

24 March 2026

# Monthly Incentives February 2026 Report

Business Plan 3 (2025-26)

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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. 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><b>Strategic Whole Energy Plans</b></p> <p>NESO will establish the capabilities, foundations and methodologies needed to deliver national and regional strategic whole energy plans.</p>
	<p><b>Enhanced Sector Digitalisation and Data Sharing</b></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><b>Fit-for-Purpose Markets</b></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><b>Secure and Resilient Energy Systems</b></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><b>Separated NESO Systems, Processes and Services</b></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><b>Clean Power 2030 Implementation</b></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><b>Operating the Electricity System</b></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><b>Connections Reform</b></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>	



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

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

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

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

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

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

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

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

Reported Metric	Performance
1 <b>Balancing Costs</b>	<b>£203m</b>
2 <b>Demand Forecasting</b>	Forecasting error of <b>717MW</b>
3 <b>Wind Generation Forecasting</b>	Forecasting error of <b>5.05%</b>
4 <b>Skip Rates</b>	Post System Action (PSA) Offers: <b>27%</b> Bids: <b>33%</b> Combined: <b>29%</b>
5 <b>Carbon intensity of NESO actions</b>	<b>6.79gCO<sub>2</sub>/kWh</b> of actions taken by NESO
6 <b>Security of Supply</b>	<b>0</b> instances where frequency was more than $\pm 0.3\text{Hz}$ away from 50Hz for more than 60 seconds. <b>0</b> voltage excursion.
7 <b>CNI Outages</b>	<b>1</b> planned, <b>0</b> unplanned system outages.



# 1. Balancing Costs

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## 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.**

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

For consistency with previous RII0-2 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:

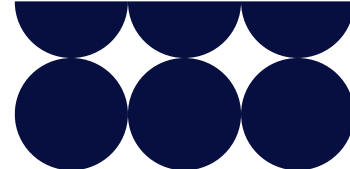
- Each year, the benchmark is created using monthly data from the preceding 3 years.
- A straight-line relationship is established between historic constraint costs, outturn wind generation and the historic wholesale day ahead price of electricity.
- A straight-line relationship is established between 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) =  $28.76 + (\text{Day Ahead baseload} \times 0.87) + (\text{Outturn wind} \times 23.51)$

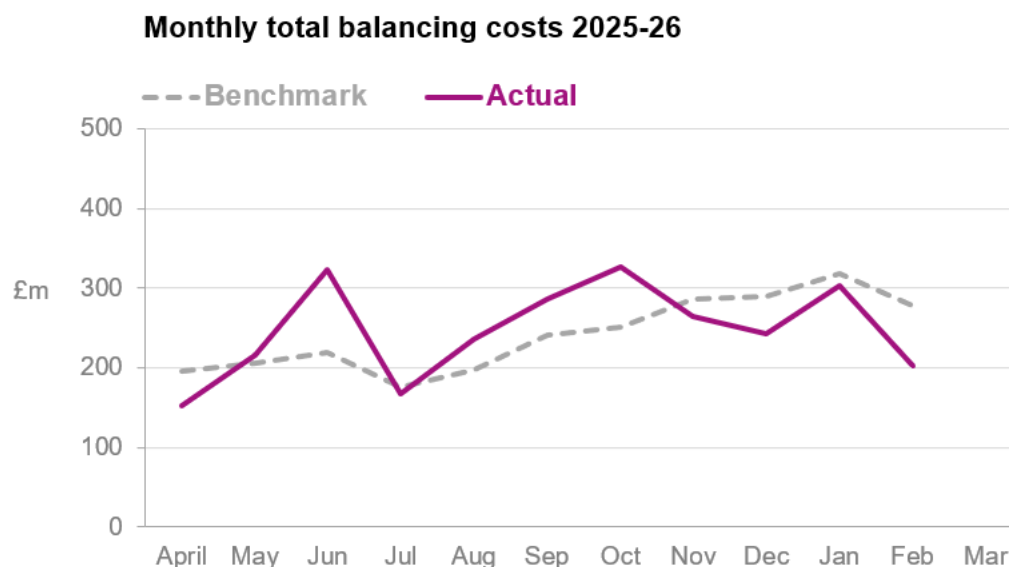


\*Constants in the formulas above are derived from the benchmark model

**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](#).

## February 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		67.3
Average Day Ahead Baseload (£/MWh)	81	77	73	80	73	72	77	82	75	100	80		n/a
Benchmark*	195	206	219	176	197	241	251	286	289	318	277		2655
<b>Outturn balancing costs<sup>1</sup></b>	<b>152</b>	<b>215</b>	<b>324</b>	<b>167</b>	<b>236</b>	<b>287</b>	<b>326</b>	<b>265</b>	<b>242</b>	<b>303</b>	<b>203</b>		<b>2719</b>

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



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

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

## Supporting information

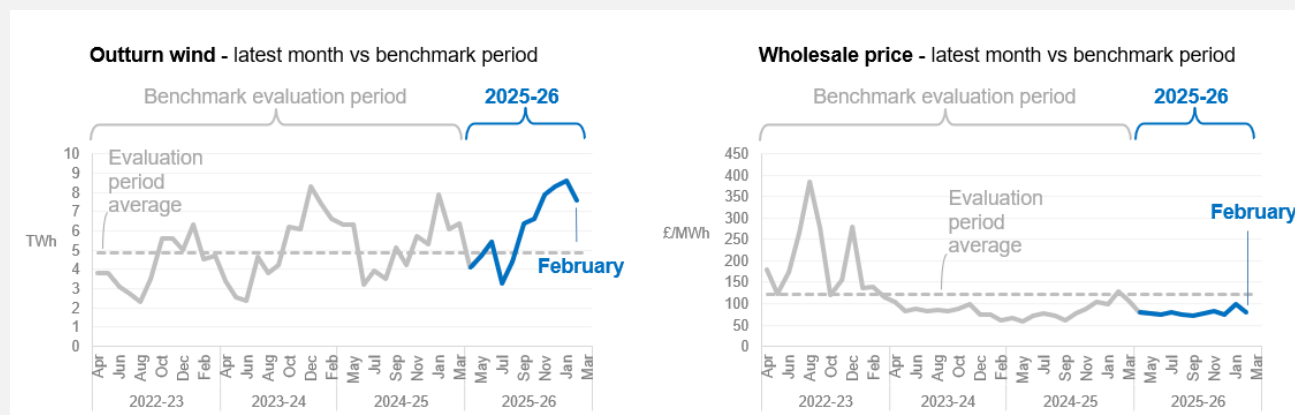
### BALANCING COSTS METRIC & PERFORMANCE

#### This month's benchmark

February's benchmark of £277m is £41m lower than January and reflects:

- An outturn wind figure of 7.6 TWh that is 1 TWh lower than January'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) of £80/MWh, that has decreased by £20/MWh compared to January, and is now more in line with the months preceding January (October to December, which ranged between £77/MWh - £82/MWh). It is also £27/MWh lower than the same period last year and falls below the evaluation period average.

A decrease in average monthly wholesale price as well as a decrease in wind outturn has led to a significant decrease in the benchmark from January.



#### Balancing Costs - Overview

The total balancing cost for February was £202.6m, which is £74.4m (~27%) below the benchmark.

After the highest-ever recorded wind outturn in January (8.6TWh), February saw a marked decrease in wind outturn by 1TWh to 7.6TWh, with the greater share of the decrease being in England and Wales (-0.7TWh). 7.6TWh is still quite a high outturn and the wind in Scotland remained higher than in preceding months, which is generally what has a greater effect on thermal constraint costs. An increase in temperatures alongside lower power prices has however



led to a marked drop in balancing costs in February. It is worth noting that there were 3 fewer days in February compared to January, which will also have contributed to the drop in total monthly costs.

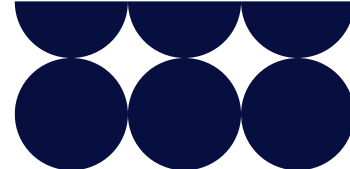
With warmer temperatures and longer daylight hours, daytime demand levels significantly decreased in February compared to January. There was slightly higher demand during the day compared to February last year, predominantly due to wet weather suppressing embedded solar generation output this year.

Despite a higher wind outturn, the level of curtailment this year was lower by 25% than in February 2025. Periods of higher wind levels coincided with a less constrained network than they did last year. Despite a generally more constrained network than last month, wind curtailment also dropped by 30% from January 2026, owing to the much lower overall wind outturn. It is also worth noting that total savings from outage optimisation amounted to approximately £101m in February 2026, an increase of roughly £25m relative to January 2026.

Voltage constraint costs have increased since January with the lower demand meaning less self-dispatch of units providing reactive power support. This meant more synchronous units were procured through the Balancing Mechanism, with the highest volumes in the southwest. There was a slight decrease in inertia spending, in part due to synchronous units running for voltage support already and therefore less additional requirement.

Non constraint costs have decreased by £25.5m. This accompanies a drop in clearing prices for all frequency response services and a lower wholesale price in February.

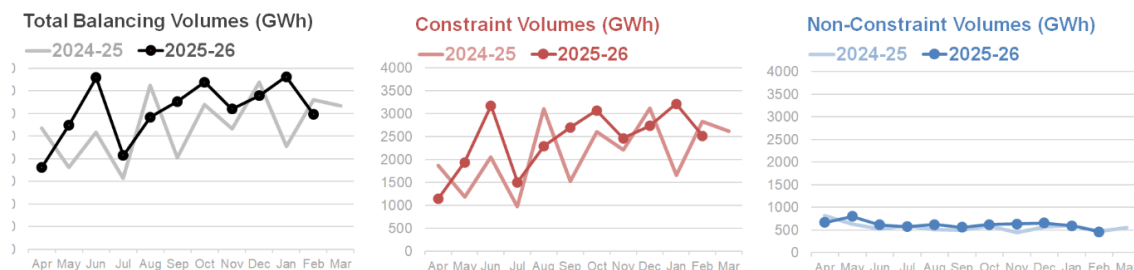
Average wholesale prices have decreased by almost £20/MWh since January, due to February's high wind outturn coinciding with warmer temperatures. The volume weighted average (VWA) price of bids was £7.5/MWh, which is less expensive than January's price of £4.5/MWh, and represents decreasing bid prices since September, with VWA prices having become positive values since January. Offer VWA prices also decreased slightly in February, from £129.5/MWh in January to £112.5/MWh. This meant replacement energy for wind curtailment behind constraints was less expensive.



**Balancing COSTS** (£m) monthly vs previous year



**absolute Balancing VOLUMES** (GWh) monthly vs previous year



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

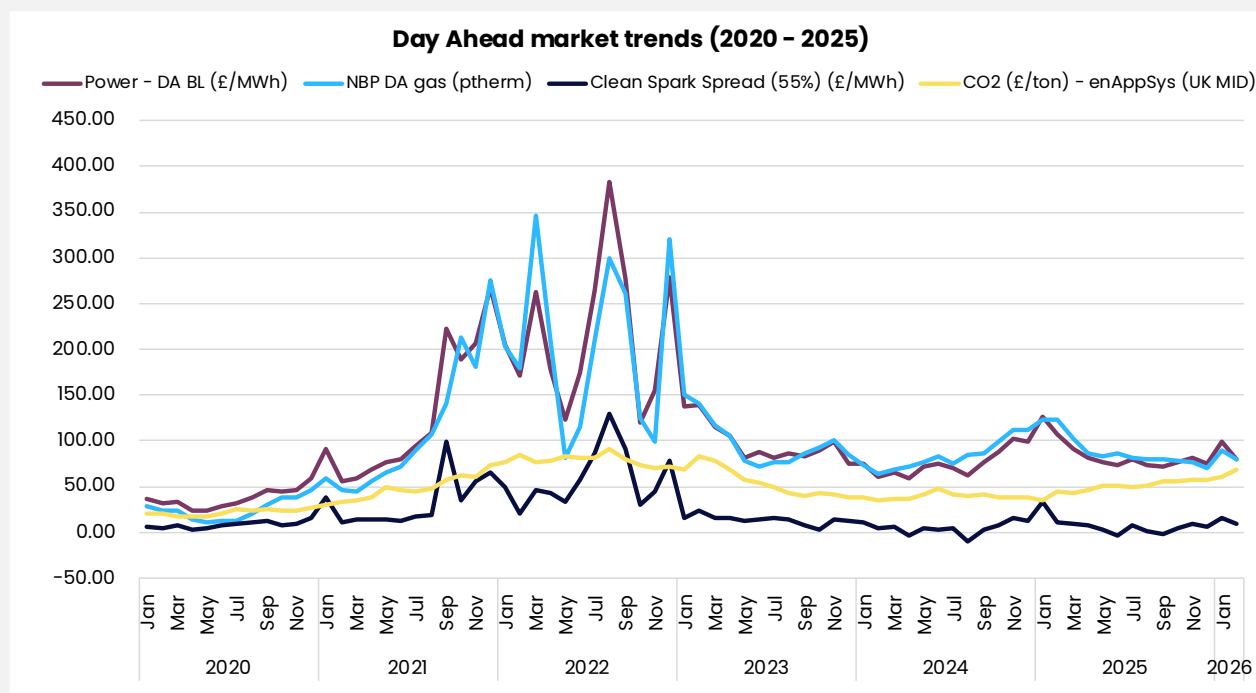
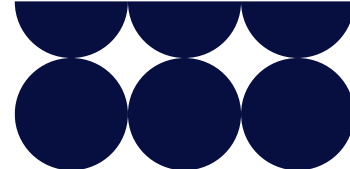
**System and Market Conditions**

**Market trends**

In February the average power price decreased compared to January by almost £20/MWh (from £99.60 to £80.05). High wind outturn alongside warmer temperatures led to power prices dropping at the turn of the month. Rising temperatures reduced gas-for-heating demand and the higher levels of system demand started to drop as GB drew closer to exiting the winter delivery period.

With low wind in the second week of February, a return to higher wind outturns in the second half of the month was initially offset by cooler temperatures, but once the daily average GB temperatures reached and remained above 10°C, power prices dropped down to ~£70/GWh in the final week of February.

UK carbon prices saw an increase to £68.35/ton (from £61.28/ton in January), which is a much larger increase of +£7.07/ton compared to the increase in EU carbon prices of +£1.46/ton. The EU prices did however remain higher overall at £74.87/ton. Gas prices in February were 80.52p/therm. Despite some early concerns on conflict in the Middle East, in the short-term, the arrival of above-average temperatures and high winds reduced demand for gas, keeping prices more stable than they could have been.



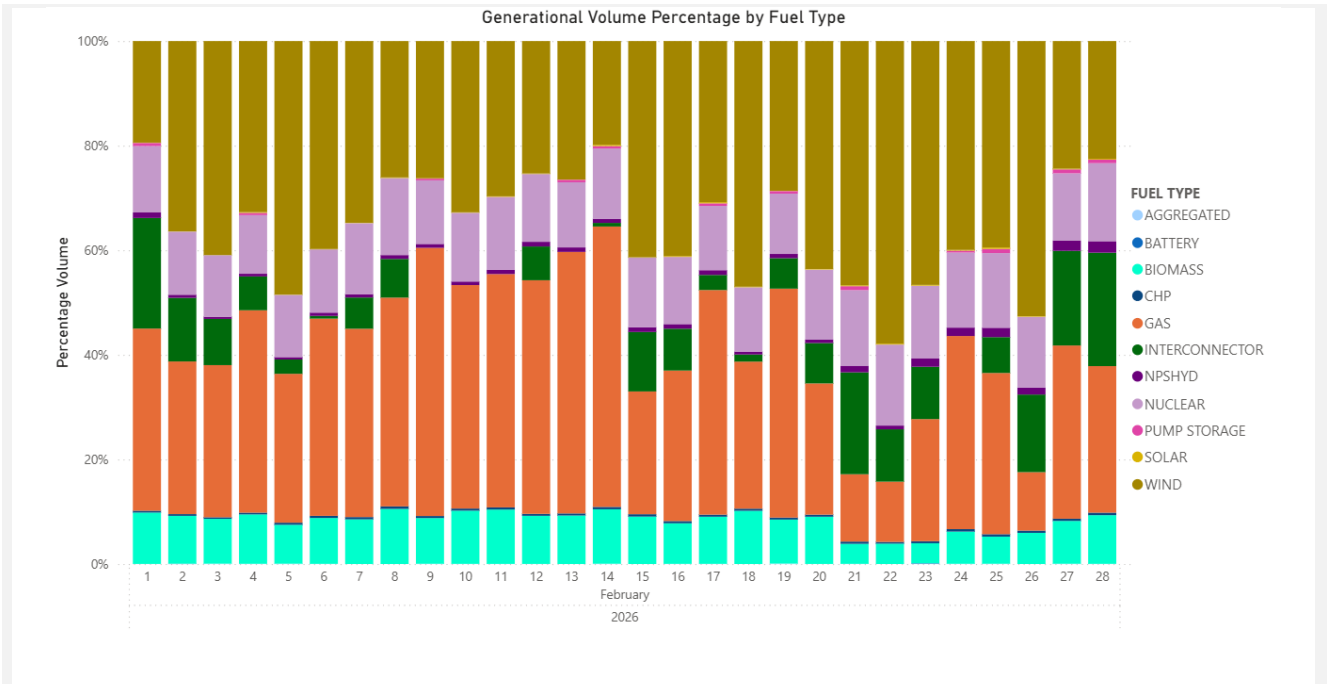
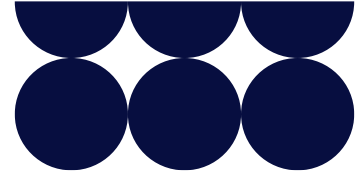
**DA BL:** Day Ahead Baseload      **NBP DA:** National Balancing Point Day Ahead

#### Generation Mix

There was a slight switch in generation mix between January and February, with wind now being the largest contributor at 36% of electricity generation and gas being second at 34%. There was a small increase in the percentage contributions for nuclear and biomass (13% and 8% respectively), and a small drop in interconnector contribution (from 9% to 7%). This continues a downward trend in interconnector contribution since December when it was at 13%.

Despite January's higher wind outturn, the wind contribution in February's generation mix was slightly higher and there were only 4 days where wind generation was less than 25% of the total daily generation (1st, 14th, 27th & 28th), compared to 8 days in January. There were two days where wind contribution reached over 50%, which were the 22nd at 58% and 26th at 53%.

The highest daily transmission system demand occurred on 10th February, meeting a low wind outturn day, however wind still contributed 33% of the generation mix on this day.

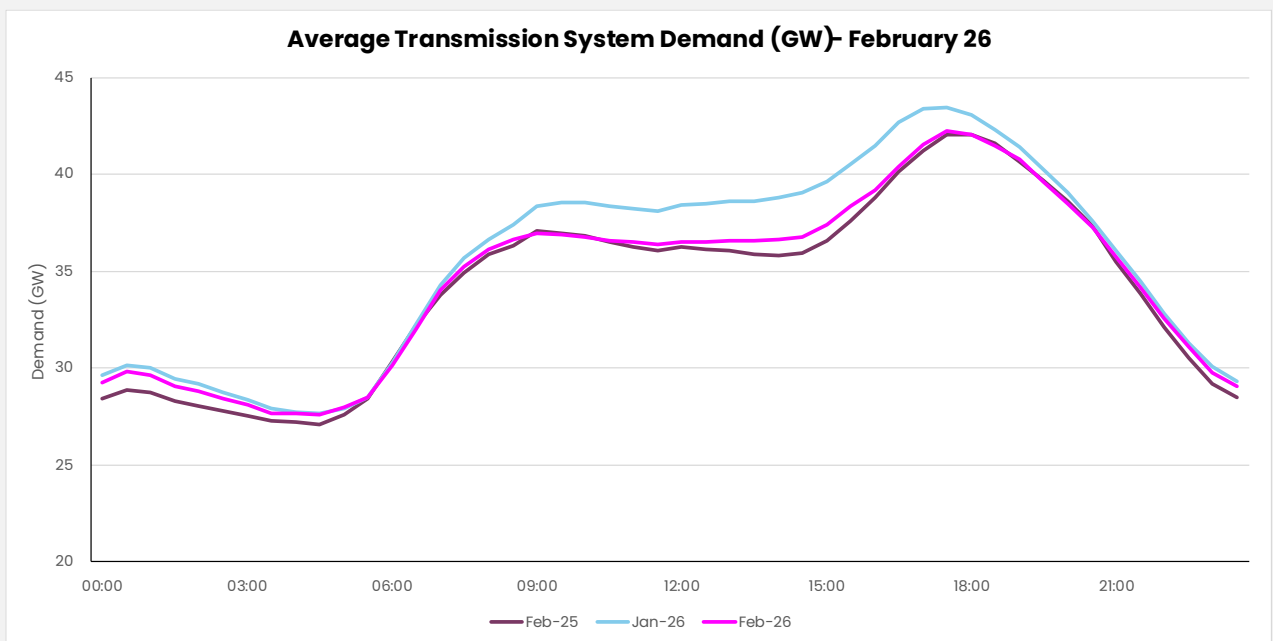


\*Generation mix includes exports from interconnectors.

### Transmission System Demand

In February 2026 the average Transmission System Demand (TSD) was in line with February 2025 throughout most of the day, with notably similar levels during the morning pickup and just after the evening peak. TSD was slightly higher this year in the early overnight hours and mid-afternoon. With significant rainfall this year, overall levels of embedded solar generation were lower and therefore there was greater reliance on the transmission system to meet the daytime demand. Demand overnight has generally been higher year-on-year as a result of flexible tariffs for e.g. overnight charging of EVs.

The demand during daytime hours was notably lower than last month (Jan-26), reflecting warmer temperatures and longer daylight hours.





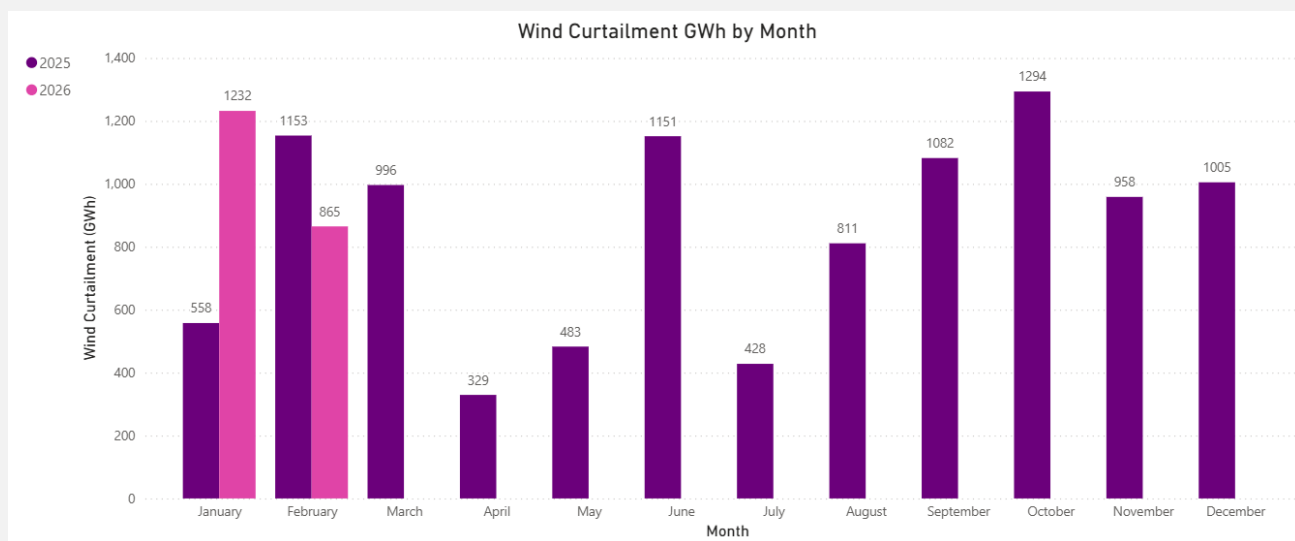
### Wind Outturn

The month was characterised by quite variable temperatures week on week. Average GB temperatures gradually rose at the start of February and were above-average for the time of year, however then dropped quite sharply to below average values in the period 14th-19th February. Temperatures then recovered and rose to seasonably high temperatures of over 10°C on 22nd February and remained around this value for the rest of the month.

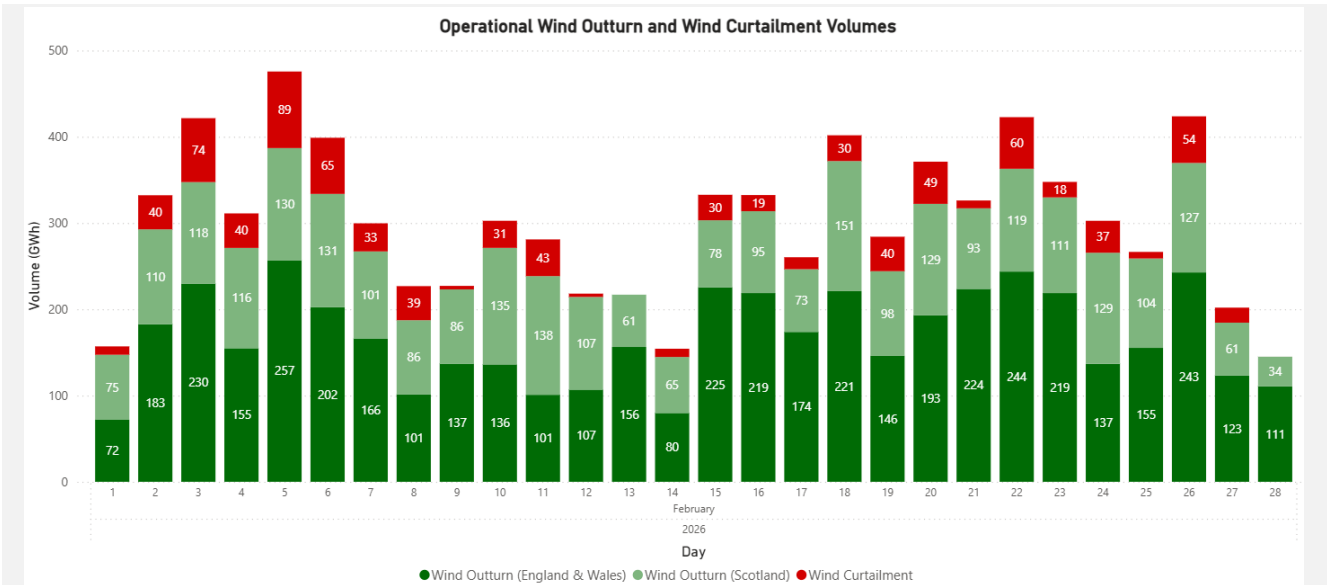
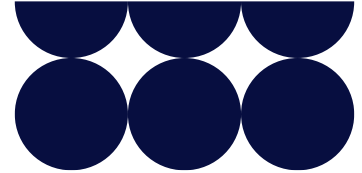
Overall wind outturn dropped from 8.6TWh in January to 7.6TWh in February. Despite the drop, January 2026 had recorded the highest-ever wind outturn and February’s outturn of 7.6TWh was still quite a high figure, being 1.2TWh higher than in February last year.

The decrease since January was seen across both Scotland (-0.3TWh) and England and Wales (-0.7TWh). Experiencing less of a drop since last month, the outturn in Scotland still remained higher than the preceding winter months, whereas in England & Wales, the outturn was at its lowest since October.

Despite a higher overall wind outturn, the level of curtailment this year was lower by 25% (865GWh in February 2026 compared to 1,153GWh in February 2025). This is due to February 2025 seeing a more constrained network in the north of Scotland during the second half of the month, which coincided with some higher wind days. Multi-stage reinforcement work on Scottish boundaries had led to planned outages exacerbating constraints this time last year. February 2026 has however seen a lower hypothetical wind outturn than the preceding winter months which has contributed to experiencing lower curtailment this month. When comparing to last month, wind curtailment dropped by 30% from January 2026. The network in February was generally slightly more constrained, however the very high wind outturn in January, with a hypothetical outturn 1.3TWh higher than February, resulted in a greater overall need for curtailment.

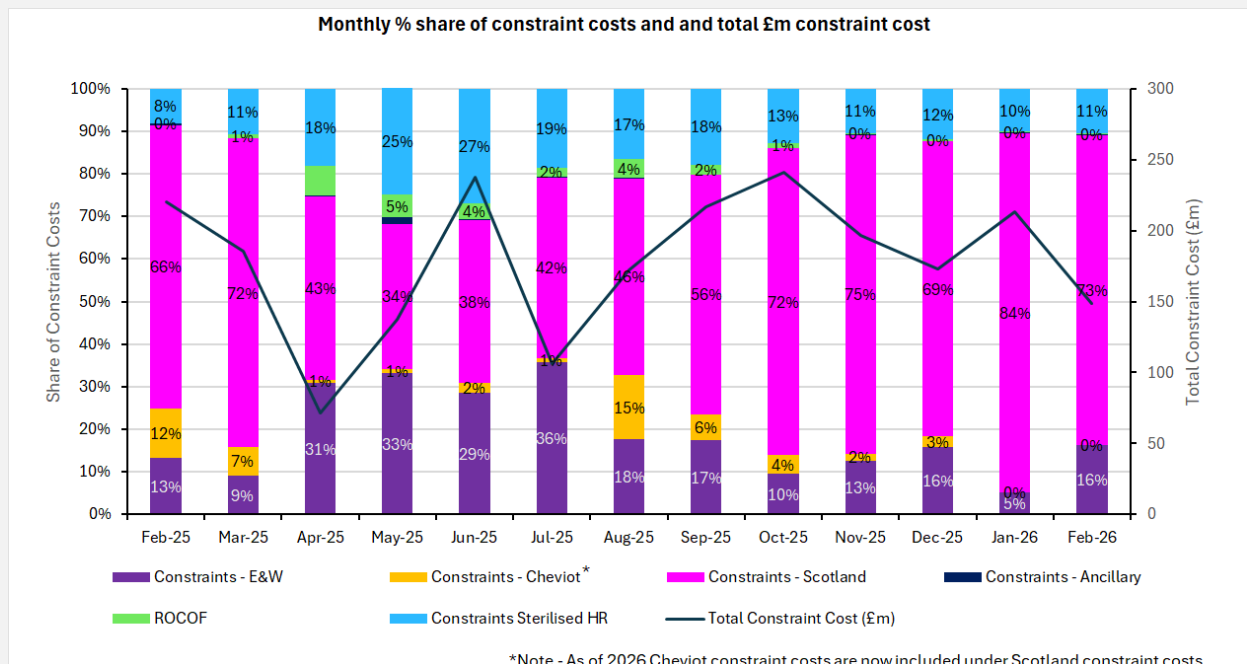


The day with the highest volume of wind curtailment occurred on Thursday 5th February (88.75 GWh). Thursday 5th February also had the highest total wind outturn this month at 475 GWh and, as a result, was the highest costing day of the month.

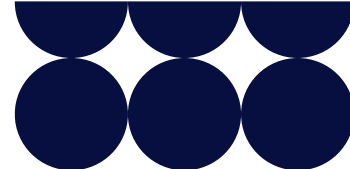


## Constraints

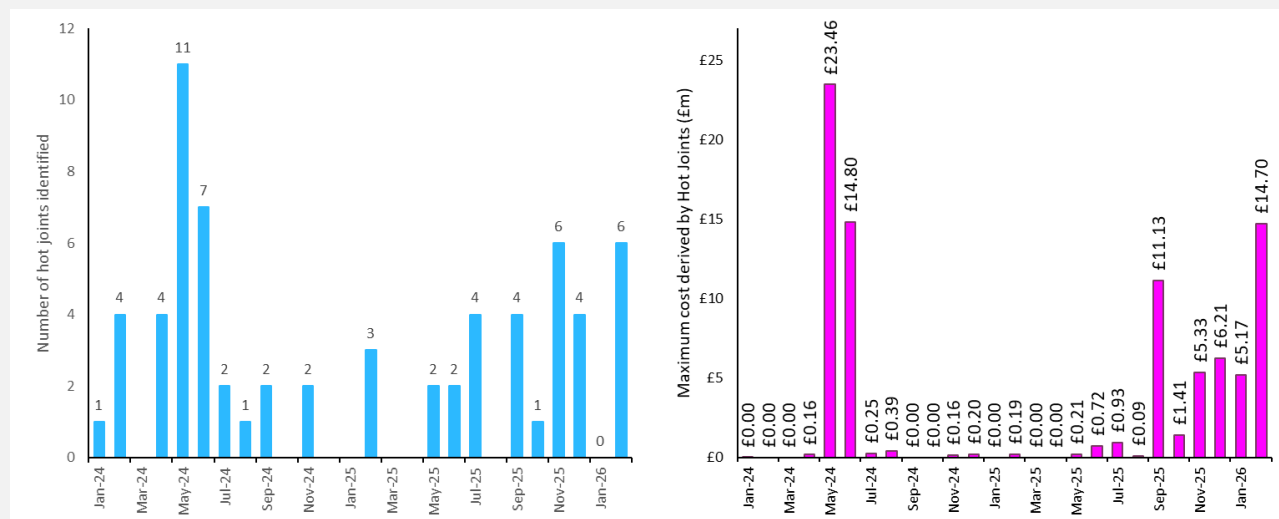
Constraint costs decreased from £213.5m in January to £148.7m in February, a decrease of £64.8m. While 84% of constraint costs had been in Scotland last month, this was reduced to 73% this month, due to an increase in England & Wales constraint costs of +£13.5m since last month. The increase in the England & Wales constraint costs in February was predominantly due to a heightened requirement to manage voltage constraint costs, particularly in the southwest. Constraint costs in Scotland decreased by £72.4m from last month, reflecting the lower wind outturn and curtailment, as well as lower power prices. Note that, as of 2026, Cheviot is no longer included as a constraint group and these costs are now included under 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 February, six hot joints were identified, three of which were resolved in the following days. The remaining three are still under assessment and awaiting resolution. The estimated maximum cost to the system for these hot joints was approximately £14.7 million during the current month.



### BALANCING COSTS DETAILED BREAKDOWN

**Balancing Costs variance (£m): February 2026 vs January 2026**

	(a) Jan-26	(b) Feb-26	(b) - (a) Variance	decrease ◀ increase Variance chart
<b>Non-Constraint Costs</b>				
Energy Imbalance	-0.2	-6.3	(6.1)	█
Operating Reserve	5.4	3.5	(2.0)	█
STOR	6.7	3.3	(3.4)	█
Negative Reserve	2.5	0.5	(2.0)	█
Fast Reserve	20.5	15.1	(5.4)	█
Response	19.3	15.2	(4.1)	█
Other Reserve	1.0	0.7	(0.3)	█
Reactive	11.2	13.3	2.1	█
Restoration	4.6	8.1	3.5	█
Winter Contingency	0.0	0.0	0.0	█
Minor Components	8.3	0.5	(7.9)	█
<b>Constraint Costs</b>				
Constraints - E&W	10.9	24.3	13.5	█
Constraints - Scotland*	180.4	108.0	(72.4)	█
Constraints - Ancillary	0.2	0.4	0.2	█
ROCOF	0.5	0.4	(0.1)	█
Constraints Sterilised HR	21.6	15.7	(5.9)	█
<b>Totals</b>				
Non-Constraint Costs - TOTAL	79.4	53.8	(25.5)	█
Constraint Costs - TOTAL	213.5	148.7	(64.8)	█
<b>Total Balancing Costs</b>	<b>292.9</b>	<b>202.6</b>	<b>(90.4)</b>	█

\*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 decreased by £64.8m and non-constraint costs decreased by £25.5m, which results in an overall decrease in costs of £90.4m



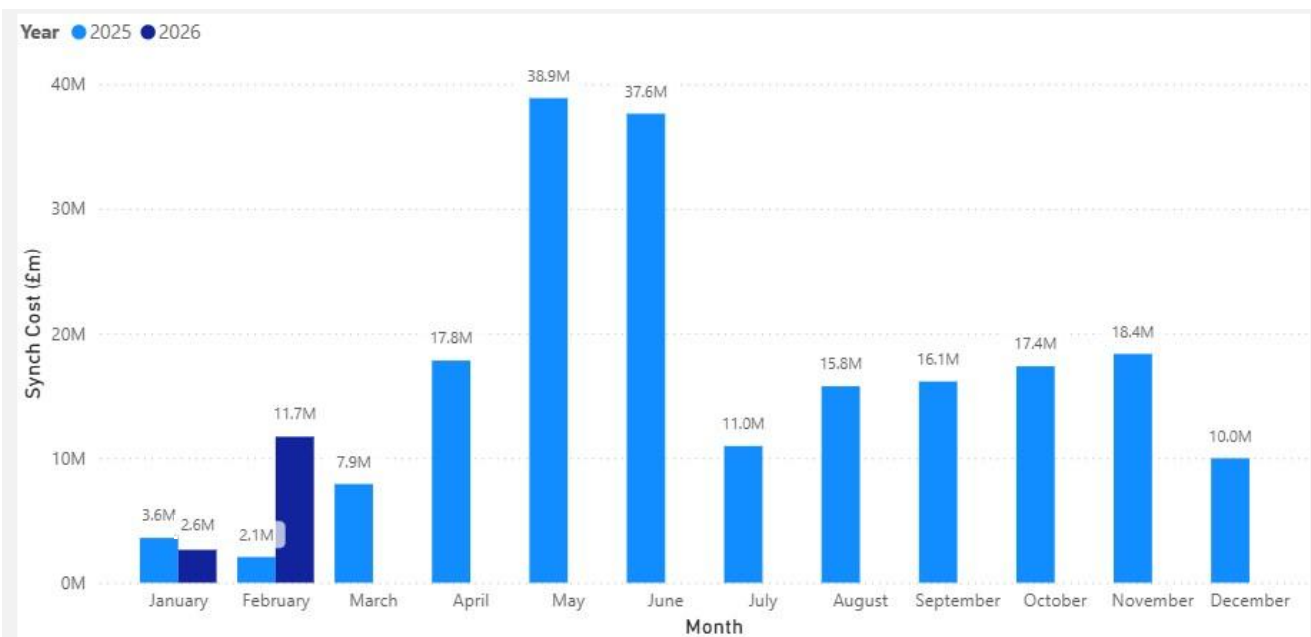
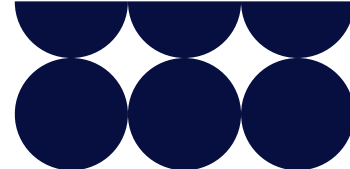
compared to January 2026. Note that February was 3 days shorter than January, which will naturally lead to some decrease in the overall cost of the month.

### Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
<p><b>Constraint-Scotland: -£72.4m</b></p> <p><b>Constraint – England &amp; Wales: +£13.5m</b></p> <p><b>Constraint Sterilised Headroom: -£5.9m</b></p> <p>Overall constraint costs decreased by £64.8m. This was largely due to a 1 TWh decrease in wind outturn reducing the amount of wind curtailment required, particularly in Scotland, where constraint costs decreased by 40%. An increase in England &amp; Wales constraint costs was driven by voltage requirements.</p> <p><b>ROCOF: -£0.1m</b></p> <p>A slight decrease in inertia spending this month was due to a lower volume of actions taken for inertia in February compared to January. The synchronous requirement for inertia was better met due to the higher volume of voltage actions taken in February.</p>	<p><b>Constraints – Scotland &amp; Cheviot: -£64.1m</b></p> <p><b>Constraints – England &amp; Wales: -£4.8m</b></p> <p><b>Constraints Sterilised Headroom: -£2.4m</b></p> <p>Constraint costs across GB have decreased by £71.5m compared to February 2025. Constraint costs in Scotland fell due to a less constrained system meeting the elevated wind levels. Constraint costs also fell in England and Wales as there was less of a requirement to manage thermal constraints in the north of England.</p> <p><b>ROCOF: +£0.2m</b></p> <p>Despite a decrease in the volume of BM actions taken for inertia this year, the cost increased. System inertia requirements are often met by running synchronous gas generators, so costs are generally driven by Offer prices of gas plants.</p>

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

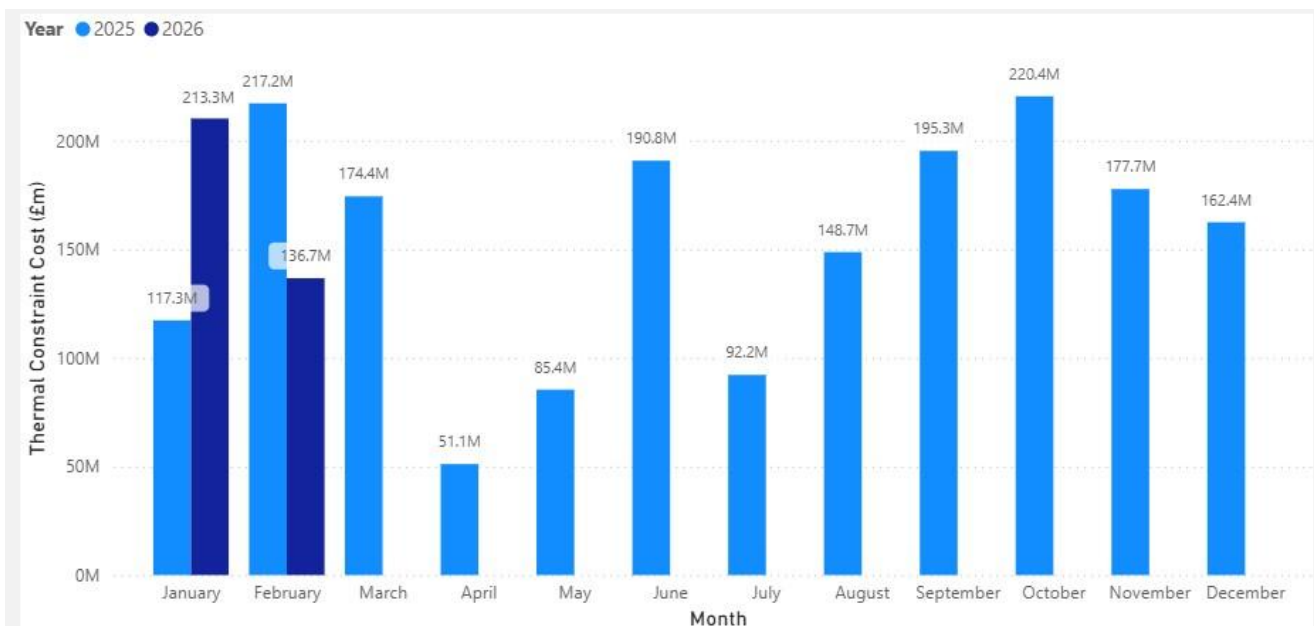
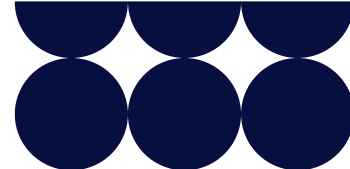
Synchronisation costs are associated with specific actions required to support voltage in the system. These actions involve units that are instructed to provide MVAr and maintain voltages within SQSS limits. It is a highly location-dependent issue, so only a limited set of assets are effective in voltage support. In February, the system synchronisation costs (what it costs to the system, which factors in energy replacement and headroom among others) were £11.7m. This represents a notable increase of £9.1m compared to January 2026 and is also £9.6m higher than the same period last year (February 2025).



Voltage spending is usually higher overnight: lower demand (as was the case in February compared to January) 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 2024 and 2025:**

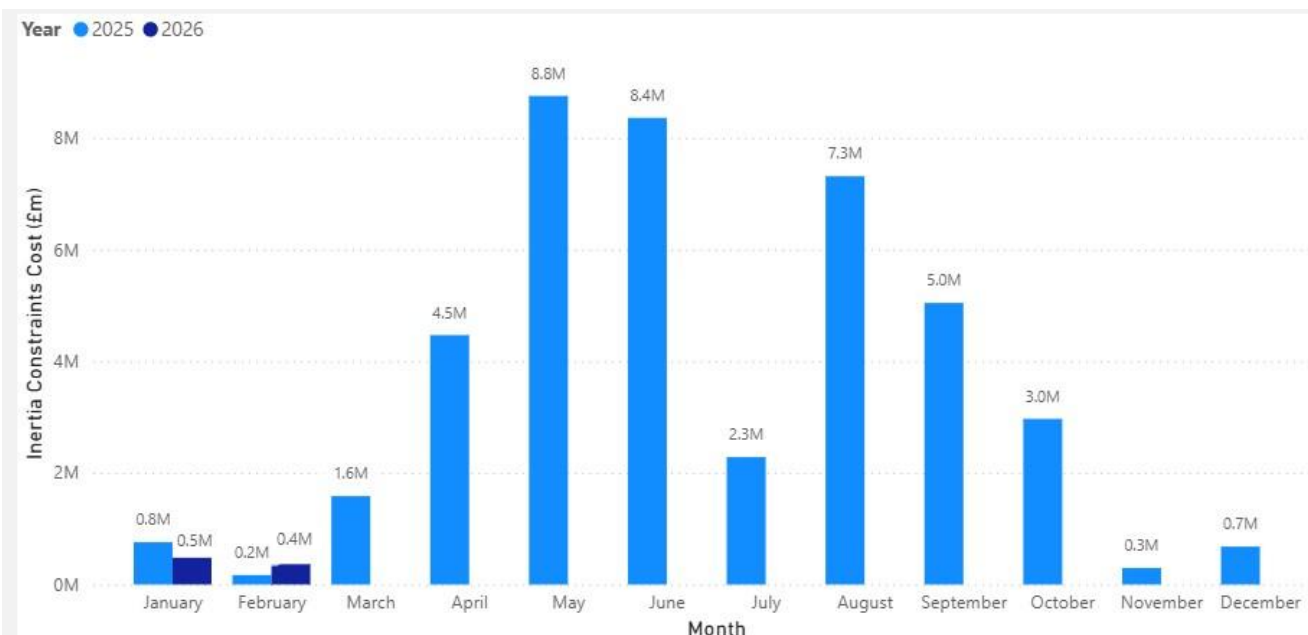
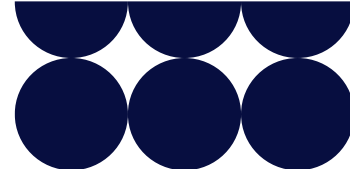
Thermal constraints are linked to operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, often referred to as the B4, B5, and B6 boundaries. The expenditure on thermal constraints is highly correlated with levels of curtailment in Scotland, as well as planned or forced outages in transmission assets that limit the grid’s transfer capacity. Thermal constraints constitute the vast majority of the system constraints, accounting for a significant percentage of system actions. In February, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £136.7m, reflecting a decrease in costs of £76.6m (36%) compared to the previous month (£213.3m). When compared to the same period last year (£217.2m in February 2025), the cost this year dropped by £80.5m (37%).



The decrease in February 2026 compared to January 2026 was due to 30% less wind curtailment, with January having had a very high wind outturn. Lower power prices also meant that the cost of replacement energy in managing thermal constraints was also less. Wind curtailment was also lower in February 2026 compared to February 2025 by 25% which drove the lower thermal constraint costs this year. The total wind outturn in February this year (7.6TWh) had been higher than February last year (6.4TWh), however there were some high wind days that coincided with a more constrained network in the north of Scotland last year, which had driven up the requirement for curtailment. Power prices were also lower by £27/MWh this year which again made the cost of replacement energy lower, further contributing to the lower thermal constraint costs.

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

Inertia refers to the resistance of the system to changes in its rotational speed. Inertia is primarily provided by the rotating mass of large synchronous generators, mainly CCGTs, but also includes hydro, pumped storage, biomass, and Combined Heat and Power (CHPs), among others. The costs associated with inertia tend to be marginal in the system compared to thermal or voltage constraints. In February, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £0.4m, which was a decrease of £0.1m compared to January 2025 but £0.2m higher than February 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
<b>+£2.1m</b>	<b>+£2.1m</b>
Reactive costs have increased slightly on last month, which is in line with the higher spending on voltage in the Balancing Mechanism. With lower demand than last month, this leads to less synchronous units self-despatching.	Reactive costs in January 2026 were very similar to February 2025, hence the same increase seen in February 2026. There was a greater requirement for voltage management actions than last year.

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.

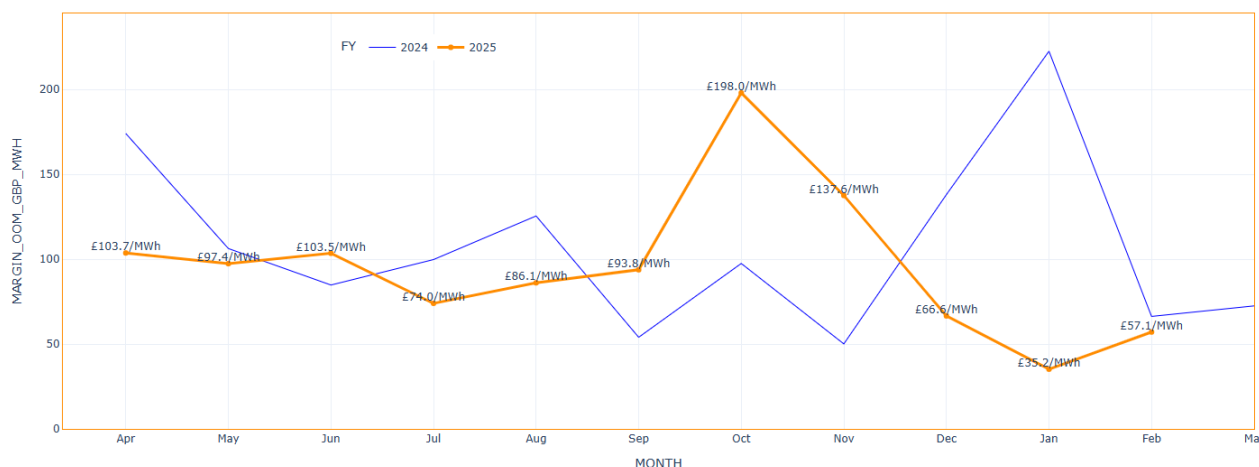
### Reserve Costs/Volumes

Reserve prices increased to £57.1/MWh in February from £35.2/MWh in January, representing a 62% increase. Prices had significantly dropped in January and the February price still presented lower than the rest of the financial year prior to January. The reserve price in February 2026 (£57.1/MWh) was not significantly different from February 2025 (£66.3/MWh) and overall prices this winter have shown less volatility than winter in the previous financial year. Monthly margin prices increased to £58/MWh in February 2026 from £35.2/MWh in January 2026 but sit at a similar level to where they were in February last year (£66.3/MWh).



### Monthly Margin prices per MWh

MARGIN\_OOM\_GBP\_MWH



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
<p><b>Operating Reserve: -£2.0m</b></p> <p><b>Fast Reserve: -£5.4m</b></p> <p>There was 24GWh decrease in the absolute volume of operating reserve procured this month, giving rise to the lower spend.</p> <p>Spending on fast reserve decreased by over £5m, which was driven by a 12GWh decrease in the absolute volume procured.</p>	<p><b>Operating Reserve: -£1.1m</b></p> <p><b>Fast Reserve: -£3.1m</b></p> <p>The absolute volume of operating reserve procured decreased by 4.5GWh which led to a lower spend this year.</p> <p>The absolute volume of fast reserve procured also decreased by 4.5GWh compared to last year but was reflected by a larger drop in costs of -£3m.</p>

We are currently in the process of quantifying the benefits associated with Balancing Reserve, and the results will be shared in the coming months. The Optional Fast Reserve service (OFR) is currently being phased out and replaced by Quick Reserve, OFR will cease operation on 17th April.

### 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
<b>-£4.1m</b>	<b>-£5.4m</b>



A decrease in absolute volume by 7.2GWh alongside lower average clearing prices for DC, DM, DR services led to a drop in costs since January.

A decrease in absolute volume by 48.7GWh led to a drop in costs since February last year.

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

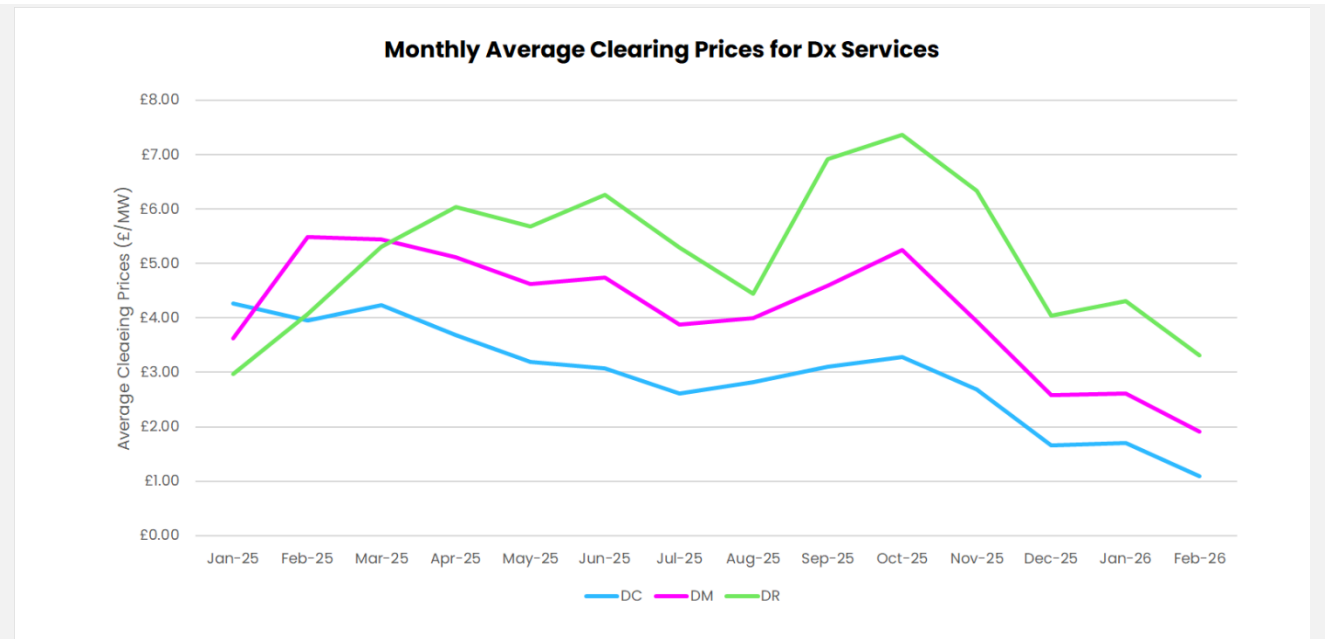
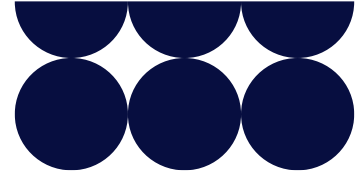
		(a)	(b)	(b) - (a)	decrease ◀ ▶ increase
		Feb-26	Jan-26	Variance	Variance chart
<b>Dynamic Services</b>	DC	1.1	1.7	(0.6)	
	DM	1.9	2.6	(0.7)	
	DR	3.3	4.3	(1.0)	

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

		(a)	(b)	(b) - (a)	decrease ◀ ▶ increase
		Feb-26	Feb-25	Variance	Variance chart
<b>Dynamic Services</b>	DC	1.1	4.0	(2.9)	
	DM	1.9	5.5	(3.6)	
	DR	3.3	4.1	(0.8)	

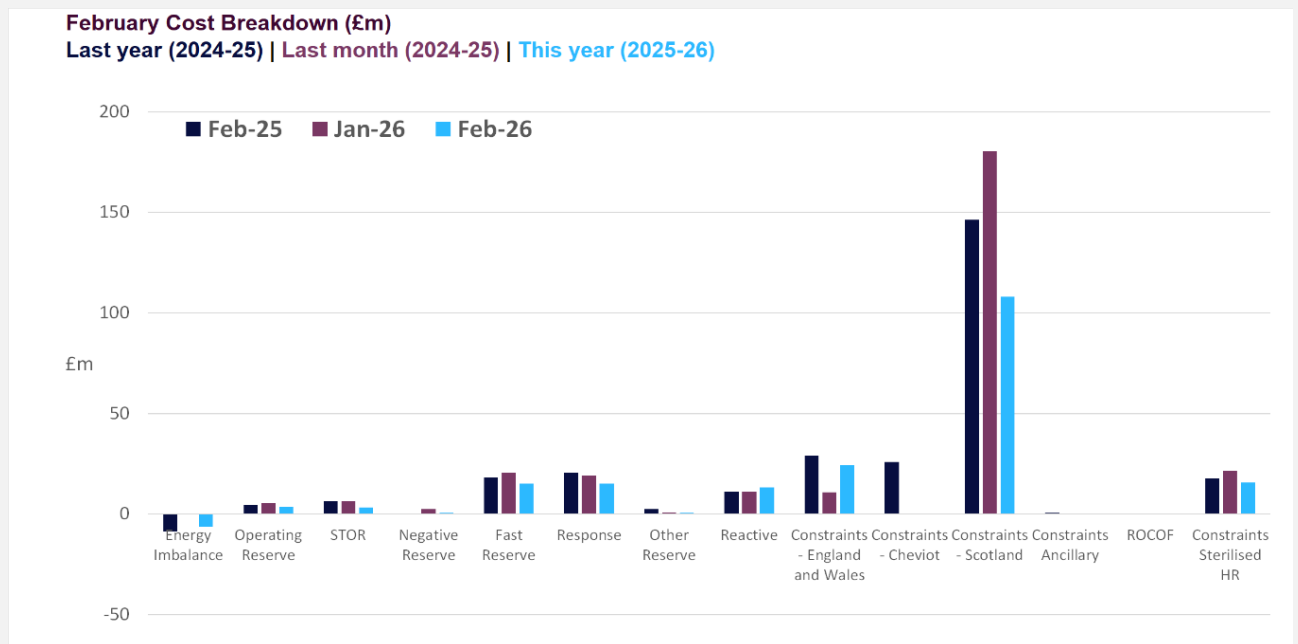
Average clearing prices for Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR) noticeably decreased from January. This marks a return to a continued downward trend for the price of all three services since October, following their slight plateau between December and January, which had been driven by January's high wind outturn impacting system conditions.

Average clearing prices for Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR) have also all decreased since February last year, particularly for DC and DM. There had been increased procurement requirements for the Dynamic Regulation (DR) service since February 2025 driving year-on-year price increases in previously reported months. However, following a complete year since the increased requirement, the year-on-year price has now dropped in February 2026 by £0.8/MW. Dynamic Moderation and Dynamic Containment average clearing prices have also decreased from last year, driven by a drop in the wholesale power price. Daily volumes of DC procured has generally decreased since last year, while daily volumes of DM have increased.



### 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**

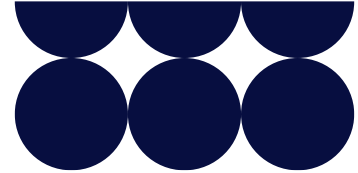
Total savings from outage optimisation amounted to approximately £101m in February 2026. This is an increase of roughly £25m relative to January 2026 (£76m). The most valuable action involved rescheduling some concurrent maintenance works at Neilston, which would have significantly affected the operation of the Western Link due to low short-circuit fault levels. The cost saving for this action is estimated in £20.2 million.

### **Cost Savings – Trading**

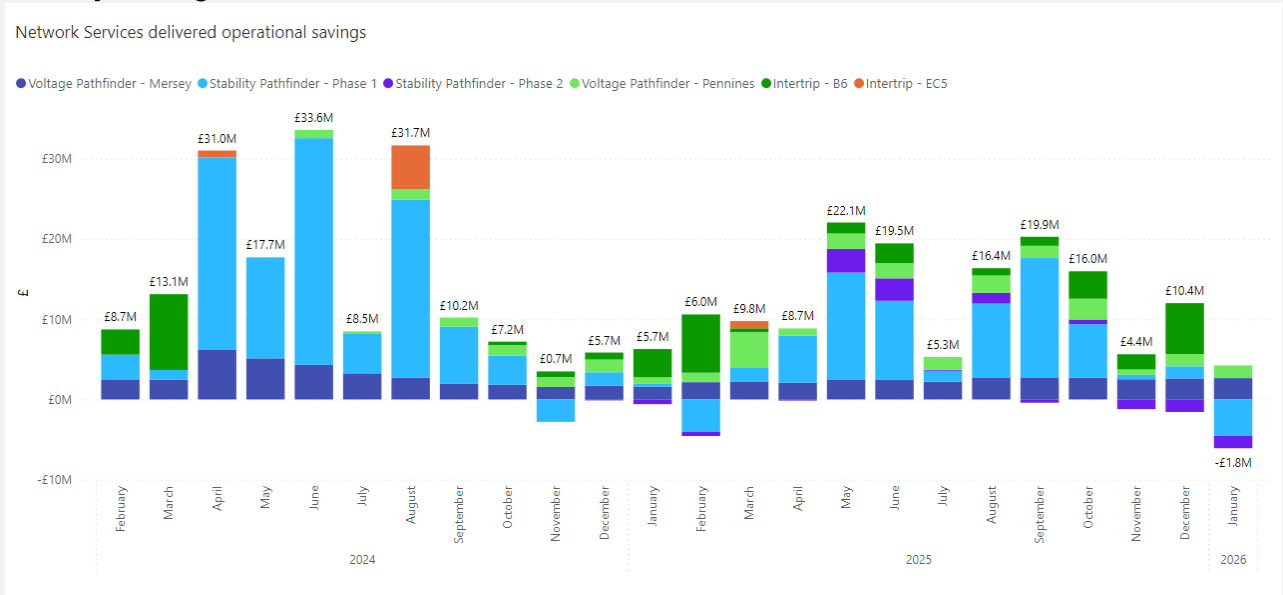
The Trading team were able to make a total saving of £8.2m in February through trading actions as opposed to alternative Balancing Mechanism (BM) actions, representing a 46% decrease on the previous month. This decrease has largely been derived from reduced overall margin trade requirements; due to a combination of cheaper alternatives available in the BM as well as experiencing less frequent tight system conditions in February. Despite lower overall savings, February saw greater savings made against thermal constraints than January, largely due to windy conditions tightening export constraints and interconnectors also fully importing, exacerbating the situation and the need to trade to reduce the flows. Voltage trade savings in February were also five times higher than the previous month due to trade prices being competitive compared to BM prices. The day with the greatest trading savings was on 19 February at a cost of £2.2m with the greatest component being for margin. On this day, there were several transmission constraints and limited BM units which could be taken, increasing the margin requirement and making Trading an economic alternative. The day with the greatest spend on trades was also the 19 February at a cost of £1.1m, with the greatest component again being for margin.

### **Cost Savings – Network Services (NS)**

We are using Network Services (NS) to implement solutions to operability challenges in the electricity system. This includes the Constraint Management Intertrip Service, and Voltage & Stability pathfinders. We have calculated that the B6 and EC5 Constraint Management Intertrip Services, Voltage Mersey, Voltage Pennines, and Stability Phase 1&2 have delivered approximately £120.7 m in savings across 2025/26 to date (April – January 2026).

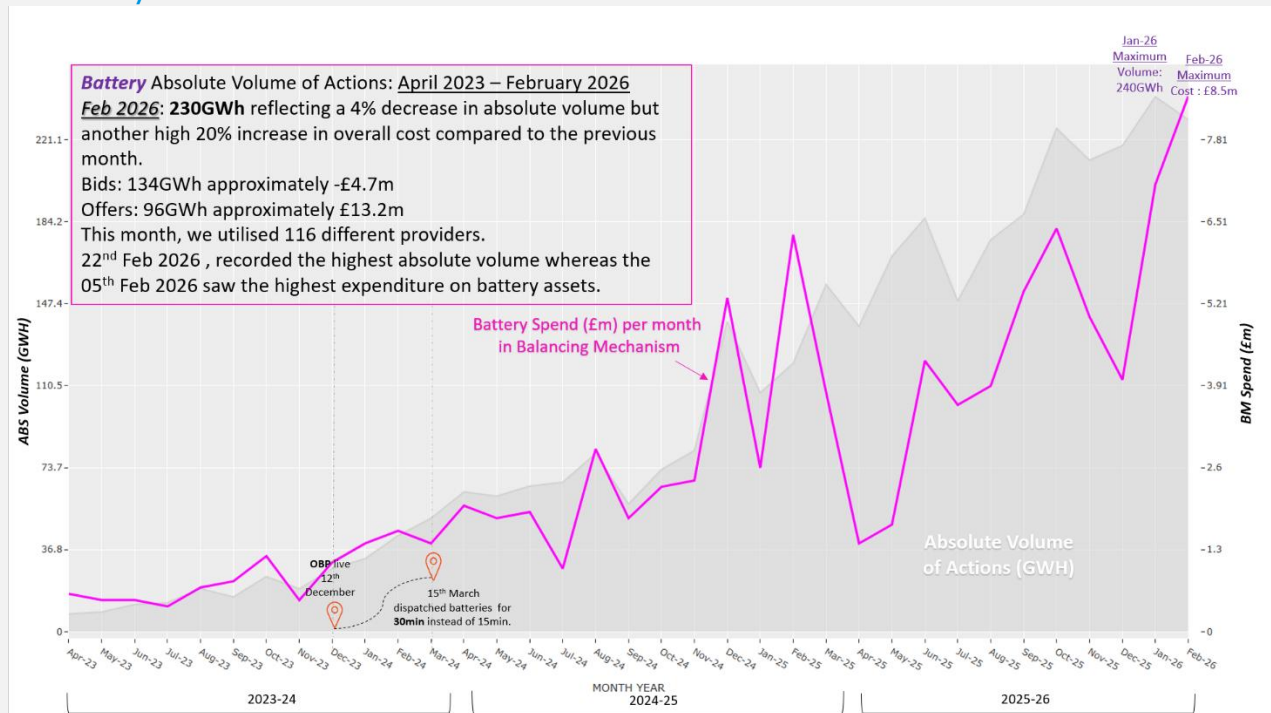


### Monthly Savings from Network Services (NS)



### NOTABLE EVENTS

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



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



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

Relative to the previous month, February 2026 saw continued growth in cost, while the absolute volume experienced a slight correction, indicating a positive trend in overall growth.

Since April 2025, the absolute volume of battery dispatch has nearly tripled compared to the same period last year and has increased more than fifteenfold since April 2023. This growth underscores our dedication to enhancing the flexibility of energy provision through battery storage and small Balancing Mechanism Units (BMUs).

## DAILY CASE STUDIES

### Daily Costs Trends

February's balancing costs were £203m which is £90m lower than the previous month, keeping in mind that February was a shorter month. There was only one day in February with a total cost above £15m (5 February), and a further 4 days with a cost over £10m (3rd, 6th, 19th, 22nd). This is far fewer high costing days than in January and led to the daily average cost decreasing from £9.4m to £7.3m between January and February.

The highest cost day was Thursday 5 February, with a total cost of approximately £16m. It is of note that since May 2025 all the monthly highest costing days have been above £20m, so February 2026 represents a significant reduction in daily cost volatility. The higher costs on 5 February compared to the rest of the month were driven by the highest wind outturn during the month, as well as the highest level of wind curtailment. The day also had the largest output of embedded wind generation. Due to wet weather, with a yellow weather warning for rain and sleet in Scotland, there was a low solar output. 5 February had the second-lowest embedded solar output in the month, which was ten times lower than the highest output day. Less embedded solar generation puts a higher demand on the transmission system, which in the case of February 5, helped to mitigate the requirement for curtailment and potentially higher costs, as has been seen in previous months.

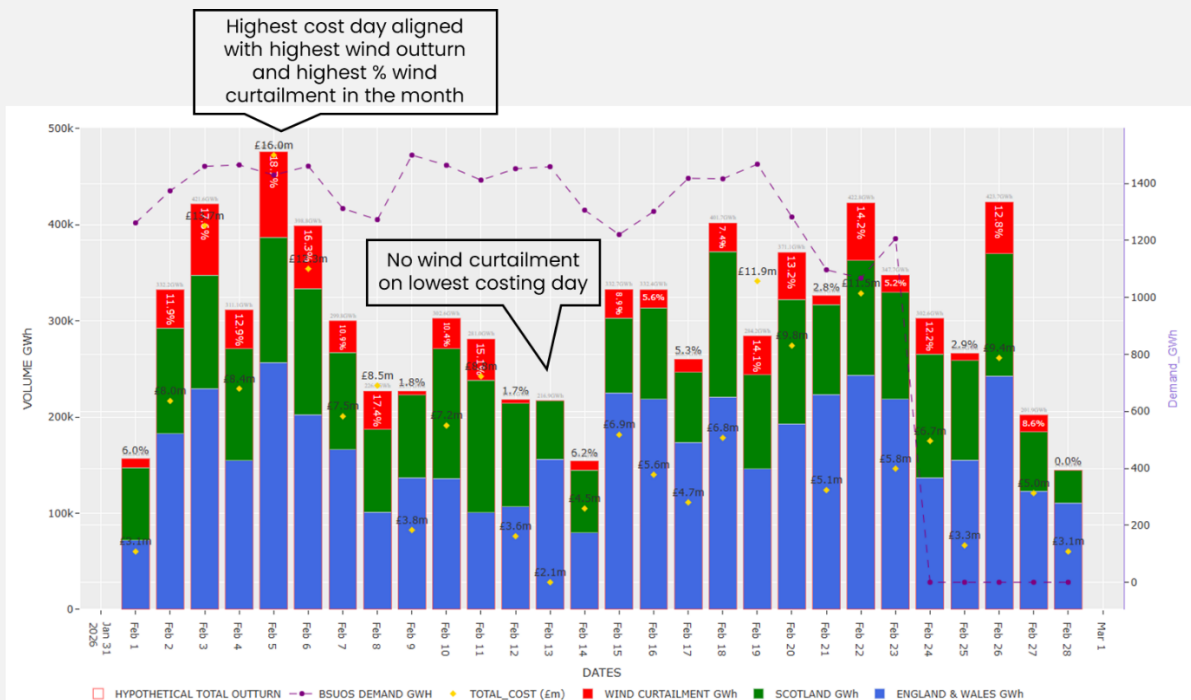
The lowest cost day was Friday 13 February with a total cost of approximately £2m. There were a few days with lower wind outturn than this date, however Friday 13th experienced no wind curtailment. There were some one-day outages taken and one unplanned outage for a hot joint, but these were manageable with minimal constraint.



## February Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUOs Demand

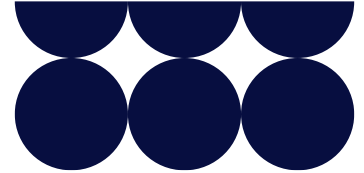
The chart below serves the purpose of supporting the transparency and the descriptions above. It is the daily "tour" of wind performance. With this graph we can trace, for example, how wind performance and low demand affect the cost of each day.

- 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



BSUoS Demand is the absolute volume (MWh) for each active BMU including transmission losses. It is the demand that has been resolved by BM and trades. Not available for 24<sup>th</sup>-28<sup>th</sup> at time of report production.

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).

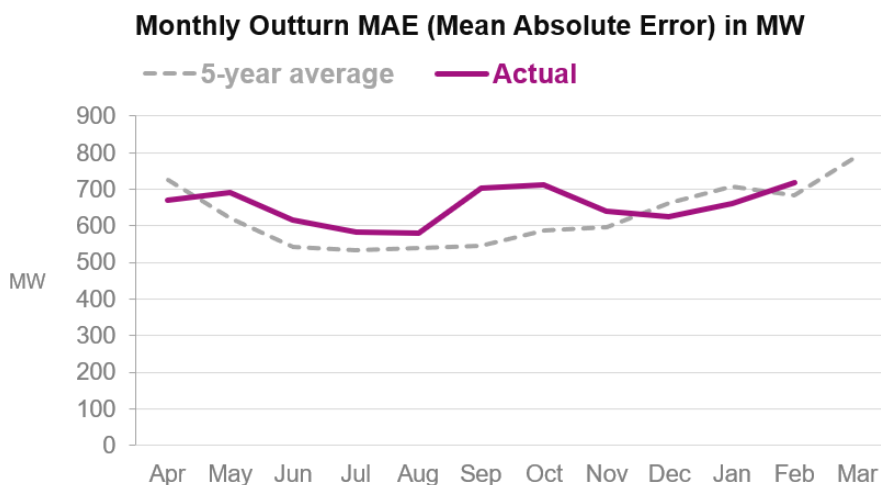
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS<sup>2</sup>) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn)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

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

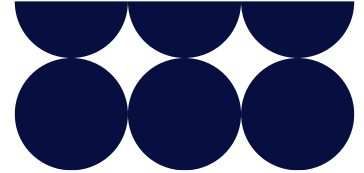
In order to provide transparency of our performance, we compare each month's actuals to the previous year, and to the average of the previous 5 years' actuals for the same month.

### February 2025-26 performance

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



<sup>2</sup>Demand | BMRS ([bmreports.com](http://bmreports.com))



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

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

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

### Supporting information

In February 2026 forecasting error averaged 717MW, against the previous 5-year average of 684MW. YTD performance is currently 654MW, vs 5-year average of 613MW.

February was an exceptionally wet month, with prolonged rainfall across England, Wales and parts of Scotland. Frequent snowfall found in Northern England, Scotland and Wales. Temperatures warmed towards the second half of the month with England exceeding 18 degrees. While temperatures were higher, prolonged cloud cover meant this was one of the dullest Februarys ever recorded.

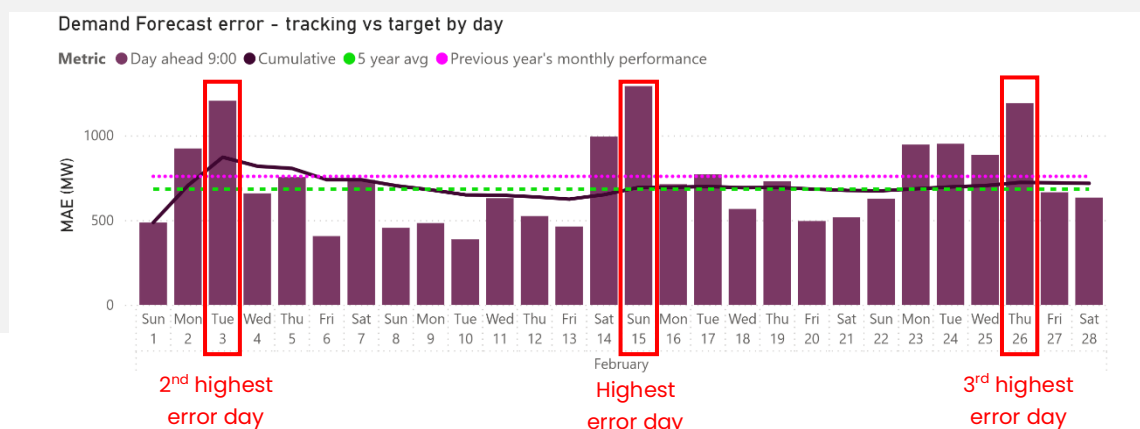
The largest absolute demand error this month was 4.8GW on 15 February, SP25.

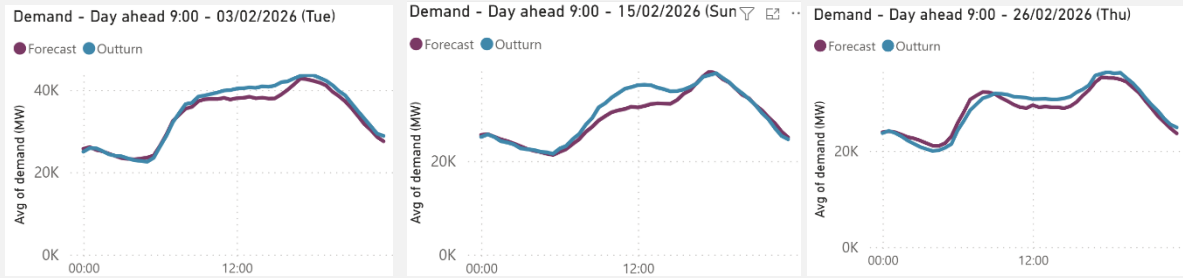
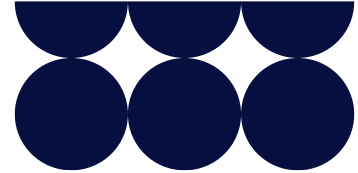
The minimum demand was 19.7GW on 23 February, SP9. The maximum demand was 43.6GW on 3 February, SP37. Solar generation peaked at 10.4GW on 14 February.

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

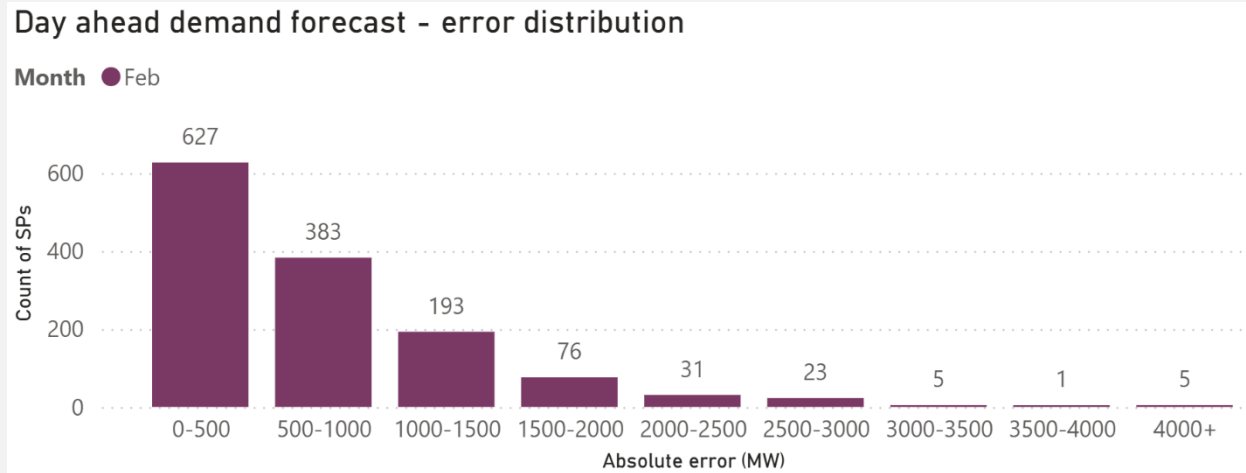
Work continues on our solar forecast upgrades. These will make use of blended-weather (solar irradiance) and blended-forecasts (MW) and we aim to release to production in Q2 2026.

#### Days of Interest:

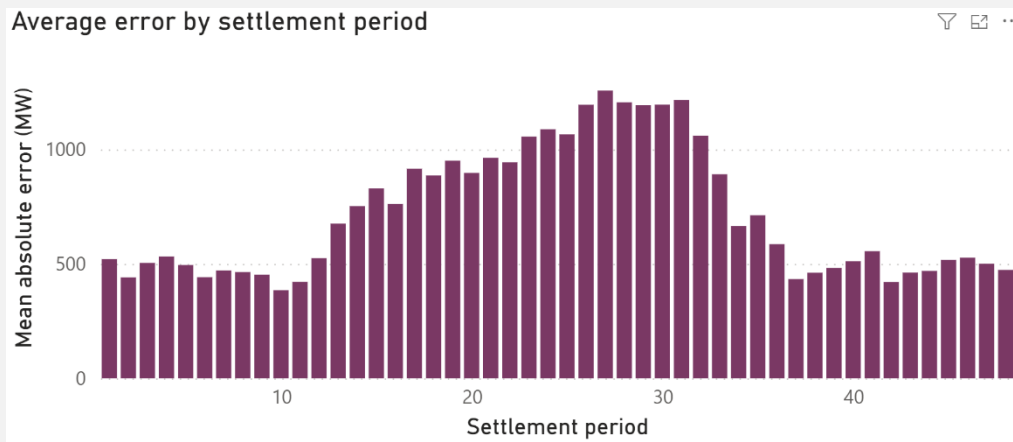




The distribution of settlement periods by error size is shown below:

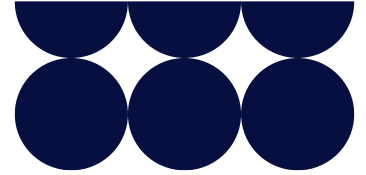


The distribution of average error by settlement period is shown below:



The days with largest MAE were 3, 15, and 26 February.

Day	Error (MAE)	Major causal factors
3	1205	Forecast errors due to solar forecast error in the middle of the day (over-forecast), weather forecast error as well as human behaviour.
15	1291	Forecast errors likely due to solar forecast error in the middle of the day (over-forecast), as well as changes in human behaviour with the beginning of half-term.



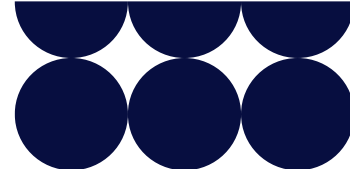
26	1191	Forecast errors likely due to solar forecast error in the middle of the day (over-forecast), as well as changes in human behaviour.
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**Missed / late publications**

There were no late or missed publications in February.

**Demand Flexibility Service**

Demand Flexibility Service (DFS) was used on 4, 14, and 19 February, with an accumulated total of 241MWh procured. These will nominally affect the national demand outturns but are not included in the day ahead forecast.



## 3. Wind Generation Forecasting

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### 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).**

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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:

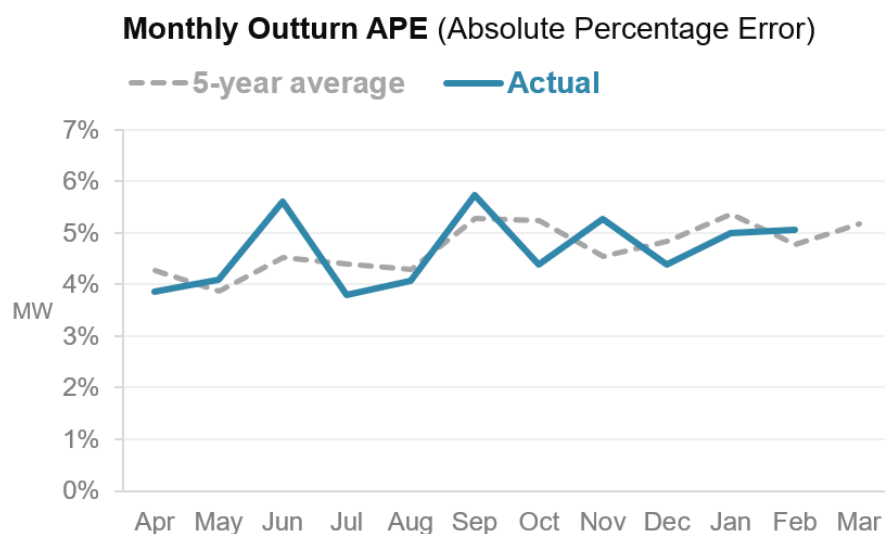
- re-declare maximum export limit (MEL) from a positive value day-ahead to zero at real-time; or
- re-declare their physical notification (PN) from a positive value day-ahead to zero at gate closure of the Balancing Mechanism.

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.



## February 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).

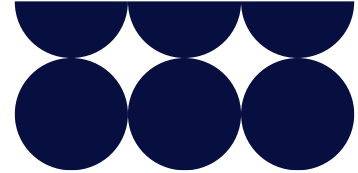
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Previous 5-year average (%)	4.26	3.87	4.53	4.39	4.30	5.27	5.23	4.55	4.84	5.36	4.78	5.18
Previous year outturn (%)	4.64	3.60	4.72	4.24	4.15	5.04	4.70	3.63	3.86	4.40	3.97	5.20
<b>APE (%)</b>	<b>3.85</b>	<b>4.09</b>	<b>5.61</b>	<b>3.80</b>	<b>4.06</b>	<b>5.74</b>	<b>4.38</b>	<b>5.27</b>	<b>4.43</b>	<b>4.96</b>	<b>5.05</b>	

\*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 February 2026, BMU wind forecasting error averaged 5.05%, against the 5-year average of 4.78%. YTD performance is currently 4.65%, vs 5-year average of 4.67%.

February 2026 was dominated by a stronger-than-usual Atlantic jet stream which repeatedly steered low-pressure systems towards the UK. This resulted in a persistently windy and unsettled regime, especially across western and coastal areas.



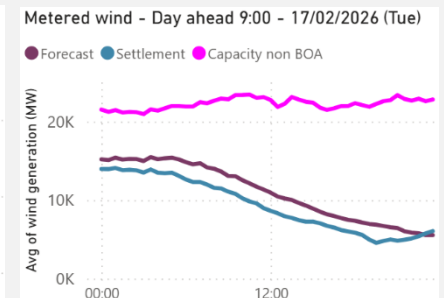
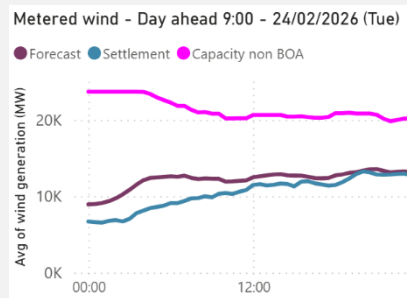
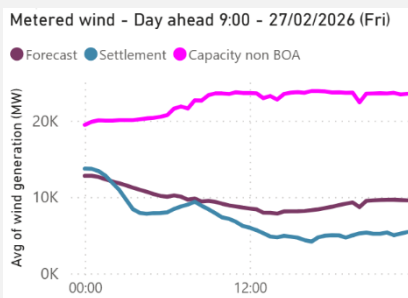
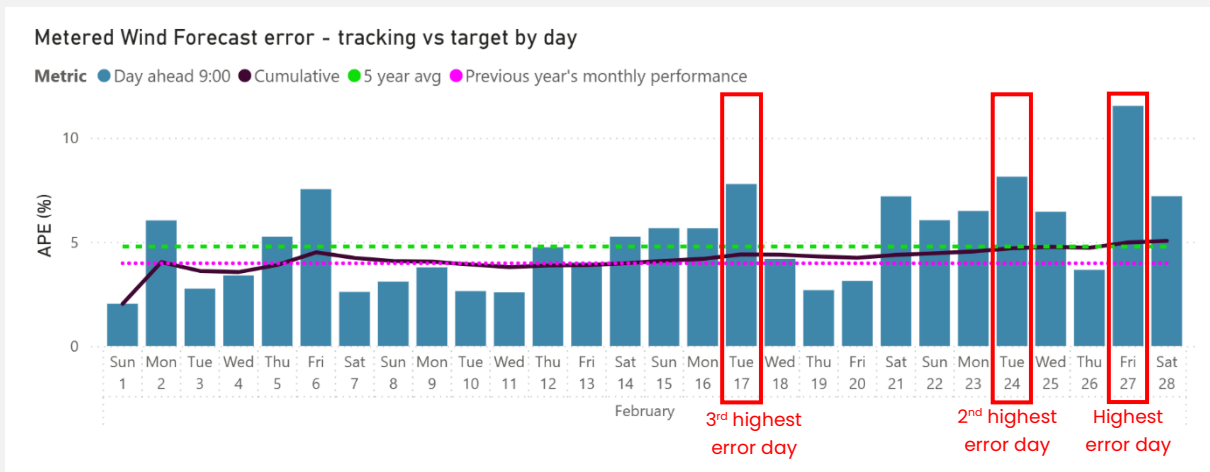
Issues were observed with settlement metering data for much of the month, which had a direct effect on the current recorded performance. We anticipate data corrections in future settlement runs.

Metric-adjusted wind generation peaked at 16.6GW on 2 February, SP36. Wind forecast absolute error peaked at 4.6GW on 27 February, SP46.

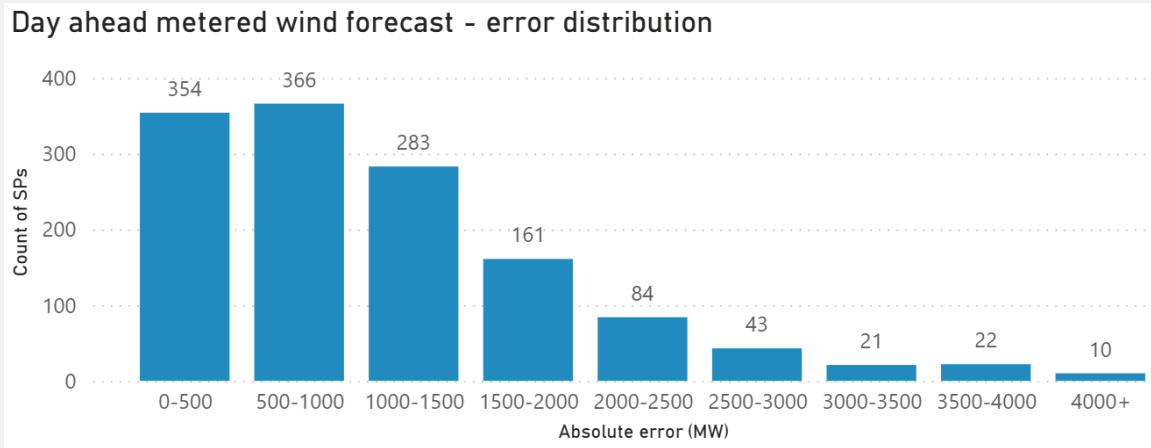
Work continues on our wind generation forecast upgrades and we have now released the blended-weather (windspeed) feature. Work continues on the wind-direction feature and we aim to release to production in Q1 2026. From Q2, we intend to focus on enhancing our within-day capability.

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:

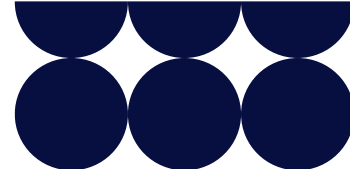


#### Details of largest error

Day	Error (APE)	Major causal factors
17	7.8	Wind speed forecast errors at day-ahead stage
24	8.1	Wind speed forecast errors at day-ahead stage
27	11.5	Wind speed forecast errors at day-ahead stage

#### Missed / late publications

There were no missed or late publications in February.



## 4. Skip Rates

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### **Performance Objective**

**Operating the Electricity System**

### **Related Success Measure**

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

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

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

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

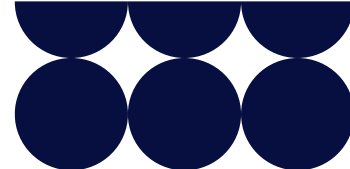
**Develop and share a methodology to measure the skip rate of actions taken to manage system constraints.**

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

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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.



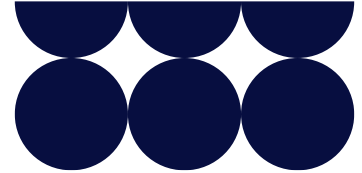
This Reported Metric measures the skip rate for bids and offers based on stage 5 of the Post System Action (PSA) methodology and will also include any updated methodology agreed with industry. More information on the skip rate definition and methodology can be found [here](#).

**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%	
Bids	43%	42%	47%	46%	39%	42%	40%	35%	37%	40%	33%	
<b>Combined</b>	<b>42%</b>	<b>39%</b>	<b>38%</b>	<b>42%</b>	<b>35%</b>	<b>36%</b>	<b>34%</b>	<b>34%</b>	<b>32%</b>	<b>31%</b>	<b>29%</b>	

**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	
Offers – in merit Energy volume	148	205	356	215	279	359	437	309	392	516	405	
Offers – All in merit volume (System & Energy)	504	901	1052	529	943	971	1084	878	838	827	732	
Bids – Skipped volume	141	148	111	127	122	102	93	108	103	80	68	
Bids – in merit Energy volume	336	352	234	277	316	243	234	310	280	200	203	
Bids – All in merit volume (System & Energy)	815	995	1576	962	1344	1488	1815	1597	1660	1921	1510	
Combined Bid & Offer – skipped volume	204	219	227	205	208	218	226	211	216	224	176	



## Supporting information

### FEBRUARY UPDATES

#### Skips Behind Constraints

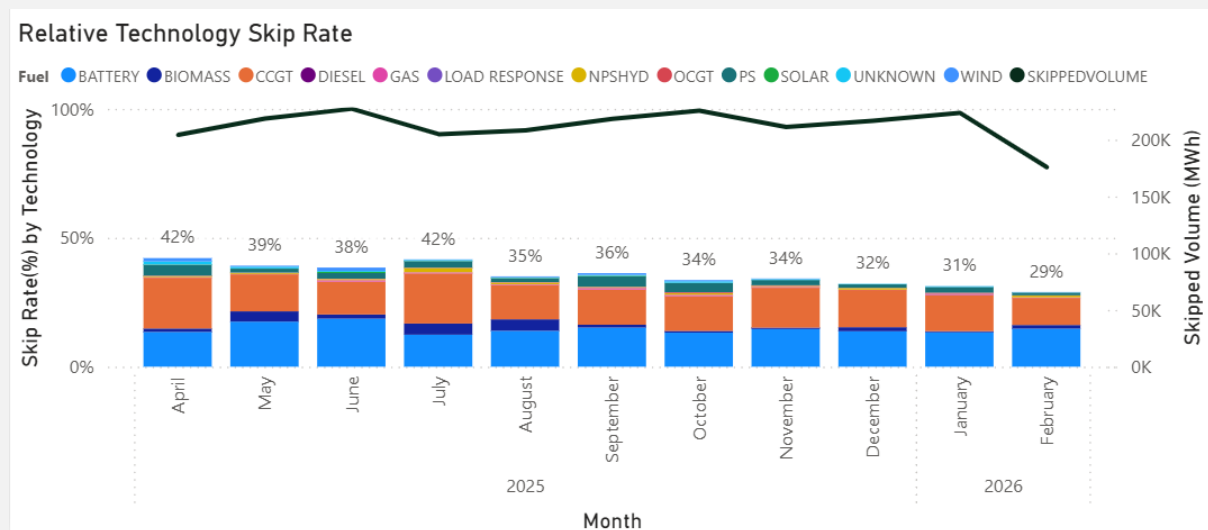
Following the Dispatch Transparency Forum on 28 January in London, we continued working to finalise a methodology for calculating skip rates behind active thermal constraints with an aim to provide transparency on dispatch decisions made for these units. We presented this methodology to industry on 6 March to provide an opportunity for final feedback. The webinar was well received by the industry and the overall sentiment was positive.

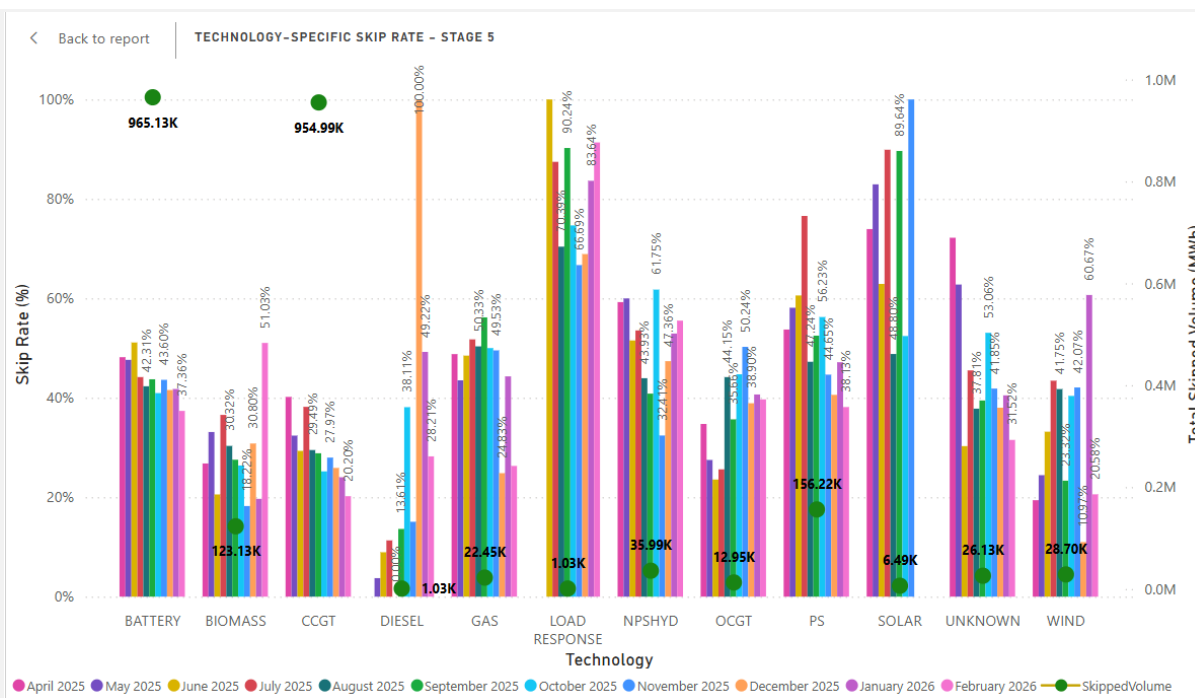
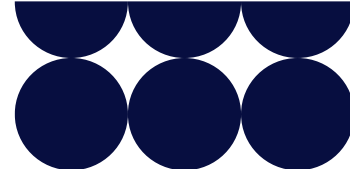
#### Skip Rate Reduction Target

Having carefully reviewed industry feedback, we can now confirm our decision to set an average skip rate target of 30% (Stage 5 PSA) from January 2026 to June 2026 inclusively. This is a short-term target, put in place ahead of the implementation of GC0166, when the current methodology for skip rates will be revisited to account for the impact of this Grid Code change. With regards to skip rate parity across technology types, whilst we won't be setting a target for each technology type, we recognise the importance of transparency in this area and remain committed to continue publishing this data and investigating outliers. We published an [open letter](#) on our website explaining this.

### FEBRUARY PERFORMANCE – COMBINED BIDS AND OFFERS

The combined bid and offer skip rate continued to trend downwards and reached its lowest value in February 2026 (29%). The average skip rate for January and February is 30%, which is on target.



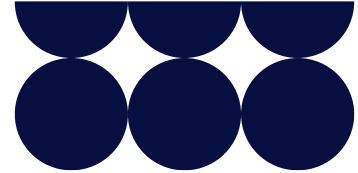


The combined technology specific skip rate has continued to trend down for most technology types since April 2025. This includes Batteries and CCGTs which account for most of the skipped volume. Some technology types see very high or low technology specific skip rates when they have small in merit volumes. The graph shows that Biomass and Load Response experienced the most significant increases in skip rates from January 2026 to February 2026, while Diesel, Wind and Gas saw the largest decreases. The increase for Biomass has been driven by a larger volume of in-merit Bid volume, compared to previous months, and a slower ramp rate for Bids (run-down rate export) than Offers (run-up rate export), meaning that these units were not able to deliver the volume in the required time. Biomass units were sent Bid instructions in some of the time periods with the highest skipped volume showing that these units were utilised where appropriate.

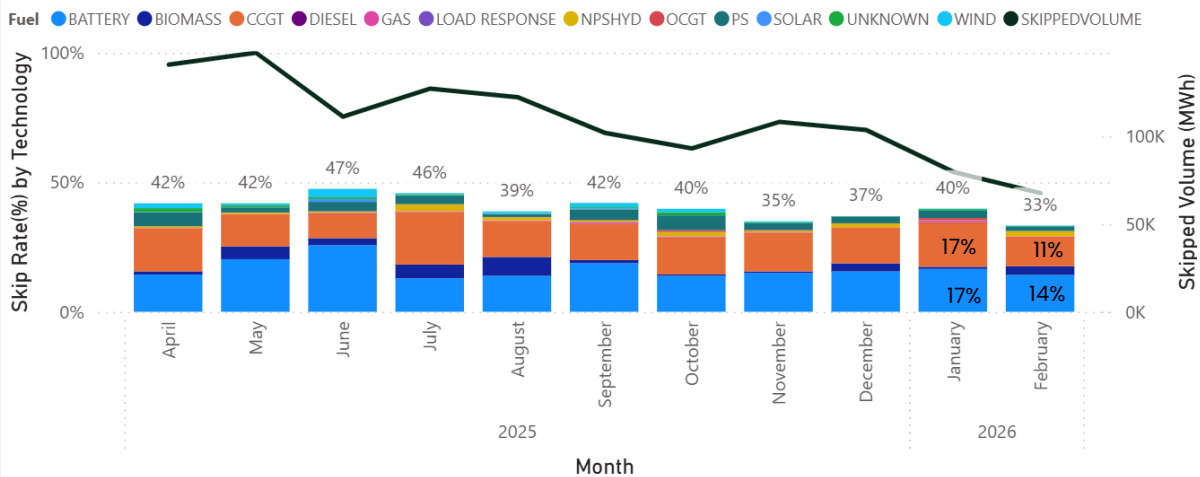
Note: In the technology specific skip rate graph 'Gas' refers to gas reciprocating units, which are typically small, aggregated units. 'Load Response' is based on the fuel type category used by Elexon. These are typically Demand Side Flexibility (DSF) units. We have published a dedicated dataset to report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

**Bids**

The Bid skip rate has decreased from January (40%) to February (33%), and the skipped volume has decreased from 80GWh to 68GWh. CCGTs accounted for a lower proportion of skipped volume in February (11%) compared to January (17%) and the Technology Specific skip rate for CCGTs has come down to 21% in February from 31% in January. Batteries account for a lower proportion of the skip rate in February (14%) compared to January (17%) and the Technology Specific skip rate has decreased from 47% to 43%. This has been driven by a greater percentage reduction in skipped volume (33GWh to 29GWh), compared to in-merit volume (70GWh to 67GWh).



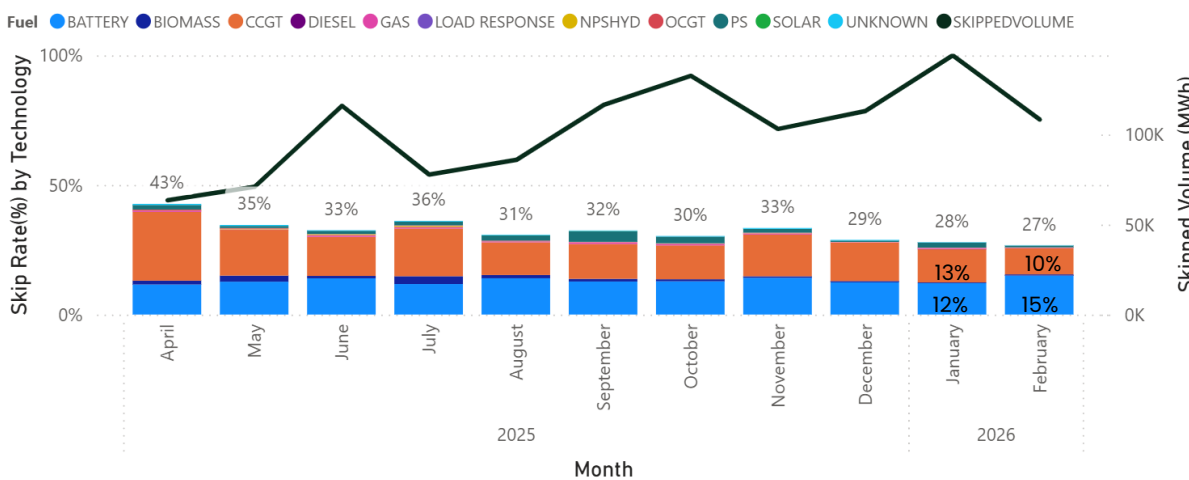
### Relative Technology Skip Rate

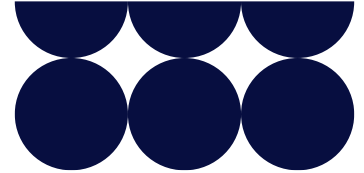


### Offers

The Offer skip rate decreased in February (27%) from January (28%). CCGTs account for a lower proportion of skipped volume in February (10%) than January (13%), and the Technology Specific skip rate has decreased from 21% in January to 20% in February. Batteries account for a higher proportion of skipped volume in February (15%) than January (12%), and the Technology Specific skip rate has decreased from 39% in January to 35% in February.

### Relative Technology Skip Rate





# 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).**

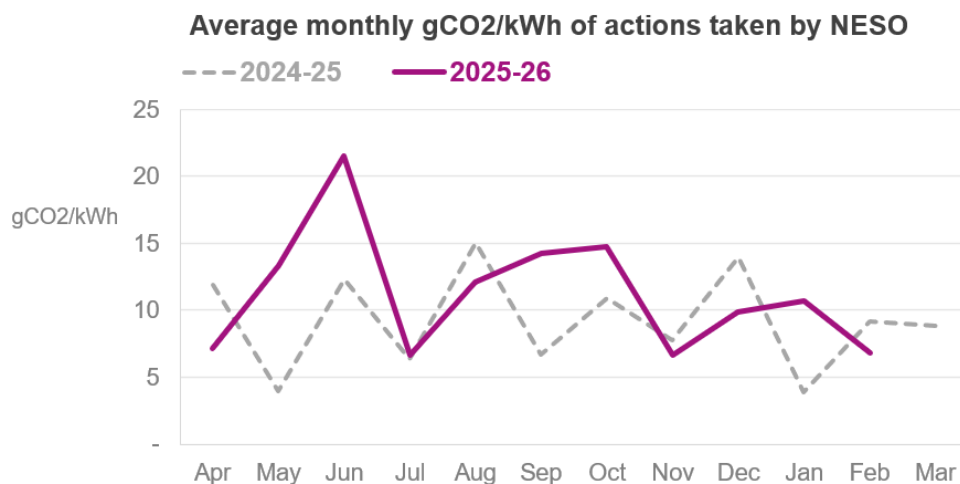
This Reported Metric measures the difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the Balancing Mechanism (BM) and the equivalent profile with balancing actions applied.

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO<sub>2</sub>/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](#).

### February 2025–26 performance

**Figure: 2025–26 Average monthly gCO<sub>2</sub>/kWh of actions taken by NESO (vs 2024–25)**



**Table: Average monthly gCO<sub>2</sub>/kWh of actions taken by NESO**

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
<b>Carbon intensity (gCO<sub>2</sub>/kWh)</b>	7.16	13.36	21.53	6.64	12.11	14.22	14.75	6.68	9.85	10.71	6.79	

### Supporting information

We report the average monthly gCO<sub>2</sub>/kWh of actions taken by NESO in line with reporting requirements. Alignment of the ZCO technologies with the CP30 technologies could see biomass and CHP units treated differently in this report, but no change has been made as yet.

In February the average monthly carbon intensity from NESO actions was 6.79g/CO<sub>2</sub>/kWh. This is 3.92g/CO<sub>2</sub>/kWh lower than January, and 4.46g/CO<sub>2</sub>/kWh lower than the YTD average of 11.25g/CO<sub>2</sub>/kWh.

The maximum difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the BM and the equivalent profile with balancing actions applied was 55.07g/CO<sub>2</sub>/kWh which took place on 6 February at 01:30. This is 3.89g/CO<sub>2</sub>/kWh lower than the highest point in January of 58.96g/CO<sub>2</sub>/kWh.

On 6 February constraints were active due to high levels of wind and weather warnings across the South of the UK.



## 6. Security of Supply

### Performance Objective

#### Operating the Electricity System

### Success Measure

**As the electricity system in Great Britain evolves, we will transform the capabilities of our people, processes and systems and continue to deliver economic and efficient real-time operation of the electricity transmission system, as measured through the Security of Supply reporting evidence (BP2: RRE 1I).**

This Reported Metric shows when the frequency of the electricity transmission system deviates more than  $\pm 0.3\text{Hz}$  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.



## February 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	
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	
Voltage Excursions defined as per Transmission Performance Report <sup>3</sup>	0	0	1	0	0	1	0	0	0	0	0	

## Supporting information

No reportable voltage or frequency excursions during February.

<sup>3</sup> <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.

### February 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	
Integrated Energy Management System (IEMS)	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	
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0	



## Supporting information

In February 2026 there was one planned CNI system outage. The outage was to carry out regular maintenance activities on the BM production systems, and impacted the key BM Suite components used for scheduling and dispatch of generation.

This change took place on 24 February, and was planned in advance, in collaboration with our control rooms to ensure it did not introduce a conflict with other known periods of high activity. Notifications are posted to the industry, via BMRA, at 7 days prior and 1 day prior.

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

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

There were no other planned outages during February.

There were no unplanned outages during February.

National Energy System Operator  
Faraday House  
Warwick Technology Park  
Gallows Hill  
Warwick  
CV34 6DA

[www.neso.energy](http://www.neso.energy)

