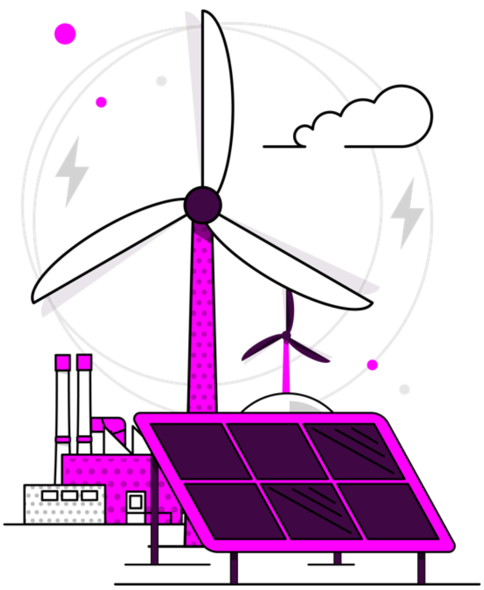
24 June 2025

Monthly Incentives May 2025 Report

Business Plan 3 (2025-26)

NESO
National Energy System Operator

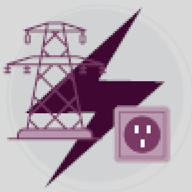
Contents



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 May 2025:

	Reported Metric	Performance
1	**Balancing Costs**	**£215m**
2	**Demand Forecasting**	Forecasting error of **692MW**
3	**Wind Generation Forecasting**	Forecasting error of **3.97%**
4	**Skip Rates**	Post System Action (PSA) Offers: **35%** Bids: **43%**
5	**Carbon intensity of NESO actions**	**13.36 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.

May 2025 performance

Figure: 2025-26 Monthly balancing cost outturn versus benchmark

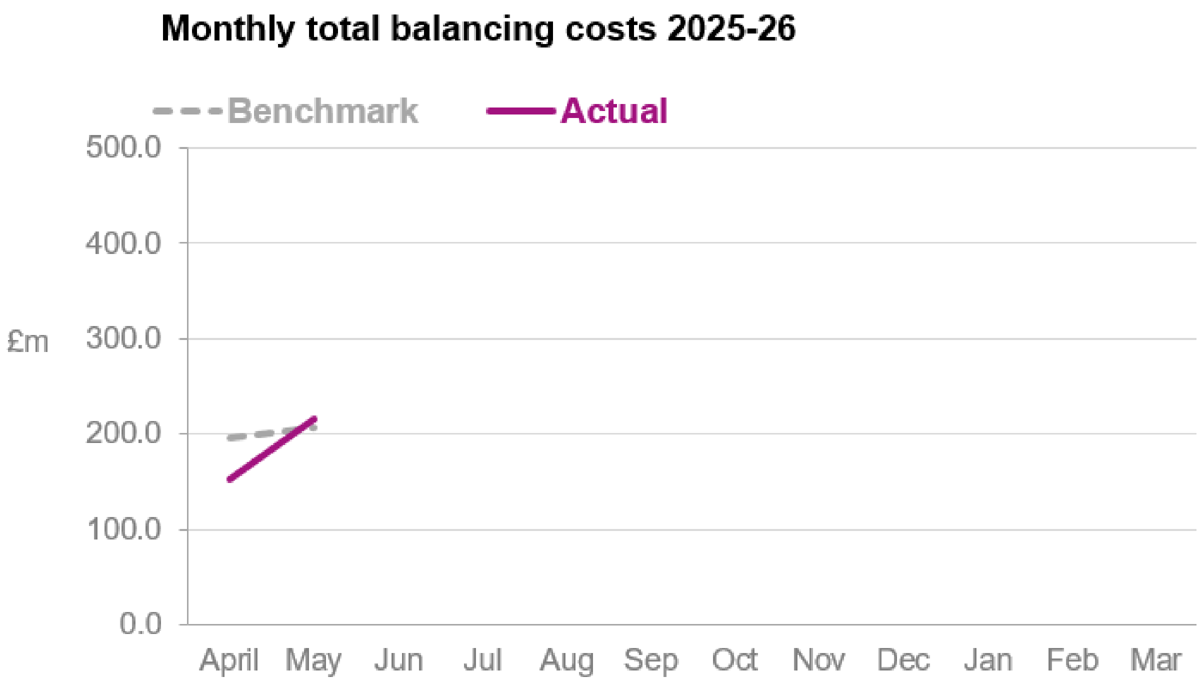


Table: 2025-26 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	4.1	4.7											8.8
Average Day Ahead Baseload (£/MWh)	81	77											n/a
Benchmark*	195	206											402
Outturn balancing costs[1]	**152**	**215**											**368**

[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.

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

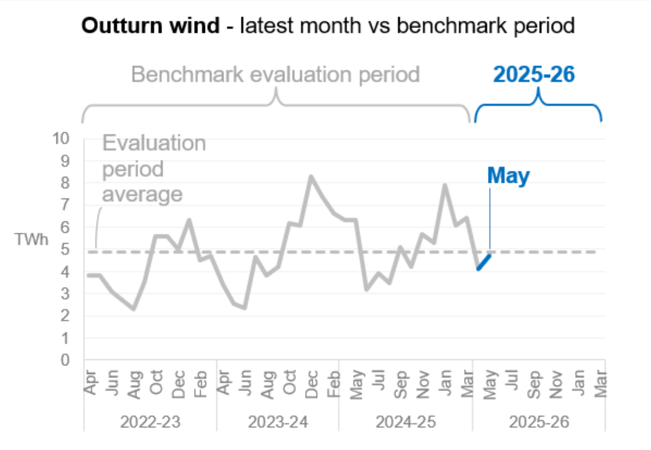
BALANCING COSTS METRIC & PERFORMANCE

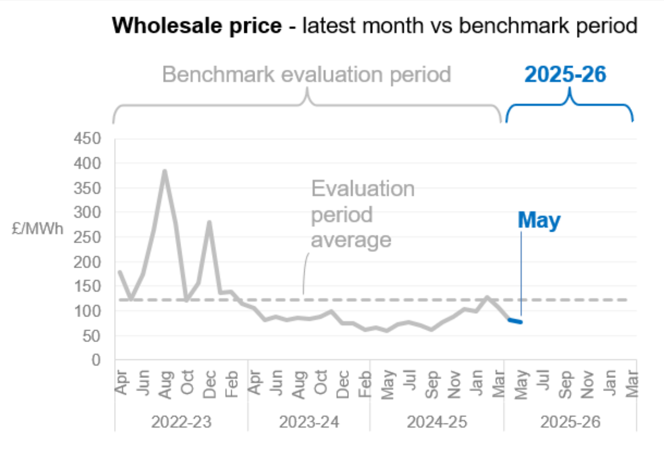
This month's benchmark

The May benchmark of £206m is £11m higher than April 2025 and reflects:

- An **outturn wind** figure of 4.7 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) however, is higher than April 2025's figure (4.1 TWh).
- An average monthly **wholesale price** (Day Ahead Baseload) that has decreased compared to April 2025 but remains higher than the previous year. However, it remains lower than the evaluation period average.

The higher wind outturn for May combatting the lower wholesale prices but being weighted higher is what caused the slight increase in May's benchmark compared to April.





Variable	May 2025	April 2025	May 2024
Average Wholesale Price (£/MWh)	**77**	**+4**	**-5**
Total Wind Outturn (TWh)	**4.7**	**-0.6**	**-1.5**
Benchmark (£m)	**206**	**+11**	**-40**

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

Balancing Costs - Overview

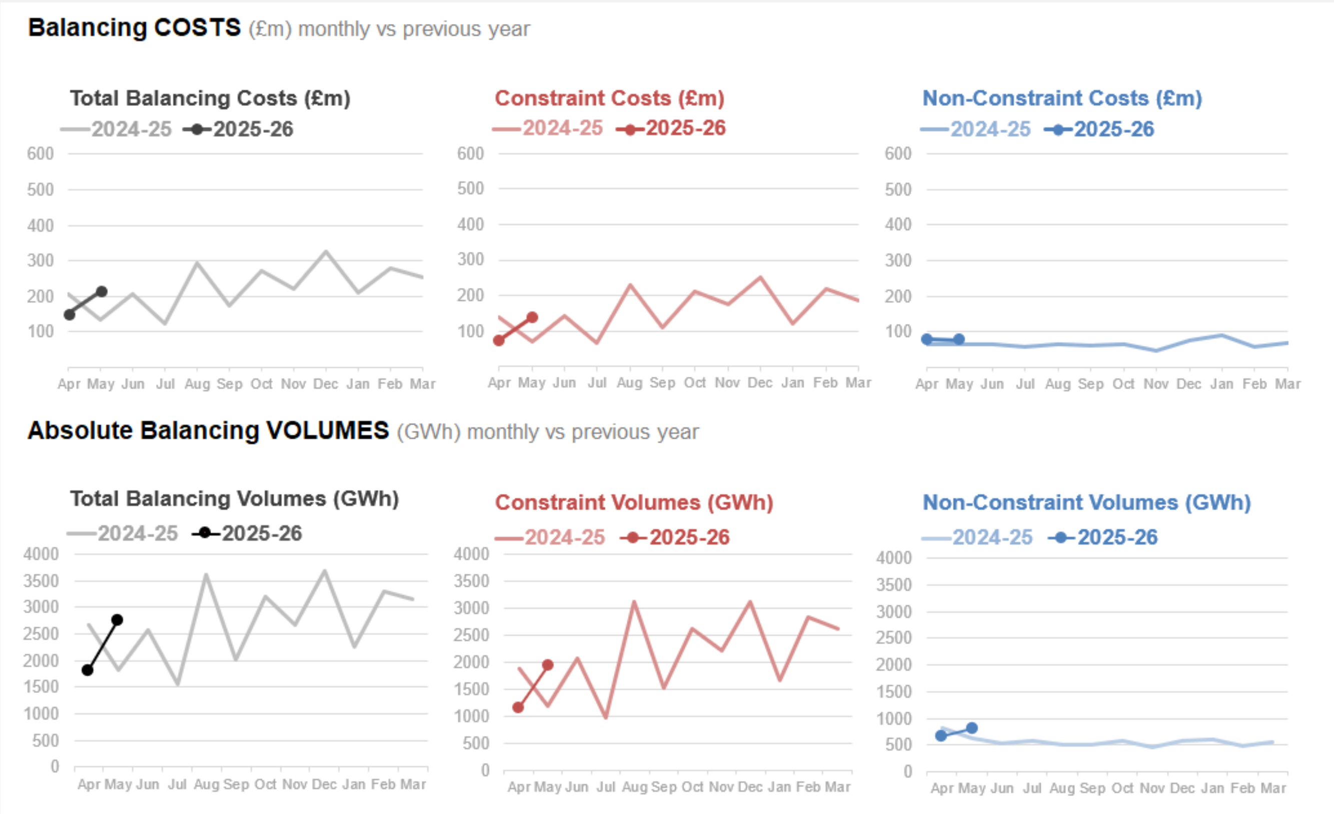
The total balancing cost for May was £215m, which is £9m (~4%) above the benchmark.

May was a month where total wind was high for the time of year. In the middle of May we had consistent lower levels of wind which resulted in low amounts of wind curtailment to begin with. However, the first and final week had significantly higher levels of wind, resulting in more wind curtailment and higher constraint costs, with 58% of constraint costs within Scotland.

A short-term outage in Scotland contributed to additional constraint spending for voltage and thermal management in the first week of the month, but the majority came towards the end of May with the bank holiday weekend which saw a historically low system demand period and high wind and solar generation which required significant re-dispatch actions by NESO. We also have ongoing outages taking place in Scotland causing various constraints on high wind days.

Voltage and inertia costs were up in May 2025, to their highest costs for the year so far at £38.1m and £8.3m respectively. The main driver for voltage costs being high was the low demand periods we have seen in May which means we have to dispatch synchronous generators to provide reactive power support which drives up these costs compared to when they would typically self-dispatch. An outage in the Midlands additionally caused increased need for voltage management. High inertia spending is also linked to the increased procurement by NESO for synchronous generators when we see low demand periods and high wind outturn.

Average wholesale prices were down £5/MWh from April 2025 and £1/MWh more expensive than May 2024. The volume weighted average (VWA) price of bids was £0.69/MWh showing the increased spending compared to last month's price of £10.3/MWh. The VWA price for offers increased marginally from £119/MWh to £122.2/MWh. Non-constraint costs have reduced by £0.4m, while non-constraint volumes have increase of 139GWh.

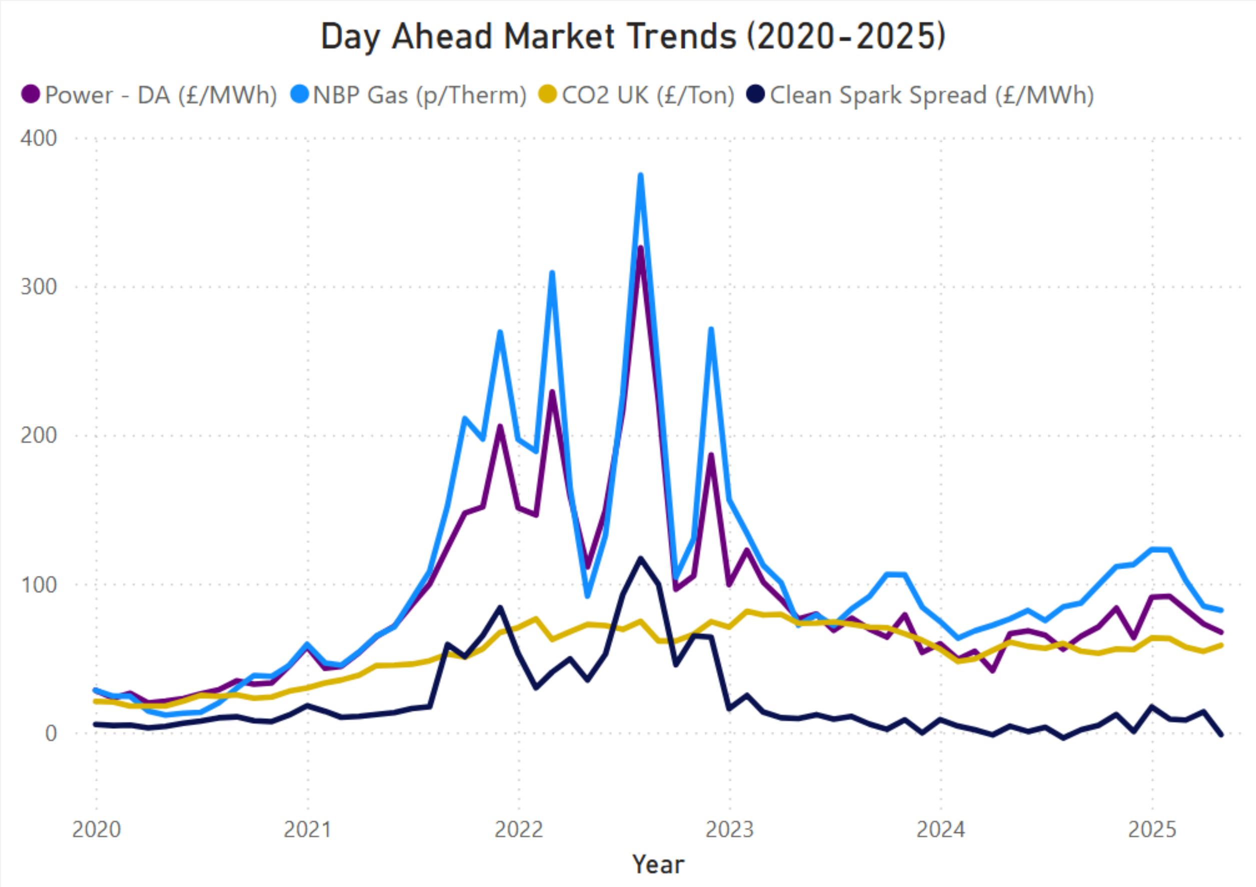


*Please note that the charts above now show <u>absolute volume</u> rather than net volume.

System and Market Conditions

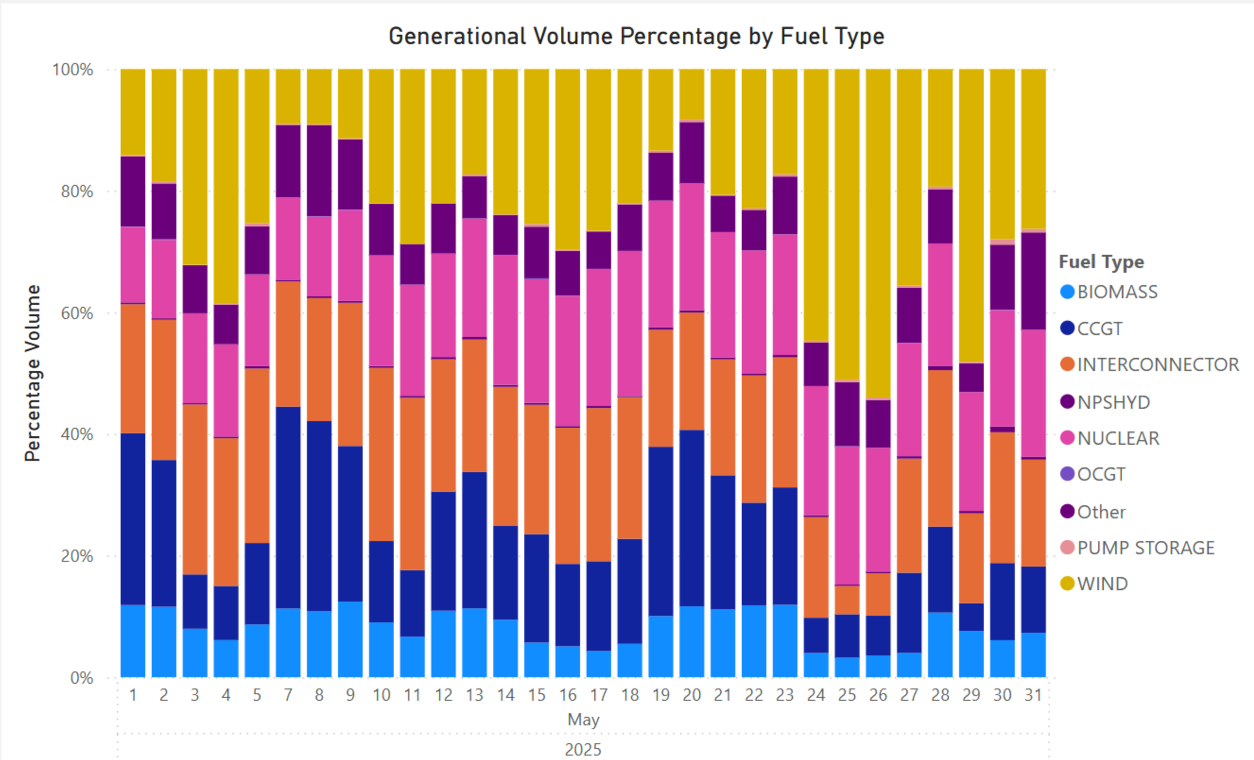
Market trends

Power and Gas prices continued to trend downwards in May 2025 with Power, Gas and Clean spark spread reaching their lowest prices so far in 2025 at £77.2/MWh, 83.0p/therm and -£3.5MWh respectively. However, Power and Gas Day ahead remain higher than May 2024. CO_2 prices rose slightly from £46.0/Ton to £51.1/Ton.



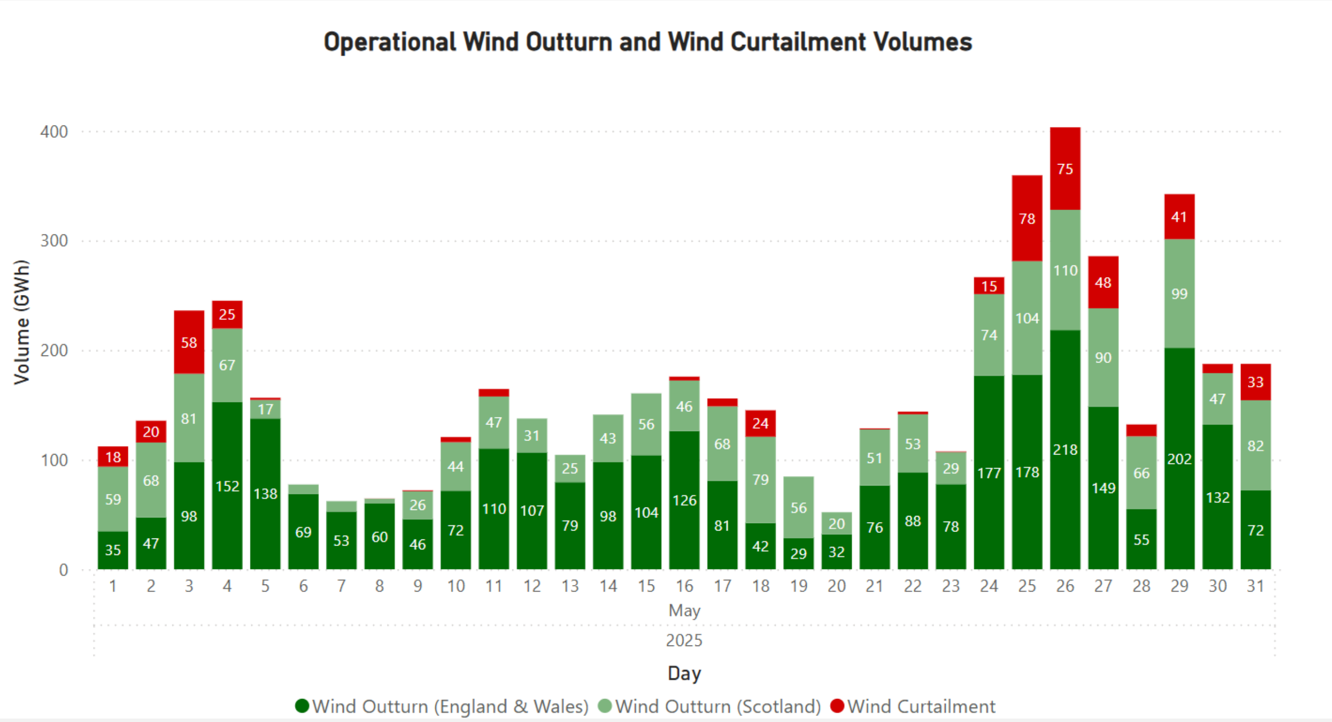
DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Generation and demand



In April we saw low wind which meant we had an increased reliance on CCGT, however in May we have seen a decrease in CCGT by around 4% of total generation and a volume reduction around 1TWh. Wind made up around 21% of volume in April however increased to 25% in May.

25 May was the highest balancing costs day and although wind outturn was higher on the 26th, we curtailed more volume on the 25th due to it being a very low demand day, which saw with the lowest demand half hour to date being recorded between 2:30 and 3:00pm. Due to the large portion of wind generation NESO had to run various units for voltage and inertia support which brought some of those costs up along with the curtailment of wind due to the low demand and also to allow the additional units required for inertia and voltage to run.

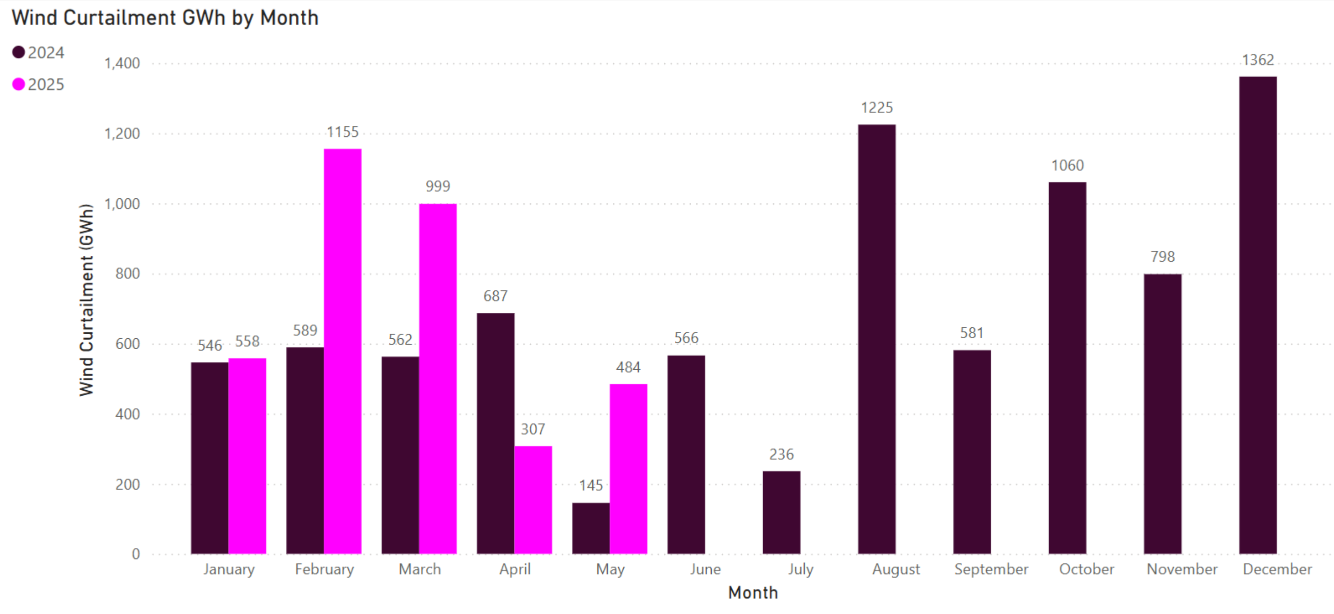


Wind Outturn

May saw mostly settled weather throughout the middle of the month, however the first week saw a couple of days with some higher than average wind speeds in northern Scotland and the final week showing some unsettled days due to a low pressure system.

Overall wind outturn in May was up from the previous month and same time last year, with 4.7TWh total, compared to 4.1TWh total in April 2025 and 3.2TWh in May 2024. This is mostly influenced by the final week in May showing higher averages than usual.

Total curtailment in May was up from April, at 484GWh compared to 307GWh in April. This is clearly shown above as mostly being influenced by the final week of May with the unexpected increase in wind generation.

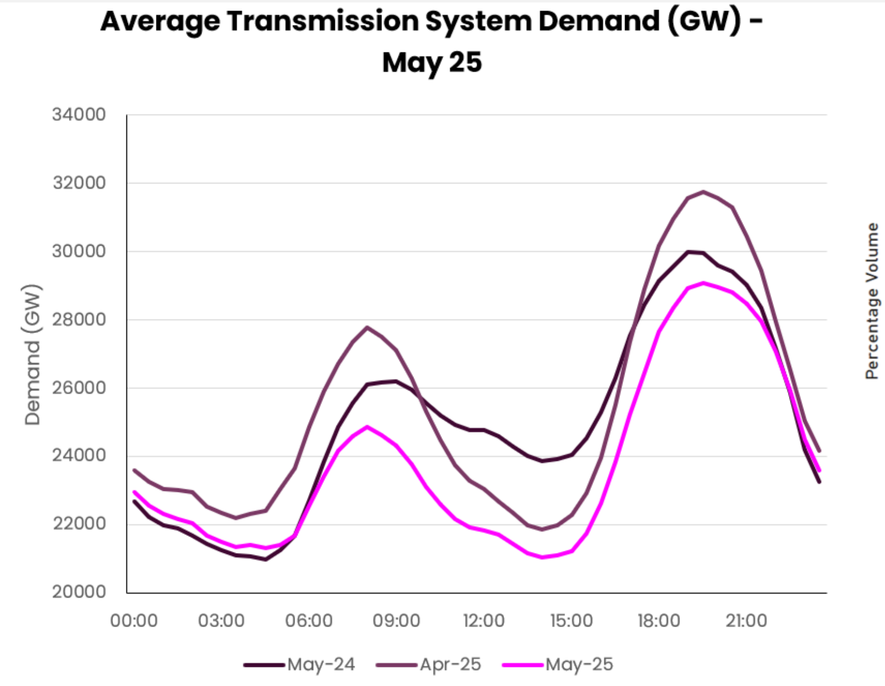


The day with the highest volume of wind curtailment occurred on the 25 May with 75GWh which aligns with the highest cost day of the month.

Transmission System Demand

May saw a historically low demand period on the 25 May at 2:30-3:00pm. But we saw extremely low demand over the whole month with the below showing average settlement period demand throughout May 2025.

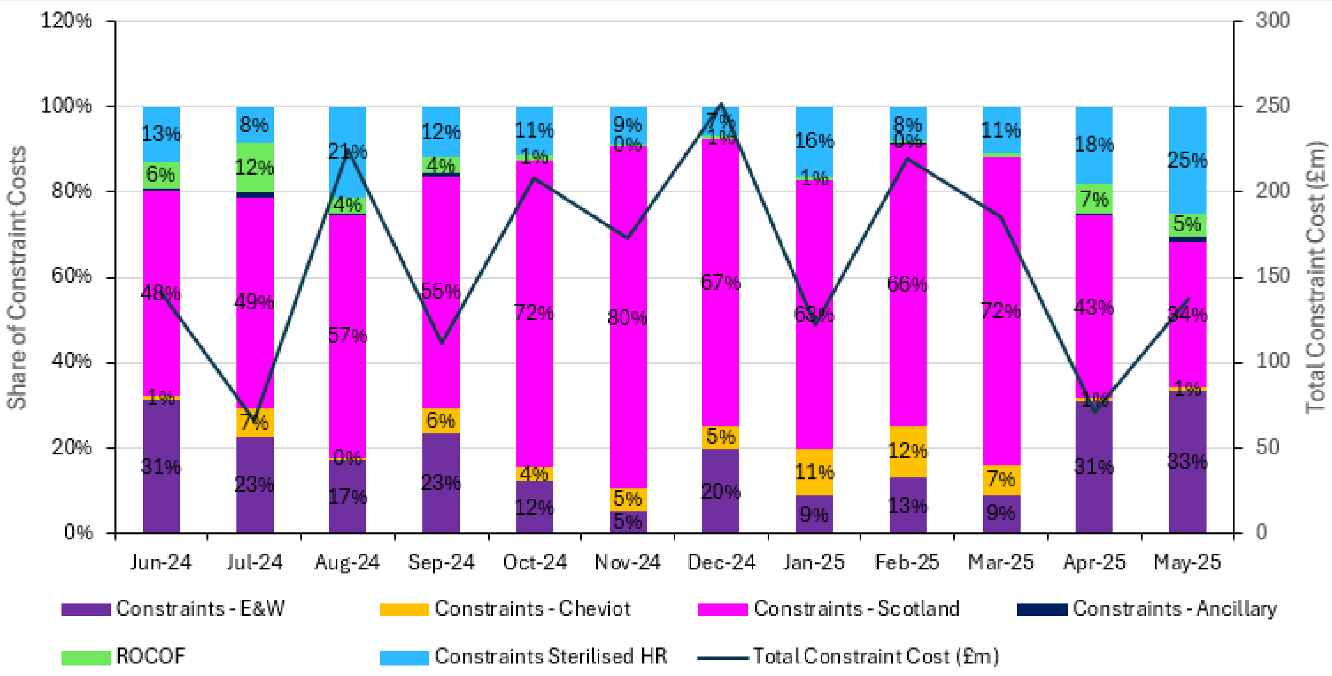
We can see it's significantly lower than May 2024 throughout the month. And most of the time we are also seeing lower demand levels than April 2025 except from the early hours of the morning. On average each settlement period was 9% lower than the previous month demand. Similar to April, May has seen an average daytime afternoon demand minimum that is lower that the overnight demand.



Constraints

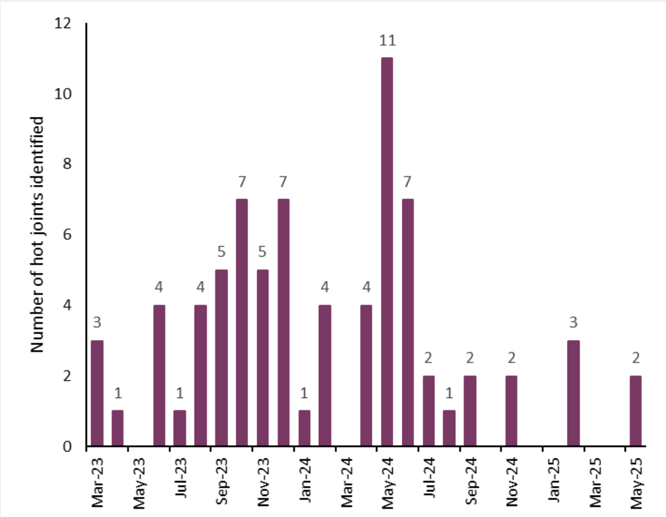
Constraint costs in May increased from £71.6m to £137.4m, an increase of £65.8m from the previous month. All constraint regions saw an increase compared to April 2025.

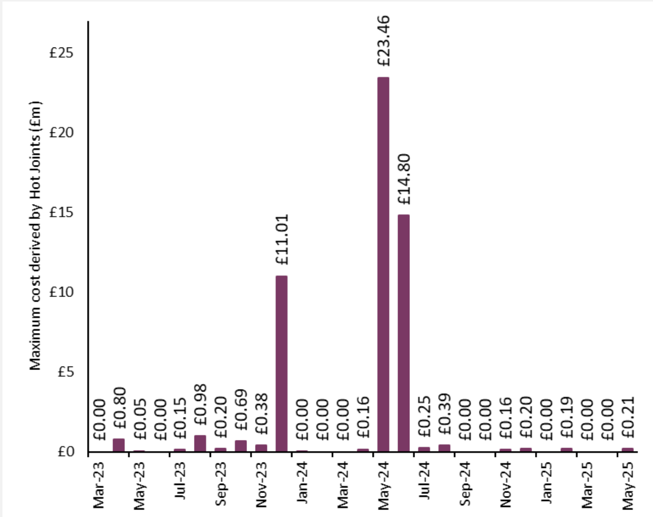
April was a substantially low month for wind curtailment where we saw around half the volume we saw in April 2024, however May 2025 did not follow this trend and we curtailed significantly more than May 2024 with 484GWh in May 2025, an increase of 349GWh compared to last year and 177GWh more than April. The key factors for this increase are the higher than average hypothetical wind generation along with the low demand periods at the end of May causing large volumes of wind to need to be curtailed for system security.



Network Availability

We continue to monitor the occurrence of hot joints in the system and their potential cost impact. Two hot joints were identified in May, one in Drax 400 kV and another in Kemsley 400 kV. The cost impact remained low with a maximum estimated value of £205k.





BALANCING COSTS DETAILED BREAKDOWN

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

		(a) Apr-25	(b) May-25	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Non-Constraint Costs	Energy Imbalance	4.1	2.5	(1.6)	
	Operating Reserve	12.4	16.5	4.0	
	STOR	4.8	4.4	(0.4)	
	Negative Reserve	0.6	0.3	(0.3)	
	Fast Reserve	10.6	8.8	(1.8)	
	Response	25.7	24.1	(1.6)	
	Other Reserve	1.0	0.6	(0.4)	
	Reactive	15.4	13.8	(1.6)	
	Restoration	3.3	4.7	1.5	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	2.2	2.2	0.0	
Constraint Costs	Constraints - E&W	22.1	45.8	23.7	
	Constraints - Cheviot	0.5	1.3	0.8	
	Constraints - Scotland	30.8	46.6	15.8	
	Constraints - Ancillary	0.2	2.2	2.0	
	ROCOF	5.1	7.3	2.2	
	Constraints Sterilised HR	12.9	34.3	21.4	
Totals	Non-Constraint Costs - TOTAL	80.0	77.9	(2.1)	
	Constraint Costs - TOTAL	71.6	137.4	65.9	
	Total Balancing Costs	**151.5**	**215.3**	**63.8**	

As shown in the totals from the table above, constraint costs increased by £65.9m and non-constraint costs decreased by £2.1m which results in the overall increase in costs of £63.8m compared to April 2025.

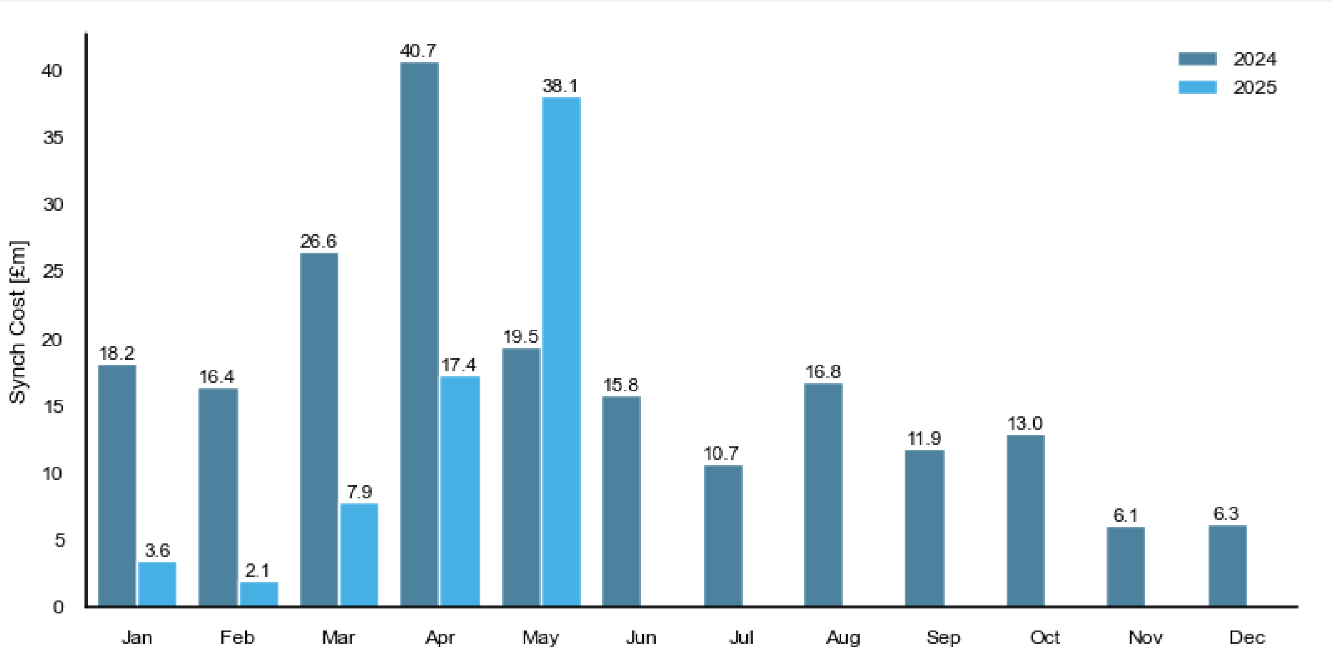
Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: +£16.6m **Constraint – England & Wales: +£23.7m** **Constraint Sterilised Headroom: +£21.4m** Constraint costs increased by £63.7m in April, coinciding with a 0.8 TWh increase in the absolute volume of actions. Wind outturn increased in May which has acted to increase the volume of actions to manage constraints, alongside ongoing outages in Scotland.	**Constraints – Scotland & Cheviot: +£32.2m** **Constraints – England & Wales: -£6.7m** **Constraints Sterilised Headroom: -£22.9m** Constraint costs have decreased by £67.8m compared to last year. Wind outturn increased significantly compared to its May 2024 level, which was particularly high for the time of year.

ROCOF: +£2.2m	ROCOF: +£5.0m
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. Higher wind outturn in April contributed to increased inertia regulation as non-synchronous generation met a larger proportion of the self-dispatched generation mix.	High wind outturn in May 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.

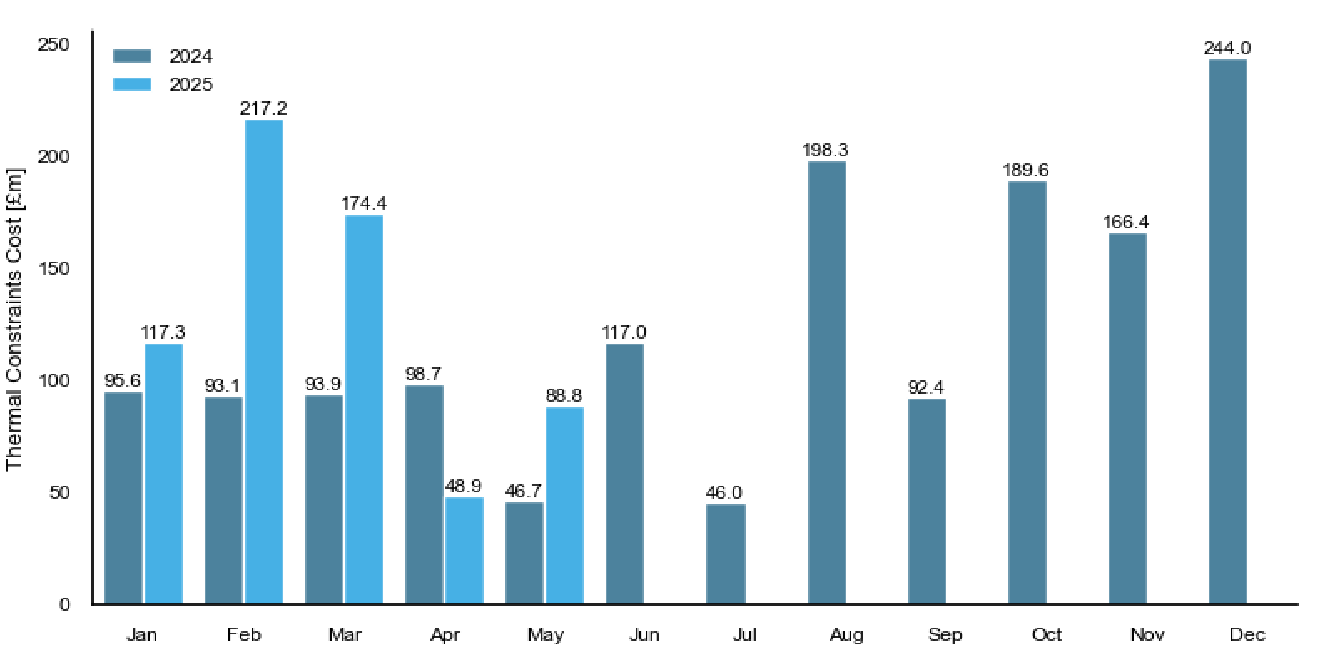
Voltage – Monthly system cost of synchronisation actions for voltage control across 2024 and 2025:

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 May, the system synchronisation costs (what it costs to the system, which factors in energy replacement, headroom among others) amounted to £38.1m, marking the highest record in 2025, and an increase of £18.8m on the same period in 2024.



Higher voltage costs have been driven by 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. There was also an increase in actions to manage voltage requirements in the Midlands in May as a result of outage works impacting voltage levels in the region. Work is ongoing to minimise voltage costs through 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 South Wales.

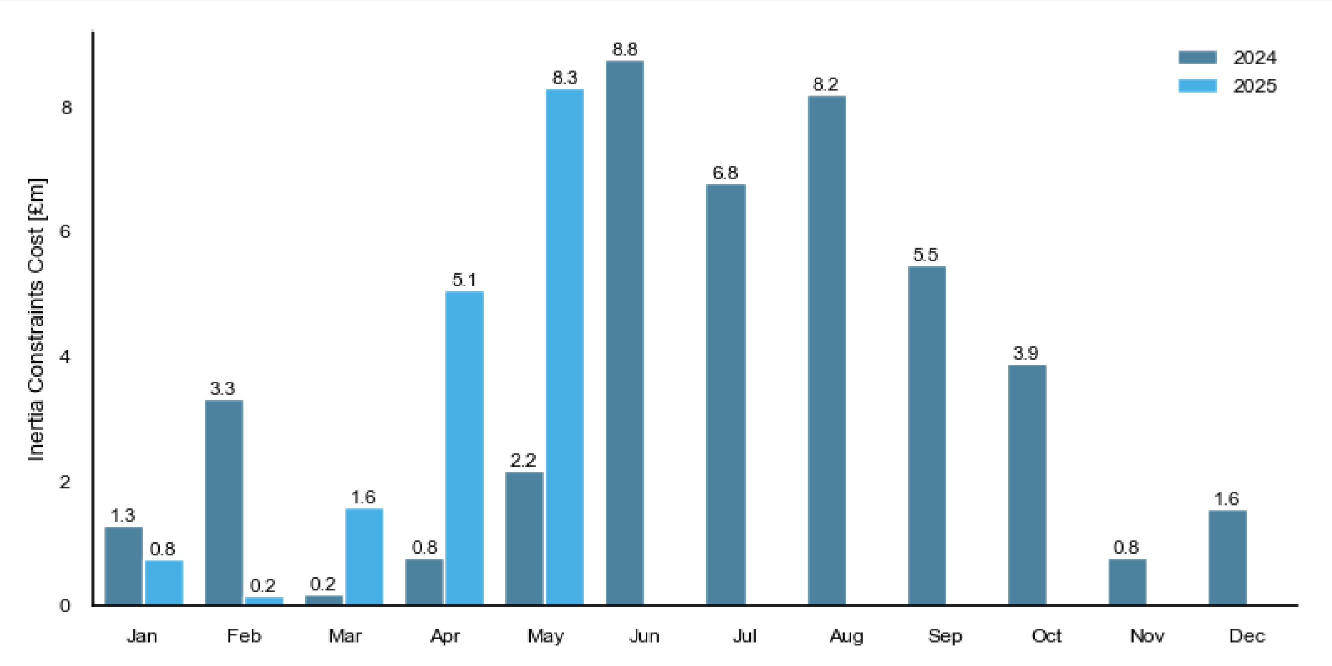
Thermal – Monthly system cost of actions for thermal management across 2024 and 2025: Thermal constraints are associated with operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, 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 May, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £88.8m, reflecting a rise in costs compared to the previous month (£48.9m) and the same period last year (£88.8m).



May was a month where total wind outturn was high for the time of year leading to an increase in wind curtailment (484 GWh). Ongoing planned outages in Scotland are also continuing to impact constraints in the Scottish region. Higher wind outturn consequently drove increase operational costs related to managing these constraint boundaries during May.

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 May, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £8.3m, marking the highest record in 2025. These costs are also higher compared to the same period in 2024 (£2.2m).



The expenditure on inertia in May rose mainly due to operational conditions related to periods of low demand and high wind outturn. This results in a lower number of synchronous units providing inertia 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

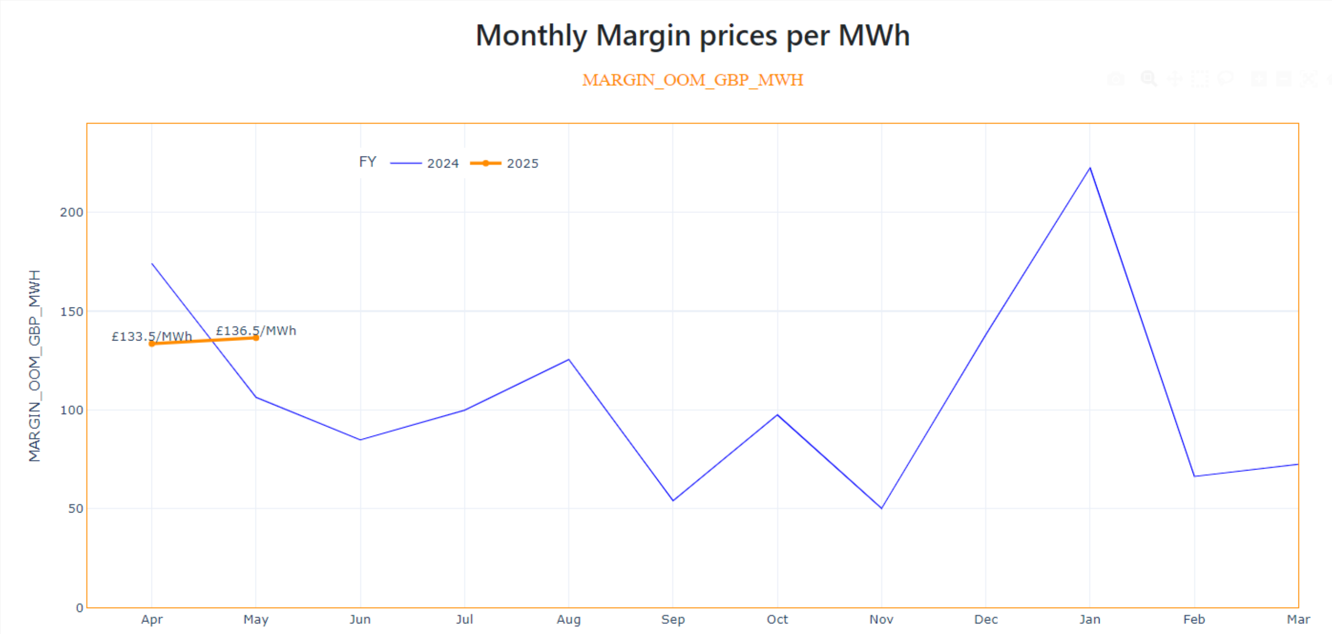
The volume-weighted average price for reactive power was £4.3/MVAr in May 2025.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£1.6m The volume-weighted average price decreased to £4.3/MVAr down from £4.8/MVAr in April.	**+£0.5m** The volume-weighted average price increased from £3.5/MVAr to £4.3/MVAr compared to last year.

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

Reserve Costs/Volumes

Reserve prices increased to £136.5/MWh in May from £133.5/MWh in April 2025. This is despite a slight decrease in the absolute volume of actions taken over May and the month on month fall in wholesale price.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£4.0m **Fast Reserve: -£1.8m** There was a 0.6 GWh decrease in the absolute volume of reserve required to secure the system compared to April.	**Operating Reserve: +£7.1m** **Fast Reserve: -£7.0m** There was a 42 GWh increase in the absolute volume of reserve required to secure the system compared to May 2024. Volume weighted reserve prices were higher year-on-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
-£1.6m There was an 8 GWh increase in the volume of actions compared to April but clearing prices for Dynamic Services were down on the previous month.	**+£10.7m** The volume of actions taken for response increased 55 GWh compared to May 2024. Clearing prices were also higher year-on-year.

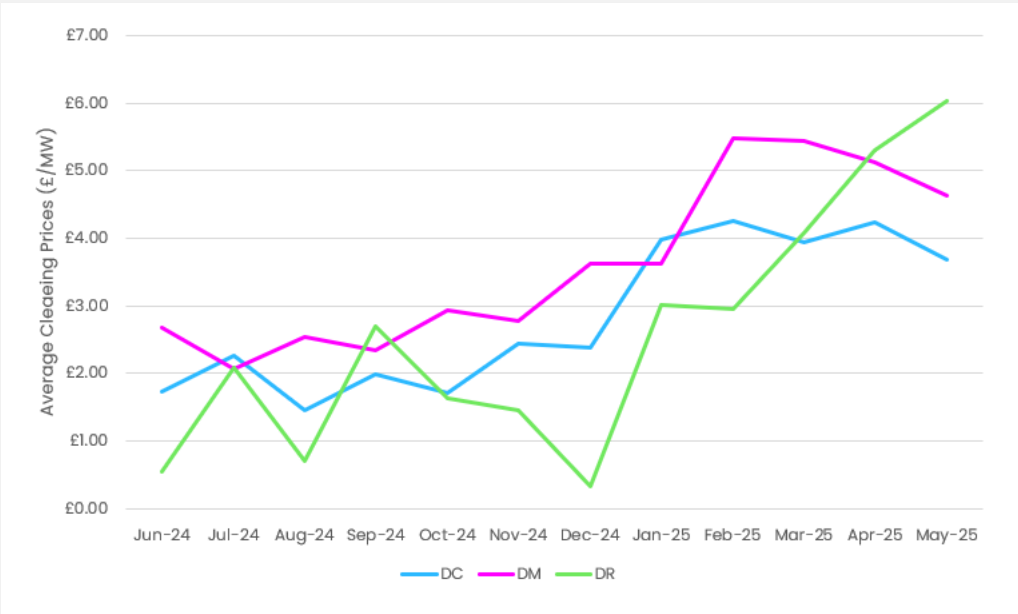
Dynamic Services Average Clearing Prices: May 2025 vs April 2025

		(a) May-25	(b) Apr-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	3.2	3.7	(0.5)	
	DM	4.6	5.1	(0.5)	
	DR	5.7	6.0	(0.4)	

Dynamic Services Average Clearing Prices: May 2025 vs May 2024

		(a) May-25	(b) May-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	3.2	1.7	1.5	
	DM	4.6	1.9	2.7	
	DR	5.7	0.5	5.1	

Average clearing prices were down for all three Dynamic Services in May compared to the previous month. This is in line with a reduction in wholesale prices and spreads. However, all three services saw an increase in average clearing prices to May last year.



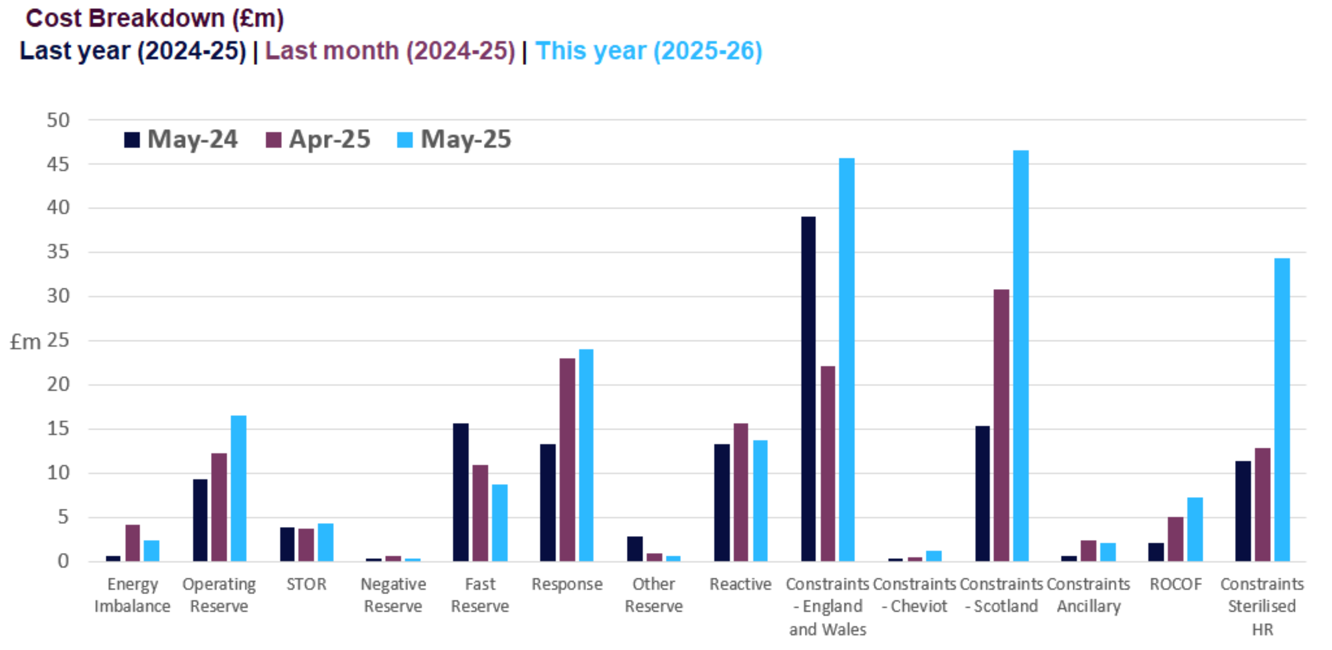
Comparison breakdown

Constraint costs were up by £65.9m compared to the previous month, this is due to increases across all constraint elements for May 2025 primarily due to high wind at the end of May and increased voltage and inertia management across the month. We saw a significant increase in England and Wales constraints up from £22m in April to £46m, an increase of £24m.

Constraint costs are also up from last year by a similar amount at £68m however with the largest increase being from the Scottish region by £31m up from £15m in May 2024 to £47m in May 2025. The main factor in this increase is the wind outturn and curtailment in May 2025 compared to 2024 which is shown in the wind outturn section.

Thermal constraints dominated May's costs with other elements being relatively similar to April cost breakdown with some elements such as reserve showing lower outturn costs in May than the previous month and last year.

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 £23m in May 2025. This represents a decrease of around £89m compared to April, where savings were £112m. The most valuable action involved implementing different running arrangements for two substations in the North-East (Keadby 400 kV and Thornton 400 kV), resulting in an approximate 1000 MW increase in transfer capacity for two system constraints. The estimated cost savings for this action was roughly £5.4m.

Cost Savings – Trading

The Trading team were able to make a total saving of £25.6m in May through trading actions as opposed to alternative BM actions, representing a 109% increase on the previous month. Trades savings were largely down to substantial trading for downwards margin, due to periods of low demand and high renewable generation, including some record high solar generation. Thus this meant that cheaper wind options were being largely bid off, the remaining alternative options were quite expensive, so trading was a more practical option. Trading against an alternative action of Emergency Instruction / Emergency Assistance was significant over the month, largely driven by the need to manage import and export flows on IFA. The greatest daily trading savings was £5.7m on the 4 May with the greatest component being for downwards regulation. The day with the greatest spend on trades was on the 10 May at a cost of £1.3m with the greatest component being for managing voltage constraints in southern central England.

Cost Savings – Network Services (NS)

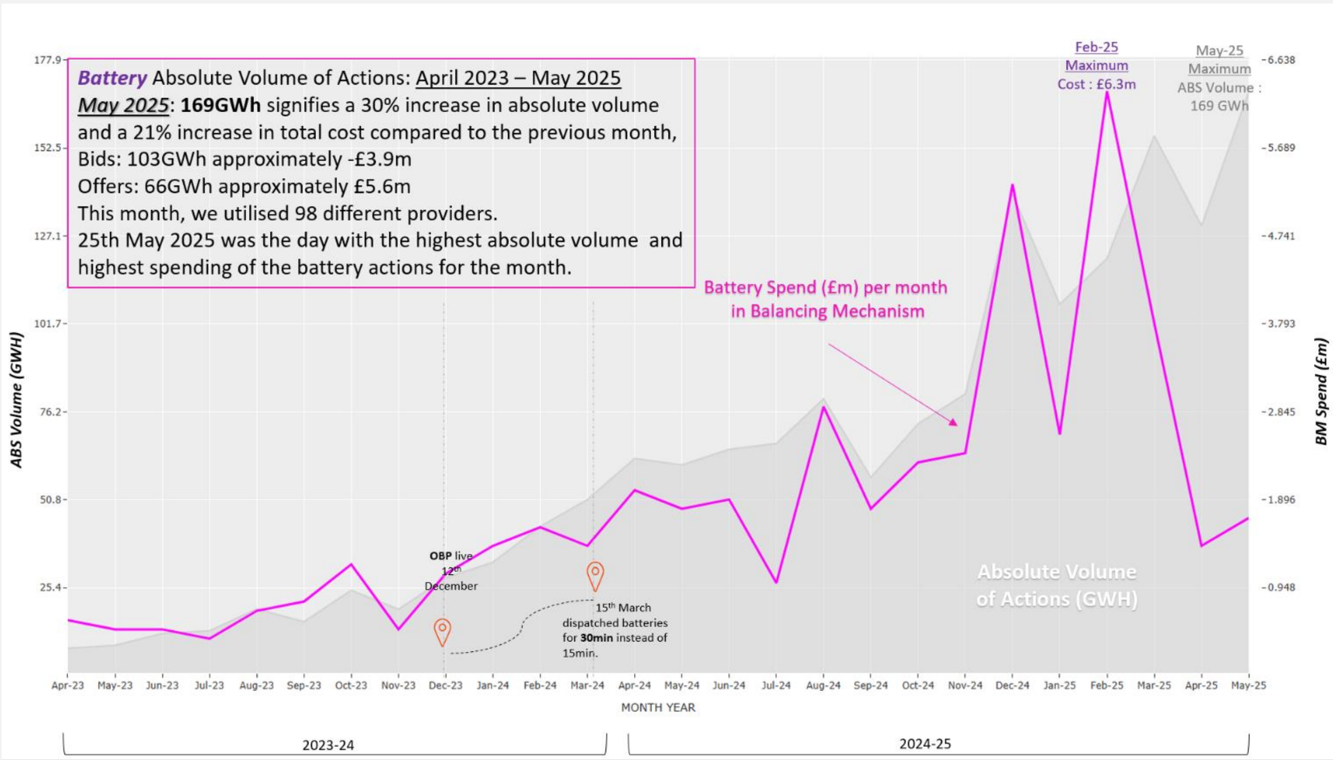
We are using Network Services (NS) to implement solutions to operability challenges in the electricity system. This includes the Constraint Management Intertrip Service, and Voltage & Stability pathfinders. We have calculated that the B6 and EC5 Constraint Management Intertrip Services, Voltage Mersey, Voltage Pennines, and Stability Phase 1 have delivered approximately £9m in savings in the first month of 2025/26.

NOTABLE EVENTS

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

May 2025

W



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 increased compared to the previous month, April 2025. The absolute volume of battery dispatch has nearly tripled compared to last April

2024, demonstrating our dedication to enhancing the flexibility of energy provided by battery storage and small BMUs over the last year. Most of the expenditure for batteries for this month was associated with constraints.

DAILY CASE STUDIES

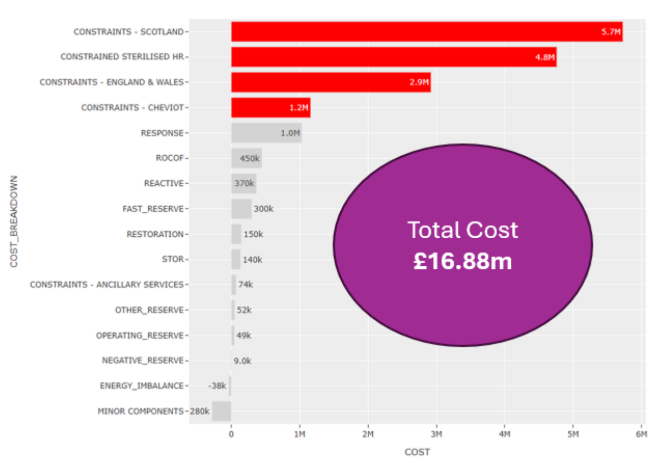
Daily Costs Trends

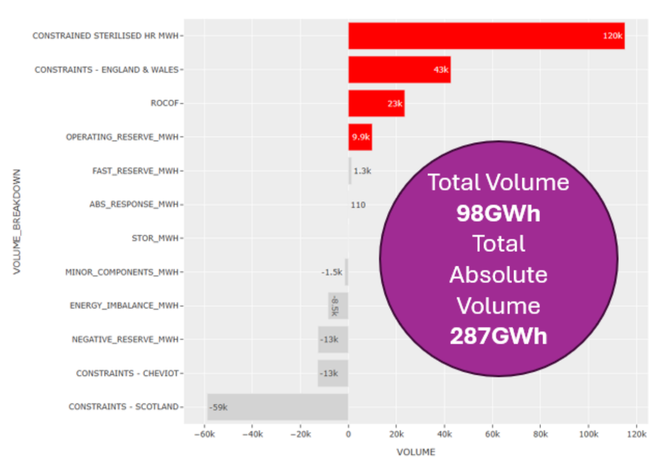
May's balancing costs were £216m which is £64m higher than the previous month. We had two days above £15m total costs which were the 25 and 26 May (bank holiday weekend) with the highest being the 25th. There was a further 3 days with costs above £10m which were 3, 27 and 29 May. The daily average cost increased by £1.7m from £5.3m in April to £6.9m in May.

The high cost day on 25 May had a total cost of £17m where the majority of these cost elements came from constraints which were caused by the high wind speeds and low demand on the grid.

The lowest day was on 9 May with a total cost of approximately £3.18m, being very closely followed by the 19th at £3.2m. 9 May saw high solar embedded generation which allowed the control room to reduce the number of actions taken to compensate for lower than forecast wind output on the day, with one cancelled action avoiding up to £145k in balancing costs.

High-Cost Day – 25 May 2025





May 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.

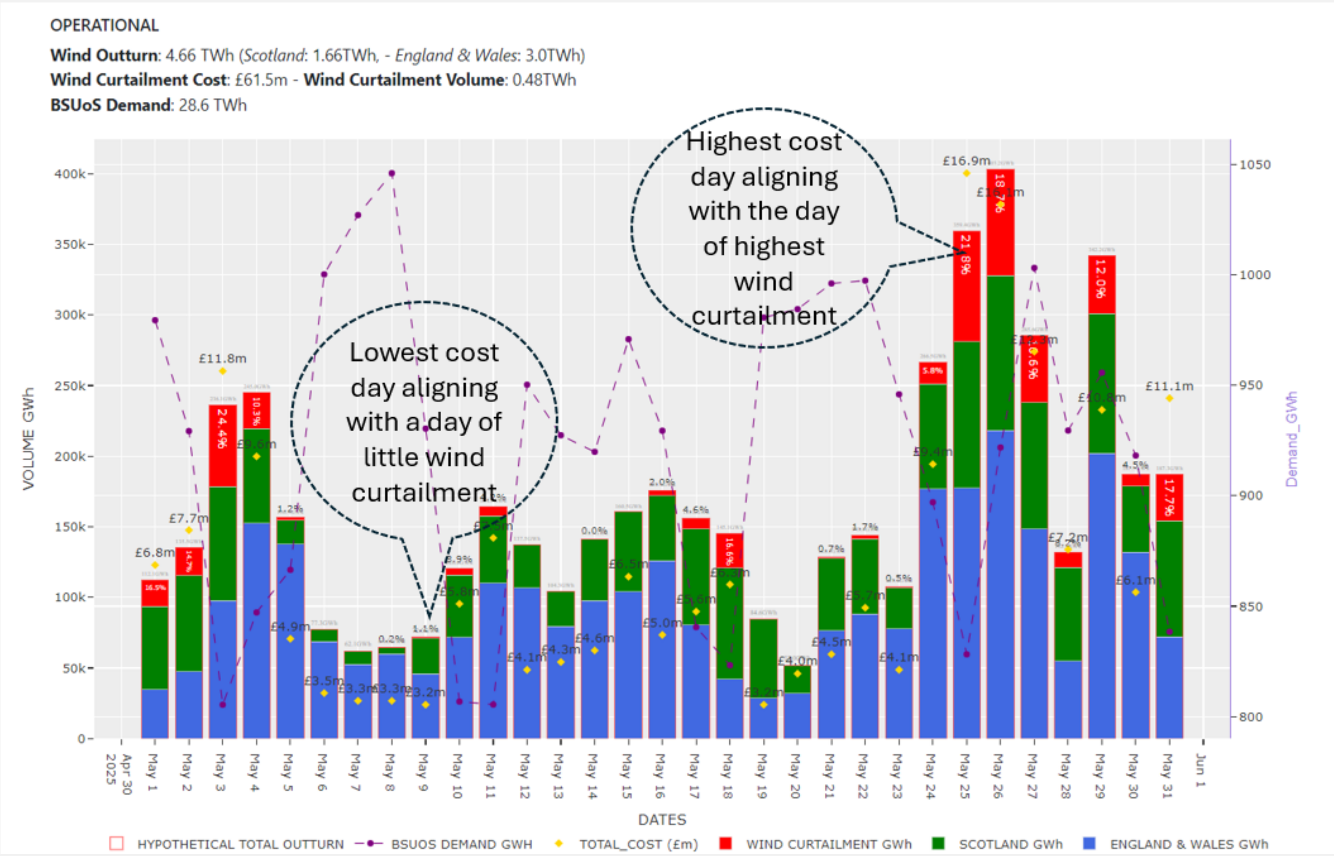
KEY: **Blue bars:** Wind generation in England and Wales

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).

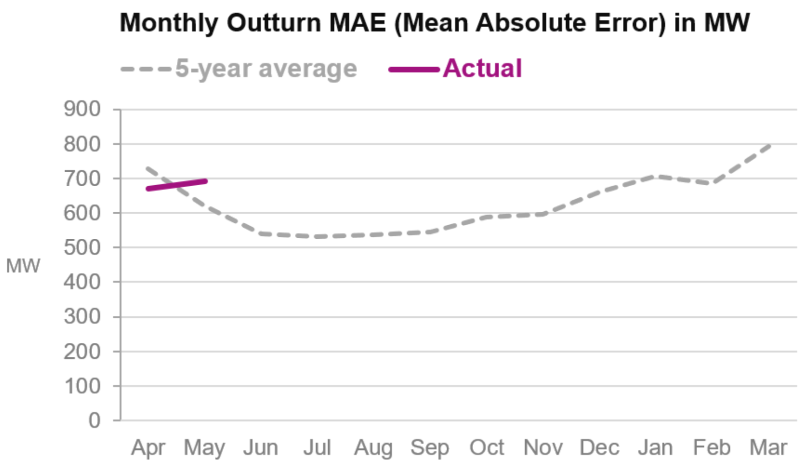
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each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

May 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**	**692**										

*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.

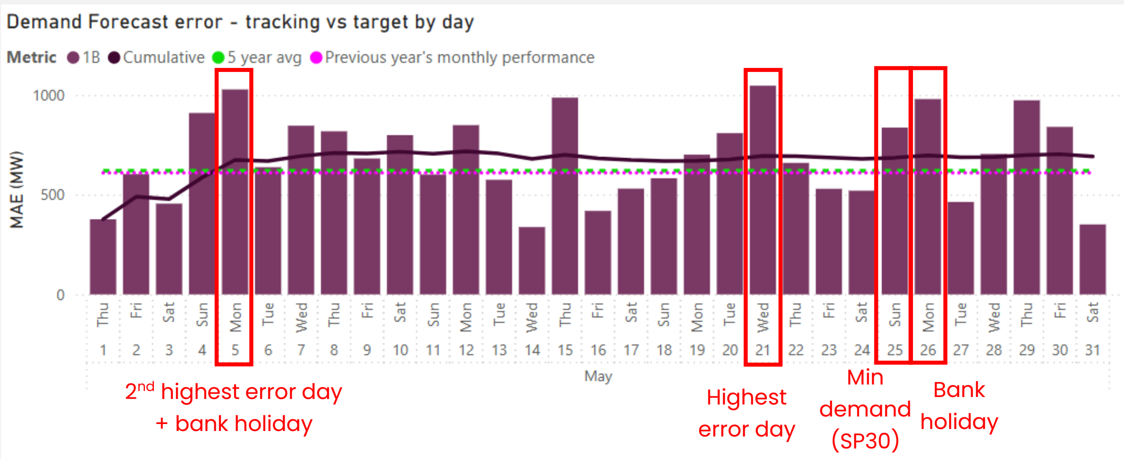
Supporting information

In May 2025, forecasting error averaged 692MW, an increase on the previous 5-year average of 620MW of 72MW (11.6%).

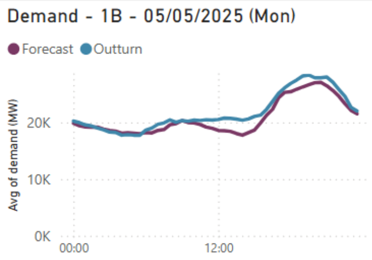
The remarkably good Spring weather continued in May, with continuous periods of sunshine.

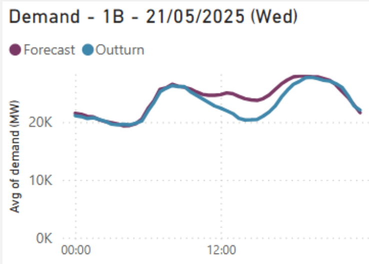
Solar forecasting errors remained the largest contributor to national demand errors, with the unseasonal sustained good weather compounding the reduced performance. New solar models are currently being tested and validated, to minimise such effects.

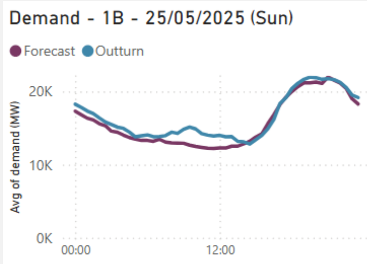
May witnessed the lowest demand on record to-date, dropping down to 12.8GW on 25 May (SP30). This was influenced by strong winds and clear skies over the Bank Holiday weekend.



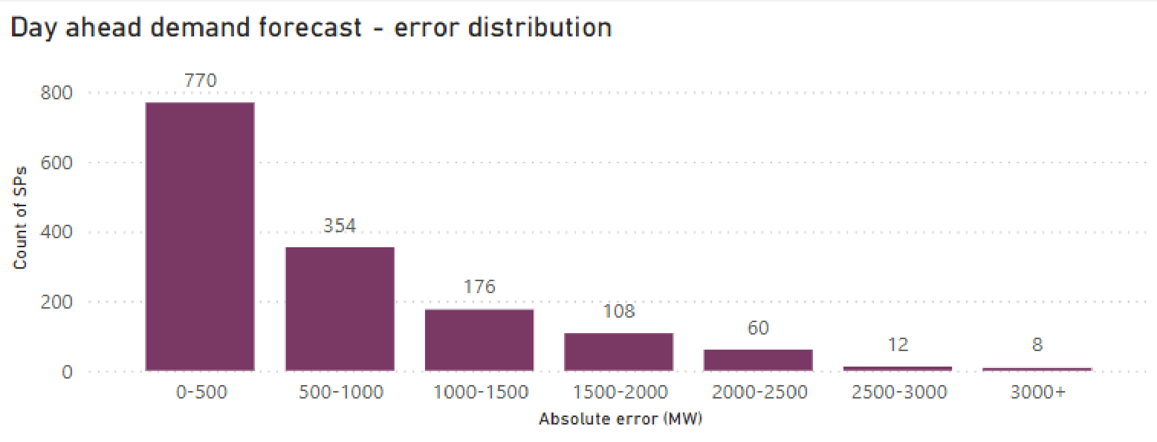
Days of Interest:



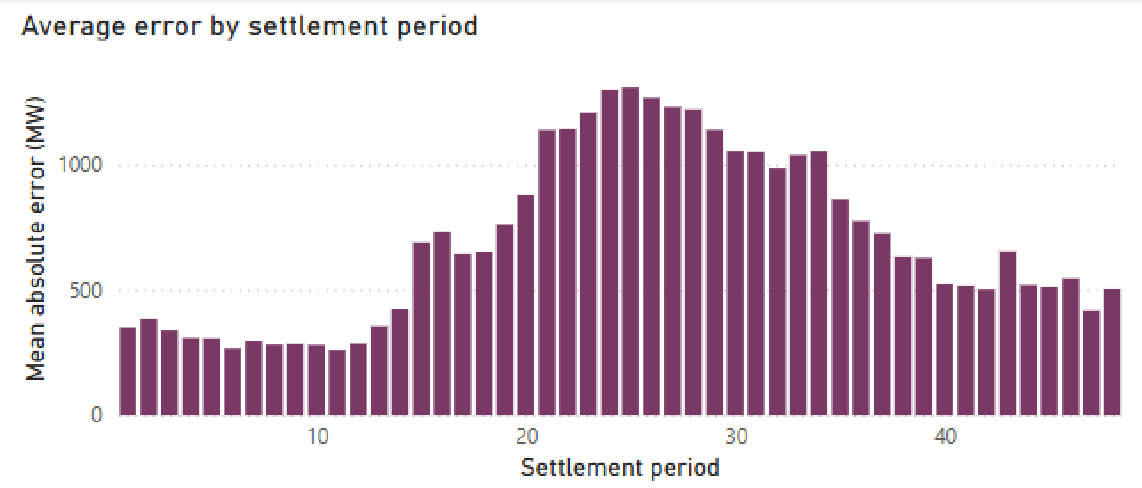




The distribution of settlement periods by error size is shown below:



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



The days with largest MAE were 5 May and 21 May.

Day	Error (MAE)	Major causal factors
5	1028	Solar forecasting errors and other weather effects influencing demand
21	1047	Solar forecasting errors

Missed / late publications

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

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 6, 7, 8, 9, 15, 16, 19, 20 and 28 May, with an accumulated total of 506MWh 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.

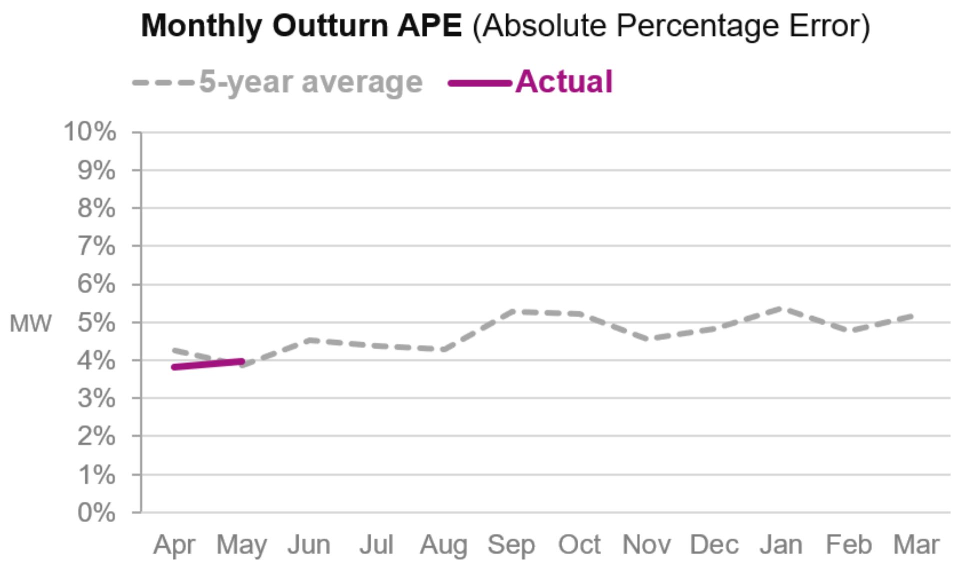
Sites deemed to have withdrawn availability are those that:

- 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.

May 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**	**3.97**										

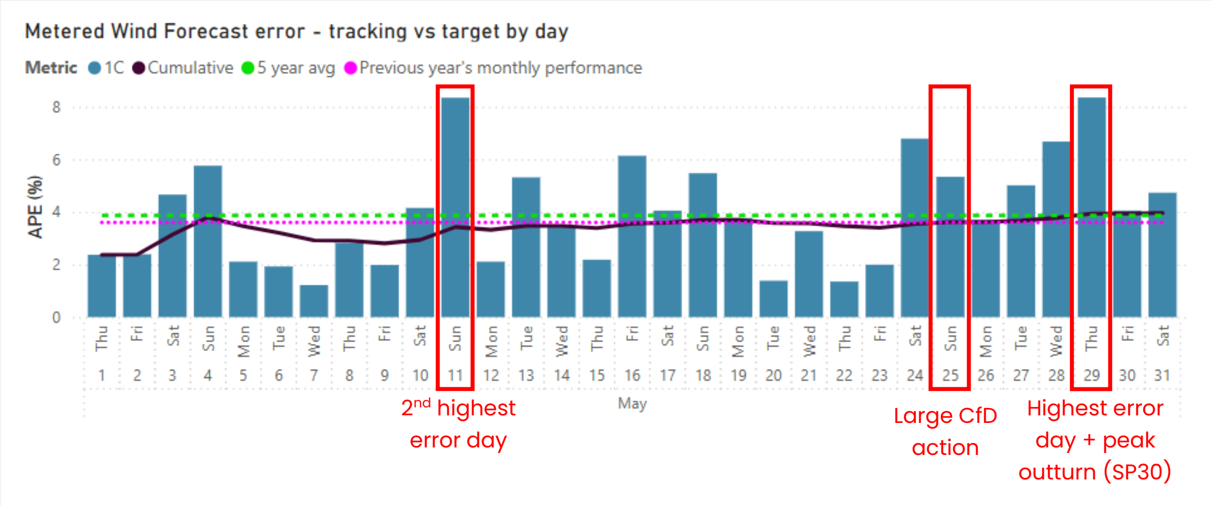
*Ofgem will no longer use a benchmark to assess our performance against this Metric however we will continue to report the previous 5-year average and last year outturn as an indicator.

Supporting information

In May 2025, BMU wind forecasting error averaged 3.97%, an increase on the 5-year average of 3.87%.

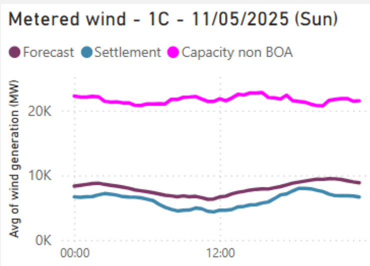
May was generally a mild month, with the first 3 weeks dominated by high pressure systems (causing calmer wind conditions). From 23 May, the weather turned more unsettled, with lower pressure and frontal systems bringing rain and more varied wind conditions.

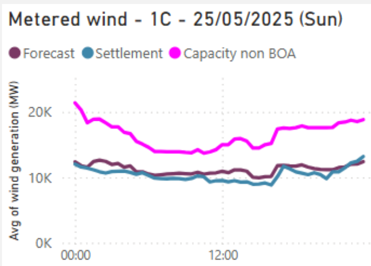
On 25 May, Day Ahead energy prices went negative for a large portion of the day – this was due to the extremely low national demand and very high renewable energy contribution. This market-pricing influenced the behaviour of some wind units with Contracts for Difference, who choose to self-curtail (~3.5GW). Note: this curtailment effect is naturally compensated for in the daily performance record.

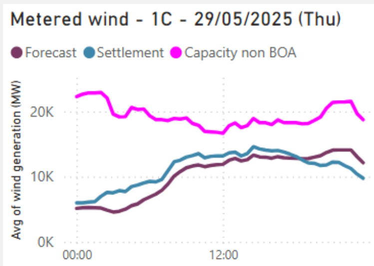


Wind generation peaked at 14.6GW on 29 May, SP30.
Wind forecast absolute error peaked at 3.4GW on 28 May, SP2.

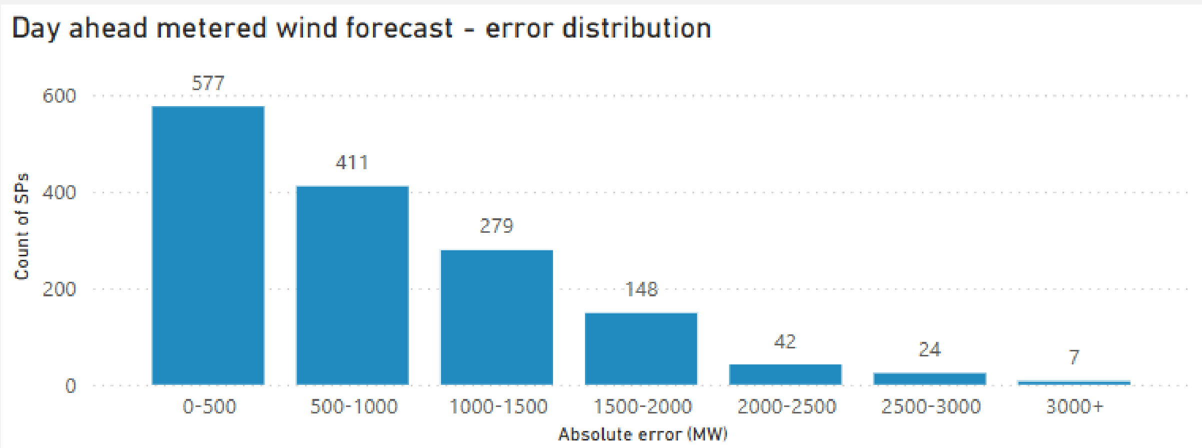
Days of Interest:







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



Details of largest error

Day	Error (APE)	Major causal factors
11	8.35	Wind speed forecast errors at day-ahead stage
29	8.36	Wind speed forecast errors at day-ahead stage

Missed / late publications

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

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%	35%										
Bids	45%	43%										

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										
Offers – in merit Energy volume	148	205										
Offers – All in merit volume (System & Energy)	504	901										
Bids – Skipped volume	150	154										
Bids – in merit Energy volume	336	352										
Bids – All in merit volume (System & Energy)	815	995										

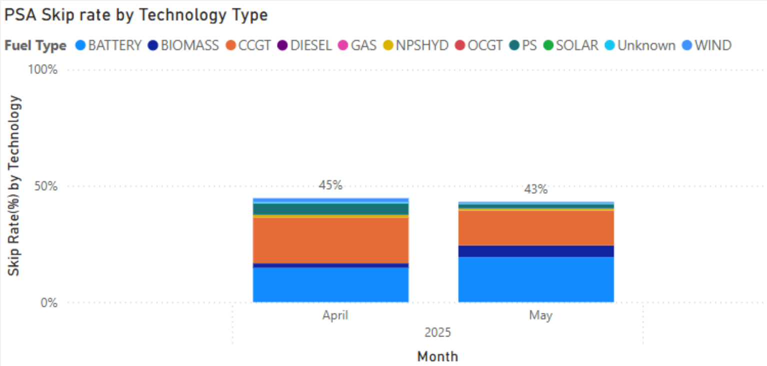
Supporting information

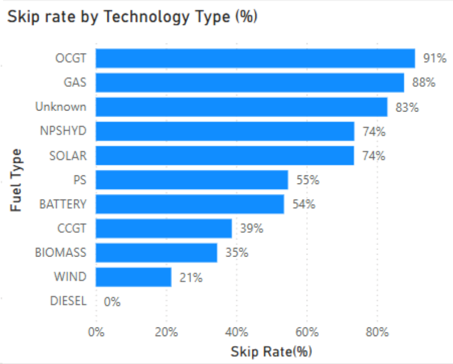
The Offer skip rate has reduced from 43% in April to 35% in May. Although the skipped offer volume was slightly higher in May than April the total in-merit energy offers was significantly increased in May due, in part, to the need to replace energy that was constrained off due the high level of wind and thermal constraints across the network. The Bids skip rate has remained fairly consistent from April to May both in terms of the percentage skip rate and the skipped volume; there was a slight increase in both skipped volume and in-merit volume due to the extra day in the month.

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. The different stages within the methodology represent the removal of different types of units that are not accessible to balancing engineers in real-time. The stages are provided to aid transparency around units excluded from the final calculation rather than representing operational stages of the power system

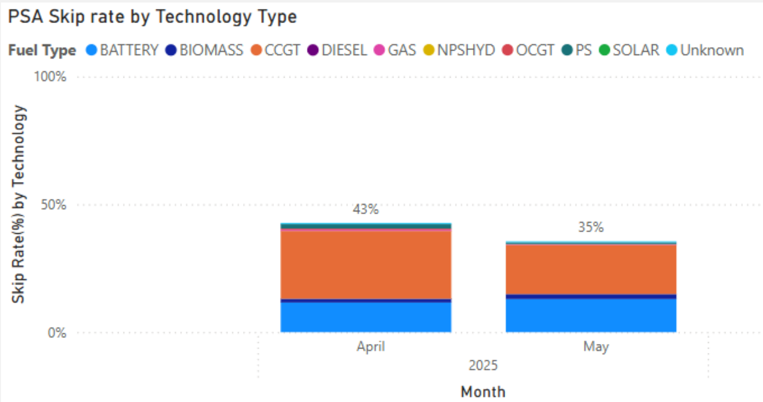
Following improvements to the published datasets to remove inconsistencies, we have expanded this metric to include the skip rate for technology types. We have included two calculation methods. The left graphs show how different technology types contribute to the overall skip rate. The right graphs show the skip rate within each fuel type, combined for April and May.

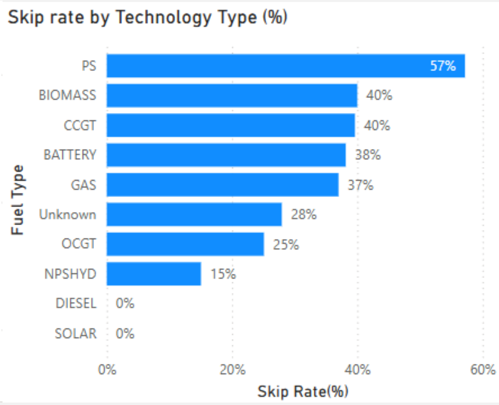
Bids





Offers





Note: In these graphs 'Gas' refers to gas reciprocating units, which are typically small, aggregated units.

See the April report for our Skip Rate Programme roadmap.

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.

May 2025-26 performance

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

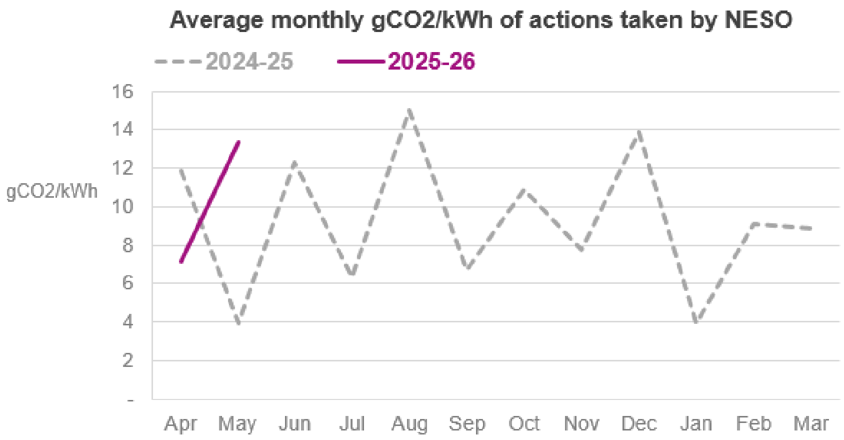


Table: Average monthly gCO2/kWh of actions taken by NESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	7.16	13.36										

Supporting information

In May we continue to report the average monthly gCO2/kWh of actions taken by NESO in line with reporting requirements. Alignment of CP30 with ZCO technologies would see the inclusion of biomass, which has yet to be reflected in reporting figures.

In May, the average monthly carbon intensity from NESO actions was 13.36g/CO2/kWh based upon ZCO definition (excluding biomass). This is 6.20g/CO2/kWh higher than last month and provides a YTD average of 10.26g/CO2/kWh.

The maximum difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the BM and the equivalent profile with balancing actions applied was 74.33g/CO2/kWh which took place on 3 May 2025 at 12.30. This is 21.32CO2/kWh higher than the highest point in April 2025 which took place on 27 April at 1400.

On 3 May NESO intervention was required to manage voltage and inertia levels to manage downward margin.

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.

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

Supporting information

There were no reportable voltage or frequency excursion in May 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.

May 2025-26 performance

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

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

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

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

Supporting information

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

National Energy System Operator
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