

NESO RIIO-2 Business Plan 3 (2025-26)

Incentives BP3 End-Scheme Report

Reported Metrics Annex

May 2026

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Introduction

As part of the RII0-2 price control, we published our third Business Plan (BP3) in January 2025. It sets out our delivery focus for the period April 2025 to March 2026 against eight Performance Objectives alongside additional requirements arising from Ofgem’s Final Determinations. Each Performance Objective is underpinned by a set of Success Measures intended to represent the key deliverables or milestones which, if achieved, demonstrate progress towards the Performance Objective.

Our BP3 Performance Objectives for 2025–26

WHOLE ENERGY	
	<p>Strategic Whole Energy Plans</p> <p>NESO will establish the capabilities, foundations and methodologies needed to deliver national and regional strategic whole energy plans.</p>
	<p>Enhanced Sector Digitalisation and Data Sharing</p> <p>NESO will work with the sector to develop an aligned and interoperable digital ecosystem that enables industry digitalisation collaboration utilising innovation, underpinned by transparent data sharing and access.</p>
	<p>Fit-for-Purpose Markets</p> <p>NESO will support the government in making informed decisions on policy and market reform across the whole system. We will also continue to reform our own markets to level the playing field and deliver value to consumers.</p>
	<p>Secure and Resilient Energy Systems</p> <p>NESO will improve whole energy system emergency preparedness and resilience. We will ensure the necessary capabilities and requirements are in place and facilitate industry readiness to meet the Electricity System Restoration Standard.</p>
	<p>Separated NESO Systems, Processes and Services</p> <p>NESO will transition remaining systems, processes and services from National Grid to NESO ownership to enhance our capabilities and establish our autonomy and full independence.</p>
	<p>Clean Power 2030 Implementation</p> <p>NESO will play a pivotal role in securing clean power for Great Britain by 2030 on the path to net zero by 2050. Building on our 2024 advice to government on pathways to a clean, secure, operable and deliverable electricity system, we will move to action and implementation in line with the government’s CP30 action plan.</p>
	<p>Operating the Electricity System</p> <p>NESO will transparently operate a safe, reliable and efficient system throughout BP3, while continuing to transform the capabilities of our people, processes and systems to enable secure zero-carbon operation of the system by the end of 2025.</p>
	<p>Connections Reform</p> <p>NESO will drive delivery and implementation of a reformed connections process that enables projects needed for 2030 and beyond to connect in a timely and coordinated manner.</p>
	<p>Operating the Electricity System</p> <p>NESO will transparently operate a safe, reliable and efficient system throughout BP3, while continuing to transform the capabilities of our people, processes and systems to enable secure zero-carbon operation of the system by the end of 2025.</p>



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

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

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

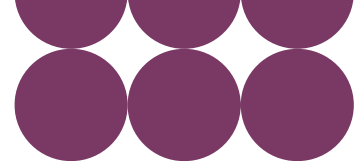
In several cases our performance against Reported Metrics directly contributes to our Success Measures. In other cases, they apply reputational incentives which are supplementary to Ofgem's public performance assessment. Ofgem will no longer measure our performance against pre-determined benchmarks for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

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

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

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

Report	Published report content	Dates required by
Monthly	<ul style="list-style-type: none"> • Reported Metrics 	17th working day of the following month
Quarterly	<ul style="list-style-type: none"> • Reported Metrics • Performance Objectives Progress updates 	17th working day of the following month
Six-month and end of year	<ul style="list-style-type: none"> • Reported Metrics • Performance Objectives Progress updates • Value for Money reporting • Stakeholder survey results 	23 October 2025 and 16 May 2026



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

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

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

Please see our incentives [website](#) for more information on the scheme and to access our reports.

Reported Metrics

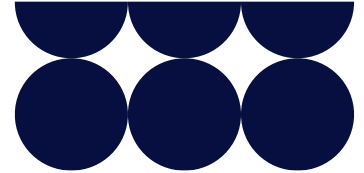




Summary of Reported Metrics

The table below summarises our Reported Metrics for March/Q4 2026:

Reported Metric	Performance
1 Balancing Costs	March: £373m
2 Demand Forecasting	March: Forecasting error of 985MW
3 Wind Generation Forecasting	March: Forecasting error of 4.20%
4 Skip Rates	March: Post System Action (PSA) Offers: 29% Bids: 36% Combined: 30%
5 Carbon intensity of NESO actions	March: 14.82gCO₂/kWh of actions taken by NESO
6 Security of Supply	March: 0 instances where frequency was more than ± 0.3 Hz away from 50Hz for more than 60 seconds. 0 voltage excursion.
7 CNI Outages	March: 0 planned, 0 unplanned system outages.
8 Short Notice Changes to Planned Outages	Q4: (October) 1.66 delays or cancellations per 1000 outages due to a NESO process failure. (November) 0 delays or cancellations per 1000 outages due to a NESO process failure. (December) 1.32 delays or cancellations per 1000 outages due to a NESO process failure.
9 Zero Carbon Operability Indicator	Q4: Highest ZCO% of 97.80% after NESO operational actions, based on the CP30 definition of zero carbon. Using original RIIO-2 definition, the maximum ZCO% was 92.10% .
10 Constraints Cost Savings from Collaboration with TOs	Q4: £536m
11 Day-ahead procurement	Q4: 97% balancing services procured at no earlier than the day-ahead stage.
12 Accuracy of Forecasts for Charge Setting – BSUoS	Q4: Month ahead BSUoS forecasting accuracy (absolute percentage error) of; January: 28% February: 7% March: 33%
13 Balancing services procured in a non-competitive manner	H2: £153m spend on non-competitive services. Volume 43.9 TWH and 23.2 TVARH
14 Future Savings from Operability Solutions	H2: i) Saved balancing costs: £44.4m ii) Monetised carbon reductions: £56m



		iii) Indicative impact on the SZCP limit: See Reported Metric 14 (Future Savings from Operability Solutions) for details
15	EMR Demand Forecasting Accuracy	Annual: T-1 forecast accuracy of 0.9% T-4 forecast accuracy of 3.7%
16	Accuracy of Forecasts for Charge Setting – TNUoS	Annual: Actual total TNUoS revenue for 2025-26 is within 1.4% of the budget



1. Balancing Costs

Performance Objective

Operating the Electricity System

Success Measure

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

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

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

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

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

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

Non-constraint costs = $62.25 + (\text{Day Ahead baseload} \times 0.478)$

Constraint costs = $-33.49 + (\text{Day Ahead baseload} \times 0.39) + (\text{Outturn wind} \times 23.51)$

Benchmark (Total) = $28.76 + (\text{Day Ahead baseload} \times 0.87) + (\text{Outturn wind} \times 23.51)$

**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](#).

March 2026 performance

Figure: 2025–26 Monthly balancing cost outturn versus benchmark

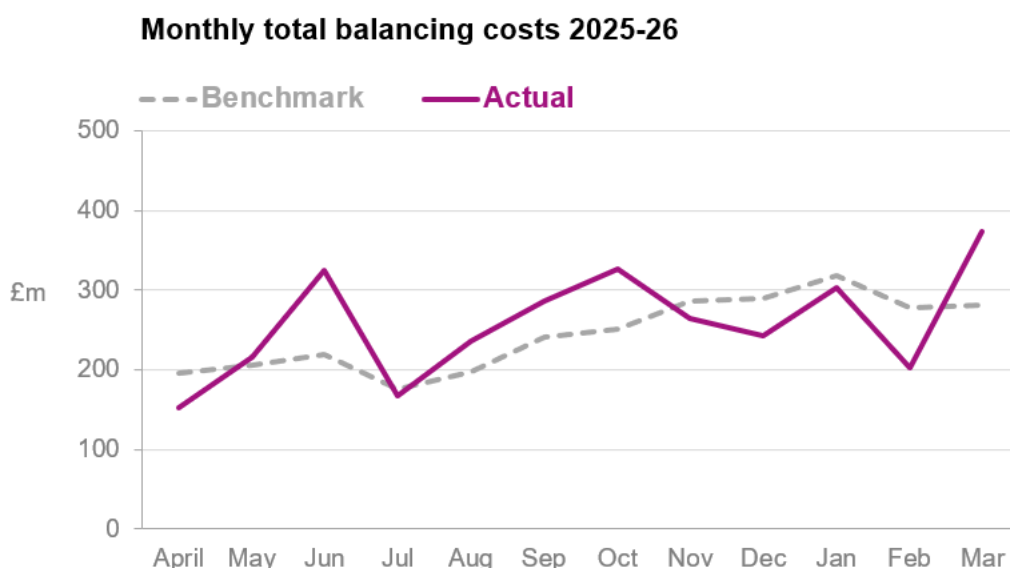


Table: 2025–26 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	4.1	4.7	5.4	3.3	4.4	6.4	6.6	7.9	8.3	8.6	7.6	7.1	74.4
Average Day Ahead Baseload (£/MWh)	81	77	73	80	73	72	77	82	75	100	80	98	81
Benchmark*	195	206	219	176	197	241	251	286	289	318	277	281	2936
Outturn balancing costs¹	152	215	324	167	236	287	326	265	242	303	203	373	3093

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.

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



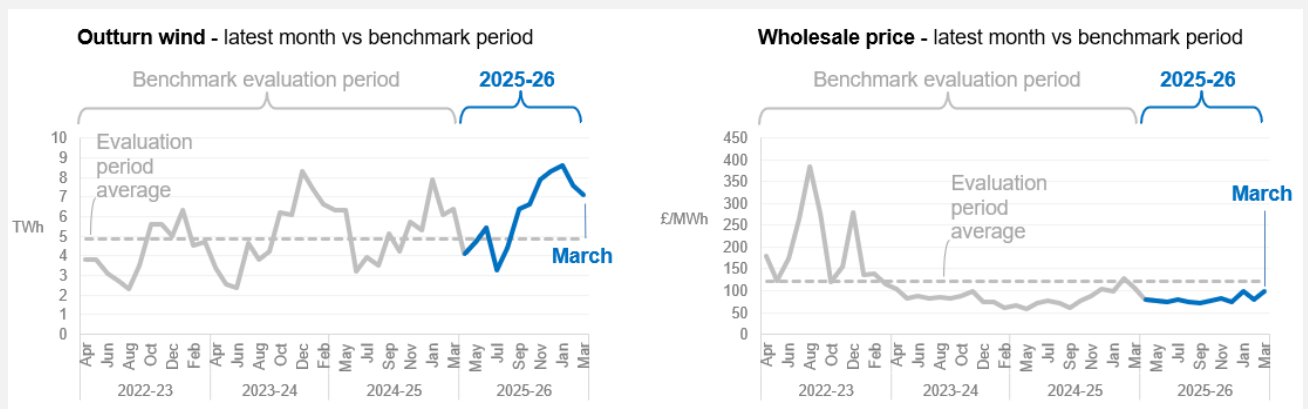
*Ofgem no longer use a benchmark to assess our performance against this Metric however, we continue to report this as an indicator against the outturn figure.

BALANCING COSTS METRIC & PERFORMANCE

This month's benchmark

March's benchmark of £281m is £4m higher than February and reflects:

- An outturn wind figure of 7.1 TWh that is 0.5 TWh lower than February's outturn and the lowest outturn seen since October. It is higher than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 5.0 TWh).
- An average monthly wholesale price (Day Ahead Baseload) that has increased compared to February 2026 (from £80.05/MWh to £98.28/MWh) and is higher than the same period last year. It falls below the evaluation period average.
- Note: Although total wind outturn was higher in February than in March, unconstrained wind outturn was higher in March, driving higher wind curtailment. The benchmark only reflects total wind outturn and average wholesale prices, and does not capture unconstrained wind or regional effects. In March, a higher share of wind occurred in Scotland, where the system is more constrained than last month, contributing to higher costs relative to the benchmark.

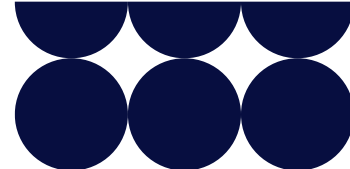


Balancing Costs - Overview

The total balancing cost for March was £372.8m, which is £91.8m (~33%) above the benchmark.

Following a high wind outturn in February (7.6 TWh), March recorded the highest wind outturn ever observed for a March at 7.1 TWh, despite being slightly lower month-on-month. While total wind outturn fell compared to February, unconstrained wind was higher, alongside an increase in Scottish wind outturn from 2.9 TWh to 3.1 TWh, which typically has a greater impact on thermal constraint costs. The higher Scottish wind outturn coincided with constrained system conditions, increasing wind curtailment, and higher power prices in March, driven by geopolitical developments in the Middle East, further contributed to the increase in balancing costs.

With warmer temperatures and longer daylight hours, daytime demand levels dropped sharply in March compared to February. Compared to March last year, demand was higher for most of the day, but was slightly lower during the evening peak, before aligning again later.

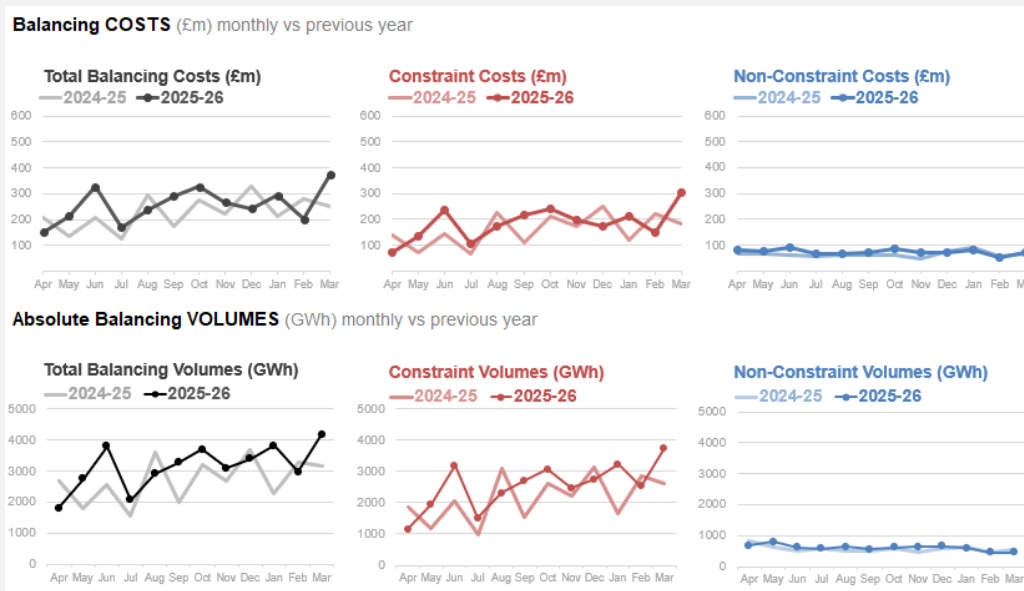


Despite overall wind outturn in March 2026 being slightly lower than February, unconstrained wind was higher, leading to an increased requirement for curtailment. Around 1.5 TWh of wind was curtailed, an increase of 0.6 TWh compared to February, driven by a higher proportion of wind outturn in Scotland, where outturn increased from 2.9 TWh to 3.1 TWh. In addition, both wind outturn and curtailment were higher than March 2025, which contributed to higher balancing and constraint costs during the month.

Voltage constraint costs increased in March, as lower demand reduced the level of self-dispatch from units providing reactive power support. This resulted in more units being procured through the Balancing Mechanism to manage voltage, with the highest volumes observed in the south-west. Inertia costs also increased slightly, reflecting an increase in the volume of inertia-related actions from 12 GWh to 22 GWh during the month.

Non-constraint costs increased by £16.6m in March. This accompanied an increase in clearing prices for all frequency response services and higher wholesale price in March.

Average wholesale prices have increased by almost £18/MWh since February, driven by higher power prices, largely reflecting geopolitical developments in the Middle East. While high wind outturn and warmer temperatures placed some downward pressure on prices, this was outweighed by the market response to increased geopolitical risk. The volume weighted average (VWA) price of bids turned negative at -£7.99/MWh, compared to £7.54/MWh in February, representing a higher monthly cost. At the same time, the VWA offer price increased to £144.94/MWh, driven by higher wholesale power prices during the month. This wider gap between bid and offer prices meant that balancing actions taken through the Balancing Mechanism were more expensive overall.

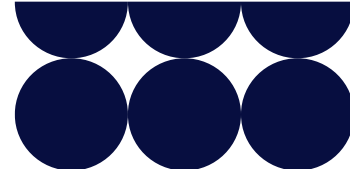


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

Market trends

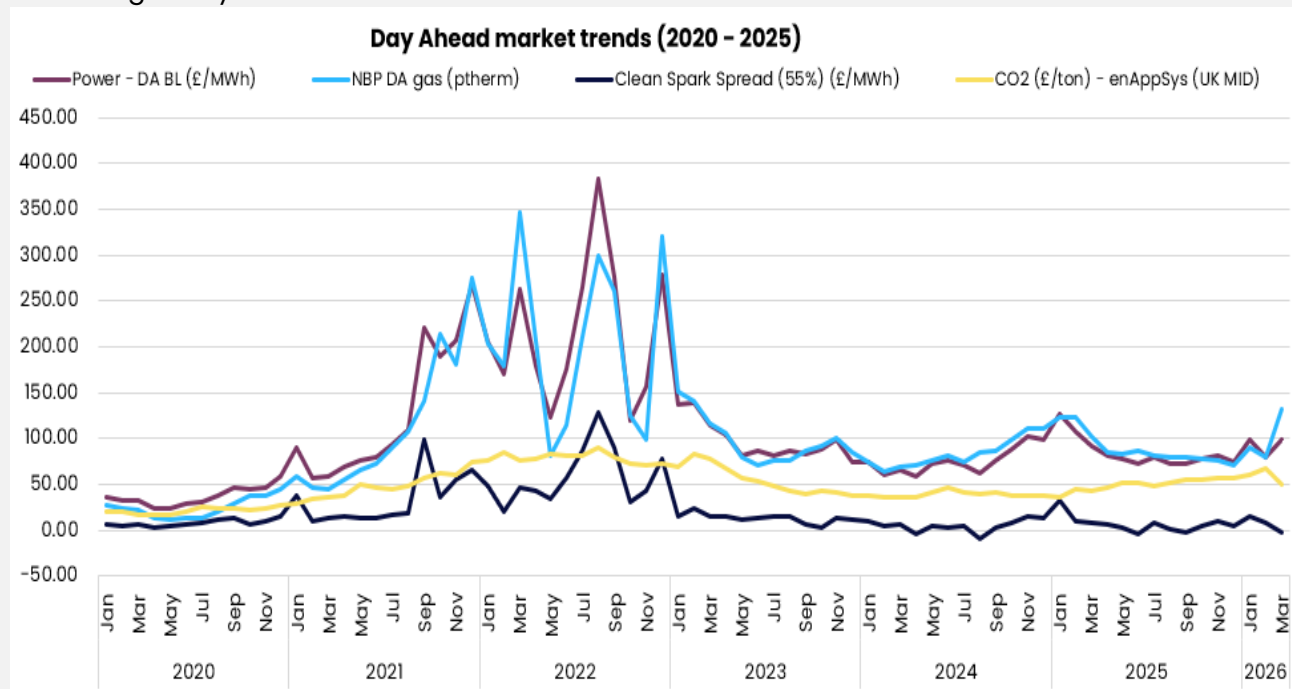
In March, the average power price increased compared to February, rising from £80.05/MWh to £98.28/MWh. This was driven by escalating geopolitical uncertainty in the month, particularly



following the closure of the Strait of Hormuz, which raised concerns over global gas and oil supply and pushed prices higher.

While March saw many periods of high wind outturn, which at times placed downward pressure on prices, the overall price trend was dominated by geopolitical risk and higher fuel prices. During lower wind periods, reliance on gas-fired generation and interconnectors increased, exposing prices further to volatility in international gas markets. As a result, price movements through the month were influenced more by fuel price dynamics and geopolitical developments than by weather led fundamentals alone.

UK carbon prices decreased to £50.90/ton (from £68.35/ton in February), reflecting reduced demand expectations and periods of stronger renewable output. In contrast, gas prices rose sharply to 132.24p/therm (from 80.52p/therm in February) amid heightened geopolitical risk. Although lower carbon prices reduced generation costs, this was outweighed by the sharp increase in gas prices. Consequently, the Clean Spark Spread fell from £8.79/MWh in February to -£1.89/MWh, indicating reduced profitability for gas-fired generation despite its continued role in balancing the system.

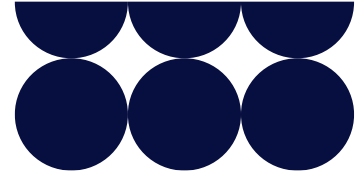


DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Generation Mix

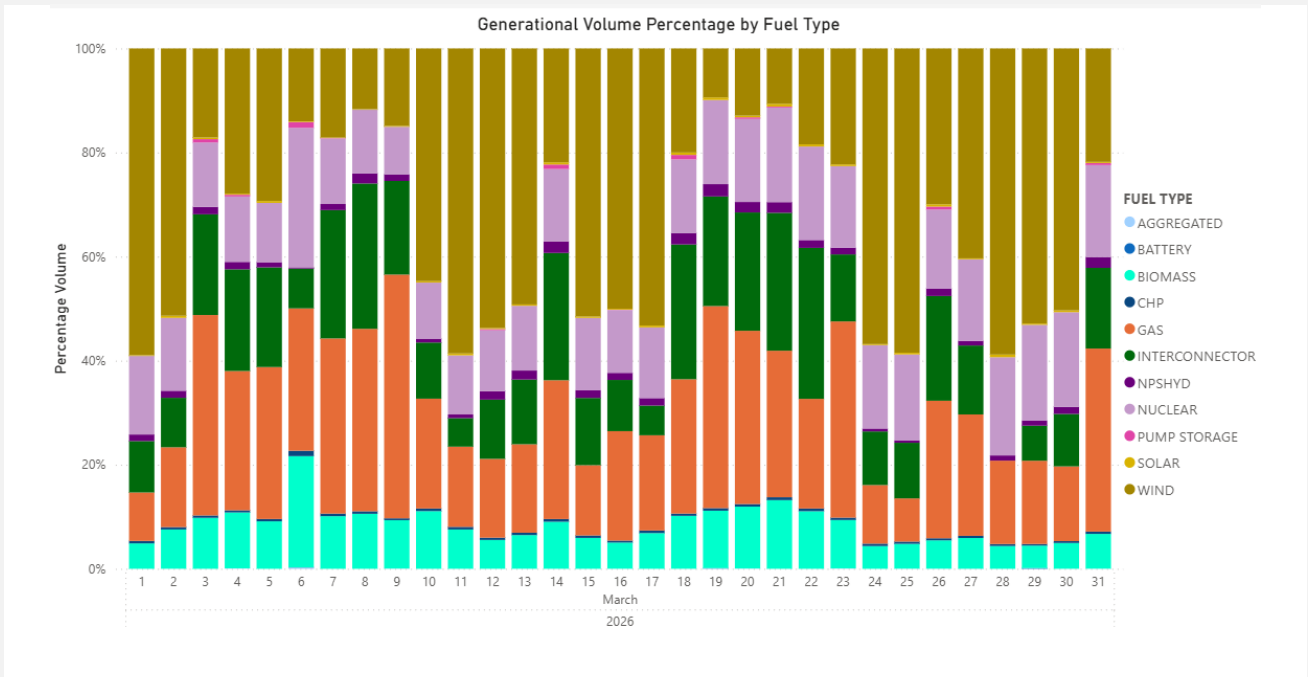
March saw a clear shift in the generation mix compared to February, most notably through a sharp increase in interconnector contribution, which rose to 15.38% of total generation from 7.38% in February. Over the same period, gas contribution fell again, dropping to 24.19% of the overall mix. Wind remained a key contributor, broadly similar to February, but showed significant variability across the month. Nuclear increased further, reaching 15.47%, up from 11.36% in January, while biomass remained broadly consistent with contributions seen in previous months.

The daily generation mix varied notably across March, particularly during periods of lower wind outturn. On 7–9 March and 18–23 March, wind contributed less than 20% of total daily generation.



During these periods, interconnectors and gas dominated the mix, increasing output to compensate for reduced renewable generation. This continued to underline the importance of flexible thermal generation and imports in supporting the system during low-wind conditions.

The highest Transmission System Demand (TSD) of the month occurred on 6 March, coinciding with one of the low wind outturn days, with wind contributing only 14% of total generation. On this day, both biomass and nuclear reached their highest shares of the month, contributing 21.39% and 26.82% respectively, and together accounting for 48.21% of total generation. Gas contributed 27.36%, while interconnectors provided 7.65%, illustrating how non-wind generation sources supported the system during peak demand conditions.

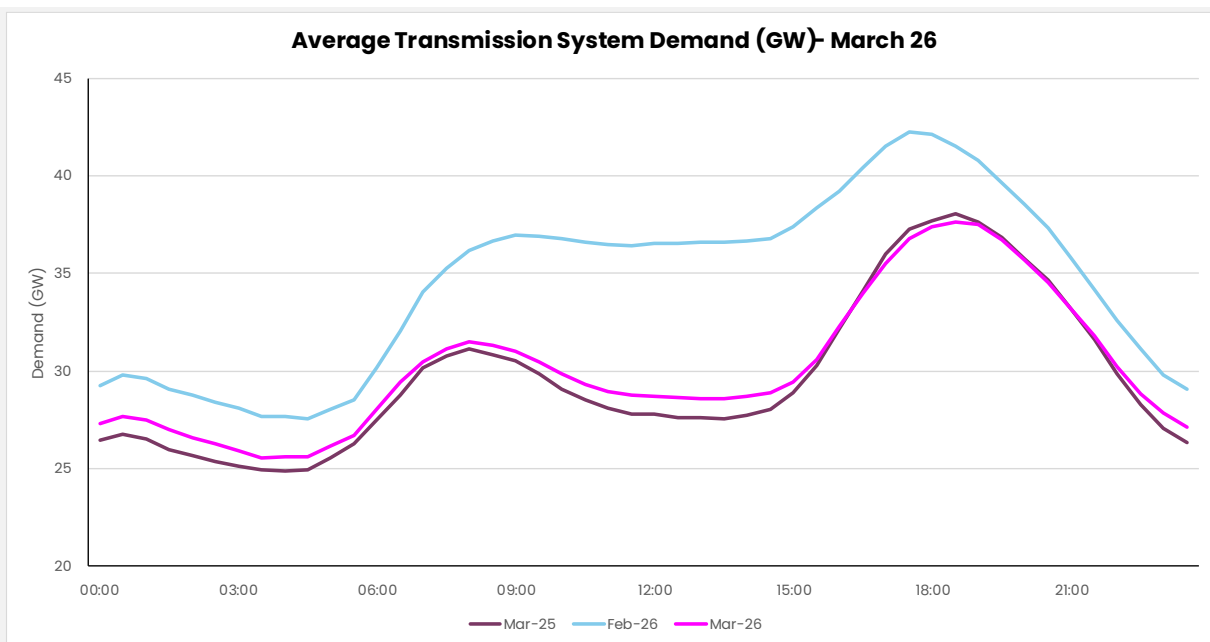
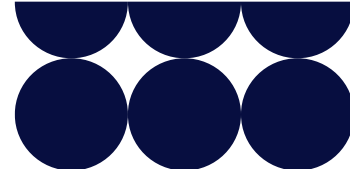


*Generation mix includes exports from interconnectors.

Transmission System Demand

In March 2026 the average Transmission System Demand (TSD) followed a similar profile to March 2025 but was higher up to around 16:00. Demand in March 2025 was slightly higher at the evening peak but more closely aligned with the previous year in the later evening period.

Compared to February 2026, demand was lower throughout the day. The gap was wider during daytime hours and narrowed into the evening and overnight. This reflects warmer weather and longer daylight hours in March, reducing heating demand and increasing embedded solar generation, leading to lower reliance on the transmission system.



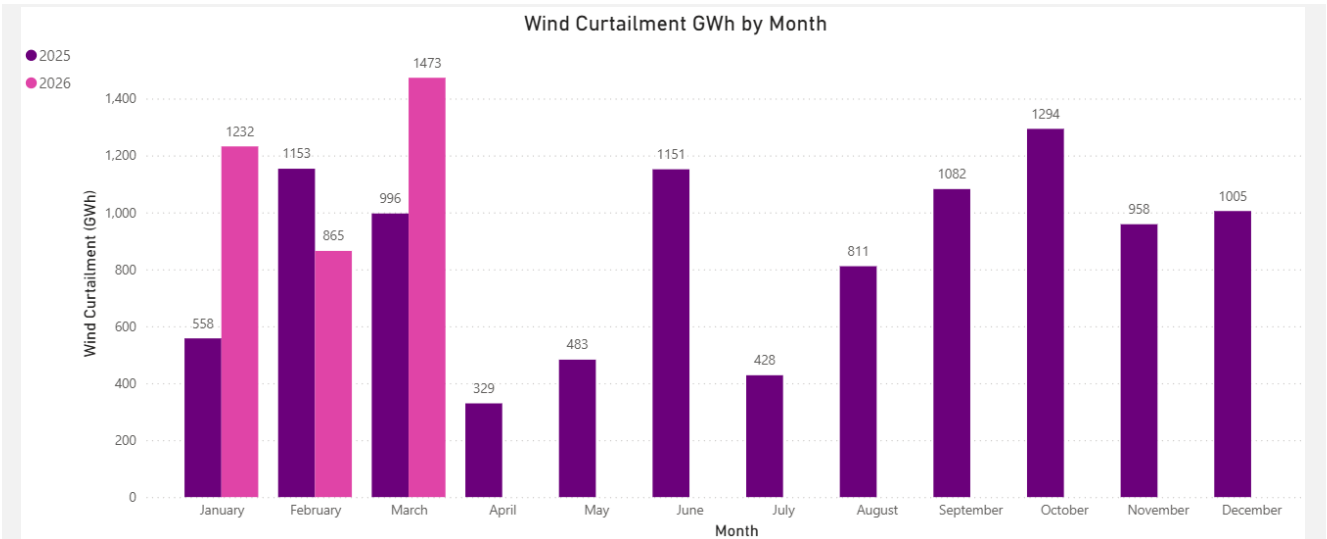
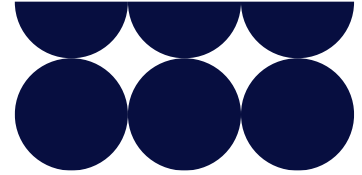
Wind Outturn

March was characterised by generally mild but changeable conditions. Average GB temperatures were slightly above average at the start of the month before becoming more variable through early March. A more settled spell around mid-March saw temperatures rise and remain above the seasonal average. Later in the month, unsettled conditions returned with stronger winds, particularly affecting Scotland and northern parts of the UK, before conditions improved again toward the end of March, leaving the month milder than average overall.

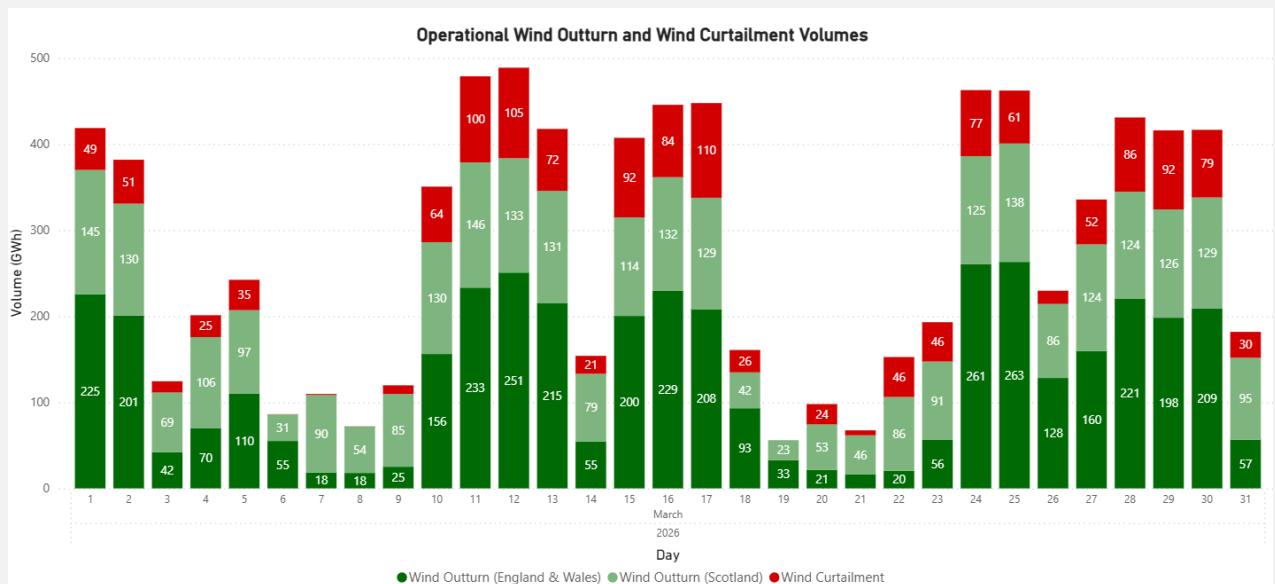
Overall wind outturn dropped from 7.6 TWh in February to 7.1 TWh in March, continuing the fall from the record-high levels seen in January. However, wind outturn in March 2026 was still higher than March last year (5.3 TWh). March also recorded the lowest wind outturn since October 2025.

The change since February differed by region. England & Wales wind outturn fell by 0.7 TWh to 4.0 TWh, the lowest level since August. In contrast, Scotland wind outturn increased by 0.2 TWh to 3.1 TWh, representing the second-highest Scottish wind outturn on record.

Wind curtailment increased sharply in March 2026 compared to both February 2026 and March 2025. Total curtailment rose from 865 GWh in February to 1,473 GWh in March and was also higher than March 2025 (996 GWh). Although total GB wind outturn declined slightly from February to March, the increase in Scottish wind outturn and the reduction in England & Wales resulted in a greater proportion of wind generation being located in more constrained northern regions. Periods of elevated wind output during March therefore translated into higher curtailment volumes relative to both the previous month and the same period last year.

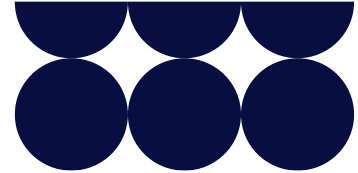


The day with the highest volume of wind curtailment occurred on Thursday 17 March (109.97 GWh). Thursday 12 March had the highest total unconstrained wind outturn this month at 489 GWh and, as a result, was the highest costing day of the month.

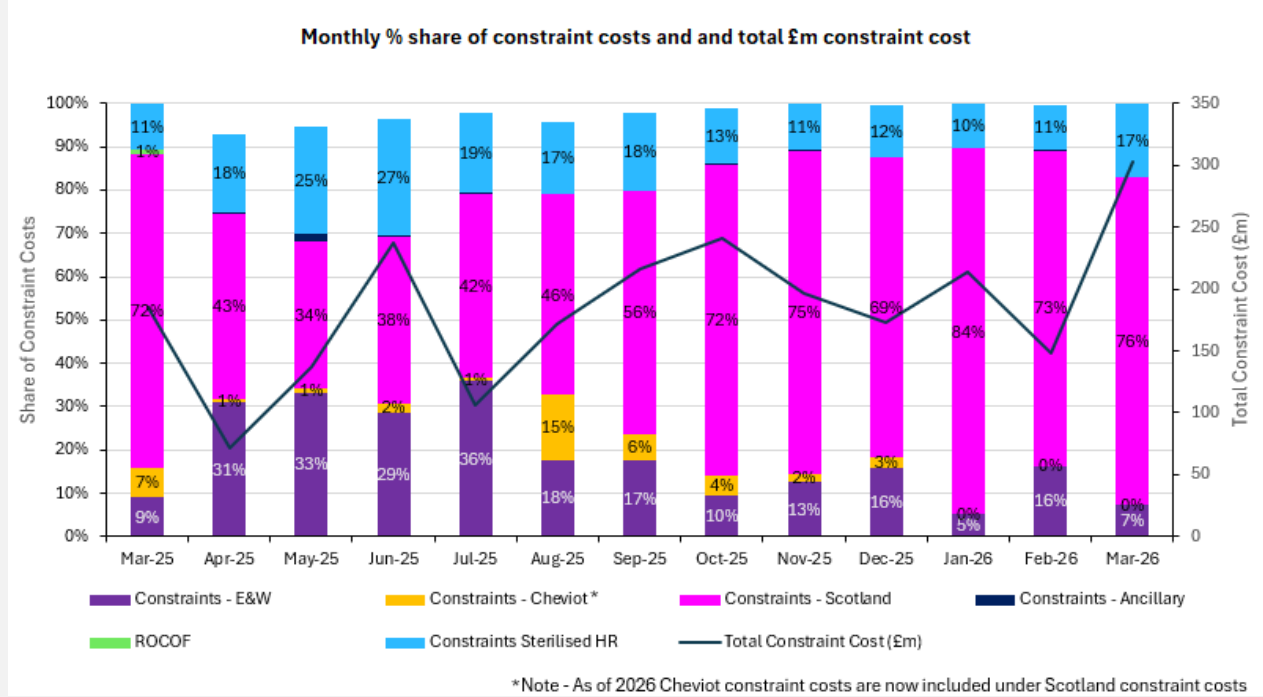


Constraints

Constraint costs increased from £148.7m in February to £303.27m in March, an increase of £154.5m. The increase was driven largely by a rise in Scottish constraint costs, which accounted for 76% of total constraint costs, up from 73% in February. Constraint costs in Scotland increased by £121.0m month-on-month, reflecting higher wind outturn and a significant increase in wind curtailment, with Scottish wind generation rising to 3.1 TWh, compared to 2.9 TWh in February. The higher volume of wind generation placed increased pressure on north–south transmission boundaries, increasing the requirement for thermal constraint actions. In contrast, constraint costs in England & Wales decreased slightly, which further increased Scotland’s overall share of costs. Higher power prices during March also increased the cost of replacement energy required to manage these constraints, contributing to the overall rise in thermal constraint costs.

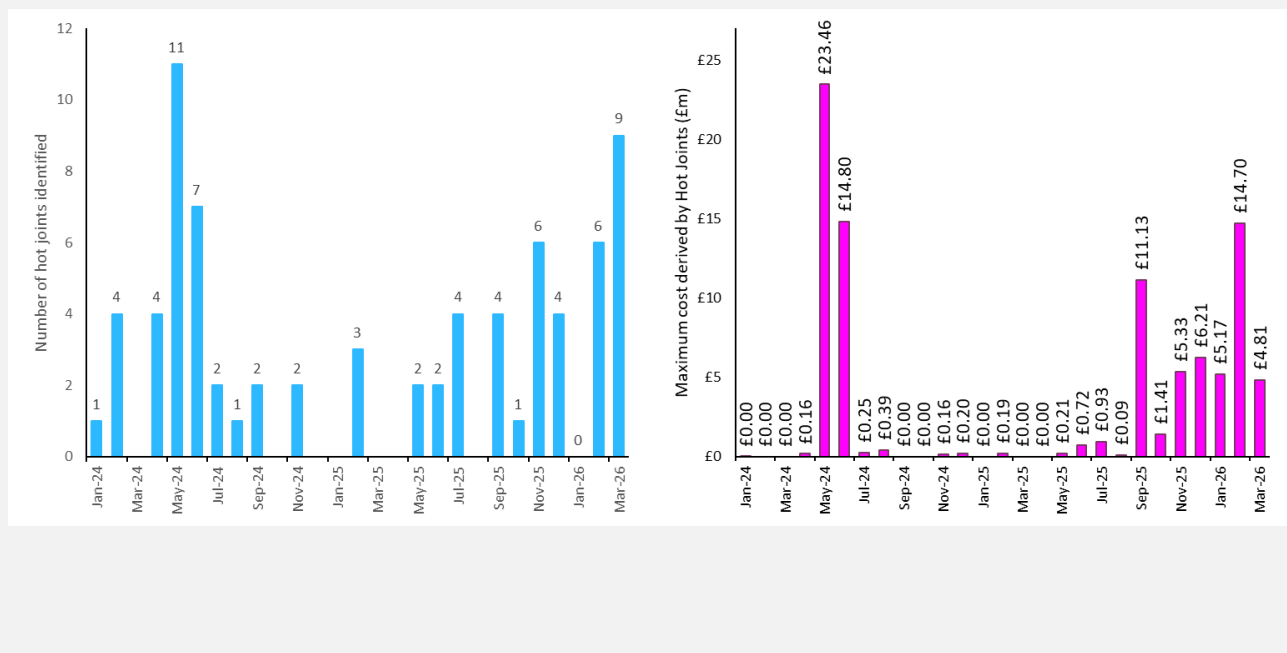


Note: From 2026 onwards, Cheviot is no longer reported as a separate constraint group and its costs are included within Scotland.



Network Availability

Hot joints refer to transmission equipment that tends to overheat during normal operational conditions. Transmission Owners are responsible for notifying NESO of any service reductions associated with this equipment. Hot joints in the system have both operational and economic impacts. In March 2026, nine hot joints were identified, several of them located in the South-East and South-West of England. At the moment of writing this report, there are two still under assessment and awaiting resolution. The estimated maximum cost to the system for these hot joints was approximately £4.8 million in March 2026.





BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): March 2026 vs February 2026					
	(a)	(b)	(b) - (a)	decrease ◀ increase	
	Feb-26	Mar-26	Variance	Variance chart	
Non-Constraint Costs	Energy Imbalance	-6.3	-0.8	5.4	
	Operating Reserve	3.5	4.7	1.3	
	STOR	3.7	2.5	(1.2)	
	Negative Reserve	0.5	0.5	0.0	
	Fast Reserve	13.4	24.4	11.0	
	Response	14.8	21.0	6.3	
	Other Reserve	0.8	1.6	0.7	
	Reactive	13.8	12.5	(1.3)	
	Restoration	8.1	6.4	(1.7)	
	Winter Contingency	0.0	0.0	0.0	
Constraint Costs	Minor Components	0.6	-3.5	(4.1)	
	Constraints - E&W	24.3	22.1	(2.3)	
	Constraints - Scotland*	108.0	229.9	121.8	█
	Constraints - Ancillary	0.4	0.2	(0.2)	
	ROCOF	0.4	0.4	0.1	
Totals	Constraints Sterilised HR	15.7	50.8	35.2	█
	Non-Constraint Costs - TOTAL	52.8	69.4	16.6	█
	Constraint Costs - TOTAL	148.8	303.4	154.6	█
	Total Balancing Costs	201.6	372.7	171.2	█

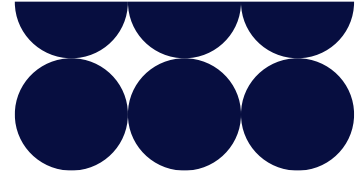
*Note - As of 2026 Cheviot constraint costs are now included under Scotland constraint costs

As shown in the totals from the table above, constraint costs increased by £154.6m, while non-constraint costs increased by £16.6m, resulting in an overall increase in total costs of £171.2m compared to February 2026.

Note: The increase in the overall balancing cost of the month was predominantly driven by higher wind curtailment and higher power prices.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
<p>Constraint-Scotland: +121.8m</p> <p>Constraint – England & Wales: -2.3m</p> <p>Constraint Sterilised Headroom: +£35.2m</p> <p>Overall constraint costs increased by £154.6m, driven by higher wind outturn and curtailment in Scotland, where constraint costs rose by around 113%. Higher power prices further amplified the increase in constraint costs, while England & Wales saw a slight decrease due to lower wind outturn.</p>	<p>Constraints – Scotland & Cheviot: +£97.8m</p> <p>Constraints – England & Wales: +£5.4m</p> <p>Constraints Sterilised Headroom: +£29.3m</p> <p>Wind outturn was higher in March 2026, totalling 7.1 TWh, compared to 5.3 TWh in March 2025, which led to increased curtailment and higher constraint costs across GB. The impact was most pronounced in Scotland, where higher wind output coincided with network constraints, and higher power prices this year further amplified the increase in costs.</p> <p>ROCOF: -£1.1m</p>



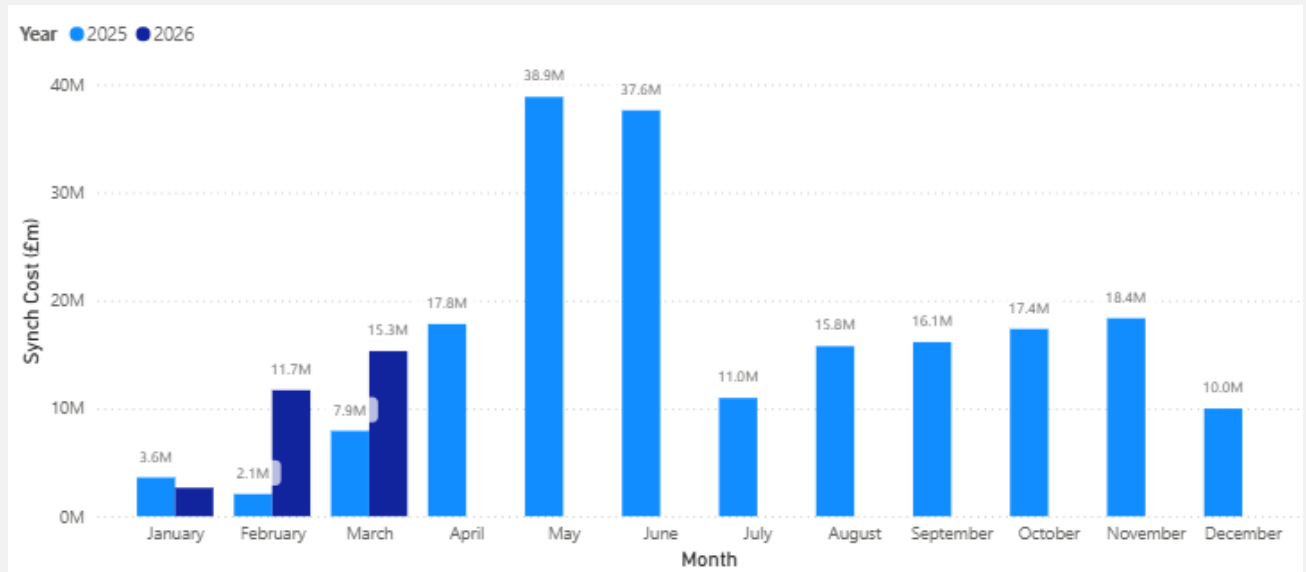
ROCOF: +£0.1m

A slight increase in inertia spending this month was due to a higher volume of actions taken for inertia in March compared to February. An increase of 9 GWh in the volume of actions was observed during this period.

Costs were lower compared to March 2025 due to a significant reduction in inertia-related actions, with the absolute volume falling from 87.4 GWh to 21.9 GWh, reducing the volume of inertia procured through BM actions during the month.

Voltage – Monthly system cost of synchronisation actions for voltage control across 2025 and 2026:

Synchronisation costs are associated with specific actions required to support voltage in the system. These actions involve units that are instructed to provide MVARS and maintain voltages within SQSS limits. It is a highly location-dependent issue, so only a limited set of assets are effective in voltage support. In February, the system synchronisation costs (what it costs to the system, which factors in energy replacement and headroom among others) were £15.3m. This represents an increase of £3.6m compared to February 2026 and is also £7.4m higher than the same period last year (March 2025).

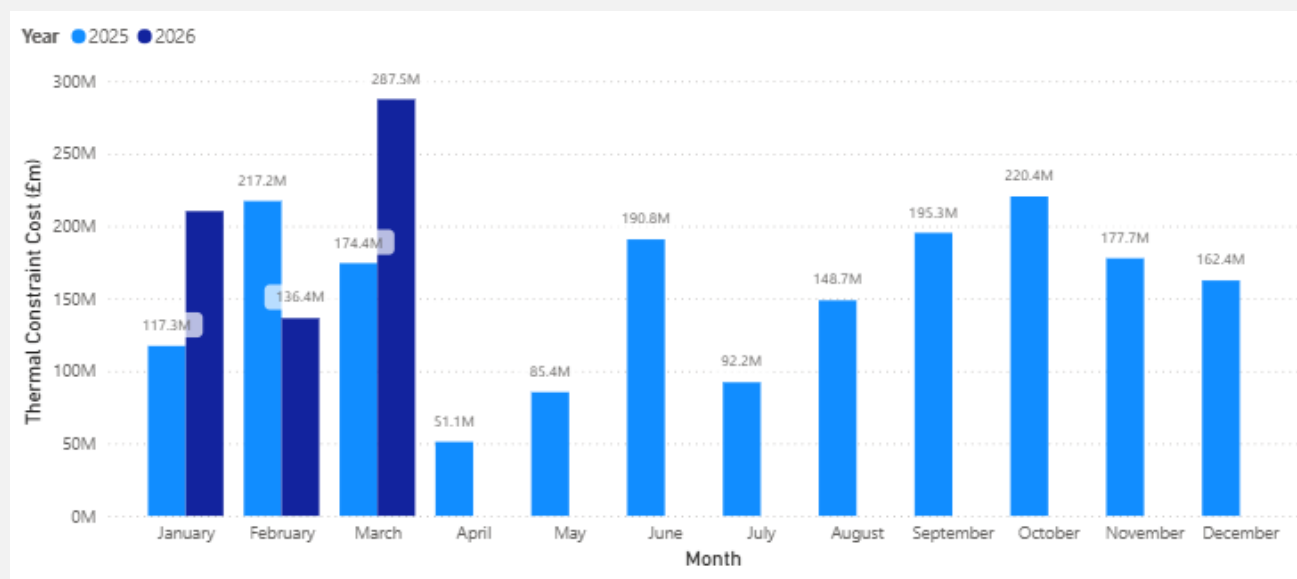


Voltage spending is usually higher overnight: lower demand (as was the case in March compared to February) means that some synchronous units (mostly CCGTs) that usually provide reactive support are not self-dispatched, which forces NESO to procure those services through the Balancing Mechanism. Most voltage costs arise from the South-West region of Great Britain, where the system relies on Combined Cycle Gas Turbines (CCGTs) for voltage management. However, the system operational condition and outages in other areas also influence the system spend. The increase in voltage costs during the month reflects a lower demand and greater need to run units to manage the voltage in the southwest.



Thermal – Monthly system cost of actions for thermal management across 2025 and 2026:

Thermal constraints are linked to operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, often referred to as the B4, B5, and B6 boundaries. The expenditure on thermal constraints is highly correlated with levels of curtailment in Scotland, as well as planned or forced outages in transmission assets that limit the grid’s transfer capacity. Thermal constraints constitute the vast majority of the system constraints, accounting for a significant percentage of system actions. In March, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £287.5m, reflecting a notable increase in costs of £151.1m (111%) compared to the previous month (£136.4m). When compared to the same period last year (£174.2m in March 2025), the cost this year increased by £113.1m (65%).



The increase in March 2026 compared to February 2026 was driven primarily by a significant rise in wind curtailment, which increased by around 70% month-on-month. Although February recorded a relatively high overall wind outturn, wind generation in Scotland was lower (2.9 TWh) than in March (3.1 TWh). The higher Scottish wind output in March placed greater pressure on transmission boundaries, increasing the requirement for curtailment and associated thermal constraint actions.

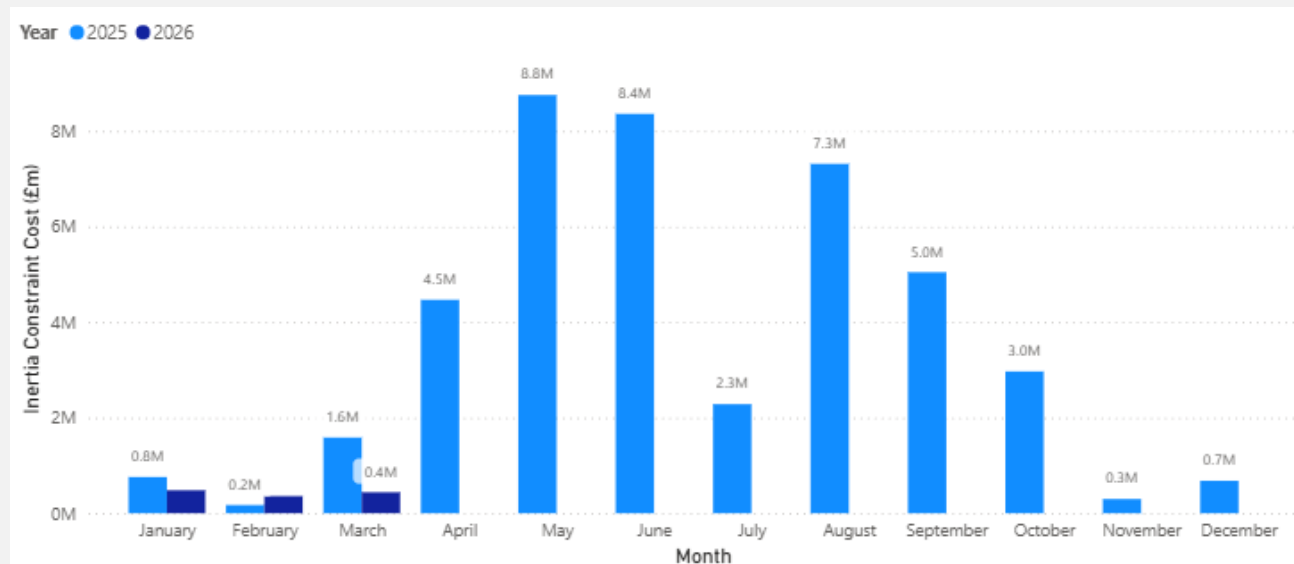
Wind curtailment was also 48% higher in March 2026 compared to March 2025, which further contributed to higher thermal constraint costs this year. This was supported by higher total wind outturn in March 2026 (7.1 TWh) compared to March 2025 (5.3 TWh), increasing the volume of constrained generation. In addition, power prices were higher by £3.84/MWh compared to last year, driven by geopolitical developments in the Middle East, which increased the cost of replacement energy required to manage constraints. The combination of higher curtailment volumes and higher replacement energy costs therefore drove the increase in thermal constraint costs in March.

Inertia – Monthly system cost of actions for inertia management across 2025 and 2026:

Inertia refers to the resistance of the system to changes in its rotational speed. Inertia is primarily provided by the rotating mass of large synchronous generators, mainly CCGTs, but also includes



hydro, pumped storage, biomass, and Combined Heat and Power (CHPs), among others. The costs associated with inertia tend to be marginal in the system compared to thermal or voltage constraints. In March, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £0.4m, which was a £0.1m increase compared to February 2025, but was £1.2m lower than March 2025.



The graph shows that in general inertia spending is lower during the winter months, which is due to the higher demand on the system, which leads to a higher volume of self-dispatching synchronous generation fulfilling inertia requirements.

Reactive Costs/Volumes

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£1.3m	-£2.8m
Reactive costs decreased slightly compared to last month. This was driven by a reduction in ORPS prices, which fell from £5.3/MVArh in February 2026 to £4.8/MVArh in March, although this was partly offset by higher voltage-related spending in the Balancing Mechanism.	Reactive costs in March 2026 were lower than March 2025, driven by lower ORPS prices (£4.8/MVArh compared to £5.5/MVArh last year). There was a greater requirement for voltage management actions compared to last year, but this only partly offset the reduction in ORPS prices, resulting in lower overall reactive costs.

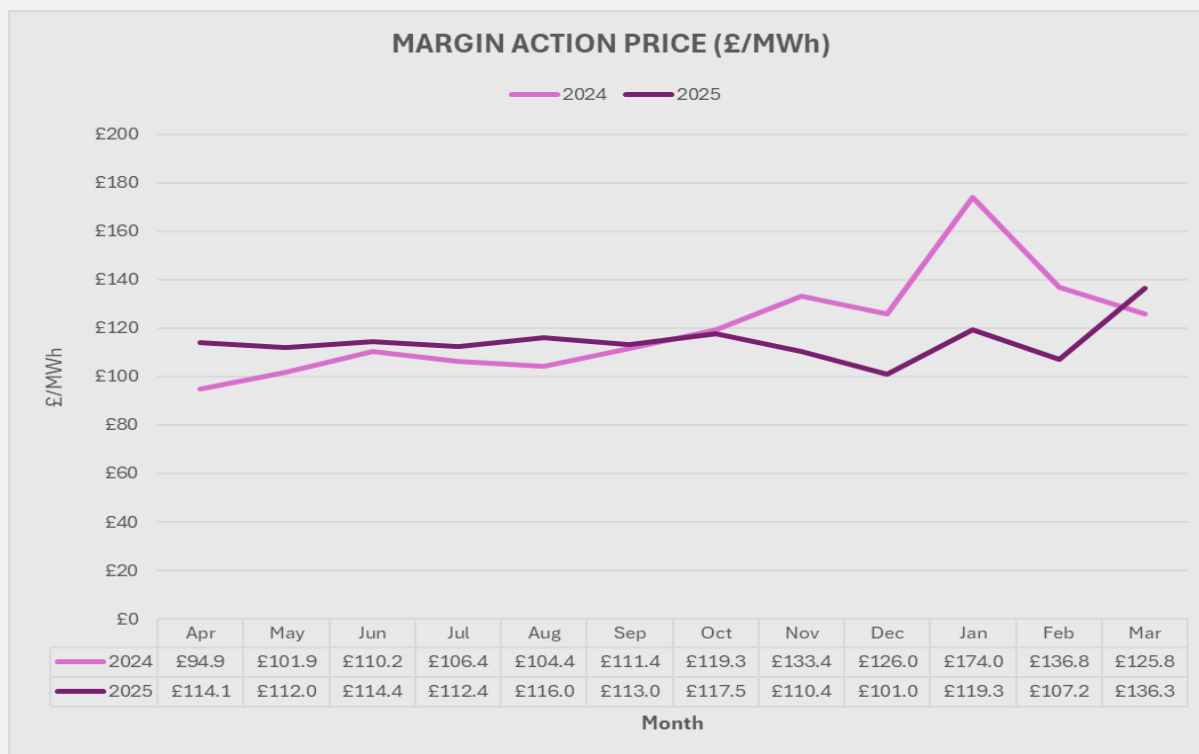
We have started a Network Innovation Allowance (NIA) project that will review the Obligatory Reactive Power Service (ORPS) methodology to ensure that the service remains fit for purpose and cost reflective.

Reserve Costs/Volumes

Following the trend seen this month, the volume-weighted average price for margin actions increased compared to both last month and March 2025. Prices increased to £136.3/MWh, up from £107.2/MWh last month and £125.8/MWh in March 2025.

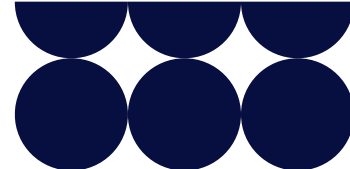


Note: Following the report upgrade, we have implemented a more robust method for reporting the volume-weighted average price for margin actions. The calculation now considers only offer prices and volumes, excluding imbalances, which we believe better reflects actual market conditions.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
<p>Operating Reserve: +£1.3m</p> <p>Fast Reserve: +£11.0m</p> <p>There was 23GWh increase in the absolute volume of operating reserve procured this month, giving rise to the higher spend.</p> <p>Spending on fast reserve increased by over £11m, which was driven by a 17.2GWh increase in the absolute volume procured.</p>	<p>Operating Reserve: -£2.3m</p> <p>Fast Reserve: +£3.4m</p> <p>The absolute volume of operating reserve procured decreased by 9.7GWh which led to a lower spend this year.</p> <p>The absolute volume of Fast Reserve procured increased by 14.8 GWh compared to last year, which was reflected in a £3.4m increase in costs.</p>

We are currently in the process of quantifying the benefits associated with Balancing Reserve, and we will share the results in the coming months. The Optional Fast Reserve service (OFR) has been phased out and was replaced by Quick Reserve; OFR ceased operation at 23:00 on 17 April 2026.



Response Costs/Volumes

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

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£6.3m	-£1.8m
Although the absolute volume decreased by 13.7 GWh, higher average clearing prices for DC, DM and DR led to an increase in costs compared to February.	A decrease in absolute volume of 66.9 GWh led to a reduction in costs compared to March last year, although the overall change in costs was relatively small.

Dynamic Services Average Clearing Prices (£/MW): March 2026 vs February 2026

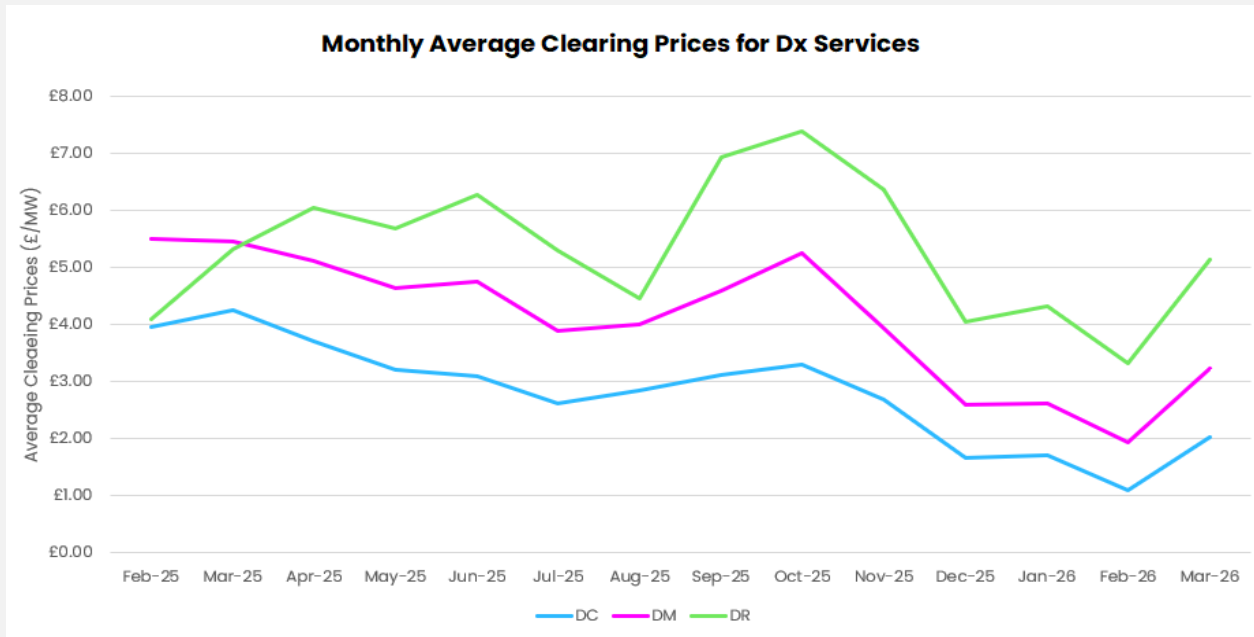
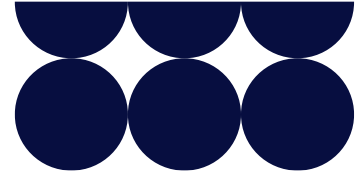
		(a)	(b)	(b) - (a)	decrease ◀ ▶ increase
		Mar-26	Feb-26	Variance	Variance chart
Dynamic Services	DC	2.0	1.1	0.9	
	DM	3.2	1.9	1.3	
	DR	5.1	3.3	1.8	

Dynamic Services Average Clearing Prices (£/MW): March 2026 vs March 2025

		(a)	(b)	(b) - (a)	decrease ◀ ▶ increase
		Mar-26	Mar-25	Variance	Variance chart
Dynamic Services	DC	2.0	4.2	(2.2)	
	DM	3.2	5.4	(2.2)	
	DR	5.1	5.3	(0.2)	

Average clearing prices for Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR) increased in March 2026 compared to February, which saw the lowest clearing prices for all three services this financial year. The increase reflects the rise in wholesale power prices during the month and was observed across all three services, feeding through into higher clearing prices after February's low levels.

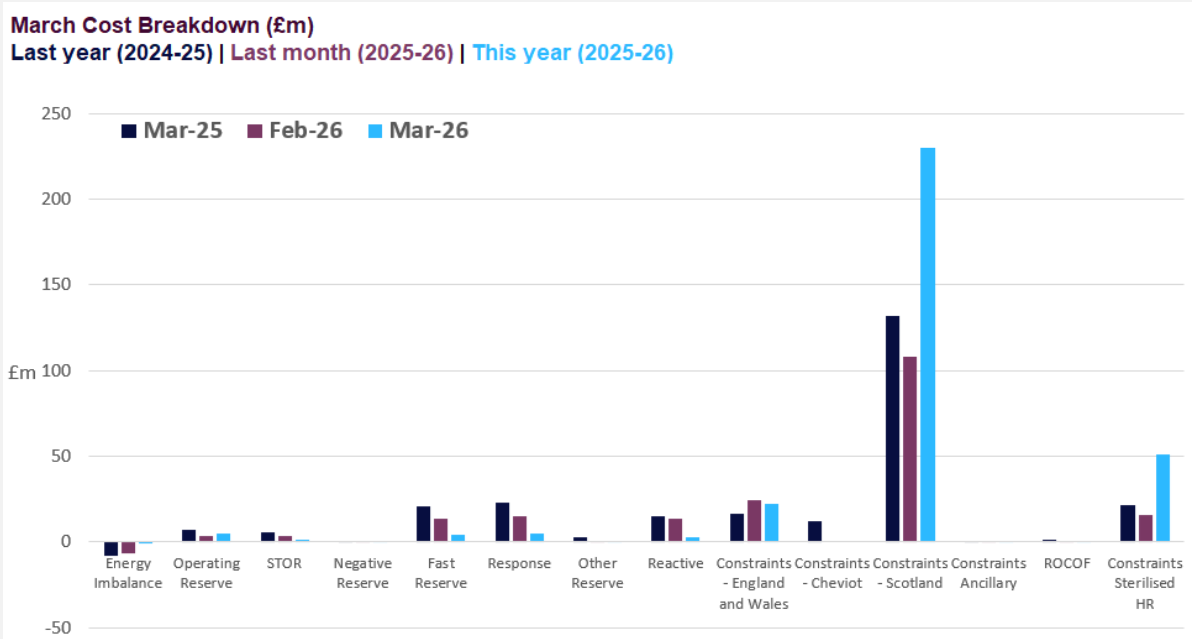
Average clearing prices for all three dynamic services remained lower than March 2025. This is mainly due to higher battery participation compared to last year, which has increased available supply into these services and led to greater competition among batteries, resulting in lower clearing prices year-on-year, particularly for DC and DM, even with higher power prices in March.

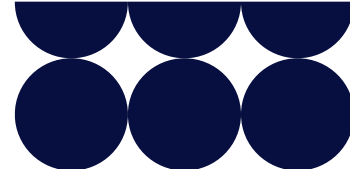


Comparison breakdown

The graph below shows the breakdown of monthly balancing costs by category compared to the previous month and the same month in the previous year. Thermal constraints are currently the largest component of balancing costs. We are progressing several initiatives to reduce thermal constraint volumes/costs including the Constraints Collaboration Project and Constraint Management Intertrip Service. Network Service Procurement projects for voltage and stability are also helping to provide solutions for network management at lower costs.

Note that Constraints – Cheviot are now combined with Constraints – Scotland for 2026.





COST SAVINGS

Cost Savings – Outage Optimisation

Total savings from outage optimisation amounted to approximately £329m in March 2026. This is an increase of roughly £228m relative to February 2026 (£101m). The most valuable action was the implementation of an optimal running arrangement that significantly improved system security mitigating the risk of unserved demand between Elstree and Rye House. The cost saving for this action is estimated at £29.8 million.

Cost Savings – Trading

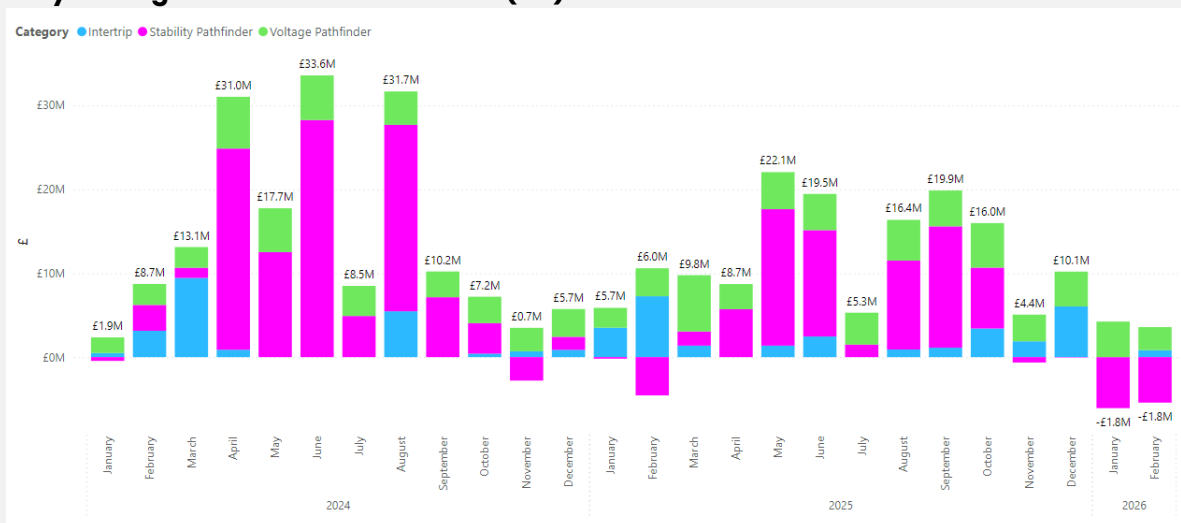
The Trading team were able to make a total saving of £4.5m in March through trading actions as opposed to alternative BM actions, representing a 45% decrease on the previous month. This was also the lowest monthly trading saving of the year. Trading activity was lower in March, partly down to thermal units having higher trade prices for overnight periods due to rising gas prices, meaning it was more economical to accept units in the BM. Increased wind levels and interconnectors on full import led to trading savings on downwards regulation and thermal constraints, while savings were also made on margin. The day with the greatest trading savings was 1 March at a cost of £1.4m with the greatest component being for downwards regulation. The day with the greatest spend on trades was the 25 March at a cost of £1.0m, with the greatest component being for managing voltage in Southern England.

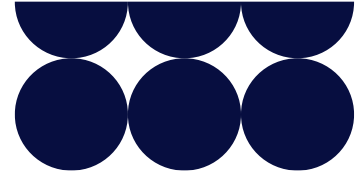
Cost Savings – Network Services (NS)

We are using our Network Services (NS) programme to implement solutions to operability challenges in the electricity system. This programme is made up of the various procurement processes for Constraint Management Intertrip Services (CMIS), Reactive Power (Voltage) and Stability. Previously, these processes were known as ‘Pathfinder’ tenders, however they are now procured through our established markets for CMIS, Reactive Power and Stability under this programme.

We have calculated that the B6 and EC5 Constraint Management Intertrip Services, Voltage Mersey, Voltage Pennines, and Stability Phase 1&2 have delivered approximately £118.6 m in savings across 2025–26 to date (April 2025 – February 2026).

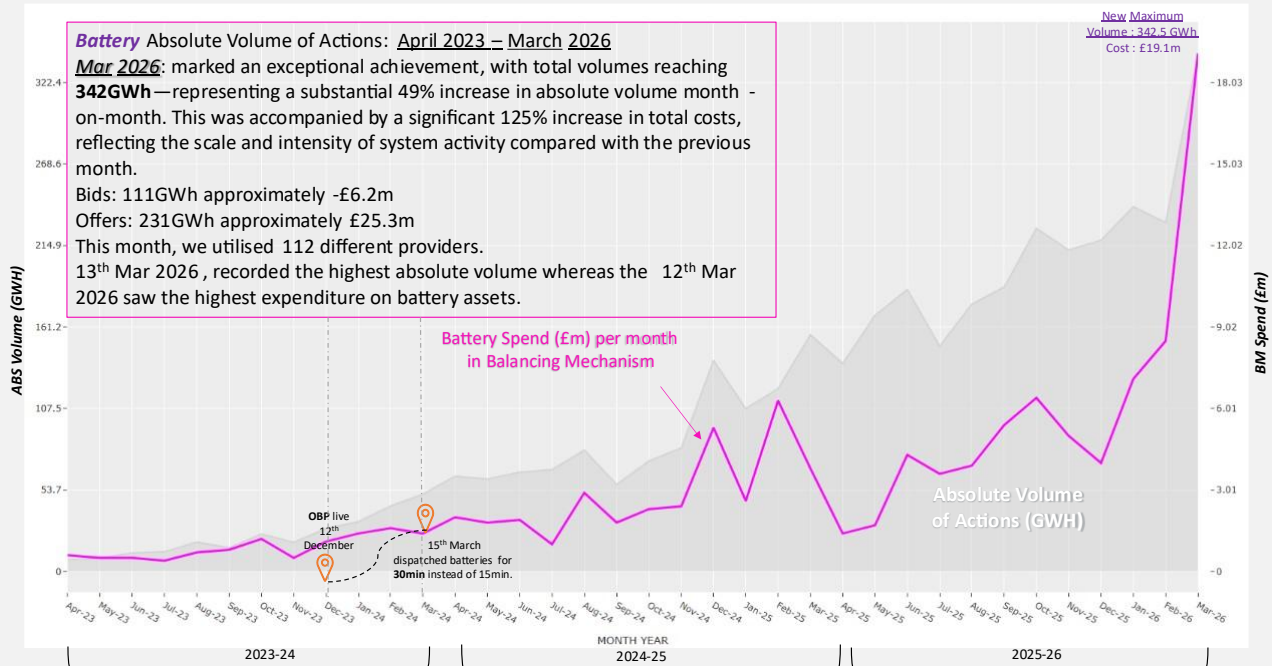
Monthly Savings from Network Services (NS)





NOTABLE EVENTS

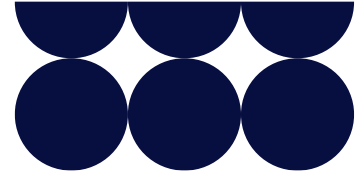
Monthly Absolute Volume of actions and spend for Batteries in the BM March 2026



This graph illustrates a clear upward trend in both cost and volume over the observed period from April 2023 to March 2026. Early on, both metrics remained relatively low and stable with minor fluctuations until late 2023 when the first stage of the Open Balancing Platform (OBP), our new platform to support bulk dispatch, went live on 12 December 2023. There is an initial spike followed by continued growth throughout 2024 with periodic dips and peaks—most notably sharp increases around August–September of each year. Since then, our ability to dispatch a greater number of typically smaller BMUs within a settlement period has increased. This has unlocked greater capability to dispatch batteries in the BM.

Compared with February, March 2026 continued the upward trajectory in balancing costs, accompanied by a particularly strong acceleration in absolute volumes. This combination points not only to sustained growth, but also to a marked increase in the intensity and scale of system activity.

Looking over a longer horizon, battery dispatch volumes have grown rapidly. Since April 2025, absolute volumes have almost tripled year-on-year and are now more than fifteen times higher than in April 2023. This step-change highlights the increasing operational role of batteries within the BM and reflects our continued focus on unlocking system flexibility through battery storage and smaller BMUs.



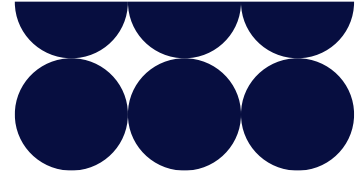
DAILY CASE STUDIES

Daily Costs Trends

March's balancing costs were £373m, which is £171m higher than February, making it the highest-cost month in this financial year. March experienced a higher number of high-cost days, with 10 days recording costs above £15m (11, 12, 13, 15, 16, 17, 24, 28, 29 and 30 March) and a further 7 days exceeding £10m (2, 4, 10, 22, 23, 25 and 27 March). In comparison, February had only one day above £15m, which led to the average daily balancing cost increasing from £7.2m in February to £12.0m in March.

The highest cost day in March was Thursday 12 March, with a total cost of approximately £24.8m, making it the most expensive day of the 2025–26 financial year. March was also the only month in the financial year to record five days with costs above £20m, highlighting the increased frequency of high-cost days compared to other months. The higher costs on 12 March were driven by the highest unconstrained wind outturn of the month, which increased the requirement for wind curtailment. System conditions were also tightened by a yellow weather warning and numerous transmission outages in Scotland, which reduced available network capacity and led to a higher level of balancing actions on the day.

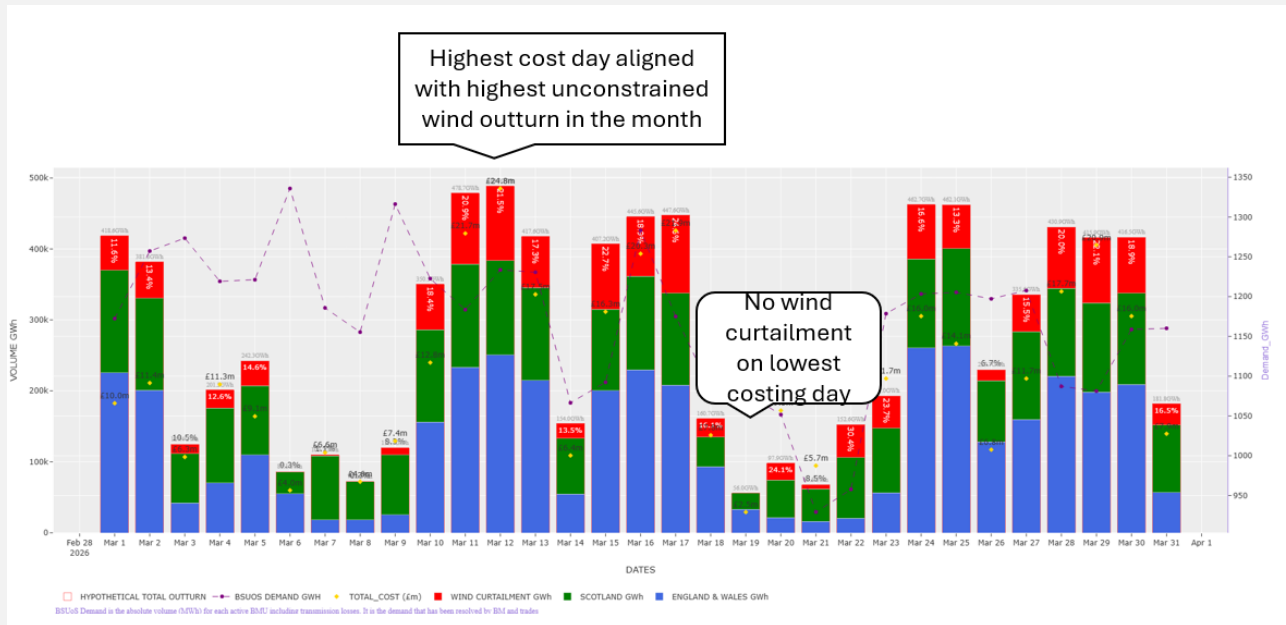
The lowest cost day was Thursday 19 March, with a total cost of approximately £2.5m. This coincided with the lowest wind outturn of the month and no wind curtailment on the day. There were two other low-wind days, Friday 6 March and Sunday 8 March, which also experienced no wind curtailment.



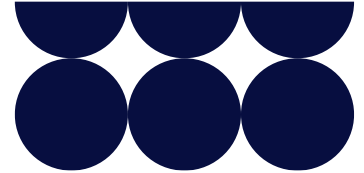
March Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUoS Demand

The chart below serves the purpose of supporting the transparency and the descriptions above. It is the daily "tour" of wind performance. With this graph we can trace, for example, how wind performance and low demand affect the cost of each day.

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



High-cost days and balancing cost trends are discussed every week at the [Operational Transparency Forum](#) to give ongoing visibility of the operability challenges and the associated NESO control room actions.



2. Demand Forecasting

Performance Objective

Operating the Electricity System

Success Measure

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

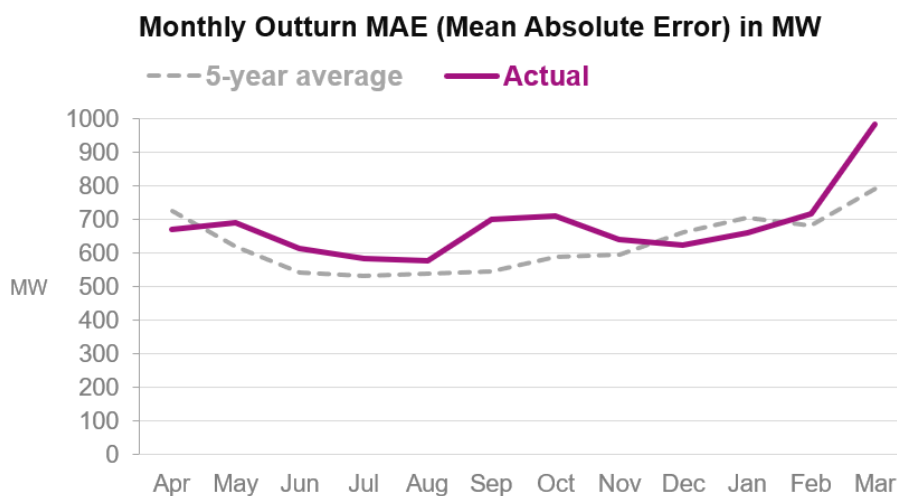
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each half hour period. BMRS is now known as Elexon Insights².

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

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

March 2025–26 performance

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



²Elexon Insights

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Previous 5-year Average (MW)	727	620	541	532	538	545	588	596	662	707	684	793
Previous year outturn (MW)	687	610	565	528	596	612	578	591	652	735	758	850
Absolute error (MW)	671	692	616	584	579	702	711	641	626	662	717	985

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

Supporting information

In March 2026 forecasting error averaged 985MW, against the previous 5-year average of 793MW. Full year performance is 682MW, against a 5-year average of 628MW.

March was a very changeable but generally mild month, with periods of settled weather interspersed with periods of unsettled weather. Day Ahead Solar (weather) forecast errors continue to be the largest contribution to the metric performance, which are exacerbated by changing or complicated cloud conditions. An example of this can be seen by the severe swings in solar output between 28–30 March, where daily solar generation peaks were:

28th: 10.8GW

29th: 4.1GW

30th: 9.5GW

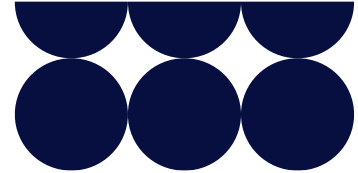
However, demand metric performance was not linked to pure solar (MW) magnitude.

The largest absolute Day Ahead demand error this month was 5.5GW on 29 March, SP27.

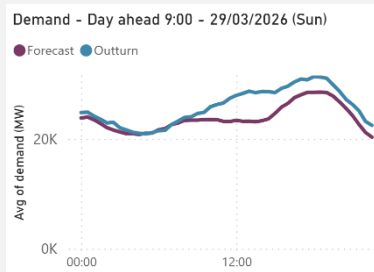
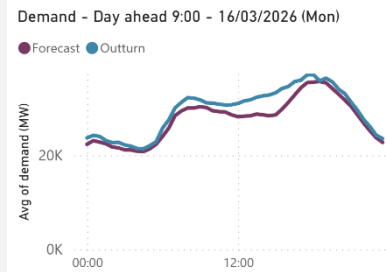
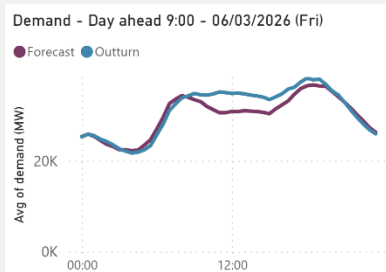
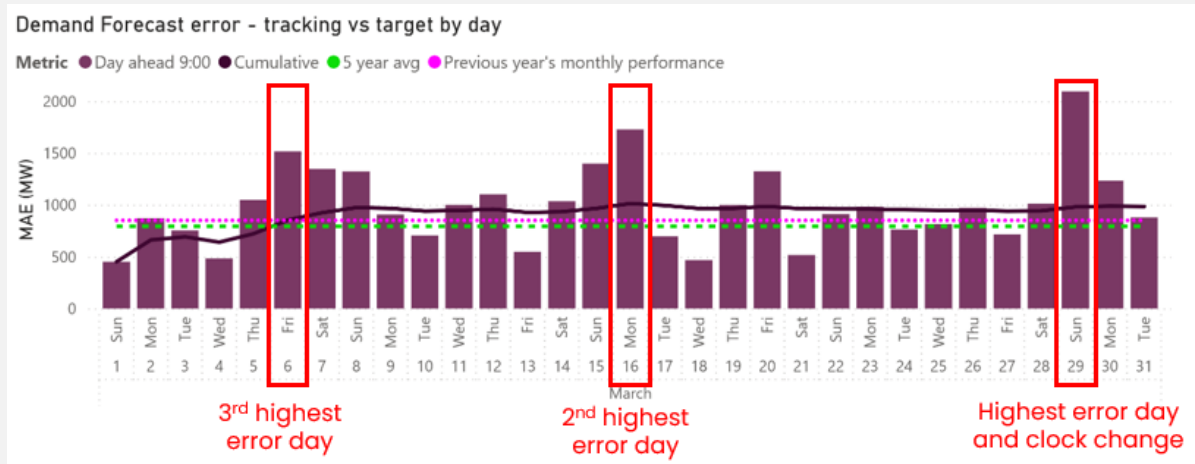
The minimum demand was 18.1GW on 21 March, SP27. The maximum demand was 38.2GW on 3 March, SP37. Solar generation peaked at 13.1GW on 19 March.

Work continues on rebuilding our national demand forecast models. These will adopt Machine Learning/AI technology and will make use of the latest generation weather data, with an approval for operational use expected in Q2 2026.

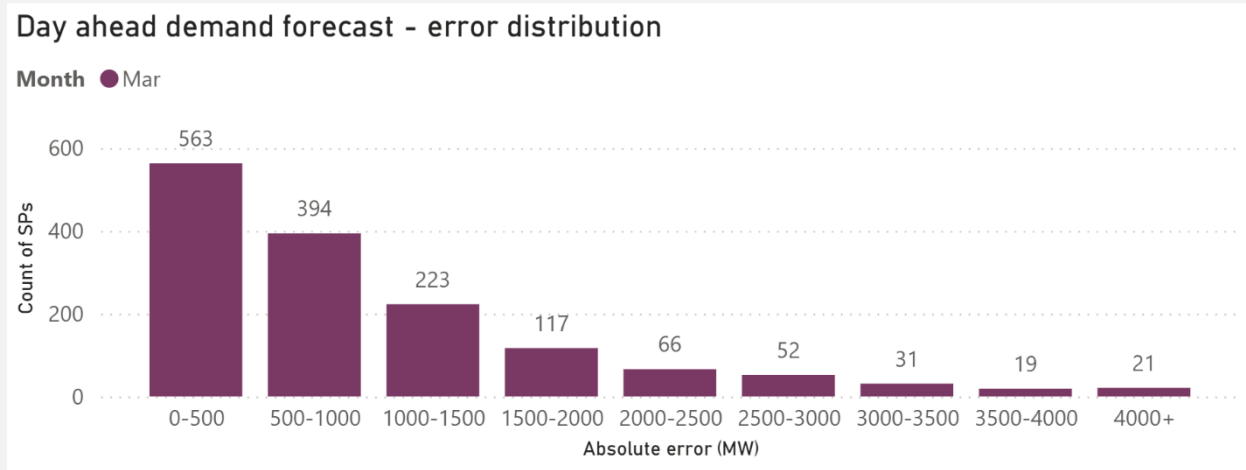
Work continues on our solar forecast upgrades. These will make use of blended-weather (solar irradiance) and blended-forecasts (MW), and we aim to release to production in Q2 2026. Further upgrades are planned, which will improve the geo-spatial application of the core weather forecast.



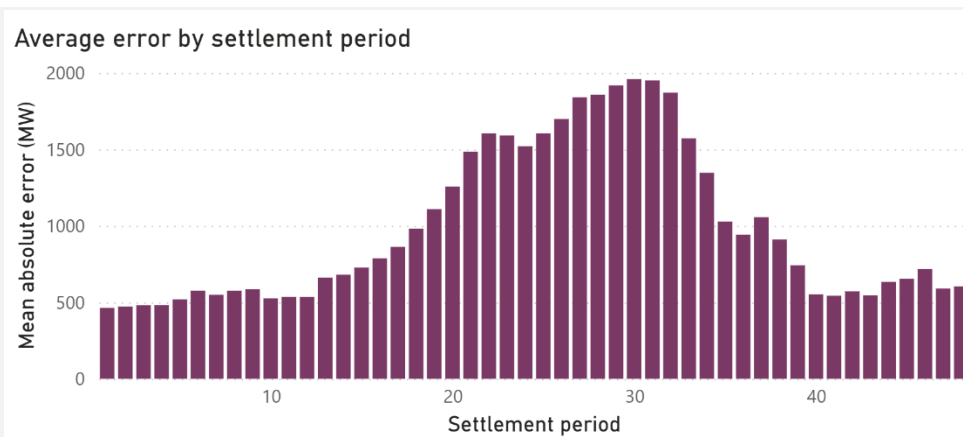
Days of Interest:



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



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



The days with largest MAE were 6, 16, and 29 March.

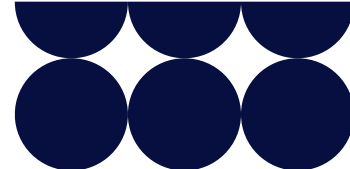
Day	Error (MAE)	Major causal factors
6	1515	Forecast errors due to solar forecast error in the middle of the day.
16	1728	Forecast errors due to solar forecast error in the middle of the day.
29	2094	Forecast errors due to solar forecast error in the middle of the day and other modelling errors in the evening including an under-forecast demand peak

Missed / late publications

There were no late or missed publications in March.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 9, 10, 11, 16, 20, 22, 23 and 27 March, with an accumulated total of 827MWh procured. These will nominally affect the national demand outturns but are not included in the day ahead forecast.



3. Wind Generation Forecasting

Performance Objective

Operating the Electricity System

Success Measure

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

This Reported Metric measures the average absolute error between day-ahead forecast (between 09:00 and 10:00, as published on NESO data portal) and post-event outturn wind settlement metering (as published on the Elexon insights portal) for each half hour period as a percentage of capacity for BM wind units only. The data will only be taken for sites that:

- did not have a bid-offer acceptance (BOA); and
- did not withdraw availability completely between time of forecast and time of metering, for the relevant settlement period. We publish this data on its data portal for transparency purposes.

Sites deemed to have withdrawn availability are those that:

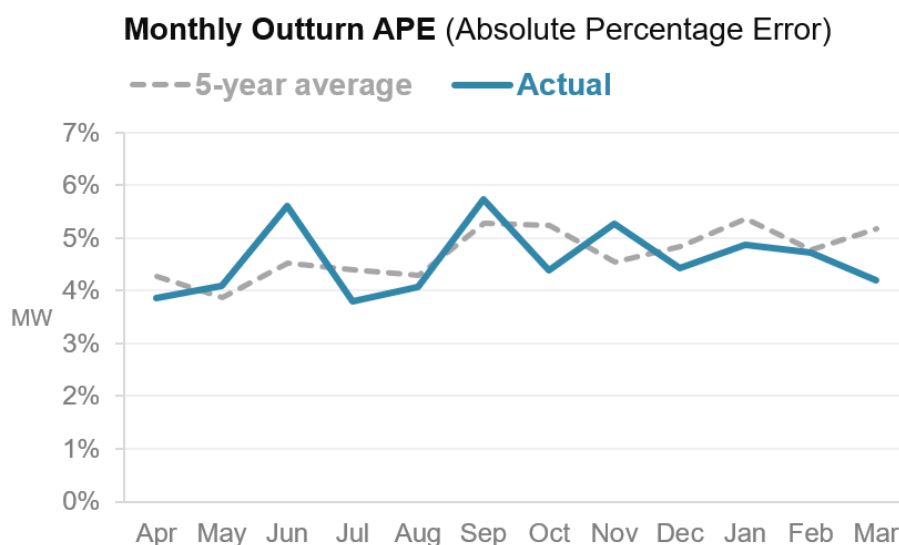
- re-declare maximum export limit (MEL) from a positive value day-ahead to zero at real-time; or
- re-declare their physical notification (PN) from a positive value day-ahead to zero at gate closure of the Balancing Mechanism.

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



March 2025–26 performance

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



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

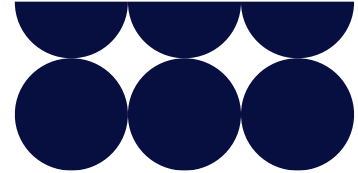
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Previous 5-year average (%)	4.26	3.87	4.53	4.39	4.30	5.27	5.23	4.55	4.84	5.36	4.78	5.18
Previous year outturn (%)	4.64	3.60	4.72	4.24	4.15	5.04	4.70	3.63	3.86	4.40	3.97	5.20
APE (%)	3.85	4.09	5.61	3.80	4.06	5.74	4.38	5.27	4.43	4.86	4.72	4.20

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

Supporting information

In March 2026, BMU wind forecasting error averaged 4.20%, against the 5-year average of 5.18%. Full BP3 performance is 4.58%, vs 5-year average of 4.71%.

March 2026 saw alternating high and low wind periods, with more settled conditions between 3–9 and 18–23 March. There were no named storms and only six low impact warnings issued by the Met office.

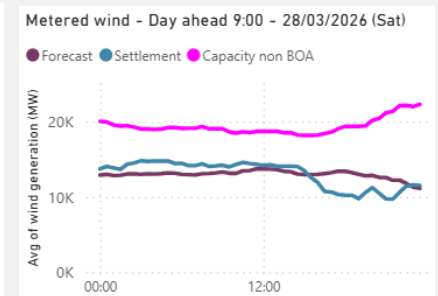
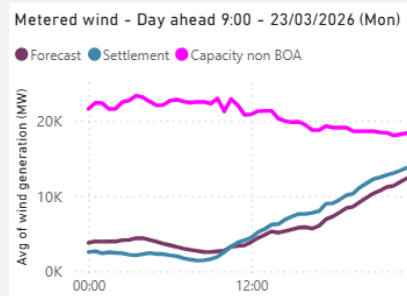
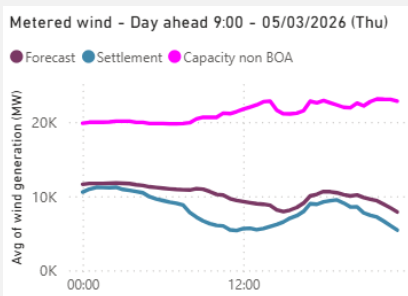
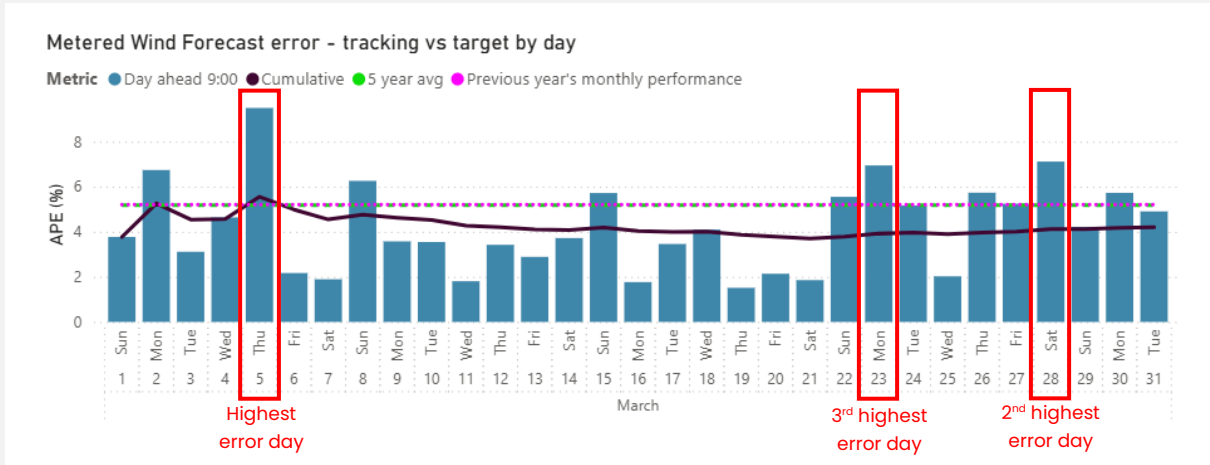


Metric-adjusted wind generation peaked at 16.9GW on 1 March, SP45. Wind forecast absolute error peaked at 4.3GW on 5 March, SP20.

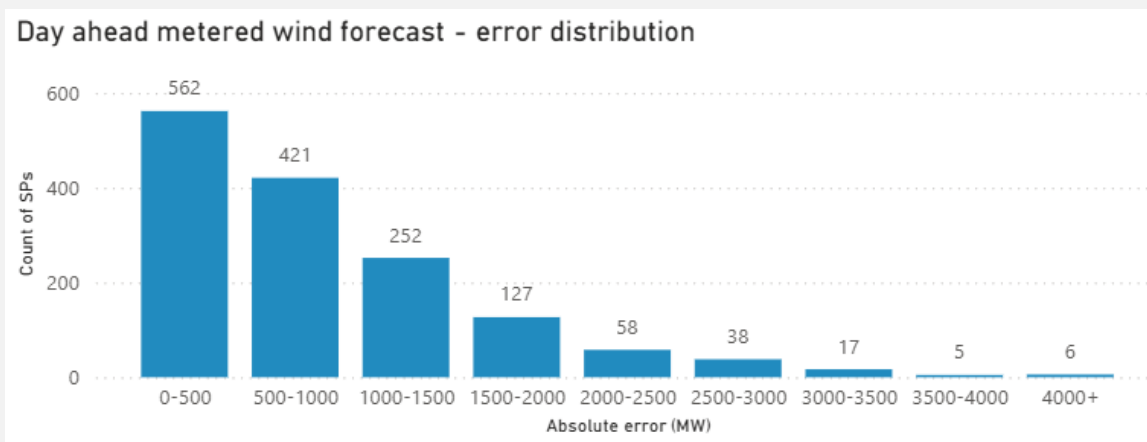
Work continues on the wind-direction feature, and we aim to release to production in Q1 2026/27. From Q2, we intend to focus on enhancing our within-day capability.

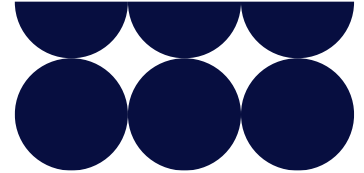
Metric values for previous months have been recalculated with updated settlement outturns, and these are reflected in the YTD performance.

Days of Interest:



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



**Details of largest errors**

Day	Error (APE)	Major causal factors
5	9.5	Wind speed forecast errors at day-ahead stage
23	6.9	Wind speed forecast errors at day-ahead stage
28	7.1	Wind speed forecast errors at day-ahead stage

Missed / late publications

There were no missed or late publications in March.



4. Skip Rates

Performance Objective

Operating the Electricity System

Related Success Measure

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

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

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

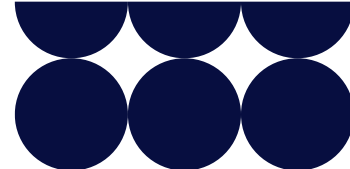
Work closely with industry to develop and set an absolute numerical target for skip rates within the BP3 period.

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

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

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

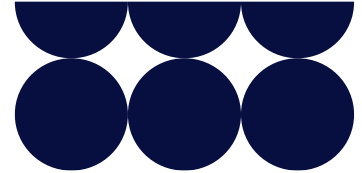
This Reported Metric measures the skip rate for bids and offers based on stage 5 of the Post System Action (PSA) methodology and will also include any updated methodology agreed with industry. More information on the skip rate definition and methodology can be found [here](#).

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Offers	43%	35%	33%	36%	31%	32%	30%	33%	29%	28%	27%	29%
Bids	43%	42%	47%	46%	39%	42%	40%	35%	37%	40%	33%	36%
Combined	42%	39%	38%	42%	35%	36%	34%	34%	32%	31%	29%	30%

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Offers – skipped volume	63	71	116	78	86	116	133	103	113	144	108	190
Offers – in merit Energy volume	148	205	356	215	279	359	437	309	392	516	405	654
Offers – All in merit volume (System & Energy)	504	901	1052	529	943	971	1084	878	838	827	732	1214
Bids – Skipped volume	141	148	111	127	122	102	93	108	103	80	68	40
Bids – in merit Energy volume	336	352	234	277	316	243	234	310	280	200	203	111
Bids – All in merit volume (System & Energy)	815	995	1576	962	1344	1488	1815	1597	1660	1921	1510	2121
Combined Bid & Offer – skipped volume	204	219	227	205	208	218	226	211	216	224	176	231



Supporting information

END OF YEAR UPDATES

Skips Behind Constraints

Following multiple industry engagements to gather feedback on the proposed skips behind constraints methodology, we published the [final methodology](#) at the end of March and will now commence implementation.

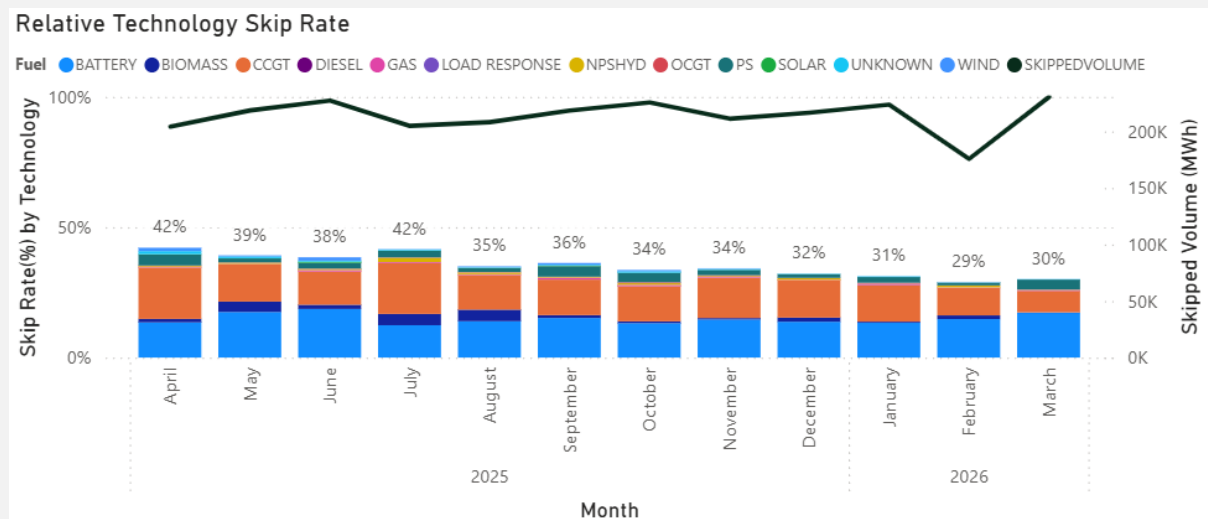
Skip Rate Reduction Target

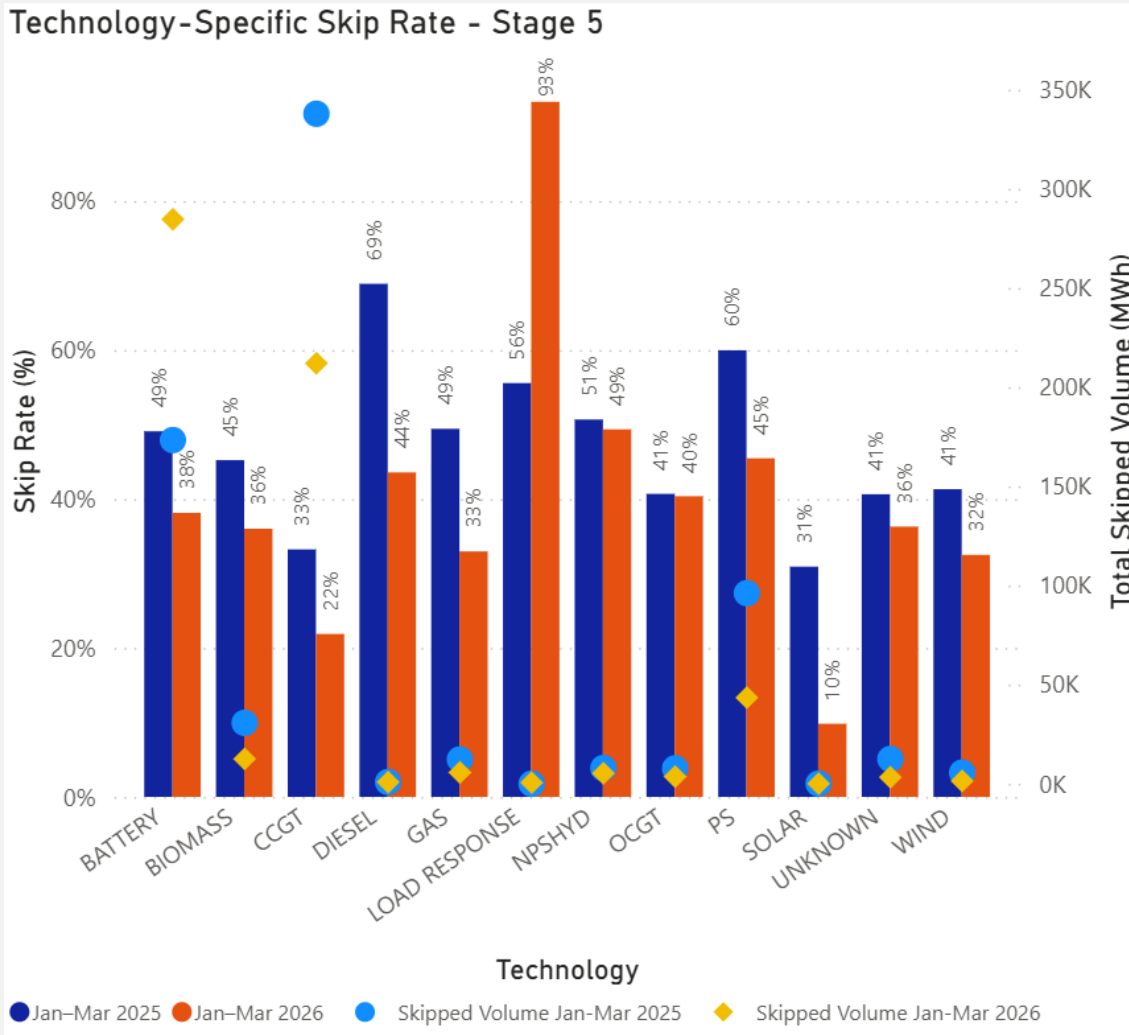
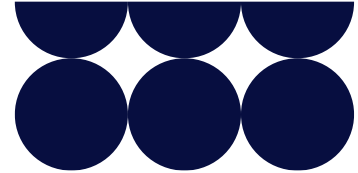
A skip rate target was developed using observed performance trends and stakeholder feedback. Following feedback that the initial proposal was not sufficiently stretching, this was revised to an average PSA stage 5 skip rate of 30% between January and June 2026. This represents a 10-percentage point reduction compared with the same period in 2025 and reflects the delivery position ahead of GC0166 implementation. We published an [open letter](#) on our website explaining this.

FULL YEAR PERFORMANCE – COMBINED BIDS AND OFFERS

The combined bid and offer skip rate showed a clear downward trend across the year, falling from 42% in April 2025 to 30% in March 2026, with the lowest monthly skip rate achieved in February (29%).

The average skip rate from January to March 2026 was 30%, which aligns with the short-term skip rate target set for January 2026 to June 2026 and is a notable improvement compared to the same period last year, where the average was 40%. This positive trend highlights the impact of the initiatives we have implemented throughout the year.

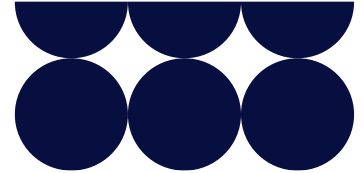




The chart above shows technology-specific skip rates comparing January–March 2025 with January–March 2026. Overall, skip rates have reduced year-on-year across most technologies, indicating improved dispatch efficiency and convergence towards the short-term target of around 30%.

CCGTs and Batteries account for the majority of skipped volume. For CCGTs, the average skip rate during January–March 2025 was 33%, but this figure decreased to 21% for January–March 2026. Similarly, batteries saw a decline in their skip rate, moving from 49% in January–March 2025 to 38% in the same months of 2026. Batteries were the only technology type to see higher skipped volume in 2026, which represents a significant increase in ‘in-merit’ volume – battery dispatch volume more than doubled in January–March 2026 (~900 GWh) vs 2025 (~400 GWh). Load Response units saw higher and more volatile skip rates in 2026 however we are prioritising investigating this, seeking an improvement in the trend.

Note: In the technology specific skip rate graph above, ‘Gas’ refers to gas reciprocating units, which are typically small, aggregated units. ‘Load Response’ is based on the fuel type category used by Elexon. These are typically Demand Side Flexibility (DSF) units. We have published a dedicated dataset to report skip rates for DSF units and incorporated this into our external dashboard.



5. Carbon intensity of NESO actions

Performance Objective

Operating the Electricity System

Success Measure

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

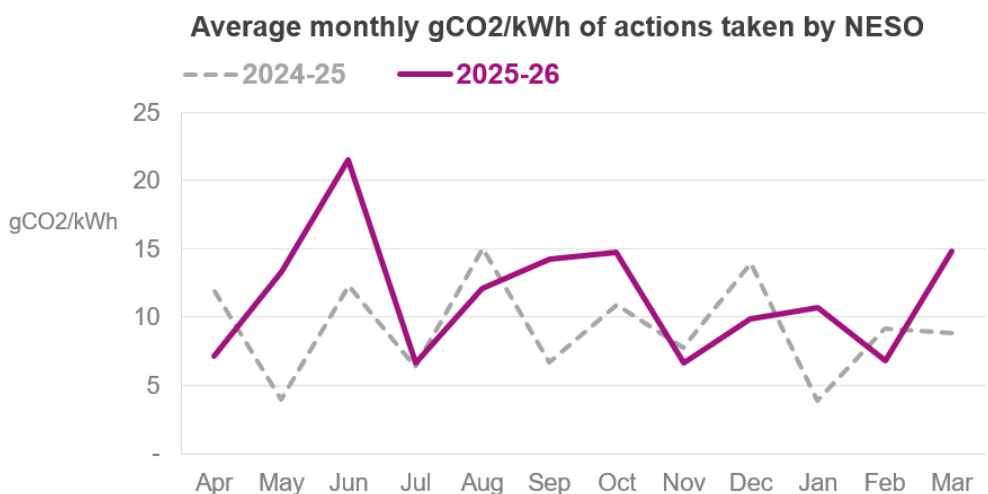
This Reported Metric measures the difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the Balancing Mechanism (BM) and the equivalent profile with balancing actions applied.

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

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

March 2025–26 performance

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



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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO₂/kWh)	7.16	13.36	21.53	6.64	12.11	14.22	14.75	6.68	9.85	10.71	6.79	14.82

Supporting information

We report the average monthly gCO₂/kWh of actions taken by NESO in line with reporting requirements. Alignment of the ZCO technologies with the CP30 technologies could see biomass and CHP units treated differently in this measure, but no change has been made yet.

March 2026 performance

In March the average monthly carbon intensity from NESO actions was 14.82g/CO₂/kWh. This is 8.03g/CO₂/kWh higher than February, and 3.27g/CO₂/kWh higher than the YTD average of 11.55g/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 65.10g/CO₂/kWh which took place on 29 March at 07:30. This is 10.03g/CO₂/kWh higher than the highest point in February of 55.07g/CO₂/kWh.

BP3 Performance Summary 2025–2026

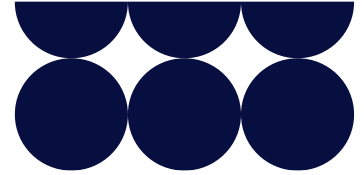
Over the last year we have measured the difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the Balancing Mechanism (BM) and the equivalent profile with balancing actions applied.

Across 2025–26, the average monthly carbon intensity of NESO actions ranged from 6.64g/CO₂/kWh to 21.53gCO₂/kWh, with an annual average of 11.55gCO₂/kWh. The first half-year averaged 12.50gCO₂/kWh compared with 10.60gCO₂/kWh in the latter half-year, with months exceeding 11gCO₂/kWh reducing from 4 to 2.

Variations in year-on-year performance are strongly linked to uncontrollable system conditions, including periods of severe weather, where interventions were required to safeguard operability.

Compared to last year, this year shows a wider range, driven by a small number of higher-intensity months, with a single peak at 21.53 gCO₂/kWh (June). In 2024–25 the average difference for the year was 9.22g/CO₂/kWh, this has increased to 11.55g/CO₂/kWh in 2025–26. The last 3 quarters of 2025–26 have seen consistent quarterly averages between 10–11g/CO₂/kWh compared to the last 3 quarters of 2024–25 that fluctuated between 7–11g/CO₂/kWh.

Across 2025–2026 lower levels of difference have taken place in April 2025 when a record 97.8% ZCO was achieved. July, November, and February also experienced low levels of difference and we have seen ZCO levels in excess of 90% in these months.



As we are calculating an average of difference for 2025-2026, we have also observed an increased number of NESO actions throughout the year where we have reduced the carbon intensity on the system e.g., on 6 November 2025 NESO actions improved the average of difference by $-37.3\text{g}/\text{CO}_2/\text{kWh}$ over the midnight settlement period.



6. Security of Supply

Performance Objective

Operating the Electricity System

Success Measure

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

This Reported Metric shows when the frequency of the electricity transmission system deviates more than $\pm 0.3\text{Hz}$ 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 $\pm 0.5\text{Hz}$ away from 50 Hz for more than 60 seconds
- The frequency was $0.3\text{Hz} - 0.5\text{Hz}$ away from 50Hz for more than 60 seconds.
- There is a voltage excursion outside statutory limits. For nominal voltages of 132kV and above, a voltage excursion is defined as the voltage being more than 10% away from the nominal voltage for more than 15 minutes, although a stricter limit of 5% is applied for where voltages exceed 400kV.

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

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

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



March 2025–26 performance

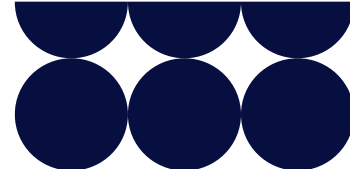
Table: Frequency and voltage excursions (2025–26)

	2025–26											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz for over 60 seconds)	0	0	0	0	0	0	0	0	0	0	0	0
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0	0	0	0	0	0	0
Voltage Excursions defined as per Transmission Performance Report ³	0	0	1	0	0	1	0	0	0	0	0	0

Supporting information

There were no reportable voltage or frequency excursions during March.

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



7. CNI Outages

Performance Objective

N/A

Success Measure

N/A

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

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

March 2025-26 performance

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

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

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

Planned	2025-26											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	1 outage 215 mins	1 outage 115 mins	0	0	1 outage 150 mins	0	1 outage 120 mins	1 outage 217 mins	0
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0	0

Supporting information

There were no outages, either planned or unplanned, encountered during March 2026.



8. Short Notice Changes to Planned Outages

Performance Objective

N/A

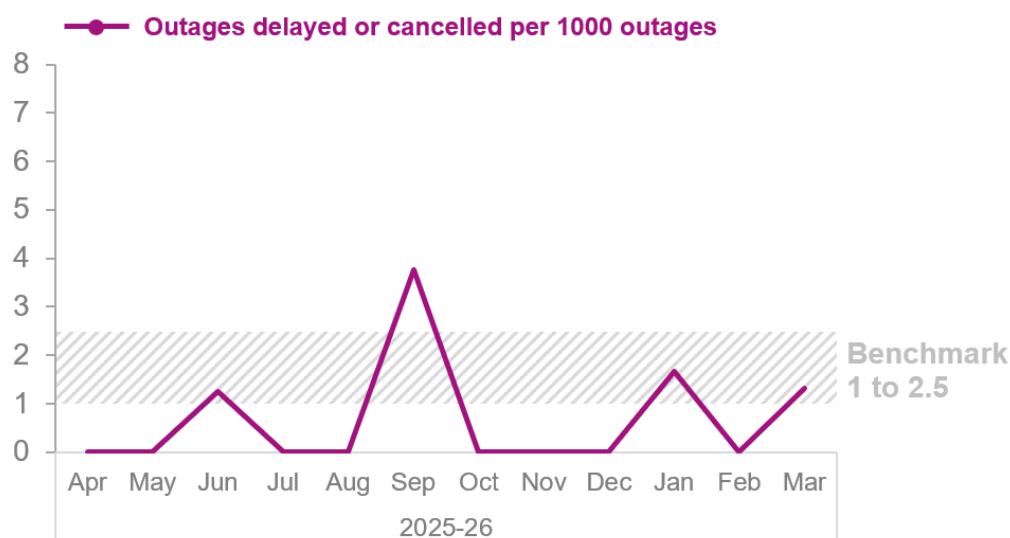
Success Measure

N/A

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

Q4 2025-26 performance

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



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

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	727	750	804	807	676	796	750	758	554	602	534	757	8515
Outages delayed/cancelled due to NESO process failure	0	0	1	0	0	3	0	0	0	1	0	1	6
Number of outages delayed or cancelled per 1000 outages	0	0	1.24	0	0	3.77	0	0	0	1.66	0	1.32	0.70

Supporting information

We successfully released 602 outages in January, 534 outages in February and 757 outages in March. Across these three months there were two delays or cancellations due to a NESO process failure, with one event occurring in January and the other in March. The cumulative number of stoppages or delays per 1000 outages to year end is 0.70.

The first delay was caused by a discrepancy between the constraint limit handed over by the Planning department and the Control Room, where there was a large difference and additional generation would be required to be constrained in real-time to secure the network. There was an on-going fault on the network affecting a HVDC circuit that would significantly alter the system flows and the return date was uncertain. Due to the limited timescales to investigate the discrepancy, the outage was postponed and sent back to the Planning department to investigate. An Operational Learning Note (OLN) was written and is to be distributed across the Planning department and the Control Room to share corrective actions to reduce the likelihood of a reoccurrence.

The second delay was caused by a lower constraint limit that was identified by the control room who were looking to maximise flows across a major constraint boundary due to several outages on the network simultaneously. It was identified that the limitation was caused by a single circuit trip, and a pre-fault action was required to be agreed with the Transmission Owner (TO) which put additional demand at risk. As this was not identified in planning timescales, it had not been discussed with the TO Planning team and was consequently rejected by the TO Control Room. An alternative strategy was agreed on the morning of the outage that resolved the constraint issue, and it was able to be released. However, it was delayed by over one hour. An Operational Learning Note (OLN) is being drafted and will be distributed across the planning department and Control Room.



9. Zero Carbon Operability Indicator

Performance Objective

Operating the Electricity System

Success Measure

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

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

For this Reported Metric, each generation type is defined as whether it is zero carbon or not. Zero carbon generation includes hydropower, nuclear, solar, wind, battery and pumped storage technologies.

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

Definition updated to reflect CP30

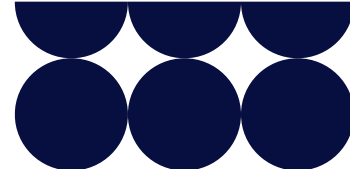
Following the Government's Clean Power 2030 Action Plan (CPAP) we have updated our definition of zero carbon generation sources to align with the clean power technologies. Within this report we will report performance under our revised ZCO definition, as well as continuing to report the original RIIO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

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

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

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

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



Regular reporting on actual ZCO

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

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

For each month, the settlement period that has the highest ZCO figure (after our operational actions were enacted) is displayed. The corresponding market ZCO figure is also included. It is worth noting that this market ZCO figure might not necessarily be the maximum zero carbon generation that the market provided over the month. For example, the maximum zero carbon generation provided by the market in Q2 2023-24 was 98% on 28 September 2023, settlement period 8. However, for that period the final ZCO dropped to 80% after our operational actions were taken into account, meaning that this was not the highest ZCO of the month.

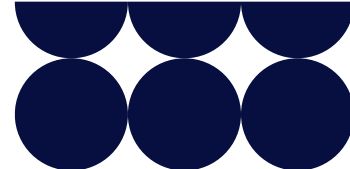
The graphs further below show the underlying data by settlement period and highlight when the maximum monthly values occurred.

Table: Q4 maximum zero carbon generation percentage by month (2025-26)

Month	CP30 aligned definition			Original RIIO-2 definition		
	Highest ZCO% in the month ⁴	Market provided ZCO% ⁵	Date / Settlement Period	Highest ZCO% in the month ⁴	Market provided ZCO% ⁵	Date / Settlement Period
April	97.77	99.99	1 April SP32	89.14	95.31	2 April SP33
May	96.76	99.97	29 May SP27	88.30	96.98	29 May SP27
June	96.49	97.96	10 June SP18	89.60	96.96	3 June SP26
July	95.93	99.95	14 July SP31	90.05	96.71	7 July SP28
August	93.68	99.00	30 Aug SP33	90.42	96.14	30 Aug SP34
Sept	95.51	99.92	15 Sep SP19	88.00	96.44	15 Sept SP24
Oct	96.35	99.96	26 Oct SP25	91.23	96.50	26 Oct SP43

⁴ after NESO operational actions

⁵ during the same day and settlement period

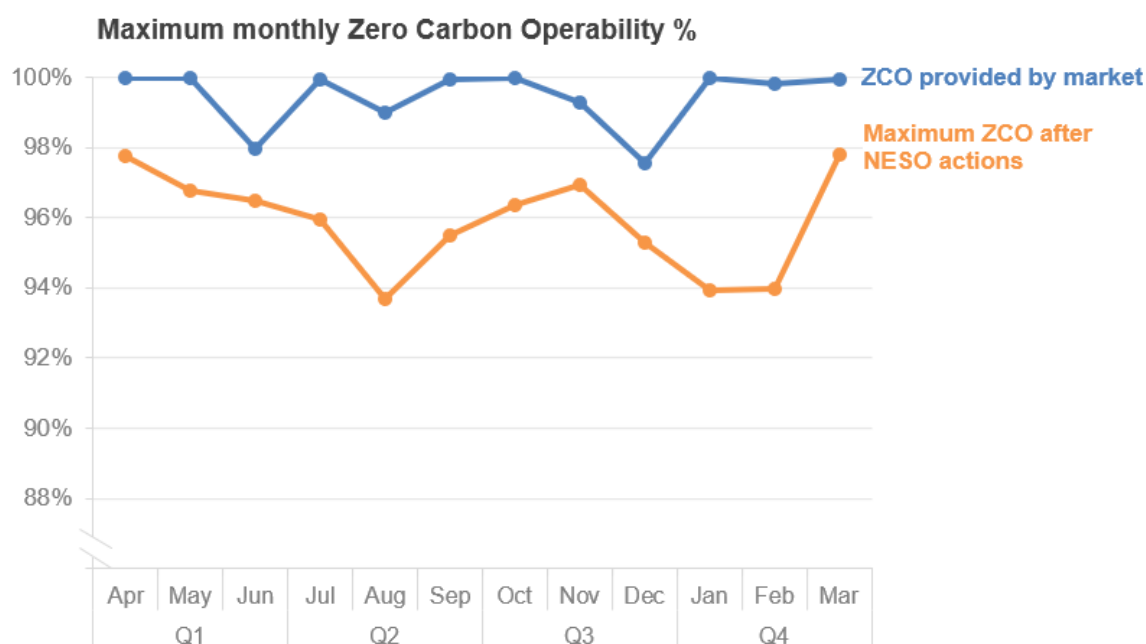


Nov	96.95	99.29	1 Nov SP20	90.09	93.65	1 Nov SP19
Dec	95.27	97.56	7 Dec SP42	88.96	94.77	7 Dec SP48
Jan	93.95	99.97	2 Jan SP8	87.75	94.86	2 Jan SP8
Feb	93.97	99.81	22 Feb SP19	88.15	96.60	22 Feb SP19
March	97.80 ⁶	99.94	30 Mar SP23	92.10	95.70	25 Mar SP29

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

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

Using **CP30 aligned** definition of ZCO



⁶ We have not claimed a ZCO record for the settlement period in March 2026 due to instructions placed on CHP units excluded from the ZCO calculation.

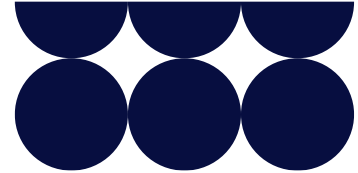


Figure: Q4 2025–26 ZCO by Settlement Period, before and after NESO operational actions

Using **CP30 aligned** definition of ZCO

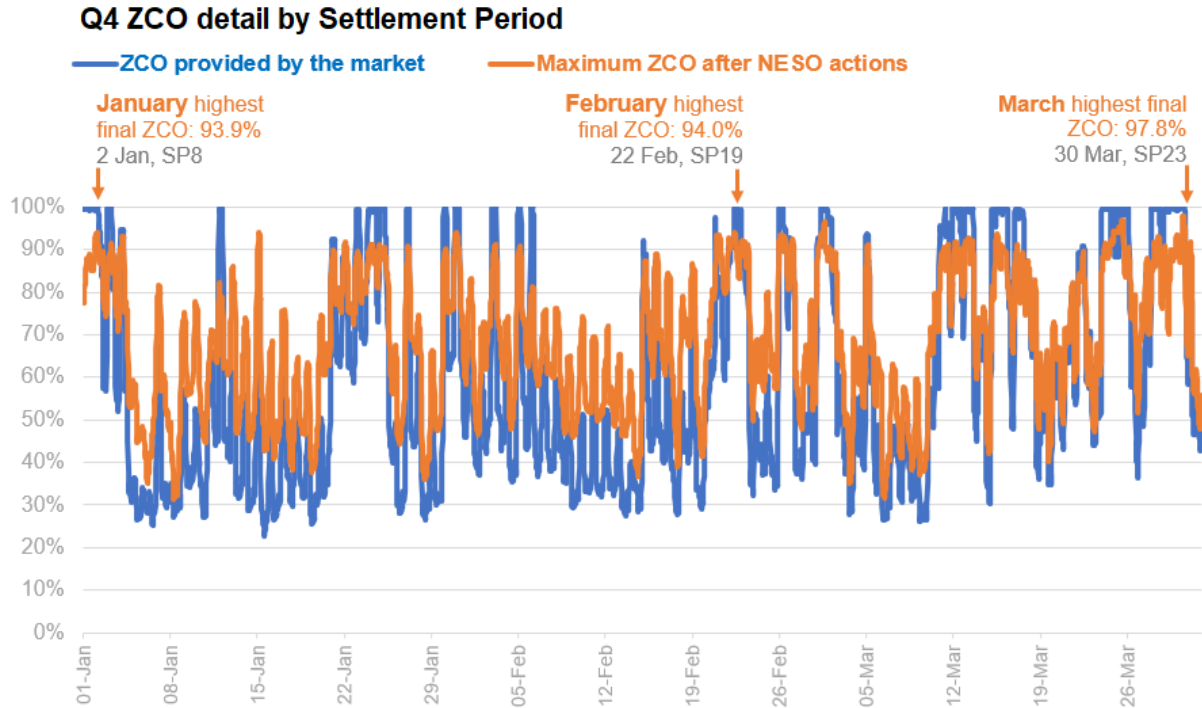
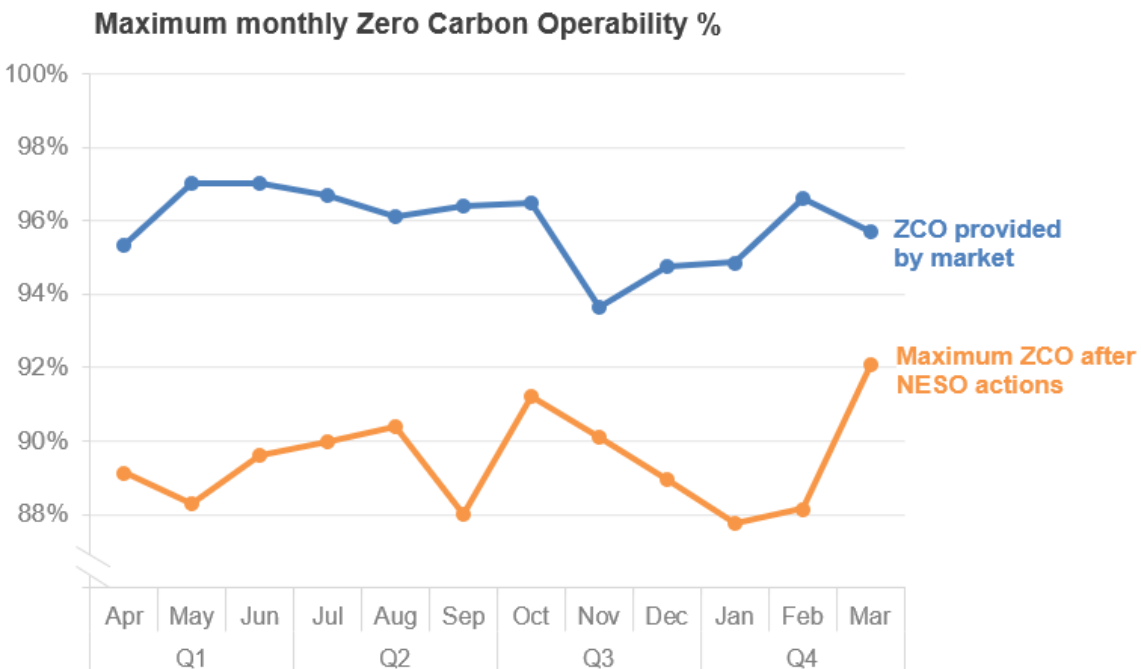


Figure: Maximum monthly ZCO% after NESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred) – two-year view

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



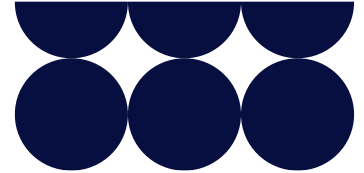
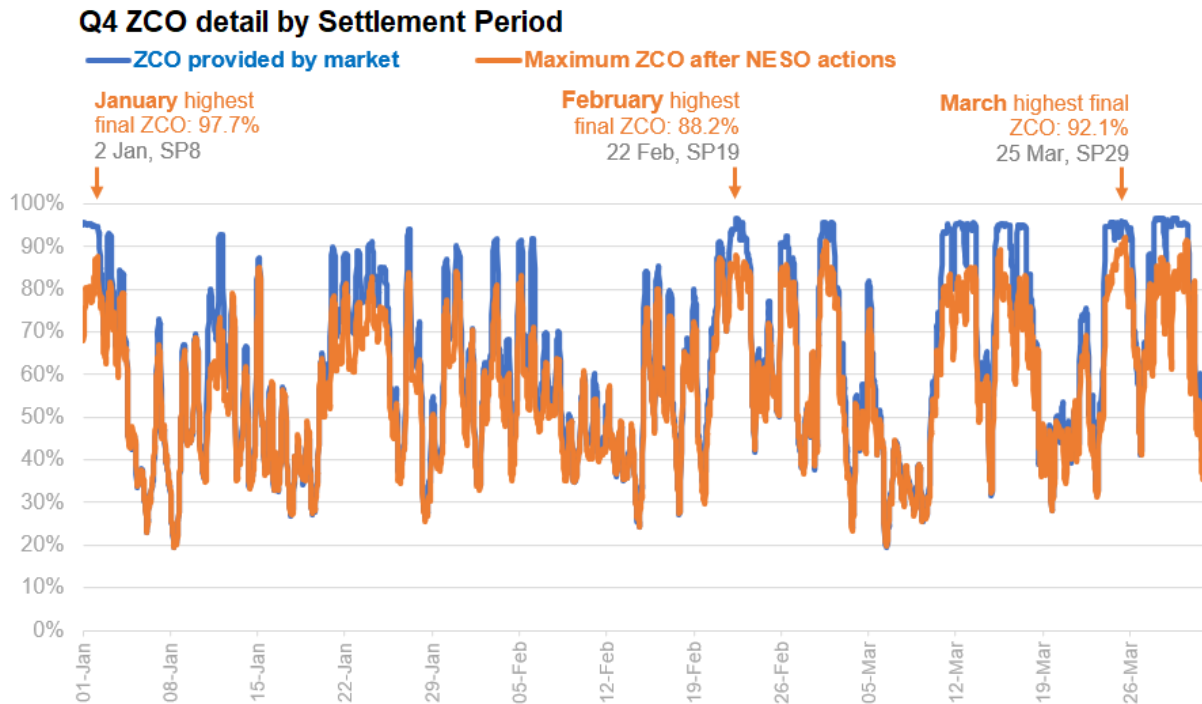


Figure: Q4 2025–26 ZCO by Settlement Period, before and after NESO operational actions

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

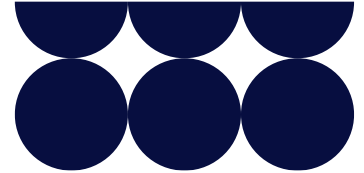


Supporting information

Since the original ZCO ambition was launched in 2019, a progressive and sustained programme of change has enabled us to iteratively improve the critical services required to operate the system. How we meet new critical requirements has transitioned from arrangements designed for a fossil-fuel-dominated system at the start of the century to new services explicitly designed for a zero-carbon future, enabled by modern technologies and to enable carbon free system operations we need enough capacity to deliver our operational requirements and for the market to deliver the opportunity.

Over the past year we have seen further progress to enable ZCO delivery, most significantly with Stability Pathfinder Phase 2 projects commissioning. These have delivered additional zero carbon sources of stability to support operating the system securely using innovative grid-forming battery technologies and synchronous compensators. Alongside this we have continued to reform and develop our markets; completing the launch of Quick Reserve, and most recently Slow Reserve, and changes to our frequency management policy. This has meant additional routes to market for low carbon technologies and driven competitive prices.

We adjusted our internal processes to provide early identification of potential high-ZCO operating periods, and assessment of operating options to utilise the zero carbon generation being delivered by the market.



Our ZCO ambition is to meet transmission level demand with zero carbon sources. Our internal analysis in early 2025 identified a potential window in which 100% zero carbon operability could be achievable starting October and increasing through to December 2025. This operability window covered a limited demand range, but over time and as future enabling projects deliver, these windows will expand to wider demand ranges. The assessment indicated that under certain system conditions, stability requirements could be met entirely by zero-carbon assets considering: projects delivered to date, such as the initial Stability Pathfinder projects, and lowering of the FRCR policy; those projects likely to be delivered in 2025, and the available generation mix. With the projects included in the study now successfully delivered, working in combination with the generation mix, the stability requirements of the system can be met by zero carbon assets – under certain conditions.

NESO's absolute demonstration of this capability is conditional on several factors. The market must deliver a 100% zero-carbon generation mix, and do so when system conditions and consumer demand can be supported solely by zero carbon assets. The market has delivered very high levels of zero carbon generation on multiple occasions throughout 2025, and reached 100% in February for three settlement periods. However, these 100% periods did not coincide with wider conditions that would support operating the system 'carbon-free' i.e., when system conditions, and consumer demand could be supported. While opportunities to fully realise 100% ZCO have therefore been limited, substantial progress has been made in operating the system with higher volumes of zero carbon generation, doing so more frequently, and doing it for longer durations. This includes operating for over a day, 26.5 consecutive hours, above 90% ZCO on 24 - 25 March 2026.

Performance of ZCO has continued to strengthen; in April 2025, a new ZCO record was achieved with the system operating at 97.8% zero carbon. This was not an isolated event, the monthly maximum ZCO exceeded 95% in 9 months of 2025-26, and increasing volumes of wind generation were supported - culminating in the latest wind record set in March 2026. Across the year, the system operated:

- above 95% ZCO for 108 settlement periods,
- between 90–95% ZCO for over 1,600 settlement periods, and
- between 80–90% ZCO for approximately 4,400 settlement periods.

While a single settlement period at 100% ZCO has not yet been demonstrated, the performance shows how, in partnership with industry, both the generation mix and the supporting stability tools have been progressively delivered, enabling NESO to operate the system with more zero-carbon generation, more often, and for longer durations, while maintaining secure and reliable operation.

NESO have worked closely with DESNZ, Ofgem, and GB Media in briefing in preparations for reaching this historic achievement for GB which we hope to realise soon - as further enabling projects and further zero carbon assets deploy.



Highest final ZCO by month vs previous year

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

Quarter	Month	2024/25	2025-26	Difference
Q1	April	92.2%	89.1%	-3.1%
	May	83.4%	88.3%	+4.9%
	June	86.1%	89.6%	+3.5%
Q2	July	86.7%	90.1%	+3.4%
	August	89.2%	90.4%	+1.2%
	September	84.6%	88.0%	+3.4%
Q3	October	85.1%	91.2%	+6.1%
	November	84.6%	90.1%	+5.5%
	December	89.4%	89.0%	-0.4%
Q4	January	88.7%	87.7%	-0.95%
	February	86.6%	88.2%	+1.55%
	March	93.5%	92.1%	-1.40%

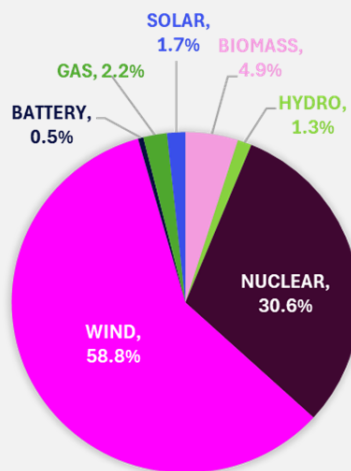
CHP change confirmed on 30 September 2025 (CP30 2025-26 data contains adjustments not included in 2024/25.)

Zero Carbon Operation Case Studies

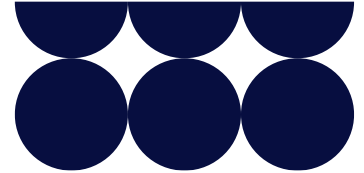
Case Study 1: 1 April 2025 – Record ZCO Operation

On 1 April 2025 Settlement Period 32, the GB system achieved 97.77% Zero Carbon Operation, with only 278.7MW of gas generating. During this settlement period the market offered 99.99% of generation from zero carbon sources, with a small amount of generation from other sources. The control room actions were taken in economic merit order to balance supply and demand, manage voltage and to increase inertia. This included adding 278.7MW of gas and an increase of CHP generation from 483MW to 961MW.

Figure: Chart showing the breakdown of generation by fuel type for the record highest ZCO period



Zero Carbon Fuel Types		
BIOMASS	616.2MW	4.9%
HYDRO	163.6MW	1.3%
NUCLEAR	3848.3MW	30.6%
WIND	7396.8MW	58.8%
BATTERY	58.8MW	0.5%
PUMP STORAGE	0MW	0.0%
SOLAR	207.3MW	1.7%
Non-Zero Carbon Fuel Types		
CCGT	0MW	0.0%
DSB	0MW	0.0%
OCGT	0MW	0.0%
OTHER	0MW	0.0%
GAS	278.7MW	2.2%
LOAD RESPONSE	2.0MW	0.0%



The total demand in this settlement period was below the range in which we expect to be able to operate a fully zero carbon system and occurred prior to our ZCO capability commencing.

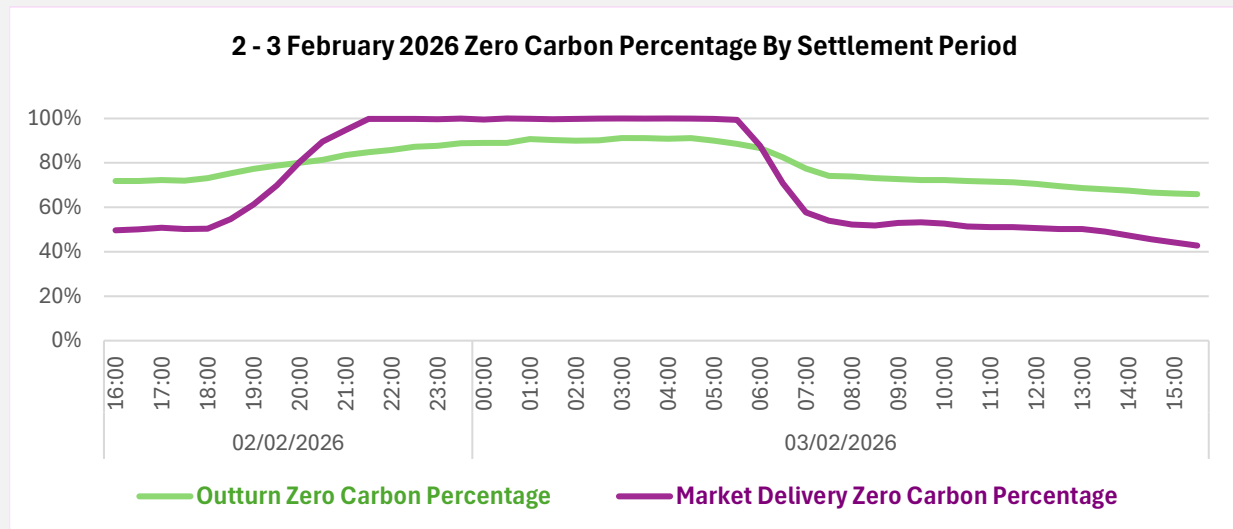
This performance was enabled by high volumes of wind generation with the zero-carbon generation meeting most of the 120GVAs inertia requirement, and access to zero carbon sources of fast acting response via Dynamic Containment supporting inertia management.

We have programmes in progress to continue improving our ability to secure the system, specifically addressing inertia and voltage management. Similar performance has been repeatedly demonstrated as shown by the Zero Carbon Operability Indicator (BP2: RRE 1F).

Case Study 2: 3 February 2026 – Market Delivering 100% ZCO

On 3 February 2026, in Settlement Periods 2, 7 and 9, between 00:30 – 01:00, 03:00 – 03:30 and 04:00 – 04:30 the market delivered a fully 100% Zero Carbon Generation mix, with no non-zero carbon generation offered at transmission level.

Figure: Chart showing when the market has delivered 100% of transmission level generation from zero carbon sources

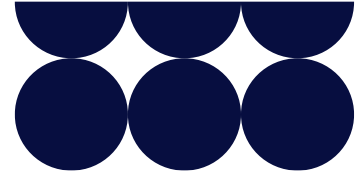


This demonstrates that under favourable system conditions, the market can offer a fully zero-carbon generation mix.

In this case gas units were increased in economic merit order to balance the demand in real time and as voltage support.

The demand during the period when the market was delivering a high ZCO percentage was within the range in which we expect to currently be able to operate a fully zero carbon system, however we do not expect to be able to manage this overnight initially due to system stability. However, we have yet to see the market deliver this during the day.

Conversely, we are starting to see more periods where NESO actions increase the percentage of ZCO from what the market has provided as demonstrated in figure 2. This is due to generation from gas powered plant being redistributed, to either ZCO assets and/or to CHPs and distributed assets, to manage both system conditions and local constraints.



In addition, the system has been operated at high zero carbon for prolonged periods. Between 29 - 30 May 2025, the system operated at >90% ZCO for 23.5 hours and >95% ZCO for 10.5 hours. This was with a maximum of 99.98% Zero carbon provided by the market with constraints on Scottish wind and CCGTs dispatched to provide both voltage and inertia support.



10. Constraints Cost Savings from Collaboration with TOs

Performance Objective

N/A

Success Measure

N/A

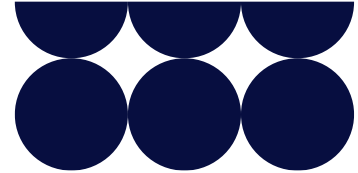
The Transmission Operators (TOs) need access to their assets to upgrade, fix and maintain the equipment. TOs request this access from NESO, and we then plan and coordinate this access. We look for ways to minimise the impact of outages on energy flow and reduce the length of time generation is unable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

This Reported Metric measures the estimated £m avoided constraints costs through NESO-TO collaboration.

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

1. ODI-F savings: Actions taken through the System Operator: Transmission Owner (SO:TO) Optimisation ODI-F
 - i. Output Delivery Incentives (ODIs) are incentives that form part of the TOs' RII0-2 framework. They are designed to encourage licensees to deliver outputs and service quality that consumers and wider stakeholders want to see. These ODIs may be financial (ODI-F) or reputational (ODI-R).
 - ii. One of these ODIs, the SO:TO Optimisation ODI-F, is a new two-year trial incentive to encourage the Electricity Transmission Owners (TOs) to provide solutions to NESO to help reduce constraint costs according to the STCP 11-4.⁷ procedures. NESO must assess the eligibility of the solutions that the TOs put forward in line with STCP 11-4, and must deliver the solutions in order for them to be included as part of the SO:TO Optimisation ODI-F and for this metric.

⁷ The [STCP 11-4](#) 'Enhanced Service Provision' procedure describes the processes associated with NESO buying a service from a TO where this service will have been identified as having a positive impact in assisting NESO in minimising costs on the GB Transmission network.



- iii. For this metric, where constraint savings are delivered through the SO:TO Optimisation ODI-F, the savings are calculated in line with the methodology for that incentive.
2. Other savings: Actions taken separate from the SO-TO Optimisation ODI-F
- i. NESO also carries out other activities to optimise outages. In these cases, the assumptions used for estimating savings will be stated in the supporting information.

Figure: Estimated £m savings in avoided constraints costs (ODI-F) – 2025-26

(Estimated savings in GWh are also shown for context)

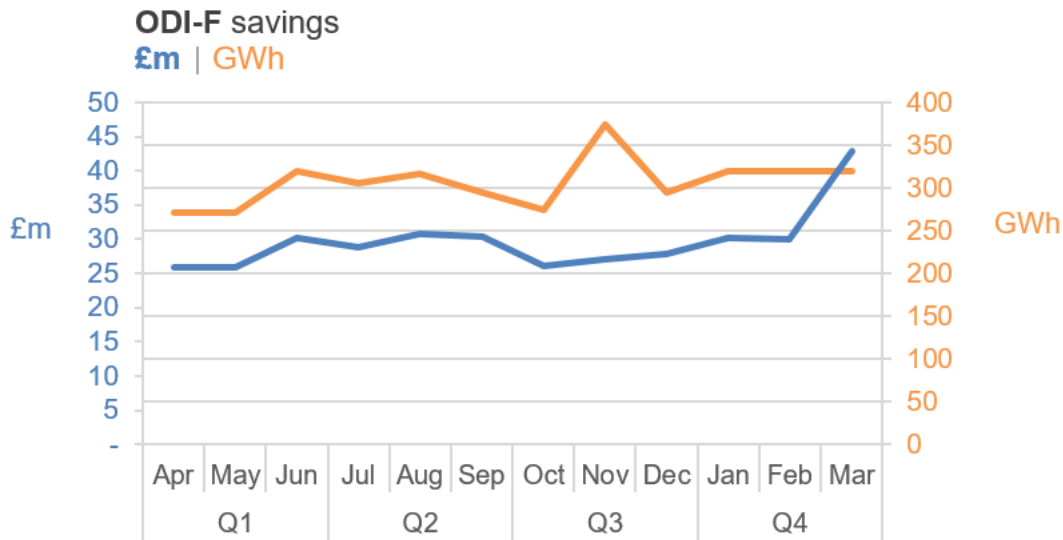
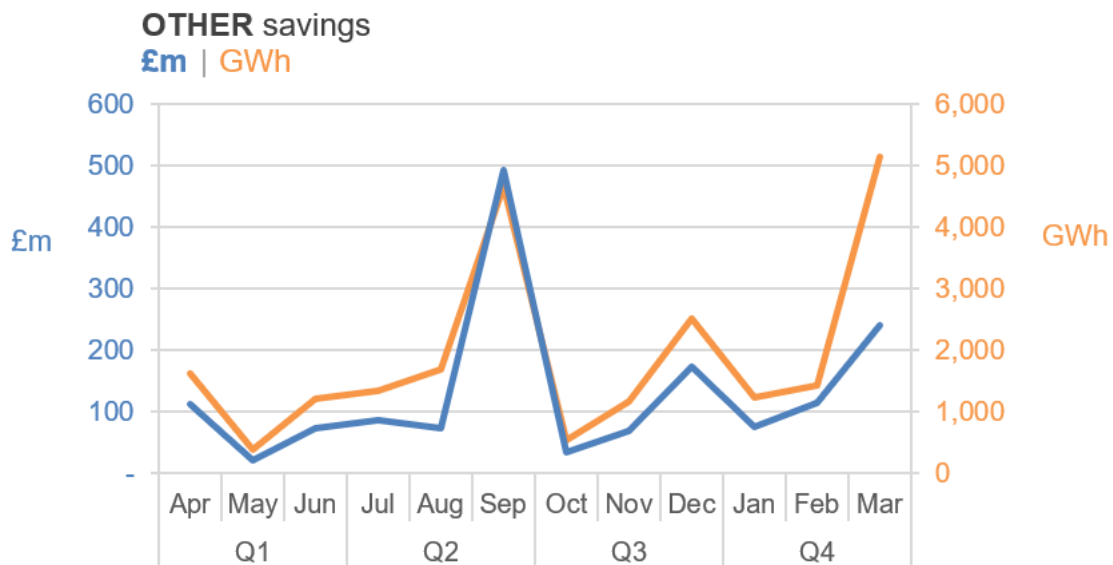


Figure: Estimated £m savings in avoided constraints costs (Other) (Estimated savings in GWh are also shown for context)

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



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

	ODI-F savings	Other savings	ODI-F savings	Other savings
	£m	£m	GWh	GWh
Apr	25.98	111.78	271.85	1,628.50
May	25.79	20.30	271.33	376.00
Jun	30.13	73.70	320.05	1216.20
Jul	28.87	85.10	306.01	1341.50
Aug	30.84	73.95	316.37	1,695.80
Sep	30.34	491.32	294.01	4,666.80
Oct	26.09	34.37	274.91	534.60
Nov	27.06	69.83	374.34	1,162.60
Dec	27.80	171.97	294.11	2,512.20
Jan	30.26	76.35	318.90	1,240.70
Feb	30.03	115.00	318.90	1,423.90
Mar	42.95	240.95	318.90	5,133.00
YTD	356.13	1,564.62	3,679.69	22,931.80

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

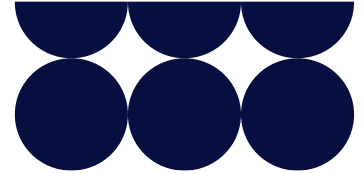
Prices of £36 per MWh are used for conventional generation and £75 per MWh for renewable generation.

Supporting information

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

The Network Access Planning (NAP) team has progressed and completed **21** approved enhanced service provisions from TO's through STCP 11.4 that provide constraint cost savings this year. Some of these provisions are highlighted below:

- In January, we received a system access request from National Grid Electricity Transmission (NGET) on the circuit connecting Drax in North Yorkshire to Eggborough, Selby District in North Yorkshire needed to carry out refurbishment works on the circuits. Due to this request, the DRESHEX1 boundary was to be constrained heavily. To minimize the impact, NAP agreed upon enhancements based on static and dynamic weather conditions for the parallel circuit connecting Drax in North Yorkshire, Eggborough and Selby District in North Yorkshire. As a result, these enhancements saved **30.77 GWh** of energy and resulted in an outturn cost of **£2.46 million** for the end consumer.



- In March, National Grid Electricity Transmission (NGET) and Network Access Planning (NAP) agreed upon static enhancements to use Winter ratings for two circuits connecting North Tyneside to Newburn Bridge Road, Blaydon on Tyne. These improvements were required because of a forced downrating on the double circuit. As a result, these enhancements saved **75.49 GWh** of energy and resulted in an outturn cost of **£7.85 million** for the end consumer.
- In 2025/2026 NGET, SPT, SSENT and NAP provided year-round enhancements. The service includes the Western Link Run Back scheme, TARS services, and a bypass on a 275kV double circuit connecting Aberdeenshire and Angus in Scotland. These services facilitated the management of constraint boundaries, outage placement, and pre- and post-fault network loading. Over the 2025/2026, these services altogether resulted in a saving of **3218.85 GWh** of energy and an outturn cost of **£305.62 million** to the end consumer.

During 2025–2026, NAP has achieved approximately **£356.13 million** in constraint cost savings through STCP 11.4 with the release of **3679.69 GWh** of additional capacity.

Please be advised that figures for previous quarters have been updated following comprehensive reviews at the end of 2025–2026, as detailed in the attached table of figures later in this section. Three enhancements were utilised throughout the year: the West Link Run Back scheme, Dynamic Line Ratings Services and the Kintore–Fetteresso 275kV double circuit outage bypass. These enhancements were implemented consistently over the 12 months.

Financial savings have been precisely calculated for the 2025–2026 year based on actual costs incurred. No forecast savings are included in this section. GWh outturn savings are proportionately derived from the forecast GWh values and the actual outturn cost savings.

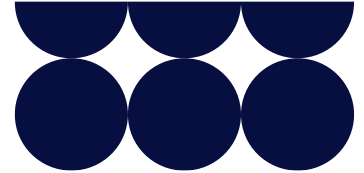
Other Savings (Customer Value Opportunities):

We have demonstrated significant progress over the past three months. In collaboration with our stakeholders, Transmission Owners (TOs) and Distribution Network Operators (DNOs), we have identified and documented **99 instances in quarter 4, and 300 during 2025/2026** where our actions have directly contributed to adding value for end consumers. Additionally, our innovative approaches have successfully facilitated increased generation capacity for connected customers.

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

Some examples of these instances include:

- In January, NAP received a system access request from National Grid Electricity Transmission (NGET) on a Quad Booster at an electrical substation located in West Ham, Newham, Greater London for one week, which needed to carry out Ad hoc repairs and maintenance on the asset. However, this asset is installed on the circuit connecting Islington, Greater London to Newham, Greater London and is actively used to control



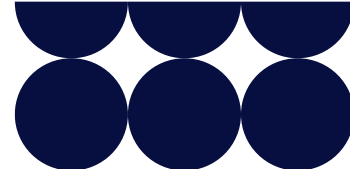
thermal overloads on the circuit. Due to this request, ESTEX boundary would be constrained heavily. To minimize the impact, NAP and NGET agreed to reconfigure the substation located in Newham, Greater London to enhance the ESTEX boundary. This action resulted in saving **295GWh** of energy worth approximately **£22 million**.

- In February, NAP received a system access request from Scottish Power Transmission on the circuit connecting Kilmarnock, Scotland to South Lanarkshire, Scotland and a Supergrid Transformer in Kilmarnock South 400kV substation needed as part of the Kilmarnock South 400kV substation refurbishment works. However, due to this request the AYRSHIRE (AYREX) boundary would be heavily constrained. To minimize this impact, NAP agreed with SPT to provide enhanced ratings on the 2 Supergrid Transformers located in Kilmarnock South substation connecting Ayrshire, Scotland to Kilmarnock, Scotland. This action resulted in saving **447.6 GWh** of energy worth approximately **£33.6 million**.
- In March, NAP received a system access request from NGET for a circuit connecting Knowsley to St Helens, Merseyside to fix defects on the circuit. However, to minimize impact of this outage, NAP agreed with NGET to align this request with a planned outage on a circuit connecting South Ribble to Knowsley. This action resulted in saving **216 GWh** of energy worth approximately **£16.2 million**.

This section of the report encompasses actions monitored up until the conclusion of BP3. There was a notable increase in CVOs during Q4, primarily attributed to an excessive number of value opportunities arising from the rapid escalation in outages as the new plan year commenced, thereby presenting more opportunities to optimise the plan.

The customer value opportunities, along with others, collectively amount to an additional **22.9 TWh (approximately £1.56 billion)** of generation capacity for the 2025–26 financial year. This surplus capacity would have otherwise been restricted, incurring costs to the end consumer.

The £/MWh figure for savings is calculated per outage. Savings for conventional generation are calculated using £36 per MWh, while renewable generation uses £75 per MWh. Where a full commercial cost-benefit analysis is available, those figures are used instead. Due to the high price per MWh in fully costed CVOs and the increase in renewable generation on the network, the average price per MWh is approximately £65.



11. Day-ahead procurement

Performance Objective

N/A

Success Measure

N/A

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

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

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

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

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

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

Non-day-ahead: Mandatory Frequency Response only. Previously, this also included Long Term STOR, however since April 2025, this service is no longer procured.



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

Q4 2025–26 performance

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

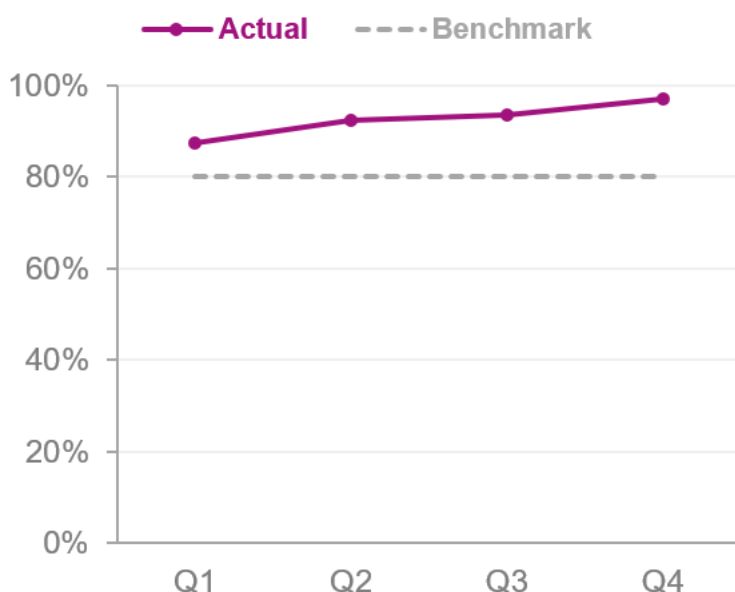


Table: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4	YTD
Volume of balancing services procured (average per procurement period)	MW	5,276	5,025	4,927	4,807	20,035
Volume procured no earlier than day-ahead (average per procurement period)	MW	4,605	4,648	4,612	4,660	18,525
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	87%	92%	94%	97%	92.5%
Benchmark*	%	80%	80%	80%	80%	80%

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



Volume details by service

Type	Service	Unit	Q1	Q2	Q3	Q4	YTD
Day-ahead	DC	MW	1,275	1,218	1,101	1,001	4,595
	DM	MW	294	361	516	529	1,700
	DR	MW	448	482	488	489	1,907
	Static FFR	MW	202	198	192	217	809
	STOR	MW	1,751	1,679	1,588	1,673	6,691
	BR	MW	10	10	9	9	38
	QR	MW	625	710	718	741	2,794
	Total	MW	4,605	4,658	4,612	4,660	18,535
Non Day-ahead	MFR	MW	730	377	315	147	1,569
	STOR long-term	MW	N/A	N/A	N/A	N/A	N/A
	Total	MW	730	377	315	147	1,569
All	Grand Total	MW	5,335	5,028	4,927	4,807	20,097

Supporting information

In Q4 the percentage of balancing services procured at no earlier than day-ahead has increased to 97%, against the benchmark of 80%.

With the growth in Response and Reserve competitive markets, we can procure more of our requirements at day-ahead so have less reliance on non-day ahead procured services. As Quick Reserve has matured, we have seen a steady move to more competitively procured day-ahead volumes being utilised. With the retirement of Optional Fast Reserve service at the end of the quarter this will drive a further increase going forward as the volume will be absorbed into QR. This, along with the continued increasing volume of MWs procured in the Dynamic Moderation and Regulation service resulting in the decrease in procured MFR, is reflected in the percentage increase mentioned above. Noting a slight increase in STOR volume and a decrease in MFR for the final quarter, this is in line with the winter requirement each year. This will also be the final quarter for the STOR service making way for Slow Reserve Q1 2026-27.



12. Accuracy of Forecasts for Charge Setting – BSUoS

Performance Objective

N/A

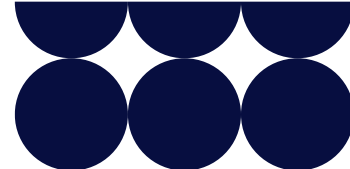
Success Measure

N/A

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

The BSUoS charge (£/MWh) is now based upon a fixed tariff. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) are forecast for six-monthly tariffs and are set ahead of the chargeable tariff period. For 2025-26, Fixed Tariff 5 (April 25 – September 25) was published in June 2024. Fixed Tariff 6 (October 25 – March 2026) was published in December 2024.

We continue to forecast balancing costs monthly and measure our performance against this forecast. It remains an important metric to support the fixed tariff methodology by being the main component of the fixed BSUoS tariff. The BSUoS cost forecast (costs rather than what is charged against the fixed tariff) is probabilistic and therefore produces percentile values. The published forecast for each month is based on the central value of the BSUoS cost forecast (50th percentile). If the outturn BSUoS costs are below the 50th percentile of the cost forecast, then the actual costs for that month would be lower than the forecast predicted, provided the actual volume is at or above the estimate (and vice versa).



Q4 2025–26 performance

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

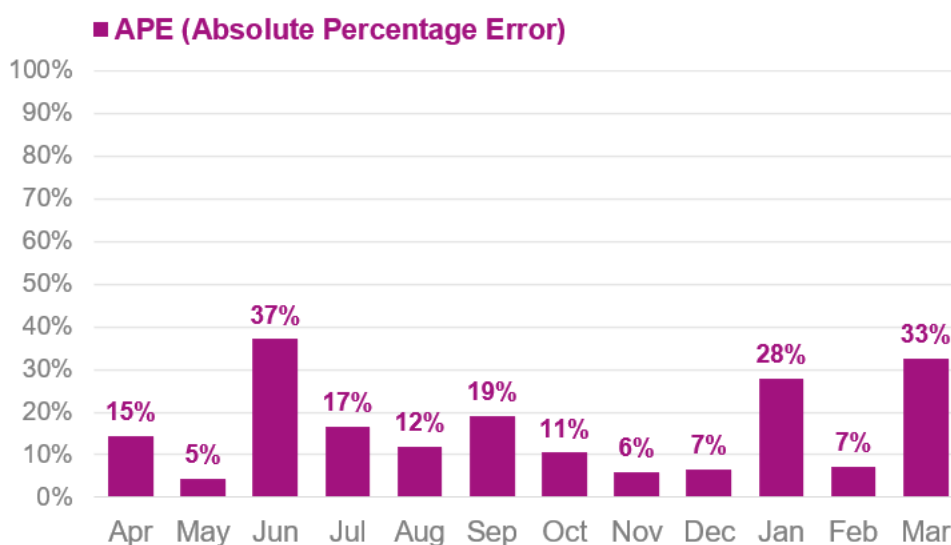


Table: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance – one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	9.53	13.02	18.54	10.43	14.19	15.97	18.17	14.57	12.93	14.19	12.33	19.14
Month-ahead forecast (£ / MWh)	11.15	12.46	13.52	12.51	12.67	13.40	16.45	15.49	14.49	11.10	13.30	14.44
APE (Absolute Percentage Error)⁸	14.5	4.5	37.1	16.7	12.0	19.2	10.5	5.9	6.6	27.8	7.3	32.5
Average Monthly APE (by Quarter)	18.7			16.0			7.7			22.5		

Supporting information

Q4 Performance:

The average monthly Absolute Percentage Error for Q4 is 22.5%, with actuals being higher than month-ahead forecasts for January and March.

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

⁸ Monthly APE% figures may change with updated settlements data at the end of each month. Therefore, subsequent settlement runs may impact the end of year outturn.

**Costs:**

Total balancing costs across the quarter outturned above our month-ahead forecast across the quarter, with the largest variance from our March 2026 forecast.

In January, balancing costs outturned around the 85th percentile of our month-ahead forecast, £76m higher than expected. Constraint costs were the largest component of this difference, £62m higher than forecast. Wholesale electricity market prices averaged £94/MWh, compared with a month-ahead forecast of £80/MWh.

February out-turned below forecast, at the 30th percentile of the month ahead forecast, £36m below forecast, mainly driven by lower than constraint costs and energy imbalance costs outturning below forecast.

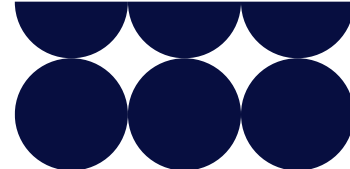
The largest variance was in March, which outturned above the 95th percentile of the month ahead forecast, £110m above expectation, mainly driven by constraint costs. Constraints costs were £117m above our forecast, and £155m higher than the February outturn. Wholesale market prices averaged £96/MWh, compared to a forecast of £84/MWh. Additionally, we have found previously that a higher proportion of demand being met by renewable generation tends to correlate with higher constraint costs. We had forecasted 40% of demand to be met by renewables; this outturned at 50%.

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

Volumes:

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

Across Q4 our average monthly volume forecasting error was 0.3%. The largest variance was in January, with volumes out-turning above forecast.



13. Balancing services procured in a non-competitive manner

Performance Objective

N/A

Success Measure

N/A

This Reported Metric measures the volume and spend for non-competitive services for contracts. For the purpose of this metric, we have included volumes where the decision to instruct non-competitive services is made after 31 March 2024, even if the contract terms were signed before (e.g. Mandatory Frequency Response). Figures are reported in GWh/GVARh for the contracted month, which is calculated as the contracted volume in MW multiplied by the number of contracted hours.

Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded. However, all SO-SO trades and NTC application, as well as any other non-competitively procured services with contract award after this date, are included.

H2 2025-26 performance

Figure: Volume and spend for non-competitive services for contracts



*Reactive volume is measured in GVARh and is not directly comparable to the other services measured in GWh but is included in the graph with this caveat.

**Table: Volume and spend for non-competitive services**

	Service	Unit	H1	H2	Full Year
VOLUME	Frequency Response****	GWh	4,743	3,121	7,864
	Reserve****	GWh	6,634	6,757	13,391
	Constraints***	GWh	0	0	0
	SO-SO trades	GWh	21,960	21,840	43,800
	Net Transfer Capacity (NTC)	GWh	12,298	12,230	24,528
	Total Volume in GWh	GWh	45,635	43,948	89,583
	Reactive (in GVARh)	GVARh	24,654	23,223	47,877
SPEND	Frequency Response	£m	12	4	16
	Reserve	£m	45	37	82
	Constraints	£m	0	0	0
	SO-SO trades *	£m	2	0	2
	Net Transfer Capacity (NTC)**	£m	0.15	0	0
	Reactive	£m	134	112	246
	Total spend	£m	193	153	346

*SO-SO trades, trade volumes and costs for services provided to NESO by another country's system operator have been included. Services provided by NESO to another country's System Operator are excluded.

**NTC cost was updated for Q1 to show payments to provider only – this logic to be used going forward

***For Q2 – Super SEL category has moved from Constraints to Reserve

****Total non-competitive procurement for Frequency Response and Reserve in 13. Balancing services procured in a non-competitive manner will not align with volume stated in the success measure. This is because Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded from, 13. Balancing services procured in a non-competitive manner, as per the agreed methodology.



Supporting information

Frequency Response

The volume of non-competitive services procured in Frequency Response is Mandatory Frequency Response (MFR). MFR is used as an element of our response holding that can be instructed within operational timescales. We are actively considering alternatives to the current MFR service to reduce this volume in the future and have continued to engage with stakeholders on this.

Reserve

This volume of non-competitive Reserve is made up of the intra-day Optional Fast Reserve product, where prices for the service can be updated by providers per Settlement Period close to real-time.

**The Optional Fast Reserve product will cease April 2026, the volume will move to other day ahead reserve services depending on provider engagement.*

Optional Fast Reserve is used for short-term frequency management outside contracted Fast Reserve windows e.g., periods where wind may have dropped unexpectedly, or demand has increased more than anticipated. Note that day-ahead procured STOR is to replace the largest loss and thus utilisation should always be quite low.

**STOR also ceased operation on 31 March 2026 and was replaced with Slow Reserve, therefor absorbing the above requirement in terms of the largest loss.*

Super SEL, which is now included as a Reserve service, is an active but optional contract that a number of generators can provide as a backup to other solutions.

Constraints

No non-competitive constraint contracts were used.

SO-SO Trades

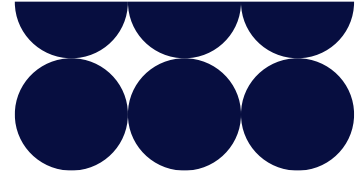
Historically SO-SO Trades were available to us across the IFA and IFA2, Nemo Link, EWIC and Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 and Nemo Link, the current required notice period is longer than the hourly gates provide, meaning we can no longer use this service.

EWIC, Greenlink & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. We do not trade via third Parties and therefore only have access to CBB.

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

Net Transfer Capacity (NTC)

A capacity management process is used to ensure secure system operation for both Interconnectors and onshore TSOs. This process can result in the reduction in capacity through the application of a Net Transfer Capacity (NTC) and this reduction is defined as a non-frequency ancillary service.



Standard Licence Condition C28 requires that we procure non-frequency balancing services using market-based procedures. NTC is not procured through market-based procedures and therefore requires a derogation from this requirement. The procurement of NTC cannot be market-based due to technical parameters and the fact that alternative actions are not sufficient or economically efficient.

On 28 September 2023, Ofgem granted us a derogation against C28 for NTCs until 30 September 2026. This follows a request we sent to Ofgem to extend this derogation in August. They also approved our revised NTC Commercial Consultation Methodology, which applies from 1 October 2023. This gives our Control Room certainty that they can use this vital tool when required for system security over the coming years.

NTCs are our only way of guaranteeing system security in real time. As a result, they are as near to real-time calculated values as the market structure allows. Any restrictions are based on the forecast system conditions for that particular real-time period and are reflective of the limits of GB system security.

Reactive

Over the last 12 months, we have continued to develop our reactive power markets to enhance competition as part of our procurement strategy.

Most notably:

- In July 2025 we launched the invitation to tender stage for the first Long-term Reactive Power Market tender 'Long-term 2029' which is competitively procuring reactive power across England and Wales from 2029 to 2039 via a long-term contract. This tender is a first-of-a-kind bundled tender with restoration and stability with the aim to help drive down costs through more optimised procurement.
- In January 2026 we launched a pre-market consultation for the Mid-term Reactive Power Market. This market will seek to competitively procure requirements using mid-term contracts (e.g. 1 year, 2 years) to cover forecasted requirements, generator and network outages. This consultation sought further industry feedback on the market design prior to market launch, demonstrating the continued industry collaboration in the development of this new market. We are currently preparing for the launch of this mid-term reactive power market later this year (2026).

Once both reactive power markets are in use, we expect that we will be able to competitively procure a greater share of our requirements.

It is also of note that areas of higher need are not necessarily the same locations as where assets are located and able to compete for the provision of MVAr. The Southwest is a prime example of this, where limited assets mean we are limited in our ability to competitively tender for these services.



14. Future Savings from Operability Solutions

Performance Objective

N/A

Success Measure

N/A

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

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

In each report we show projects concluded in the BP3 period, with estimated benefits up to the end of contracts. In the narrative we also call out what upcoming projects are likely to be included in subsequent reports during NESO1.

H2 2025–26 performance

i. Saved balancing costs

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

Operability Solution projects	LATEST VIEW
	End-Scheme 25–26 View: Forecast Savings £m
Mid-term Y-1 Stability Market: Year 2	44.4
TOTAL	44.4

Supporting information

Stability Market

The second Mid-term (Y-1) Stability Market tender for Year 2 2026/27 concluded in January 2025 with five synchronous condenser solutions contracted to provide 7.3GVA.s of inertia



capability to the GB network. This builds on the success of the first tender and continues to provide a route to access inertia capability from economic and carbon free sources.

Looking ahead

In upcoming reports, we expect to report on forecast benefits from further operability measures, including the new mid-term reactive power markets, new intertrip contracts in Scotland, the next round of Stability Y-1 and the ongoing Long Term 2029 tender.

ii. Monetised carbon reductions

The carbon prices used in the tables below are taken from the BEIS publication '[Valuing greenhouse gas emission in policy appraisal](#)'. These prices are also those used in our [RIIO-2 Business Plan 2 Cost-Benefit Analysis – Annex 2](#). The prices are weighted for the calendar year in which the services are contracted to deliver.

Table: Mid-term (Y-1) Stability Market: Year 2 – (October 2026 – September 2027)

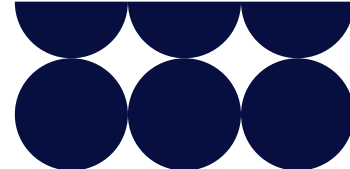
Mid-term (Y-1) Stability Market: Year 2 – (October 2026 – September 2027)	Unit	Oct 26 – Sept 27
CCGT generation output avoided in GWh	GWh	530
Carbon intensity for Gas (Combined Cycle) from NESO Carbon Intensity Forecast Methodology	gCO ₂ /kWh	394
CO ₂ in tonnes	tCO ₂	210,000
Carbon price (Central Case pro rated)	£/tCO ₂ e	267
Savings	£m	56

Supporting information

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

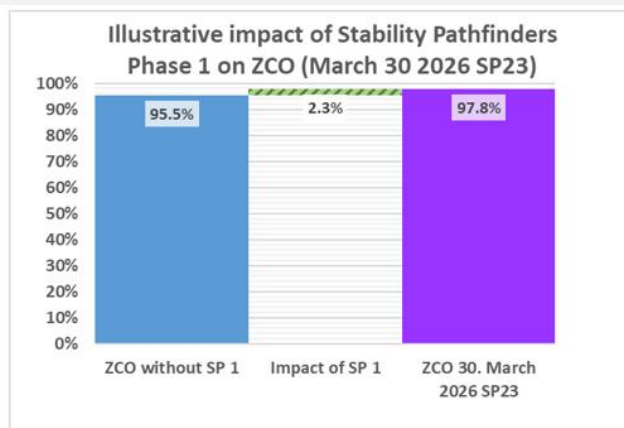
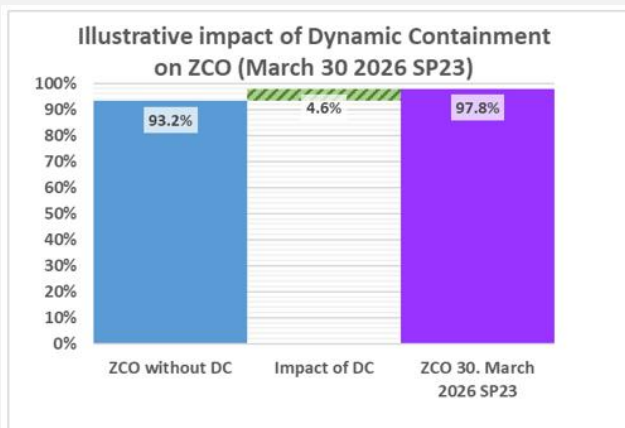
iii. Any indicative impact on the SZCP limit

As outlined in our [Operability Strategy Report 2025](#), we updated the Zero Carbon Operation (ZCO) methodology to reflect the clean power technologies as set out in the [Clean Power Action Plan](#). Under this methodology, the record for zero carbon operation was 97.80% during settlement period 23 (SP23) on 30 March 2026 (the methodology has been updated to exclude CHPs, unless instructed by the control room, as outlined in the Zero Carbon Operability Indicator Reported Metric.) We also saw a high level of ZCO% coupled with low inertia on April 1 2025 SP15.



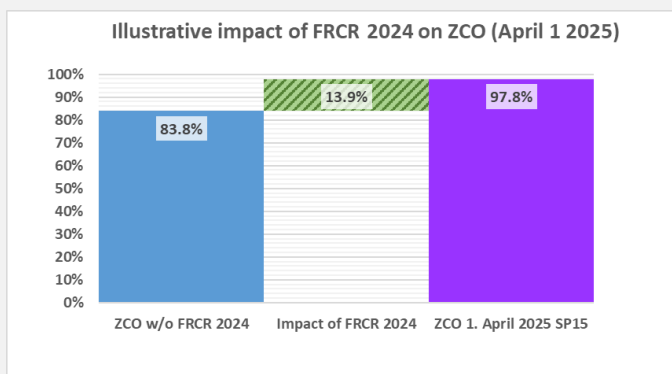
We have used these settlement periods to provide illustrative examples of how NESO programmes have impacted the ZCO% achieved.

The graphs below show how much lower the ZCO% would have been on 30 March 2026 without the delivery of Stability Phase 1 and Dynamic Containment. Each programme has been assessed independently rather than cumulatively.

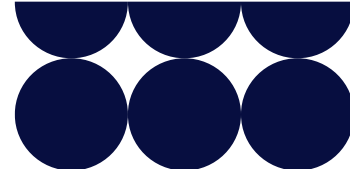


- **Dynamic Containment (DC)** has significantly reduced the need to hold legacy frequency response products. Without DC, an additional 2,000MW of headroom would have been required on synchronous carbon emitting generation. This equates to 8 units at 250MW each, which would have reduced the ZCO% to 93.2%.
- **Stability Pathfinders Phase 1 (SPPH1)** procured 12.5 GVAs of zero carbon inertia, provided by synchronous condensers, eliminating the need for four synchronous fossil units equivalent to 1000MW of generation. As shown by the graph on the right, without Phase 1 the ZCO% would have been 95.5%.

The following graph shows how much lower the ZCO% would have been on 1 April 2025 without the reduced inertia threshold delivered by FRCR 2024.



The **Frequency Control and Risk Report (FRCR) 2024**, approved by Ofgem on 27 September 2024, led to the implementation of a reduction to the minimum inertia requirement from 140 to 120GVA.s. The lower minimum inertia requirement allows the grid to operate with fewer fossil based synchronous generators. In our illustrative example, seven additional units at 250MW would have been required in this settlement period to meet the previous requirement of 140GVA.s. That would have reduced the ZCO(%) achieved to only 83.8%.



Impact of Current/Future Programmes

FRCR 2025 proposed reducing the minimum inertia requirement from 120GVA.s to 102GVA.s as part of enabling a zero carbon electricity system. Following consultation and additional studies by Ofgem, we are awaiting a final decision. As an illustrative example, on 1 April 2025 there was 121GVA.s of inertia on the system in SP15, only marginally above the current limit but with a headroom of 19GVA.s to the proposed new limit of 102GVA.s. Absent other considerations, such as voltage, this could have allowed a further seven synchronous fossil generation units to be removed from the system which would have increased the ZCO% closer to 100%.

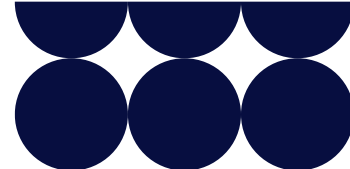
Note: The calculations make assumptions about the contribution to system needs on 15 April 2024, taken from FRCR. Each synchronous generator provides 3GVA.s of inertia, operating at a minimum output (Stable Export Limit – SEL) of 250MW with a maximum available output of 500MW.

Whilst this exercise has shown that future projects could enable zero carbon operation on days like 1 April 2025 or 30 March 2026, there are further projects that will also act as enablers for extended periods of low or zero carbon operation such as Stability Pathfinders Phases 2 and 3. For example, phase 3 procured 17.1GVA.s which would remove the need for up to five synchronous fossil generators (1250MW).

Our Voltage Network Services are delivering new non-fossil generating sources of reactive power which will reduce dependence on fossil based synchronous generation for voltage management, further enabling zero carbon operation.

Through the Long-term 2029 tender, our first bundled procurement of stability, voltage and restoration services, we are seeking additional services for delivery in 2029. This tender covers all of GB and offers providers the option to bid on one or more of these services using the same asset. Stability and Voltage services must be able to be provided at 0MW and will act as an enabler for extended zero carbon operation. This tender process is still in progress.

We're currently preparing for the launch of a Mid-Term Reactive Market later in 2026 following the progress that has been made with market design work and the most recent market consultation that was facilitated in January 2026. This will complement our mid-term stability market, providing us with a platform for procuring voltage services closer to operational timescales.



15. EMR Demand Forecasting Accuracy

Performance Objective

N/A

Success Measure

N/A

This Reported Metric measures the accuracy of NESO's peak national demand forecast. This forecasting is done as part of NESO's role as Electricity Market Reform (EMR) Delivery Body (DB). We aim to optimise the volume of capacity procured in the Capacity Market through more accurate forecasts of peak demand, which are used by the Secretary of State to determine the volume of capacity to procure.

The peak demand forecast accuracy measures the absolute percentage difference between our forecast and outturn of peak National Demand.

For outturn peak National Demand, we used Peak Average Cold Spell (ACS) i.e., peak weather corrected National Demand, as this is the most effective measurable proxy. This percentage gives a value greater than, or equal to, zero, and indicates how accurate the peak demand forecasts are excluding the impact of embedded wind generation. The closer to zero the percentage, the more accurate the forecast.

Over forecasting leads to unnecessary capacity being procured, which increases the cost to consumers. Under forecasting leads to either more capacity needing to be procured later (potentially at a greater cost) or risks security of supply.

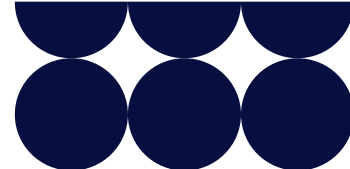
All forecasts that outturn post 1 April 2023 will be assessed against this measure.

For 2025-26, the accuracy of two forecasts will be measured as follows:

- The T-1 forecast made in 2024-25, for delivery in 2025-26
- The T-4 forecast made in 2021-22, for delivery in 2025-26

Forecast accuracy is the absolute difference between forecast ACS Peak National Demand and outturn ACS Peak National Demand, given as a percentage of the outturn ACS Peak National Demand.

Under BP3, EMR Demand Forecasting Accuracy is reported for transparency and learning and is not assessed against predefined performance thresholds.



2025–26 Performance

Table: One-year view of peak demand forecast accuracy

Auction	Forecast made in	Delivery Year	Forecast GW	Actual GW	Forecast accuracy
T-1	2024-25	2025-26	46.0	46.4	0.9%
T-4	2021-22	2025-26	44.7	46.4	3.7%

Results are provisional based on access to settlement data

Improvements to analysis

Our long-term demand forecasting analysis feeds into a range of processes, including the Future Energy Scenarios (FES), Electricity Market Reform (EMR), the Electricity Ten Year Statement (ETYS), Regional Energy Strategic Plan (RESP) as well as gas security of supply and network planning processes.

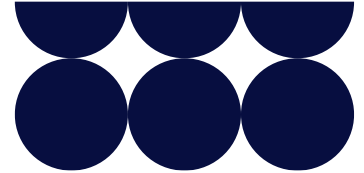
We have continued to focus on increasing the transparency of our work to our key stakeholders, setting up challenge and review sessions where they have had the opportunity to comment on our modelling inputs, and then giving an early view of our outputs. We have held bilateral discussions with a very wide range of stakeholders from both industry and regulatory and trade bodies to dive into topics such as Heat, Transport, Industrial and Commercial demand, and we were able to use the feedback we received to set the inputs for our modelling.

New data and partnerships with the Distribution Network Operators and Transmission Network Owners have allowed us to substantially improve our access and use of connection queue data to improve multiple models. This has primarily been used to reform our Data Centre models' output peak demand impacts as well as annual energy demands (a key model due to the significant growth expected in this area) as well as for modelling rail and other directly connected demand loads.

Changes to our modelling of Electric Vehicle (EV) demand included a slower forecast adoption rate informed by more detailed historic sales data, updates to mileage and efficiency assumptions, inclusion of the EV mileage tax, and updates to charging location assumptions.

A new air conditioning model to replace our legacy assumptions and better inform this fast-growing domestic demand and its impact on annual energy demands.

The culmination of a long running project to replace our heat pump profiles with more accurate real-world data as part of a project with Cardiff University has led to substantial



improvements in our residential heat modelling with substantial updates made to both profiles and annual consumption data.

Crowd Flex, a Strategic Innovation Fund project has provided substantial amounts of new data on how domestic flexibility responds to price signals and how it behaves in a real-world dispatch environment. We have used this to start to reform our approach to Demand Side Response from a residential perspective and have adjusted many of our core assumptions on how this flexibility can be dispatched within our models, focusing on the different tiers of price response capacity can be grouped within.

Challenges and uncertainties

There remain significant uncertainties in forecasting the energy systems peak demand beyond the inherent uncertainty from such a variable system that is so heavily dependent on market conditions. This means that use of historic data is highly challenging for predicting the future, particularly in a world of rapid decarbonisation. Areas of uncertainty to note include:

- The changes to the regulatory environment remain rapid and the impacts uncertain over the long-term future. We have been working with rapid changes to policy around connections for both generation and future demand as well as changes to taxation and economic policy such as the now planned introduction of an EV levy and the announcement of the Warm Homes Plan.
- Acceleration of deployment of embedded generation and storage technologies, including a growth in such technologies operating as behind the meter assets. This is occurring alongside greater growth in micro applications at the residential scale. This has added substantial uncertainty to the relationship between underlying and national demand and remains a challenge to track due to these assets' less visible profiles.
- Economic challenges around ongoing impacts from geopolitics and global conflict such as those in Ukraine and Iran; ongoing changes to energy demand since Covid; and wider international trade disruption have posed substantial challenges in modelling their recovery and the wider impact on future economic performance and the energy demands associated with them. It is also important to note that our latest analysis was carried out prior to the developments in Iran and that this will further impact the accuracy of our forecasts going forward.



16. Accuracy of Forecasts for Charge Setting – TNUoS

Performance Objective

N/A

Success Measure

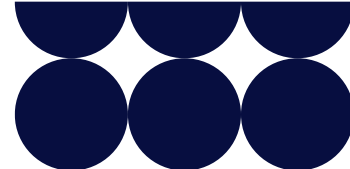
N/A

This Reported Metric shows the accuracy of Transmission Network Use of System (TNUoS) forecast used to set industry charges against the actual outturn charges.

Accuracy of Forecasts for Charge Setting – TNUoS (reported annually)

The TNUoS tariff setting methodology describes how much of the total required revenue should be collected from Suppliers and Generators, which requires a wide range of tariffs to be calculated. These tariffs aim to reflect the costs of how, when and where Suppliers and Generators use the transmission system. Final TNUoS tariffs are set by 31 January for the next charging year commencing 1 April, and out-turn revenue is known by the end of April following the charging year.

Customer type	Liable for	Detail
Suppliers	TNUoS Demand charges	The Non Half-Hourly (NHH) demand tariff is charged for consumption between 4pm-7pm for every day of the charging year, and the Half-Hourly (HH) demand tariffs are applied to import or export over Triads (the three periods of highest net GB system demand). The TDR demand charges are based on site counts or unmetered supply volume per day as provided by the DNOs (except for TRN1 to TRN4 bands which are determined by NESO).
Generators	TNUoS Generation charges	All Generators are liable for the Wider TNUoS Generation tariff. They may also be required to pay onshore local circuit and onshore local substations tariffs depending on where they connect to the transmission system. Offshore local tariffs are also created following asset transfer of the offshore transmission system, which are then charged to offshore generators.



The charging bases used to calculate TNUoS tariffs are the inputs that can be responsible for significant variance between budget and actual TNUoS revenue. The TDR demand tariffs require an assumed demand charging base for each of the 22 charging bands. The locational demand tariffs require an assumed demand charging base for each of the 14 demand zones and for each type of demand (NHH, HH gross demand and HH embedded export). The generation charging base is the best view of the amount of Transmission Entry Capacity (TEC) contracted by Generators for the charging year.

Value Figures rounded to the nearest £m, therefore totals may differ slightly from the sum of the four components

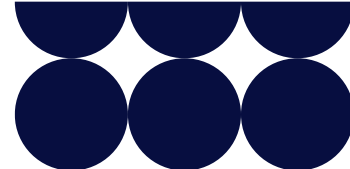
Table: Forecast value vs. outturn value TNUoS Performance

TNUoS Charging	Forecast £m	Actual £m	Variance £m	Variance %
NHH Demand	93	85	-8	-8.7%
HH Demand	28	22	-6	-23%
TDR Demand	3,836	3848	12	0.31%
Generation	1,129	1,061	-68	-6.03%
TOTAL	5,086	5,016	-70	-1.4%

Table: Forecast volume vs. outturn volume TNUoS Performance

TNUoS Charging	Forecast	Actual	Variance	Variance %
NHH Demand (TWh)	24.3	22.4	-1.9	-7.75%
HH Demand (GW)	16.9	19.7	3	16.22%
TDR Demand (bn)	11.7	11.8	0	0.41%
Generation (GW)	88.7	74.2	-15	-16.35%

For each charge type, the **Forecast** is what we aim to collect for each tariff and **Actual** is how much we collected.



Supporting information

Several events can impact out-turn TNUoS revenue once TNUoS tariffs have been set 14 months earlier. 2025-26 demand volumes continue to be suppressed below those seen prior to the start of the war in Ukraine and resulting higher energy prices. Generation revenue may be impacted by unforeseen delays to stations connecting to the transmission system or delays in the transfer of an offshore transmission system. The explanations of variance described below is based on the final available settlement metering data i.e. volume.

TNUoS charge Explanation of variance

TDR Demand We continue to see some data refinement from customers and DNOs throughout the 2025-26 charging year. There have been significant shifts between LVNo Mic and LV band/, the removal of non-final demand and de-energised sites as customers have queried data with their DNOs. A charging base of 11.7bn site count days was assumed at tariff setting compared to 11.8bn site count days outturn (increase of 0.41%) with revenue up £12m at outturn (increase of 0.31%).

NHH Demand A charging base of 24.3TWh was assumed at tariff setting for 2025-26. Actual 2025-26 out-turn NHH demand is 7.75% lower at 22.4TWh.

HH Demand HH Gross Demand:

A charging base of 16.9GW was assumed at tariff setting for 2025-26. Actual 2025-26 out-turn HH demand is 16% higher at 19.7 GW.

HH Embedded Export

A charging base of 7.4GW was assumed at tariff setting for 2025-26. Actual 2025-26 out-turn for EE demand is 35% higher at 10GW. This resulted in outturn credits paid for 2025-26 exports (£38m), 66% higher than budget at tariff setting (£22.9m).

Generation The amount of Transmission Entry Capacity (TEC) assumed at 2025-26 tariff setting was 88.7GW compared to actual TEC invoiced of 74.2GW. The delay of asset transfer for several offshore transmission systems means that offshore tariffs could not be introduced and charged to offshore Generators as early as anticipated when Final tariffs were set leading to a reduction of £12.35m. Combined with a lower-than-expected number of new connections, this means that in 2025-26 overall TNUoS Generation revenue is 6% less than budget.

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