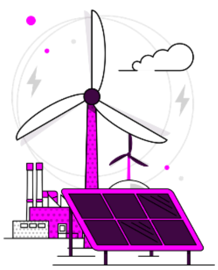
23 September 2025

Monthly Incentives August 2025 Report

Business Plan 3 (2025-26)

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

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

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

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

Reported Metrics

Summary of Reported Metrics

The table below summarises our Reported Metrics for August 2025:

	Reported Metric	Performance
1	**Balancing Costs**	**£236m**
2	**Demand Forecasting**	Forecasting error of **579MW**
3	**Wind Generation Forecasting**	Forecasting error of **4.03%**
4	**Skip Rates**	Post System Action (PSA) Offers: **31%** Bids: **40%** Combined: **36%**
5	**Carbon intensity of NESO actions**	**12.11 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**	**1** planned and **0** unplanned system outages

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.

August 2025 performance

Figure: 2025-26 Monthly balancing cost outturn versus benchmark

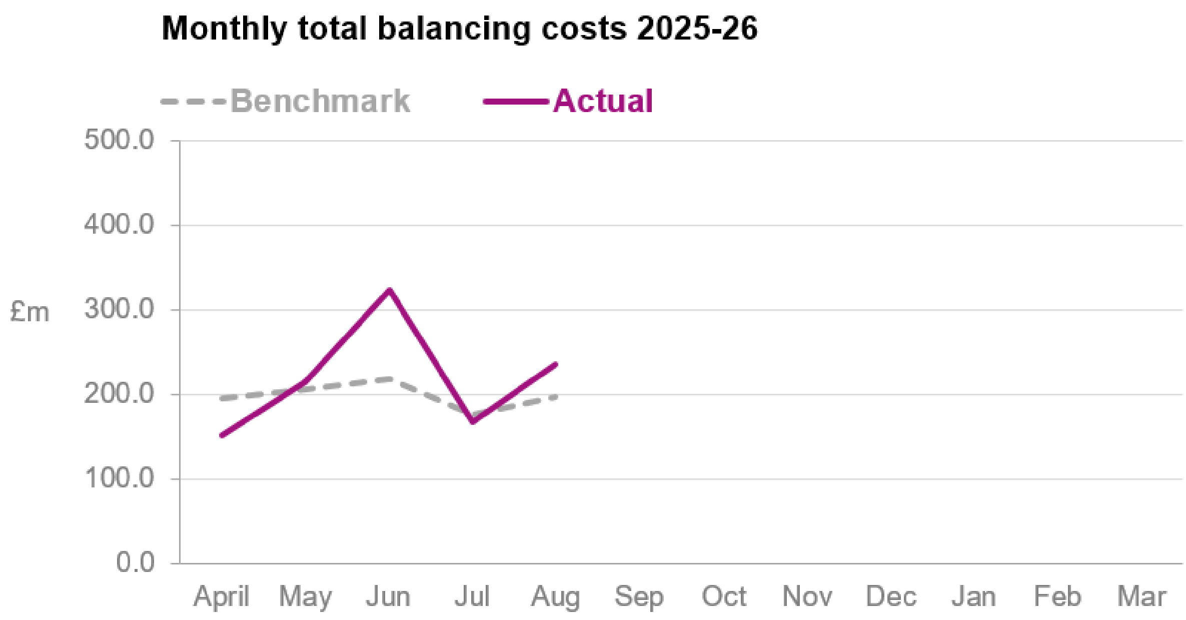


Table: 2025-26 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	4.1	4.7	5.4	3.3	4.4								21.9
Average Day Ahead Baseload (£/MWh)	81	77	73	80	73								n/a
Benchmark*	195	206	219	176	197								994
Outturn balancing costs[1]	**152**	**215**	**324**	**167**	**236**								**1094**

[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

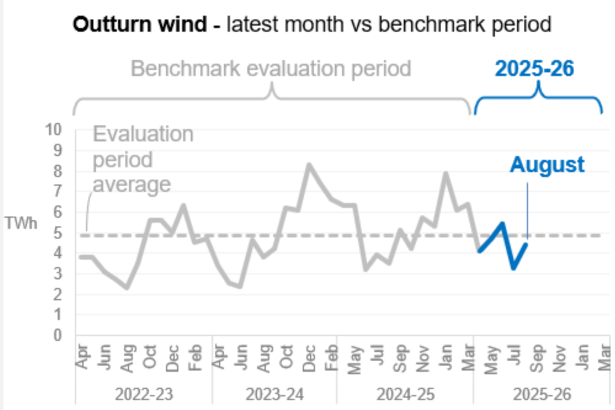
BALANCING COSTS METRIC & PERFORMANCE

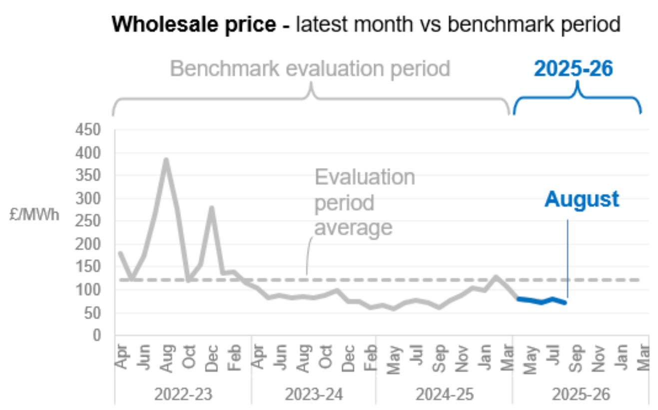
This month's benchmark

The August benchmark of £197m is £21m higher than July 2025 and reflects:

- An outturn wind figure of 4.4 TWh that is lower than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 5.0 TWh) and is higher than July 2025's figure (3.3 TWh).
- An average monthly wholesale price (Day Ahead Baseload) that has decreased compared to July 2025 and is higher than the previous year. However, it remains lower than the evaluation period average.

The higher wind outturn has caused the increase in August's benchmark compared to July but has been somewhat negated by lower wholesale prices.





Variable	August 2025	July 2025	August 2024
Average Wholesale Price (£/MWh)	**73**	**+7**	**-11**
Total Wind Outturn (TWh)	**4.4**	**-1.1**	**+0.7**
Benchmark (£m)	**197**	**-21**	**+5**

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

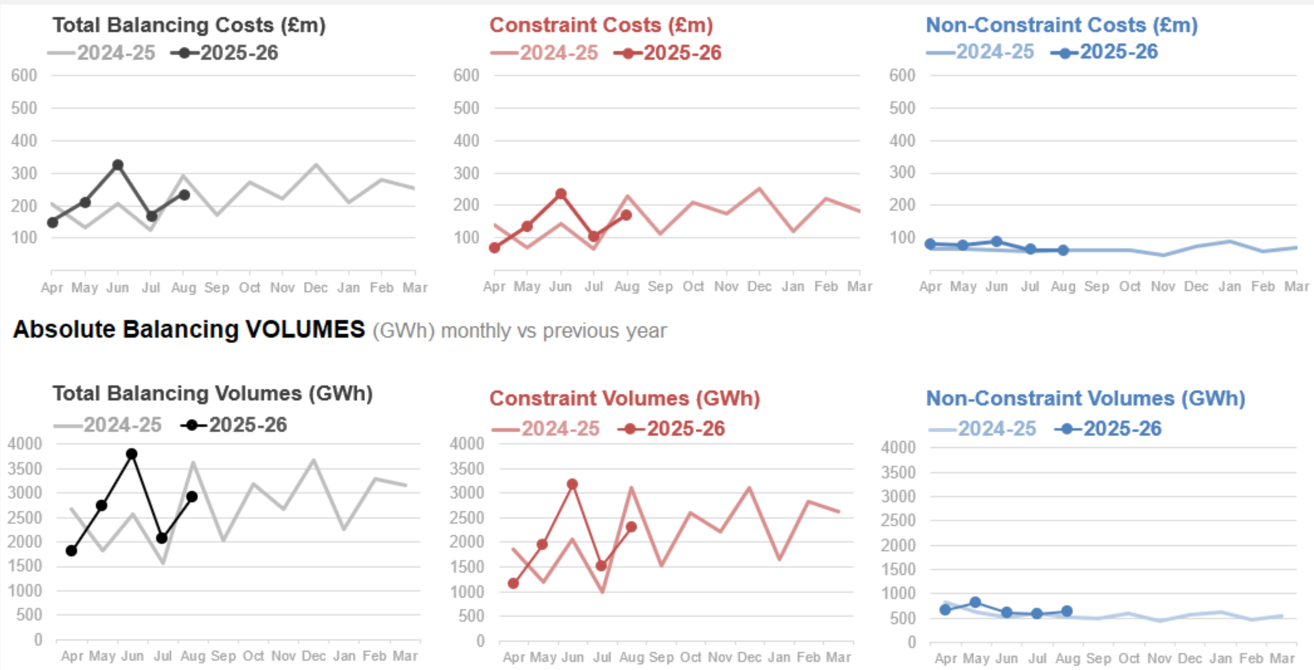
Balancing Costs – Overview

The total balancing cost for August was £235.5m, which is £38.5m (~20%) above the benchmark.

August saw an uptick in wind outturn compared to the previous month for the year at 4.4 TWh, up from 3.3 TWh in July. This has supported a significant increase in constraint costs, with wind curtailment volumes up to 811GWh from 428GWh last month. Voltage and stability constraints also saw an increase in costs compared to last month, in part linked to higher wind outturn in the system. Higher wind meant that some synchronous units (mostly CCGTs) that usually provide reactive and inertia support are displaced to meet demand, which forces us to procure those services through the Balancing Mechanism.

A return to more changeable weather conditions in August meant that the cost of thermal constraint costs increased from July. This included Storm Floris which particularly affected northern Scotland. The cost of thermal constraints has however reduced in comparison to August 2024, which had been a particularly high costing month last year due to abnormally high wind outturn for the time of year.

Average wholesale prices decreased by £7/MWh from July 2025 and increased £11/MWh from August 2024. The volume weighted average (VWA) price of bids was -£10.2/MWh, which is more expensive than July's price of £5.2/MWh. The VWA price for offers has decreased from £124.5/MWh to £121.2/MWh. Non-constraint costs have decreased by £0.8m, following an increase in the absolute volume of non-constraint actions 53.7GWh.

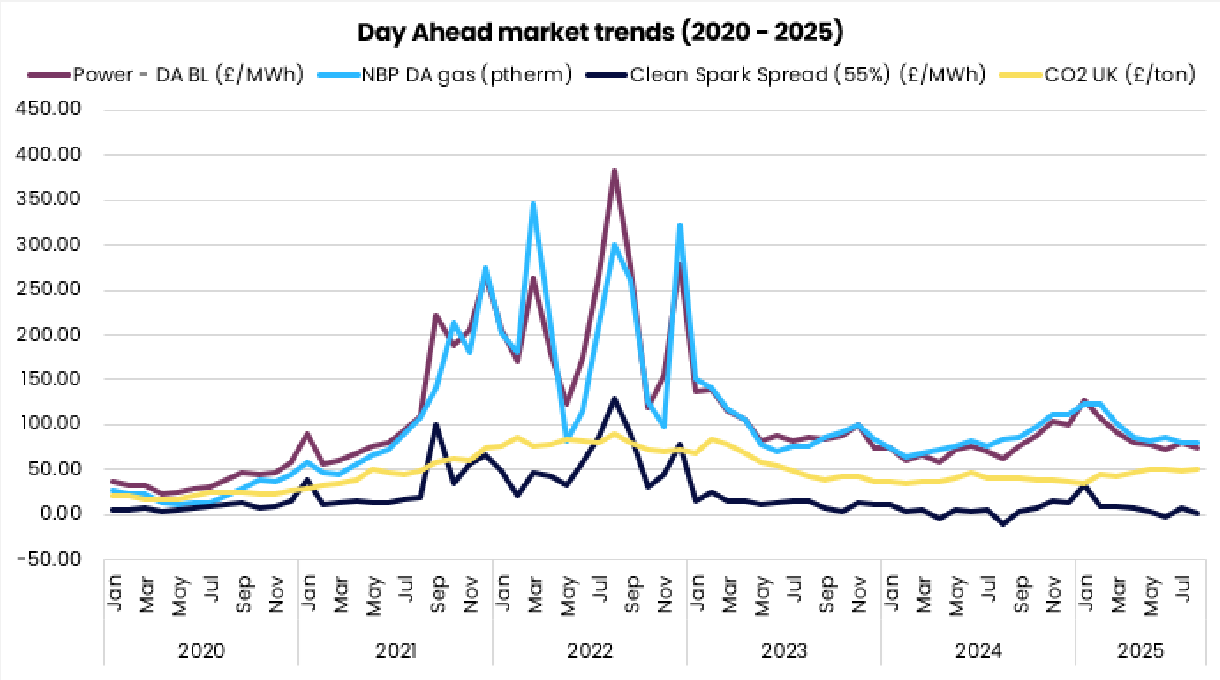


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

Market trends

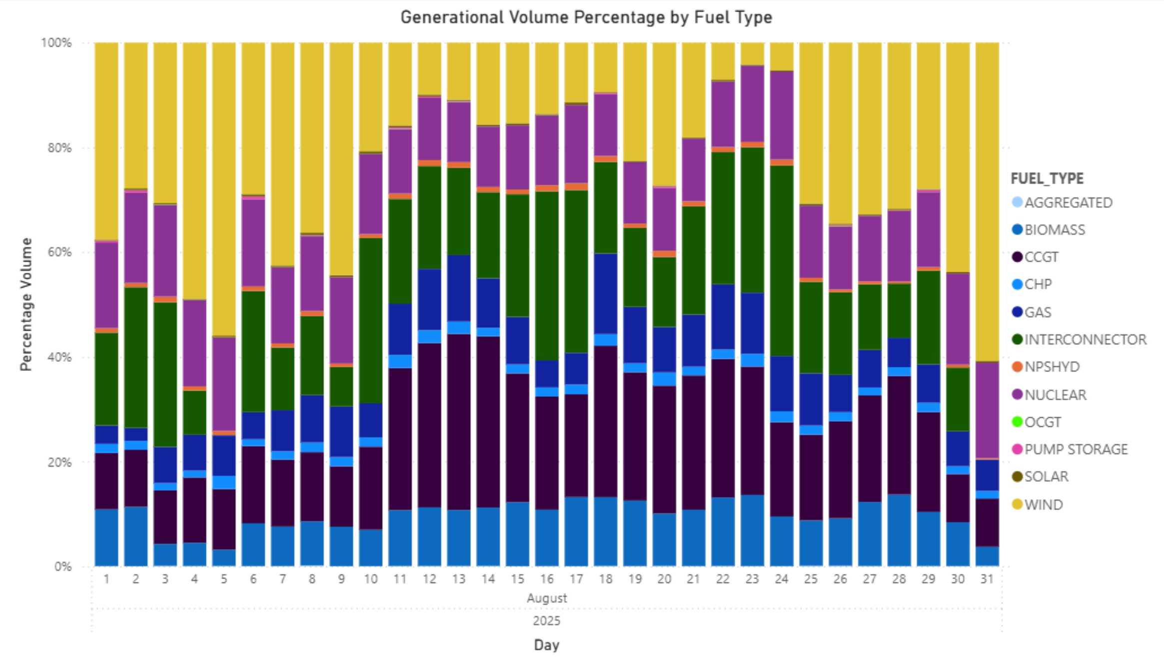
After a slight rise in July's power prices to £80.25/MWh, the prices in August (£73.43/MWh) dropped back to a similar level as June (£73.01/MWh). There was also a subsequent drop in the Clean Spark Spread Price from last month. Gas prices have continued to fall slightly this month, reaching 79.27p/therm. After a dip last month, CO2 prices have risen again to £51.55/ton, a price more representative of May and June. Due to some geopolitical uncertainty during the month of August, there has been a mixed outlook for gas and carbon prices this month. Heatwave and low wind conditions early in August were driving higher power prices but were replaced by more seasonally average temperatures by the end of the month, though with mixed wind conditions.



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

Generation Mix

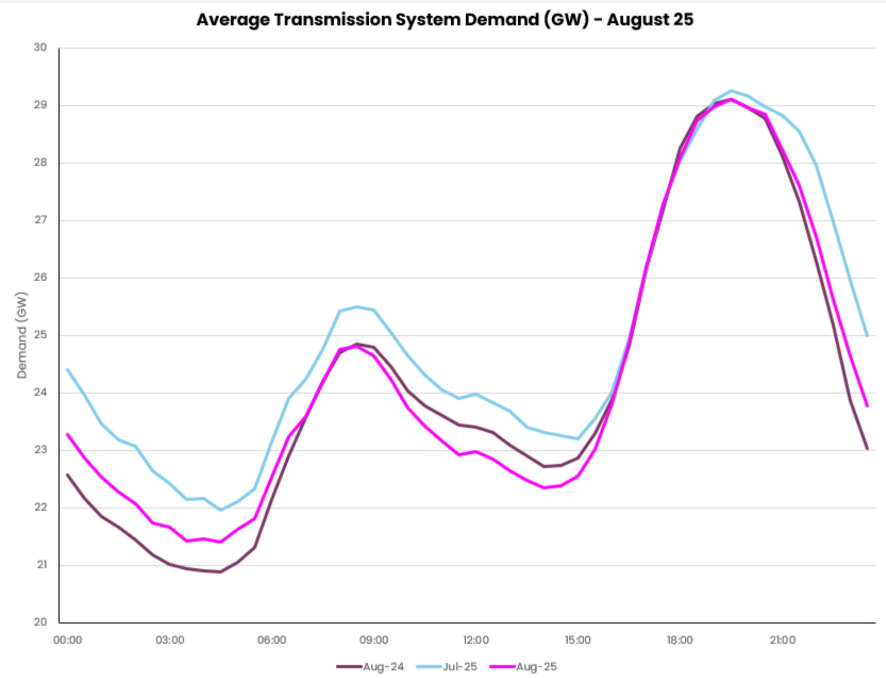
In August wind made up the largest share of the generation mix (26%), with CCGTs (20%) and Interconnectors (18%). This is a change from last month where CCGTs had the largest share of the generation mix. The chart shows how dominant wind sources were at the start end of the month, particularly on 5 and 31 August, where wind accounted for 56% and 60% of the daily generation mix respectively. However, in the middle of the month CCGTs and Interconnectors took a more dominant share, with wind falling below 10% on several days.



*Generation mix includes exports from interconnectors.

Transmission System Demand

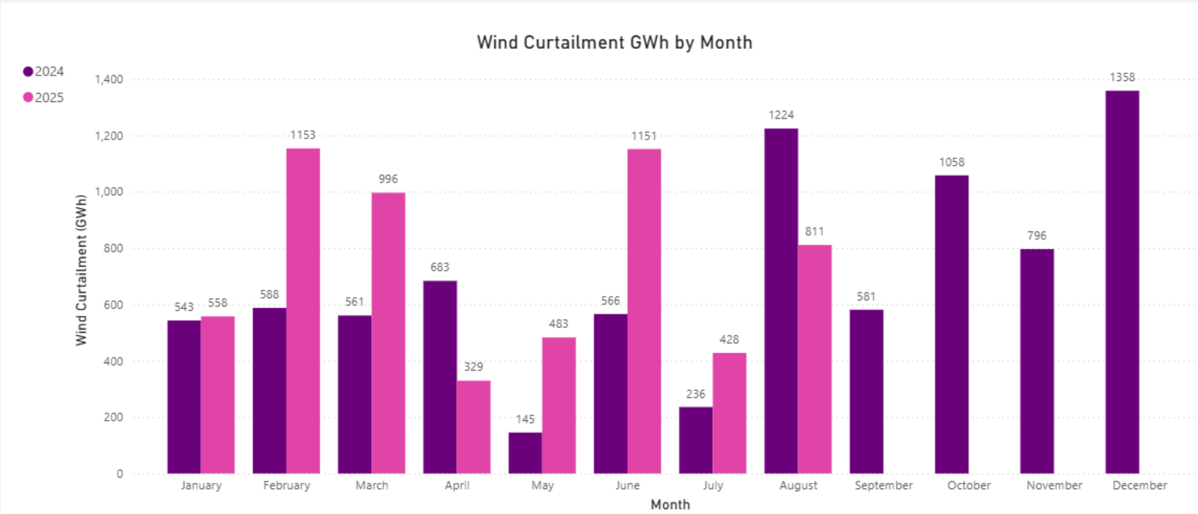
In August the average Transmission System Demand (TSD) was generally lower than the previous month throughout the day. Comparing August to the same month in 2024, the average TSD was notably higher during the overnight period, with the average TSD being on average 596MW higher between midnight and 6am. However, during the middle of the day (9am – 3pm), the average TSD was 373 MW lower than in August 2024, primarily due to increased embedded wind and solar generation suppressing the demand during daylight hours.



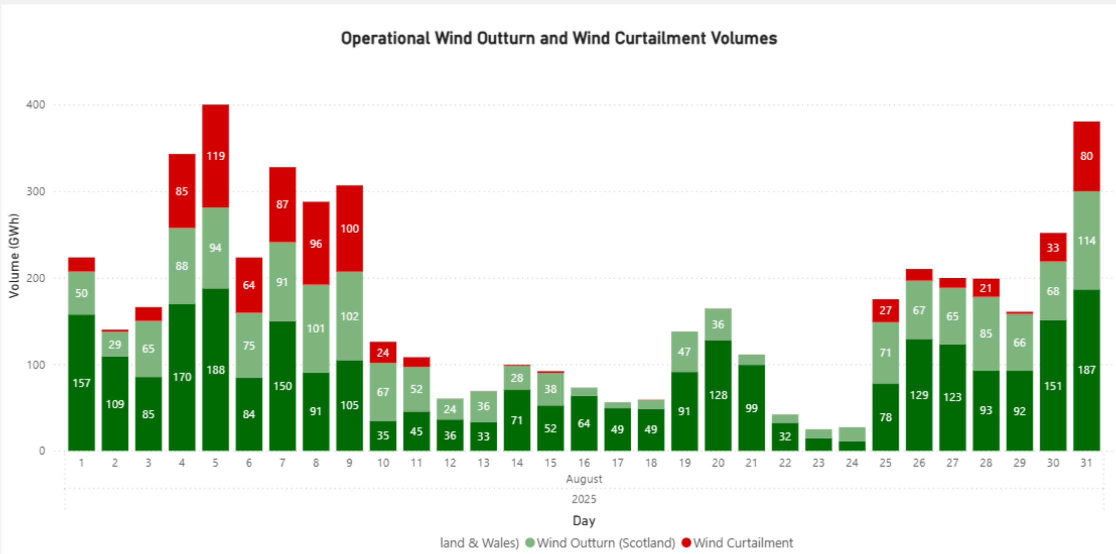
Wind Outturn

August 2025 began with unsettled conditions, notably impacted by Storm Floris, which brought wind and rain across much of the UK. From the second week, high pressure systems introduced more settled and brighter weather, particularly during midday periods. Toward the end of the month, conditions turned unsettled again, with outbreaks of rain and cooler-than-average temperatures, especially along the western coasts.

Overall wind outturn rose from 3.3 TWh in July to 4.4 TWh in August, with a 46% increase in England & Wales (from 1.9 TWh to 2.8 TWh) and a 19% increase in Scotland (from 1.4 TWh to 1.7 TWh) compared to the previous month, giving a 35% increase overall. However, there was a decrease in the volume of curtailment compared to August 2024. August consequently saw an increase in wind curtailment, reaching 811 GWh compared to 428 GWh in July. The majority of this curtailment occurred early in the month, coinciding with Storm Floris.



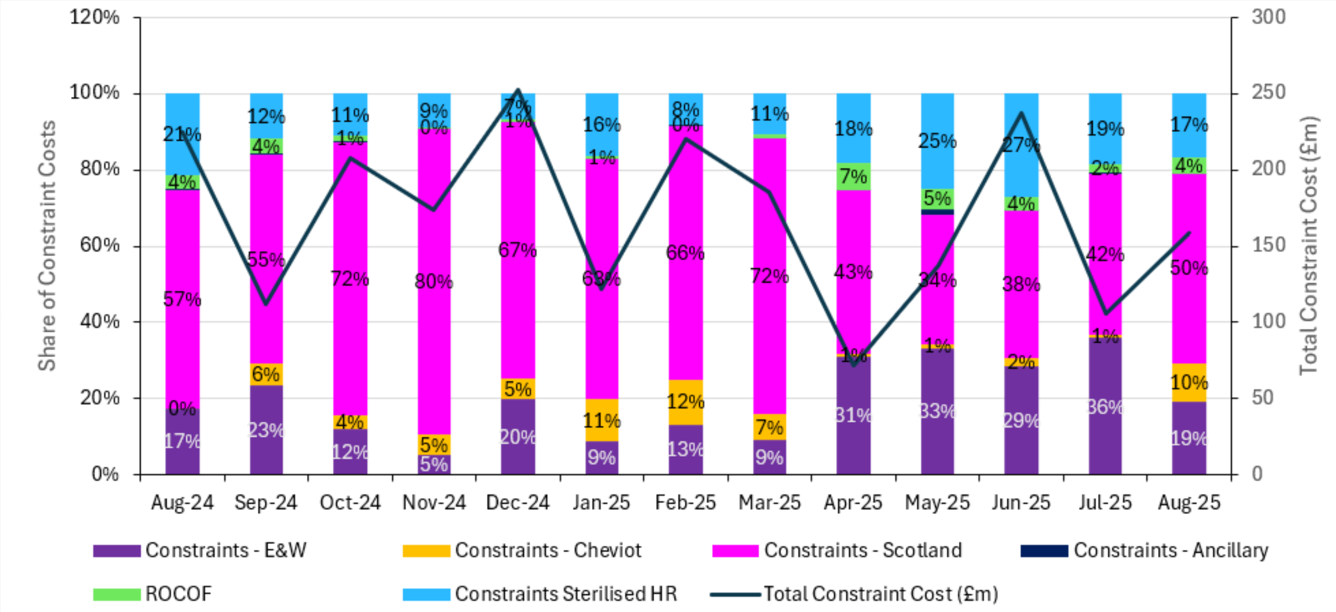
The day with the highest volume of wind curtailment occurred on 5 August with 119GWh which was also the highest cost day of the month. This is aligned with storm Floris.



Constraints

Constraint costs increased from £105.7m in July to £171.9m in August, an increase of £66.3m. This increase was observed across all constraint categories. The share of constraints therefore remained similar to the previous month, with the largest changes seen in Constraints – Cheviot and Constraints – England & Wales which saw shares increase to 10% and decrease to 19% respectively.

Wind outturn across England & Wales and Scotland ticked up in August, marking a high wind outturn month seasonally. This led to a notable rise in wind curtailment volumes compared to July, driven largely by unsettled weather conditions early in the month, including Storm Floris.



BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): August 2025 vs July 2025

		(a) Jul-25	(b) Aug-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-0.2	-0.7	(0.5)	
	Operating Reserve	7.2	10.4	3.2	
	STOR	5.4	5.7	0.3	
	Negative Reserve	1.2	0.4	(0.8)	
	Fast Reserve	11.7	12.4	0.6	
	Response	20.8	20.8	(0.0)	
	Other Reserve	0.6	0.9	0.3	
	Reactive	12.5	12.4	(0.1)	
	Restoration	3.1	2.6	(0.6)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	2.1	-1.2	(3.3)	
Constraint Costs	Constraints - E&W	34.6	30.5	(4.1)	
	Constraints - Cheviot	0.9	25.8	24.9	
	Constraints - Scotland	46.5	79.5	33.0	
	Constraints - Ancillary	0.2	0.2	(0.1)	
	ROCOF	2.3	7.3	5.0	
	Constraints Sterilised HR	21.1	28.6	7.6	
Totals	Non-Constraint Costs - TOTAL	64.3	63.6	(0.7)	
	Constraint Costs - TOTAL	105.7	171.9	66.3	
	Total Balancing Costs	**170.0**	**235.5**	**65.6**	

As shown in the totals from the table above, constraint costs increased by £66.3m and non-constraint costs decreased by £0.7m which results in an overall increase in costs of £65.6m compared to July 2025.

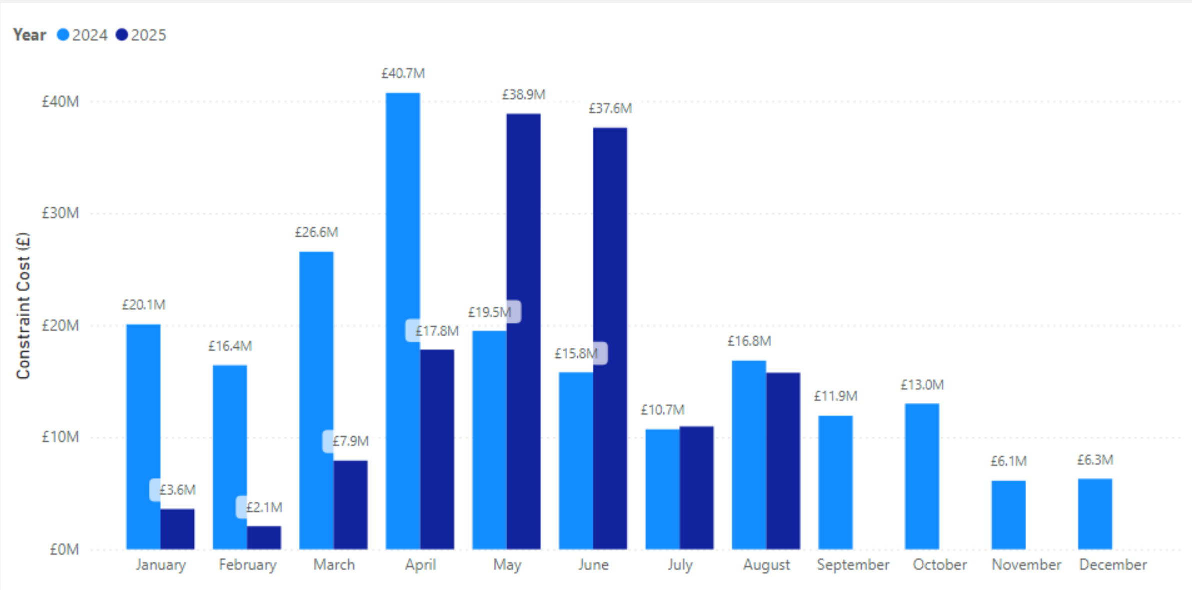
Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: +£57.9m **Constraint – England & Wales: -£4.1m** **Constraint Sterilised Headroom: +£7.6m** Overall constraint costs increased in August by £53.3m, which coincided with an increase in the absolute volume of actions taken. This was largely due to a return to more changeable weather conditions in August, including Storm Floris which particularly affected northern Scotland. Meanwhile, the cost of managing constraints specifically in England and Wales has reduced since last month.	**Constraints – Scotland & Cheviot: -£17.29m** **Constraints – England & Wales: -£7.83.6m** **Constraints Sterilised Headroom: -£25.5m** Constraint costs across the UK have decreased by £50.62m compared to August last year, which is in line with a decrease in the absolute volume of actions taken this year. Of note, is that the Cheviot costs increased, while Scotland and Cheviot as a whole saw a decrease, indicating that the constraints were felt further south this year in Scotland. It is worth noting that August was a particularly high costing month for constraints in 2024.

ROCOF: +£5.0m	**ROCOF: -£0.89m**
As July saw a significant drop in costs for managing system inertia due to low wind outturn, the increase in costs this month represents a return to previous levels, with the value being very similar to May and June this year.	There was a slight decrease in inertia spend compared to August 2024. This decrease will be in part due to the high volume of wind on the system in August 2024 and therefore less need for inertia regulation as a result of lower wind levels this year.

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

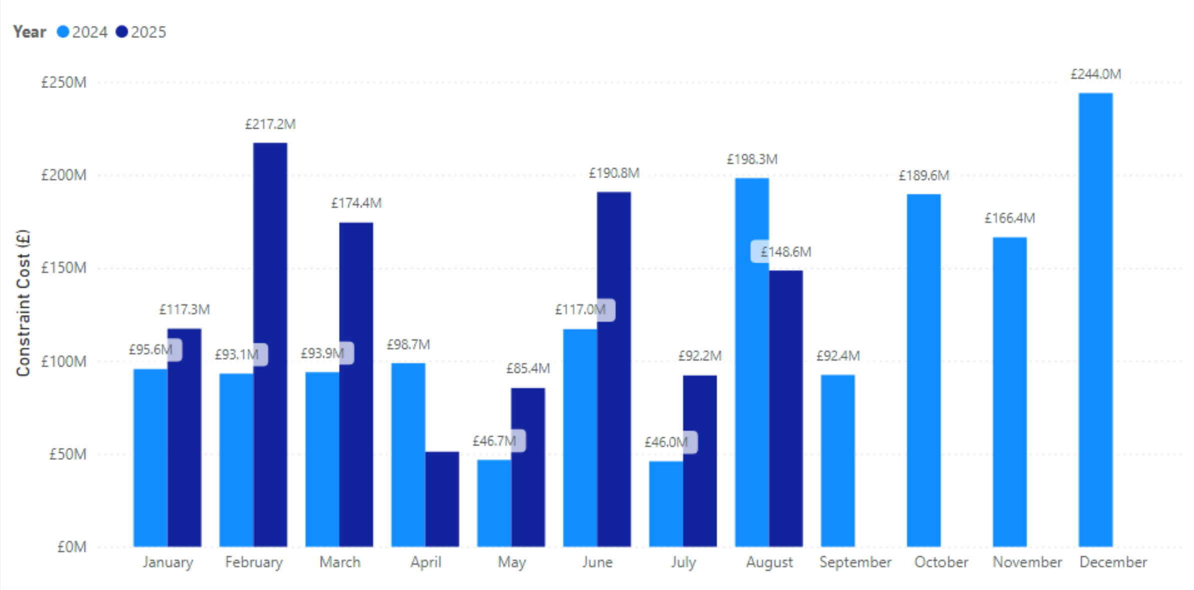
Synchronisation costs are associated with specific actions required to support voltage in the system. These actions involve units that are instructed to provide MVArs and maintain voltages within SQSS limits. It is a highly location-dependent issue, so only a limited set of assets are effective in voltage support, depending on their location. In August, the system synchronisation costs (what it costs to the system, which factors in energy replacement and headroom among others) amounted to £15.8m, an increase of roughly £4.8m on last month, and just £1m lower than August 2024.



Voltage spending is usually higher overnight due to lower demand at this time of day. 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.

Most of the spending is allocated to the South-West region of Great Britain, where the system relies on Combined Cycle Gas Turbines (CCGTs) for voltage management. An important CCGT in the region was on a planned outage until August, which resulted in a limitation of available resources for voltage control. Despite this, spending in the current month has not been significantly affected.

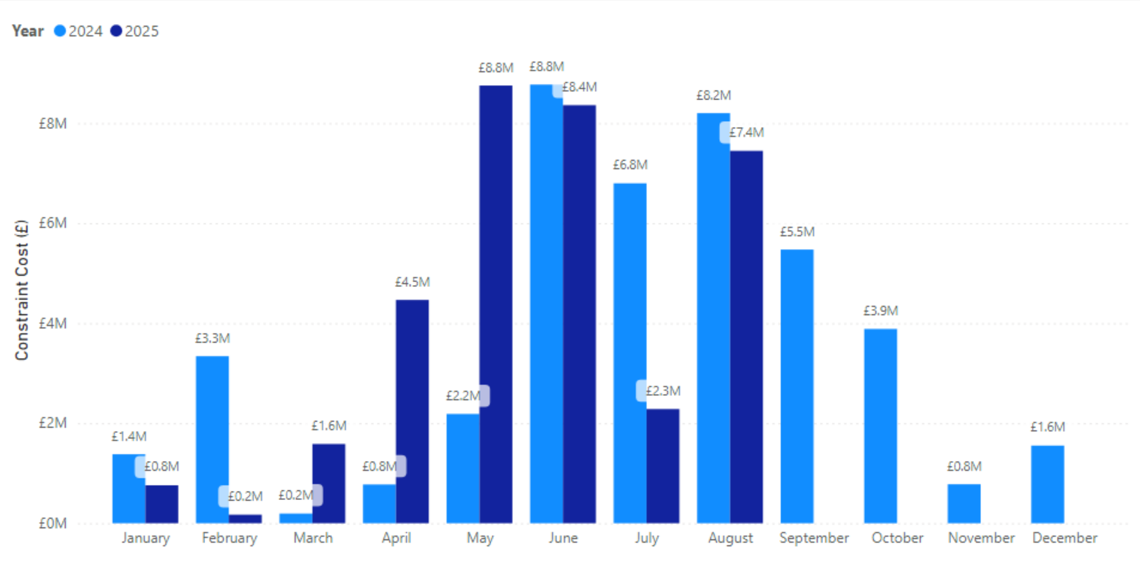
Thermal – Monthly system cost of actions for thermal management across 2024 and 2025:
Thermal constraints are associated with operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, 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 vast majority of the system constraints, accounting for a significant percentage of system actions. In August, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £148.6m, reflecting an increase in costs of over £50m compared to the previous month (£92.2m) but comparatively was down £50m compared to the same period last year (£198.3m).



July had seen a large reduction in wind curtailment this year and so the increased thermal constraint costs this month represent a pick-up in wind curtailment again (811 GWh in August, compared to 428 GWh in July). In contrast, August 2024 had seen a particularly high level of wind curtailment and so there is a substantial drop in thermal constraint costs seen this year.

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, 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 August, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £7.4m, resulting in an increase of £5.1m compared to last month (£2.3m) and just £0.8m lower than August 2024.



The expenditure on inertia increased in August due to a significant amount of wind generation on the system, accounting for roughly 26% of the total generation mix for the month. Additionally, demand was slightly lower than in the previous month. In this sense, August saw a reduced number of synchronous generators self-dispatching to provide inertia. These factors combined led to the need for NESO to procure inertia through the Balancing Mechanism.

Reactive Costs/Volumes

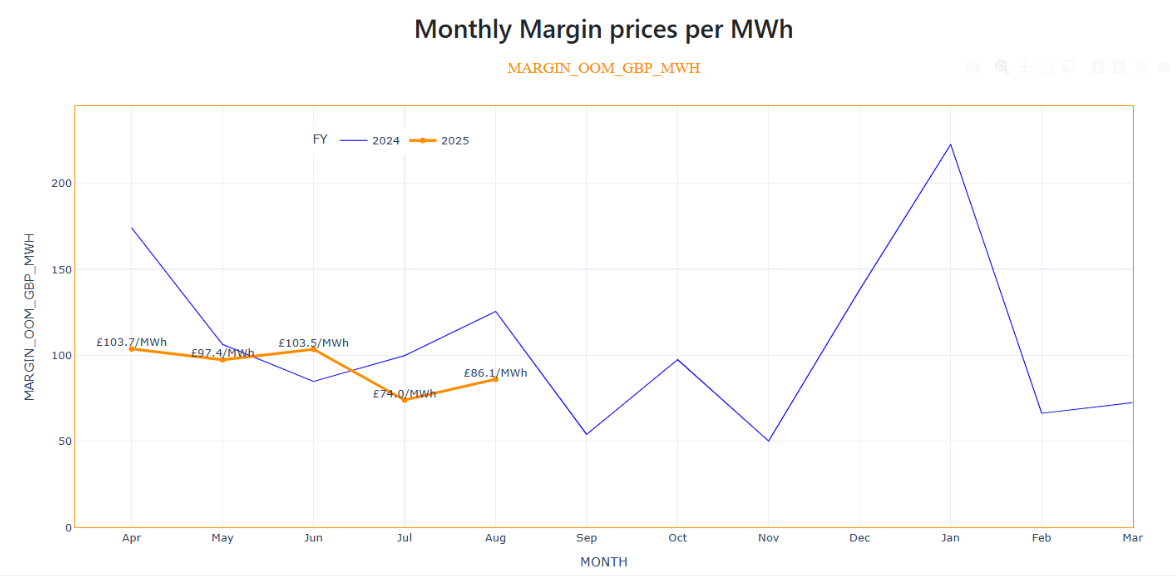
The volume-weighted average price for reactive power was £3.9/MVAr in August 2025.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£0.1m The volume-weighted average price decreased to £3.9/MVAr down from £4.1/MVAr in July.	**+£0.52m** The volume-weighted average price slightly increased from £3.8/MVAr to £3.9/MVAr compared to last year.

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

Reserve Costs/Volumes

Reserve prices increased to £86.1/MWh in August from £74.0/MWh in July 2025. This decrease corresponds with a drop in the absolute volume of reserve actions taken in August compared to July.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£3.2m **Fast Reserve: +£0.6m** There was a 60.28 GWh increase in the absolute volume of operating reserve required to secure the system compared to July.	**Operating Reserve: +£6.4m** **Fast Reserve: -£7.3m** There was a 63.2 GWh decrease in the absolute volume of operating reserve required to secure the system compared to August 2025.

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
£0.0m There was a 13.7 GWh decrease in the absolute volume of actions compared to July. Clearing prices for DC and DM services ticked up, while prices for DR services were lower than in the previous month.	**+£4.0m** The volume of actions taken for response increased 31.8 GWh compared to August 2024. Clearing prices were also higher year-on-year across all Dynamic Services.

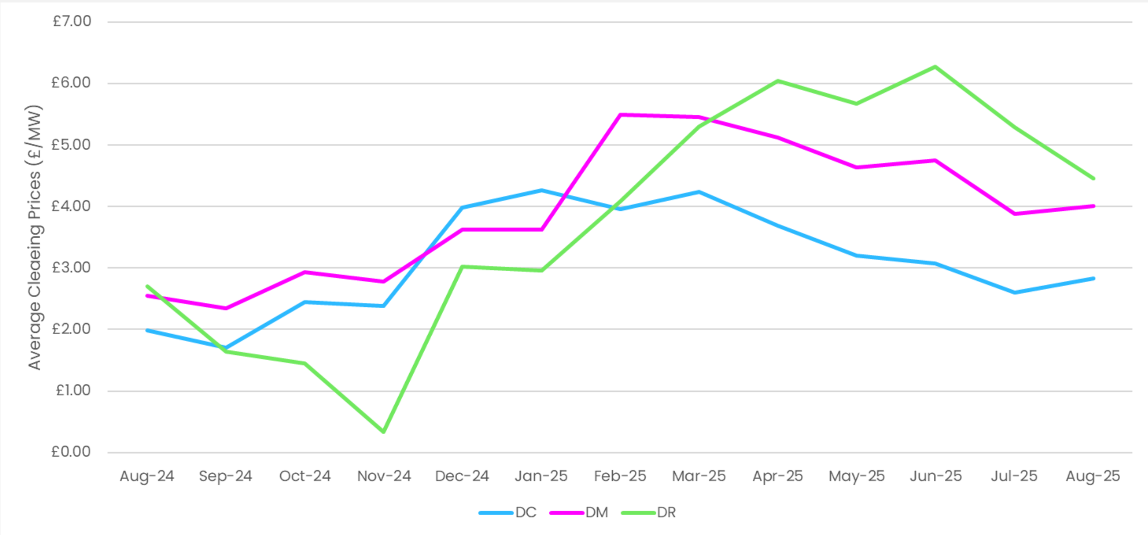
Dynamic Services Average Clearing Prices (£/MW): August 2025 vs July 2025

		(a) Aug-25	(b) Jul-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	2.8	2.6	0.2	
	DM	4.0	3.9	0.1	
	DR	4.4	5.3	(0.8)	

Dynamic Services Average Clearing Prices: August 2025 vs August 2024

		(a) Aug-25	(b) Aug-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	2.8	2.0	0.8	
	DM	4.0	2.5	1.5	
	DR	4.4	2.7	1.8	

Average clearing prices slightly increased in August for both Dynamic Containment (DC) and Dynamic Moderation (DM). For DC, prices rose from £2.60/MW to £2.82/MW, while for DM, they increased from £3.88/MW to £4.00/MW. Dynamic Regulation (DR) saw a significant reduction on the clearing price relative to July 2025, moving from £5.29/MW to £4.45/MW in August. However, all three services saw an increase in average clearing prices to August last year, corresponding to higher target volumes (pay as clear markets), particularly for DR and DM. There is also some seasonality to the pricing, less DC is needed over winter when there is a lot of inertia on the system. In this sense, this tends to be more expensive in spring/summer.

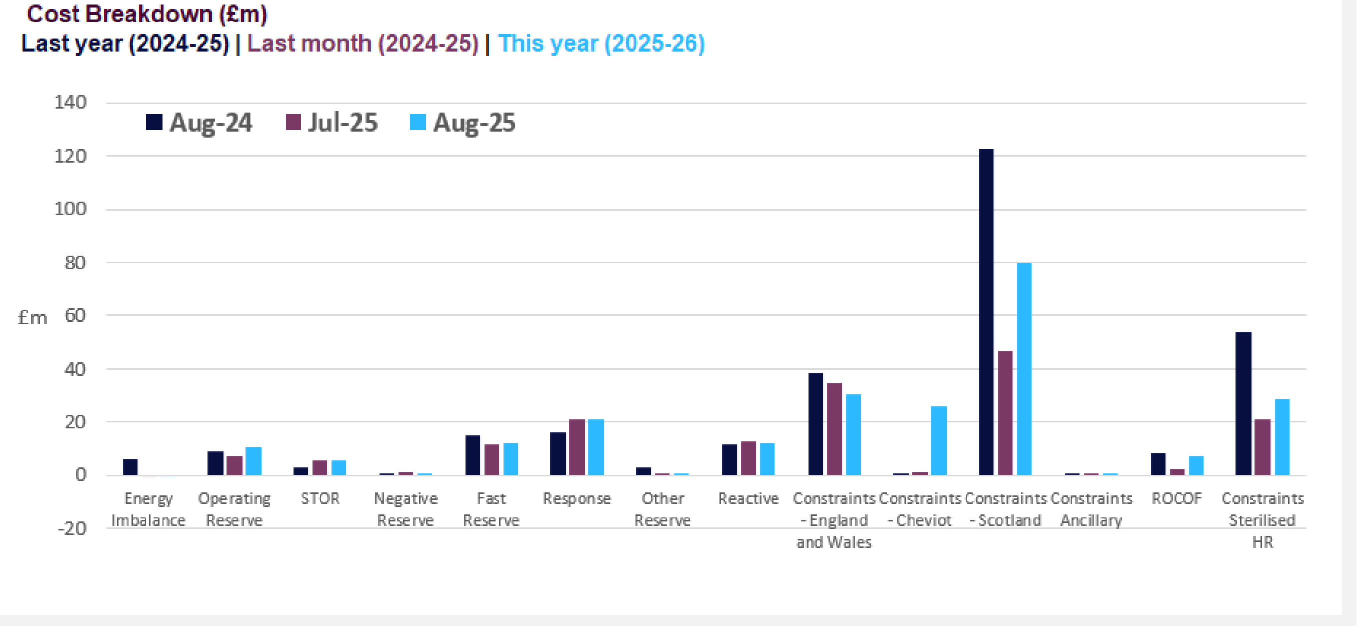


Comparison breakdown

Constraint costs increased by £66.3m compared to the previous month. Higher costs were seen across all constraint categories, which is largely due to a significant increase in wind outturn in the first week of August due to Storm Floris. Voltage and inertia spending increased month-on-month, reflecting lower system demand and a reduced share of synchronous generation in the overall generation mix. However, total constraint costs remained lower compared to last year due to reduction in wind outturn compared to August 2024.

Non-constraint costs decreased slightly by £0.7 million compared to July 2025, mainly due to a modest rise in operating reserve costs, which was offset by a reduction in minor component costs. Thermal constraints are currently the largest component of balancing costs.

We are progressing several initiatives to reduce thermal constraint volumes/costs including the Constraints Collaboration Project and Constraint Management Intertrip Service. Network Service Procurement projects for voltage and stability are also helping to provide solutions for network management at lowest cost.



COST SAVINGS

Cost Savings – Outage Optimisation

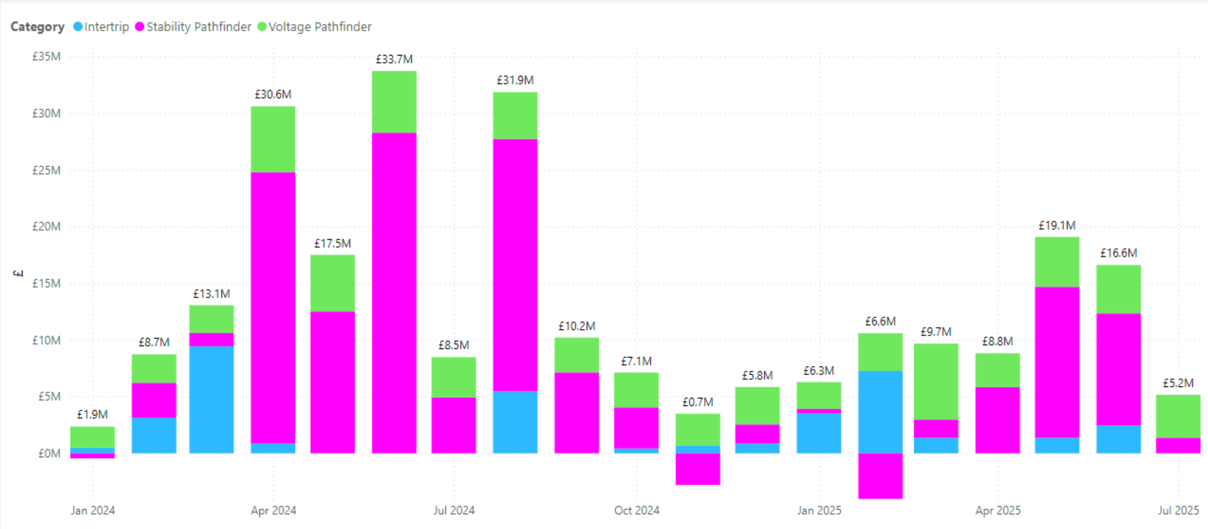
Total savings from outage optimisation amounted to approximately £62.8m in August 2025. This is a reduction of roughly £22.3m relative to July 2025 (£85.1m). The most valuable action was rejecting the proposed date change to a planned outage in West Weybridge 275 kV substation. The new dates overlapped with another planned outage at the same substation, which would have significantly reduced the transfer capacity of a constraint in the area by 600 MW. The estimated cost savings for this action was roughly £13.1m.

Cost Savings – Trading

The Trading team were able to make a total saving of £22.9m in August through trading actions as opposed to alternative BM actions, representing a 76% increase on the previous month. Trading savings increased in August with conditions typical for the time of year with low demand and high renewable generation, which led to greater need for trading to help manage thermal constraints. Trading was also facilitated by various outages throughout the month which when coupled with higher temperatures meant that there was an increase in the frequency of managing thermal constraints. There was also a need to trade for both positive and negative margin as well during the month, providing a similar combined cost saving to July. The day with the greatest trading savings was 20 August at a cost of £4.1m with the greatest savings being made for managing the ESTEX boundary. The day with the greatest spend on trades was 12 August at a cost of £1.3m with the greatest component being for managing the SEIMP constraint.

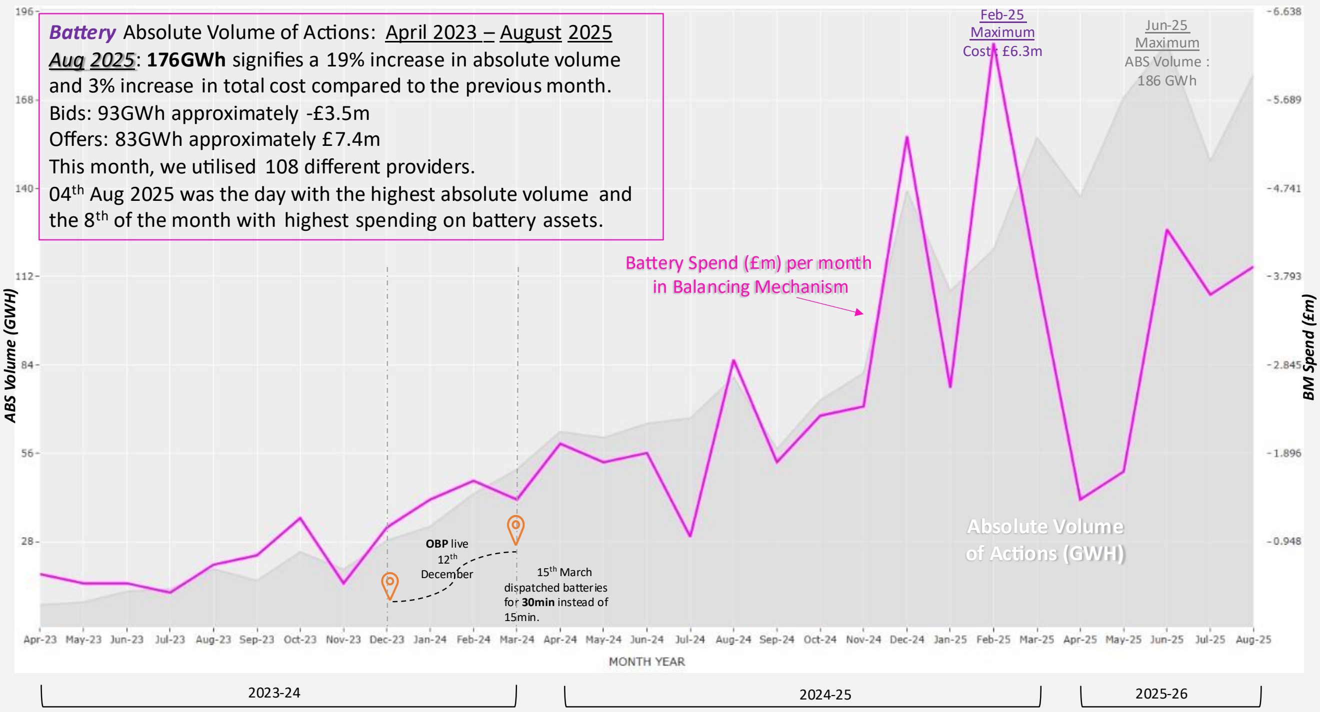
Cost Savings – Network Services (NS)

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 £49.65m in savings across 2025/26 to date (April – July 2025).



NOTABLE EVENTS

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

In comparison to the previous month, July 2025, both the overall volume of actions and the total costs have increased. Since April 2025, the absolute volume of battery dispatch has nearly tripled compared to the same period last year and has increased more than fifteenfold since April 2023. This growth highlights our commitment to improving the flexibility of energy provision through battery storage and small Balancing Mechanism Units (BMUs).

DAILY CASE STUDIES

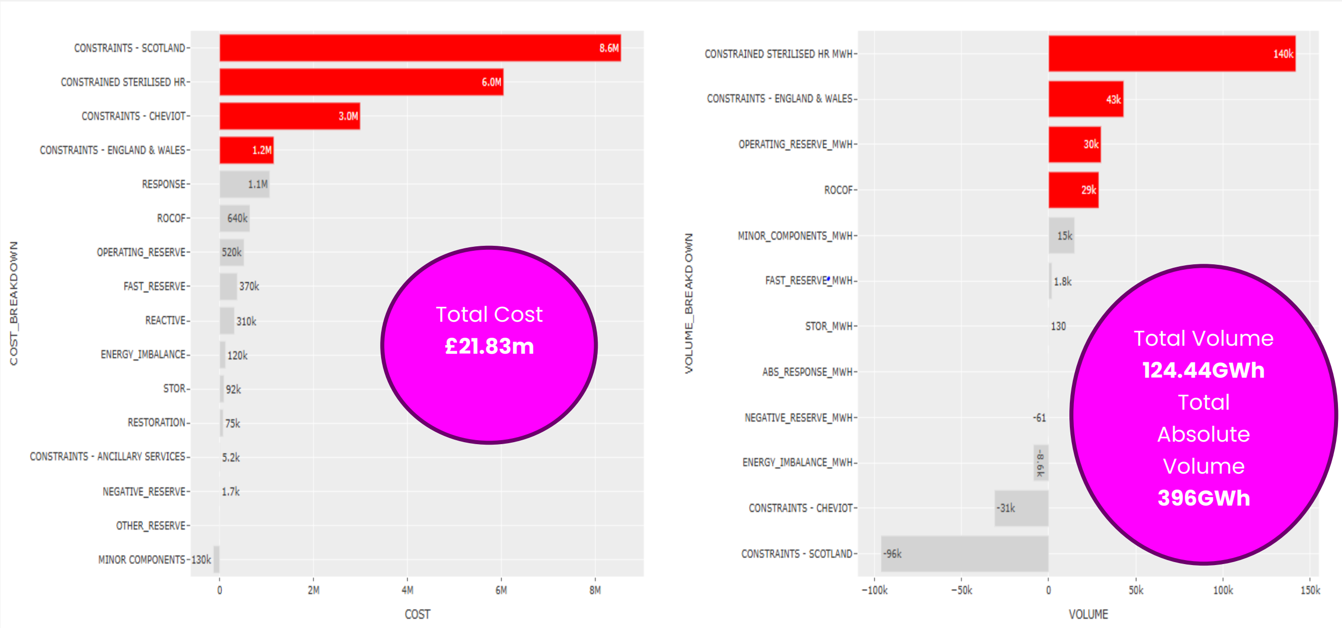
Daily Costs Trends

August's balancing costs were £235.5m which is £65.6m higher than the previous month. There were six days with a total cost above £15m (4, 5, 7, 8, 9 and 31 Aug) with the highest cost day of the month being 5 August. There were a further one day with costs above £10m which was 6th August. The daily average cost rose by £2.2m, from £5.5m in July to £7.7m in August, driven by high-cost days at the start and end of the month, while most mid-month days were significantly lower than the daily average cost.

The highest cost day was 5 August, with a total cost of approximately £22m. These high costs were driven by the large volume of actions taken at the tail end of Storm Floris, which hit the UK on 4 and 5 August. High costs on this day were largely due to high spend on constraints, with the highest spend allocated to Scottish constraints. Units were also run on the day for voltage support and to support system inertia.

The lowest cost day was 22 August at a cost of approximately £2.46m. The majority of the BM cost on the day was attributed to voltage management, and a low percentage of thermal constraint.

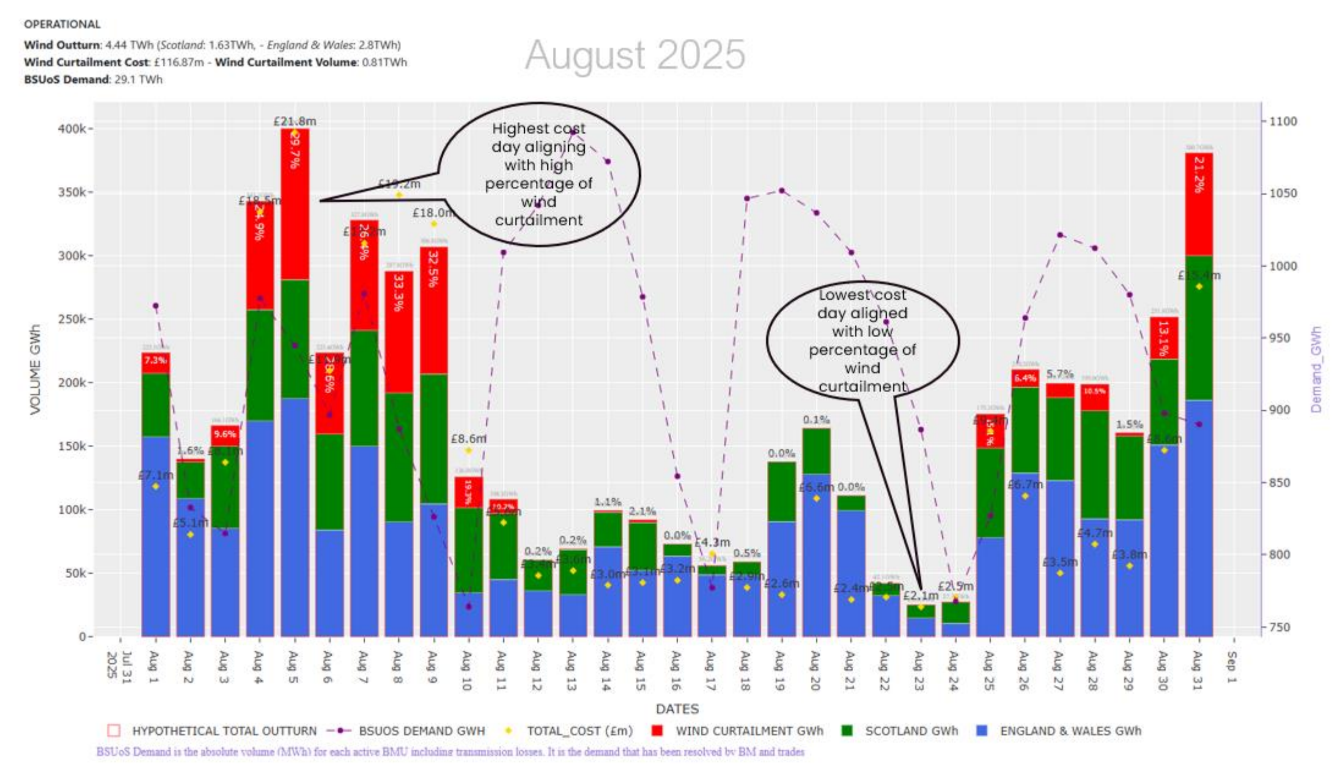
High-Cost Day – 5 Aug 2025



August 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).

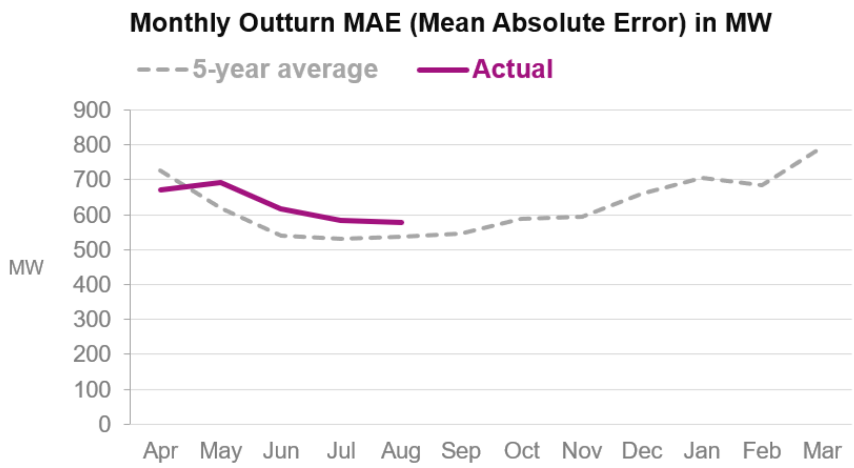
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each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

August 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**	**616**	**584**	**579**							

*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 August 2025 forecasting error averaged 579MW - a 41MW (7.6%) increase on the previous 5-year average of 538MW, but an improvement on August 2024 (596MW).

August was an unsettled month, including thunderstorms, a heatwave and storm Floris. Temperature and sunshine hours were both above average for August.

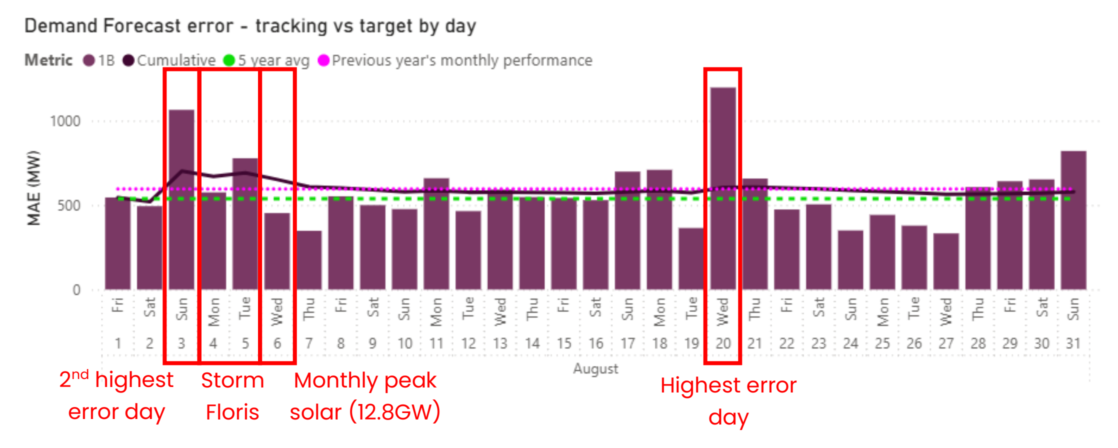
Solar forecasting errors remained the largest contributor to national demand errors, especially visible on 3 and 20 August. These days had complex cloud cover conditions which were very difficult for Numerical Weather Prediction (NWP) weather-forecasts to model, leading to significant revisions at short lead times. This was seen across many forecasting models (internal and external), using a range of weather forecast providers.

The new National Solar model has been tested, validated, and shows improved accuracy. It is pending release to production systems in early September.

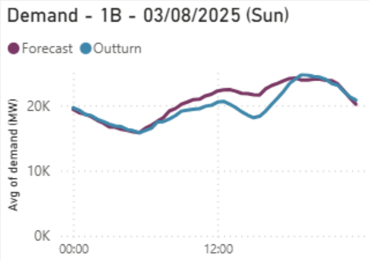
Solar generation peaked at 12.8GW on 6 August.

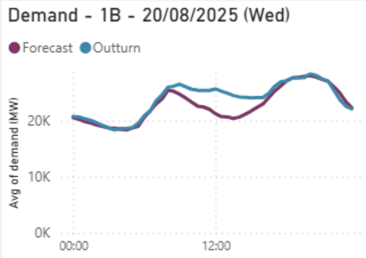
The largest absolute demand error this month was 4.5GW on 20 August, SP26.

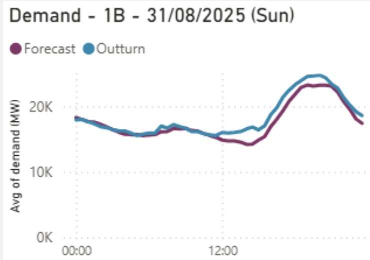
The minimum demand was 13.3GW on 9 August, SP30



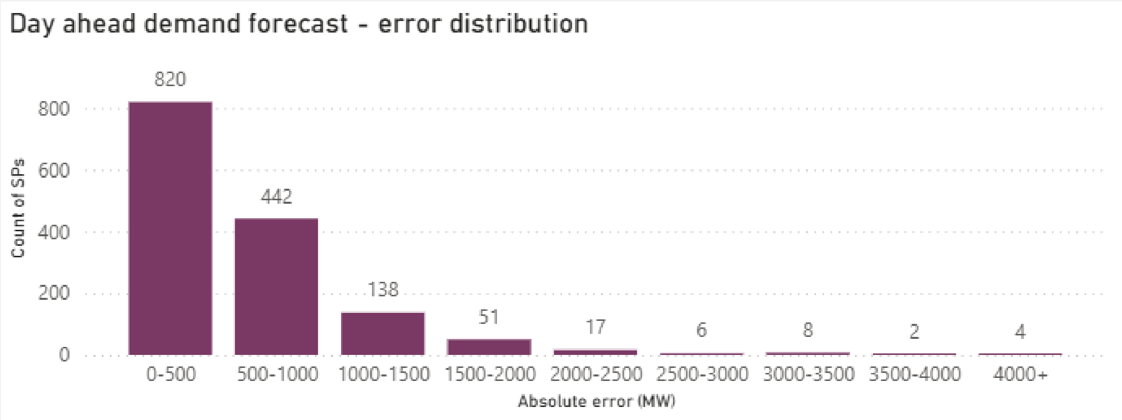
Days of Interest:



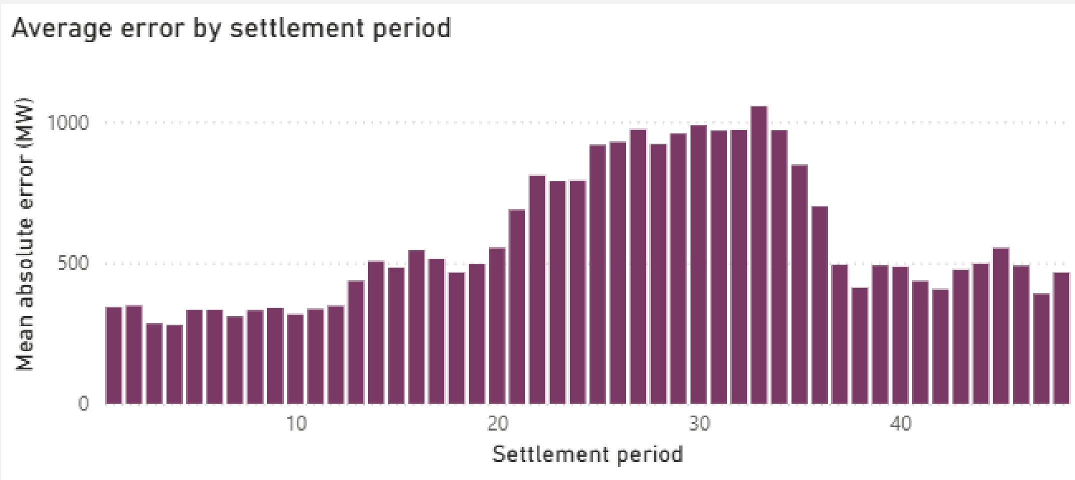




The distribution of settlement periods by error size is shown below:



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



The days with largest MAE were 3, 20 and 31 August.

Day	Error (MAE)	Major causal factors
20	1196	Solar forecasting errors
3	1064	Solar forecasting errors
31	820	Solar forecasting errors, wind forecasting errors and other factors not captured in models

Missed / late publications

Day ahead demand forecasts were published late on 22 and 30 August, due to IT issues which have since been rectified.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 1 and 4 August, with an accumulated total of 21.5MWh 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.

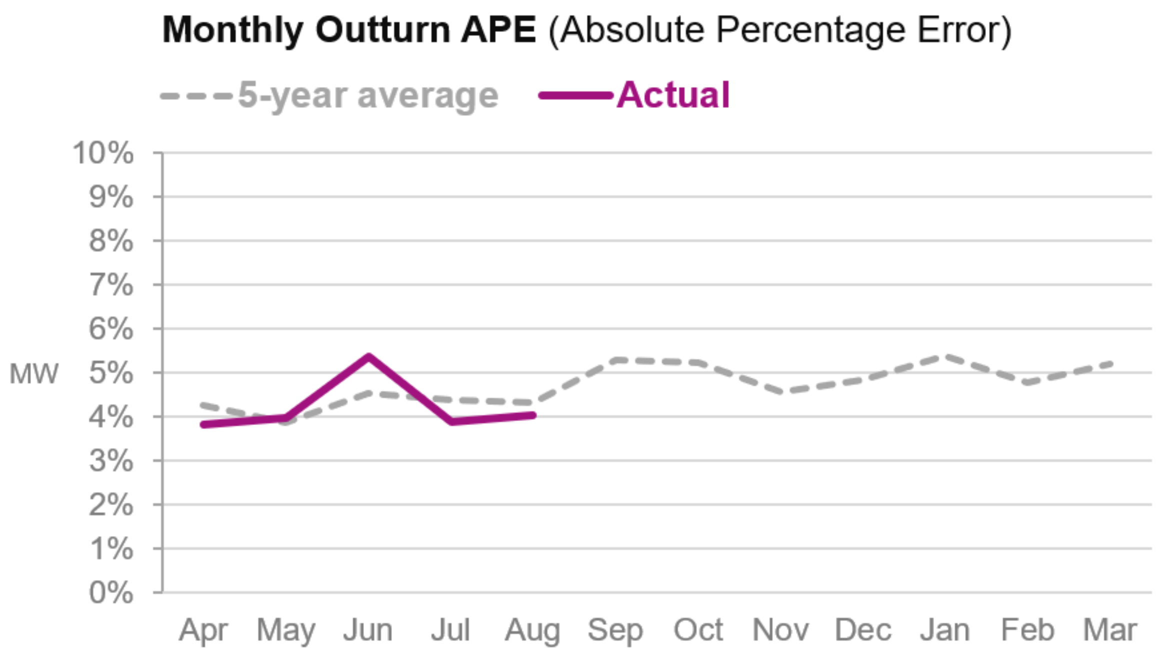
Sites deemed to have withdrawn availability are those that:

- 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.

August 2025-26 performance

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



In line with the BP2 methodology reported from the BP2 18-Month Report onwards (published in October 2024), the APE% that we report excludes some of the factors that are outside 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	4.30	5.27	5.23	4.55	4.84	5.36	4.78	5.18
Previous year outturn (%)	4.64	3.60	4.72	4.24	4.15	5.04	4.70	3.63	3.86	4.40	3.97	5.20
APE (%)	**3.85**	**4.09**	**5.61**	**3.80**	**4.03**							

*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 August 2025, BMU wind forecasting error averaged 4.03%, an improvement on the 5-year average of 4.30%.

August began with unsettled weather and storms, including storm Floris on 4-5 August. This storm mostly affected Northern England and Scotland, bringing rain and wind gusts of up to

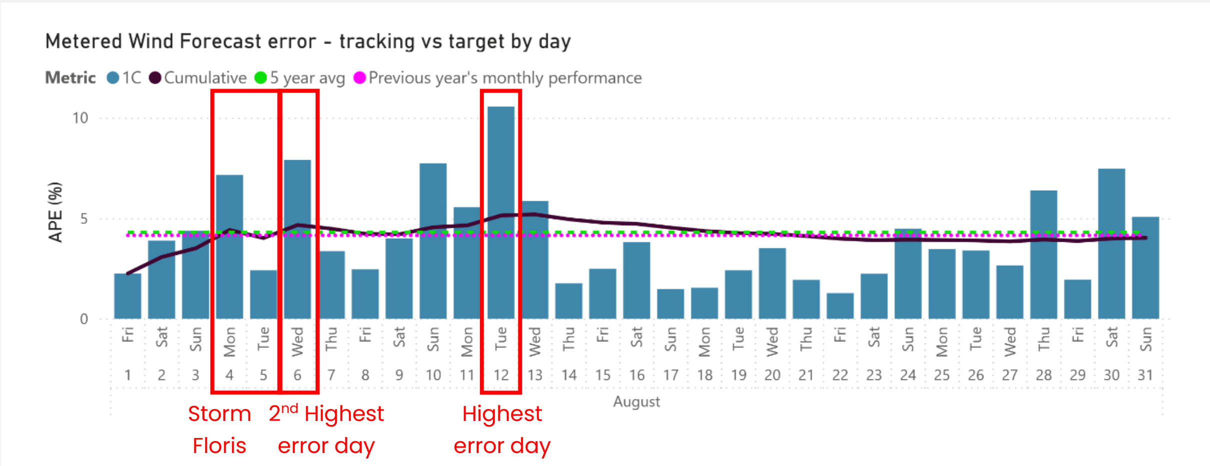
82mph. Over 70,000 properties in the Highlands, Moray and Aberdeenshire were reported to have lost power supplies.

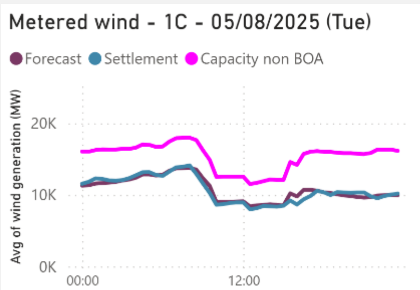
Extended periods of negative energy prices caused some large wind units with Contracts for Difference (CfDs) to redeclare to 0 after forecasts were published. These redeclarations reached approx. 4.6GW on 5 August, 3.3GW on 9 August, and 1GW on 31 August. These redeclarations are accounted for in the current metric.

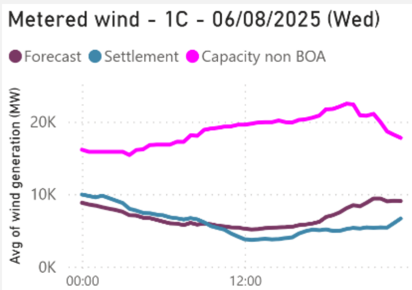
Wind generation peaked at 14.7GW on 4 August, SP29.
Wind forecast absolute error peaked at 4.1GW on 6 August, SP44.

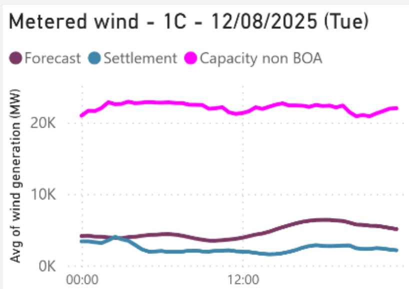
Note: metric performance for July has been recalculated with updated settlement data, which in this case has caused a very slight increase in reported accuracy.

Days of Interest:

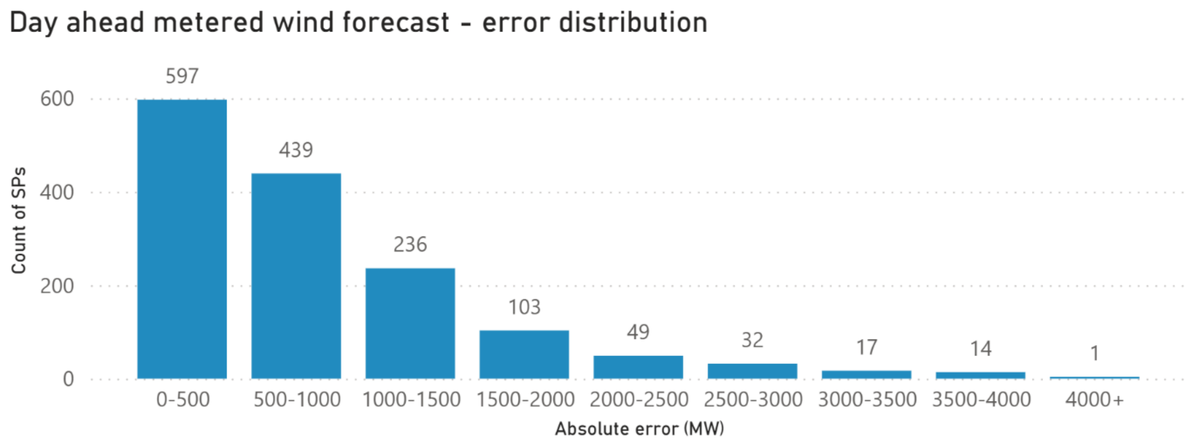








The distribution of settlement periods by error size is summarised below:



Details of largest error

Day	Error (APE)	Major causal factors
12	10.6	Wind speed forecast errors at day-ahead stage, especially offshore
6	7.9	Wind speed forecast errors at day-ahead stage, especially towards end of forecast window
10	7.7	Wind speed forecast errors at day-ahead stage, especially towards end of forecast window

Missed / late publications

Day ahead wind generation forecasts were published late on 22 and 30 August, due to IT issues which have since been rectified.

4. Skip Rates

Performance Objective

Operating the Electricity System

Related Success Measure

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

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

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

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

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

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

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

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

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

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Offers	43%	35%	33%	36%	31%							
Bids	45%	43%	51%	47%	40%							
Combined	44%	40%	40%	42%	36%							

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Offers – skipped volume	63	71	116	78	86							
Offers – in merit Energy volume	148	205	356	215	279							
Offers – All in merit volume (System & Energy)	504	901	1052	529	943							
Bids – Skipped volume	150	154	118	130	128							
Bids – in merit Energy volume	336	352	234	277	316							
Bids – All in merit volume (System & Energy)	815	995	1576	962	1344							
Combined Bid & Offer – skipped volume	213	225	234	208	214							

Supporting information

Q1 UPDATES

Reporting and methodology:

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. Work is ongoing to add some of the identified limitations of the methodology into the calculation, which are dependent on the availability of data from the Open Balancing Programme (OBP) and currently planned for Q3 FY26.

Additional Metrics:

We have expanded this metric to include the skip rate by technology type, using two calculation methods. The first graph shows the Relative Technology skip rate for the current financial year, which shows how different technology types contribute to the overall skip rate. The second graph show the Technology Specific skip rate for each technology type for the last 3 months. This graph has been updated to include the skipped volume for each technology type as this metric can produce a very high skip rate when there is very low volume. The skipped volume on the Technology Specific graph is the total skipped volume for each technology type over the 3-month period shown. Both calculation methods are based on the PSA skip rate definition.

AUGUST UPDATES

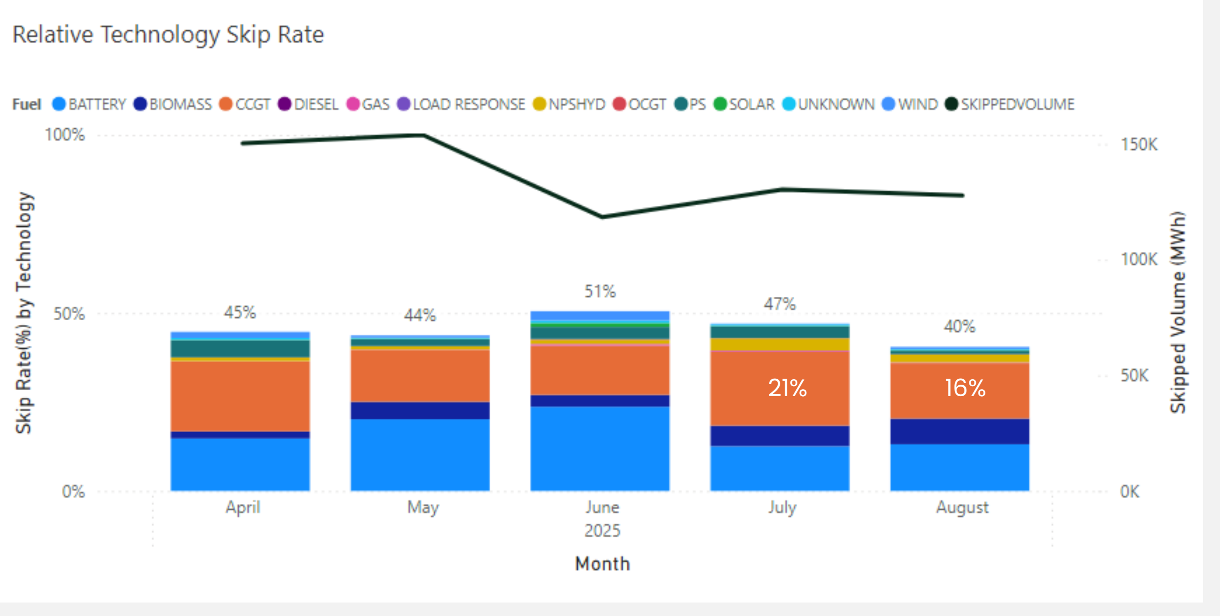
During August we have released a Beta version of an improved skip rate tool to our control Room which will assist with decision making by providing an indication of zonal allocation of energy actions for 5-minute periods up to 30 minutes ahead. This is anticipated to help reduce the occurrence of out-of-merit actions due to unit allocation across different dispatch zones. We have also continued our Root Cause Analysis activities with phase 1 of our consultancy work concluding and producing a prioritised list of hypotheses of potential causes of skips. The next phase will work to identify the causations and look to recommend solutions to reduce the occurrence of skips.

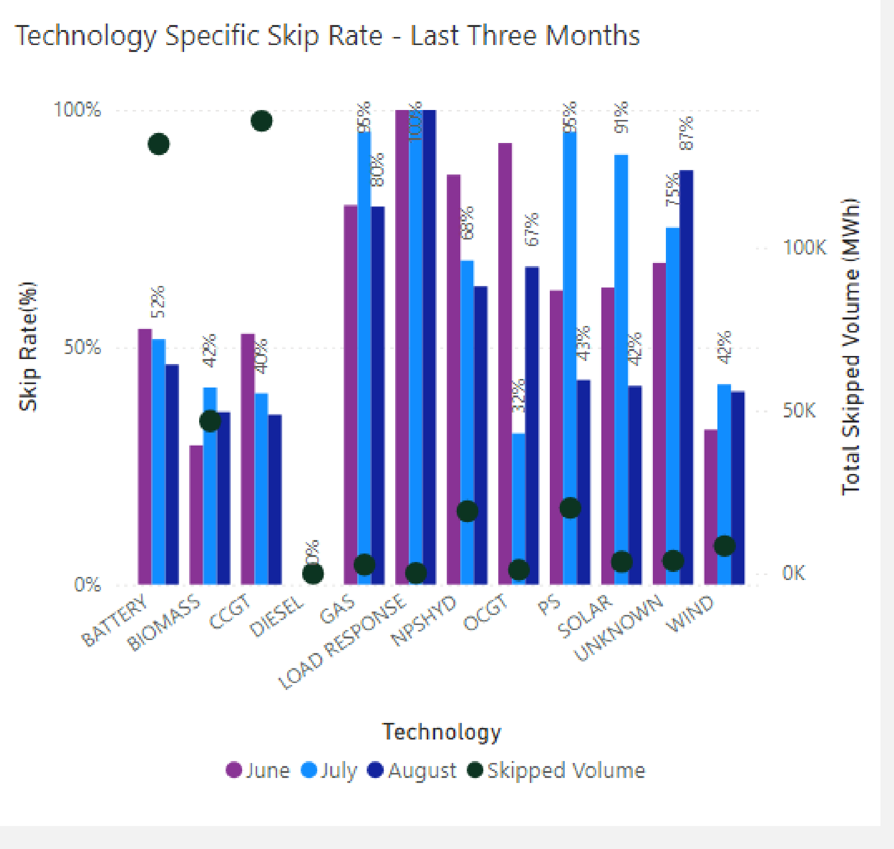
AUGUST PERFORMANCE

The Offer skip rate has decreased from July (36%) to August (31%) but skipped volume has increased due to a higher volume of actions taken in August. The Bid skip rate has decreased from 47% in July to 40% in August but skipped volume has remained constant. The increase in energy actions is as a result of lower system actions, mainly due to a lower number of days with high wind generation. The combined bid and offer skip rate has decreased from 42% in July to 36% in August.

Bids

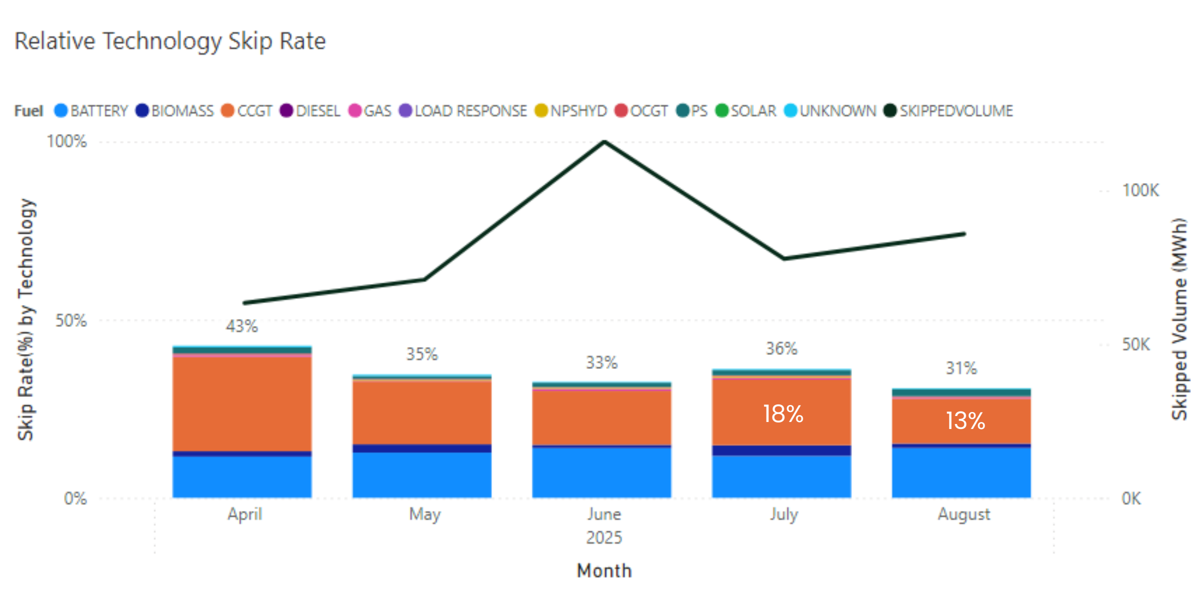
CCGTs accounted for a smaller proportion of skipped volume in August (16%) compared to July (21%) and the Technology Specific skip rate for CCGTs has also decreased from 40% to 36%. Batteries account for 13% of the skip rate in both July and August but the Technology Specific skip rate has reduced from 52% in July to 46% in August.

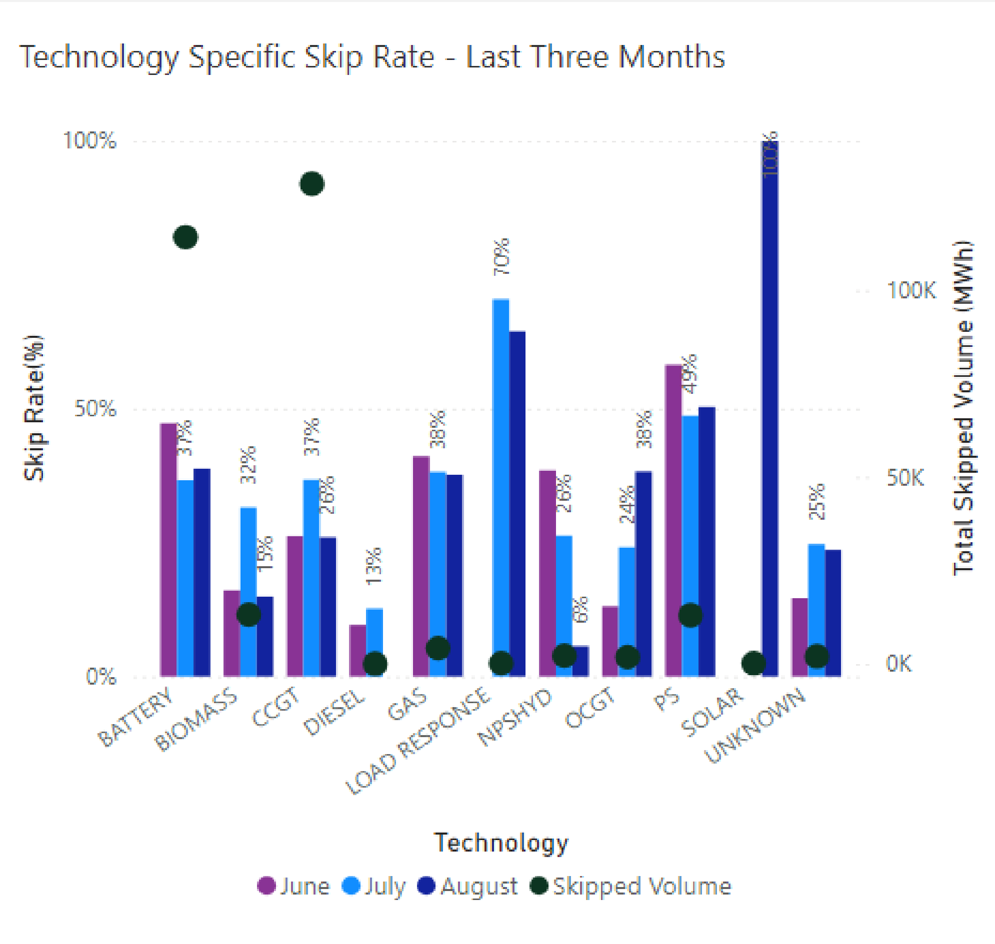




Offers

Similar to bids, CCGTs account for a lower proportion of skipped volume in August (13%) compared to July (18%) and the Technology Specific skip rate also decreased from 32% to 15%. Batteries account for a similar proportion of skipped volume in August and July, and the Technology Specific skip rate also remained fairly constant (37% in July vs 39% in August).





Note: In these graphs 'Gas' refers to gas reciprocating units, which are typically small, aggregated units. 'Load Response' is based on the fuel type category used by Elexon. These are typically Demand Side Response (DSR) units, however work is ongoing to better define and report on these units.

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.

August 2025-26 performance

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

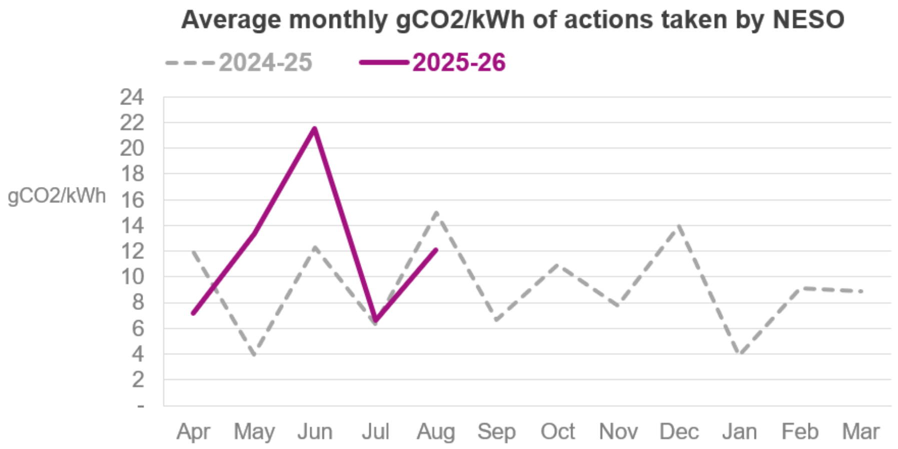


Table: Average monthly gCO2/kWh of actions taken by NESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	7.16	13.36	21.53	6.64	12.11							

Supporting information

In August we continue to report the average monthly gCO_2/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 the figures reported.

In August, the average monthly carbon intensity from NESO actions was 12.11g/CO_2/kWh. This is 5.47g/CO_2/kWh higher than July and 0.05g/CO2/kWh less than the YTD average of 12.16g/CO_2/kWh.

The maximum difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the BM and the equivalent profile with balancing actions applied was 65.67g/CO_2/kWh which took place on 4 August 2025 at 06:30. This is 10.65g/CO_2/kWh lower than the highest point in July 2025 which took place on 27 July at 08.30.

On 4 August an amber weather warning was in place and Storm Floris was due to hit the UK. This meant unconstrained transmission connected wind was expected to rapidly rise through the morning from 3.5GW to 19.5GW by midday. This required careful intervention and management resulting in increased NESO actions.

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.

August 2025-26 performance

Table: Frequency and voltage excursions (2025-26)

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

Supporting information

There were no reportable frequency or voltage excursions.

[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.

August 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	0	0	0							
Integrated Energy Management System (IEMS)	0	0	0	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	0	1 outage 215 mins	1 outage 115 mins							
Integrated Energy Management System (IEMS)	0	0	0	0	0							

Supporting information

In August 2025 there was one planned CNI system outage. The outage was to carry out a software update, along with regular maintenance activities on the BM production systems, and impacted the key BM Suite components used for scheduling and dispatch of generation.

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

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

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

There were no other planned outages during August.

There were no unplanned outages during August.

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

www.neso.energy