Public

NESO RIIO2 Business Plan 2 (2023-25)

December (Q3) 2024/25 Incentives Report

24 January 2025

NESO
National Energy System Operator

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.

FSO Day 1 Report – NESO Implementation

Alongside this month's report we have also published our Future System Operator (FSO) Day 1 Report which is a requirement of our Electricity System Operator licence (condition F10, Part C). This report includes an update on the outcomes delivered and the final costs for the transition activities carried out before 1 October 2024 for the creation of NESO. As per the NESO Performance Arrangements Governance (PAG) document, we are required to provide an update on the FSO transition activities ahead of BP2 end-scheme.

Summary of Notable Events

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

- On 16 December, we published the Summer Balancing Cost Report which provides a look back at balancing costs and associated market dynamics from April to September 2024.
- In December, we launched a new webpage dedicated to skip rates and published two documents: one on defining, measuring and addressing skip rates, and another on the skip rate methodology & implementation guide. Since 16 December, we have been publishing 3 daily datasets, starting from 15 December, which include a summary of skip rates by 30-minute periods and a detailed list of considered units. A summary of these metrics will be included in next month's report.
- On 15 December at 6:30pm, a new maximum wind record of 22,243 MW was reached, but this was broken again shortly after on 18 December at 3:30am, with 22,523 MW being generated by wind. These records played a vital role in allowing zero carbon sources to provide 56% of our electricity.
- In December, the REVEAL Innovation Project team, with significant contributions from our testing volunteer, Krakenflex, successfully delivered a Live Trial Environment Proof of Concept (POC) in Microsoft Azure. This demonstrated the technical feasibility of establishing control and metering connectivity outside of Critical National Infrastructure (CNI). The REVEAL platform aims to be a "one-stop shop" for balancing trials, enabling us to foster innovation, and collaborate with industry partners to support strategic priorities such as security of supply, decarbonisation, and operational excellence.
- We are required to review and set out the GB system frequency control policy annually through the Frequency Risk and Control Report (FRCR) process, which was introduced after the 9 August 2019 GB power cut event. The FRCR 2025 policy development included two technical webinars in November and December 2024, with over 100 attendees and extensive industry engagement. The webinars' materials were published on 20 December 2024. A bespoke Security and Quality of Supply Standard (SQSS) Panel Session will be held in January 2025, followed by the FRCR 2025 consultation in March, including a webinar to present the policy and gather industry feedback. The final policy will consider all feedback received.
- On 3 December, we launched phase one of the Quick Reserve service, aimed at improving reserve services and supporting our 2025 zero-carbon goal. Quick Reserve, replacing the Fast Reserve service, manages frequency imbalances and is divided into Negative Quick Reserve (NQR) and Positive Quick Reserve (PQR). Procured via day-ahead auctions, it is expected to save consumers £29-£32 million annually. Full service delivery (Phase 2) is planned for Summer 2025, with consultations with industry and Ofgem forthcoming.
- In December, we awarded four contracts worth £83m to secure voltage services in two regions in England from 2026 to 2036. This procurement aims to absorb more reactive power to manage high voltage issues due to increased renewable energy and decreased demand. The Voltage 2026 tender, part of the Network Services Procurement (NSP)/Pathfinder programme, sought 600 Mvar and resulted in contracts for 646 Mvar, forecasted to save consumers £318m over ten years.
- On 20 December, we submitted ambitious connections reform actions to Ofgem for approval. These reforms aim to prioritise project readiness and strategic alignment with the Government's Clean Power Action Plan, enforcing new delivery requirements and removing stalled projects to facilitate clean power projects by 2030 and beyond. The reforms promise faster connections for viable projects, a more efficient network design, and a streamlined process to support the transition to net zero. With over 750GW of projects in the queue, our proposals seek to reduce connection delays from five years to six months. Ofgem's decision is expected in Q1 2025, with the evidence submission window opening in Q2 2025 for existing projects to be assessed and provided with connection offers.
- On 9 December, we launched strategic energy planning publications for consultation, running from 9 December 2024 to 20 January 2025. The publications include the draft methodology for the Strategic Spatial Energy Plan (SSEP), high-level principles for the Centralised Strategic Network Plan (CSNP), and the transitional CSNP2 (tCSNP2) Refresh methodology. We also provided a supporting document and a webinar that was attended by nearly 450 participants. The consultation invites stakeholder input on these methodologies, with further engagement opportunities planned.

- On 6 December, we published the Gas Network Capability Needs Report (GNCNR), our first under new obligations as the independent gas network planner for Great Britain. The report assesses the National Transmission System's (NTS) capability to meet current and future requirements. The findings will guide the NTS operator, National Gas Transmission (NGT), in proposing network reinforcement options, with NESO providing a Gas Options Advice Document (GOAD) by the end of 2025.

- On 12 December, the recommended design for connecting Innovation Targeted Oil and Gas (INTOG) projects to the onshore electricity network was published. Announced in March 2023 by The Crown Estate Scotland (CES), the INTOG leasing round supports the goal of decarbonising oil and gas platforms by 50% by 2030. It includes Innovation (IN) wind farms and Targeted Oil and Gas (TOG) projects supplying renewable power to offshore platforms. CES granted 13 seabed leases, which we assessed for the Holistic Network Design Follow Up Exercise (HNDFUE). Three developers across seven projects and the NorthConnect interconnector were selected for coordination. The design considered cost, deliverability, operability, community, and environmental impacts.

Summary of Metrics and RREs

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) for Q3 2024-25.

Table 1: Summary of Metrics

Monthly (M) and Quarterly (Q) Metrics

Metric		Performance	M / Q	Status Oct	Status Nov	Status Dec	Status Q3
Metric 1A	**Balancing Costs**	December: £326m vs benchmark of £301m	M	●	●	●	●
Metric 1B	**Demand Forecasting**	December: Forecasting error of 652MW vs indicative benchmark of 635MW	M	●	●	●	●
Metric 1C	**Wind Generation Forecasting**	December: Forecasting error of 3.86% vs indicative benchmark of 4.89%	M	●	●	●	●
Metric 1D	**Short Notice Changes to Planned Outages**	Q3: (December) 5.04 delays or cancellations per 1000 outages due to a NESO process failure (vs benchmark of 1 to 2.5). Oct & Nov 0 delays or cancellations per 1000 outages due to a NESO process failure	Q	●	●	●	●
Metric 2X	**Day-ahead procurement**	82% balancing services procured at no earlier than the day-ahead stage vs benchmark of 80%	Q	n/a	n/a	n/a	●

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

Table 2: Summary of RREs

RREs don't have performance benchmarks (with the exception of 2D which is reported annually).

Monthly (M) and Quarterly (Q) RREs

RRE		Performance	M / Q
RRE 1E	**Transparency of Operational Decision Making**	December: 95.3% of actions taken in merit order	M
RRE 1F	**Zero Carbon Operability indicator**	Q3: Highest ZCO% of 89% after NESO operational actions	Q
RRE 1G	**Carbon intensity of NESO actions**	December: 13.92gCO_2/kWh of actions taken by the NESO	M
RRE 1H	**Constraints cost savings from collaboration with TOs**	Q3: £372m	Q
RRE 1I	**Security of Supply**	December: 0 instance where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	M
RRE 1J	**CNI Outages**	December: 1 planned and 0 unplanned system outages	M
RRE 2E	**Accuracy of Forecasts for Charge Setting**	December: Month ahead BSUoS forecasting accuracy (absolute percentage error) of 20%	M
RRE 3X	**Connection Offers**	Q3: 382 connection offers made within 3 months, 13 taking longer than quoted timeframes. TEC queue stands at 582 GW.	Q
RRE 3Y	**Percentage of 'right first time' connection offers**	Q3: 93% of connections offers were right first time	Q

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

Hannah Kruimer
Interim 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.

December 2024-25 performance

Figure: 2024-25 Monthly balancing cost outturn versus benchmark

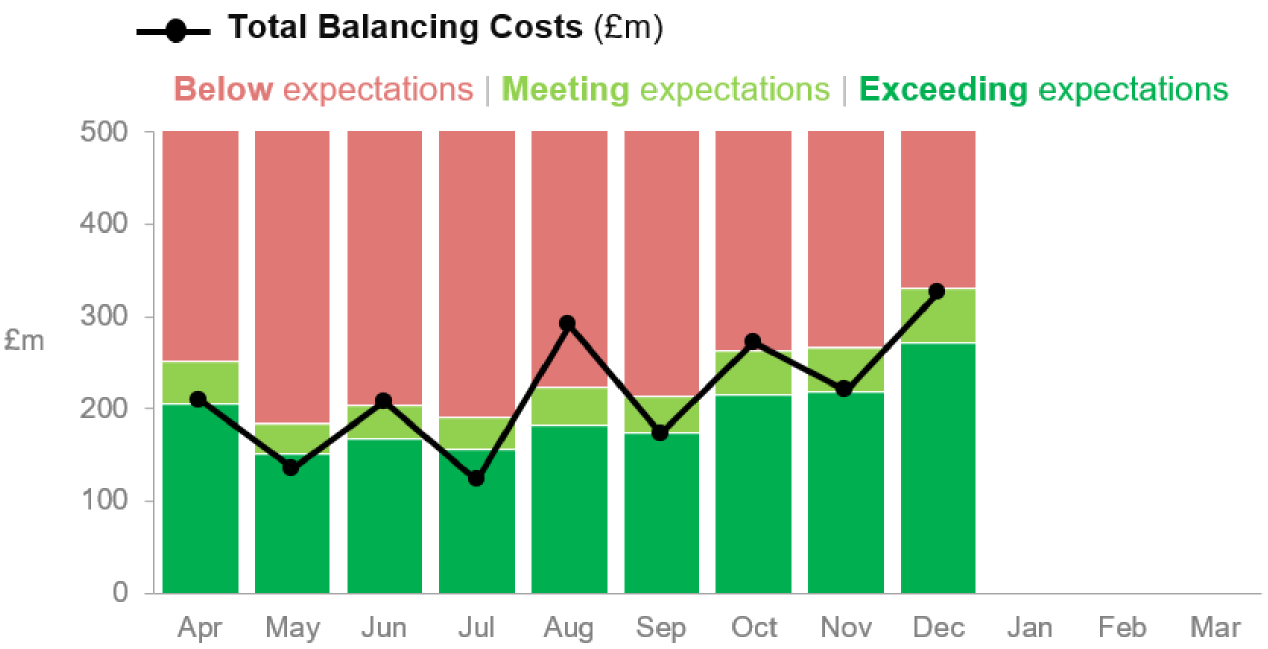


Table: 2024-25 Monthly breakdown of balancing cost benchmark and outturn

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				45.1
Average Day Ahead Baseload (£/MWh)	59	72	76	71	62	76	88	103	99				n/a
Benchmark	228	167	187	173	203	194	239	243	301				1934
Outturn balancing costs[1]	**209**	**135**	**208**	**123**	**291**	**173**	**272**	**220**	**326**				**1958**
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

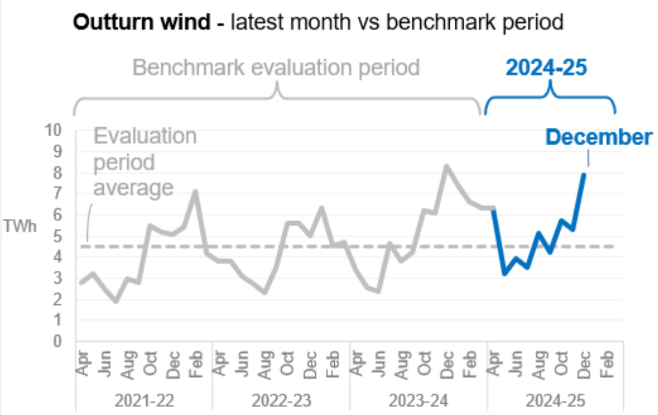
This month's benchmark

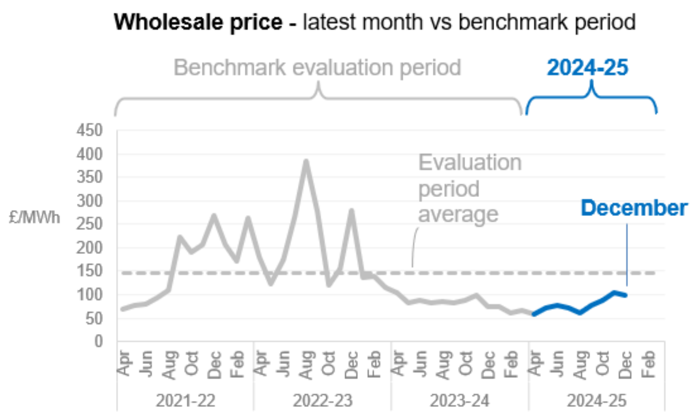
The December benchmark of £301m is £58m higher than November 2024 and reflects:

- An **outturn wind** figure of 7.9 TWh that is the highest 2024-25 so far, higher than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 4.5 TWh) and higher than last month's figure (5.3 TWh).
- An average monthly **wholesale price** (Day Ahead Baseload) that has decreased compared to November 2024 but remains elevated compared to the rest of 2024-25). However, it remains lower than the evaluation period average.

The elevated wholesale prices in December, coupled with high wind outturn, resulted in the highest overall benchmark so far in 2024-25.

[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	December 2024	November 2024	December 2023
Average Wholesale Price (£/MWh)	99	+4	-25
Total Wind Outturn (TWh)	7.9	-2.6	+0.4
Benchmark (£m)	301	-58	-2
Performance	●	●	●

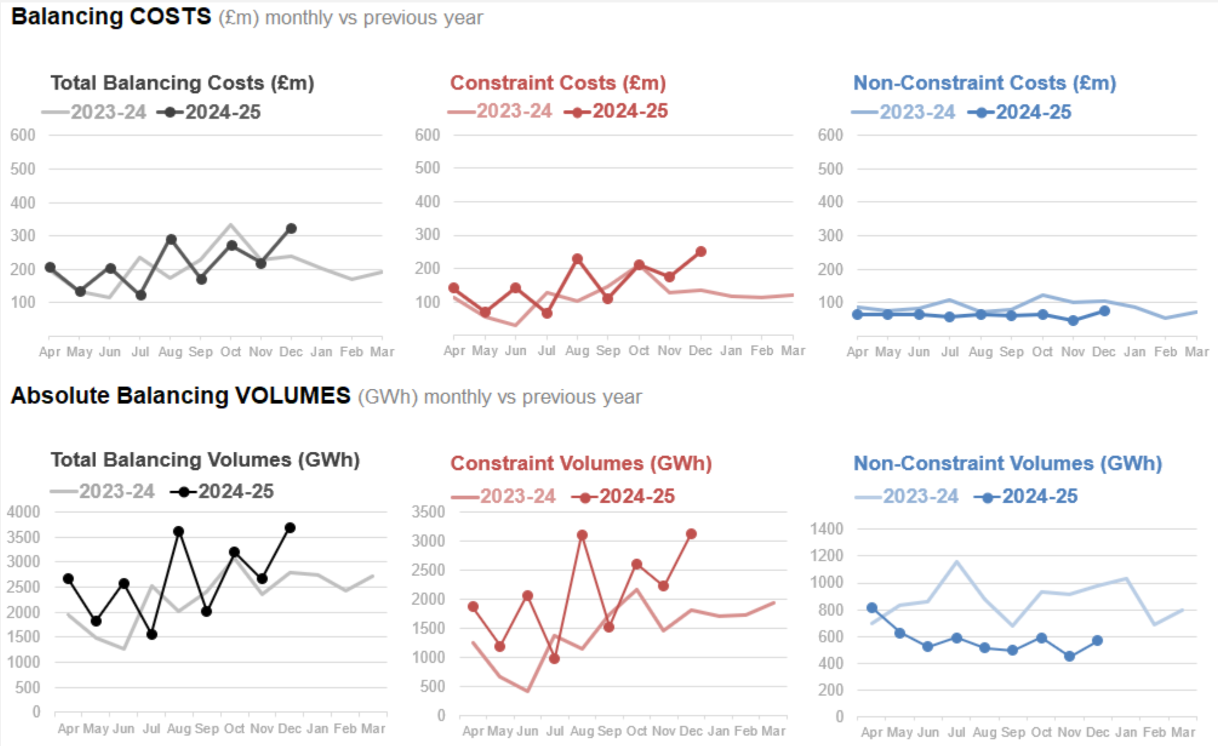
*The first three rows show the outturn measures for this month and difference in the previous month and same month last year, while the bottom row outlines outturn performance for each month.

Balancing Costs - Overview

The total balancing costs for December were £326m, which is £25m (8%) above the benchmark of £301m. As the variance is within 10%, performance is meeting expectations.

Partly down to Storm Darragh between 6 and 8 December, overall wind outturn rose 49%, from 5.3 TWh in November to 7.9TWh in December, with England & Wales and Scotland having increases of 52% and 42% respectively. This led to a £78.6m increase in overall constraint costs, with an increase of £40.4m in England & Wales, and £30.3m in Scotland (mainly due to high winds in Scotland and various outages over the month).

Average wholesale power prices were down £4/MWh compared to November 2024 and up £25/MWh compared to December 2023. The volume weighted average price for bids increased £10.50/MWh compared to last month (from -£120.70/MWh to -£131.20/MWh). Similarly, the volume weighted average price for offers decreased by £3.60/MWh (from +£133.10/MWh to +£129.50/MWh), in line with the monthly drop in average wholesale price. Non-constraint volumes have increased by 422 GWh (mainly due to a greater volume of operating reserve) and costs were £27.4m higher compared to November.

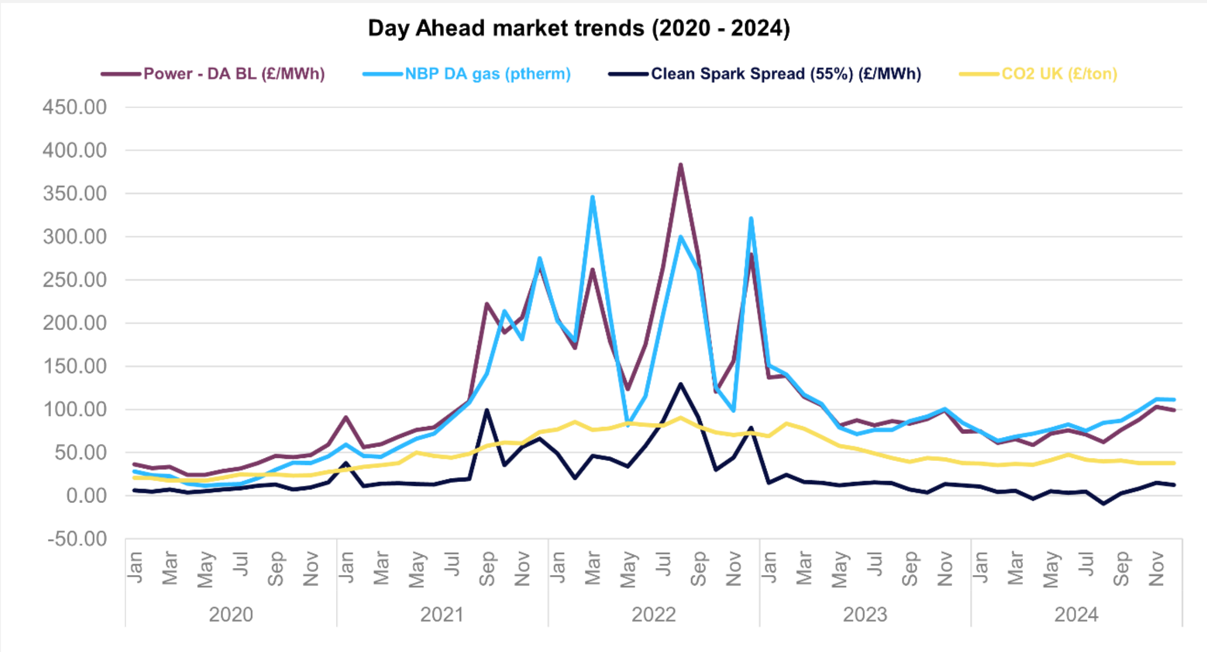


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

Market trends

Power and gas prices decreased slightly on last month, with a subsequent drop in the Clean Spark Spread Price and a slight drop in the CO_2 price. On comparison to the same period last year, power and gas prices are higher this year, while the CO_2 price is lower. There was increased heating demand due to colder temperatures earlier in the month coupled with various nuclear reactors in the north being on outage due to maintenance. However later in the month there were significant increases in wind generation which helped reduce the need for gas which contributed to the slight drop in prices.



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

Wind Outturn

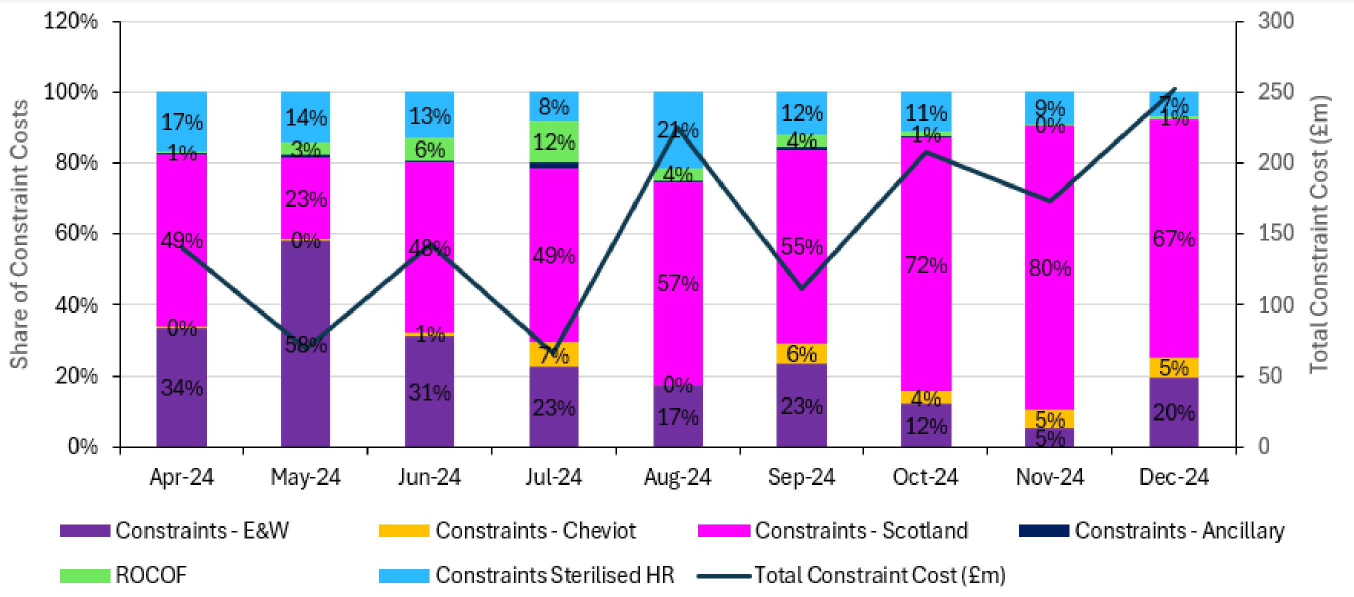
There was variable weather across December starting off with wintery showers and rain. Storm Darragh hit the UK from 6 December to 8 December with heavy wind and rain, notably in coastal areas of Wales and southwest England. Wind curtailment reached a high point in early December during this time with 87 GWh being curtailed on 7 December.

Overall wind outturn rose from 5.3 TWh in November to 7.9 TWh in December, with a 52% and 42% increase in England & Wales and Scotland respectively, giving a 49% increase overall. However, compared to December 2023, there was over twice the volume of curtailment this year, despite a lower outturn of wind in England and Wales and only a moderate increase in Scotland.

The highest wind curtailment for the month was seen on 21 December at 119 GWh, representing 24% of the outturn. This was largely due to windy weather across the country, especially in northern and western Scotland and is reflected in the high constraint costs across the Scottish boundaries.

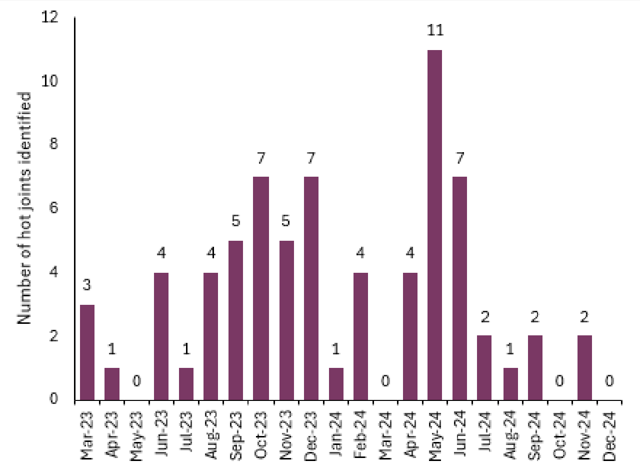
Constraints

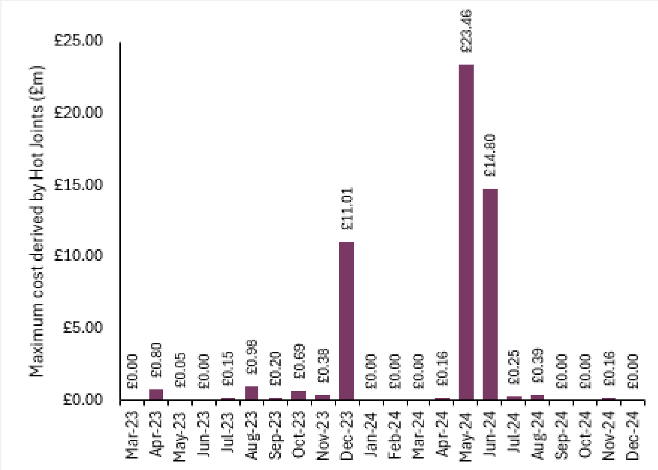
Constraint costs in December increased by £78.2m compared to November 2024. Cost increases were observed across all constraint components. Scottish constraints remained high, increasing £30.3m and £121.1m compared to last month and last year respectively. Despite this increase the proportion of costs coming from Scottish constraints fell to 67% (from 80% in November). This was primarily due to an increase in England and Wales constraints which rose £40.4m compared to November (but remained £0.8m lower year-on-year). High constraint costs were linked to high 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 December.





BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): December 2024 vs November 2024

		(a) Nov-24	(b) Dec-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-7.4	-4.1	3.3	
	Operating Reserve	3.6	10.4	6.8	
	STOR	5.5	9.9	4.4	
	Negative Reserve	0.4	2.7	2.4	
	Fast Reserve	16.1	15.8	(0.3)	
	Response	11.9	17.9	5.9	
	Other Reserve	1.5	1.9	0.4	
	Reactive	10.7	12.0	1.3	
	Restoration	2.9	3.3	0.4	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	1.5	4.0	2.6	
Constraint Costs	Constraints - E&W	9.3	50.2	40.9	
	Constraints - Cheviot	8.8	13.5	4.7	
	Constraints - Scotland	139.3	169.6	30.3	
	Constraints - Ancillary	0.3	0.4	0.1	
	ROCOF	0.8	1.4	0.7	
	Constraints Sterilised HR	15.2	17.2	2.0	
Totals	Non-Constraint Costs - TOTAL	46.6	73.9	27.2	
	Constraint Costs - TOTAL	173.6	252.2	78.6	
	Total Balancing Costs	**220.3**	**326.1**	**105.8**	

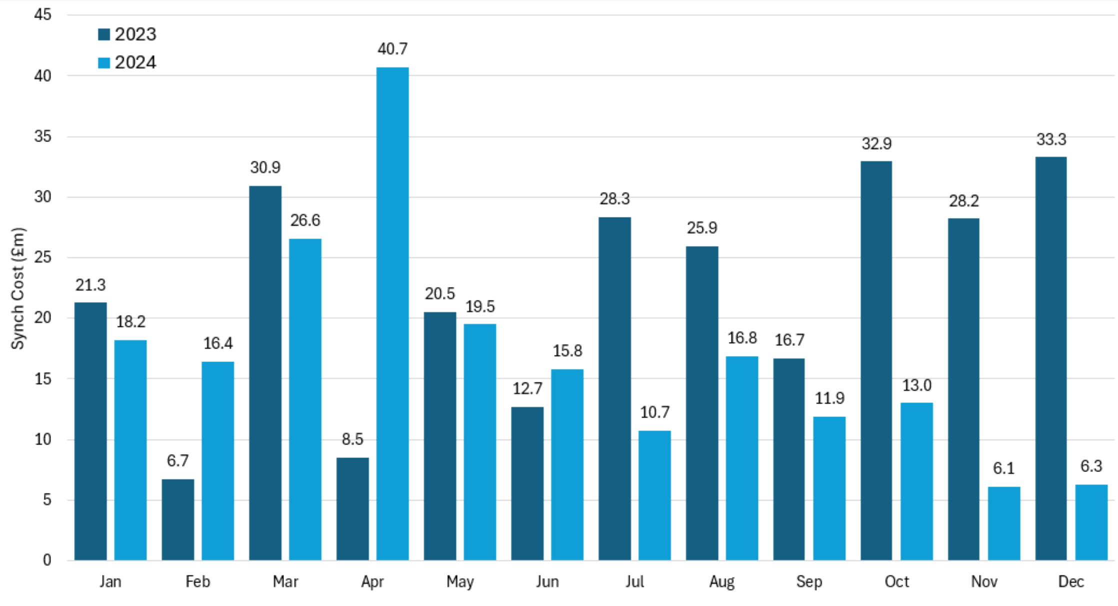
As shown in the totals from the table above, constraint costs increased by £78.6m and non-constraint costs increased by £27.2m, resulting in an overall increase in balancing costs of £105.8m compared to November 2024.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: +£35.0m **Constraint – England & Wales: +£40.9m** **Constraint Sterilised Headroom: +£2.0m** Constraint costs increased by £78.6m in December 2024, coinciding with a 987 GWh increase in the absolute volume of actions. Wind outturn has been significantly higher in December, partially down to the stormy weather seen earlier in the month.	**Constraints – Scotland & Cheviot: +£134.5m** **Constraints – England & Wales: -£0.3m** **Constraints Sterilised Headroom**: **-£14.0m** Constraint costs have increased by £116.6m compared to last year, largely down to an increase of more than 100% in the volumes of wind curtailed. Wind outturn in December 2024 was around 0.5 TWh lower than December 2023, with power prices being higher than last December. There were a few outages in Scotland along key boundaries which caused higher constraint costs than the previous year.

ROCOF: +£0.7m	ROCOF: -£3.8m
In December, the system's outturn inertia (including market-provided, stability assets, and synchronous plants used for voltage support) resulted in higher volumes to meet the minimum inertia requirements of the system. An increase of 86 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 2023 and 2024:



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 December, the system costs of synchronisation costs amounted to £6.3m, which is lower than the same period in 2023, representing the sixth consecutive month where lower costs compared to 2023 were seen.

Additional factors driving lower voltage management costs include:

- Economic assets commissioned through voltage pathfinders. This includes the ones allocated on 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

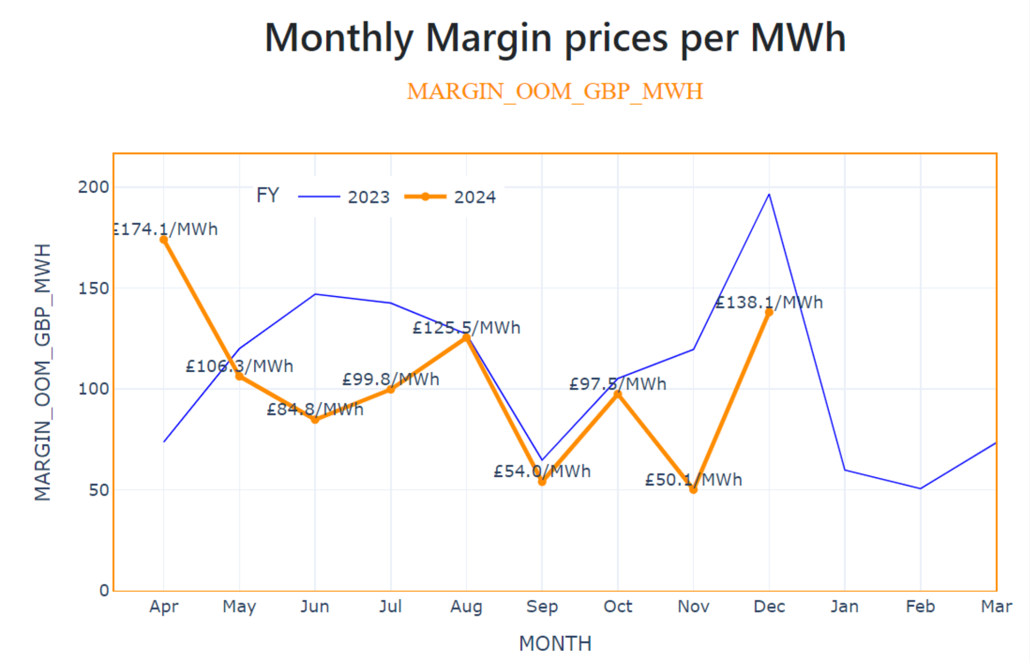
The volume-weighted average price for reactive power was £4.4/MVAr in December 2024.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£1.3m The volume-weighted average price increased from £3.9/MVAr to £4.4/MVAr compared to last year.	**-£4.4m** The volume-weighted average price decreased from £5.0/MVAr to £4.4/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 £138.1/MWh in December from £50.1/MWh in November 2024.This is aligned with an increase of 987 GWh in absolute volume of actions taken over December and comes despite the slight month on month fall in wholesale price and is partly linked to the increase of operating reserve procured.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£6.8m **Fast Reserve: -£15.1m** There was a 391 GWh increase in the volume of Operating Reserve required to secure the system compared to November.	**Operating Reserve: -£17.3m** **Fast Reserve: -£12.8m** The introduction of the Balancing Reserve service in March has the potential to decrease reserve prices in the BM contributing to lower costs than last year.

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 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
+£5.9m There was a 2.0 GWh decrease in the volume of actions compared to October. Higher costs were linked to higher clearing prices for response services.	**+£1.9m** The volume of actions taken for response reduced 51.1 GWh compared to December 2023, although clearing prices were higher.

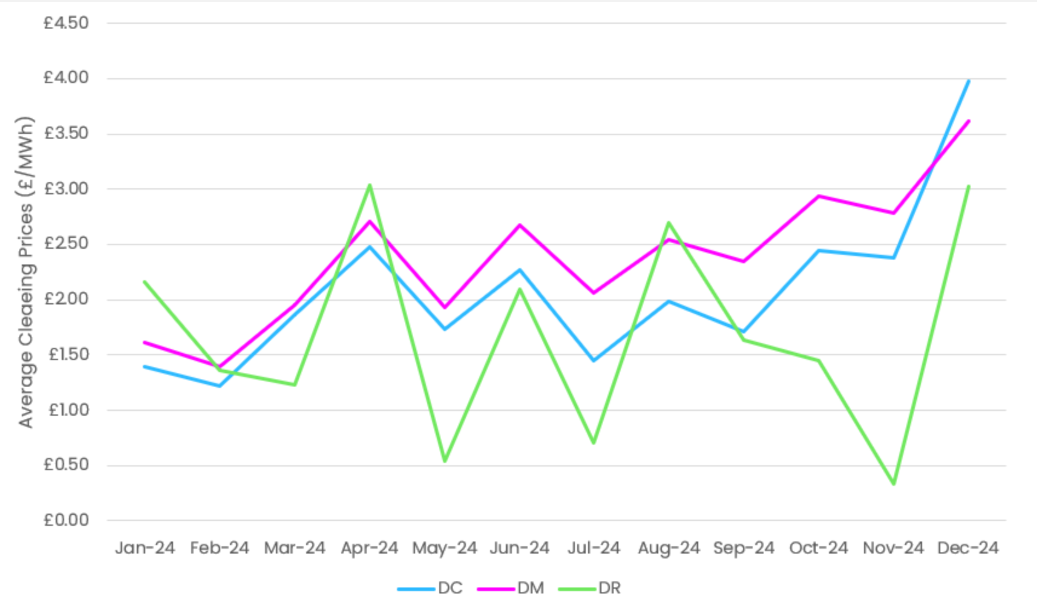
Dynamic Services Average Clearing Prices: December 2024 vs November 2024

		(a) Dec-24	(b) Nov-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	4.0	2.4	1.6	
	DM	3.6	2.8	0.8	
	DR	3.0	0.3	2.7	

Dynamic Services Average Clearing Prices: December 2024 vs December 2023

		(a) Dec-24	(b) Dec-23	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	4.0	1.4	2.6	
	DM	3.6	2.1	1.5	
	DR	3.0	3.1	(0.0)	

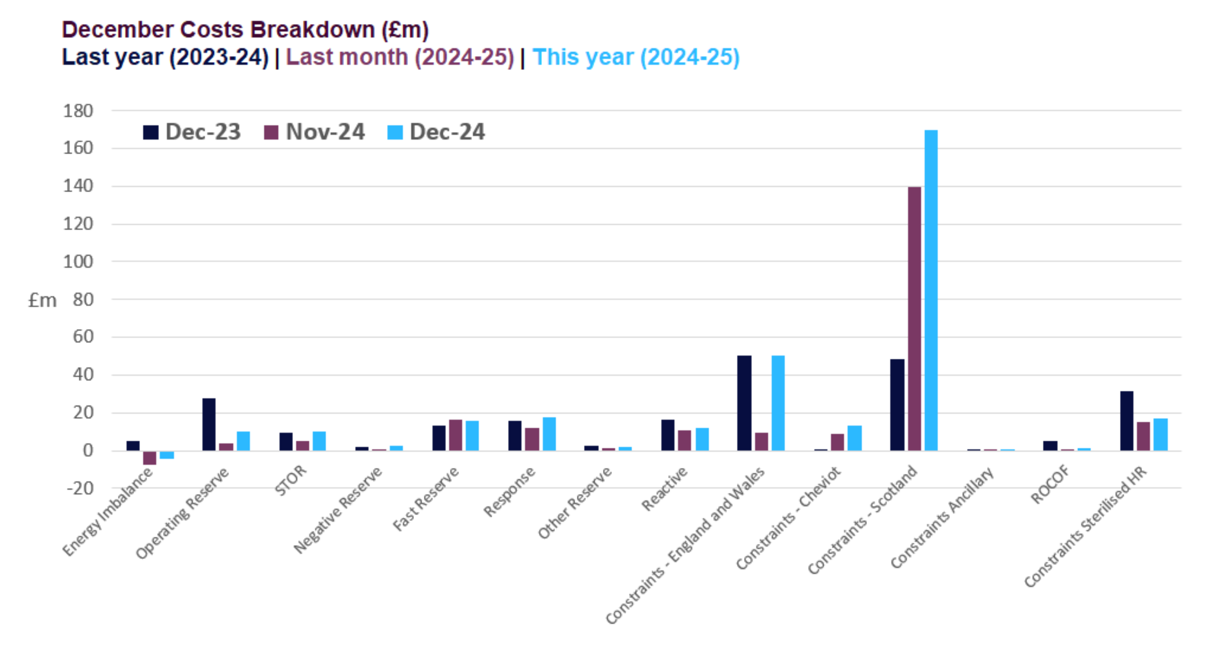
Average clearing prices for DC, DM and DR increased in December compared to November 2024 and December 2023.



Comparison breakdown

Constraint costs were up by £78.2m compared to the previous month, this is due to an increase in both England and Wales (£40.4m increase) and Scotland (£30.3m increase). Constraint costs are also up on last year, by £116.2m largely down to high costs from Scottish constraints, despite constraint volumes being 200 GWh lower. Non-constraints costs increased by £27.4m from last month, largely driven by increases in most categories (especially operating reserve and response) and small deviations in others, however non constraint costs were £31.6m lower than December 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 were roughly £138m in December 2024, this represents an increase of around £91m relative to November (£47m). The action that yielded the greatest value was that a double circuit outage in Scotland was avoided by adjusting the work methodology by taking a longer duration single circuit outage. The extension of the single circuit was aligned with other works on the network which meant there were no additional costs with the extended works. This resulted in the removal of the double circuit outage which had a significant impact on constraints in the region. The estimated cost savings for this action are around £91m.

Cost Savings – Trading

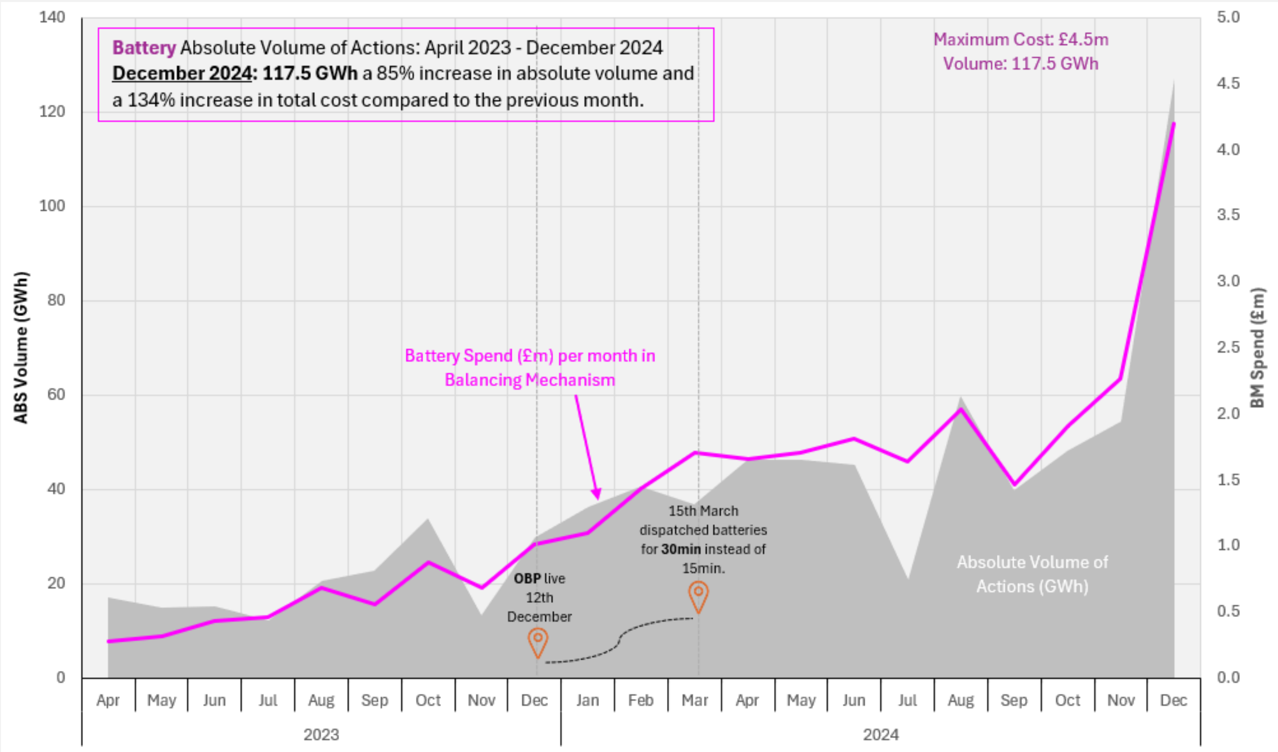
The Trading team were able to make a total saving of £25.6m in December 2024 through trading actions as opposed to alternative BM actions, representing a 112% increase on the previous month. Margin trades were much higher this month compared to previous months, both for upwards and downwards margin. An increase in downwards margin trades was seen during periods of high wind, while upwards margin trades were seen mainly during times of peak demand coupled with interconnector exports. Savings due to voltage trading remained low due to competitive prices in the BM, reducing opportunities for trading. The day with the greatest spend on trades was 3 December at a cost of £7.7m. The greatest component was margin, as the margins were tight during portions of the day which led to a Capacity Market Notice being issued, which was subsequently cancelled following completion of interconnector trades.

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 £283m 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 December 2024



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 cost have both increased compared to the previous month (November 2024). Battery dispatch increased to a new record absolute volume, at 117.5 GWh, illustrating our commitment to maximising the flexibility of energy offered by battery storage and small BMUs over the last year. Most of the spend for batteries was related to margin and minor components.

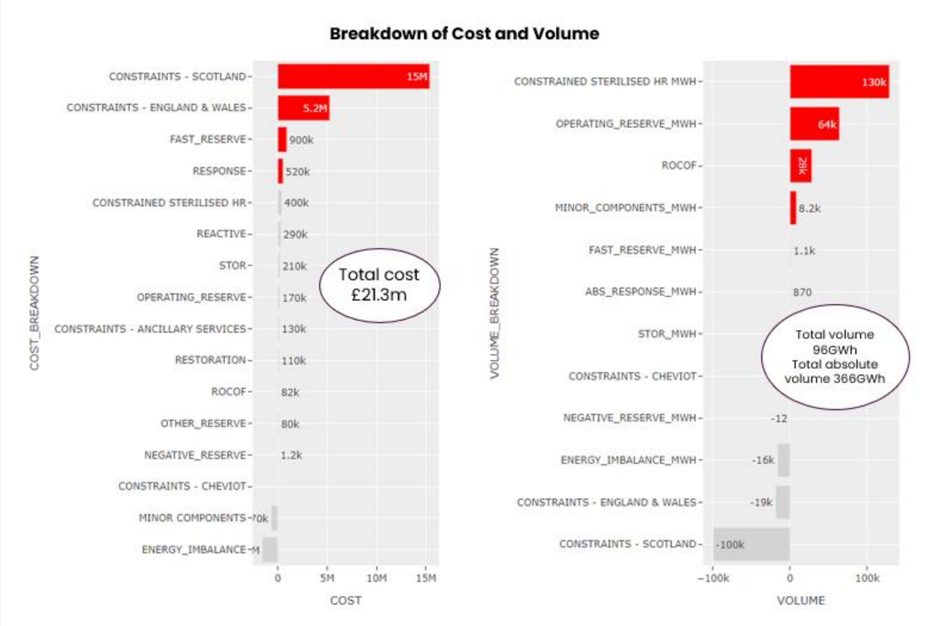
DAILY CASE STUDIES

Daily Costs Trends

December's balancing costs were £326.1m which is £105.8m higher than the previous month. Six days were recorded with costs above £15m (7,18, 21, 22, 29, and 31) with an additional nine having a daily total cost over £10m (4, 8, 15, 16, 17, 20, 24, 25, 30). The daily average rose by £3.2m compared to November 2024 (£7.3m to £10.5m).

The lowest cost day was observed on 14 December, with a total balancing cost of approximately £2.3m. This was down to low wind curtailment, coupled with the monthly lowest net volume of actions taken to manage the system. The highest cost day was 21 December, with a total spend of £21.3m. This day saw the highest volume of wind curtailment during the month, with actions to manage Scottish constraints making up around 70% of the total costs. This was brought about from windy conditions over the weekend on 21 and 22 December, with particularly high winds across northern and western Scotland.

High-Cost Day – 21st December 2024

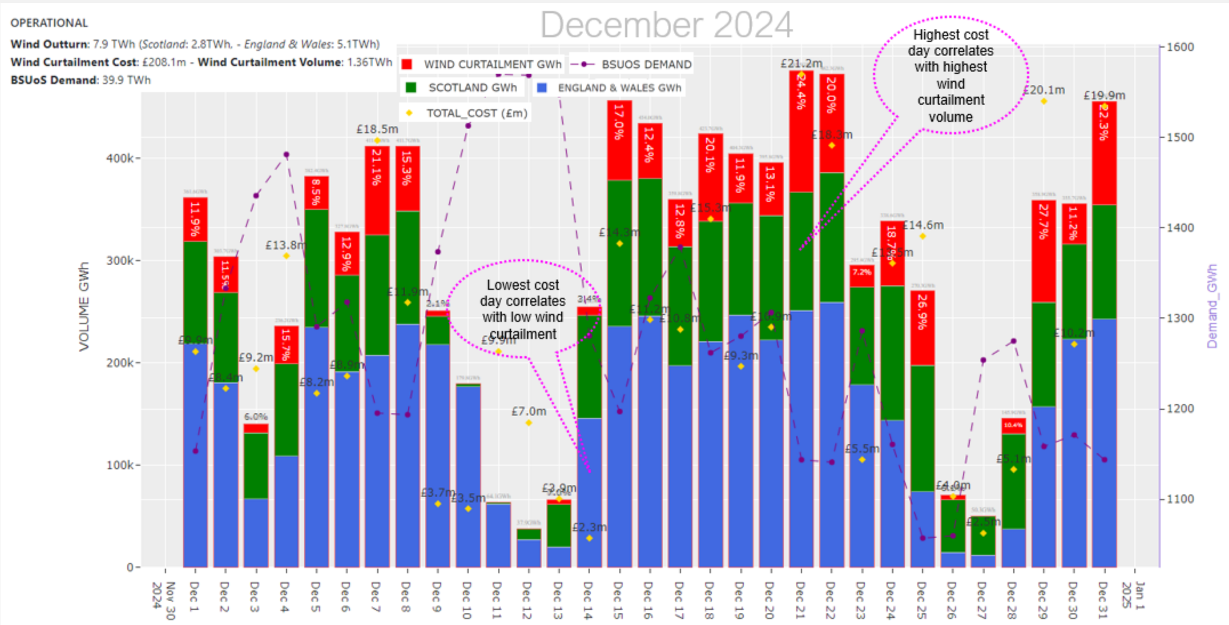


December Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUoS Demand

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.

December 2024-25 performance

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

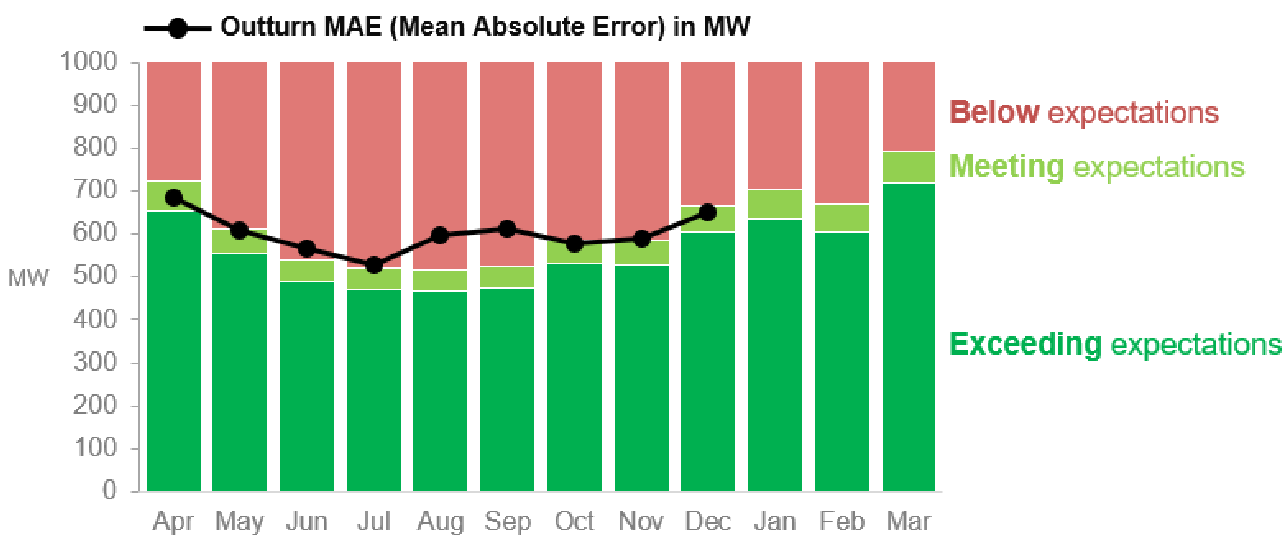


Table: 2024-25 Monthly absolute MW error vs Indicative Benchmark

	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**			
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)

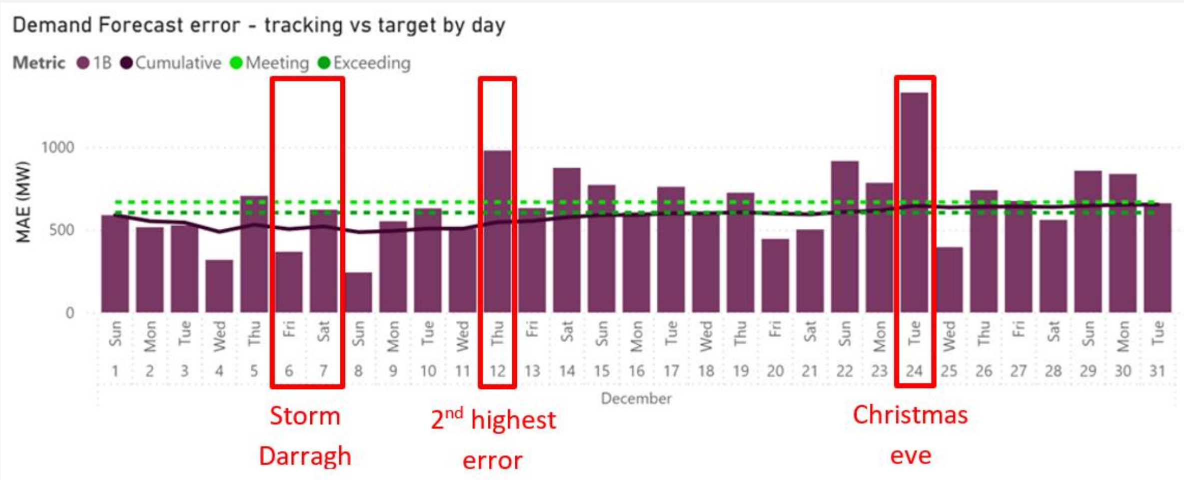
Supporting information

In December 2024, the mean absolute error (MAE) of our day ahead demand forecast was 652 MW compared to the indicative benchmark of 635 MW. The 5% range around this benchmark extends from 603 to 667 MW, meaning our performance met expectations for December.

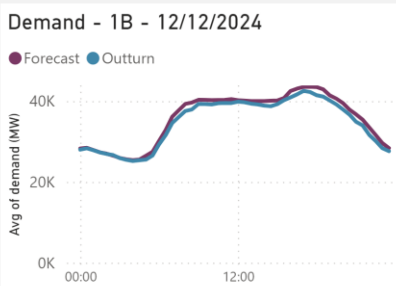
The Met Office reports that December was “a stormy month but mainly mild with brief colder interludes”. Storm Darragh affected the UK on 6 and 7 December.

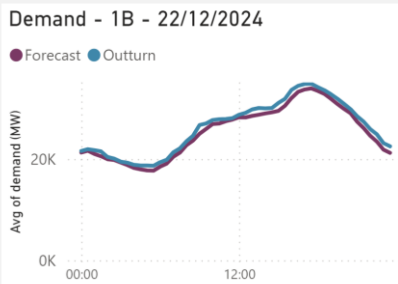
The Christmas holiday period is always challenging, as the positioning of Christmas within the working week heavily influences consumer behaviour and travel. It was back in 2019 (pre-Covid) when Christmas Day last fell on a Wednesday. Christmas Eve was the highest error day (1329MW), but Christmas Day was very predictable and accurate (395MW).

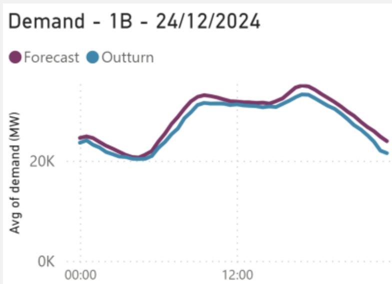
The largest demand forecast error this month was 2.8 GW on 24 December, while demand peaked at 43.3GW on 11 December.



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







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	325	22%
1500 MW	92	6%
2000 MW	17	1%
2500 MW	3	0%

The days with largest MAE were 12, 22, and 24 December.

Day	Error (MAE)	Major causal factors
12 Dec	979	Process/Model/Profile error - Current diagnostics do not identify the distinctive causal factor
22 Dec	915	Contributions from weather forecast data (i.e. temperature) and solar forecast error
24 Dec	1329	Small contributions from embedded wind generation forecast errors overnight, and larger errors from other process/model/profile errors, likely due to changed behaviours on Christmas Eve.

Missed / late publications

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

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 December: 3, 10 and 12, with a cumulative total effect of 2400MWh.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 3, 9, 10, 11, 12, and 27 December, with an accumulated total of 327MWh procured. These will nominally affect the national demand outturns, 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.

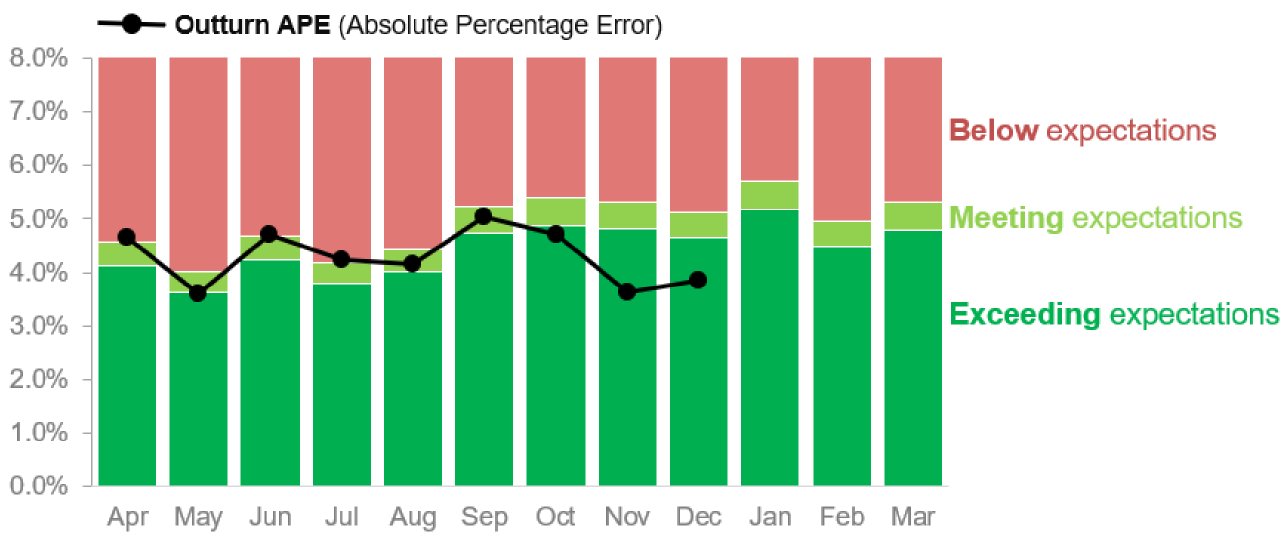
Sites deemed to have withdrawn availability are those that:

- 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.

December 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**			
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**			
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

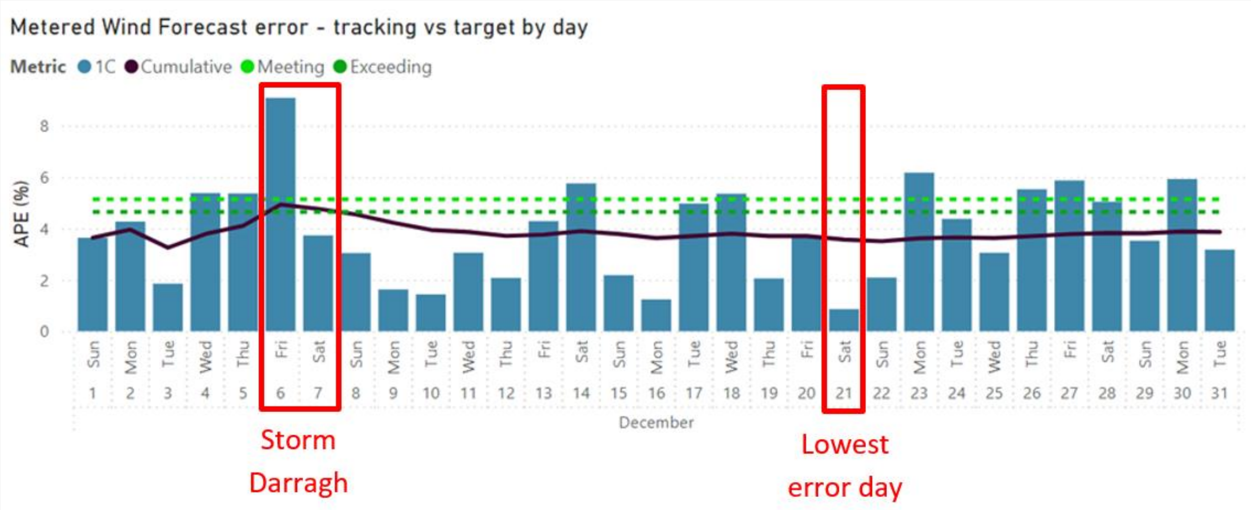
In December 2024, the mean absolute percentage error (corrected for redeclarations to zero and revisions to Settlement Metering) is currently reported as 3.86% against the corresponding monthly benchmark of 4.89%. The 5% range around this benchmark extends from 4.65% to 5.13%, meaning our performance exceeded expectations for December.

The mean absolute percentage error for the original 1C metric was 3.91%, compared to the monthly benchmark of 4.93%. The 5% range around this benchmark extends from 4.68% to 5.18%. meaning performance on this metric also exceeded expectations.

December was a varied month, with multiple high-pressure depressions (bringing low and stable wind) as well as named storm Darragh (bringing strong, unstable wind and rain).

The most significant error was on 6 December, during the period affected by storm Darragh. This storm resulted in the Met Office issued a red warning, with winds gusting at 31 to 36m/s (69 – 81mph) or higher. Wind speeds dipped and rebounded over the day due to a weather system passing over parts of the UK.

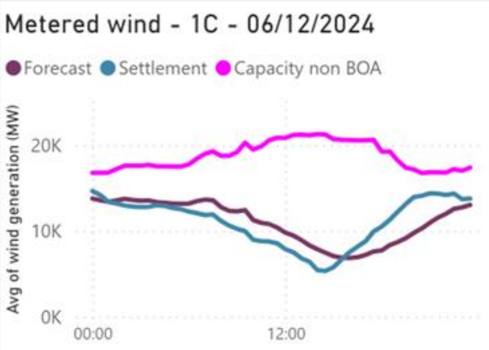
The largest wind forecast error this month was 4.2 GW on 6 December, settlement period 41.



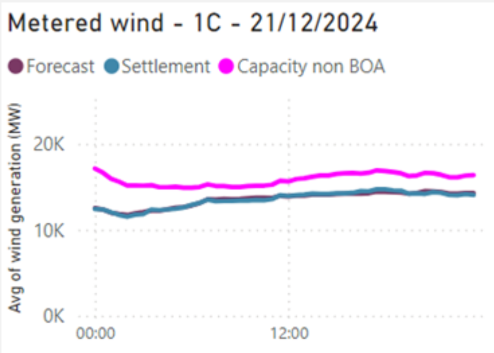
The day with largest APE (9.08%) was 6 December, while wind generation peaked at 15.3GW on 15 December.

The day with lowest APE (0.86%) was 21 December. This was the second lowest error day of the incentive year, and this accuracy was achieved even with high winds (13.5GW generation average over the day).

Largest error



Smallest error



Details of largest error

Day	Error (APE)	Major causal factors
6 Dec	9.08	Weather (wind speed) errors at day ahead, especially the timing of a weather system passing over UK.

Missed / late publications

There were no occasions of missed or late publications in December.

Metric 1D Short Notice Changes to Planned Outages

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

Q3 2024-25 performance

Figure: 2024-25 Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

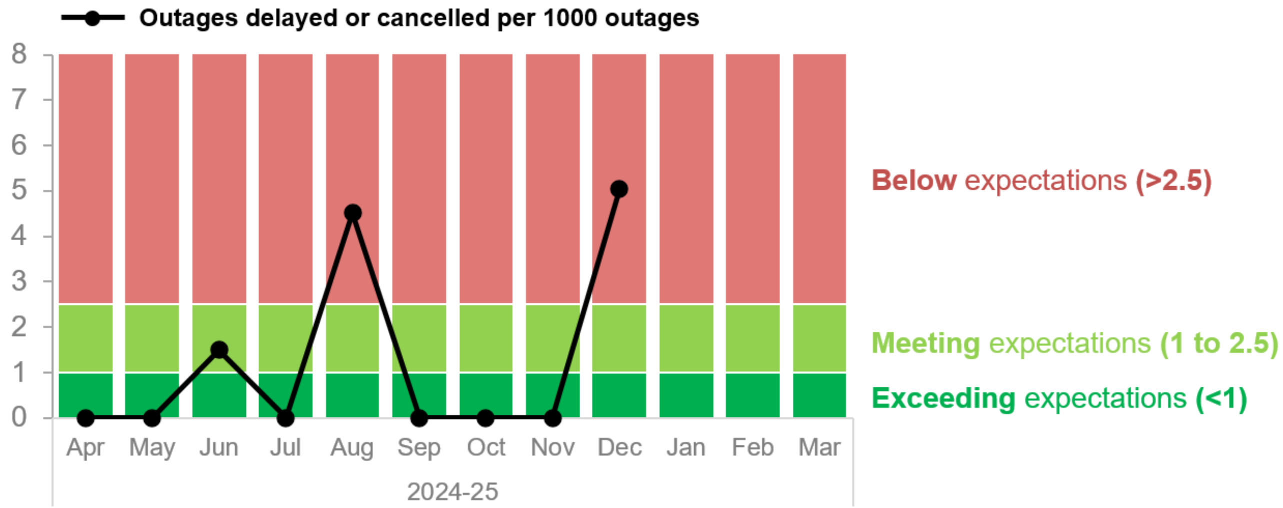


Table: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	673	614	670	784	665	729	738	730	397				6000
Outages delayed/cancelled due to NESO process failure	0	0	1	0	3	0	0	0	2				6
Number of outages delayed or cancelled per 1000 outages	0	0	1.49	0	4.51	0	0	0	5.04				1.00
Status	● (dark green)	● (dark green)	● (light green)	● (dark green)	● (red)	● (dark green)	● (dark green)	● (dark green)	● (red)				● (light green)

Performance benchmarks:

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

Supporting information

We successfully released 738 outages in October and 730 outages in November with zero delays or cancellations due to an NESO process failure.

For December, we successfully released 397 outages. There was two delays or cancellations due to a NESO process failure. The number of stoppages or delays per 1000 outages for December was 5.04, which is outside of the ‘Meets Expectations’ target of less than 2.5 delays or cancellations per 1000 outages. The cumulative number of stoppages or delays per 1000 outages is 1.00 which is ‘Meets Expectation’ target of less than 1.00. The two events are summarised below:

The first delay was caused by a substation running arrangement that the NESO control room had concerns on their being demand at risk for a short duration during network switching. Our control room and the DNO reassessed a substation running arrangement that would not result in overstressing any equipment and would secure the demand to mitigate the risk. An Operational Learning Note (OLN) has been written to outline the considerations of taking this specific outage and preventative actions.

The second delay was caused due to a particular fault that resulted in a network overload that had not been identified within planning timescales and was picked up by our control room before the outage was to be released. It was identified that a Super Grid transformer (SGT) had a de-rating by the Transmission Owner that was missed due to human error, and it was observed that this SGT became overloaded for a particular fault in the offline analysis. An Operational Learning Note (OLN) has been written that identified a process failure of the de-rating not being applied to the offline study which meant it relied upon being known by the planning engineer manually which was missed. Consequently, this process has been reviewed and modified to prevent a reoccurrence.

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.

December 2024-25 performance

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

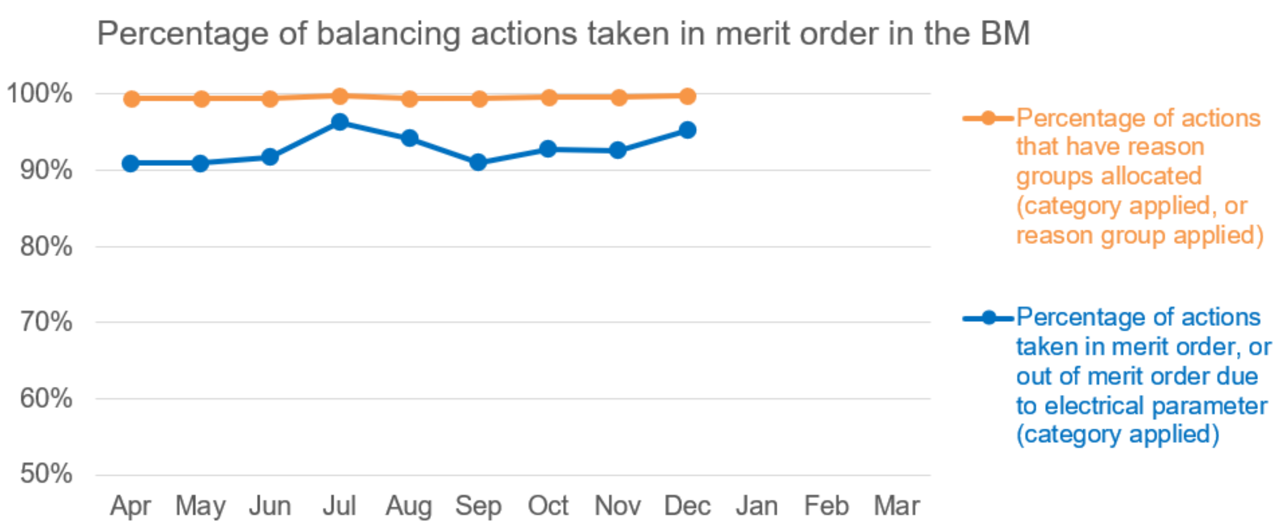


Table: Percentage of balancing actions taken outside of merit order in the BM

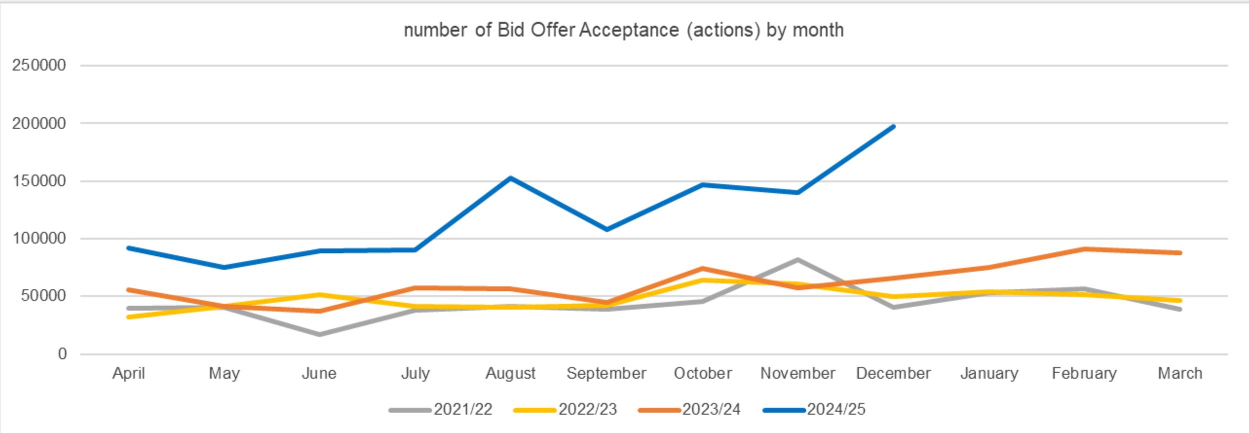
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	90.9%	90.9%	91.7%	96.3%	94.2%	91.0%	92.8%	92.6%	95.3%			
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.4%	99.5%	99.4%	99.8%	99.5%	99.4%	99.6%	99.7%	99.8%			
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%			

Supporting information

December performance

This month 95.3% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 4.4% 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 December, there were 187,797 BOA (Bid Offer Acceptances) and of these, only 438 remain with no category or reason group identified, which is 0.2% of the total. The number of BOAs in December was significantly higher than previous months. This is largely due to an increase in the number of battery BOAs from 93k in November to 149k in December.



Other activities

We hosted another webinar on the LCP methodology on 19 December covering the results of the analysis and the report. The webinar recording is available here.

We are now publishing three new datasets on Skip Rates with data included from 15 December. A summary metric from these datasets will be included in the next NESO Incentives Report.

RRE 1F Zero Carbon Operability Indicator

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

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

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

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

Part 1 – Defining the maximum ZCO limit for BP2

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

Table: Forecast maximum ZCO% after our operational actions

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

Part 2 – Regular reporting on actual ZCO

Every quarter we report the ZCO provided by the market versus the ZCO following 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, 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 ZCO that the market provided over the month. For example, the maximum ZCO 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 final 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 (2024-25)

Month	Highest ZCO% in the month (after NESO operational actions)	ZCO% provided by the market (during the same day and settlement period)	Date / Settlement Period
April	92.3%	94.7%	15 Apr SP29
May	83.4%	93.8%	12 May SP28
June	86.1%	88.6%	4 Jun SP28
July	86.7%	92.7%	4 July SP33
August	89.2%	95.0%	21 Aug SP24
September	84.6%	91.1%	30 Sep SP3
October	85.1%	94.4%	13 Oct SP3
November	84.6%	94.1%	23 Nov SP44
December	89.4%	95.7%	23 Dec SP4

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

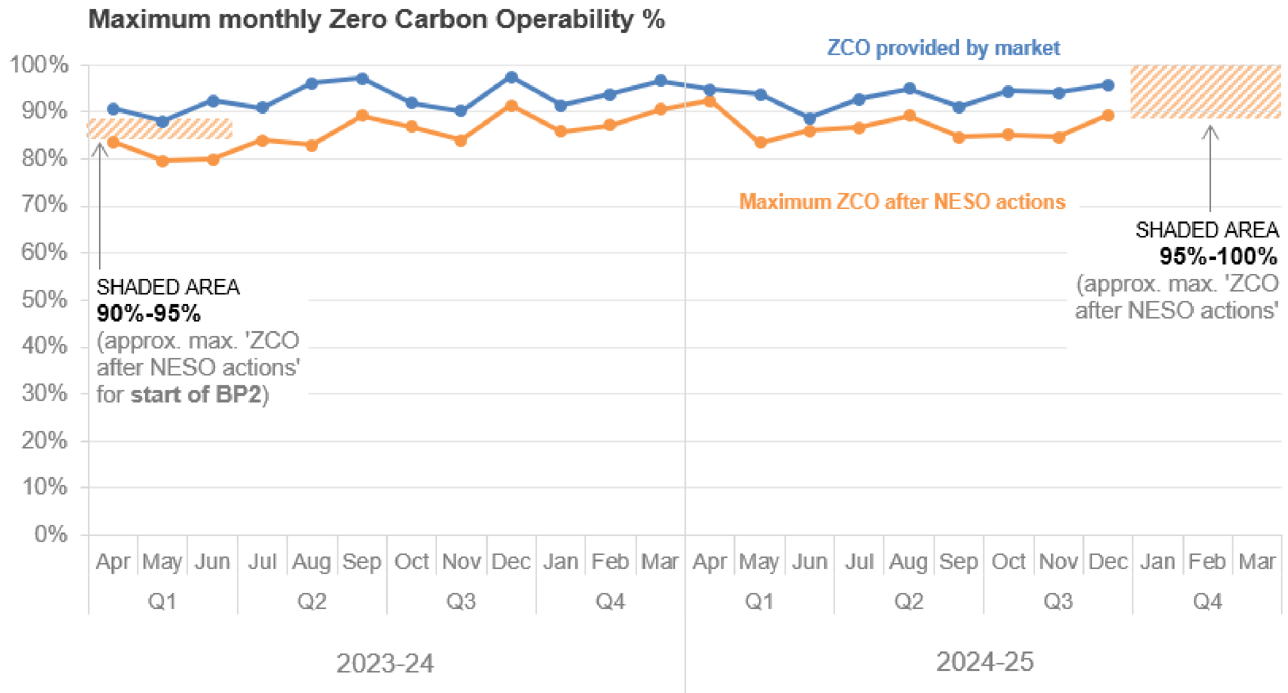
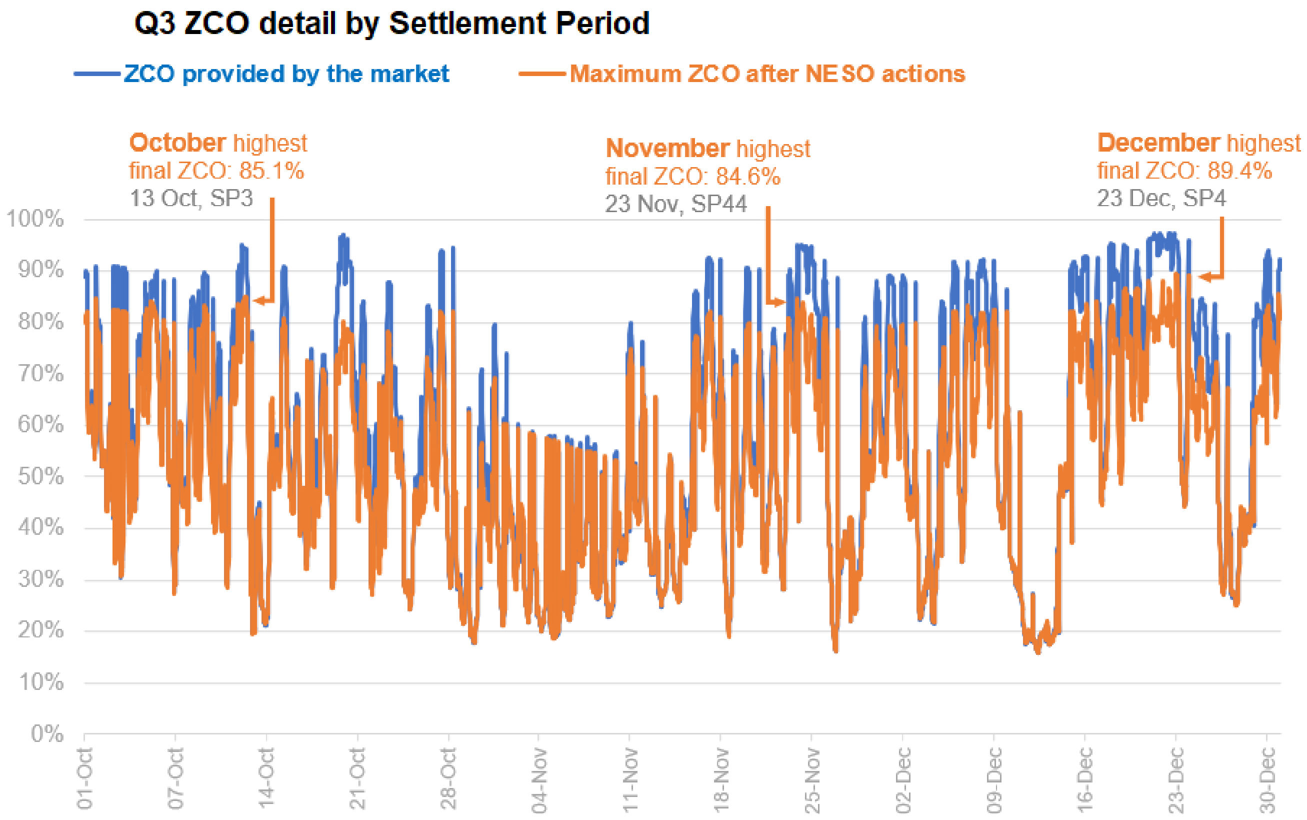


Figure: Q3 2024-25 ZCO by Settlement Period, before and after NESO operational actions



Supporting information

In Q3 2024-25, the monthly average highest ZCO was 86% which is consistent with the Q1 and Q2 monthly average of 87%.

The YTD average ZCO% performance for a single settlement period at this time in 2023 was 84.6%. The current YTD average is 2.2% higher at 86.8%.

In October the highest ZCO% performance for a single settlement period was 85%. On 13 October transmission connected wind output was forecast to begin the day high but decreased rapidly leading to an increase in our actions.

In November the highest ZCO% performance for a single settlement period remained at 85%. On 23 November Storm Bert arrived from the Atlantic. Transmission connected wind output was forecast to remain very high but the storm weather warnings lead to system constraints. Balancing actions were taken to manage these constraints.

December ZCO% performance for a single settlement period increased to 89%, which is the highest % since April 2024 when a record 92% ZCO was achieved.

On 23 December, unconstrained wind output was forecast to decrease from 16GW at 5am to 10GW by midday and remained flat for the rest of the day with a further increase from 9pm to 15GW. A number of circuit trips and multiple faults resulted in increased intervention from NESO to stabilise system frequency.

Highest final ZCO by month vs previous year

Quarter	Month	2023	2024	Difference
Q1	April	83.6%	92.2%	+8.6%
	May	79.6%	83.4%	+3.8%
	June	79.9%	86.1%	+6.2%
Q2	July	83.9%	86.7%	+2.8%
	August	82.9%	89.2%	+6.3%
	September	89.1%	84.6%	-4.5%
Q3	October	86.8%	85.1%	-1.7%
	November	84.0%	84.6%	+0.6%
	December	91.3%	89.4%	-1.9%
Q4	January	85.8%		
	February	87.1%		
	March	90.5%		

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.

December 2024-25 performance

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

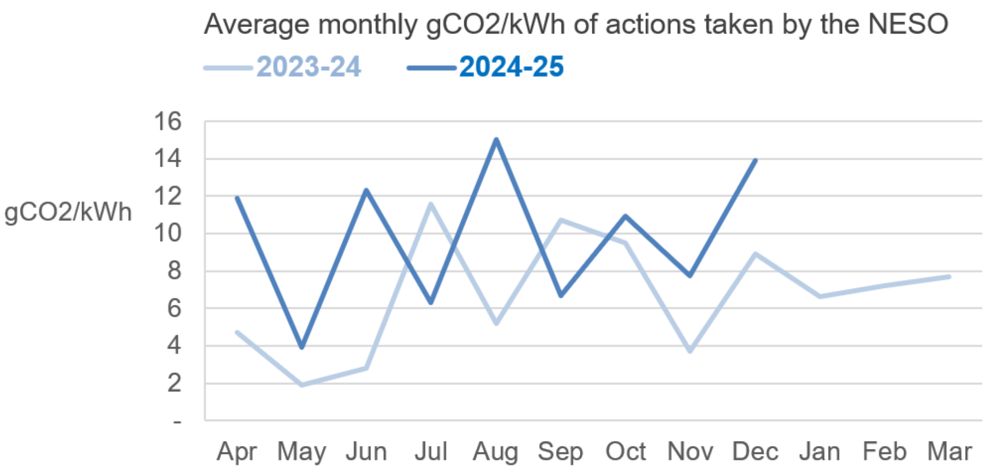


Table: Average monthly gCO2/kWh of actions taken by NESO

	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			

Supporting information

In December, the average monthly carbon intensity from NESO actions was 13.92g/CO2/kWh. This is 6.18g/CO2/kWh higher than November and 4.06g/CO2/kWh higher than the 2024 YTD average of 9.86g/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 55.68g/CO2/kWh which took place on 7 December at 1130. This is 7.52g/CO2/kWh lower than November's highest difference of 63.2g/CO2/kWh.

On 7 December the Met Office issued a Red warning for high winds in Wales. Multiple Yellow and Amber warnings remained in place for the rest of the UK due to high wind and rain, requiring a higher level of NESO interventions in preparation for Storm Darragh's arrival.

The market position from 23:00 until 03:00 was significantly below the forecast demand resulting in increased actions from NESO. During this time the wind had become volatile and gains were not as forecast resulting in increased actions from NESO.

Yellow wind weather warnings issued by the Met Office across 15/16 December and 21/22 December resulted in an increase in NESO actions, raising the average monthly carbon intensity from NESO actions to an average of 13.92g/CO2/kWh

RRE 1H Constraints Cost Savings from Collaboration with TOs

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

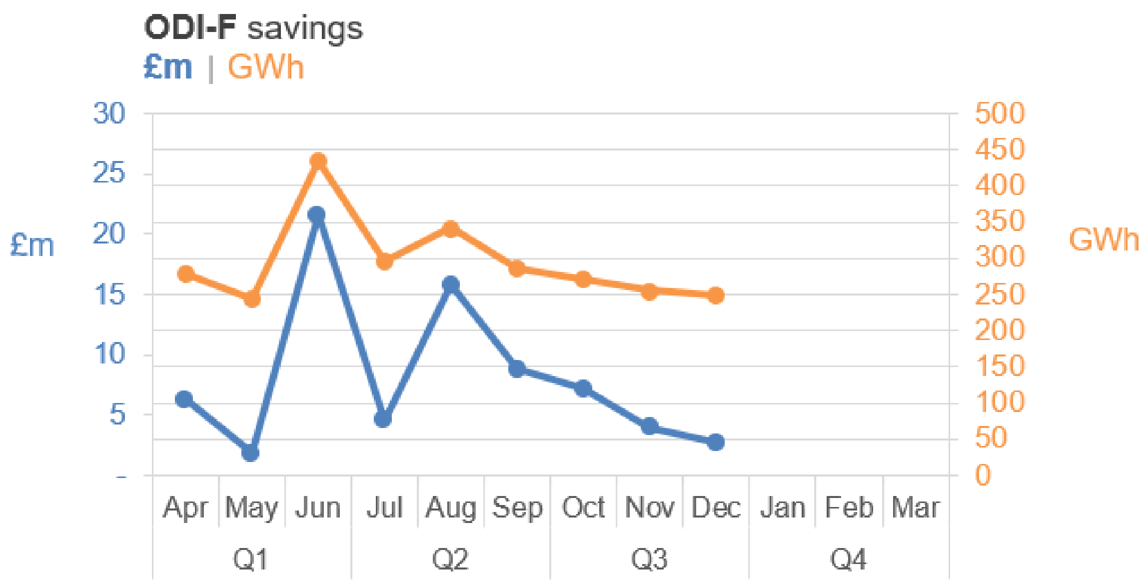
There are two ways NESO can work with the TOs to minimise constraint costs. We will report on both for RRE 1H:

- ODI-F savings: Actions taken through the System Operator: Transmission Owner (SO:TO) Optimisation ODI-F
    - 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).
    - 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[3] 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 this RRE 1H.
    - For RRE 1H, where constraint savings are delivered through the SO:TO Optimisation ODI-F, the savings are calculated in line with the methodology for that incentive.
- Other savings: Actions taken separate from the SO-TO Optimisation ODI-F

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) – 2024-25

(Estimated savings in GWh are also shown for context)



[3] 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.

Figure: Estimated £m savings in avoided constraints costs (Other)

(Estimated savings in GWh are also shown for context)

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

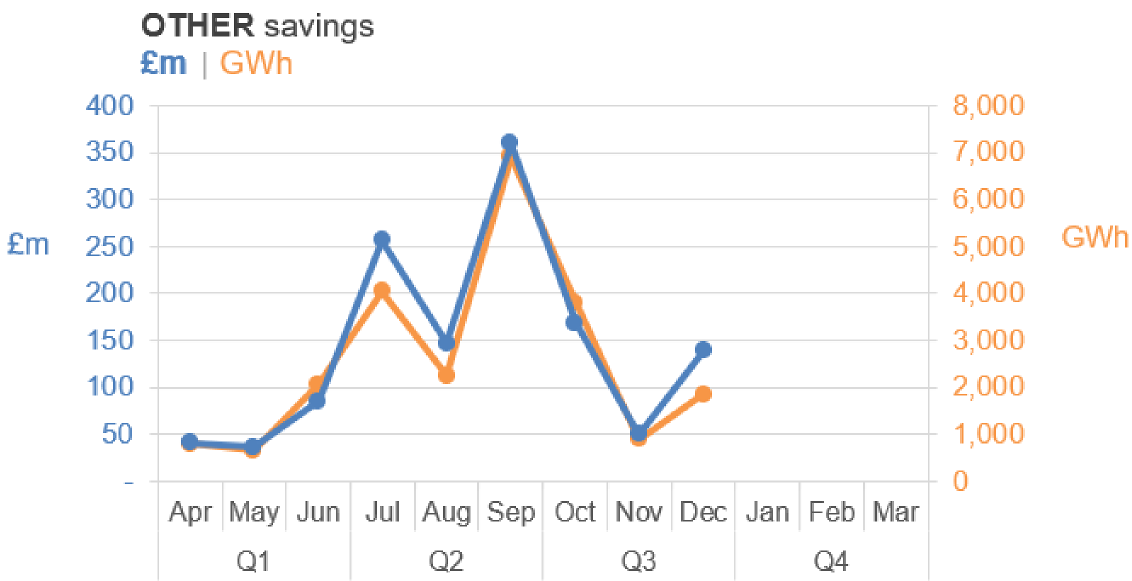


Table: Monthly estimated £m savings in avoided constraints costs (2024-25)

	ODI-F savings	Other savings	ODI-F savings	Other savings
	£m	£m	GWh	GWh
Apr	6.3	41.3	278.8	810.1
May	1.8	36.6	243.4	661.3
Jun	21.6	85.4	434.6	2078.8
Jul	4.6	256.2	295.7	4037.8
Aug	15.8	147.0	341.6	2244.1
Sep	8.8	360.1	286.9	6901.7
Oct	7.2	168.8	271.9	3803.8
Nov	4.0	50.1	255.0	889.4
Dec	2.7	138.7	248.3	1856.2
Jan				
Feb				
Mar				
YTD	**72.9**	**1284.3**	**2656.2**	**23283.2**

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 **four approved enhanced service provisions** from TO's through STCP 11.4 that provided constraint cost savings this quarter. Some of these provisions are highlighted below:

In October, NGET and NAP agreed a dynamic weather-based increase in ratings on a 400kV circuit in the North West region connecting greater Manchester to Lancashire, to facilitate a planned outage on another 400kV circuit in the North West region between two 400kV substations in Lancashire, needed to undertake environmental based works at a 400kV substation in Lancashire. This increment in ratings saved **33.0 GWh** of energy and an outturn cost of **£5.6 million** to the end consumer.

In November, a dynamic weather-based increase in ratings was agreed between NGET and NAP on a 275kV circuit in the North West region between Merseyside and Lancashire. This enhancement facilitated an outage on the parallel 275kV circuit connecting the same regions, needed to complete commissioning and protection works for the new Interbus Super Grid Transformer at a 400kV substations in Lancashire. This increment in ratings saved **14.50 GWh** of energy and an outturn cost of **£2.35 million** to the end consumer.

In December, NGET and NAP agreed dynamic and static weather-based enhancements on a 275kV circuit in the North East region connecting Northumberland and Newcastle upon Tyne, to facilitate an outage on the 400kV circuit connecting the same region to Eccles in Scotland. This outage was needed for undertaking maintenance and safety related works at Eccles 400kV substation. The enhancement saved **9.41 GWh** of energy and an outturn cost of **£1.08 million** to the end consumer.

In Q3, NAP has realised **775 GWh** approximately **£13.9 million** of cost savings through STCP 11-4. This reporting contains savings for started and completed enhancements, and also enhancements that running across the year have been distributed across each month. There are several ongoing enhancements which will be included in the next quarterly reports once they have successfully completed.

Other Savings (Customer Value Opportunities (CVO)):

The Network Access Planning team has made good progress over the last three months. In collaboration with our stakeholders (TOs and DNOs), we have identified and recorded **72 instances this quarter**, where the NESO's actions directly resulted in adding value to the end consumers and its innovative ways of working facilitated increased generation capacity to the connected customers.

Such actions include moving outage dates, splitting/separating outages, reducing return to service times, obtaining enhanced ratings from TOs, re-evaluating system capacity, identifying and facilitating opportunity outages, aligning outages with customer maintenance and generator shutdowns, proposing, and facilitating alternative solutions for long outages that impact customer, and many more.

Some examples of these instances include:

NAP received a system access request in October from NGET on a 400kV circuit in the North Wales region of Snowdonia, needed for the cable replacement project between the two 400kV substations in this region. Given the delays associated with the commissioning of the third 400kV circuit in the same region, NAP advised NGET to take the number two 400kV circuit outage outside winter period to avoid leaving Dinorwig generator on a single circuit risk during winter. Therefore, the number two 400kV circuit outage in this region was replanned to start outside winter period (March 2025), and also when the number three 400kV circuit is commissioned. This action saved the end consumer **423 GWh** of energy circa **£15.2 million.**

In November, NAP received an outage request on a 400kV circuit in the South West region connecting Melksham and Seabank, and a Melksham 400kV Shunt Reactor, to undertake maintenance and refurbishment works on the shunt reactor. This outage was forecast to cost **£10 million** for voltage support. However, given the unavailability of Didcot power station during this period, NAP advised NGET to align the refurbishment works with another outage planned in March 2025. This action saved the end consumer **£10 million**, because this cost will not be needed when the outage is taken in March 2025.

In December, NAP received a double circuit outage request on the 275kV circuits in Fetteresso area of Kincardine and Mearns region from SSEN-T, required to facilitate the rebuild and expansion of the Fetteresso 275kV substation. This double circuit outage would cause a boundary capability reduction and impact the output of the Western Link HVDC. NAP advised SSEN-T to consider single circuit working to mitigate the limitations caused by the double circuit outage. The single circuit working extended the outage duration by 6 weeks, but there was no additional constraint cost for the extended period. This action saved the end consumer **1.2 TWh** of energy circa **£91.4 million.**

The above and many more customer value opportunities represent a total of **6.55 TWh** approximately **£357.7 million** of extra generation capacity across Q3, which would have otherwise been constrained at a cost to the end consumer.

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

RRE 1I Security of Supply

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.

December 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			
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			
Voltage Excursions defined as per Transmission Performance Report[4]	0	0	0	0	0	0	0	0	0			

Supporting information

December performance

There were no reportable voltage or frequency excursion in December 2024.

[4] 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.

December 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			
Integrated Energy Management System (IEMS)	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			
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0			

Supporting information

December performance

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

This change took place on 5 December, and was planned in advance, in collaboration with our control rooms to ensure it did not introduce a conflict with other known periods of high activity. Notifications are posted to the industry, via BMRA, at 7 days prior and 1 day prior.

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

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

There were no other planned outages during December.

There were no unplanned outages during December.

Notable events during December 2024

New maximum wind record

In December, wind was our largest source of generation, providing 38.9% of Great Britain's electricity. Our ability to harness the power of windy conditions achieved two maximum wind records in December.

A new record of 22,243MW was reached on 15 December at 6:30pm but broken again shortly after with 22,523MW being generated by wind on 18 December at 3:30am. These records played a vital role in allowing zero carbon sources to provide 56% our electricity.

Balancing Costs Summer Report published

On 16 December, we published our Summer Balancing Cost Report which provides a look back at balancing costs and associated market dynamics from April to September 2024.

Balancing costs over the summer period were up slightly on last year following an increase in constraint costs due to higher wind outturn and lower constraint limits, although this increase was largely offset by lower non-constraint costs. The report also explores recent market developments impacting balancing costs, including reductions to the system's inertia requirements which have contributed to significant stability cost savings this year, and the evolution of battery dispatch volumes since the implementation of the Open Balancing Platform.

This update forms part of our regular reporting on Balancing Costs, providing transparency on cost drivers and actions that we take to deliver savings.

Defining, measuring, and addressing skip rates

In December we launched a new webpage dedicated to skip rates. We have since published two documents, one explaining how we are defining, measuring and addressing skip rates, and one describing the skip rate methodology and implementation guide.

From 16 December, we have been publishing three datasets daily with data included from 15 December. These datasets include a summary of the skip rate by 30-minute time period and a detailed list of the units that were considered. A summary of these new metrics will be included in next month's report.

Key Milestone reached in REVEAL Innovation project

The REVEAL Innovation Project team, with significant contributions from our testing volunteer, Krakenflex, has successfully delivered a Live Trial Environment Proof of Concept (POC) in Microsoft Azure. We are demonstrating for the first time, the technical feasibility of establishing control and metering connectivity, outside of Critical National Infrastructure (CNI).

REVEAL is an ongoing, NESO led, Network Innovation Allowance (NIA) funded innovation project with a vision of becoming our "one-stop shop" for balancing trials activity. The secure, cloud-based platform will enable us to foster innovation and collaborate with partners across our industry, forging key partnerships to test and validate new technologies with agility. Whilst protecting operational excellence, improving the efficiency and scalability of industry trials and facilitating the engagement of smaller market participants will be vital in providing the flexibility required as we collectively strive towards a sustainable future for all.

In December 2024, the REVEAL team and our delivery partner Cap Gemini, in close collaboration with Krakenflex proved the REVEAL Live Trial Environment POC. Successfully and securely sharing Electronic Dispatch Logger (EDL), Electronic Data Transfer (EDT), and Operational Metering Data across a site-to-site Virtual Private Network (VPN), the team replicated control and metering connectivity data sent to and from the Control Room. Developing this capability outside of CNI will for the first time, enable the Balancing Programme to trial modified control signals and new technologies without risk of disrupting day-to-day Control Room operations.

Proving the REVEAL POC through successful integration testing with Krakenflex is a milestone to be celebrated but to unlock the true value of REVEAL, the team's focus shifts to the next phases. Further development and insights from across the industry and NESO will be critical in guiding the Team's 'build by demand' approach, ensuring the platform can support NESO's strategic priorities.

By continuously improving the REVEAL solution, we aim to create a robust and scalable platform that supports its strategic ambitions of security of supply, decarbonisation, and operational excellence. This ongoing collaboration with Krakenflex and other market participants will be a key factor in driving innovation and achieving our energy transition goals.

Frequency Risk and Control Report: Model and Data webinar

We are obliged to review and set out the GB system frequency control policy at least once in each financial year through the Frequency Risk and Control Report (FRCR) process. This process was introduced following the 9 August 2019 GB power cut event through the SQSS modification GSR027 - Review of the NETS SQSS Criteria for Frequency Control that drive reserve, response and inertia holding on the GB electricity system. Our analysis clarifies the impact on frequency reliability and cost, and presents recommendations to achieve an appropriate balance. We conduct an industry consultation on our recommendations and submit the report to the SQSS Panel for review and recommendation. The report is submitted by 1 April to Ofgem for approval.

The previous editions of the FRCR policy have been successfully implemented by us in the National Electricity Transmission System (NETS) and have delivered significant benefits to GB consumers.

Based on feedback from the industry, to enhance engagement and transparency in this complex subject, during the development of the FRCR 2025 policy, we organised two technical webinars on 27 November and 11 December. These webinars aimed to explain the FRCR methodology and present detailed models and data. Prior to the webinars, we received 112 registrations from a range of industry participants and customers. During the webinars, we saw 105 attendees at peak; we received 35 questions and managed to answer 22 live. We published the webinar slides, recordings, and Q&A documents on 20 December 2024.

In January 2025, we will hold a bespoke SQSS Panel Session and facilitate an open discussion with all the Panel members. Our engagement with the wider industry will continue in March when we launch the FRCR 2025 consultation. A webinar will be held in the middle of the consultation to present this year's policy and gather industry comments and feedback. All feedback will be considered for the final policy or recorded for future development of the FRCR.

Role 2

(Market developments and transactions)

Metric 2X Day-ahead procurement

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

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

Note that in line with the terms of a derogation from the requirements of Article 6(9) of the Electricity Regulation, 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, Balancing Reserve, Quick reserve

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

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

Q3 2024-25 performance

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

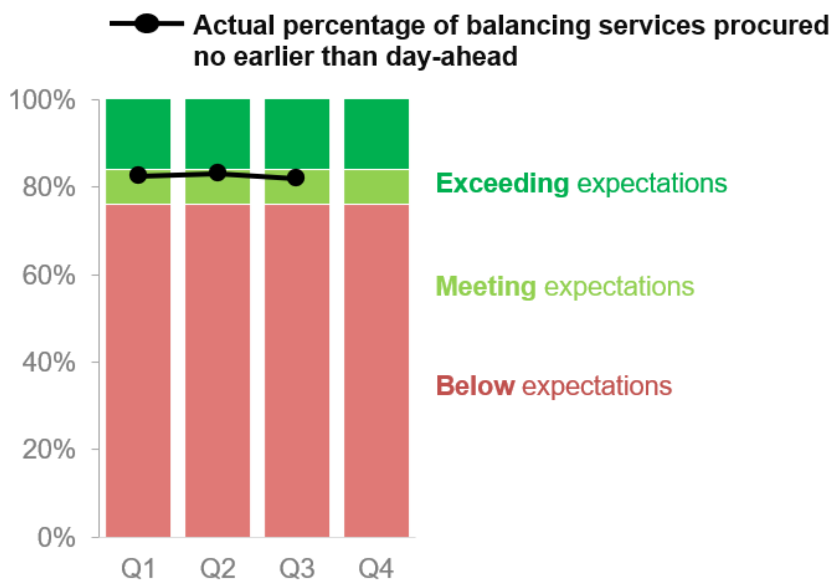


Table: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4	Full Year
Total volume of balancing services procured	MW	11,968	12,228	7,862		32,058
Volume procured no earlier than day-ahead	MW	9,695	10,022	6,449		26,166
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	81%	82%	82%		82%
Benchmark	%	80%	80%	80%		80%
Status	n/a	●	●	●		●

Performance benchmarks:

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

For year 2, the benchmark increases to 80%

Data content Information: Data consists of final settlement data for first two months of the most recent quarter with 3rd month to be provided within the next submission of the report.

Supporting information

In Q3, 82% of balancing services volume was procured no earlier than day-ahead, compared to the benchmark of 80%, and therefore meeting expectations.

The decrease in MWs procured over the period is in line with the end of the summer period where requirement is slightly lower.

Balancing reserve was launched earlier in the year and is beginning to mature into a fully established reserve service. Quick Reserve service went live in December which created a co-opted auction with response services, whilst the market familiarises with co-opted auction this may have initially impacted the MW volumes procured across these services.

The overall STOR MW requirement was decreased slightly in line with current market requirements.

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

This Regularly Reported Evidence (RRE) shows the accuracy of Balancing Services Use of System (BSUoS) forecasts used to set industry charges against the actual outturn charges.

The BSUoS charge (£/MWh) is now based upon a fixed tariff. 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 2024/25, Fixed Tariff 3 (April 24 – September 24) was published in June 2023. Fixed Tariff 4 (October 24 – March 2025) was published in December.

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 2024-25 performance

Figure: 2024-25 Monthly BSUoS forecasting performance (Absolute Percentage Error)

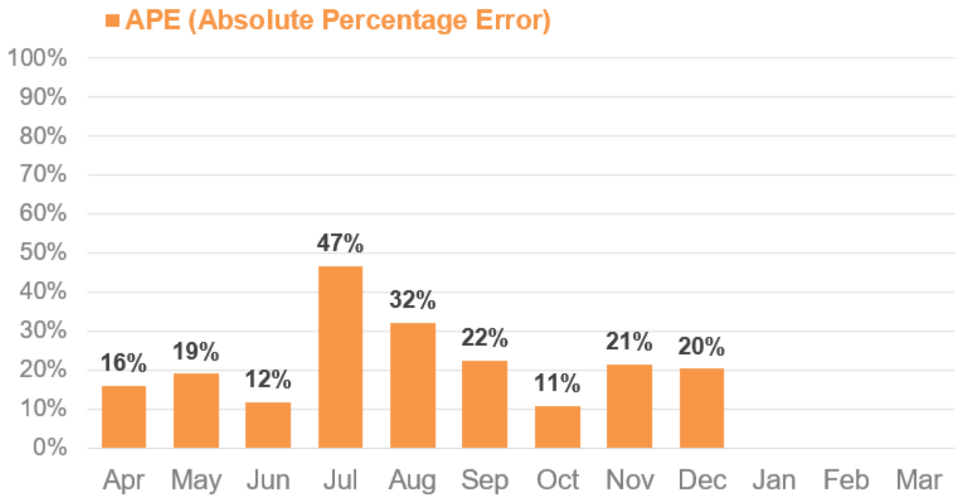


Table: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	11.5	8.5	12.7	8.0	16.5	10.4	14.4	11.5	15.0			
Month-ahead forecast (£ / MWh)	9.7	10.2	11.2	11.7	11.2	12.7	15.9	13.9	12.0			
APE (Absolute Percentage Error)[5]	**16.0**	**19.0**	**11.8**	**46.6**	**32.1**	**22.4**	**10.7**	**21.3**	**20.3**			

[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.

Supporting information

Q3 Performance:

The average monthly Absolute Percentage Error for Q3 has decreased since Q2 (17.4% vs 33.7%).

The BSUoS monthly 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. Over the past quarter, these two variables have driven many of the differences between our forecasted and outturn costs.

Costs:

Costs were below our month-ahead forecast in both October and November, out turning around the 35th and 20th percentile respectively.

In both months, the proportion of demand met by renewables was between 9 – 12% lower than our forecast. We have previously found that a higher proportion of renewables tends to drive higher constraint costs.

Conversely, in December, costs exceeded our month-ahead forecast, out-turning at around the 90th percentile.

The proportion of demand met by renewables was 11% higher than our month-ahead forecast, with constraint costs £91m above forecast.

Volumes:

Across Q3, our average monthly volume forecasting error was 0.94%. This small variance is likely to be due to weather and temperature fluctuations.

Notable events during December 2024

Launch of Quick Reserve service: Enhancing Our Energy Stability

We are proud to announce that phase one of the new Quick Reserve service became operational from Tuesday, 3 December 2024. This new service is part of the suite of services we are introducing to improve our existing reserve services and to support our 2025 ambition to be able to operate the electricity network with zero-carbon.

Quick Reserve is needed for frequency management when there is an imbalance between supply of energy and demand for energy. It will replace our existing Fast Reserve service and will be responsible for reacting to pre-fault disturbances to restore the energy imbalance quickly and return the frequency close to 50.0 Hz.

Quick Reserve, separated into Negative Quick Reserve (NQR) and Positive Quick Reserve (PQR) products to manage frequency in both directions, is procured via a single simultaneous day ahead auction. These auctions co-optimise Quick Reserve with the existing Dynamic Response products, with market welfare being maximised across all services.

Phase 1 of the service will deliver greater efficiencies in supporting system balancing, potentially delivering consumer savings in the region of £29-£32 million each year. Delivery of the full service (Phase 2) will take place in Summer 2025. We are soon to consult with industry and Ofgem on the proposed enduring service and procurement rules.

Role 3

(System insight, planning and network development)

RRE 3X Timeliness of Connection Offers

This Regularly Reported Evidence (RRE) reports on the number of connection offers made within 3 months of clock start date, and the number of connection offers made that took longer than 3 months. The table is populated based on the offers sent during the quarter.

We provide this information separately for the England and Wales area, the Scotland area and by Transmission Owner (TO) area:

- England and Wales: National Grid Electricity Transmission (NGET)
- Central and Southern Scotland: SP Transmission (SPT)
- North of Scotland: Scottish & Southern Electricity Networks (SHET)

In year 1 (2023-24), in England and Wales, while the two-step offer process has been running, we have been reporting:

- The number of standard offers issued within 3 months.
- For two-step offers,
  - the number of (one-step) offers issued within 3 months;
  - the number of two-step offers issued within 9 months, after counter signature of the step one offer; and
  - the number of any connection offers that took longer than the above timeframes.

The two-step offer process concluded on 31st May, 2024. As a result, reporting on this process ceased in Q1 of Year 2 (2024-25).

As of 2 September 2024, Transitional Arrangements have been implemented for all new directly connected transmission applications. We will report on the timeliness of offers sent under these arrangements, with the first offers expected to be issued in Q4 2024-25.

We also report on the scale of the connection queue in terms of GW and time from offer acceptance to connection date. We include a breakdown of assets in the connection queue by size, technology type, and TO area.

Please note these figures are consistent with the Connections monthly data submission provided to Ofgem.

Q3 2024-25 performance

Table: Quarterly connection offers by time taken

Area	Connection offers issued:	Q1	Q2	Q3	Q4	Total
NGET (England and Wales)	(Standard offer) Within 3 months	146	225	228		599
	(One-step) Within 3 months	-	-	-		0
	(Two-step) Within 9 months*	332	-	-		332
	New transitional offers	-	-	-		0
	Longer than the above timeframes	115	-	10		125
	Total	**593**	**225**	**238**		**1056**
SPT (Scotland)	(Standard offer) Within 3 months	53	61	63		177
	New transitional offers	-	-	-		0
	Longer than 3 months	0	2	-		2
	Total	**53**	**63**	**63**		**179**
SHET (Scotland)	(Standard offer) Within 3 months	95	100	91		286
	New transitional offers	-	-	-		0
	Longer than 3 months	2	0	3		5
	Total	**97**	**100**	**94**		**291**
TOTAL	Within 3 months / 9 months*	**626**	**386**	**382**		**1394**
	Longer than the above timeframes	**117**	**2**	**13**		**132**
	% Within 3 months / 9 months*	**84%**	**99%**	**97%**		**91%**
	% Longer than 3 months	**16%**	**1%**	**3%**		**9%**
	Total	**743**	**388**	**395**		**1526**

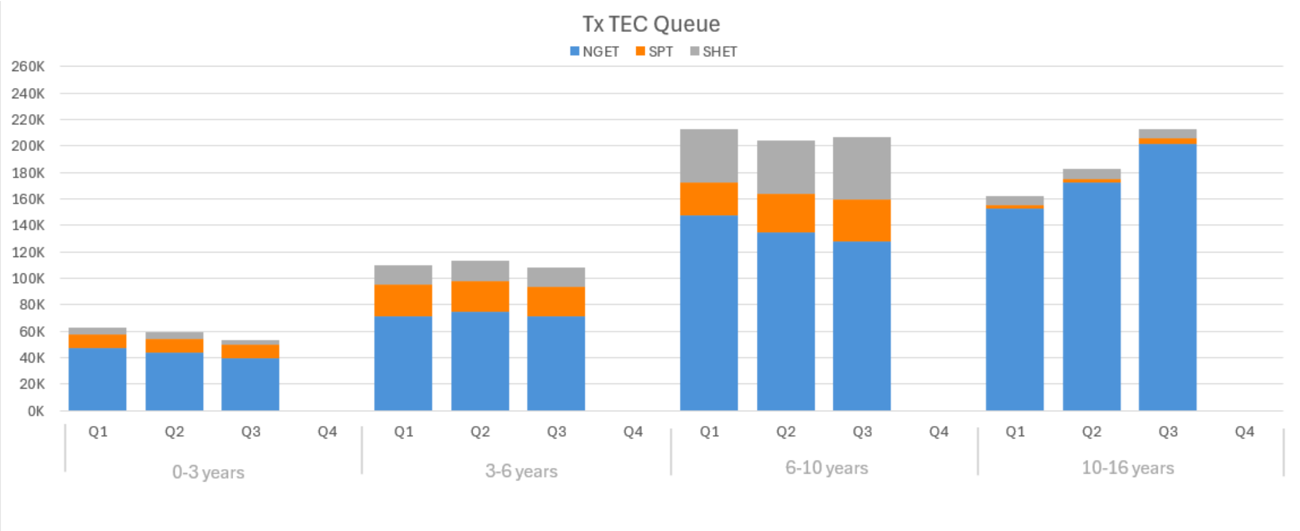
* After countersignature of the step one offer

500 1st Step Applications – 7 did not receive an offer (withdrawn) - remaining 493 Offers Made before 1 March 2024

477 2nd Step Offers made – 29 Issued before 1st March 2024 – 448 issued before 31st May 2024

The two-step process was originally agreed with Ofgem to conclude on the 1 March 2024, however it was agreed that for connection applications received between 27 November 2023 and 29 February 2024, they could be extended to 1 June 2024.

Graph: Connections queue in MW split by time from offer acceptance to connection: Q1 (30 June 2024) vs Q2 (30 Sep 2024) vs Q3 (31 December 2024) vs Q4 (31 March 2025) **



** Graph updated to show Queue in relation the base year 2024

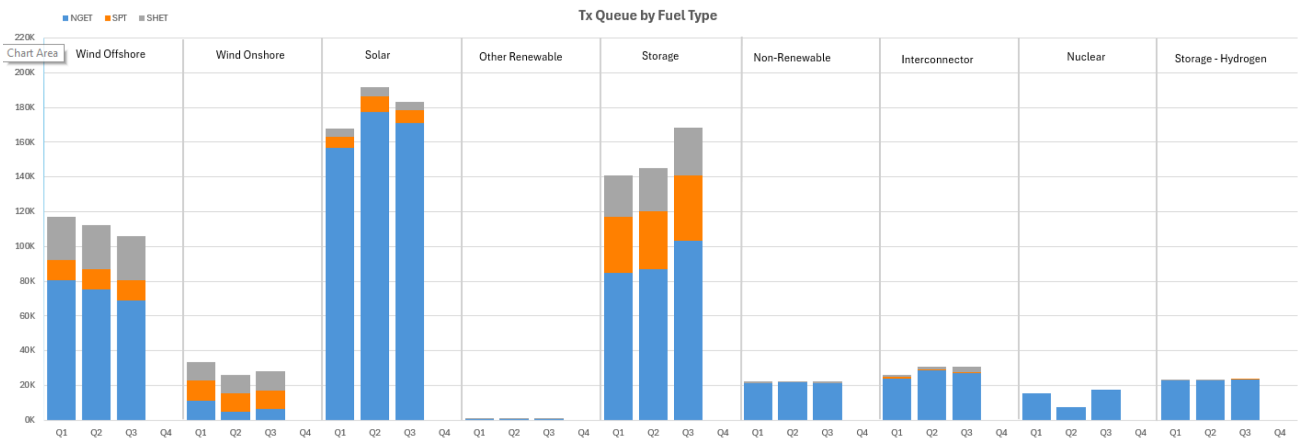
The above graph records the connection queue based on the MWs that are scheduled to connect at various future time horizons. Previously (for Q1 and Q2 reports) it was measuring the time to connect from 2023-24, but this has been revised so that it now measures the time to connect from 2024-25.

Table: Connections queue in MW split by time from offer acceptance to connection

Host TO	Unit	0-3 years	3-6 Years	6-10 Years	10-16 Years	Total*
NGET	MW	39,839	71,253	127,494	201,583	**440,169**
SPT	MW	9,673	22,587	32,175	3,829	**68,264**
SHET	MW	3,789	14,556	47,402	7,489	**73,236**
Total*	MW	**53,301**	**108,396**	**207,071**	**212,901**	**581,669**

*Timescale MW values are rounded up in this table but Totals are reflective of the unrounded base figures and therefore might appear slightly lower than the sum of the columns or rows.

Graph: Connections queue in MW by technology type (31 December 2024) **



** Graph updated to show figures as at true Quarter end

Table: Connections queue in MW by technology type (31 December 2024)

*Technology Type MW values are rounded up in this table but Totals are reflective of the unrounded base figures and therefore might appear slightly lower than the sum of the columns or rows.

Host TO	NGET	SPT	SHET	Total*
Wind Offshore	69,081	11,356	25,574	**106,011**
Wind Onshore	6,613	10,574	11,095	**28,282**
Solar	170,778	7,778	4,738	**183,294**
Other Renewables	754	-	312	**1,066**
Storage	103,180	37,850	27,368	**168,398**
Non-Renewable	21,517	-	950	**22,467**
Interconnector	27,033	700	3,200	**30,933**
Nuclear	17,620	-	-	**17,620**
Storage - Hydrogen	23,592	5	-	**23,597**
TOTAL*	**440,168**	**68,263**	**73,237**	**581,668**

Supporting information

Timeliness of connection offers

Application volumes have continued to rise compared to 2023-24, as evidenced by the number of offers being issued by NGET and SPT. SHET, however, issued slightly fewer offers this quarter.

Connections queue

The Connections queue has grown from 553GW at the end of Q2 to 582GW at the end of Q3. This increase is primarily driven by new connection applications from battery storage and solar developers. There is an observed rise in connection dates within the 10-16 year period, aligning with average connection timescales.

As outlined above, the connection date graph has been re-baselined to start from 2024-5 as Year 0, updating the previous 2023-4 baseline. Q1 and Q2 figures have also been adjusted to reflect accurate quarter ends. Data is extracted from the monthly Ofgem Databooks, which were unpublished at the time of Q1 & Q2 compilations.

CUSC modification CMP376 (Inclusion of Queue Management process within the CUSC) was approved and implemented in November 2023. This introduces queue management milestones into connection contracts and allows us to terminate contracted projects which are not progressing against agreed milestones. This is a significant step towards being able to reduce the size of the overall queue and remove stalled projects. Our connections reform proposals (proposed to go live in Q2 2025) will go further and faster towards reducing the overall queue by removing stalled projects.

RRE 3Y Percentage of 'right first time' connection offers

This RRE measures the % of connection offers made which did not need reissuing. For those that needed reissuing, we break these down by reason.

We include details of the number of connection offers made for the England and Wales area, and the Scotland area, in addition to each TO area. During the period where the 2-step offer process is in place, we will report this separately for step 1 and step 2 offers.

The two-step process concluded on 31st May 2024, however as Right First-Time reporting is measured on when the offer was signed, we are likely to see 2nd Step offers reflected in this table until the end of Q3.

Q3 2024-25 performance

Table: Quarterly % of 'right first time' connection offers

Area	Connection offers	Q1	Q2	Q3	Q4
NGET	Total Step 1 offers signed	1	1	0	
	Number right first time	0	1	0	
	Percentage right first time	**0%**	**100%**	**100%**	
	Total Full / Step 2 offers signed	86	264	208	
	Number right first time	75	238	174	
	Percentage right first time	**96%**	**97%**	**96%**	
SPT	Total connection offers signed	54	38	52	
	Number right first time	44	21	38	
	Percentage right first time	**93%**	**92%**	**87%**	
SHET	Total connection offers signed	68	33	50	
	Number right first time	52	22	29	
	Percentage right first time	**90%**	**95%**	**86%**	
TOTAL	Total connection offers signed	209	336	310	
	Number right first time	172	282	241	
	Percentage right first time	**92%**	**96%**	**93%**	

Table: Connection offer that needed reissuing by reason

Area	One-step connection offers	Q1	Q2	Q3	Q4	Total
NGET	Customer driven	5	16	26		47
	NESO driven	5	6	8		19
	TO driven	2	12	12		26
	Total	**11***	**26***	**34***		**71***
SPT	Customer driven	6	5	6		17
	NESO driven	4	4	7		15
	TO driven	4	10	2		16
	Total	**10***	**17***	**14***		**48***
SHET	Customer driven	7	6	10		23
	NESO driven	8	2	7		17
	TO driven	2	4	8		14
	Total	**16***	**11***	**21***		**54***
TOTAL	Customer driven	19	27	42		88
	NESO driven	16	12	22		50
	TO driven	8	26	22		56
	Total	**37***	**54***	**69***		**194***

* Please note that re-offers can be driven by more than one factor. Therefore, the totals can be lower than the sum of the figures for each reason.

Supporting information

The increase in NESO driven Re-Offers may primarily be categorised into the following causes:

- SHEPD Outstanding Acceptances Backlog (Scotland region-specific) – since April 2024, SHEPD has experienced a backlog of outstanding acceptances awaiting signature. This resulted in 5 NESO-driven re-offers being issued to embedded customers due to the significant time lapse since the original offer was issued. As a result, the TO determined that the original offer was invalid and required an update.
- Two re-offers were required due to missing Transmission Owner Reinforcement Instruction (TORI) data, which was not submitted by the Transmission Owner in time for the licensed offer deadline. The re-offers were issued when the updated TORI data was received.
- Twelve re-offers resulted from errors by NESO Customer Contract Managers (CCM) that needed correction.
- Three re-offers agreed at post-offer negotiations.

The monthly reporting of re-offers is currently under review to identify measures for performance enhancement.

Notable events during December 2024

Voltage 2026 Contracts to Delivery £318m in consumer savings

In December, NESO announced the award of four contracts worth a combined £83m to secure voltage services in two regions in England between 2026 and 2036.

The voltage network services procurement programme looks for the most cost-effective ways to absorb more reactive power on the transmission network to address high voltage system issues. As a result of an increase in renewable energy generation and drop in minimum demand and power consumption at the distribution level, NESO needs to adapt and find new ways to manage the changing patterns of reactive power.

Voltage 2026 is the third tender that has been carried out under the Network Services Procurement (NSP)/Pathfinder programme.

In December 2023, a tender was launched for the provision of 600 Mvar; (400 Mvar in the North of England and 200 Mvar in London). This was open to all technology types such as existing generators and new-build projects across the market.

After an extensive procurement process, NESO has awarded four contracts for the provision of 646 Mvar across both regions. These contracts will deliver forecasted consumer saving of £318m across the ten year period.

Strategic Energy Planning activities:

Strategic Energy Planning publications launch

Our responsibilities around energy planning have expanded. We're taking a strategic approach that considers energy needs at national and regional levels, across different types of energy such as electricity, gas and hydrogen. As we develop a whole energy system approach, we are considering community and environmental interests, as well as safeguarding system resilience and minimising system cost.

To ensure our plans are robust and that stakeholders are given a voice from the start of these processes, we are consulting (from 9 December 2024 to 20 January) on a series of draft methodologies and outputs. On 9 December 2024, we launched three publications for consultation:

- The **Strategic Spatial Energy Plan (SSEP) draft methodology**, which sets out the principles and method for delivering the SSEP
- The **Centralised Strategic Network Plan (CSNP) high level principles**, which will underpin the methodology for the CSNP and
- The **transitional CSNP2 (tCSNP2) Refresh methodology**, for refreshed analysis using our interim network planning approach.

We also published a supporting document explaining how our strategic energy planning deliverables interact with each other and with wider NESO activities, and held a webinar for interested parties that was attended by almost 450 participants.

Our methodology publications have been informed by input from stakeholders and, beyond this consultation, there will be further opportunities to engage in the development of the SSEP and CSNP. The publications, webinar recording and information on the consultation are available on our website.

Publication of our Gas Network Capability Needs Report (GNCNR)

We serve as the independent gas network planner for Great Britain (GB), with specific responsibilities outlined in the gas planner licence. The Gas Network Capability Needs Report (GNCNR), published on 6 December 2024, is our first publication under these new obligations and demonstrates our whole system approach to energy planning.

The report presents our independent view of GB's gas transmission system - the National Transmission System (NTS) - and its capability to meet current and future network requirements.

The findings within the report will be used by the NTS operator, National Gas Transmission (NGT), to propose network reinforcement options in the Strategic Planning Options Proposal (SPOP). Following this, we will assess any proposed reinforcement options and create a Gas Options Advice Document (GOAD) by the end of 2025. This two-yearly cycle will allow for gas network capability needs to be identified and network reinforcement options to be developed and assessed.

You can read more about the GNCNR and review the report on our website.

Ambitious package of connections reform actions set out

On 20 December, we submitted a package of ambitious connections reform actions to Ofgem for approval. If approved, these reforms will shift the connections process to prioritise project readiness and strategic alignment with the Government's Clean Power Action Plan, enforcing new delivery requirements and eliminating stalled projects to make way for genuine 'ready' clean power and demand projects by 2030 and beyond.

Connections Reform will offer faster connections for viable projects aligned to strategic energy plans, a more coordinated and efficient network design that benefits customers and consumers, and a streamlined process that effectively supports the transition to net zero.

Pending Ofgem approval, our proposed reforms aim to address the expanding connections queue, which currently includes over 750GW of projects— more than twice the amount needed to achieve clean power by 2030 or net zero by 2050. These reforms are part of broader efforts to reduce the connection delay for projects from five years to just six months.

Ofgem is now deliberating on our proposals to return their decision in Q1 2025. In Q2 2025 the evidence submission window will open, subject to Ofgem approval, where existing projects in the connections queue will be invited to submit evidence to the 'Gate 2 to Whole Queue' process - a one-off exercise, in which all existing projects in the connections queue will be assessed against set criteria and be provided with either a firm 'Gate 2' offer, or a Gate 1 offer, with an indicative connection location and date.

Published Beyond 2030: Innovation and Targeted Oil and Gas (INTOG)

The Innovation Targeted Oil and Gas (INTOG) leasing round was announced by The Crown Estate Scotland (CES) in March 2023 to help support the aims of the North Sea Transition Deal (NSTD) in one of the overarching goals of decarbonising oil and gas platforms by 50% by 2030. Innovation (IN) projects are small scale wind farms that have a capacity of 100 MW or less. These will showcase new and innovative offshore wind technologies such as floating offshore wind turbines. Targeted Oil and Gas (TOG) projects have the additional aim of supplying renewable power to offshore oil and gas platforms. This can reduce or remove their on-site fossil fuel powered generation used on platforms for providing heat and power.

A total of 13 seabed leases were granted by CES in the North Sea, following this we assessed each individual project to determine what projects to include in scope of our Holistic Network Design Follow Up Exercise (HNDFUE). Considerations for incorporation considered; progress to date, connection agreements and route to market amongst other project variables. A total of 3 developers across 7 INTOG projects were selected to be considered for coordination – alongside an interconnector. The interconnector NorthConnect opted in to the design exercise to allow potential continuation of work that had already been completed to date with another in scope developer (CENOS).

We carried out a design exercise to recommend how to connect the in scope projects to the onshore electricity network. The recommended design considered all four design objectives detailed in our Terms of Reference (ToR) which includes; total cost, deliverability and operability, community impact and environmental impact. All four design objectives were considered throughout the design process on an equal footing whilst engaging with a broad range of stakeholders. We published our recommended design on the 12 December 2024.

NESO
National Energy
System Operator