ESO RIIO2 Business Plan 2 (2023-25)

August 2024-25 Incentives Report

24 September 2024

ESO

Contents

Introduction

As part of the RIIO-2 price control, we submitted a second Business Plan to Ofgem in August 2022. It sets out our proposed activities, deliverables, and investments for years three and four of RIIO-2 (2023-2025) as we respond to the rapidly changing external environment.

The ESO's Delivery Schedule sets out in more detail what the ESO will deliver, along with associated milestones and outputs, for the "Business Plan 2" period.

Ofgem, as part of its Final Determinations for the RIIO-2 price control, set out that the ESO would be subject to an evaluative incentive framework, assessing our performance in delivering the Business Plan.

The updated ESO Reporting and Incentives (ESORI) guidance sets out the process and criteria for assessing the performance of the ESO, and the reporting requirements which form part of the incentive scheme for the BP2 period. Every month, we report on a set of monthly performance measures; Performance Metrics (which have benchmarks) and Regularly Reported Evidence items (which do not have benchmarks). This report is published on the 17th working day of each month, covering the preceding month.

Every quarter, we report on a larger set of performance measures, and also provide an update on our progress against our Delivery Schedule in the RIIO-2 deliverables tracker. Our six-month and eighteen-month reports will broadly be similar to our usual quarterly report.

Our mid-scheme and end of scheme reports will be more detailed, covering all of the criteria used to assess our performance.

Following our Business Plan 2 (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 BP2 DD&T investment portfolio. As per the ESORI guidance, we are required to provide quarterly reports directly to Ofgem as part of the CMF. We feel it is important to share updates with our external stakeholders and industry as part of the framework. So, we'll be including a summary of the CMF update every six months alongside our incentives reporting.

Please see our website for more information.

Summary of Notable Events

In August we successfully delivered the following notable events and publications. We provide further detail on each of these under the role sections:

- On 13 August, the Balancing Transformation Programme and Markets hosted a well-attended webinar to gather feedback on the strategy for implementing the Quick Reserve service on the Open Balancing Platform (OBP). The webinar received positive feedback on its organisation and informative content.
- On 7 August, we held an industry Q&A session following the publication of the interim results of the Constraints Collaboration Project (CCP) at the end of July. The CCP took a collaborative approach, seeking solutions from the industry to address constraints. Market-based options for constraints markets showed potential value for end-consumers, leading us to further investigate their detailed design. Technical solutions to increase flow over transmission lines were also proposed, but require further investigation due to technical challenges. We will maintain ongoing collaboration and engagement with the industry, providing regular communications, as we work towards a final decision on the options by the end of Q1 2025.
- On 6 August, the Capacity Market Prequalification Window officially opened, allowing the industry an 8-week period to submit their applications for assessment ahead of the upcoming CM auctions in March 2025. As the EMR Delivery Body, we have implemented CM Rules changes, improved the end-to-end process, and introduced a new Customer Portal project. Dedicated support teams, an integrated Customer Guidance website, and training videos have been provided to assist the industry in navigating the new Portal and understanding the Regulations and Rules.
- On 16 August, BETA testing commenced for the Connections 360 application. This tool aims to simplify the display of national grid information, providing details on connected projects, capacity, and availability for connections. It will offer industry stakeholders greater insight, reduce speculative applications, and assist with application management. Phase two of BETA testing is currently underway, with a targeted go-live date of 1 October 2024, aligned with the NESO launch.
- On 13 August, we published our recommended design for the connection of 4.5GW of floating offshore wind in the Celtic Sea (The Crown Estate's leasing Round 5), between South Wales and South West England. This is the first time we've provided a recommended network design ahead of the outcome of a leasing round, marking a key achievement delivered in close collaboration with our key stakeholders.

Summary of Metrics and RREs

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) for August 2024.

Metric/RRE		Performance	Status
Metric 1A	**Balancing Costs**	£291m vs benchmark of £203m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 596MW vs indicative benchmark of 515MW	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 5.1% vs indicative benchmark of 4.4%	●
Metric 1D	**Short Notice Changes to Planned Outages**	4.51 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	●
RRE 1E	**Transparency of Operational Decision Making**	94.2% of actions taken in merit order or driven by an electrical parameter	N/A
RRE 1G	**Carbon intensity of ESO actions**	15.02gCO_2/kWh of actions taken by the ESO	N/A
RRE 1I	**Security of Supply**	0 instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	1 planned and 0 unplanned system outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 32%	N/A

Below expectations ● **Meeting expectations** ● **Exceeding expectations** ●

We welcome feedback on our performance reporting to box.soincentives.electricity@nationalgrideso.com

Hannah Kruimer
Interim Head of Regulation

Role 1 (Control Centre operations)

ESO

Metric 1A Balancing cost management

This metric measures the ESO's outturn balancing costs (including Electricity System Restoration costs) against a balancing cost benchmark.

A new benchmark was introduced for BP2. Analysis has shown that the two most significant measurable external drivers of balancing costs are wholesale price and outturn wind generation. The new benchmark was derived using the historical relationships between those two drivers and balancing costs:

i. The benchmark was created using monthly data from the preceding 3 years.

ii. A straight-line relationship has been established between historic constraint costs, outturn wind generation and the historic wholesale day ahead price of electricity.

iii. A straight-line relationship has been established between historic non-constraint costs and the historic wholesale day ahead price of electricity.

iv. Ex-post actual data input into the equation created by the historic relationships to create the monthly benchmarks.

The formulas used 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*

ESO Operational Transparency Forum: The ESO hosts 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 panel. Details of how to sign up and recordings of previous meetings are available here.

August 2024-25 performance

Figure: 2024-25 Monthly balancing cost outturn versus benchmark

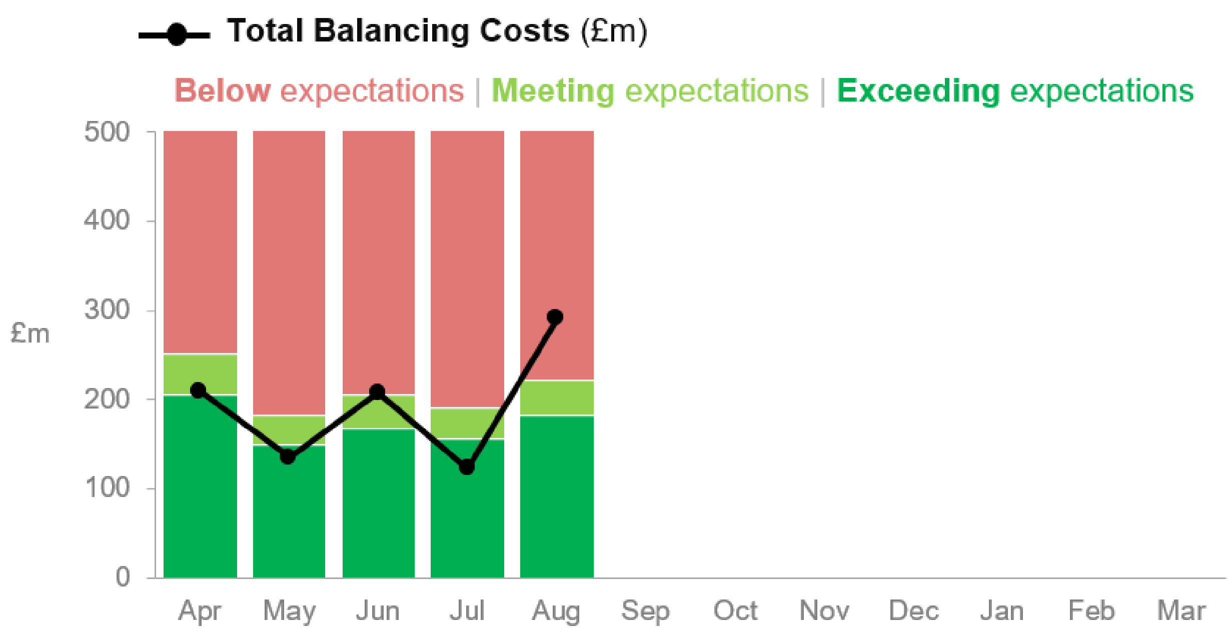


Table: 2024-25 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	6.3	3.2	3.9	3.5	5.1								22.0
Average Day Ahead Baseload (£/MWh)	59	72	76	71	62								n/a
Benchmark	228	167	187	173	203								957
Outturn balancing costs[1]	**209**	**135**	**208**	**123**	**291**								**966**
Status	●	●	●	●	●								●

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.

Performance benchmarks:

- **Exceeding expectations:** 10% lower than the annual balancing cost benchmark
- **Meeting expectations:** within ±10% of the annual balancing cost benchmark
- **Below expectations:** 10% higher than the annual balancing cost benchmark

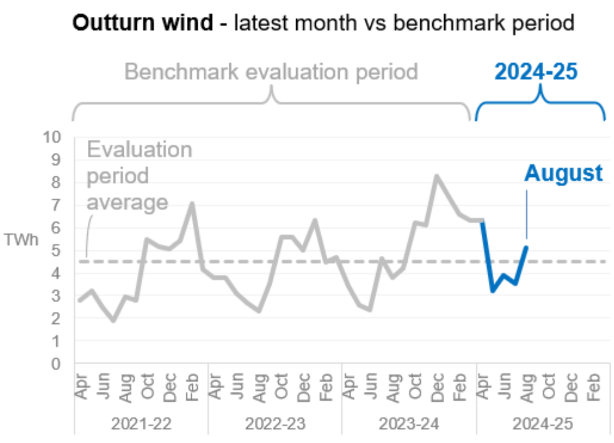
Supporting information

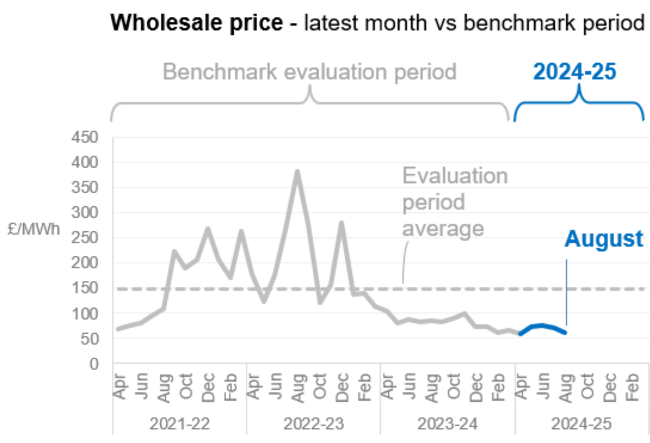
This month's benchmark

The August benchmark of £203m is £30m higher than July 2024 (£173m) and reflects:

- An **outturn wind** figure of 5.1TWh that is higher than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 4.5TWh) and is higher than last month's figure (July 2024).
- An average monthly **wholesale price** (Day Ahead Baseload) that remains low compared to the benchmark evaluation period, and £9/MWh lower than last month's figure (July 2024).

The increase in wind outturn contributed to the increase in the overall benchmark compared to last month but this was somewhat offset by the lower wholesale price.





[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.

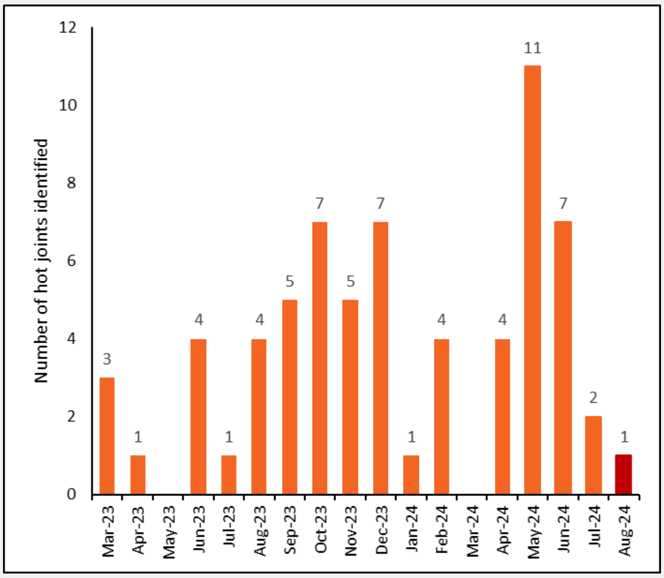
August Performance

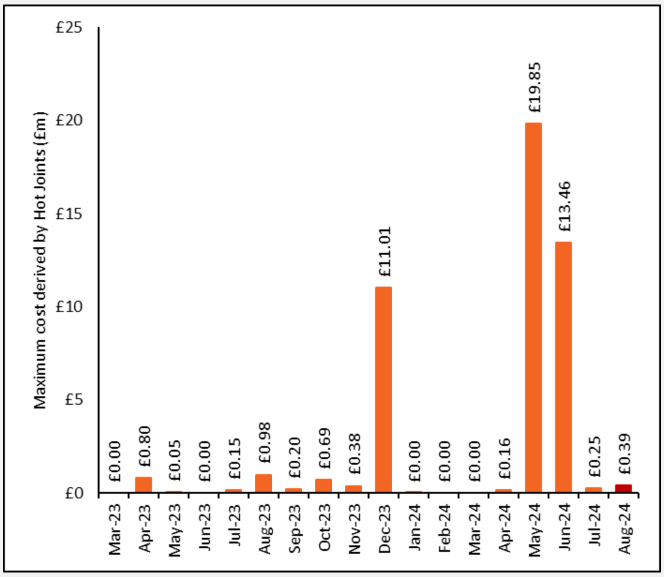
August's total balancing costs were £291m which is £88m (~44%) above the benchmark of £203m, and therefore performance is below expectations. August saw a large number of active constraints requiring management, including some ongoing outages in Scotland which amplified the impact of high wind outturn on constraint volumes. There was a 46% increase in overall wind generation compared to July and storm conditions brought particularly strong winds to North England and Scotland later in the month. Although the increased wind generation output is reflected in the benchmark there was a comparatively larger increase (~300%) in constraint volumes (predominantly in Scotland) compared to the previous month which drove the constraint cost to its highest August cost over the last 5 years. The volume weighted average price for bids increased by £50.3/MWh compared to last month (from £64.4/MWh to £114.7/MWh), and the volume weighted average offer price rose £4.2/MWh (from 104.6/MWh to £108.7/MWh).

August's balancing costs were also the highest so far in this financial year and higher than August 2023. Outages in North East Scotland were also impacting transfer capacity in this region, further contributing to costs during windy periods. Although, analysis showed that taking these outages at this time presented the lowest overall cost. Total constraint volumes have increased by 683 GWh resulting in thermal constraint actions and ROCOF actions to support system inertia. Notably, the remnants of Hurricane Ernesto on 21 and 22 August, and Storm Lilian on 23 August brought strong winds across GB, pushing up constraint volumes in the second half of the month. Although wholesale power prices fell compared to July 2024 and August last year, gas prices rose by almost 10p/therm contributing to higher offer prices for replacement energy. Non-constraint volumes also increased by 478 GWh (due to increased actions to manage operating reserve and response) although costs rose just £5.3m compared to July and were lower than August 2023.

The total savings from outage optimisation were roughly £134m in August 2024, this represents a reduction of £104m relative to July this year (£239m). The action that yielded the greatest value involved an agreement for a radial connection of a demand in Scotland, which off-loaded a 275kV circuit and improved the transfer capacity of the Western Link. Cost savings for this action are estimated to be roughly £42m.

We continue to monitor the occurrence of hot joints in the system and their potential cost impact. In August one hot joint was identified in the South East. No significant cost impact identified.





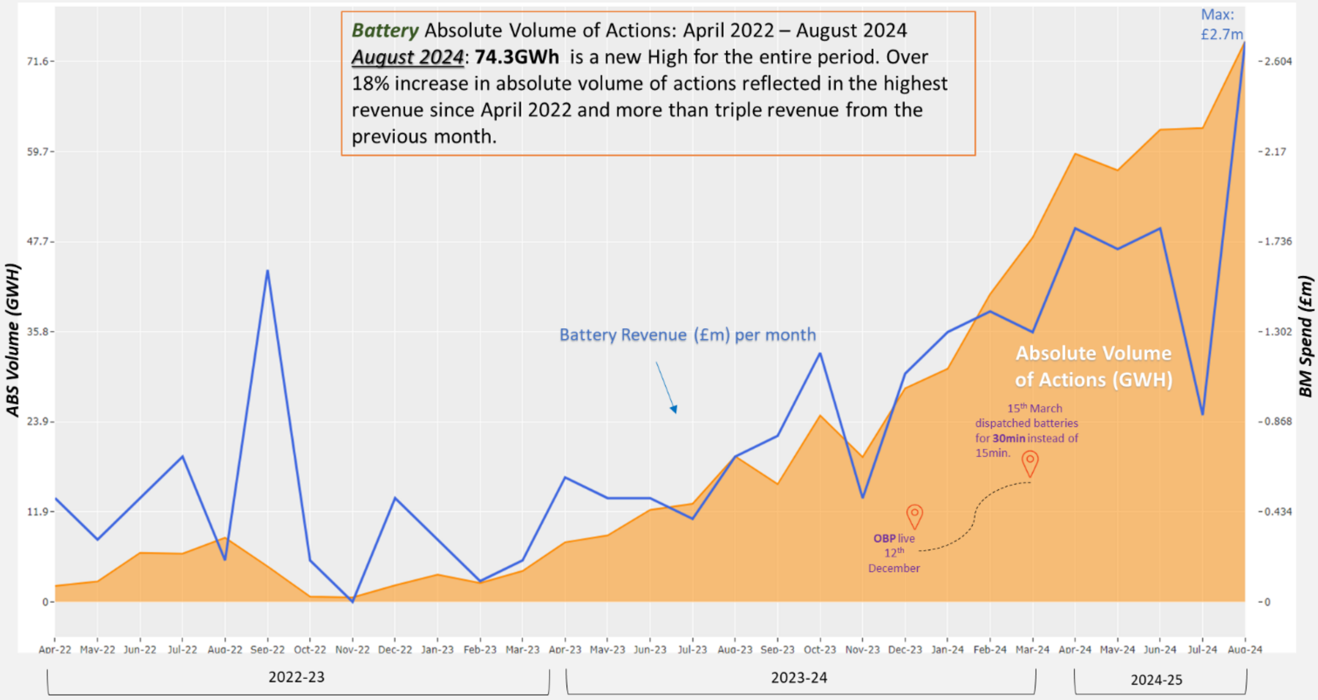
The Trading team have made a total saving of £38m in August through trading actions as opposed to alternative BM actions, representing a 59% increase on the previous month. Trades were conducted for downwards regulation, to help manage constraints and provide margin. August also saw a high level of trading activity, and sell trades were subsequently enacted to prevent Transient Over Voltages on the South Coast. The day with the greatest spends on trades was 29 August at a cost of £3.8m. The BM was scheduled for outage during the day and high volumes of interconnector trades were planned to meet energy and system requirements.

As discussed in December's incentives report, 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 August battery dispatch increased to a new record of absolute volume, at over 74 GWh. This illustrates our commitment to maximising the flexibility of energy offered by battery storage and small BMUs over the last year.

Monthly Absolute Volume of actions and spend for Batteries in the Balancing Mechanism

April 2022 to August 2024



Breakdown of costs vs previous month

Balancing Costs variance (£m): August 2024 vs July 2024

		(a) Jul-24	(b) Aug-24	(b) - (a) Variance
Non-Constraint Costs	Energy Imbalance	1.7	-1.4	(3.1)
	Operating Reserve	5.1	6.4	1.3
	STOR	3.8	4.0	0.2
	Negative Reserve	0.2	0.1	(0.1)
	Fast Reserve	15.5	13.0	(2.5)
	Response	13.5	16.0	2.5
	Other Reserve	2.5	2.6	0.2
	Reactive	11.7	11.2	(0.5)
	Restoration	2.9	3.2	0.3
	Winter Contingency	0.0	0.0	0.0
	Minor Components	0.8	7.9	7.1
Constraint Costs	Constraints - E&W	14.8	46.0	31.1
	Constraints - Cheviot	4.6	0.3	(4.3)
	Constraints - Scotland	32.3	148.7	116.4
	Constraints - Ancillary	0.6	0.2	(0.5)
	ROCOF	7.7	7.2	(0.6)
	Constraints Sterilised HR	5.4	26.1	20.8
Totals	Non-Constraint Costs - TOTAL	57.8	63.1	5.3
	Constraint Costs - TOTAL	65.4	228.4	162.9
	Total Balancing Costs	**123.2**	**291.4**	**168.2**

As shown in the total rows from the table above, constraint costs increased by £162.9m and non-constraint costs increased by £5.3m, resulting in an overall increase of £168.2m (rounded to £0.1m) compared to July 2024.

Constraint costs: The main drivers of the variances this month are detailed below:

- **Constraint-Scotland & Cheviot***: The constraint costs in Scotland and Cheviot increased by £112.1m in part due to significantly higher absolute curtailed volume of actions by 849 GWh than July 2024.
- **Constraint-England & Wales***: The constraint cost in England & Wales increased by £31.1m following an increase in the absolute volume of actions by 38 GWh.
- **Constraint Sterilised Headroom***: £20.8m increase due to an increase of 1397 GWh total volume of replacement energy. This is in line with the increase in constraint volumes in Scotland.

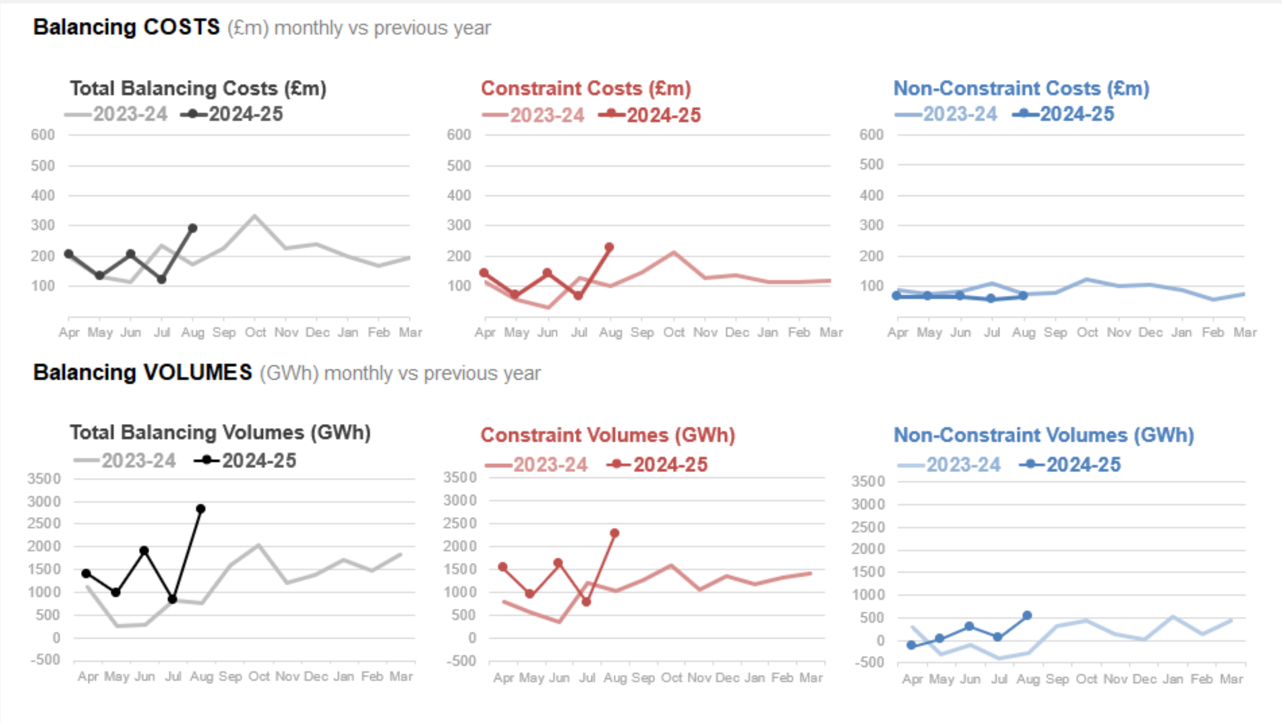
*This month saw an increase in the volume weighted average price for bids.

Non-constraint costs*: The main driver of the variance this month is:

- **Energy Imbalance**: reduced by £3.1m, in line with a 106GWh increase in negative volume of actions as the market was notably long in August except morning and evening peaks.
- **Operating Reserve**: £1.3m higher in cost following an increase of 481 GWh reserve required to secure the system.
- **Fast Reserve**: £2.5m decrease despite a 16.5 GWh increase in volume, in part due to slightly lower volume weighted average offer price for response.
- **Response**: £2.5m reduction due to an increase of 9.4 GWh in the absolute volume of actions.
- **Reactive**: £0.5m decrease due to a minor decrease in the volume average price from £3.80/MVAr to £3.75/MVAr compared to last month.

*Excluding the volume of actions from ancillary services as not yet quantified at the time of writing this report.

Constraint vs non-constraint costs and volumes



In summary, the total Constraint costs and non-constraint costs are featured below.

Constraint costs

Compared with the same month of the previous year:	We observe an increase of £127.2m in constraint costs compared to August 2023, due to a 1252 GWh increase in volume of constraint actions.
Compared with last month:	Constraint costs increased by £162.9m compared to July 2024, due to a 1506 GWh increase in volume of constraint actions, in line with a higher wind generation, particularly in Scotland.

Non-constraint costs**

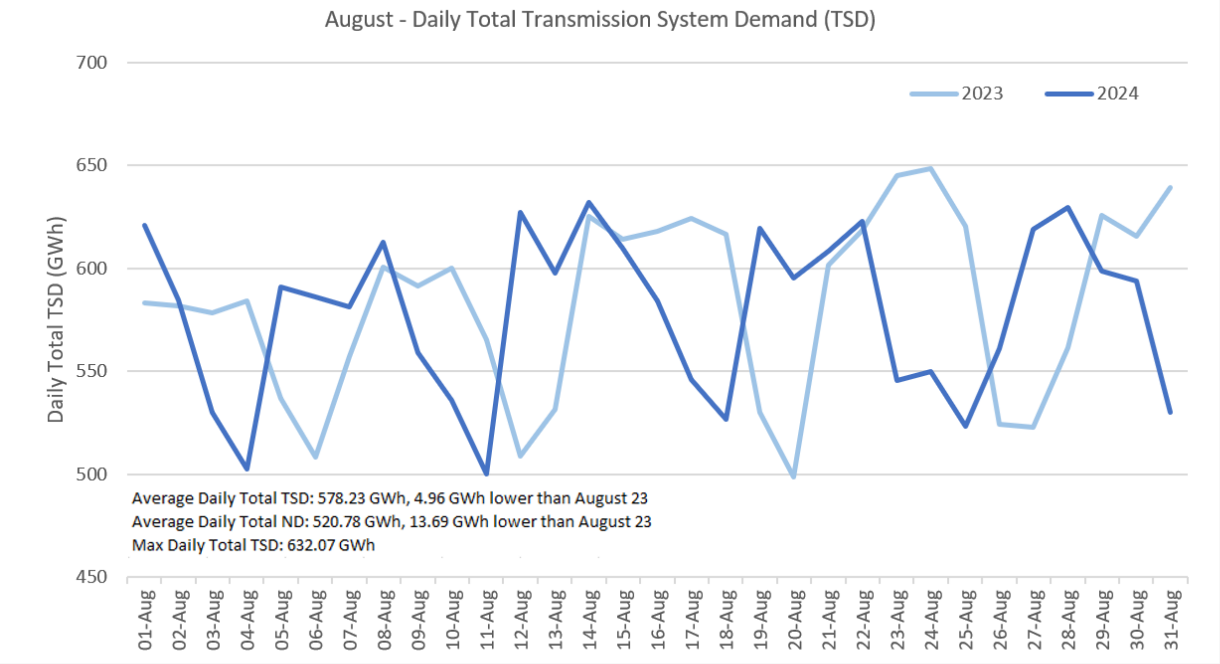
Compared with the same month of the previous year:	Non-Constraint costs were £10.4m lower than in August 2023 due to: • Slightly lower average wholesale power prices* • The total volume has lowered from –273 GWh last August to 531 GWh this August, resulting in an increase of 803 GWh in net volume of actions and a decrease of 258 GWh in absolute volume of actions.
Compared with last month:	Non-Constraint costs were £5.3m higher than July 2024, the total volume increased to 531 GWh in August, higher than 53 GWh in July as shown in the chart above, resulting in an increase of 478 GWh in volume of actions.

* Average wholesale price for August 24: £62/MWh compared to £86/MWh for August 23.

** The non-constraint category consists of several subcategories including energy imbalance, response, reserve, and restoration

August daily Transmission System Demand (TSD*)

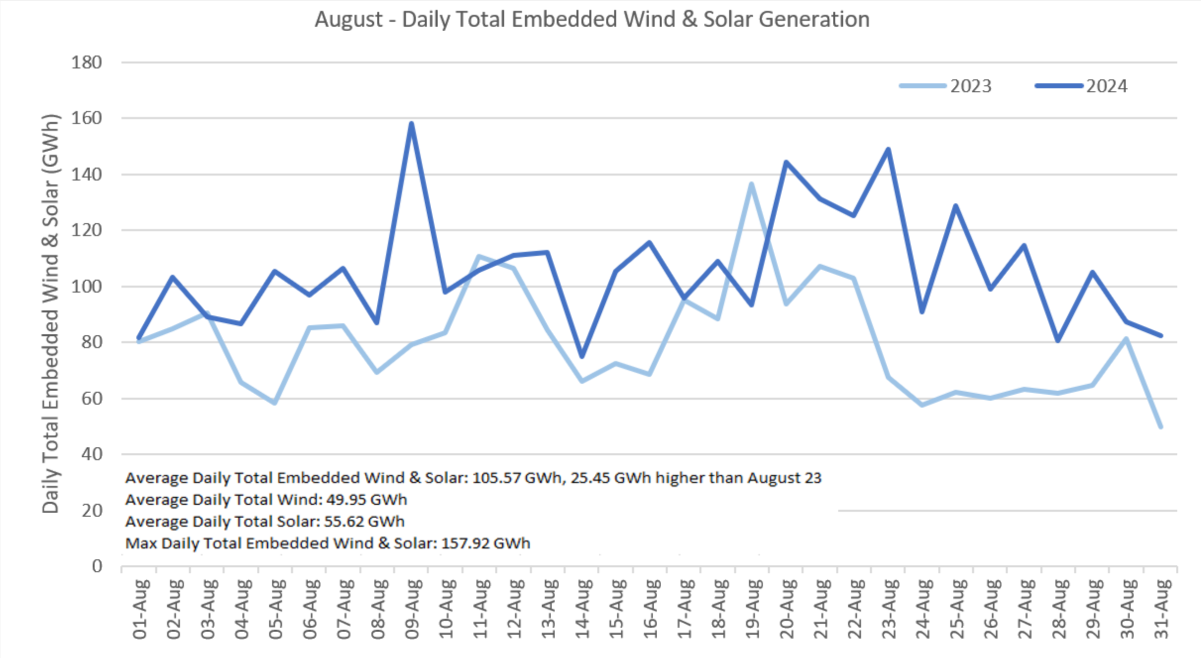
- Total Monthly National Demand (not shown below) was 13.7 GWh lower than August 2023.
- **Total Monthly Transmission System Demand*** was 5.0 GWh lower than August 2023.



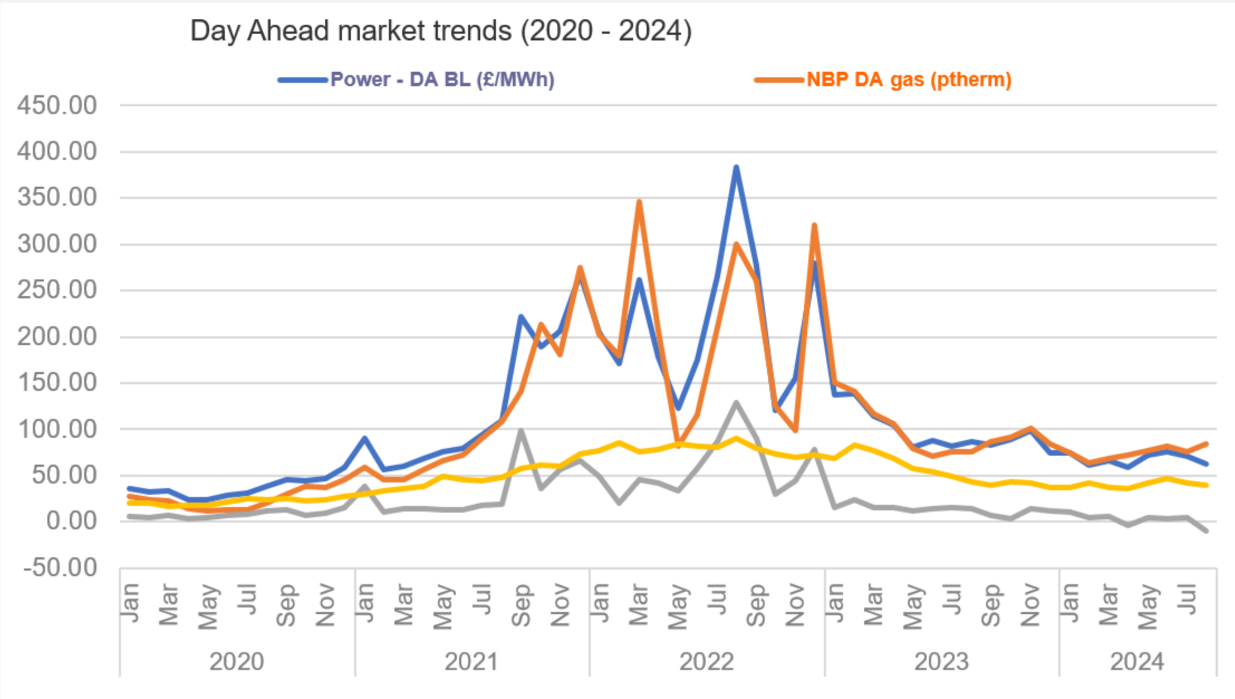
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand includes an estimate of station load of 500 MW in BST (British Summer Time) and 600 MW in GMT (Greenwich Mean Time).

August daily Embedded Wind and Solar Generation

- **Monthly Total Embedded wind & solar generation** was 25.5 GWh higher than in August 2023.
- The maximum daily total embedded wind & solar generation occurred on 9 August 2024 (157.9 GWh).



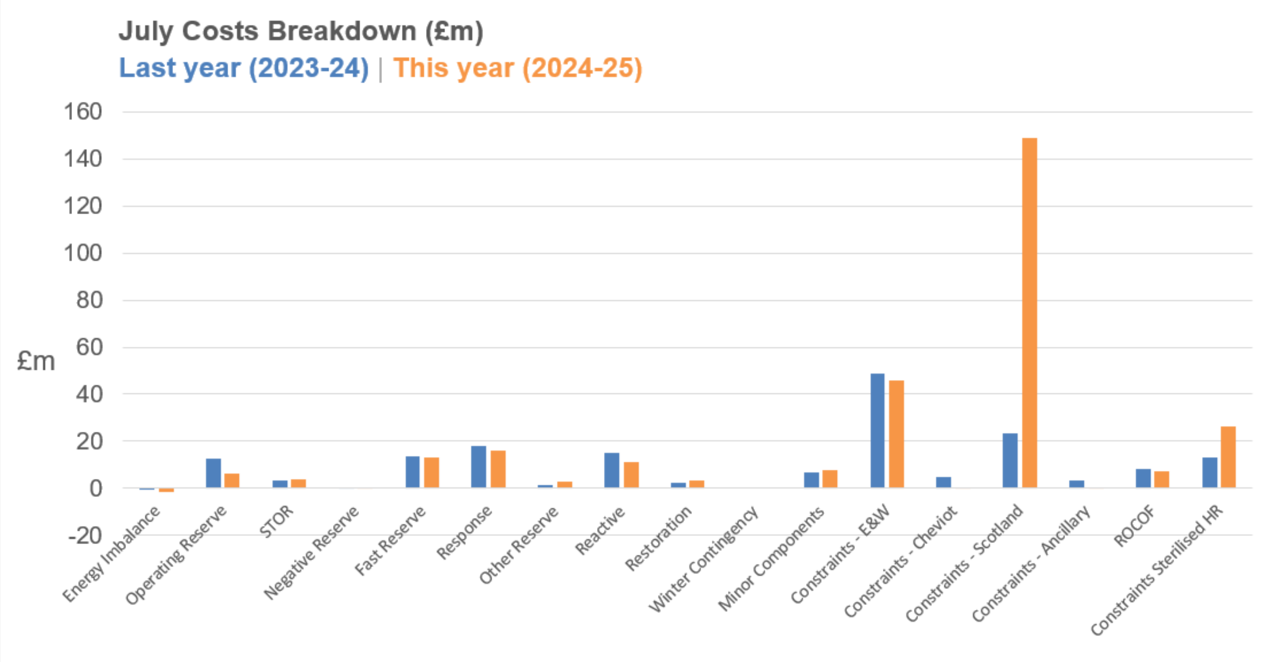
Price Trends in energy markets



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

Power and CO2 reduced compared to last month and last year. In contrast gas increased to 84.51ptherm from 75.29ptherm in July 2024 and 75.96ptherm in August 2023. There was consequently a fall in the Clean Spark Spread price.

Balancing costs increases/decreases compared with the same period from last year



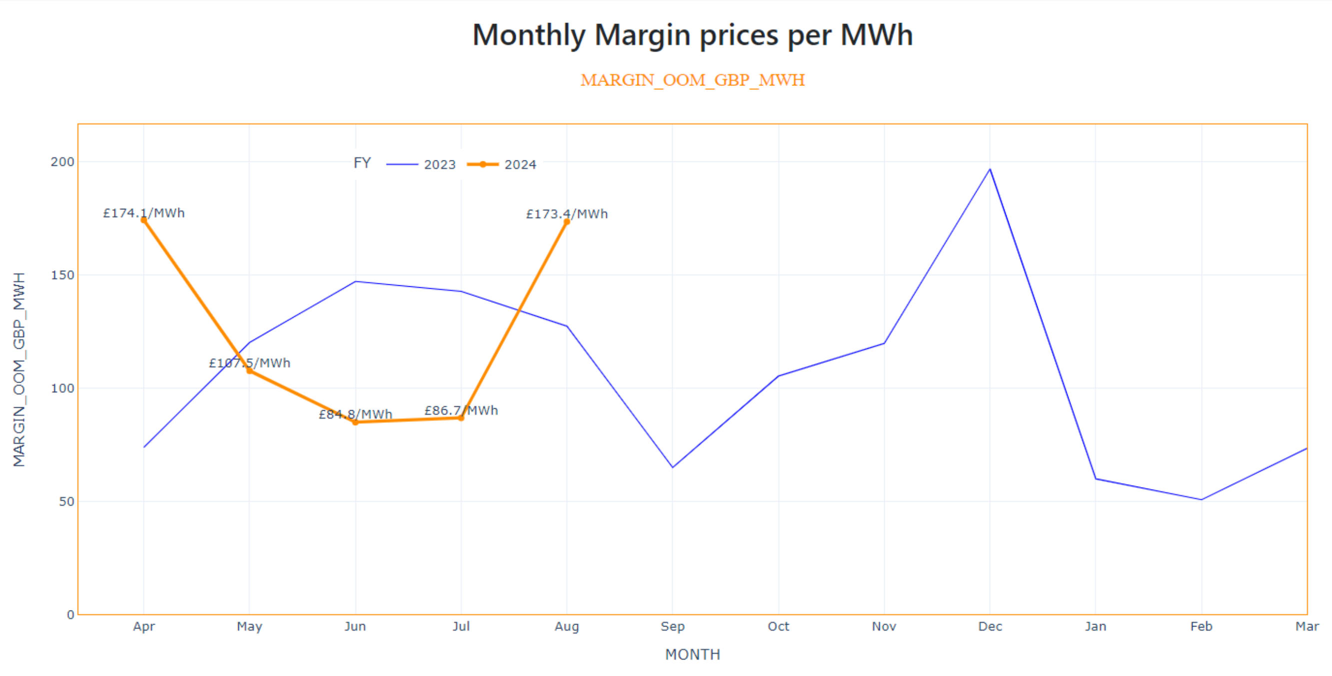
Comparing the non-constraint costs of August 2024 with those of August 2023, most categories showed a decrease or small deviation:

- **Reactive:** £4.1m decrease, due to the decrease in the weighted average price, from £4.2/MVAR to £3.8/MVAR.
- **Operating Reserve** £6.1m decrease despite a 523 GWh increase in reserve required to balance the system. The reduced cost experienced this year can be attributed, in part, to the lower energy prices compared to August 2023. Additionally, the introduction of the balancing reserve service in March has the potential to decrease reserve prices in the BM. We are currently in the process of quantifying the benefits associated with this service, and the results will be shared in the coming months.
- **Response**: £1.8m decrease due to 52 GWh less volume of actions taken.
- **Energy Imbalance:** £1.2m decrease despite a 42 GWh increase in the absolute volume of actions taken to balance the system.

Comparing the constraint costs of August 2024 with those of August 2023, there was a small decrease in all categories except Scotland and Sterilised HR which rose sharply in line with a large increase in wind outturn:

- **Constraints – Scotland & Cheviot**: £121.2m increase due to 956 GWh more absolute volume of actions.
- **Constraints – E&W**: £2.8m decrease due to taking 190 GWh less absolute volume of actions.
- **Constraints Sterilised Headroom***: £13.3m increase due to a 1,393 GWh increase in total volume of replacement energy.

Drivers for unexpected cost increases/decreases



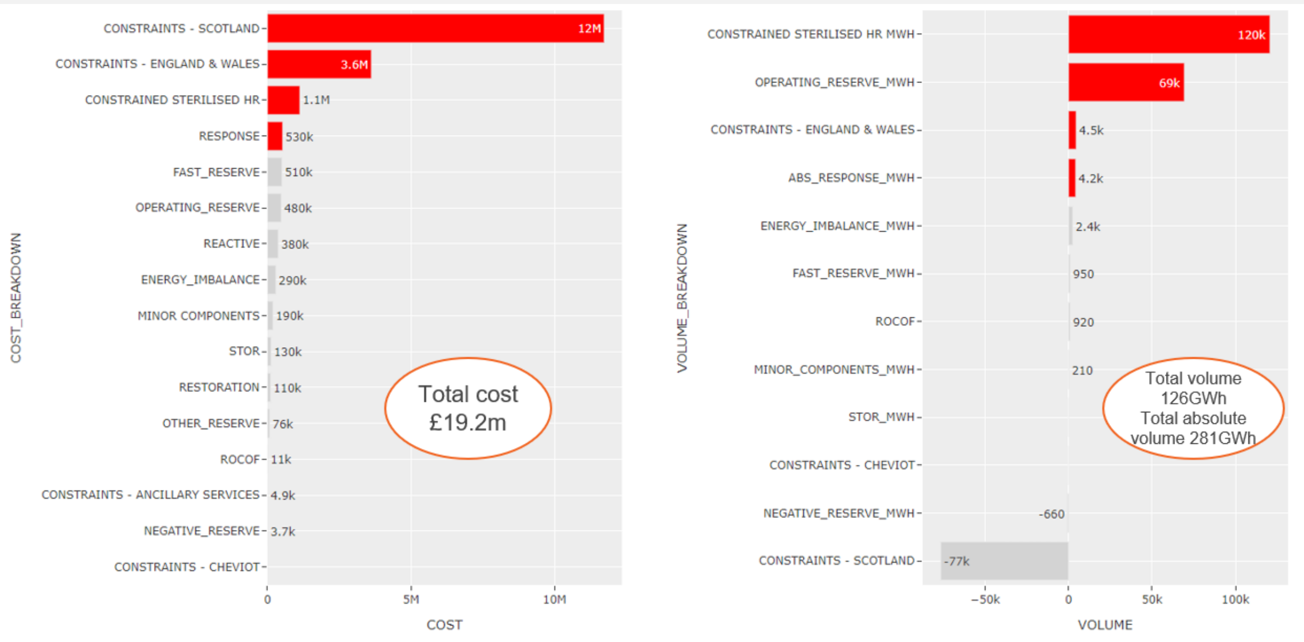
Margin prices increased to £173.4/MWh in August 2024 compared to £127.2/MWh in August 2023 and also increased significantly compared to July 2024.

Daily Costs Trends

August's balancing costs were £291m which is £168m higher than the previous month. 3 days were recorded with costs above £15m and around 45% of days had a daily total cost over £10m, resulting in an increase in the average monthly daily cost by £5.4m (from £4.0m to £9.4m).

The lowest total daily cost of £2.2m was observed on 1 August, whilst the highest total cost was observed on 27 August when the total spend was £19.2m (see 'Daily wind outturn' chart below). Thermal Export Constraints in Scotland dominated the cost breakdown on this day making up 63% of the daily cost. No individual action was expensive, but high volumes of wind curtailment and a heavily constrained system contributed to the high total balancing costs for the day.

Cost breakdown for 27 August 2024

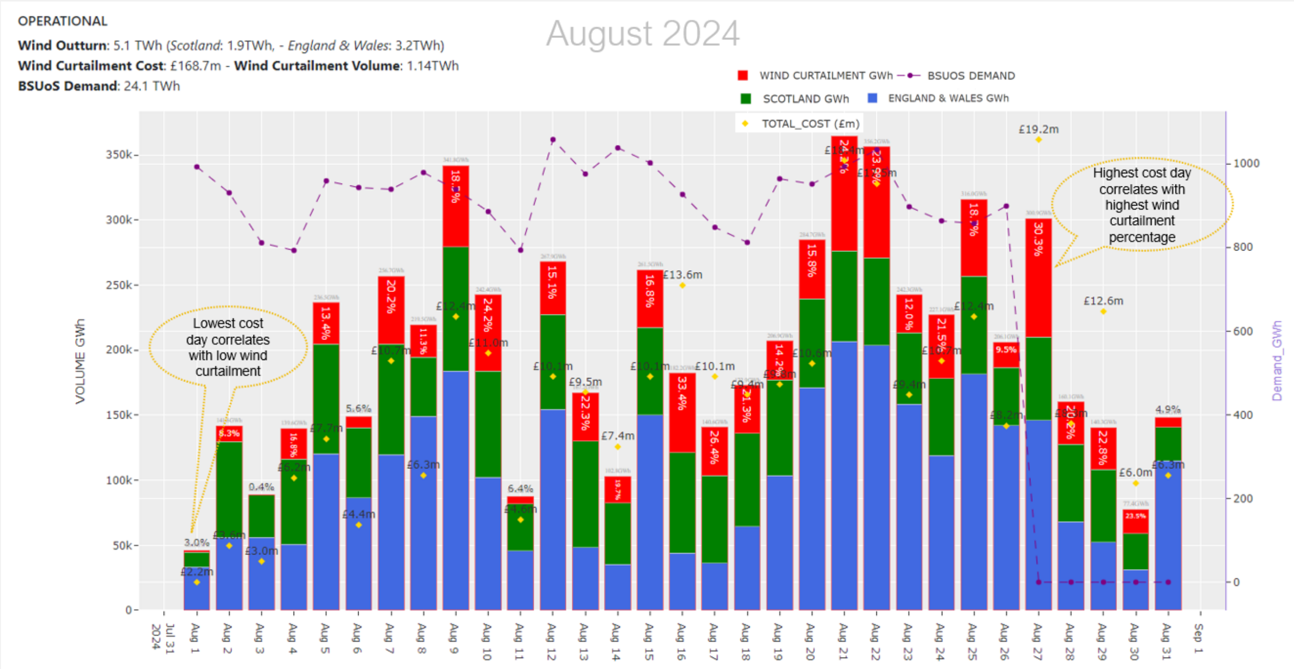


August Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUoS Demand

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 ESO control room action.

Metric 1B Demand forecasting accuracy

This 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. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

A 5% improvement in historical 5-year average performance is required to exceed expectations, whilst coming within ±5% of that value is required to meet expectations.

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

Performance will be assessed against the annual benchmark, but monthly benchmarks are also provided as a guide. The ESO will report against these each month to provide transparency of its performance through the year.

August 2024-25 performance

Indicative benchmark figures for 2024-25: Please note that the benchmark figures used below are indicative only. We have calculated these in line with the method specified by Ofgem, but we have not yet received the confirmed figures from Ofgem. We will update previous performance figures in subsequent reports once the benchmarks have been finalised.

Figure: 2024-25 Monthly absolute MW error vs Indicative Benchmark

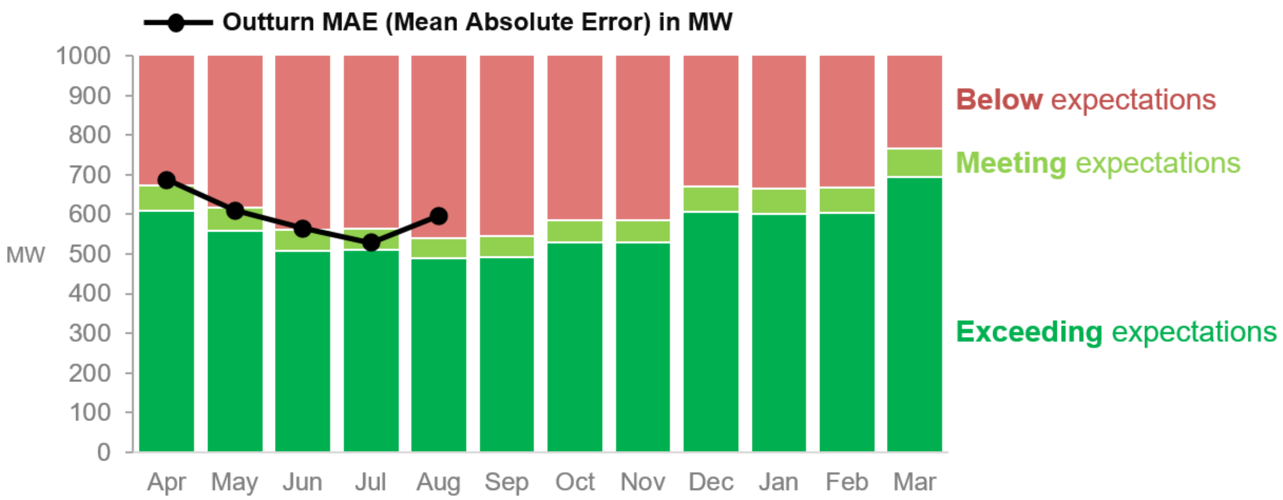


Table: 2024-25 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	642	588	534	538	515	519	558	557	639	632	636	730
Absolute error (MW)	**687**	**610**	**565**	**528**	**596**							
Status	●	●	●	●	●							

[2] Demand outturn | Insights Solution (elexon.co.uk)

Performance benchmarks:

- **Exceeding expectations:** >5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** >5% higher than 95% of average value for previous 5 years

Supporting information

In August 2024, the mean absolute error (MAE) was 596MW, which is more than 5% higher than the benchmark of 515MW and therefore below expectations.

The Met Office reports that:

"For a month that is usually renowned for setting new temperature records, August 2024 will be better known for the lack of sunshine, and very wet and windy weather. The UK was plagued by one Atlantic low pressure after another, with any settled conditions being short-lived."

This unusual and unstable weather proved challenging, which had a knock-on effect on ESO's energy forecasts.

The predominant factor in the larger error days was solar outturn. Solar irradiance was quite variable, frequently varying from sunny to cloudy days. These weather forecasts regularly changed, during within-day revisions. One of these days coincided with Storm Lillian on 23 August.

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

Error greater than	Number of SPs	% out of the SPs in the month (1488)
1000 MW	277	19%
1500 MW	114	8%
2000 MW	34	2%
2500 MW	3	0%

The days with largest MAE were August 3, 4, 19 and 23.

Missed / late publications

There were 0 occasions of missed or late publications in August.

Triads

Triads run between November and February (inclusive) each year and therefore did not affect this month's performance.

Metric 1C Wind forecasting accuracy

This metric measures the average absolute percentage error (APE) between day-ahead forecast (between 09:00 and 10:00, as published on ESO Data Portal here) and outturn wind generation (settlement metering as calculated by Elexon) 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) during the relevant settlement period.

We will publish this data on our Data Portal for transparency purposes. The benchmarks are drawn from analysis of historical errors of the five years preceding the performance year. A 5% improvement in performance is expected on the 5-year historical average, with a range of ±5% used to set the benchmark for meeting expectations.

August 2024-25 performance

Figure: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmark

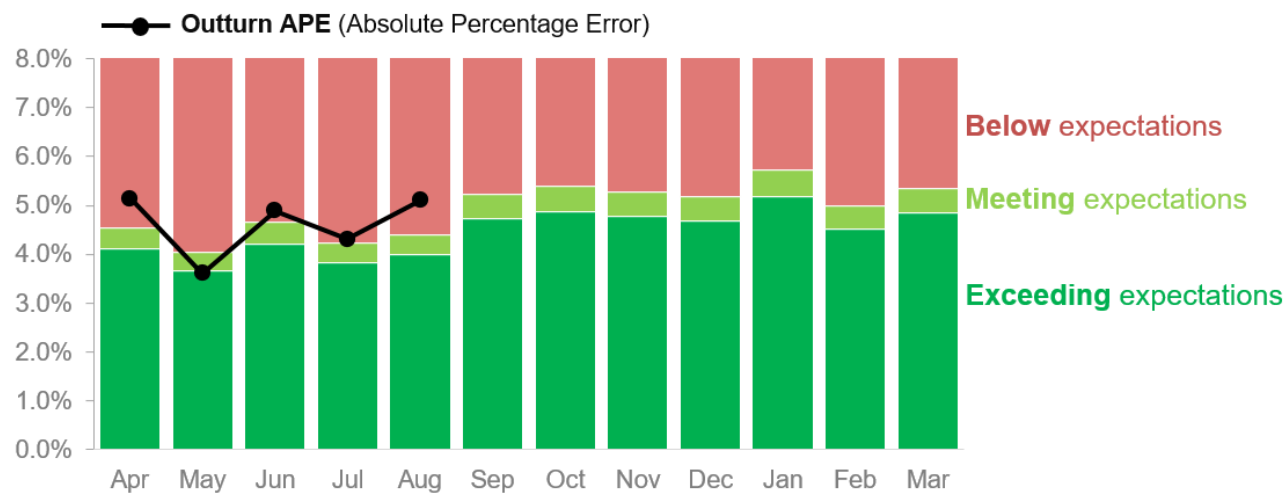


Table: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmarks

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.32	3.85	4.43	4.02	4.19	4.98	5.13	5.02	4.93	5.46	4.74	5.09
APE (%)	**5.14**	**3.61**	**4.89**	**4.30**	**5.10**							
Status	●	●	●	●	●							

Performance benchmarks:

- **Exceeding expectations:** < 5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** > 5% higher than 95% of average value for previous 5 years.

Alternative view of BMU Wind Generation Forecast APE

We have agreed with Ofgem that for 2024-25, alongside the above monthly figures we will include a post-report updated APE% view which aims to exclude 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). Both the benchmark and APE% reported below used this approach. A performance status is shown here, however this is for information only and is not part of the 2024-25 incentives assessment.

Please note that this new approach has also been proposed in the Consultation on Associated Documents to the proposed NESO licences – regulatory framework documents, which will come into effect when ESO transitions into NESO.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.34	3.82	4.45	3.98	4.22	4.99	5.13	5.07	4.89	5.44	4.73	5.05
APE (%)	**4.64**	**3.60**	**4.72**	**4.24**	**4.60**							
Status	●	●	●	●	●							

Supporting information

In August 2024, the mean absolute percentage error (APE) was 5.10%, which is more than 5% higher than the benchmark of 4.19% and therefore below expectations.

The alternative APE (corrected for redeclarations to zero and revisions to Settlement Metering) is currently reported as 4.60% against the corresponding benchmark of 4.22% for August, which is also below expectations.

Monthly error was strongly affected by four larger error days on 20, 22, 23 and 25 August. Two of these days coincided with Storm Lillian, which brought strong winds and heavy rain to northern England, Wales and Scotland on 22/23rd.

Two of the larger error days were also affected by lengthy periods of CfD behaviour on 23 and 25 August. The alternative 1C metric corrects for the majority of this CfD behaviour.

The highest wind error (over-forecast) was 5.9GW on 25 August, occurring during Settlement Period 22. This was during a period of CfD activity, where approximately 3.6GW of generation PN'd to zero after the Day Ahead forecast. However, additional partial redeclarations were observed, further contributing to the excessive error.

We are aware of some errors in the Elexon Settlement Metering data, which will be corrected in later runs and the Alternative 1C metric will adjust for these in due course.

Monthly errors are now largely influenced by only a few poor performing days. These days are predominantly swayed by poor weather data quality, particularly offshore. At present, the same small group of large offshore windfarms are having a detrimental impact on the metric performance. We are working with the Met Office and windfarm operators, to improve offshore weather forecasts.

Withdrawal of wind units

No units withdrew availability between time of forecast and time of metering.

Missed / late publications

There were 0 occasions of missed or late publications in August.

Metric 1D Short Notice Changes to Planned Outages

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

August 2024-25 performance

Figure: 2024-25 Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

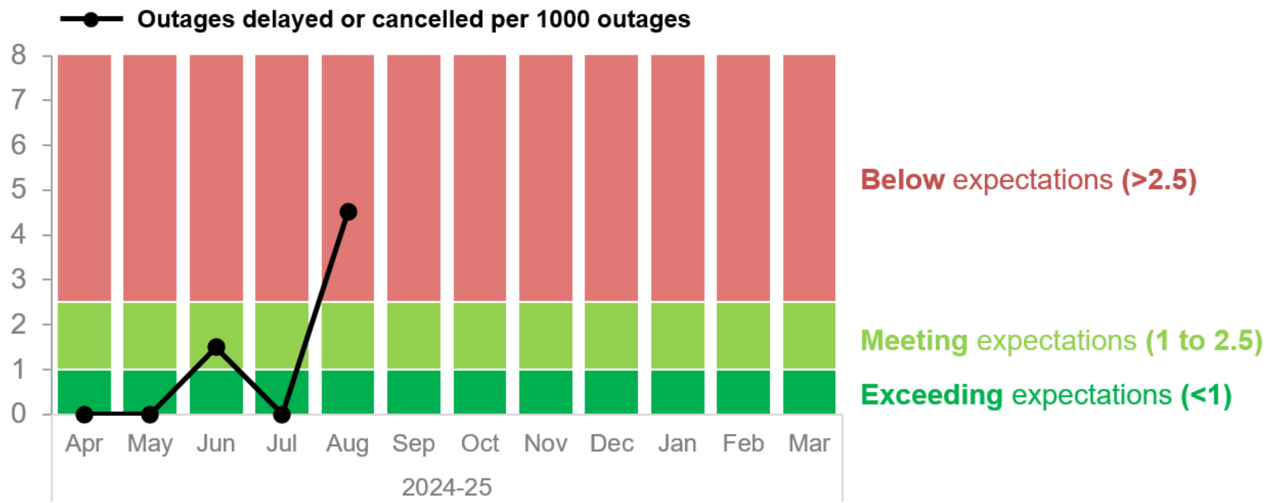


Table: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	673	614	670	784	665								3406
Outages delayed/cancelled due to ESO process failure	0	0	1	0	3								4
Number of outages delayed or cancelled per 1000 outages	0	0	1.49	0	4.51								1.17
Status	●	●	●	●	●								●

Performance benchmarks:

- **Exceeding expectations:** Fewer than 1 outage delayed or cancelled per 1000 outages
- **Meeting expectations:** 1-2.5 outages delayed or cancelled per 1000 outages
- **Below expectations:** More than 2.5 outages delayed or cancelled per 1000 outages

Supporting information

For August, we successfully released 665 outages. There were three delays or cancellations due to an ESO process failure. The number of stoppages or delays per 1,000 outages for August was 4.51, which is outside of the 'Meets Expectations' target of less than 2.5 delays or cancellations per 1,000 outages. The three events are summarised below:

1. There was a delay on an outage where it was identified that pre-fault overloading would have occurred following the switch out of the planned outage and was passed back to our planning

team to investigate. It was identified that there was a very large volume of embedded generation within the area and a localised constraint was to be created and handed over to the ESO control room to manage in real-time. It was also identified that due to the overlapping of several outage that two Grid Supply Points (GSPs) were at risk to a single Super Grid Transformer (SGT) fault that had been missed in planning timescales. Therefore, as part of the re-planning period this was resolved with an alternative network configuration to secure the two GSPs. An Operational Learning Note (OLN) has been written to highlight the operational challenges associated with this region and mitigations to capture demand at risk has been rolled out.

2. There was one delay on an outage due to concerns with system margins that was caused by overlapping outages that would result in significant constraints on the network. As the network was heavily constrained the outage was passed back to our planning team to investigate potential network optimisations and a strategy for managing system margins. The outage was successfully re-planned and released the following day. An Operational Learning Note (OLN) is being written to capture corrective measures and prevent a reoccurrence.
3. The last delay was caused by concerns on the real-time contingency analysis identifying high pre and post-fault flows through a particular circuit caused by the current planned and fault outages affecting the network configuration. As a consequence, the outage on a Super Grid Transformer (SGT) was showing to exacerbate the pre and post-fault loading of this circuit following simulations and was passed back to the ESO planning team to find an alternative slot. The outage was successfully re-planned and released the following day based on updated guidance. An Operational Learning Note (OLN) is being written to capture corrective measures and prevent a reoccurrence.

RRE 1E Transparency of operational decision making

This Regularly Reported Evidence (RRE) shows the percentage of balancing actions taken outside of the merit order in the Balancing Mechanism each month.

We publish the Dispatch Transparency dataset on our Data Portal every week on a Wednesday. This dataset details all the actions taken in the Balancing Mechanism (BM) for the previous week (Monday to Sunday). Categories and reason groups are allocated to each action to provide additional insight into why actions have been taken and ultimately derive the percentage of balancing actions taken outside of merit order in the BM.

Categories are applied to all actions where these are taken in merit order (Merit) or an electrical parameter drives that requirement. Reason groups are identified for any remaining actions where applicable. Additional information on these categories and reason groups can be found on our Data Portal in the Dispatch Transparency Methodology.

Categories include: System, Geometry, Loss Risk, Unit Commitment, Response, Merit

Reason groups include: Frequency, Flexibility, Incomplete, Zonal Management

The aim of this evidence is to highlight the efficient dispatch currently taking place within the BM while providing significant insight as to why actions are taken in the BM. Understanding the reasons behind actions being taken out of pure economic order allows us to focus our development and improvement work to ensure we are always making the best decisions and communicating this effectively to our customers and stakeholders.

We have been publishing the Dispatch Transparency dataset since March 2021, and it has sparked many conversations amongst market participants. As we continue to publish this dataset for BP2 we will also be providing additional narrative to help build trust by explaining:

- actions we are taking to increase understanding of the ESO's operational decision making
- insight into the reasons why actions are taken outside of merit order in the Balancing Mechanism
- activity planned and taken by the ESO to address and reduce the need for actions to be taken out of merit order.

August 2024-25 performance

Figure: 2024-25 Percentage of balancing actions taken in merit order to meet requirements in the Balancing Mechanism

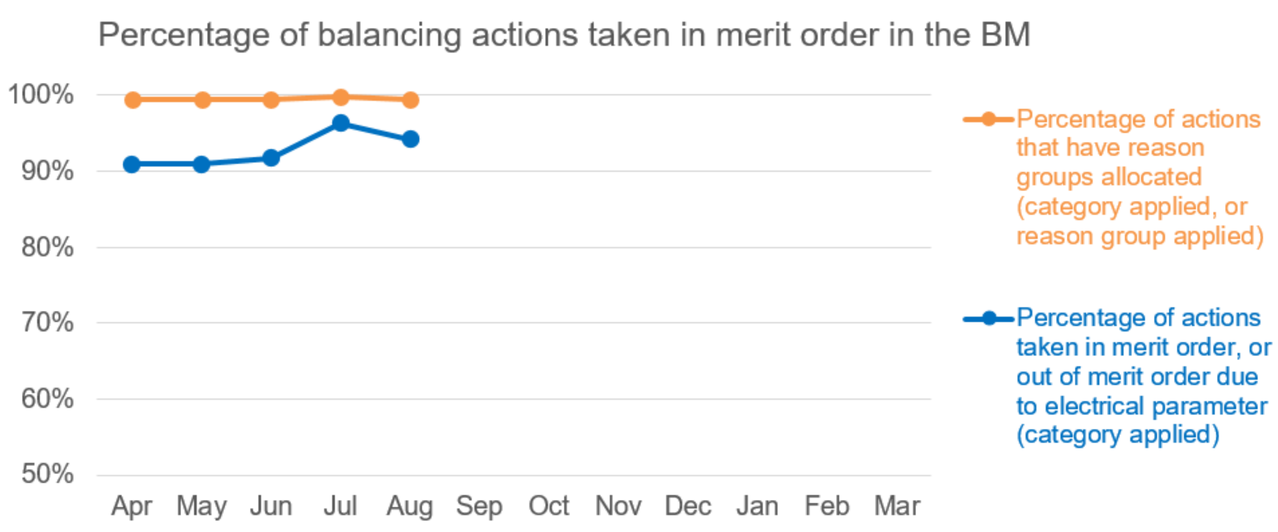


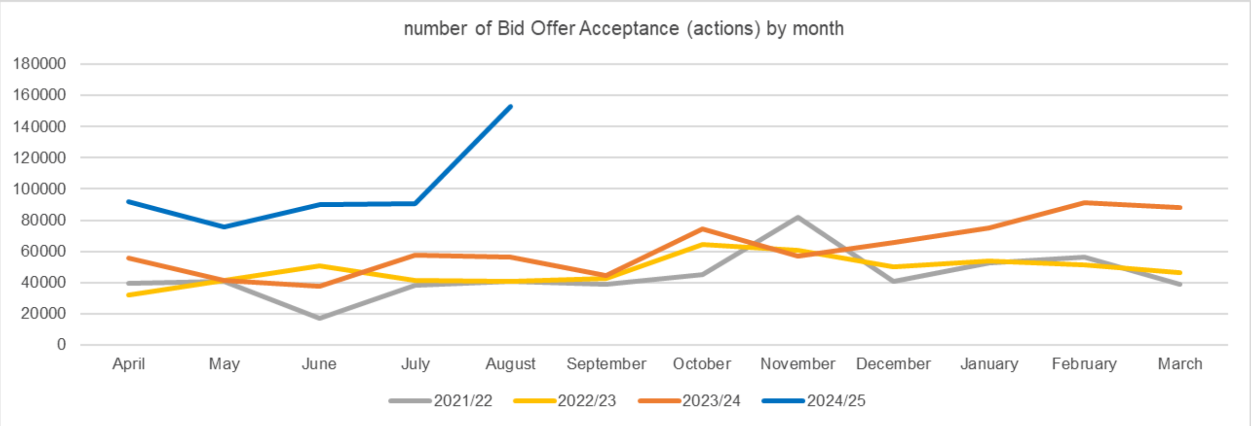
Table: Percentage of balancing actions taken outside of merit order in the BM

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	90.9%	90.9%	91.7%	96.3%	94.2%							
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.4%	99.5%	99.4%	99.8%	99.5%							
Percentage of actions with no category applied or reason group identified	0.6%	0.5%	0.6%	0.2%	0.5%							

Supporting information

August performance

This month 94.2% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 5.3% of actions were allocated to reason groups for the purposes of our analysis, and the percentage of actions with no category applied or reason group identified remained in line with previous months. During August, there were 152,757 BOA (Bid Offer Acceptances) and of these, only 767 remain with no category or reason group identified, which is 0.5% of the total. The number of BOAs increased significantly in August. A key driver of this was increase battery instructions.



Other activities

As mentioned previously, LCP Delta is progressing with their independent assurance report and we're committed to delivering this report to industry as soon as we are able. A new date for the webinar will be shared as soon as possible. Regular further updates will continue at the OTF.

RRE 1G Carbon intensity of ESO actions

This Regularly Reported Evidence (RRE) 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 RRE 1F and RRE 1G differs.

It is often the case that balancing actions taken by the ESO for operability reasons increase the carbon intensity of the generation mix. More information about the ESO's operability challenges is provided in the Operability Strategy Report.

August 2024-25 performance

Figure: 2024-25 Average monthly gCO2/kWh of actions taken by the ESO (vs 2023-24)

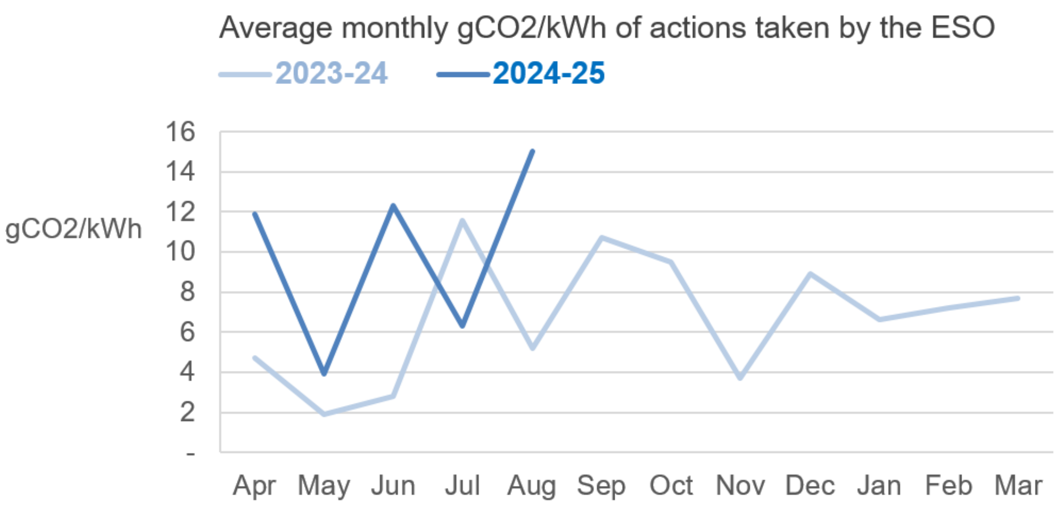


Table: Average monthly gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	11.87	3.93	12.31	6.33	15.02							

Supporting information

The average monthly gCO2/kWh of actions taken by the ESO during August 2024 was 15.02gCO2/kWh. This is an increase of 12.37gCO2/kWh compared to August 2023 and is higher than the YTD monthly average of 9.89gCO2/kWh.

The highest differences took place on 9 August at 2200 (56.18gCO2/kWh), 14 August at 2230 (56.32gCO2/kWh) and 27 August at 0930 (65.16gCO2/kWh). New constraints on these dates required ESO actions to be taken.

There were single settlement periods across the 1-6 August inclusive where ESO actions resulted in negative carbon intensity. 11, 14, 18, 26, 28, and 30 August all had single settlement periods of negative carbon intensity.

Continuous periods of action taken across 7/8 August and 19-25 August increased the overall average of difference. During 7/8 August there were busbar faults and unplanned outages requiring actions to be taken by the ESO. Across 19-25 August high volumes of actions were required to manage a heavily constrained system in multiple areas combined with low wind output.

Storm Lilian impacted large parts of the country on 23 August, causing significant disruption to transportation and community events, particularly in the north of England, Wales and Scotland. Some distribution networks experienced faults and ESO actions to manage high and volatile wind output was required.

RRE 1I Security of Supply

This Regularly Reported Evidence (RRE) 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 2024-25 performance

Table: Frequency and voltage excursions (2024-25)

	2024-25											
	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	0	0	0							

Supporting information

August performance

There were no reportable voltage or frequency excursion in August 2024.

[3] https://www.nationalgrideso.com/research-publications/transmission-performance-reports

RRE 1J CNI Outages

This Regularly Reported Evidence (RRE) 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 2024-25 performance

Table: 2024-25 Unplanned CNI System Outages (Number and length of each outage)

	2024-25											
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: 2024-25 Planned CNI System Outages (Number and length of each outage)

	2024-25											
Planned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	1 outage 265 mins	1 outage 203 mins							
Integrated Energy Management System (IEMS)	0	0	0	0	0							

Supporting information

August performance

In August 2024, there was one planned CNI system outage. The outage was to implement additional BM functionality and to carry out regular maintenance activities on the BM production systems, and impacted the key BM Suite components used for scheduling and dispatch of generation.

This change took place on 29 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 seven days prior and one 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.

Notable events during August 2024

Open Balancing Platform webinar – "OBP Interface For Non-BM Providers"

On 13 August, the Balancing Transformation Programme and Markets held a joint webinar to seek feedback on the strategy for delivering the first new non-BM service, Quick Reserve on the strategic ESO Balancing System, Open Balancing Platform (OBP). The webinar covered the proposed service design and integration between providers and the ESO, and was very well attended (over 90 industry attendees). Following the webinar, feedback has been sought on the webinar content, both on the communication model and feedback on proposed service design and OBP integration model, with a close on 10 September. We've received some great feedback on the general webinar and engagement - "The session was well run and very informative slides. We also appreciate the proactiveness of having this process, it helps providers like ourselves structure our development roadmaps accordingly and ahead of time." We are reviewing the feedback on the OBP integration and are engaging directly with those that have provided comments on the proposals.

Role 2 (Market developments and transactions)

ESO

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

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

The BSUoS charge (£/MWh) is now based upon a fixed tariff. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) are forecast for six-monthly tariffs and set 9 months ahead of the chargeable tariff period. For 2024/25, Fixed Tariff 3 (April 24 – Sep 24) was published in June 2023. Fixed Tariff 4 (Oct 2024 – Mar 2025) was published in December 2023.

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

August 2024-25 performance

Figure: 2024-25 Monthly BSUoS forecasting performance (Absolute Percentage Error)

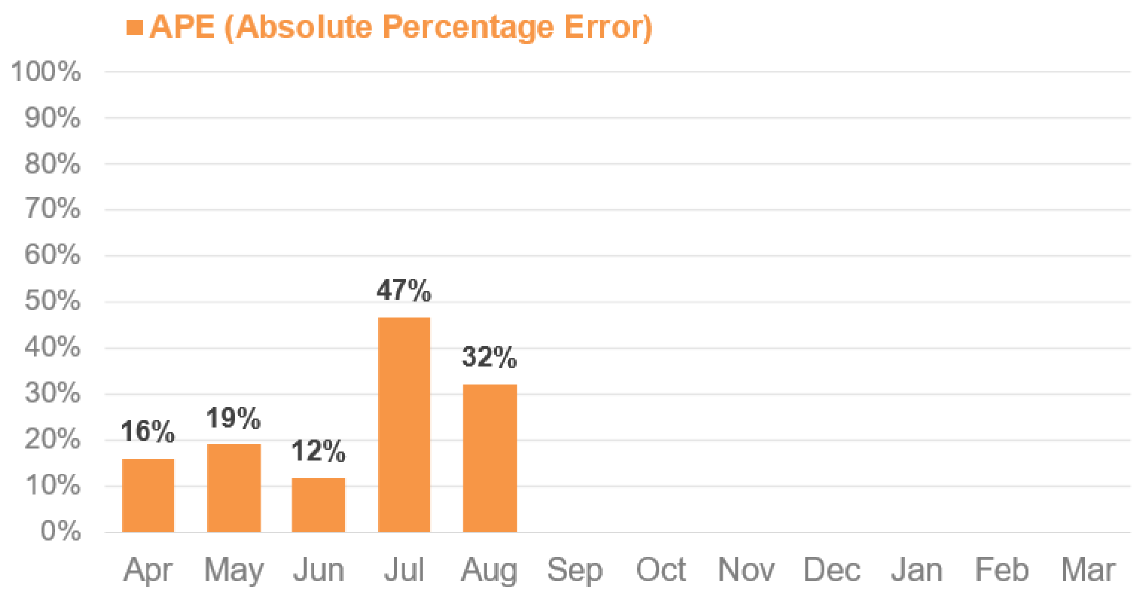


Table: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[4] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	11.5	8.5	12.7	8.0	16.5							
Month-ahead forecast (£ / MWh)	9.7	10.2	11.2	11.7	11.2							
APE (Absolute Percentage Error)[5]	**16.0**	**19.0**	**11.8**	**46.6**	**32.1**							

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

Supporting information

August Performance:

Actuals out-turned above forecast for August, with an Absolute Percentage Error of 32.13%.

This is a decrease from last month's absolute percentage error, although constraint costs were still the significant driver in the difference between our forecast and the actual outturn costs.

Costs:

August outturn costs were around the 95th percentile of the forecast produced at the beginning of July.

Our BSUS forecast is probabilistic and tries to find patterns in recent history. It also uses two key drivers in forecasting expected costs; wholesale market prices and the proportion of demand met by renewables. Based on these factors, the constraints outturn for August was significantly above expected costs. Constraint costs were £123m above forecast, with high constraint costs at the end of the month due to a combination of high levels of transmission connected wind generation and several outages taking place at the same time.

The high outturn costs seen in August will feed into our future BSUoS forecasts, as the BSUoS model includes a persistence element to account for recent forecast errors.

Volumes:

August actual volume was in line with the July forecast.

Forecast for August made at the start of July: 20.1TWh

August outturn: 20.1TWh

Notable events during July 2024

Constraints Collaboration Project webinar

At the end of July we published the interim results of the Constraints Collaboration Project (CCP), which was followed by an industry Q&A session on the 7 August. This project has taken a different approach to product development, by taking the problem to industry and asking them for their solutions. This was well-received, and we spent the following 4 months assessing the consolidated solutions provided to us. During this time, we maintained regular engagement with our customers through webinars, workshops and one to one meetings. The initial assessment for the market-based options (two kinds of constraints markets), showed that there could be some value to the end-consumer in implementing a constraints market, so we are now investigating this option further and the potential detail design of the market. There were also some technical solutions proposed to increase flow over transmission lines. The initial assessment highlighted some technical challenges to implementation, which we are currently investigating before we take it forward for implementation. Our intention is to maintain high levels of collaboration and engagement with the industry through this next phase of development and investigation with regular communications. We hope to have a final decision on the different options by the end of Q1 2025.

Launch of 2024 Capacity Market Round

Following the success of the CM Launch Event in July, we formally opened the Capacity Market Prequalification Window on 6 August, in accordance with the CM Operational Plan. The industry has 8 weeks up to 1 October to submit their application for prequalification assessment for the upcoming CM auctions in March 2025. As the Electricity Market Reform (EMR) Delivery Body, we implemented the CM Rules changes in our process and system and improved the end-to-end process through our new Customer Portal project. It is the first time for us and the industry to use the new Portal. We therefore have put in place a dedicated team to manage customer queries on the Portal as well as the process, established an integrated Customer Guidance website with over 100 documents and published a series of training videos, to help the industry understand the Regulations and Rules and complete and submit their applications through the new Portal.

Role 3
(System insight, planning and network development)

Metrics and RREs: Please note there are no metrics or monthly RREs for Role 3

Notable events during August 2024

Launch of Connections 360 BETA testing

On 16 August, BETA testing for the highly anticipated Connections 360 application began, with 20 individual testers across all three of our Transmission Owners (TOs). Connections 360 will display what is currently just a long list of information about the national grid in a much easier and more simplistic way, through plotting each grid point on a map – whether that is a sub-station or Grid Supply Point (GSPs). The map provides details on current connected projects at each GSP, the overall capacity at that point and what could be available should a company wish to connect to it. This geographic display will bring to life GSPs and sub-stations across GB, allowing customers across industry to view contracted capacities in a brand new way.

Externally, the Connections 360 will provide industry stakeholders with greater insight into the GB connections landscape, allowing for more informed connections applications to the business and cut down the volume of speculative applications that developer companies make to the business. Internally, Connections 360 will assist application management through scenario builder tools, enhanced data quality reporting and the capability to look at GSPs and sub-stations in more detail.
Phase two of the BETA testing has also now started with individuals from Developer companies and DNOs involved. The current targeted go-live date is 1 Oct 2024, in line with the NESO launch date.

Beyond 2030: Celtic Sea Offshore Design Recommendation published

On 13 August, we published our recommended design for the connection of 4.5GW of floating offshore wind in the Celtic Sea (The Crown Estate's leasing Round 5), between South Wales and South West England. This is the first time we've provided a recommended network design ahead of the outcome of a leasing round, marking a key achievement delivered in close collaboration with our key stakeholders.

To form our recommendation, we worked with The Crown Estate and National Grid Electricity Transmission (NGET) as the host Transmission Owner. We also formed a Celtic Sea Working Group made up of key energy industry and environmental stakeholders, and a Celtic Sea Community Working Group, made up of councils around the Celtic Sea region, to better understand local issues in our design process. We also held two in-person developer workshops to share our appraisals and findings with interested parties, gathering feedback from developers who would need to take on our recommendations.