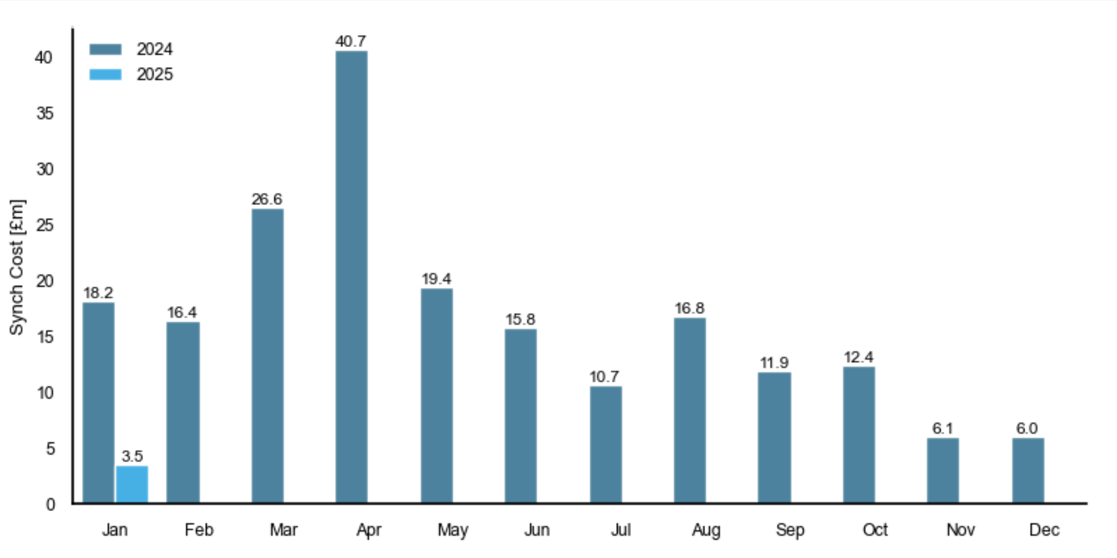
As shown in the totals from the table above, constraint costs decreased by £130.4m and non-constraint costs increased by £14.6m, resulting in an overall decrease in balancing costs of £115.8m compared to December 2024.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: -£92.9m **Constraint – England & Wales: -£39.4m** **Constraint Sterilised Headroom: +£2.8m** Constraint costs decreased by £130.4m in January 2024, coinciding with a 373 GWh decrease in the volume of actions. Wind outturn has been significantly lower in January and there has been a reduced impact from outages compared to previous months.	**Constraints – Scotland & Cheviot: +£16.2m** **Constraints – England & Wales: -£10.5m** **Constraints Sterilised Headroom: +£1.4m** Constraint costs have increased by £6.5m compared to last year, despite a 347 GWh reduction in volume. Wind outturn in January 2025 was around 1.1 TWh lower than January 2024, but power prices were significantly higher compared to last year.

ROCOF: -£0.7m	ROCOF: -£0.6m
In January, the system's outturn inertia (including market-provided, stability assets, and synchronous plants used for voltage support) resulted in lower volumes to meet the minimum inertia requirements of the system. A decrease of 151 GWh in the volume of actions was observed during this period.	The expenditure on ROCOF tends to be marginal in the system. The implementation of the FRCR requirement reduction (140 GVAs to 120 GVAs) across February to June 2024 is contributing to reduced inertia volumes and costs compared to the previous year. Additionally, the gradual addition of assets commissioned through the Stability Pathfinder Phase 2 is expected to positively contribute to inertia levels in the system, resulting in minimal ROCOF spending.

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, depending on their location. In January, the system synchronisation costs (what it costs to the system, which factors in energy replacement, headroom among others) amounted to £3.5m, which is lower than the same period in 2024.

Additional factors driving lower voltage management costs include:

- Economic assets commissioned through voltage pathfinders. This includes the ones allocated in Mersey (a 38 MVAr battery at Capenhurst and a 200 MVAr reactor in Frodsham) and Pennines (reactors at Bradford West – 100 MVAr, Stocksbridge – 200 MVAr and Stalybride – 200 MVAr).
- Stability assets commissioned through stability pathfinders. Twelve synchronous compensators received contracts through Phase 1, providing roughly 12.3 GVA.s of inertia to the system, in addition to 1.06 GVAr of absorption and 950 MVAr of injection capacity.

Reactive Costs/Volumes

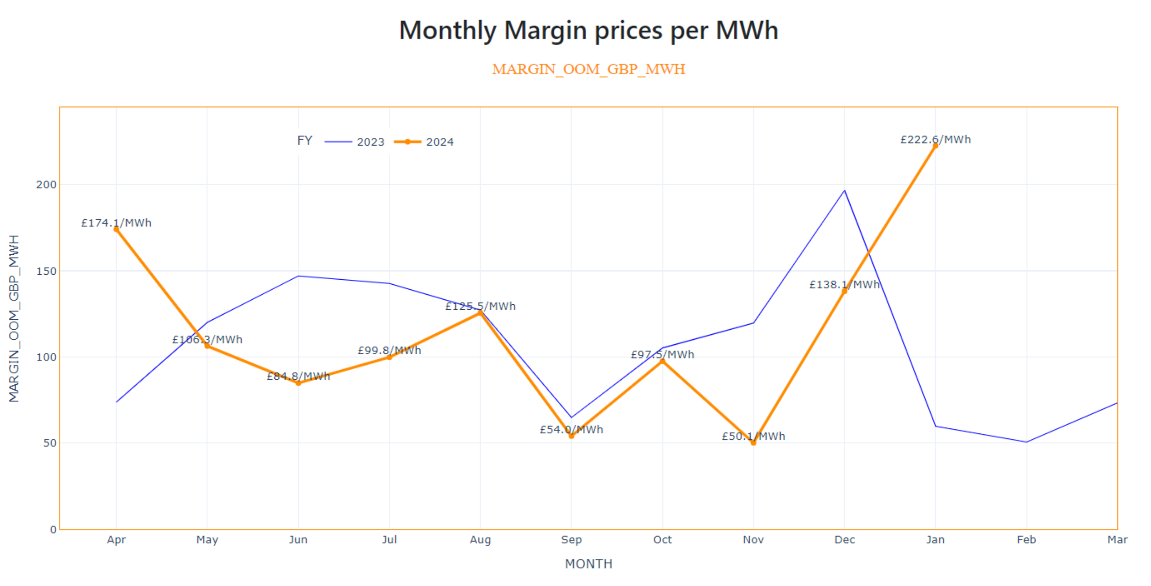
The volume-weighted average price for reactive power was £4.3/MVAr in January 2025.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£0.7m The volume-weighted average price decreased from £4.4/MVAr to £4.3/MVAr compared to last year.	-£2.8m The volume-weighted average price decreased from £4.5/MVAr to £4.3/MVAr compared to last year.

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

Reserve Costs/Volumes

Reserve prices increased to £222.6/MWh in January from £138.1/MWh in December 2024.This is aligned with an increase in the wholesale price month-on-month.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£14.9m **Fast Reserve: +£2.3m** There was a 435 GWh decrease in the volume of Operating Reserve required to secure the system compared to December but increase in margin prices over this period.	**Operating Reserve: +£8.8m** **Fast Reserve: +£2.7m** Margin prices were significantly higher in January 2025 compared to the previous year, increasing from £59.8/MWh to £22.6/MWh.

Response Costs/Volumes

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

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£2.1m There was a 13.5 GWh increase in the volume of actions compared to December. Higher costs were also linked to higher clearing prices for response services.	**+£5.4m** The volume of actions taken for response reduced 75.9 GWh compared to January 2024, although clearing prices were higher.

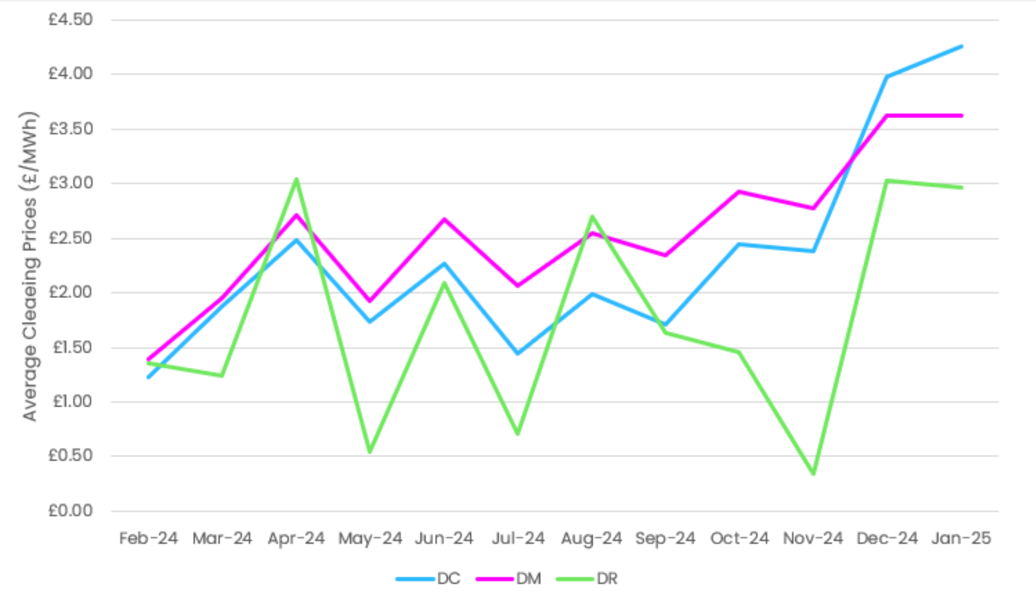
Dynamic Services Average Clearing Prices: January 2025 vs December 2024

		(a) Jan-25	(b) Dec-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	4.3	4.0	0.3	
	DM	3.6	3.6	0.0	
	DR	3.0	3.0	(0.1)	

Dynamic Services Average Clearing Prices: January 2025 vs January 2024

		(a) Jan-25	(b) Jan-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	4.3	1.4	2.9	
	DM	3.6	1.6	2.0	
	DR	3.0	2.2	0.8	

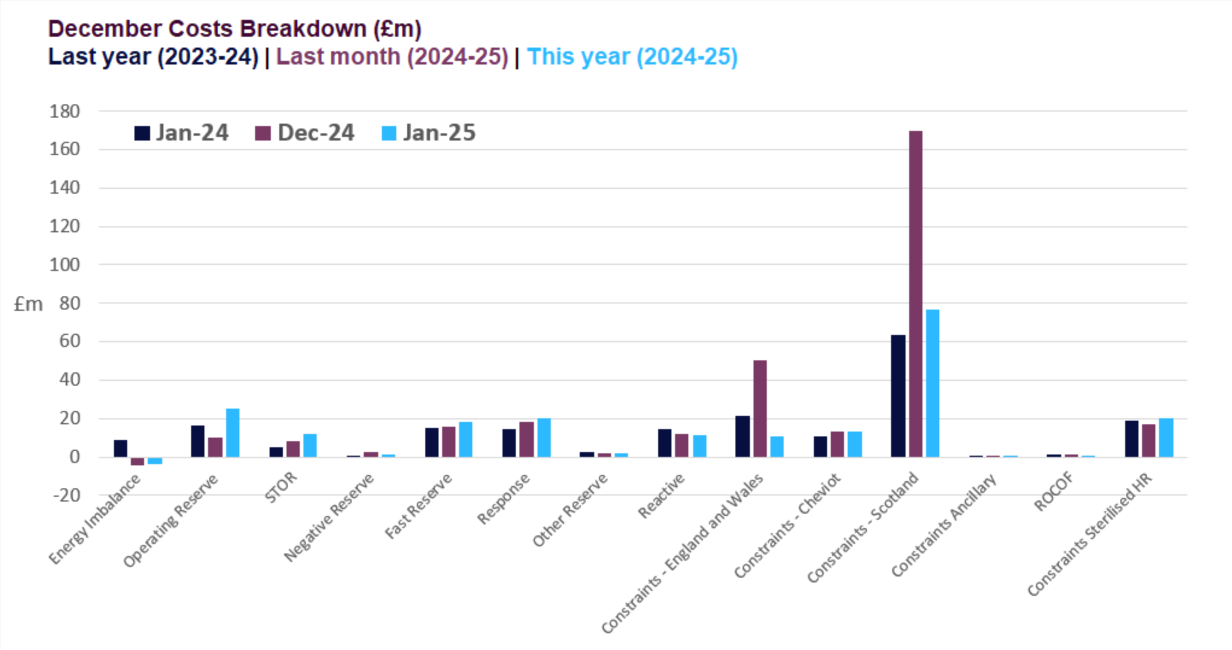
Average clearing prices for DC, DM and DR increased in January compared to December 2024 and January 2024.



Comparison breakdown

Constraint costs reduced by £130.3m compared to the previous month, this is due to a decrease in both England and Wales (£39.4m decrease) and Scotland (£92.8m decrease). However, constraint costs are up on last year, by £6.5m largely due to higher costs from Scottish constraints, despite constraint volumes being 122 GWh lower. Non-constraints costs increased by £16.5m from last month, largely driven by increases in most categories (especially operating reserve) and small deviations in others, and non constraint costs were £3.2m higher than January last year.

Thermal constraints currently dominate constraint costs. We are progressing several initiatives to reduce thermal constraint volumes/costs including the Constraints Collaboration Project and Constraint Management Intertrip Service. The ongoing Review of Electricity Market Arrangements (REMA) is also considering options that could alleviate thermal constraints over the long term such as zonal pricing. Network Service Procurement projects for voltage and stability are also helping to provide solutions for network management at lowest cost.



COST SAVINGS

Cost Savings – Outage Optimisation

Total savings from outage optimisation amounted to approximately £55 million in January 2025. This represents a reduction of around £83 million compared to December 2024, where savings were £138 million. The most valuable action taken was the alignment of two significant outages in Scotland. If these outages had been conducted separately, they would have severely reduced the transfer capacity of the B4 boundary by 1,150 MW. The estimated cost savings for this action are around £33.1 million

Cost Savings – Trading

The Trading team were able to make a total saving of £7.4m in January 2025 through trading actions as opposed to alternative BM actions, representing a 71.0% decrease on the previous month. This is the lowest saving over the last 12 months, due to a combination of factors. Over January the interconnectors have mostly been on import, often fully importing, which reduces the need for margin trades. However, there has been a rise in trading against Emergency Instruction (EI) or Emergency Assistance (EA) on certain days, especially for constraints, which is not included in our savings, with ~37% of trades being against EI and EA in January. The day with the greatest spend on trades was the 15 January at a cost of £3.16m with the greatest component being for managing the SEIMP constraint.

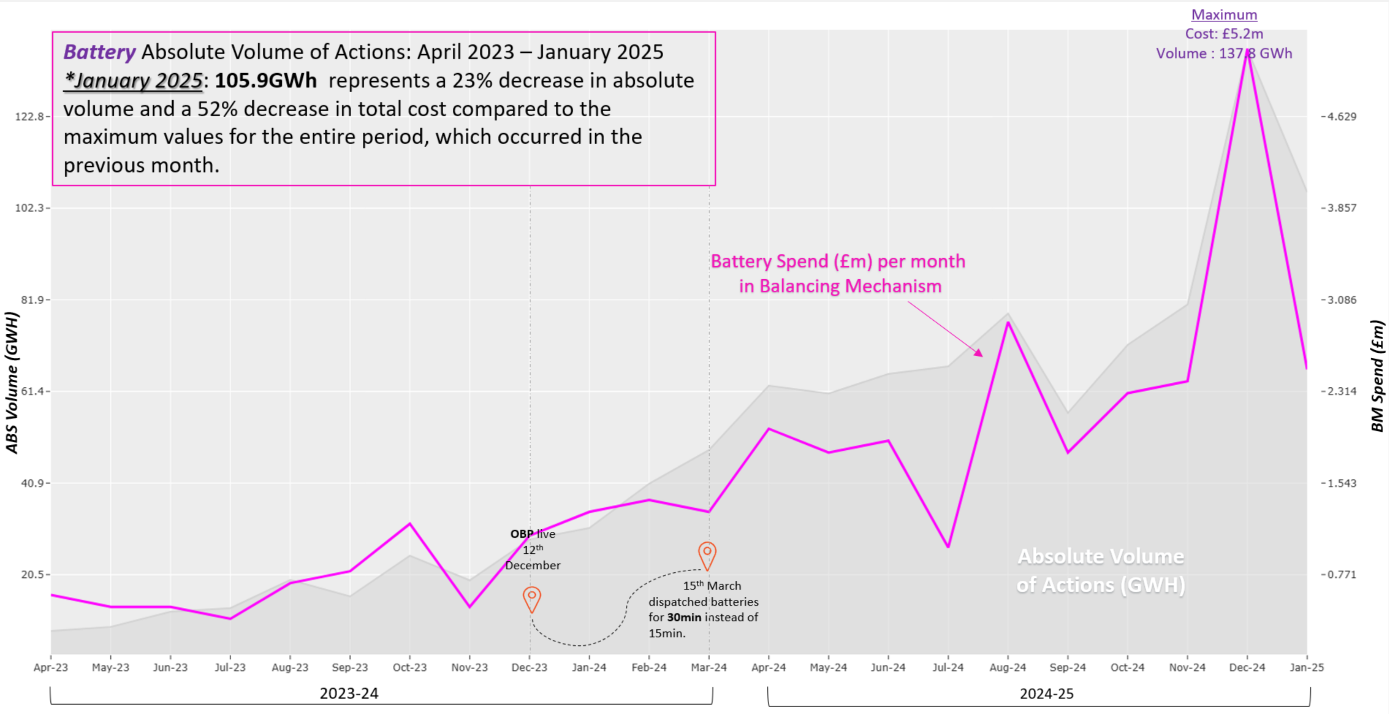
Cost Savings – Network Services Procurement (NSP)

We are using Network Services Procurement (NSP) 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, and Stability Phase 1 have delivered approximately £287m in savings since April 2023. This represents the first set of live NSP projects, with savings for other live and future projects also undergoing development and implementation, such as Voltage Pennines and Stability Phase 2.

NOTABLE EVENTS

Monthly Absolute Volume of actions and spend for Batteries in the Balancing Mechanism

April 2023 to January 2025



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

The total absolute volume of actions and costs have both decreased compared to the previous month, December 2024, which saw the maximum battery dispatch for the entire period. Although battery dispatch decreased, it remained significantly higher than in earlier periods, at approximately 106 GWh. This illustrates our commitment to maximising the flexibility of energy provided by battery storage and small BMUs over the last year. Most of the spending on batteries was related to margin and minor components.

*An update in our database of the battery fleet had as result the updated graph and figures above.

DAILY CASE STUDIES

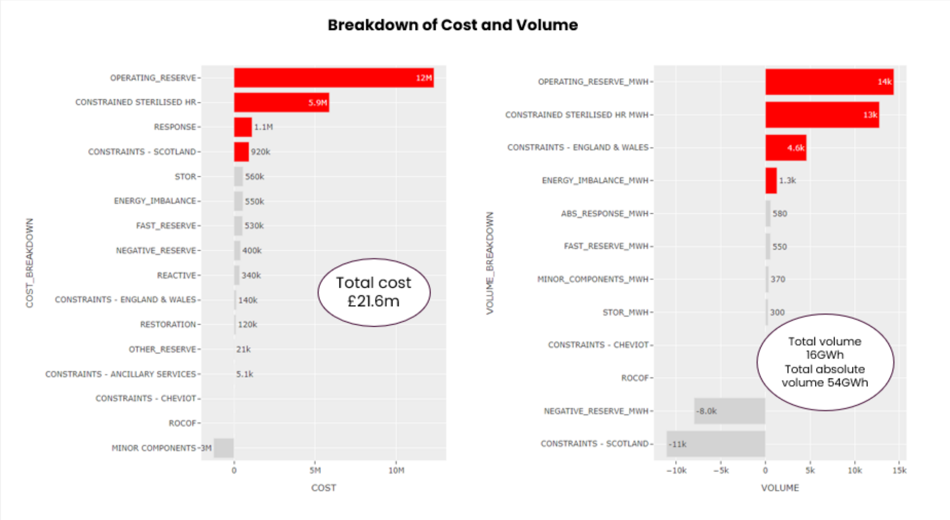
Daily Costs Trends

January's balancing costs were £212m which is £114m lower than the previous month. Two days were recorded with costs above £15m, the 8 and 14, with an additional four having a daily total cost over £10m (15, 16, 17, 24). The daily average decreased by £7.3m compared to December 2024 (£10.5m to £7.3m).

The lowest cost day was observed on 19 January, with a total balancing cost of approximately £2.0m. Generation on this day was largely met by self-dispatching plant. The highest cost day was 8 January, with a total spend of £21.6m. This day saw the largest amount of spend on operating reserve to manage tight margins due to low temperatures, high demand and weather warnings in place across large parts of the country. An Electricity Margin Notice (EMN) and a Capacity Margin Notice (CMN) were sent to inform the market and all operational system and balancing requirements were met.

More details on 8 January margins can be found here.

High-Cost Day – 8 January 2025

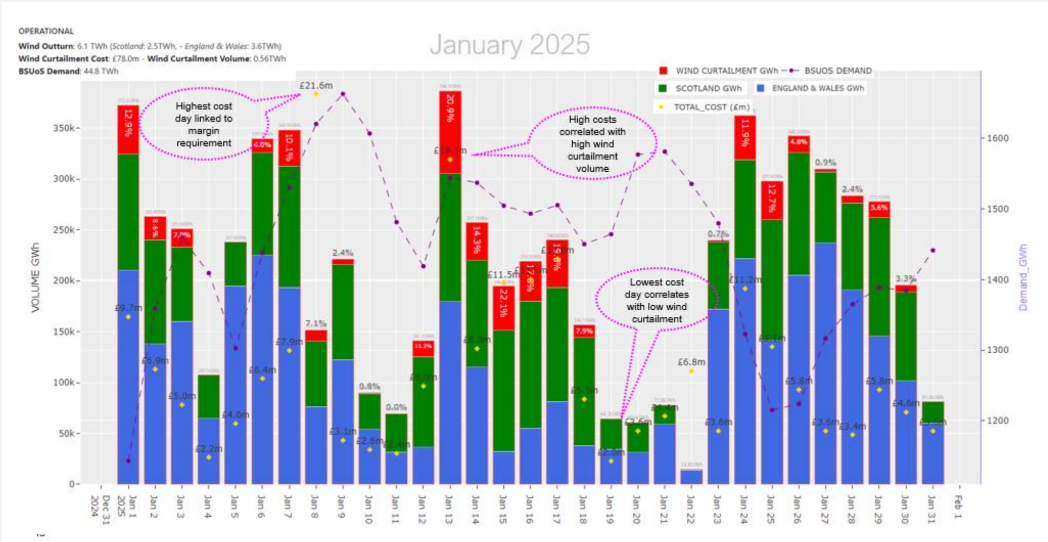


December Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUoS Demand

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.

Metric 1B Demand forecasting accuracy

This 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. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

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

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

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

January 2024-25 performance

Figure: 2024-25 Monthly absolute MW error vs Indicative Benchmark

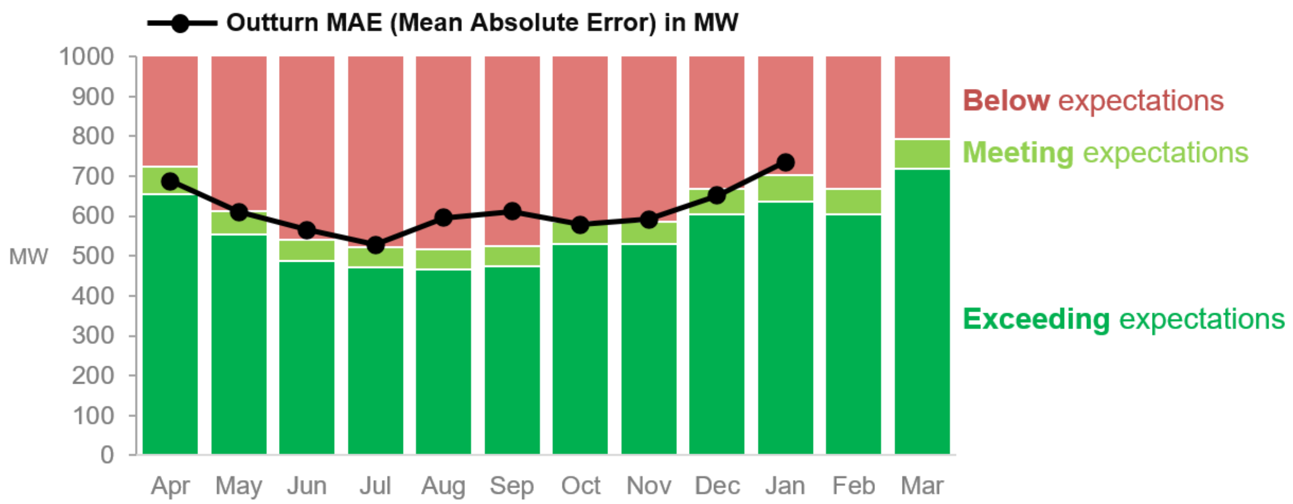


Table: 2024-25 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	690	584	514	496	491	500	559	557	635	669	637	756
Absolute error (MW)	**687**	**610**	**565**	**528**	**596**	**612**	**578**	**591**	**652**	**735**		
Status	●	●	●	●	●	●	●	●	●	●		

Performance benchmarks:

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

[2] Demand | BMRS (bmreports.com)

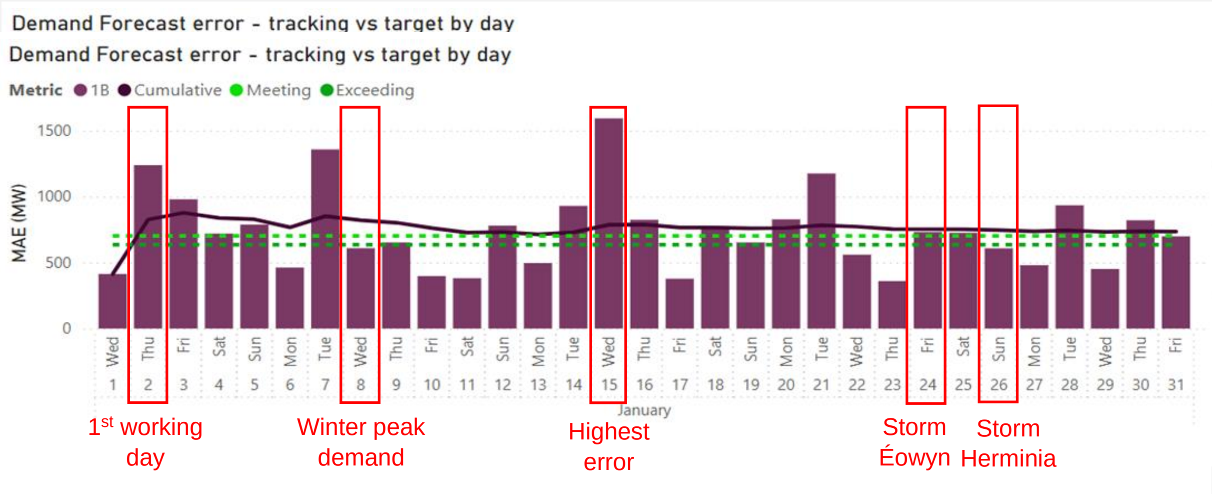
Supporting information

In January 2025, the mean absolute error (MAE) of our day ahead demand forecast was 735 MW compared to the indicative benchmark of 669 MW. The 5% range around this benchmark extends to 702 MW, meaning our performance failed to meet expectations for January.

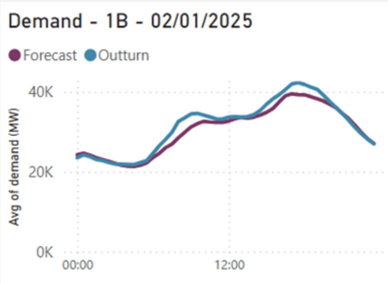
The Met Office reports that January was "very cold with snow, ice and fog first half, milder but stormy second half". Storm Éowyn hit the UK on 24 January and was followed shortly after by storm Herminia.

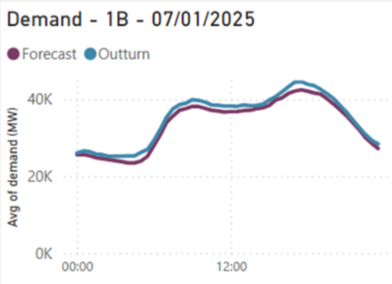
Accounting for DFS (Demand Flexibility Scheme) activity, peak demand occurred on 8 January (SP35) and this is likely to set the Winter Peak this season at 46.0GW. The cold weather period coincided with low wind levels across Great Britain, which elevated Distribution demand levels due to low Embedded Generation production.

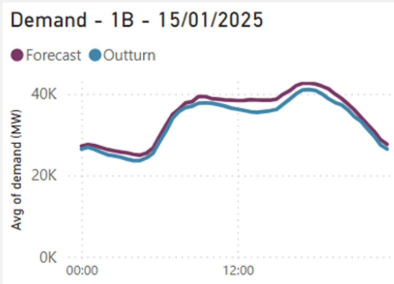
The largest demand forecast error this month was 4.1 GW on 2 January, settlement period 17.



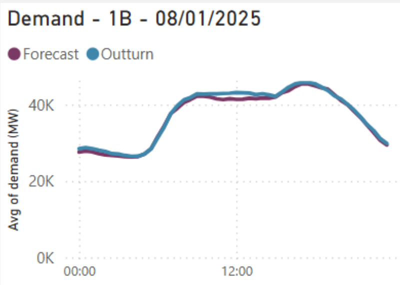
Below are details of the three days with the largest errors:







Winter peak demand:



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

Error greater than	Number of SPs	% out of the SPs in the month (1488)
1000 MW	425	29%
1500 MW	177	12%
2000 MW	60	4%
2500 MW	16	1%
3000 MW	5	0%

The three days with largest MAE were 2, 7 and 15 January.

Day	Error (MAE)	Major causal factors
2 Jan	1238	Process/Model/Profile error – First working day back after Xmas seasonal holidays. Current diagnostics do not identify the distinctive causal factor
7 Jan	1357	Embedded Wind forecast error and slow correction to rapidly cooling temperatures. Machine Learning models skewed by cycling GB temperature profiles.
15 Jan	1592	Solar forecast error and slow correction to rapidly warming temperatures. Machine Learning models skewed by cycling GB temperature profiles.

Missed / late publications

There were no occasions of missed or late publication in January.

Triads

Triads run between November and February (inclusive) each year.

Due to changes in charging methods, triads are expected to have a smaller effect than in previous years. However there may be other price related demand avoidance effects over the daily peaks.

Triad avoidance behaviour is predicted to have affected the following dates in January: 2, 9, 10, 21, 22 and 29, totalling 6850MWh.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on January 8, 14, 17, 20, 21, 22, 23 and 29, with a total of 1336MWh procured. These will affect the national demand outturn but are not included in the day ahead forecast.

Metric 1C Wind forecasting accuracy

This 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);
- 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.

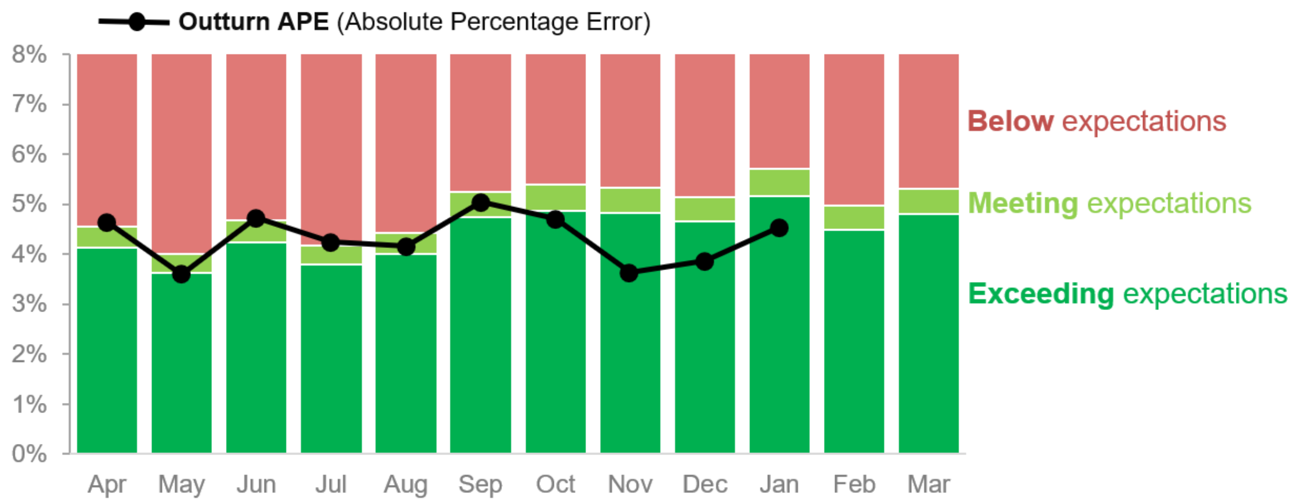
Sites deemed to have withdrawn availability are those that:

- 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.

The benchmarks are drawn from analysis of historical errors of the five years preceding the performance year. A 5% improvement in performance is expected on the 5-year historical average, with a range of ±5% used to set the benchmark for meeting expectations.

January 2024-25 performance

Figure: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmark



Change to methodology from 18-Month Report onwards

In line with the NESO Performance Arrangements Governance Document, from the 18-Month Report (published in October 2024), the APE% that we report excludes some of the factors that are outside of our control. This view excludes sites that have redeclared to zero and incorporates Initial Settlement Runs (+16 Working Days). This approach applies to the figures reported for the whole of 2024.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.34	3.82	4.45	3.98	4.22	4.99	5.13	5.07	4.89	5.44	4.73	5.05
APE (%)	**4.64**	**3.60**	**4.72**	**4.24**	**4.15**	**5.04**	**4.70**	**3.63**	**3.86**	**4.54**		
Status	●	●	●	●	●	●	●	●	●	●		

ESORI view of BMU Wind Generation Forecast APE (Previous Method)

Below, we report the APE% and benchmark based on the method described in The Electricity System Operator Reporting and Incentives (ESORI) Arrangements: Guidance Document. This applied prior to the transition to NESO on 1 October 2024, up to and including the figures reported in August 2024. This view includes sites that have redeclared to zero and does not incorporate Initial Settlement Runs (+16 Working Days).

A performance status is shown in the table below, however for the figures reported for September 2024 onwards, this is for information only and is not part of the 2024-25 incentives assessment.

Table: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmarks (ESORI method)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.32	3.85	4.43	4.02	4.19	4.98	5.13	5.02	4.93	5.46	4.74	5.09
APE (%)	**5.14**	**3.61**	**4.89**	**4.30**	**4.60**	**4.98**	**4.77**	**3.51**	**3.91**	**4.69**		
Status	●	●	●	●	●	●	●	●	●	●		

Performance benchmarks:

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

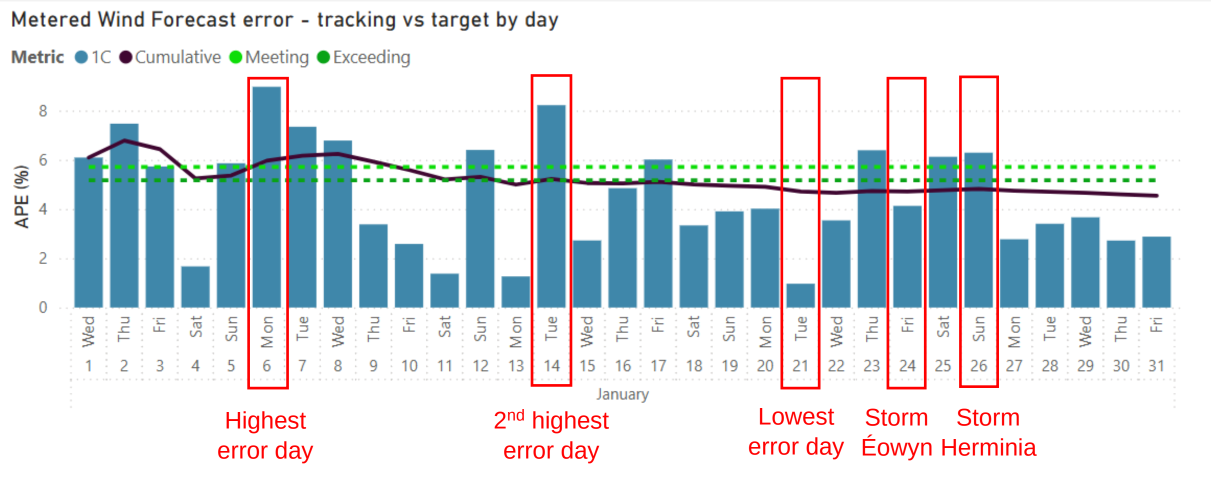
Supporting information

In January 2025, the mean absolute percentage error (corrected for redeclarations to zero and revisions to Settlement Metering) is currently reported as 4.54% against the corresponding monthly benchmark of 5.44%. The 5% range around this benchmark extends from 5.17% to 5.71%, meaning our performance exceeded expectations for January.

January was another varied month, with northerly winds caused by low pressure systems interspersed with high pressure depressions bringing calmer winds early in the month. The latter half of the month was affected by strong winds and storms Éowyn and Herminia.

According to the Met office, storm Éowyn was "the strongest UK storm in 10 years with a maximum gust of 100mph".

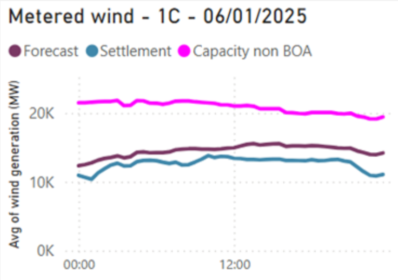
The largest forecast error this month was 3.7 GW on 1 January, SP48.

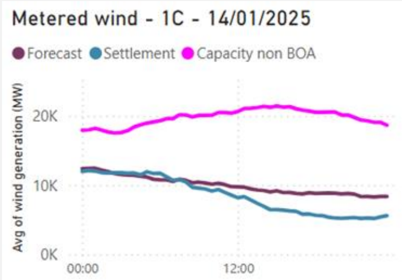


The day with largest APE (8.97%) was 6 January, while BMU wind generation peaked at 14.9GW on 26 January.

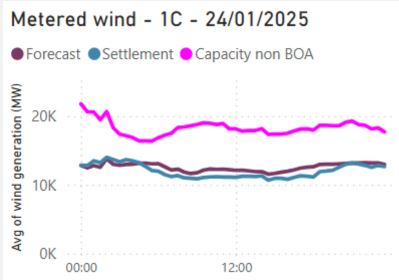
Approximately ~8GW of cut-out (High Speed Shutdown) was forecast during the worst conditions of Storm Éowyn.

Largest daily average errors





Storm Éowyn



Details of largest errors

Day	Error (APE)	Major causal factors
6 Jan	8.97	Weather (wind speed) errors at day ahead
14 Jan	8.22	Weather (wind speed) errors at day ahead, especially towards far end of forecast window

Missed / late publications

There was 1 late publication (2 January) due to an IT system issue.

RRE 1E Transparency of operational decision making

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

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

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

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

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

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

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

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

January 2024-25 performance

Figure: 2024-25 Percentage of balancing actions taken in merit order to meet requirements in the Balancing Mechanism

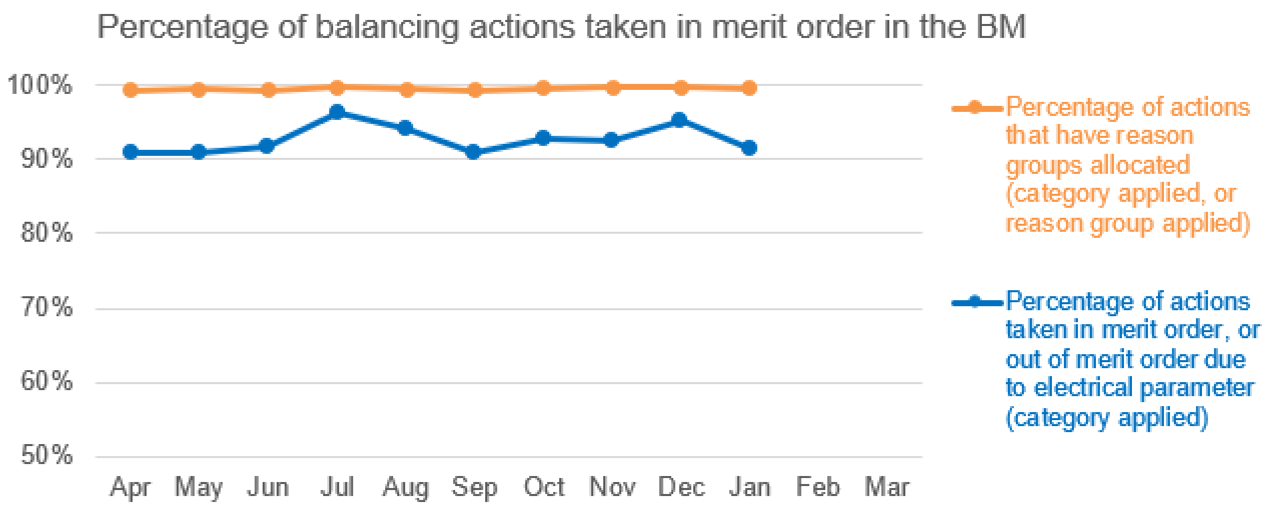


Table: Percentage of balancing actions taken outside of merit order in the BM

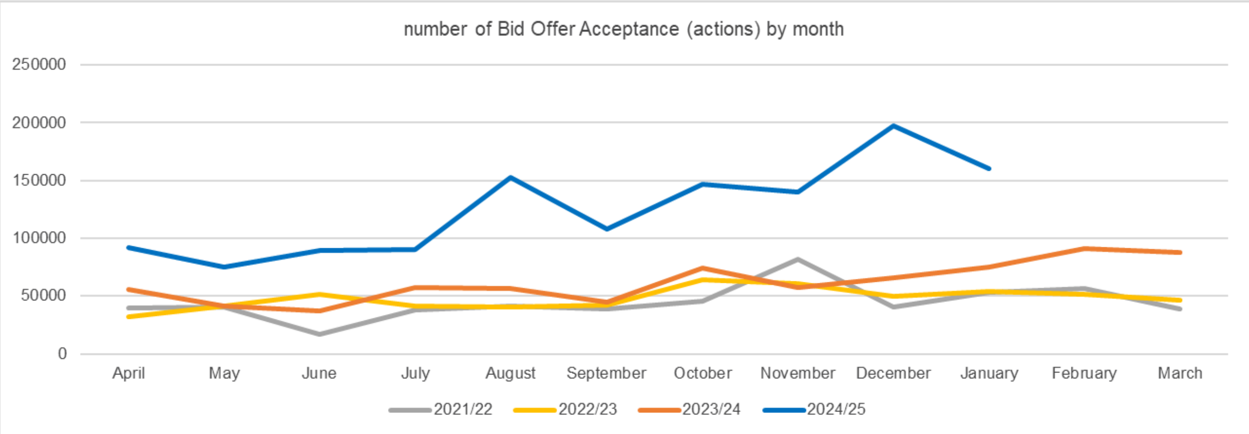
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	90.9%	90.9%	91.7%	96.3%	94.2%	91.0%	92.8%	92.6%	95.3%	91.4%		
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.4%	99.5%	99.4%	99.8%	99.5%	99.4%	99.6%	99.7%	99.8%	99.6%		
Percentage of actions with no category applied or reason group identified	0.6%	0.5%	0.6%	0.2%	0.5%	0.6%	0.4%	0.3%	0.2%	0.4%		

Supporting information

January performance

This month 91.4% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 8.3% of actions were allocated to reason groups for the purposes of our analysis, and the percentage of actions with no category applied or reason group identified remained in line with previous months.

During January, there were 159,968 BOAs (Bid Offer Acceptances) and of these, only 595 remain with no category or reason group identified, which is 0.4% of the total.



Other activities

We have published three datasets on skip rates covering data from 15th December with a fourth published covering data from 30 January:

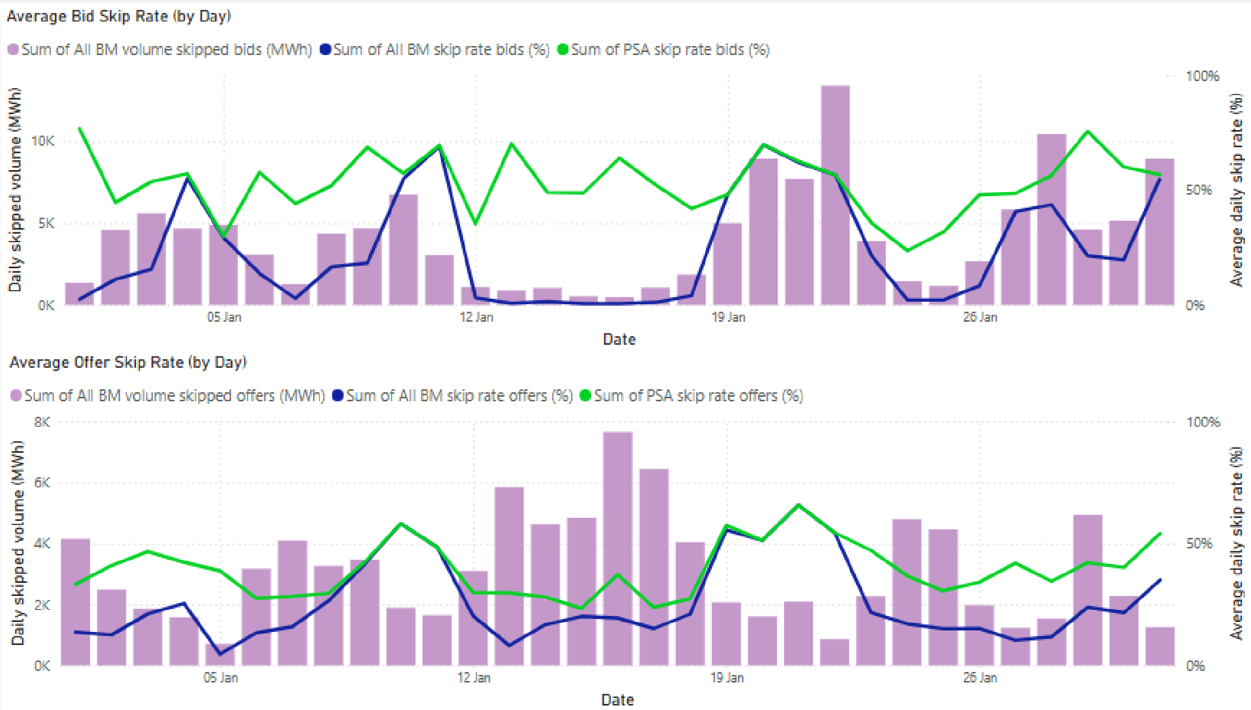
1) Skip Rate Summary: summary bid/offer skip rates and skipped volume data for each 30-minute period for each stage of exclusion as described in the methodology.
2) In Merit All Balancing Mechanism: list of in merit units with accepted & skipped volume, based on the 'All Balancing Mechanism' definition of skip rate.
3) In Merit Post System Actions: list of in merit units with accepted & skipped volume, based on the 'Post System Actions' definition of skip rate.
4) Exclusion Reasons: a list of units that were excluded with the reason why.

We are hosting an industry webinar on 27 February to discuss skip rates. This will cover the new datasets along with a summary of the skip rate methodology and other activities in the roadmap.

This is a summary of the skip rates in January for the two agreed definitions (All Balancing Mechanism & Post System Actions):

	Offers		Bids	
Average Skip Rate	All BM	PSA	All BM	PSA
January	18%	34%	11%	53%

The graph below shows daily skip rates and skipped volume.



RRE 1G Carbon intensity of NESO actions

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

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO2/kWh associated with it. For full details of the methodology please refer to the Carbon Intensity Balancing Actions Methodology document. The monthly data can also be accessed on the Data Portal here. Note that the generation mix measured by RRE 1F (Zero Carbon Operability Indicator) and 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. More information about NESO's operability challenges is provided in the Operability Strategy Report.

January 2024-25 performance

Figure: 2024-25 Average monthly gCO2/kWh of actions taken by NESO (vs 2023-24)

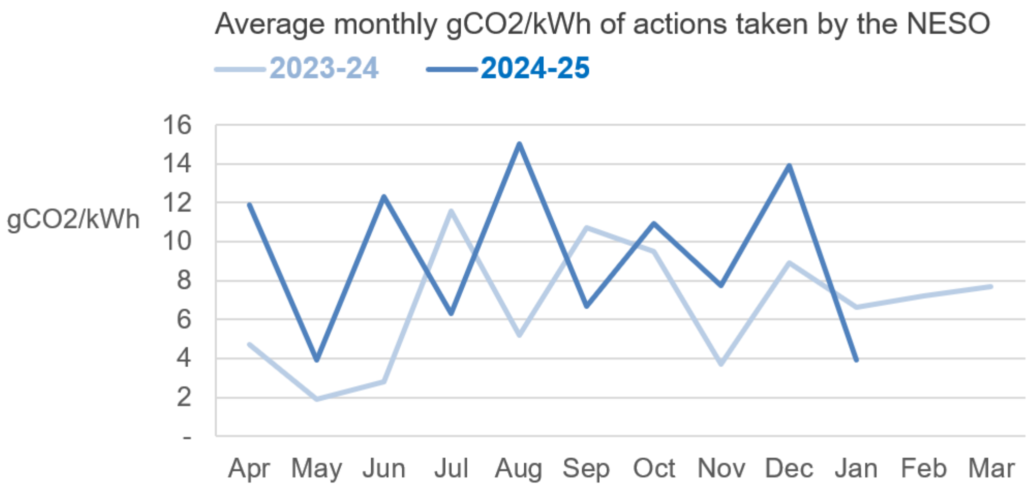


Table: Average monthly gCO2/kWh of actions taken by NESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	11.87	3.93	12.31	6.33	15.02	6.69	10.92	7.74	13.92	3.91		

Supporting information

In January, the average monthly carbon intensity from NESO actions was 3.91g/CO2/kWh. This is the lowest figure of the reporting year, 10.01g/CO2/kWh lower than December and 3.77g/CO2/kWh lower than the 2024 YTD average of 7.68g/CO2/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 45.55g/CO2/kWh which took place on 13 January at 0500. This is 10.13g/CO2/kWh lower than December's highest difference of 55.68g/CO2/kWh.

On 13 January generator assets experienced operational issues reducing their overall capability and required NESO intervention.

In comparison to January 2024 when the average monthly carbon intensity from NESO actions was 6.61g/CO2/kWh, January 2025 is 2.7g/CO2/kWh lower and the lowest since June 2023 when the average monthly carbon intensity from NESO actions was 2.81g/CO2/kWh.

RRE 1I Security of Supply

This Regularly Reported Evidence (RRE) 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 ≤ f < 49.5	up to 60 seconds	2 times per year
48.8 < f < 49.2	Any	1-in-22 years
47.75 < f ≤ 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.

January 2024-25 performance

Table: Frequency and voltage excursions (2024-25)

	2024-25											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz for over 60 seconds)	0	0	0	0	0	0	0	0	0	0		
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0	1	0	0	0		
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0	0	0	0	0	0	0		

Supporting information

January performance

There were no reportable voltage or frequency excursion in January 2025.

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

RRE 1J CNI Outages

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

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

January 2024-25 performance

Table: 2024-25 Unplanned CNI System Outages (Number and length of each outage)

Unplanned	2024-25											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	0	0	0	0	0	0		
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0		

Table: 2024-25 Planned CNI System Outages (Number and length of each outage)

Planned	2024-25											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	1 outage 265 mins	1 outage 203 mins	0	0	0	1 outage 205 mins	0		
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0		

Supporting information

January performance

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

Notable events during January 2025

Balancing Programme Beyond 2025 Webinar

On 30 January, we welcomed 106 Customers to our Balancing Programme 'Beyond 2025' webinar. The Programme's 'Beyond 25' engagement is aimed at ensuring our future balancing and forecasting transformation roadmap aligns with customer expectations and priorities, whilst enabling a decarbonised energy system and delivering consumer value – you can read more here.

Having analysed the results from the capabilities survey launched at our November Balancing Programme event, we shared what Balancing and Forecasting capabilities Industry told us they felt was most important Beyond 25 and the level of effort needed to implement the change from their side. The 21 capabilities were divided into three areas: Enhanced Dispatch, Whole System and Flexibility, and Data and Transparency.

The webinar had interactive elements enabling customers to highlight which capabilities they would like us to deep dive into at future engagement events and offered the opportunity to provide suggestions on the developments on some of the capabilities. The Balancing Programme will continue to build on this engagement through 2025, with the next updated scheduled for 6 March.

Role 2

(Market developments and transactions)

Notable events during January 2025

2025/26 Final TNUoS Tariffs published

On 31 January, we published the TNUoS Tariffs for the 2025/26 charging year, which will come into effect on 1 April. To help our customers better understand the Final Tariffs and address any questions regarding the report, we hosted a webinar on 13 February, which was attended by over 60 people. In addition to the TNUoS Tariffs, we also released the Annual Load Factors (ALFs) for the 2025/26 charging year and a timetable for the Tariff publications for the 2026/27 charging year. Our next publication will be the Initial Forecast of the 2026/27 TNUoS Tariffs, scheduled for release in April 2025. We are actively engaging with the industry through the TCMF and our webinar, as well as with Ofgem, to determine the best timetable for the 2026/27 tariff publications. The goal is to ensure that the information is available at the most useful time for industry parties, particularly for the Contracts for Difference Allocation Round 7 (CfD AR7). All these documents can be found online here.

Unlocking the potential of demand side flexibility - Q & A Webinar

On 29 January, the Unlocking the potential of demand side flexibility webinar was held. This webinar aimed to promote the two reports we published before Christmas, Enabling Demand Side Flexibility in NESO markets report and Route to Market Review Stage 2 report, and provide industry stakeholders the opportunity for clarifications and questions. More than 140 attendees joined this event. During this session, we provided a deep dive into the two reports, our plan for the next steps and addressed industry's questions and comments in a live Q&A session.

Response Reform webinar

On 22 January, we held a Response Reform Webinar. During this session, we addressed several key challenges and changes within the Frequency Response Services. The topics covered included the future of Mandatory Frequency Response (MFR) and Static Reform, focusing on ensuring these longstanding services remain fit for purpose. We explored the needs case for both of these services and highlighted some of the issues with these services that need to be addressed, we also shared some early ideas on potential solutions and early thoughts on service design.

Additionally, we discussed both short-term and long-term reforms to the Dynamic Response Services. This included introducing the needs case for Locational Procurement of Response and Reserve, the upcoming round of automated penalties, and future consultation plans.

We remain committed to engaging with industry stakeholders on these matters, following this webinar we have conducted several 1-2-1s with industry to discuss problem statements and potential solutions in more detail. We expect this activity to continue through the development of changes to all of our services.

CrowdFlex completes first year of domestic flexibility trials

CrowdFlex is a NESO led innovation project investigating the potential of domestic flexibility as a reliable grid management resource. The project is in its beta phase and has now successfully completed its first year of large-scale domestic flexibility trials. These utilisation and availability trials are testing how different recruitment messages affect participation and are gathering data to build models of domestic flexibility.

Consumer surveys have been conducted with 3,600 participants from the summer trials, with more participants being surveyed in the winter trials. The surveys so far have started to reveal some interesting insights. A report summarising the consumer survey results and the full annual progress report have now been published, detailing the progress, results and learnings to date. Further consumer trials are being conducted throughout 2025, and we are conducting deeper and more statistically significant research, with more events, multiple events a day, different messaging, and with more of a focus on low income and vulnerable customers, as well as different customer archetypes.

Role 3

(System insight, planning and network development)

Notable events during January 2025

Powering Wales Renewably

In January, we launched the beta phase of the Powering Wales Renewably innovation project. The Powering Wales Renewably innovation project is creating a digital twin of Wales' whole energy system, including electricity and gas transmission and distribution networks. The project is working with a consortium of network partners, the Welsh Government and CGI to incorporate data sets and digital technologies and create a unique common interface. We have now launched the beta phase of this project.

To accelerate the transition to renewable energy in Wales, there are several key challenges which need to be addressed, such as deciding where new assets are required, increasing the pace of new connections and deciding how flexibility on a national scale can help meet local needs. With increased visibility, network operators, local and national planning, as well as asset owners can coordinate more effectively, resulting in an increase of successful connections for renewable generation and better utilisation of flexibility.

We have been working alongside Welsh energy system industry partners in the Discovery and Alpha phases of the project, including the Welsh Government. The project has brought together stakeholders to identify priorities and address obstacles in the delivery of decarbonisation plans using new digital technology. Each stakeholder holds their own asset and network information and sharing this data onto a single open platform is fundamental to the development of the digital twin, which will become a blueprint for other regions, helping provide better awareness of the energy system for all stakeholders including Regional Energy System Planning (RESP).

Next steps in grid connections reform

In January, Connections hosted two webinars on the following topics:

- Connections Application Pause, covering key changes under the pause period beginning on 15 January and upcoming timelines.
- Connections Reform Final Proposals, covering an overview of the final reform proposals for codes and methodologies, consultation responses and key changes made as a result.

The events received significant sector engagement, with over 700 attendees each and lots of questions during the Q&A section. Customer engagement continues as part of our Reform webinar series, the next event *Connections Reform: 'protections' for existing projects*, will take place late-February.

Electricity Ten Year Statement (ETYS) 2024

On 28 January, we published the 2024 Electricity Ten Year Statement (ETYS). This is our latest view of the GB's National Electricity Transmission System (NETS), It helps us to understand the future requirements of the system, and where investment and development is needed to help us achieve our zero-carbon ambition. We set out our view on the future transmission requirements and the capabilities of NETS to meet this forecasted growth in demand; we have based this view of the system on the pathways in Future Energy Scenarios (FES) 2024 as well as our Clean Power 2030 Pathways.

This year, through our ETYS analysis, we have identified some emerging voltage issues and a requirement for an acceleration of network reinforcement in order to reduce network constraint costs for consumers as we transition to clean power. As we transition to a zero-carbon ambition operation of the NETS is becoming increasingly complex and we need to expand our view of system needs. The upcoming Centralised Strategic Network Plan (CSNP) will extend to cover a wider view of system requirements as well as providing a year-round view, building on the work we have done to develop the tools and capabilities in the ETYS process over recent years.

Launch of Mid-term Stability Y-1 Year 2 tender

On 17 January, we launched the invitation to tender (ITT) for the second round of the annual Mid-Term (Y-1) Stability Market, seeking to secure stability services between October 2026 and September 2027.

Last year, we successfully concluded the opening tender round of the Mid-Term (Y-1) Stability Market, in which it awarded 5 contracts for the provision of 5 gigavolt amps per second (GVA.s) of inertia for delivery between 2025-2026. These units will go live starting from October this year and will deliver an anticipated consumer saving of £47.3m.

For the year 2 tender, we are seeking to procure 15 GVA.s of inertia based on a technology agnostic specification. It is anticipated that this procurement will again deliver significant consumer savings as well as enabling Clean Power 2030 ambitions to be achieved.

More information on the Mid-Term (Y-1) Stability Market can be found here.

NESO
National Energy System Operator