27 May 2025

Monthly Incentives April 2025 Report

Business Plan 3 (2025-26)

NESO
National Energy System Operator

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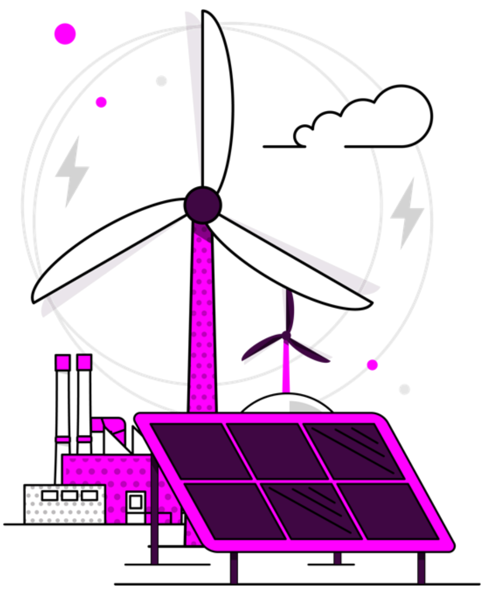
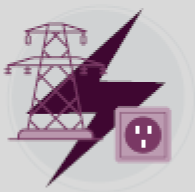


Introduction

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

Our BP3 Performance Objectives for 2025/26

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

The NESO Performance Arrangements Governance (NESO PAG) Document 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 appending 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 6-months and end of year, we will also publish the results from our Stakeholder Satisfaction 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	• Reported Metrics	17 working day of following month
Quarterly	• Reported Metrics • Performance Objectives Progress updates	17 working day of following month
Six-month and end of year	• Reported Metrics • Performance Objectives Progress updates • Value for Money reporting • Stakeholder survey results	23 October 2025 and 16 May 2026

Following our BP2 submission, Ofgem outlined the requirement for a Cost Monitoring Framework (CMF). The objective of the CMF is to provide visibility of our BP2 Digital, Data and Technology (DD&T) delivery progress and cost management, and the value being delivered across the DD&T investment portfolio. 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.

Summary of Reported Metrics

The table below summarises our Reported Metrics for April 2025:

	Reported Metric	Performance
1	**Balancing Costs**	**£152m**
2	**Demand Forecasting**	Forecasting error of **671MW**
3	**Wind Generation Forecasting**	Forecasting error of **3.81%**
4	**Skip Rates**	Offers: **43%** Bids: **45%**
5	**Carbon intensity of NESO actions**	**7.16 gCO_2/kWh** of actions taken by the NESO
6	**Security of Supply**	**0** instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. **0** voltage excursions
7	**CNI Outages**	**0** planned and **0** unplanned system outages

Reported Metrics

1. Balancing Costs

Performance Objective

Operating the Electricity System

Success Measure

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

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

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

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

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

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

Non-constraint costs = 62.25 + (Day Ahead baseload x 0.478)
Constraint costs = -33.49 + (Day Ahead baseload x 0.39) + (Outturn wind x 23.51)

Benchmark (Total) = 28.76 + (Day Ahead baseload x 0.87) + (Outturn wind x 23.51)

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

NESO Operational Transparency Forum: We host a weekly forum that provides additional transparency on operational actions taken in previous weeks. It also gives industry the opportunity to ask questions to our System Operations panel. Details of how to sign up and recordings of previous meetings are available here.

April 2025 performance

Figure: 2025-26 Monthly balancing cost outturn versus benchmark

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

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	4.1												4.1
Average Day Ahead Baseload (£/MWh)	81												n/a
Benchmark*	195												195
Outturn balancing costs[1]	**152**												**152**

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

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

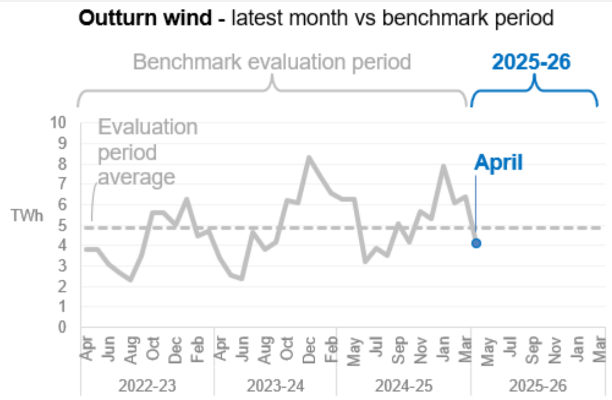
BALANCING COSTS METRIC & PERFORMANCE

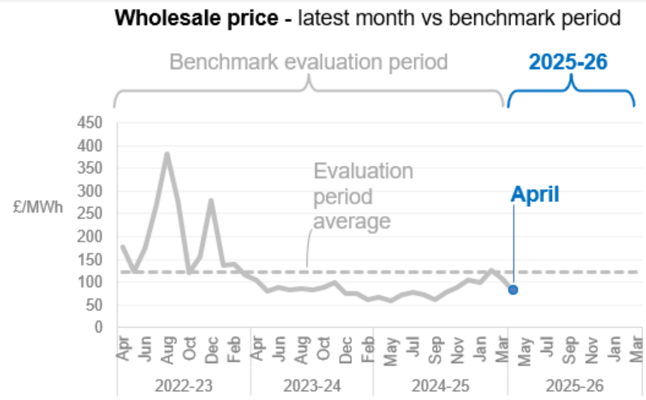
This month's benchmark

The April benchmark of £195m is £37m lower than March 2025 and reflects:

- An **outturn wind** figure of 4.1 TWh that is lower than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 4.9 TWh) and also lower than last month's figure (5.3 TWh).
- An average monthly **wholesale price** (Day Ahead Baseload) that has decreased compared to March 2025 but remains elevated compared to the previous year. However, it remains lower than the evaluation period average.

Lower wholesale prices and wind outturn both supported the decrease in the benchmark for April.





Variable	April 2025	March 2025	April 2024
Average Wholesale Price (£/MWh)	81	+11	-22
Total Wind Outturn (TWh)	4.1	+1.2	+2.2
Benchmark (£m)	195	+40	+33

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

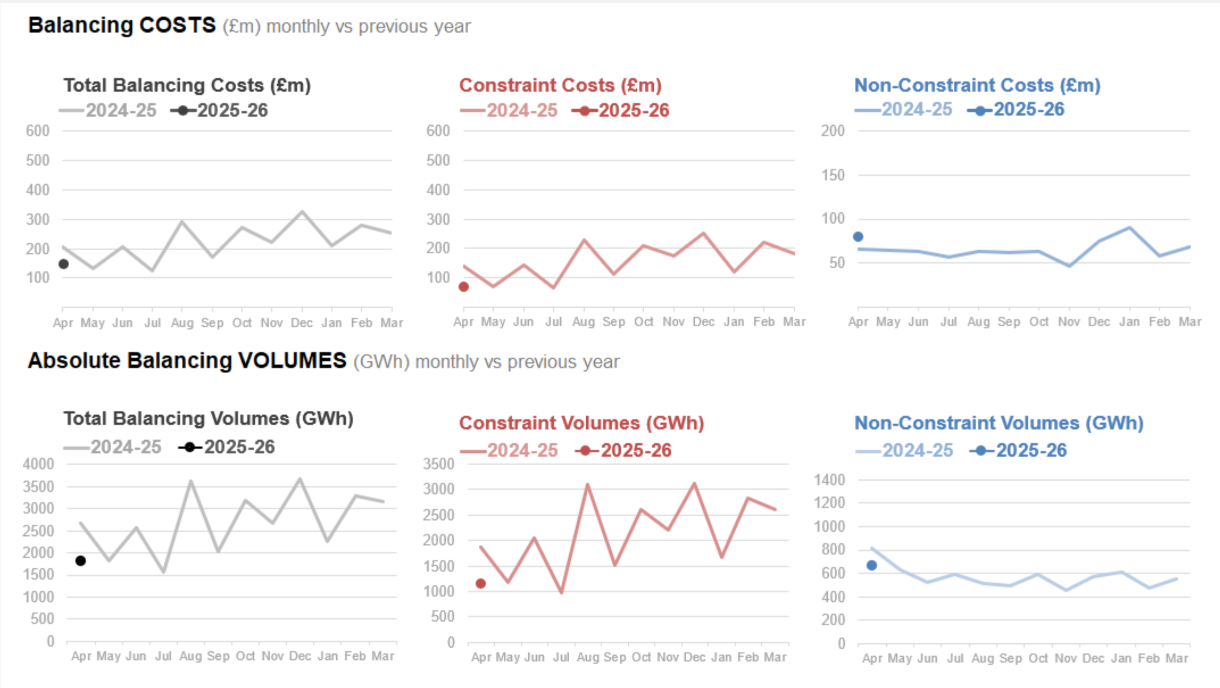
Balancing Costs - Overview

The total balancing cost for April was £152m, which is £43m (22%) below the benchmark.

April was a month with little wind, reflected in the lower levels of wind curtailment (307 GWh). This contributed to a significant reduction in constraint costs which were down £113m compared to March and £69m compared to April 2024. Scottish constraints were therefore not particularly active during the month, despite ongoing major planned outages.

April was also characterised by low transmission system demand driven by high solar generation and above average temperatures. This contributed to a rise in voltage and inertia spending in April compared to previous months this year. This is due to reduced self-dispatch of synchronous units (i.e. CCGTs) that support voltage and inertia management, which led to NESO procuring those services through the Balancing Mechanism (BM).

Average wholesale power prices were down £11/MWh compared to March 2025 but were higher by £22/MWh relative to April 2024. The volume weighted average price of bids is £10.3/MWh, representing reduced spend compared to last month's price of £2.8/MWh. The volume weighted average price for offers decreased by £9.0/MWh (from £128.0/MWh to £119.0/MWh), in line with the monthly decrease in average wholesale price. Non-constraint costs and volumes have increased by £11.4m and 114GWh respectively.

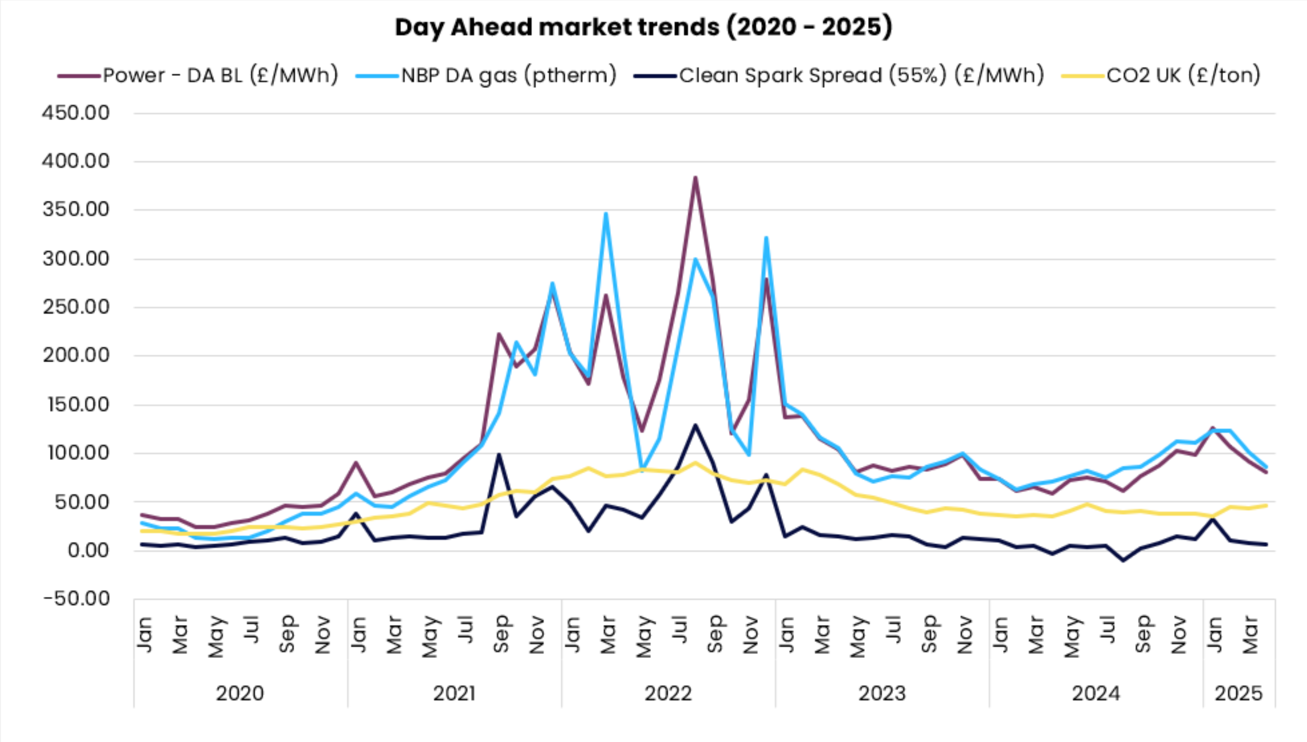


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

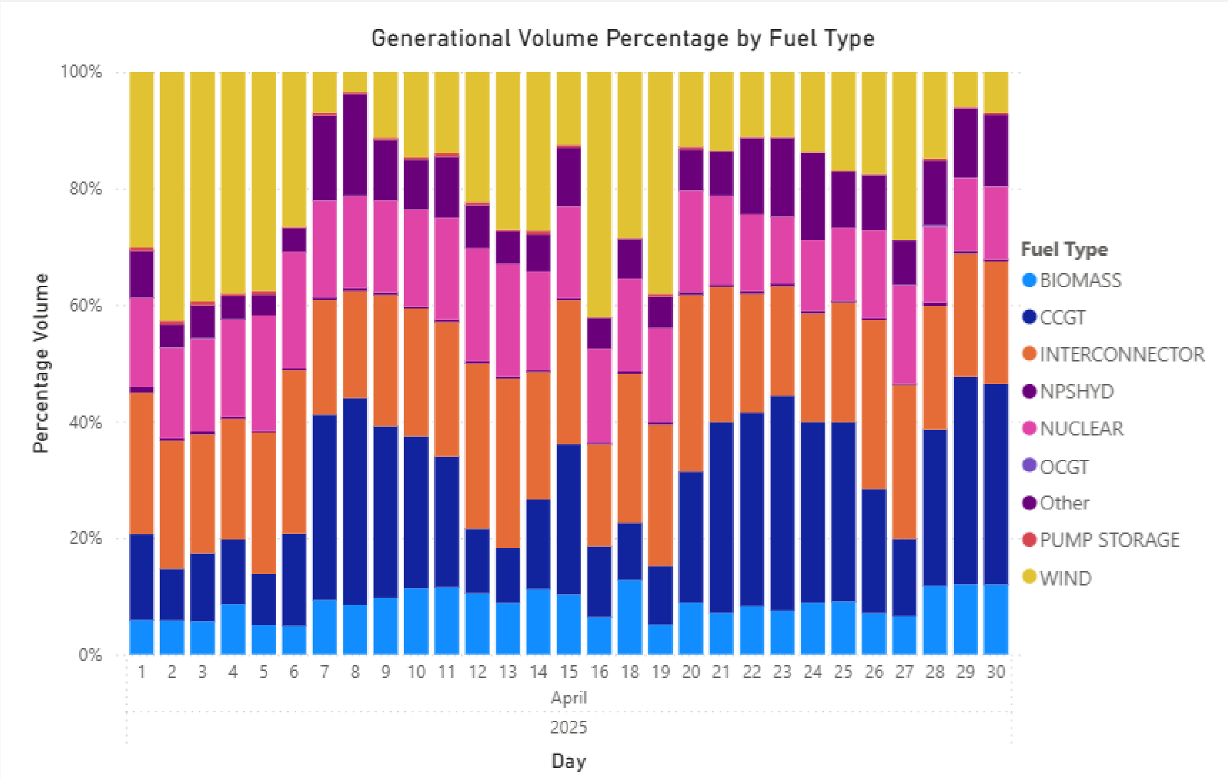
Market trends

Power and Gas prices continue to trend downwards so far throughout 2025, reaching their lowest average price in April 2025 of £80.69/MWh and 85.68p/Therm respectively. Above average temperatures in April have supported lower prices. Power and gas prices were however higher than their April 2024 prices with a rise of 38% and 20% respectively. Carbon prices dropped marginally to an average of £45.99/Ton, in line with reduced demand across the month, but was up compared to April 2024 by 28%. Clean Spark Spread saw a few days of negative prices in April and is trending downwards with lower averages compared to the last few months.



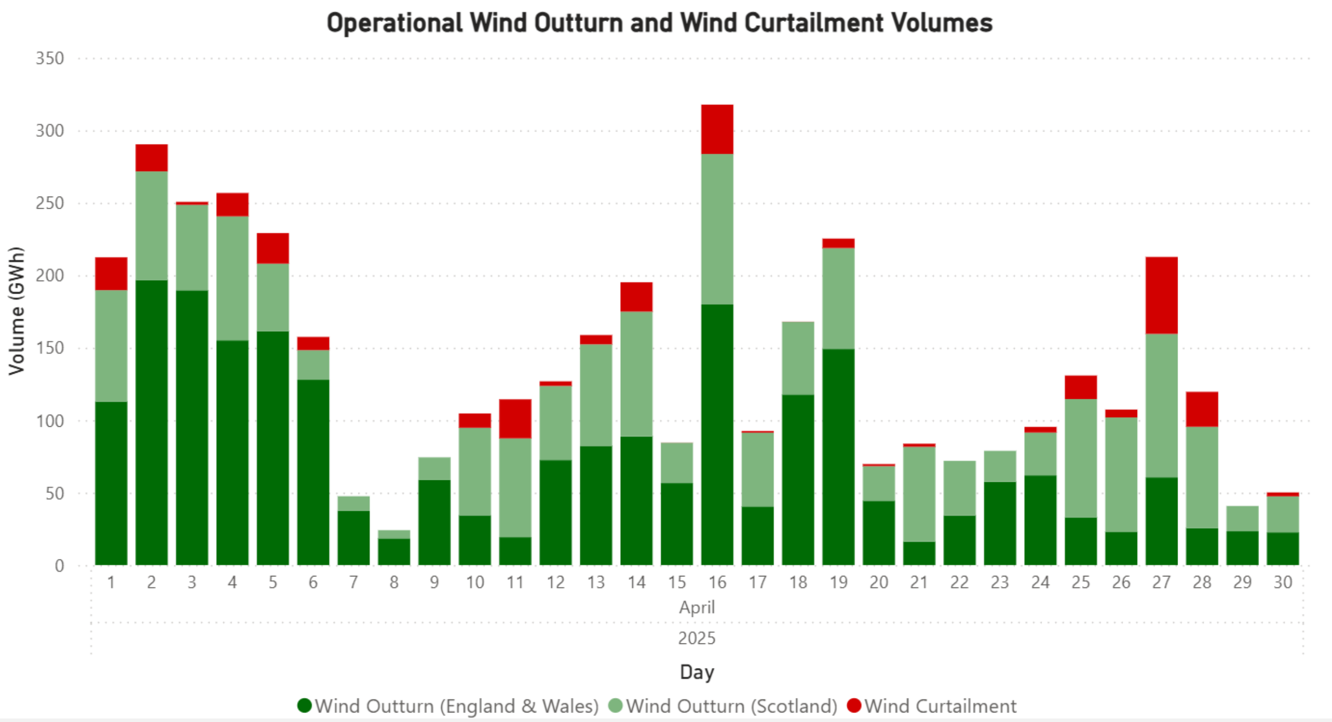
DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Generation and demand

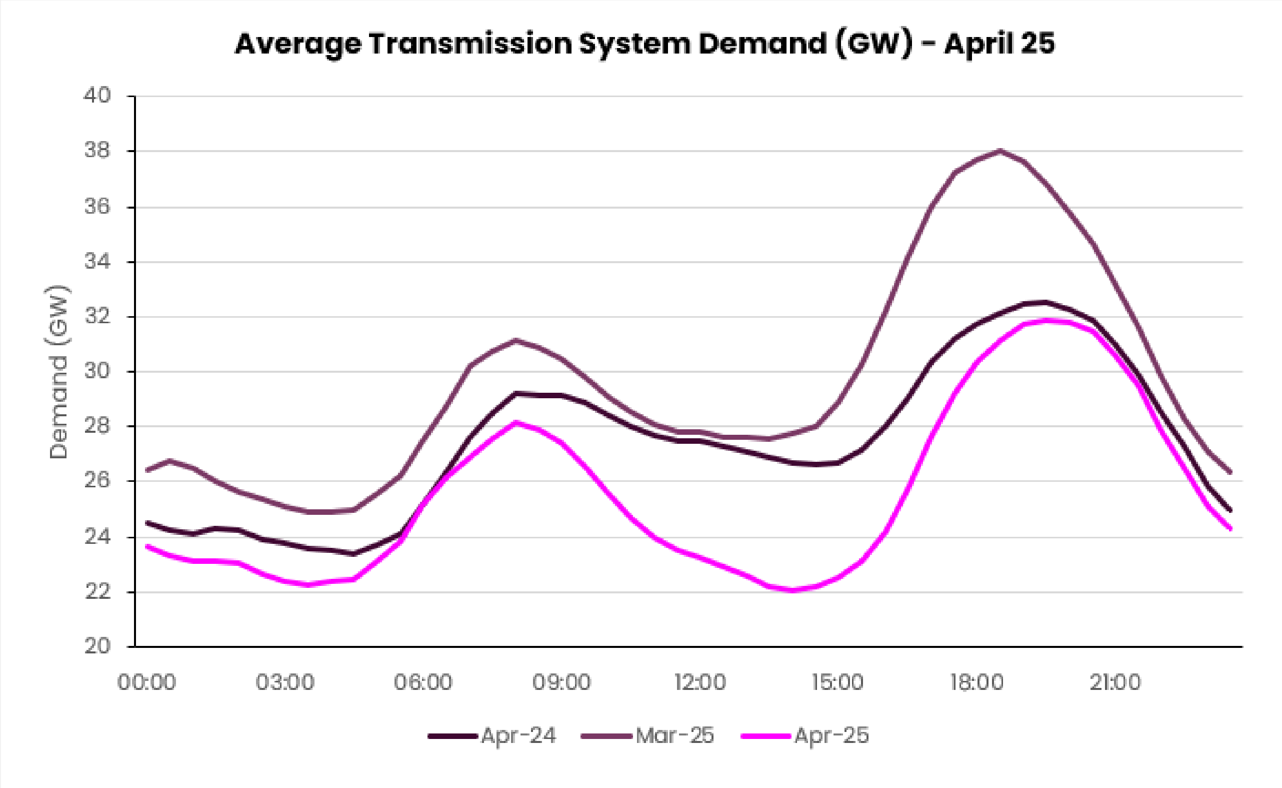


* Currently awaiting data update for 17th

In April CCGT generation was down compared to the average daily amount, and unlike similar days such as the 16th and 19th we did not have suitable wind offsetting this decrease. This is due to a high amount of wind being curtailed in Scotland due to constraints. 27 April also aligns with the day we curtailed the largest volume of wind at 53 GWh. Wind outturn made up around 20% of the total generation on the grid in April which is down slightly from March at 23% however we have seen a proportional drop in demand on the grid between the two months.



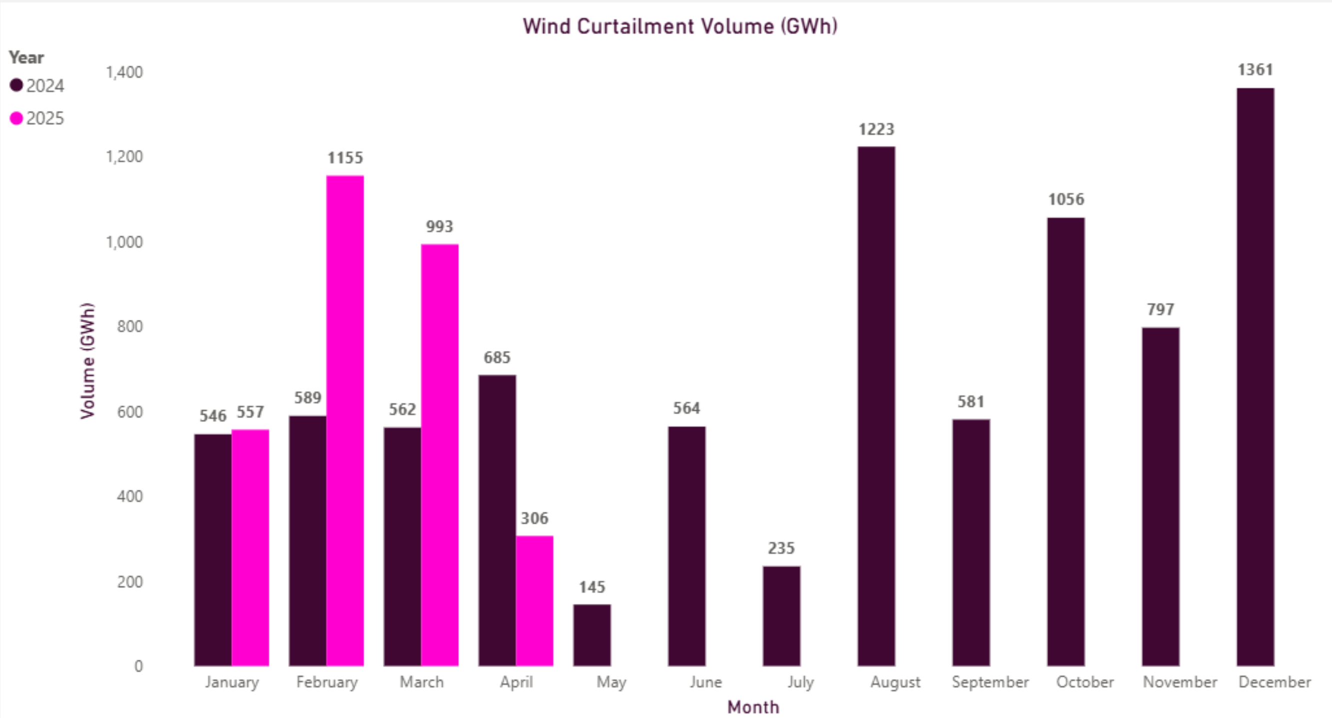
Average transmission system demand (TSD) was particularly low in April, driven by high solar generation alongside above average temperatures. This resulted in the minimum average TSD occurring in the middle of the day, at 22.0GW in settlement period 29 (which was slightly below the overnight minimum of 22.2GW). Low demand contributed to a rise in voltage and inertia spending in April compared to previous months this year. This is due to reduced self-dispatch of synchronous units (i.e. CCGTs) that support voltage and inertia management, which led to NESO procuring those services through the Balancing Mechanism.



Wind Outturn

April saw mostly settled weather with high pressure at the start and end with a few unsettled days mid-month. This showed with average wind speeds being very consistent day to day and right across the UK being a calm month across the board.

Overall wind outturn dropped from March 2025 with 5.3TWh to 4.1TWh in April. This is due to lower wind speeds across the UK compared to March which had some significantly high periods at the start and end of the month. Wind Curtailment took a significant drop in April as well down to 306 GWh curtailed which is a reduction from April 2024 at 685GWh and March 2025 at 993GWh. Around 60% of the wind generation being within England/Wales. Scotland saw 97% of actions taken to curtail wind throughout April with some large thermal constraints being managed.

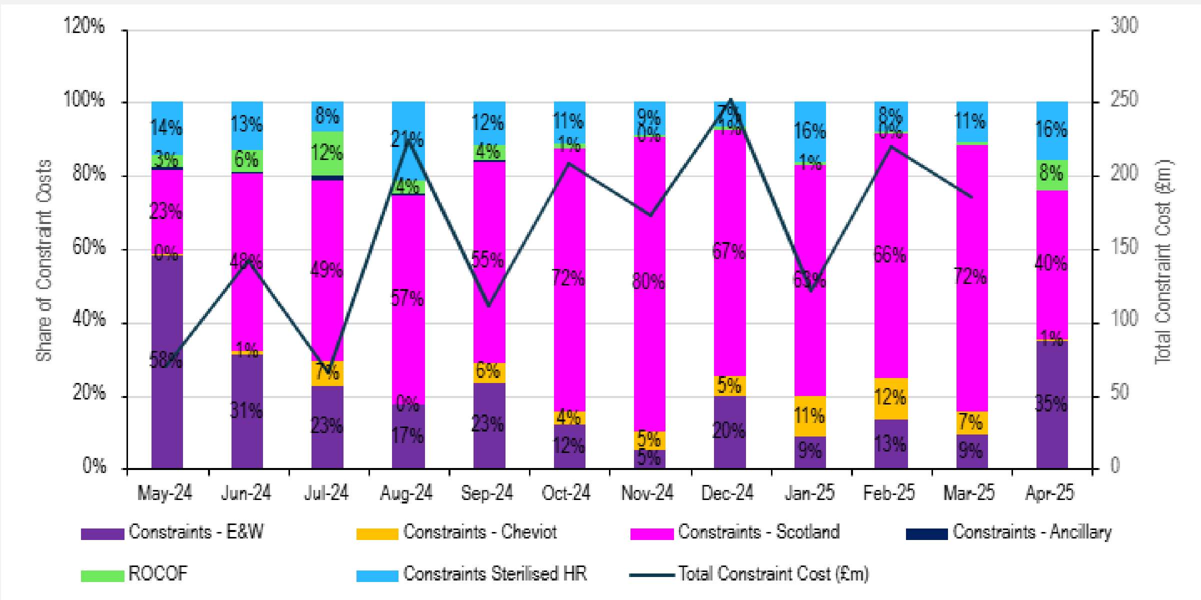


The day with the highest volume of wind curtailment occurred on the 27 April with 53GWh which aligns with the highest cost day of the month.

Constraints

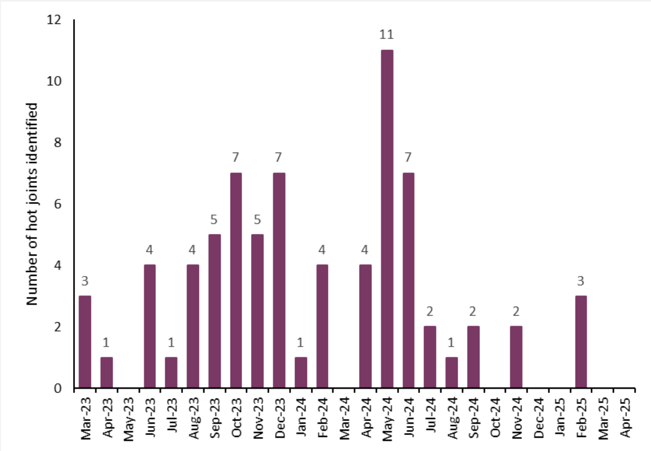
Constraint costs in April decreased from £184.1m to £71.6m, a drop of £112.5m from the previous month. There was a decrease in costs for Scotland and Cheviot of £112.8m and Contrast Sterilised HR of £8.6m. However, this was slightly counteracted by a slight increase in England and Wales constraints of £5.4m and ROCOF of £3.5m.

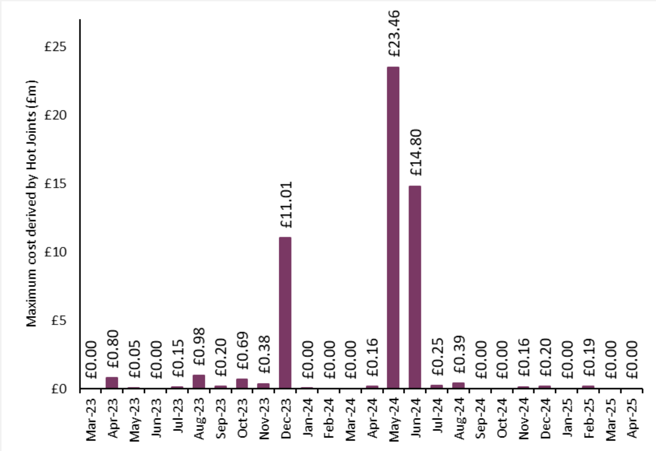
Wind outturn reduced significantly in April which has acted to lower the volume of actions to manage constraints, despite outages remaining in place in Scotland. While low demand in April contributed to higher ROCOF spend due to reduced self-dispatch of synchronous units providing inertia regulation.



Network Availability

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





BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): April 2025 vs March 2025

		(a) Mar-25	(b) Apr-25	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Non-Constraint Costs	Energy Imbalance	-8.1	4.1	12.2	
	Operating Reserve	7.0	12.4	5.4	
	STOR	5.9	4.8	(1.2)	
	Negative Reserve	0.5	0.6	0.1	
	Fast Reserve	21.1	10.6	(10.5)	
	Response	22.9	25.7	2.8	
	Other Reserve	2.6	1.0	(1.6)	
	Reactive	15.3	15.4	0.1	
	Restoration	3.5	3.3	(0.3)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	-2.0	2.2	4.3	
Constraint Costs	Constraints - E&W	16.7	22.1	5.4	
	Constraints - Cheviot	12.0	0.5	(11.5)	
	Constraints - Scotland	132.1	30.8	(101.3)	
	Constraints - Ancillary	0.2	0.2	(0.1)	
	ROCOF	1.6	5.1	3.5	
	Constraints Sterilised HR	21.5	12.9	(8.6)	
Totals	Non-Constraint Costs - TOTAL	68.6	80.0	11.4	
	Constraint Costs - TOTAL	184.1	71.6	(112.5)	
	Total Balancing Costs	**252.7**	**151.5**	**(101.2)**	

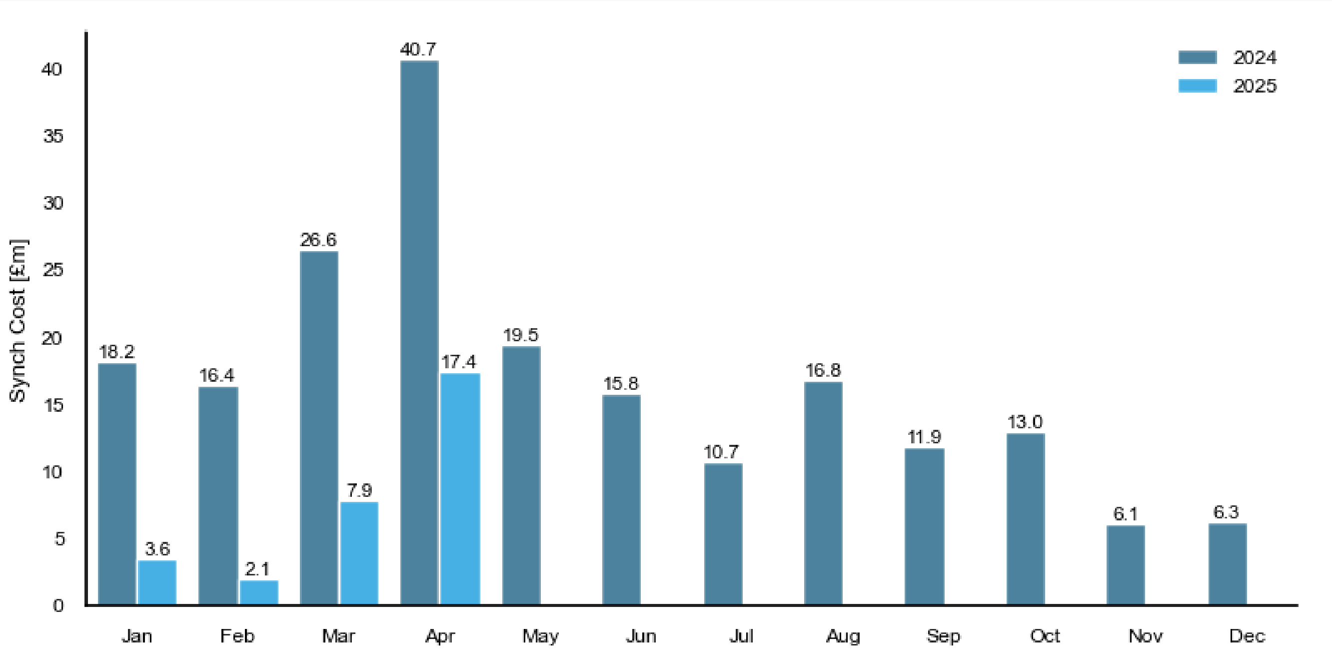
As shown in the totals from the table above, constraint costs decreased by £112.5m and non-constraint costs increased by £11.4m, resulting in an overall decrease in balancing costs of £101.2m compared to March 2025.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: -£112.8m **Constraint – England & Wales: +£5.4m** **Constraint Sterilised Headroom: -£8.6m** Constraint costs decreased by £112.4m in April, coinciding with a 1.5 TWh decrease in the absolute volume of actions. Wind outturn reduced significantly in April which has acted to lower the volume of actions to manage constraints, despite outages remaining in place in Scotland. **ROCOF: +£3.5m** In April, the system's outturn inertia (including market-provided, stability assets, and synchronous plants used for voltage support) resulted in higher volumes to meet the minimum inertia requirements of the system. This linked to operational conditions related to periods of low demand in April, resulting in a lower number of synchronous units providing inertia regulation as most of the demand is met by non-synchronous generation.	**Constraints – Scotland & Cheviot: -£37.5m** **Constraints – England & Wales: -£25.0m** **Constraints Sterilised Headroom: -£10.7m** Constraint costs have decreased by £57.4m compared to last year. Wind outturn fell significantly below its April 2024 level. April 2024 saw particularly high wind outturn for the time of year with levels this year outturning closer to previous years. **ROCOF: +£4.3m** Low demand in April also caused an increase in inertia spend relative to last year. However, the implementation of the FRCR requirement reduction (140 GVAs to 120 GVAs) is continuing to contribute to lower than otherwise inertia volumes and costs. Additionally, the gradual addition of assets commissioned through the Stability Pathfinder Phase 2 is expected to positively contribute to inertia levels in the system, resulting in reduced ROCOF spending.

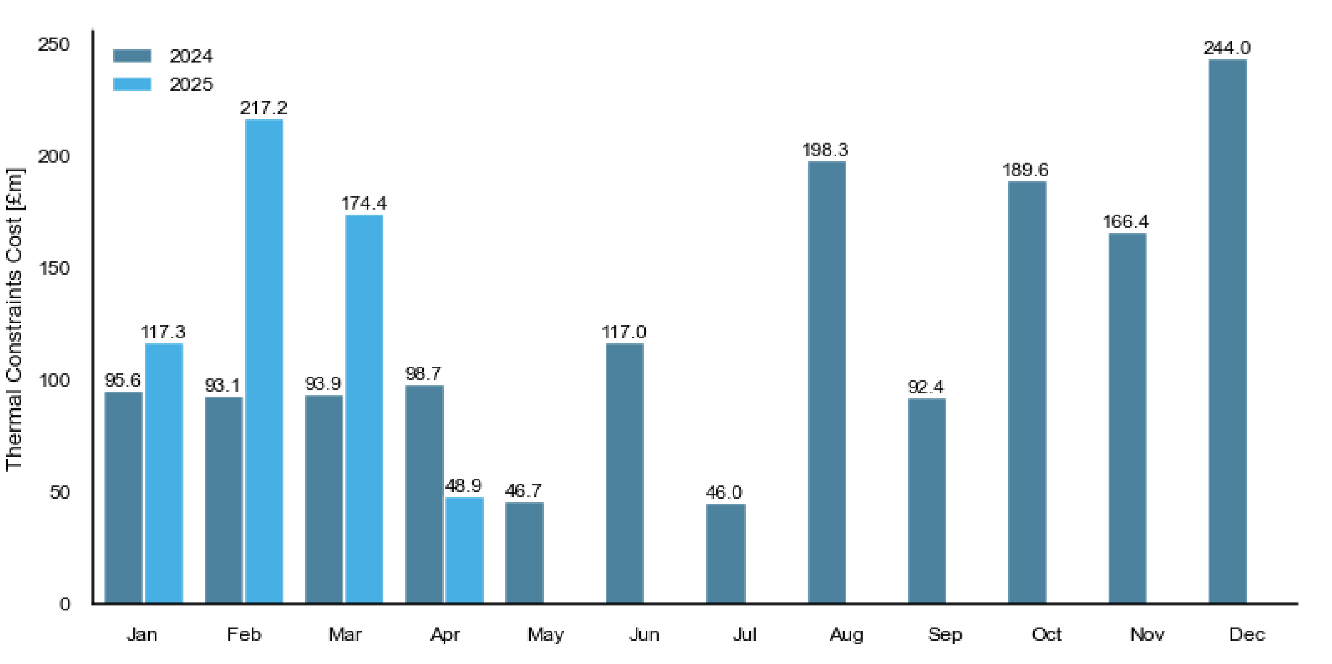
Voltage – Monthly system cost of synchronisation actions for voltage control across 2024 and 2025:

Synchronisation costs are associated with specific actions required to support voltage in the system. These actions involve units that are instructed to provide MVArs and maintain voltages within SQSS limits. It is a highly location-dependent issue, so only a limited set of assets are effective in voltage support, depending on their location. In April, the system synchronisation costs (what it costs to the system, which factors in energy replacement, headroom among others) amounted to £17.4 million, marking the highest record in 2025, but still lower compared to the same period in 2024 (£40.7 million).



Some of the factors driving the costs up are periods of low demand. This 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. Despite this, the costs in April are comparatively lower than in the same period of 2024. This is mainly due to the implementation of initiatives such as voltage pathfinders, stability pathfinders (which provide not only inertia but also voltage support), and the commissioning of assets as Greenlink interconnector in the South Wales.

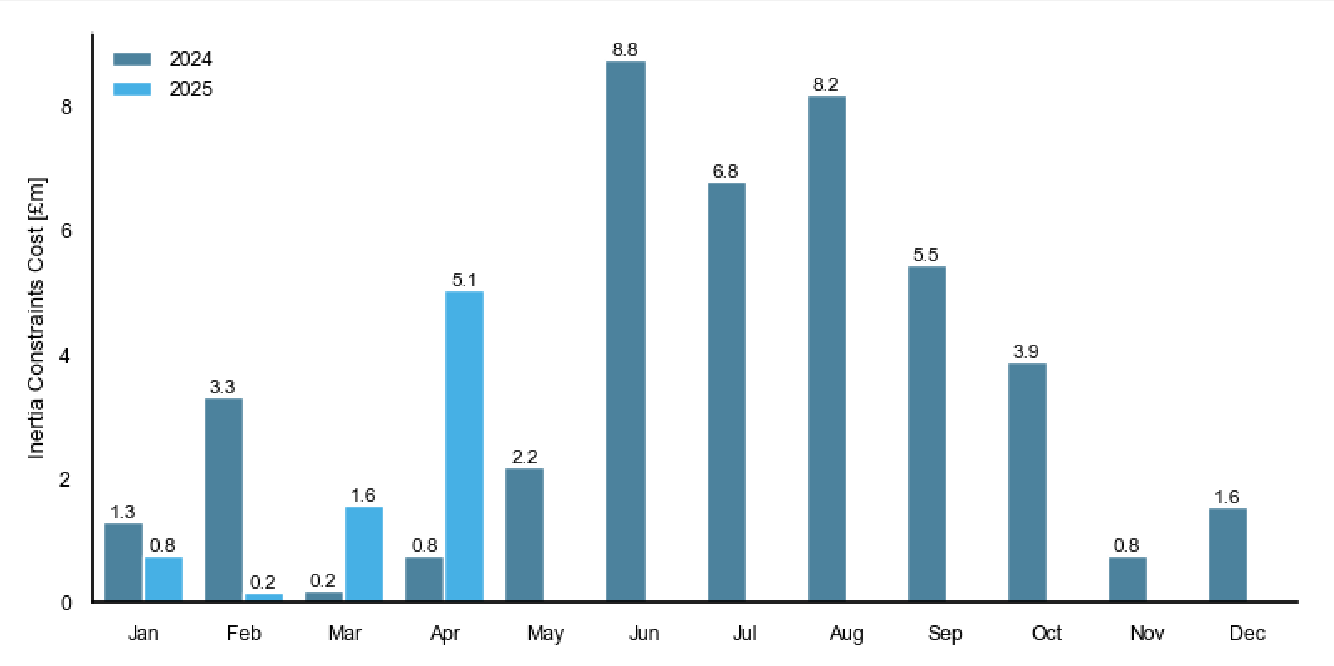
Thermal – Monthly system cost of actions for thermal management across 2024 and 2025: Thermal constraints are associated with operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, 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 lion's share of the system constraints, accounting for a significant percentage of system actions. In April, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £48.9 million, marking the lowest record in 2025 and representing almost half of the spent over the same period in 2024 (£98.7 million).



April was characterised by being a month with little wind, reflected in the lower levels of wind curtailment in 2025 (307 GWh). This implies that the Scottish constraints were not particularly active during the month, despite ongoing major planned outages. In this regard, the volumes of wind generation to bid off were significantly reduced compared to other months, which is reflected in lower operation costs related to thermal constraints

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. It is primarily provided by the rotating mass of large synchronous generators, mainly CCGTs in Great Britain, 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 April, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £5.1 million, marking the highest record in 2025. These costs are still higher compared to the same period in 2024 (£0.8 million).



Due to the same reasons for increased spending on voltage constraints, the expenditure on inertia in April rose mainly due to operational conditions related to periods of low demand. This results in a lower number of synchronous units providing inertia and voltage regulation as most of the demand is met by non-synchronous generation. This forces NESO to procure inertia through the Balancing Mechanism.

Reactive Costs/Volumes

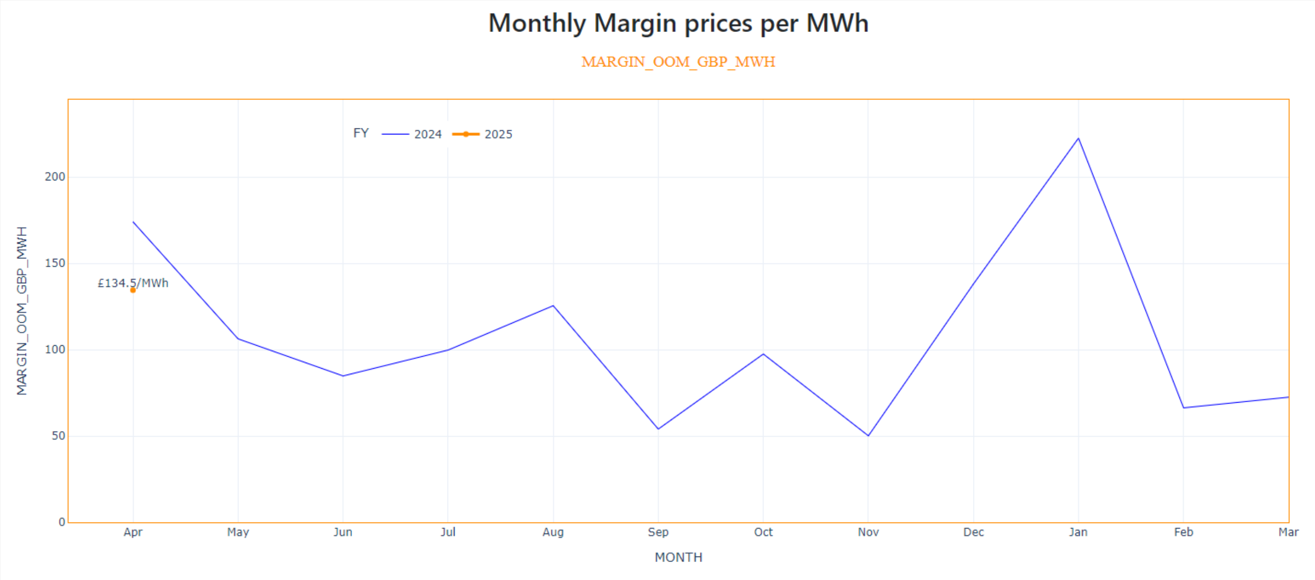
The volume-weighted average price for reactive power was £4.8/MVAr in April 2025.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£0.1m The volume-weighted average price remained similar to last month at £4.8/MVAr.	**+£3.8m** The volume-weighted average price increased from £3.5/MVAr to £4.8/MVAr compared to last year.

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

Reserve Costs/Volumes

Reserve prices increased to £134.5/MWh in April from £72.5/MWh in March 2025. This is aligned with an increase in absolute volume of actions taken over April and comes despite the slight month on month fall in wholesale price.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£5.4m **Fast Reserve: -£10.5m** There was a 16 GWh increase in the absolute volume of Operating Reserve required to secure the system compared to March.	**Operating Reserve: +£0.3m** **Fast Reserve: -£3.4m** There was a 19 GWh increase in the absolute volume of Operating Reserve required to secure the system compared to April 2024. However, volume weighted reserve prices were lower compared to last year.

We are currently in the process of quantifying the benefits associated with Balancing Reserve, and the results will be shared in the coming months.

Response Costs/Volumes

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

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£2.8m There was a 30 GWh increase in the volume of actions compared to March.	**+£9.3m** The volume of actions taken for response increased 9 GWh compared to April 2024. Clearing prices were also higher year-on-year.

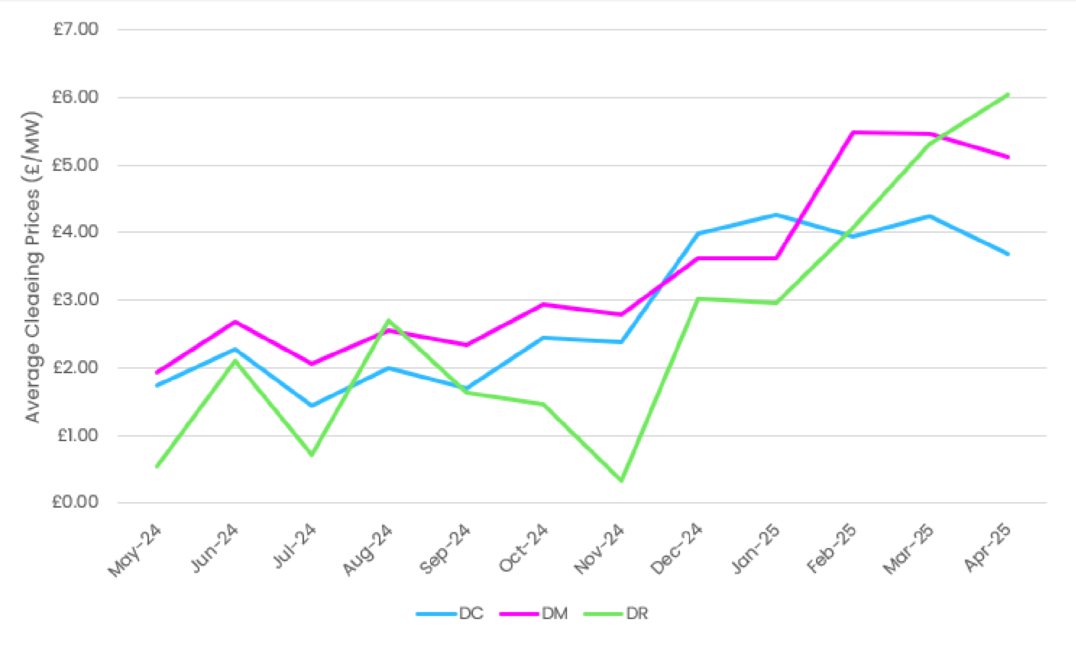
Dynamic Services Average Clearing Prices: April 2025 vs March 2025

		(a) Apr-25	(b) Mar-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	3.7	4.2	(0.5)	
	DM	5.1	5.4	(0.3)	
	DR	6.0	5.3	0.7	

Dynamic Services Average Clearing Prices: April 2025 vs April 2024

		(a) Apr-25	(b) Apr-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	3.7	2.5	1.2	
	DM	5.1	2.7	2.4	
	DR	6.0	3.0	3.0	

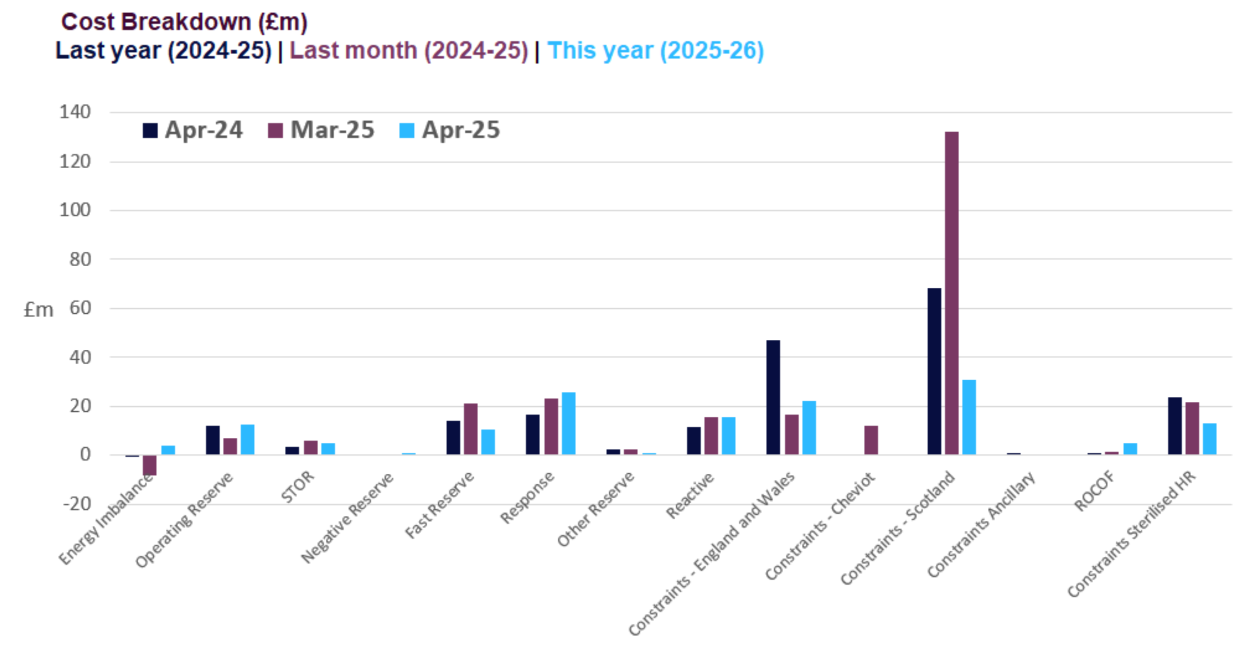
Average clearing prices for DC and DM decreased in April compared to March, in line with a reduction in wholesale prices and spreads. In contrast DR increased in line with higher requirement volumes month-on-month. All three services saw an increase in average clearing prices to April last year.



Comparison breakdown

Constraint costs were down by £112.5m compared to the previous month, this is due to a significant decrease in Scotland and Cheviot (£112.8m), although there was a slight increase in England and Wales (£5.4m). Constraint costs are also down on last year, by £69.3m due to a reduction across both England and Wales and Scotland constraints, noting that wind outturn in April 2024 was particularly high resulting in increased curtailment volumes. Non-constraints costs increased by £11.4m from last month, largely driven by increases in most categories. Non constraint costs were also up £11.9m compared to April last year.

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



COST SAVINGS

Cost Savings – Outage Optimisation

Total savings from outage optimisation amounted to approximately £112 million in April 2025. This represents an increase of around £64 million compared to March, where savings were £48 million. The most valuable action corresponds to the same one reported in March, which was extended in April 2025. This was the optimisation of the running arrangements at Waltham Cross substation (3-way split) which reduced the impact of outages within the area. The estimated cost savings for this action in April are close to £87 million, given the duration of the impact.

Cost Savings – Trading

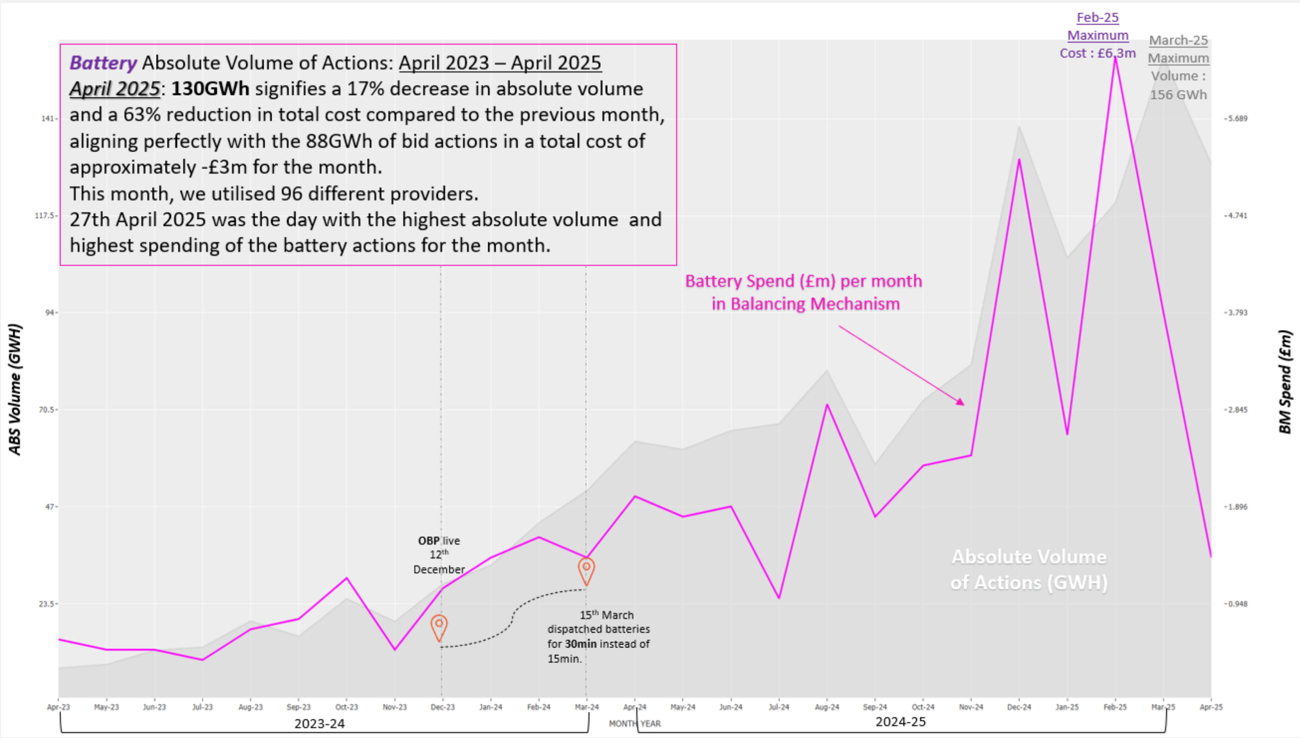
The Trading team were able to make a total saving of £12.3m in April through trading actions as opposed to alternative BM actions, representing a 31.7% increase on the previous month. Trading for downwards margin was the main driver for trading savings over the month, as because of significant wind and solar across the UK and Europe, interconnectors were often importing due to higher prices in the UK. Trading was also required to help manage the FLOWSTH constraint, which is normally an import constraint, in order to manage flows across both sides of the constraint boundary. The day with the greatest trading savings was 2 April at a cost of £2.87m with the greatest component being for downwards regulation, while the day with the greatest spend on trades was 5 April at a cost of £0.94m with the greatest component being for downwards regulation.

Cost Savings – Network Services (NS)

We are using Network Services (NS) to implement solutions to operability challenges in the electricity system. This includes the Constraint Management Intertrip Service, and Voltage & Stability pathfinders. We have calculated that the B6 and EC5 Constraint Management Intertrip Services, Voltage Mersey, Voltage Pennines, and Stability Phase 1 have delivered approximately £324m in savings during the BP2 period. We are now tracking savings delivered in the current financial year and will provide updates as this data becomes available.

NOTABLE EVENTS

Monthly Absolute Volume of actions and spend for Batteries in the BM
April 2025



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

The total absolute volume of actions and the total cost has decreased compared to the previous month, March 2025. The absolute volume of battery dispatch has more than doubled compared to last April 2024, illustrating our commitment to maximising the flexibility of energy offered by battery storage and small BMUs over the last year. Most of the spend for batteries was related to margin and minor components.

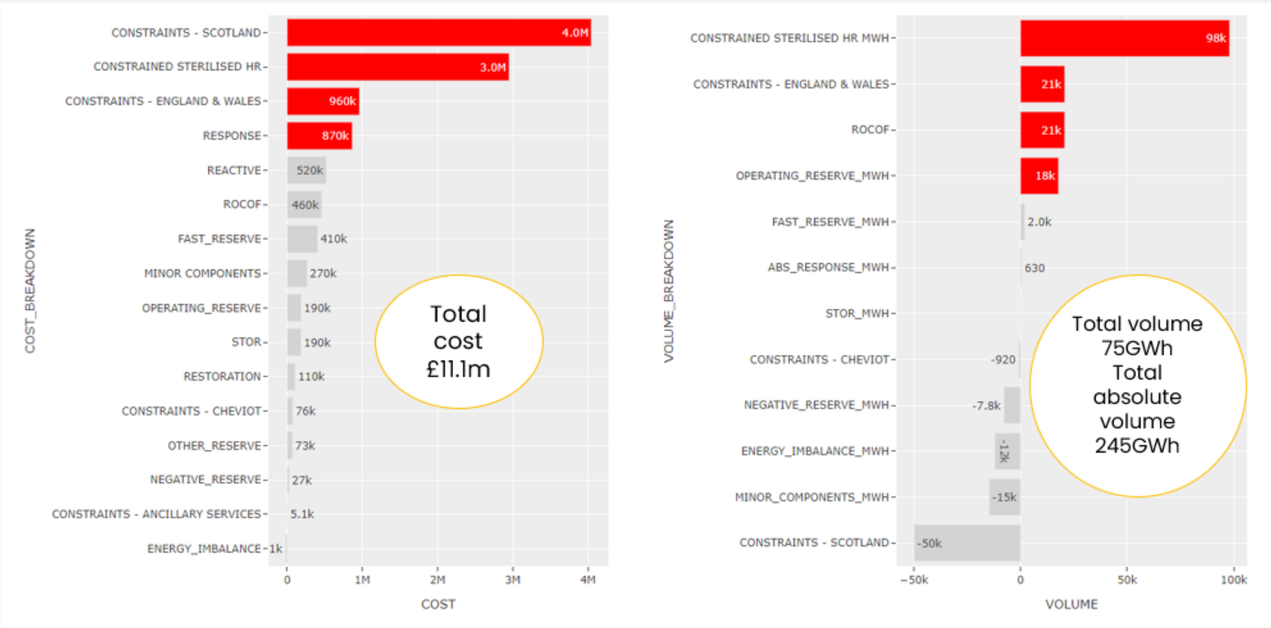
DAILY CASE STUDIES

Daily Costs Trends

April's balancing costs were £152m which is £102m lower than the previous month. Only one day was recorded with costs above £10m (27 April at £11.1m), and no days had costs above £15m. The daily average cost fell by £3.0m compared to March 2025 (£8.2m to £5.2m).

The lowest cost day was observed on 7 April, with a total balancing cost of approximately £2.2m. Low costs were due to generation needs to meet transmission system requirements being met by the market resulting in few actions via the BM. The highest cost day was 27 April, with a total spend of £11.1m. Higher costs on this day were linked to wind curtailment, with actions to manage Scottish constraints making up around 36% of the total, and voltage and inertia management.

High-Cost Day – 27 April 2025



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

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

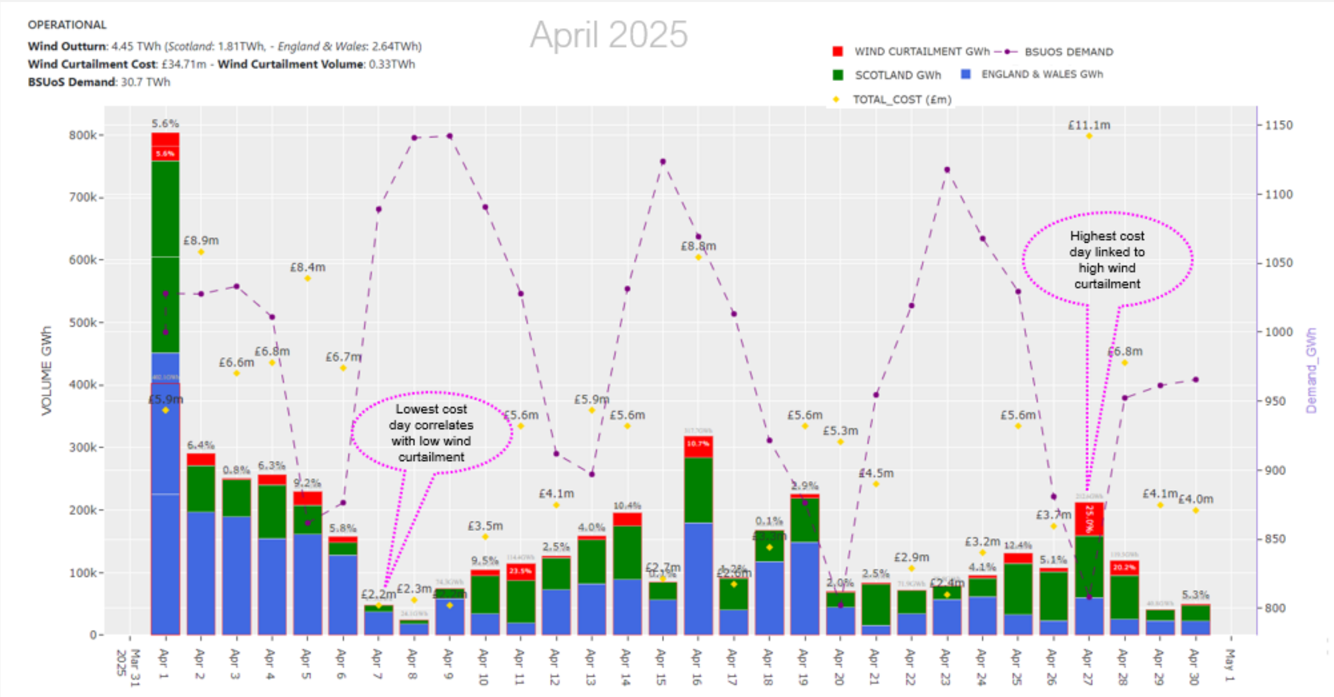
KEY: **Blue bars:** Wind generation in England and Wales

Green bars: Wind generation in Scotland

Red bars: Wind curtailment

Purple dotted line: Demand resolved by the BM and trades

Orange diamonds: Daily cost



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

2. Demand Forecasting

Performance Objective

Operating the Electricity System

Success Measure

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

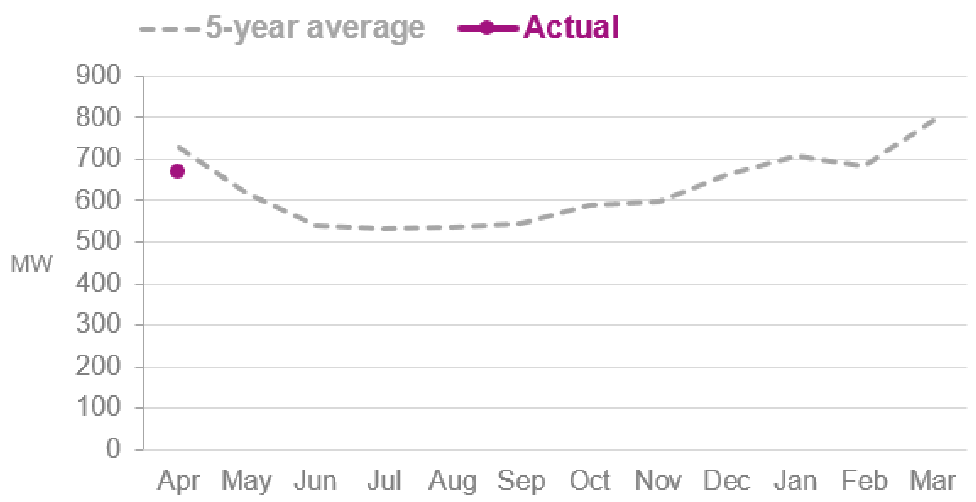
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each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

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.

April 2025-26 performance

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



[2] Demand | BMRS (bmreports.com)

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

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

*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

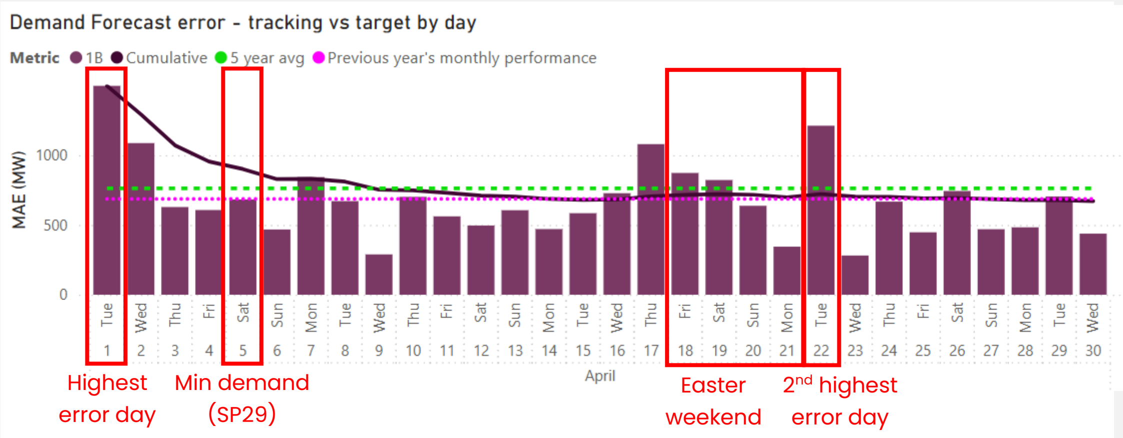
In April 2025, forecasting error averaged 671MW, improving on the previous 5-year average of 727 by 56MW (7.7%).

This was the third warmest April in the Met office's records, which reach back over 100 years. It was also the sunniest April on record for the UK with 228.9 hours of sunshine recorded, 147% of the long-term average.

Solar forecasting errors remained the largest contributor to national demand forecast errors – in part due to the unseasonal good weather. April saw occurrences of the afternoon demand out-turning lower than the overnight minimum, largely due to very high solar energy production. Although rare, this demand pattern was previously only witnessed at weekends or during lockdowns, but is slowly becoming more common even during the working week.

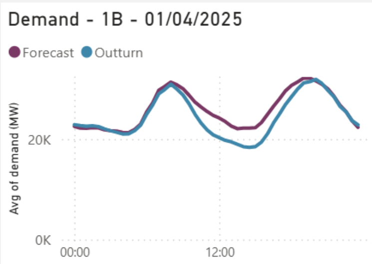
April also saw one of the lowest demands on record to-date, dropping down to 13.9GW on 5 April, SP29.

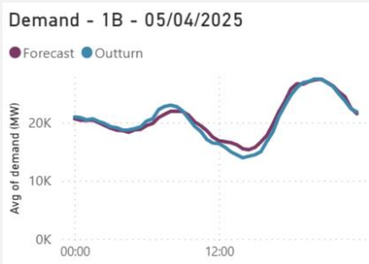
The Easter period is always difficult to forecast as the calendar-timing moves annually, as does the alignment to school holidays. Customary with many Seasonal/Bank holiday periods, the first working day back is often extremely challenging – particularly now with hybrid working patterns and changing consumer behaviour.

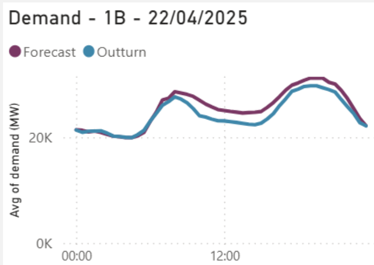


The largest absolute demand error this month was 3.9GW on April 1, SP32.

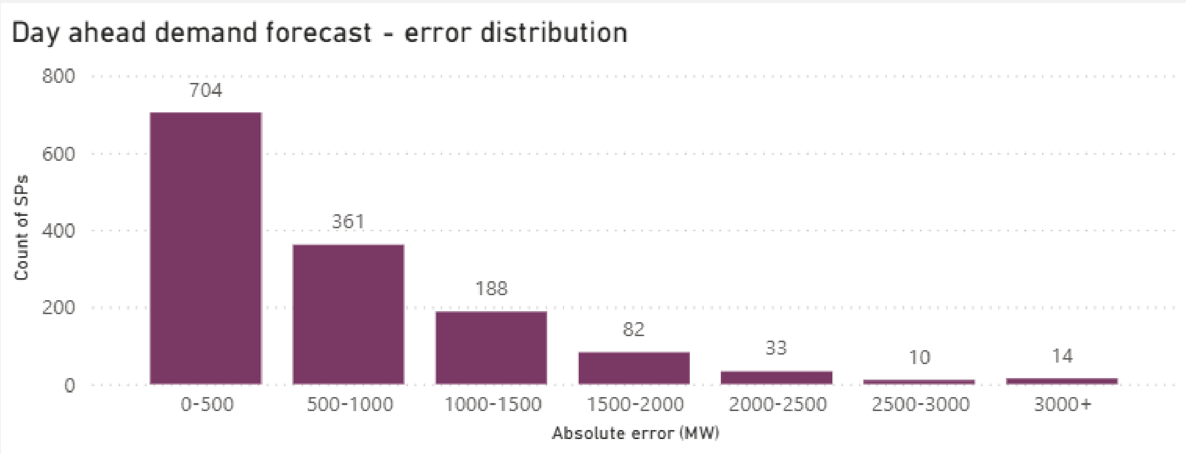
Days of Interest:







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



The days with largest MAE were 1 April and 22 April.

Day	Error (MAE)	Major causal factors
1	1498	Solar forecasting errors and other underlying effects influencing demand

22	1212	Solar forecasting errors and other underlying effects influencing demand including post-easter weekend behaviours

Missed / late publications

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

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 4, 7, 9, 10, 14 and 16 April, with an accumulated total of 205MWh 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.

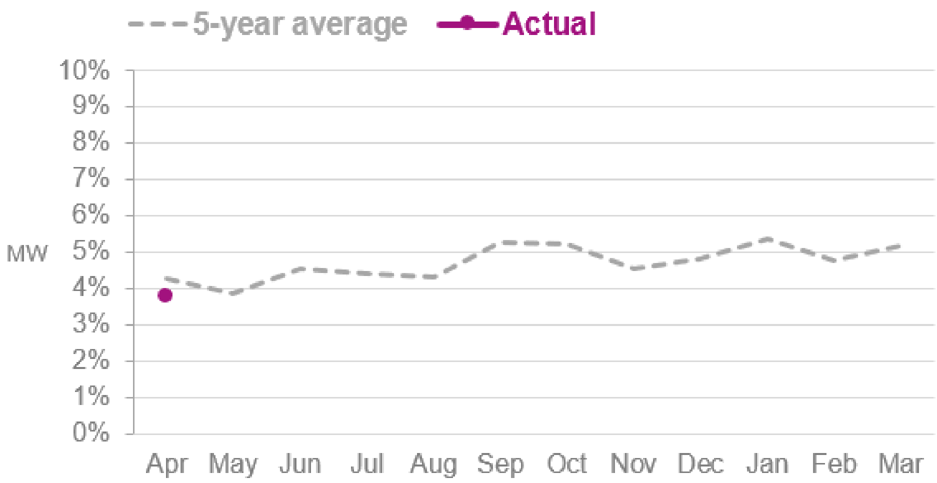
Sites deemed to have withdrawn availability are those that:

- 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.

April 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 (published in October 2024), the APE% that we report excludes some of the factors that are outside of our control. This view excludes sites that have redeclared to zero and incorporates Initial Settlement Runs (+16 Working Days).

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Previous 5-year average (%)	4.26	3.87	4.53	4.39	4.3	5.27	5.23	4.55	4.84	5.36	4.78	5.18
Previous year outturn (%)	4.64	3.60	4.72	4.24	4.15	5.04	4.70	3.63	3.86	4.40	3.97	5.20
APE (%)	**3.81**											

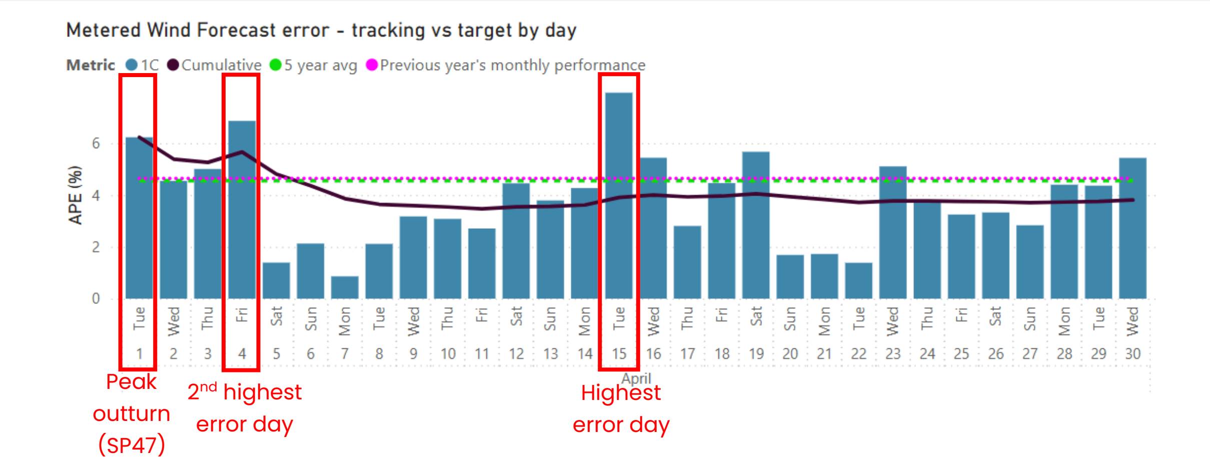
*Ofgem will no longer use a benchmark to assess our performance against this Metric however we will continue to report the previous 5 year average and last year outturn as an indicator.

Supporting information

In April 2025, BMU wind forecasting error averaged 3.81%, improving on the 5-year average of 4.26%.

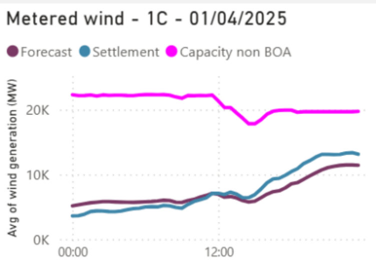
April was a mild month, with large portions dominated by high pressure systems (which led to calmer wind conditions). Mid-month a low-pressure system developed over the Bay of Biscay, drifting into Scotland and across to the North Sea. This brought some stronger and varied winds, settling when another high-pressure system re-established dominance.

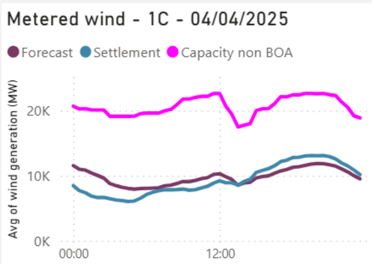
BMU Wind forecasts from our new platform continue to offer improved accuracy compared to historic averages, although we have noticed a tendency to over-forecast during low wind conditions. We aim to introduce further enhancements later in the year, once we have made corrections/improvements to our Embedded wind portfolio and GSP (Grid Supply Point) wind forecasts.

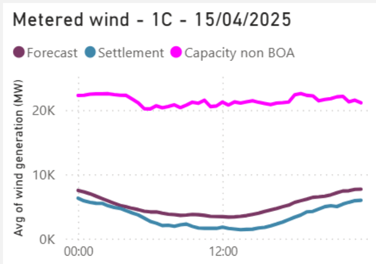


Wind generation peaked at 13.35GW on 1 April, SP47.
Wind forecast absolute error peaked at 3.7GW on 4 April, SP4.

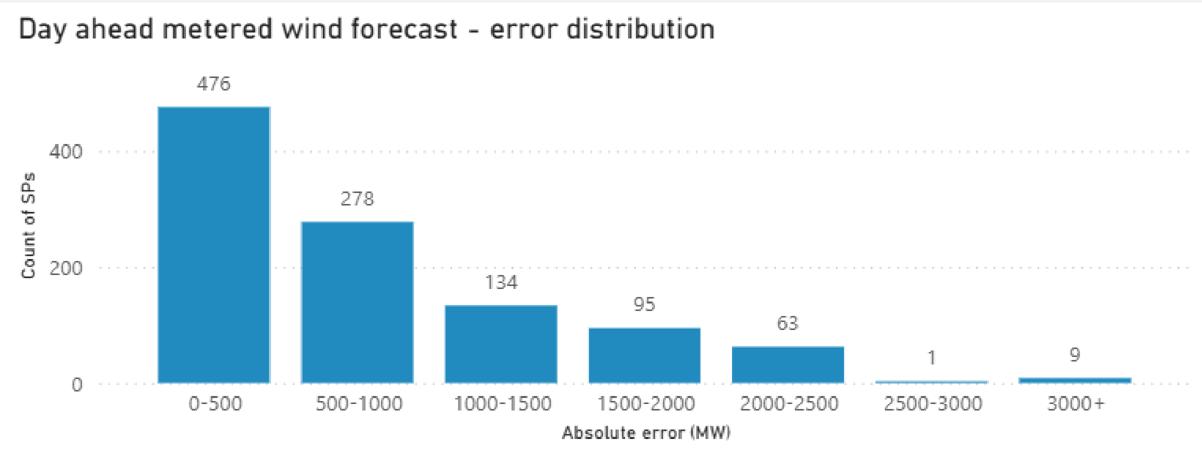
Days of Interest:







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



Details of largest error

Day	Error (APE)	Major causal factors
4	6.86	Wind forecast errors
15	7.95	Wind speed forecast errors at day-ahead stage

Missed / late publications

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

4. Skip Rates

Performance Objective

Operating the Electricity System

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.

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%											
Bids	45%											

Additional reporting by fuel type will be added next month once data is available.

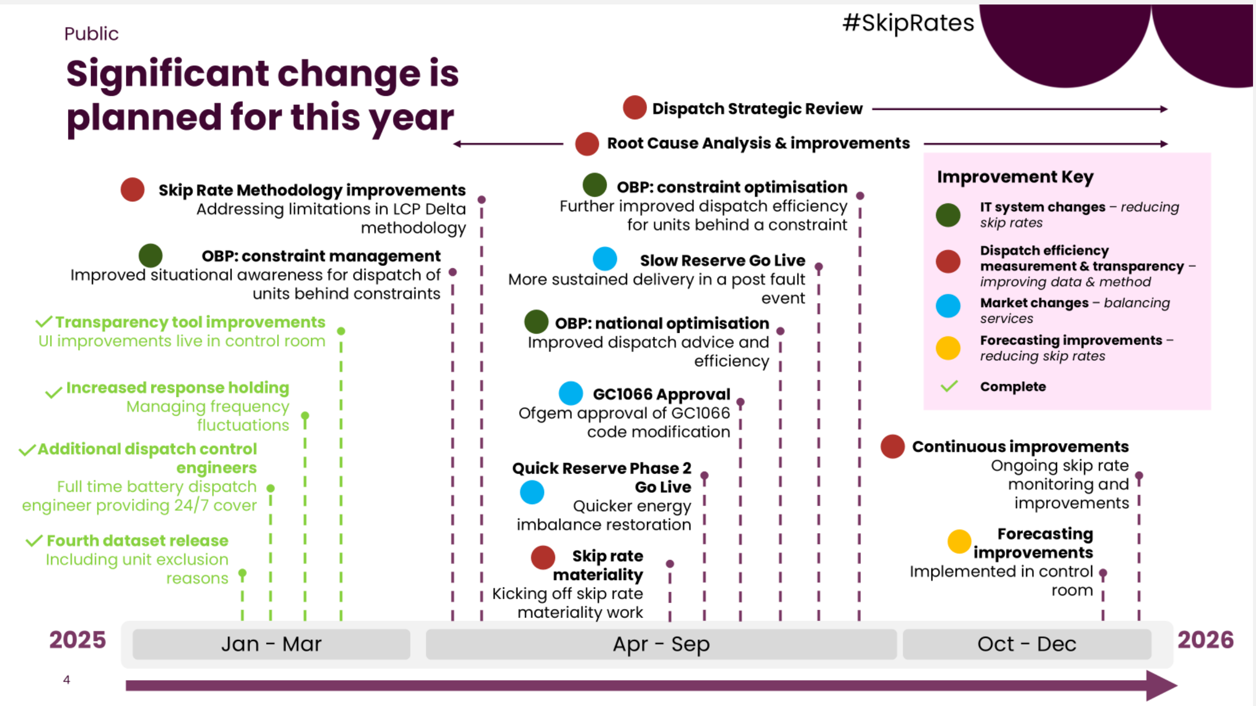
Supporting information

For April 2025, the skip rate for Offers is 43%, and the skip rate for Bids is 45%.

The definition of post system action (PSA) Skip Rate and the methodology to calculate skip rates were developed with LCP Delta and shared with industry in December 2024. We are currently reporting the PSA skip rate numbers for both bids and offers calculated at stage 5, which represents the actions available to our balancing team within the Control Room in real-time. Following improvements to the dataset publication to remove inconsistencies around marginal units, we will expand this metric to include the skip rate for technology types next month.

An initial roadmap of our activities to improve transparency and reduce skip rates was presented at the Skip Rate Webinar in February 2025, shown below. Following establishment of the Dispatch Transparency Programme the roadmap is currently being updated and will be shared with Industry.

A successful in person forum was held on 1 May with Industry where we presented updates on our milestones and the establishment of the Programme.



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.

April 2025-26 performance

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

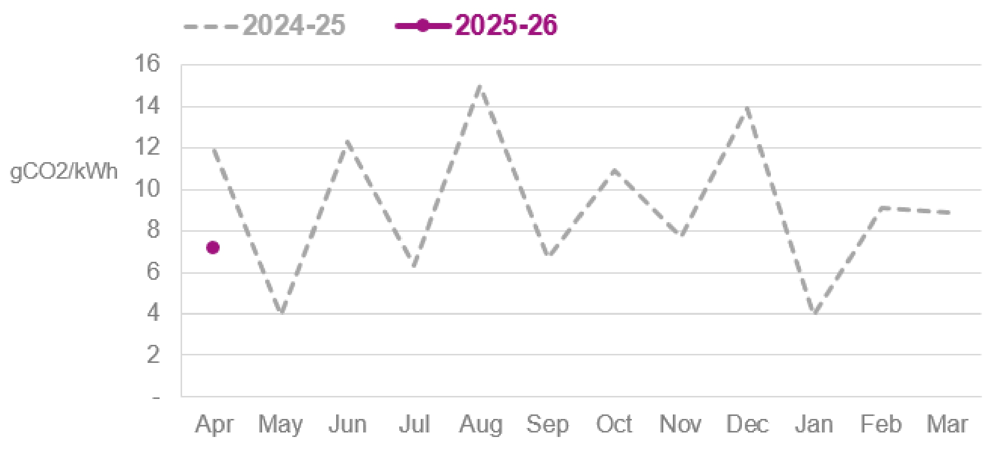


Table: Average monthly gCO2/kWh of actions taken by NESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	7.16											

Supporting information

The definition of Clean Power has now been incorporated into the changes to the generation in the ZCO. In April we continue to report the average monthly gCO2/kWh of actions taken by NESO in line with reporting requirements. Reporting statistics from May 2025 will incorporate biomass as clean power and reporting will also reflect this.

In April, the average monthly carbon intensity from NESO actions was 7.16g/CO2/kWh based upon ZCO definition (excluding biomass). This is 4.71g/CO2/kWh lower than the average at this time in 2024 when the average monthly carbon intensity from NESO actions was 11.87g/CO2/kWh (April 2024).

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 53.02g/CO2/kWh which took place on 27 April at 1400.

On 27 April there was high embedded solar and wind generation. Transmission demand was forecast to be low and required careful downward margin management resulting in NESO intervention.

6. Security of Supply

Performance Objective

Operating the Electricity System

Success Measure

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

This Reported Metric shows when the frequency of the electricity transmission system deviates more than ± 0.3Hz away from 50 Hz for more than 60 seconds, and where voltages are outside statutory limits. On a monthly basis we report instances where:

- The frequency is more than ± 0.5Hz away from 50 Hz for more than 60 seconds
- The frequency was 0.3Hz - 0.5Hz away from 50Hz for more than 60 seconds.
- There is a voltage excursion outside statutory limits. For nominal voltages of 132kV and above, a voltage excursion is defined as the voltage being more than 10% away from the nominal voltage for more than 15 minutes, although a stricter limit of 5% is applied for where voltages exceed 400kV.

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

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

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

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

Supporting information

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

[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.

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

Supporting information

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

National Energy System Operator
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Warwick
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www.neso.energy