Public

ANESO RIIO2 Business Plan 2 (2023-25)

October 2024 Incentives Report

25 November 2024

NESO
National Energy System Operator

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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 Business Plan 2 Delivery Schedule sets out in more detail what we 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 we would be subject to an evaluative incentive framework, assessing our performance in delivering the Business Plan.

An updated guidance was published in September 2024 called NESO Performance Arrangements Governance (NESO PAG) Document. It sets out the process and criteria for assessing the performance of NESO, and the reporting requirements which form part of the incentives scheme for the remainder of 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. Our eighteen-month report will broadly be similar to our usual quarterly report with the addition of providing an update on our progress against our Delivery Schedule in the RIIO-2 deliverables tracker.

Our end of scheme report 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 NESO PAG 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 October we successfully delivered the following notable events and publications. We provide further detail on each of these under the role sections:

- On 8 October, we published our Winter Outlook 2024, assessing the electricity security of supply for the upcoming winter. The report highlights a higher de-rated margin of 5.2GW (8.8% of peak demand) compared to the previous year, indicating improved supply availability. The associated Loss of Load Expectation (LOLE) is within the Reliability Standard. The Operational Surplus analysis shows sufficient operational headroom throughout winter, with plans to minimize generation restrictions and balancing costs. The report also covers global energy market assessment and close engagement with stakeholders to enhance resilience.

- On 28 October, the Connections Digital team successfully launched Connections 360, an application that provides customers with greater insights into the GB connections landscape and improved access to connections information. This empowers customers to make more informed applications, reduces speculative applications, and supports internal users with data modelling and addressing queries. Over 500 customers have already logged in and used the application, with positive feedback received at the London 2024 Connections Customer Seminar.

Summary of Metrics and RREs

The table below summarise our Metrics and Regularly Reported Evidence (RRE) for October 2024.

Metric/RRE		Performance	Status
Metric 1A	**Balancing Costs**	£272m vs benchmark of £239m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 578MW vs indicative benchmark of 559MW	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 4.70% vs indicative benchmark of 5.13%	●
RRE 1E	**Transparency of Operational Decision Making**	92.8% of actions taken in merit order or driven by an electrical parameter	N/A
RRE 1G	**Carbon intensity of NESO actions**	10.92gCO_2/kWh of actions taken by the NESO	N/A
RRE 1I	**Security of Supply**	1 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**	0 planned and 0 unplanned system outages	N/A

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

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

Hannah Kruimer

Interim Head of Regulation

NESO
National Energy
System Operator

Role 1

(Control Centre operations)

Metric 1A Balancing cost management

This metric measures NESO'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*

NESO Operational Transparency Forum: NESO 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 System Operations panel. Details of how to sign up and recordings of previous meetings are available here.

October 2024-25 performance

Figure: 2024-25 Monthly balancing cost outturn versus benchmark

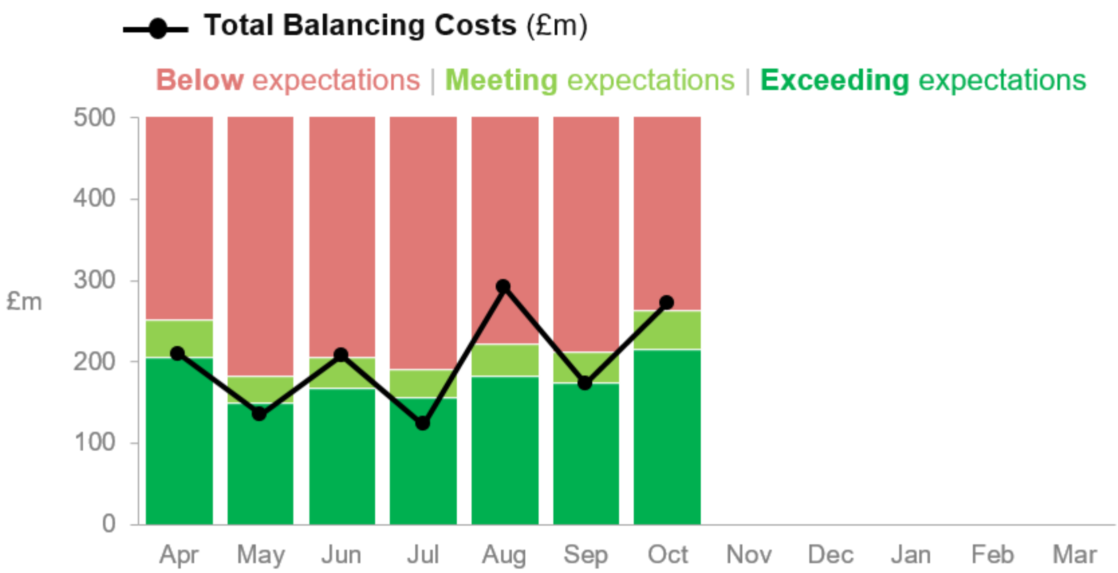


Table: 2024-25 Monthly breakdown of balancing cost benchmark and outturn

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	4.2	5.7						31.9
Average Day Ahead Baseload (£/MWh)	59	72	76	71	62	76	88						n/a
Benchmark	228	167	187	173	203	194	239						1391
Outturn balancing costs [1]	**209**	**135**	**208**	**123**	**291**	**173**	**272**						**1411**
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

BALANCING COSTS METRIC & PERFORMANCE

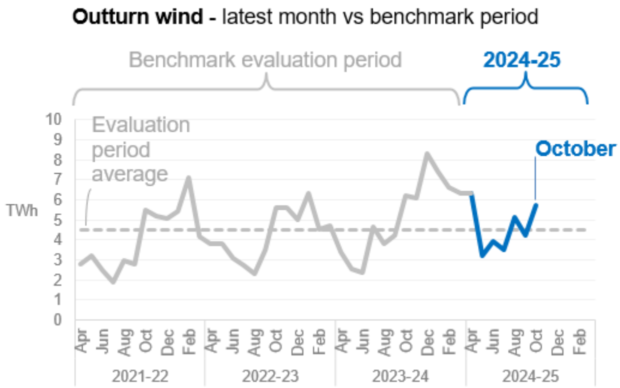
This month's benchmark

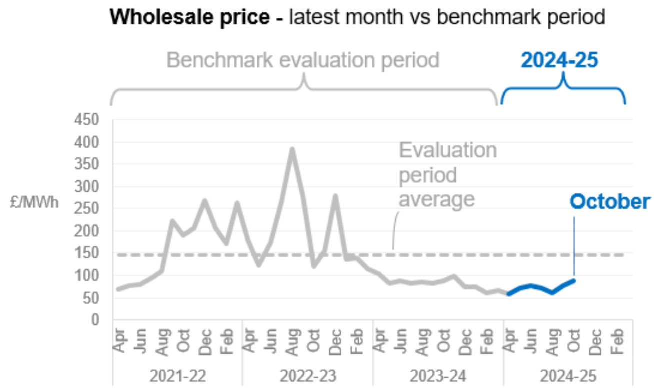
The October benchmark of £239m is £45m higher than September 2024 and reflects:

- An **outturn wind** figure of 5.7 TWh that is higher than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 4.5 TWh) and is higher than last month's figure (4.2 TWh). This is partially driven by Storm Ashley.
- An average monthly **wholesale price** (Day Ahead Baseload) that has increased this month and marks a record high so far in 2024-25. However it remains lower than the evaluation period average.

The particularly high wind outturn during October, coupled with elevated wholesale prices, resulted in the highest overall benchmark so far in 2024-25.

[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.





Variable	October 2024	September 2024	October 2023
Average Wholesale Price (£/MWh)	88	-12	+1
Total Wind Outturn (TWh)	5.7	-1.5	+0.5
Benchmark (£m)	239	-45	+19
Performance	●	●	●

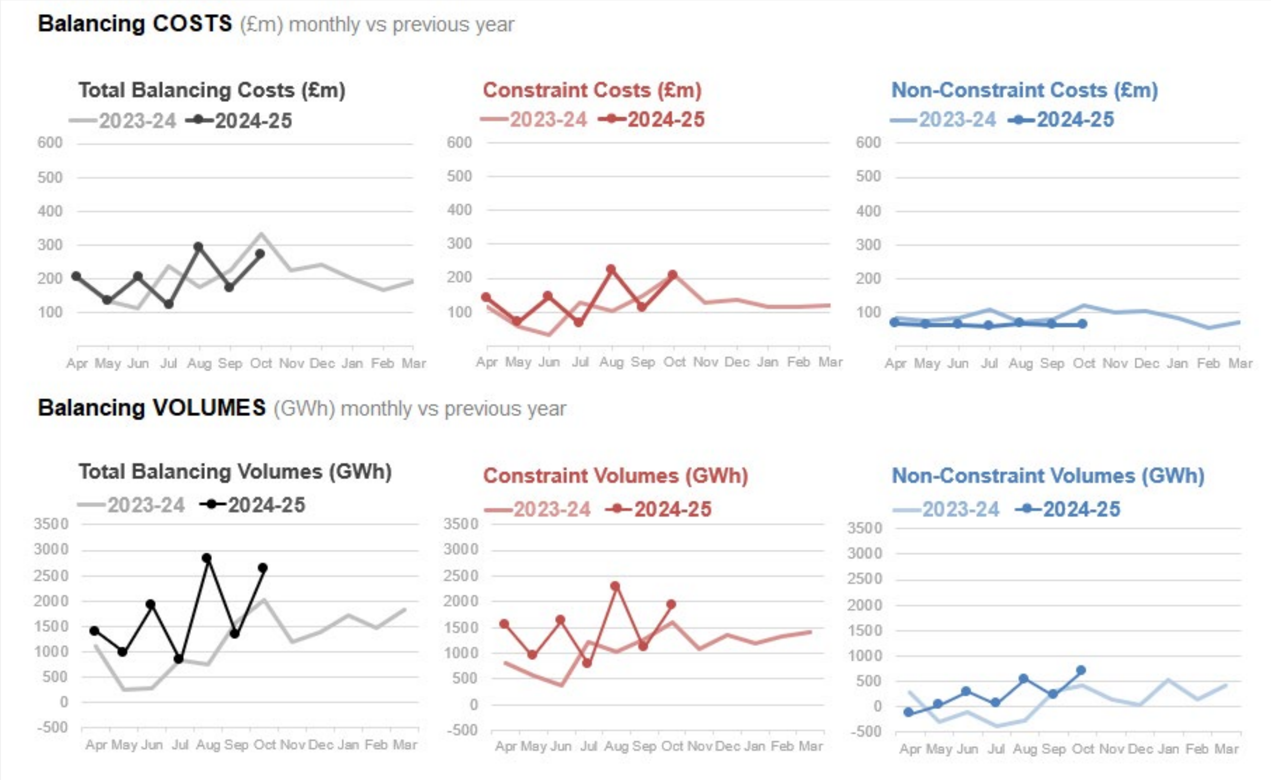
*The first three rows show the outturn measures for this month and difference in the previous month and same month last year, while the bottom row outlines outturn performance for each month.

Balancing Costs - Overview

The total balancing costs for October were £272m, which is £33m above the benchmark of £239m. As the variance is more than 10%, performance is below expectations.

The main driver of this month's high costs was exceptionally high wind generation output in Scotland. Overall wind outturn in October was at 5.7 TWh in total, which is the second highest outturn so far in 2024-25 but broadly in line with what we would expect (October 2021: 5.5 TWh, October 2022: 5.6 TWh). Although the benchmark accounts for overall GB wind output, significantly more of this month's wind generation output was in Scotland, which has a bigger impact on constraints, and is not accounted for in the benchmark. For comparison, while October's total outturn wind was 27% higher than the average across the benchmark evaluation period (the previous three years), in Scotland it was 47% higher. This is therefore the main driver of costs being more than 10% above the benchmark this month. We had to take high volumes of actions to manage thermal constraints in Scotland (more than doubling from 553 GWh in September to 1197 GWh in October). In addition, Scottish constraints continued to be impacted by several outages, which exacerbate the operational cost in the region. The outages not only limit the transfer capacity of B4 and B5 boundaries but also result in high levels of curtailment - which correlates highly with overall expenditure on balancing costs.

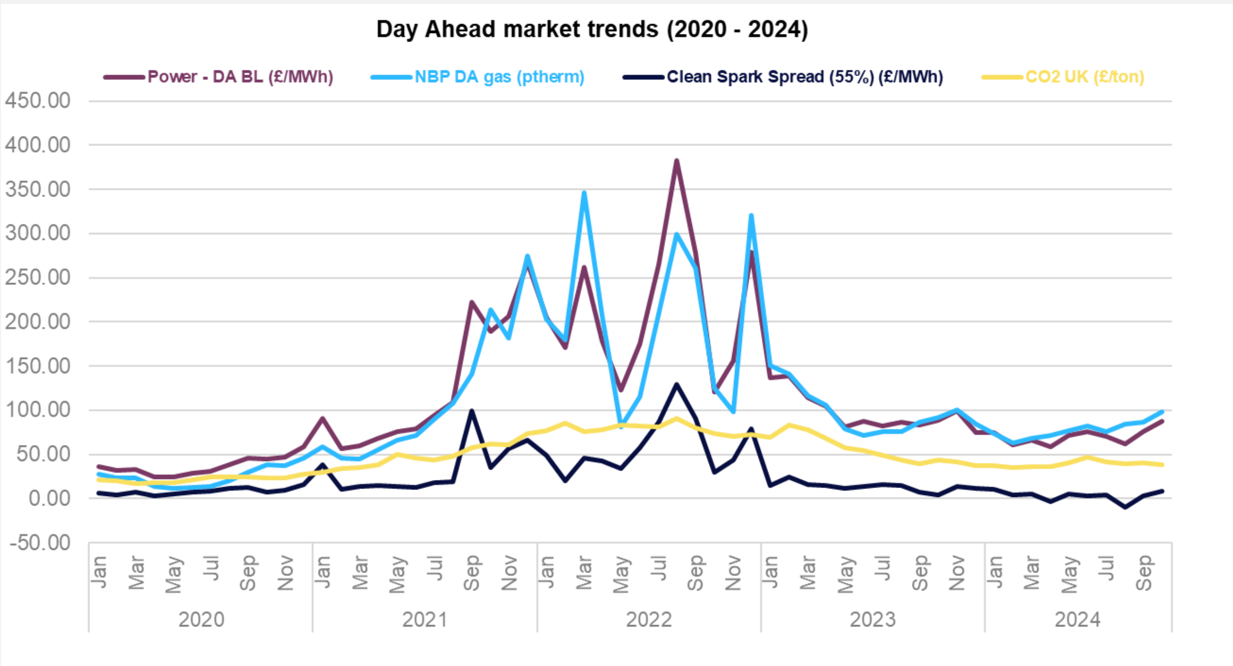
Average wholesale power prices were up £12/MWh compared to September 2024. The volume weighted average cost for the system by accepting a bid increased by £18.6/MWh compared to last month (from £101/MWh to £120/MWh). Similarly, the volume weighted average cost for the system by accepting an offer rose £9.3/MWh (from £114/MWh to £124/MWh). Non-constraint volumes increased by 470 GWh (mainly due to more actions to manage operating reserve).



System and Market Conditions

Market trends

Power and gas prices increased compared to last month, with a consequent slight rise in the Clean Spark Spread price. In contrast, the CO_2 price fell slightly compared to September 2024. Day-Ahead Power prices and CO_2 prices remained lower compared to last year whereas gas was up compared to October 2023. Lower temperatures will have acted to push up gas prices in October in line with increased heating demand moving into the winter period, with power following its counterpart higher. Meanwhile increased wind generation acted to support lower carbon prices compared to the previous month.



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

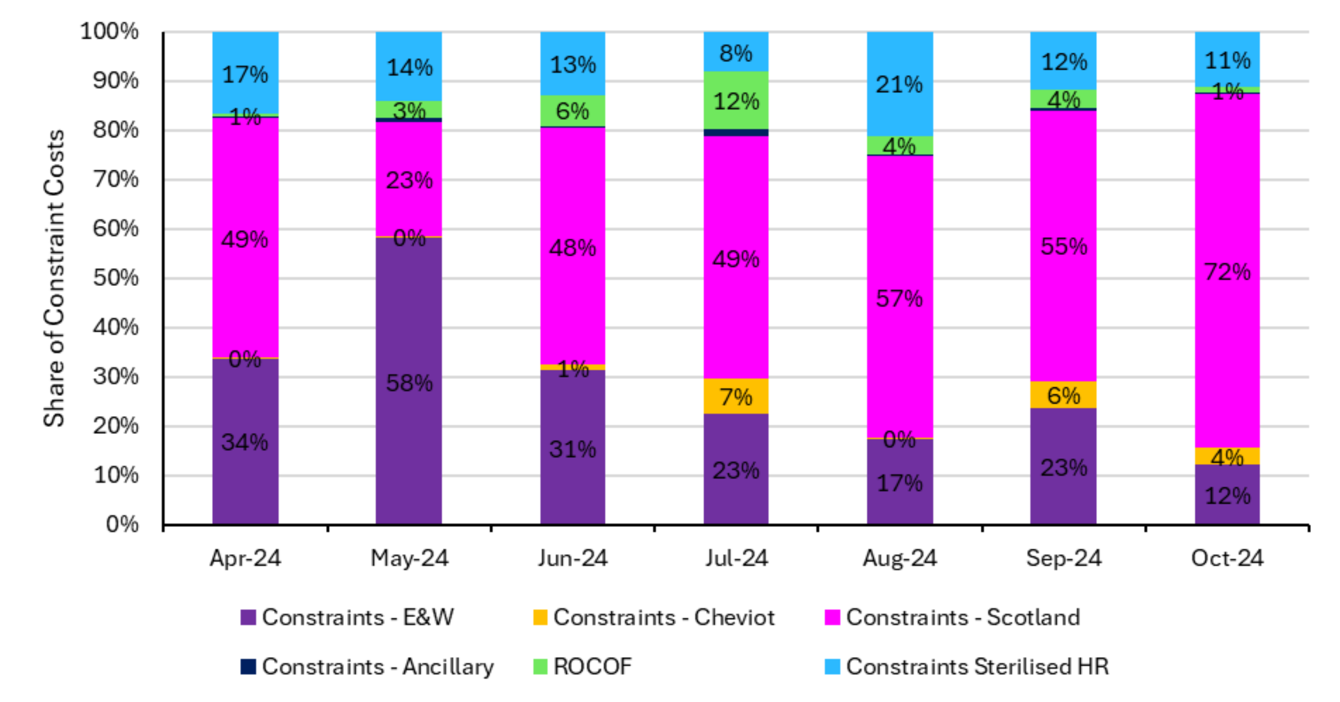
Wind Outturn

October saw a mix of conditions, starting with wet weather across the Midlands and East Anglia, followed by clear weather on the 10th and 11th. On the 20th, Storm Ashley brought heavy rain and strong winds in Scotland and some parts of England and Wales. Overall wind outturn increased to 5.7 TWh in October from 4.2 TWh in September. Regionally, there was an 18.7% increase in wind outturn in England and Wales, whereas Scotland experienced a significant 60% increase, mainly driven by windy conditions of the Storm Ashley.

On the 20th, around 5.8GW of wind was taken off behind constraints. 2GW of wind with specific CfD contracts came off under PN due to negative pricing. Operational tripping schemes, the western link HVDC and network reconfiguration were utilised to maximise transmission constraint limits. There was no impact observed on the transmission network due to Storm Ashley. There were reports of a small number of local customer interruptions in the DNO network in the North of Scotland.

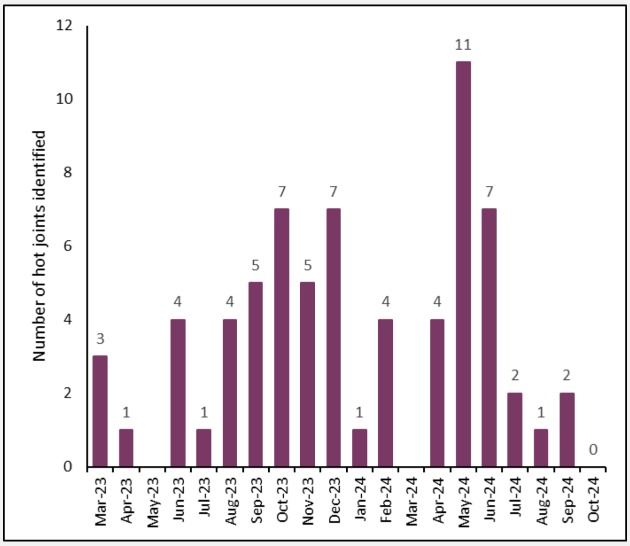
Constraints

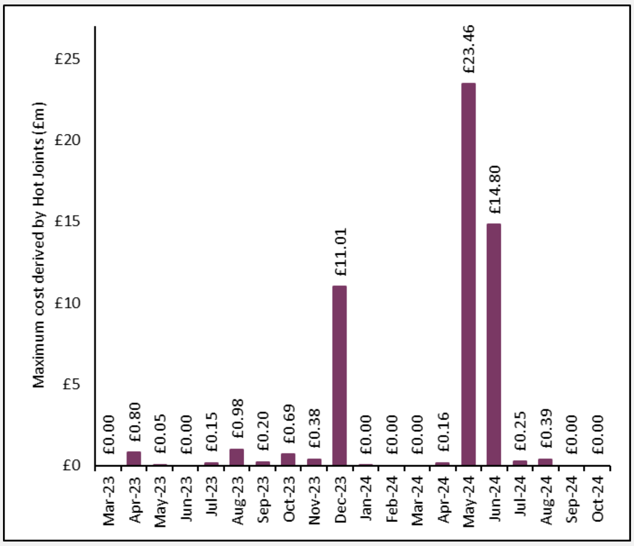
Constraint costs in October increased by £96.3m compared to September 2024. Scottish constraints accounted for approximately 92% of this increase. Windy days, primarily influenced by Storm Ashley, along with a highly constrained grid, led to particularly costly constraints in the region. It is anticipated that Scottish constraints will continue to represent a significant portion of the costs in the coming months due to various outages aimed at enhancing the transfer capacity of Scottish boundaries. In October, Scottish constraints accounted for roughly 72% of the total constraint cost, marking a record high over the current financial year.



Network Availability

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





BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): October 2024 vs September 2024

		(a) Sep-24	(b) Oct-24	(b) - (a) Variance	decrease ◂▸ increase Variance chart
Non-Constraint Costs	Energy Imbalance	2.4	0.2	(2.2)	
	Operating Reserve	5.4	5.8	0.4	
	STOR	5.3	4.9	(0.5)	
	Negative Reserve	0.3	0.5	0.2	
	Fast Reserve	19.5	18.6	(0.8)	
	Response	12.9	15.8	2.9	
	Other Reserve	2.0	1.8	(0.2)	
	Reactive	11.5	9.3	(2.2)	
	Restoration	2.6	2.7	0.1	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	2.2	4.1	1.9	
Constraint Costs	Constraints - E&W	26.2	25.2	(1.1)	
	Constraints - Cheviot	6.3	7.5	1.1	
	Constraints - Scotland	61.2	149.1	88.0	
	Constraints - Ancillary	0.6	0.3	(0.3)	
	ROCOF	4.2	2.9	(1.4)	
	Constraints Sterilised HR	13.2	23.2	10.0	
Totals	Non-Constraint Costs - TOTAL	63.9	63.5	(0.4)	
	Constraint Costs - TOTAL	111.7	208.0	96.3	
	Total Balancing Costs	**175.6**	**271.6**	**95.9**	

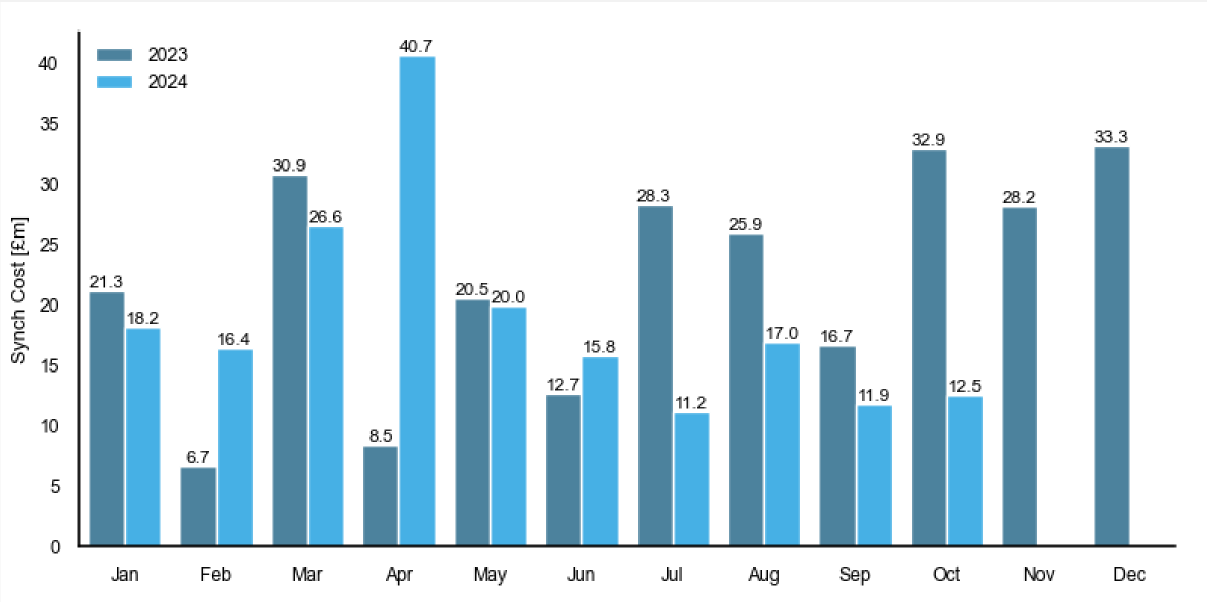
As shown in the totals from the table above, constraint costs increased by £96.3m and non-constraint costs decreased by £0.4m, resulting in an overall increase of £95.9m compared to September 2024.

Constraint Costs/Volumes

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Constraint-Scotland & Cheviot: +£89.1m **Constraint – England & Wales: -£1.1m** **Constraint Sterilised Headroom: +£10m** Constraint costs have risen by £96.3m compared to September 2024, coinciding with an 809 GWh increase in the volume of actions. Windy conditions, combined with significant outages in Scotland, have	**Constraints – Scotland & Cheviot: +£42.3m** **Constraints – England & Wales: -£17.4m** **Constraints Sterilised Headroom: -£21.3m** Constraint costs have decreased by £3.9m compared to last year, following a 317 GWh reduction in volume of actions. Wind outturn in October 2024 was similar to October 2023 (a 0.5 TWh difference) as well as wholesale prices. Several outages remain in effect

led to higher-than-expected costs in managing the constraints of the region. **ROCOF: -£1.4m** In October, the system's outturn inertia (including market-provided, stability assets, and synchronous plants used for voltage support) resulted in lower volumes to meet the minimum inertia requirements of the system. A reduction of 41 GWh in the volume of action was observed during this period.	impacting Scottish constraints compared to September last year. **ROCOF: -£7.6m** The expenditure on ROCOF tends to be marginal in the system. The implementation of the FRCR requirement reduction (130GVAs to 120GVAs) in June 2024 is contributing to reduced inertia volumes and costs compared to the previous year. Additionally, the gradual addition of assets commissioned through the Stability Pathfinder Phase 2 is expected to positively contribute to inertia levels in the system, resulting in minimal ROCOF spending.

Voltage – Monthly synchronisation costs for voltage across 2023 and 2024:

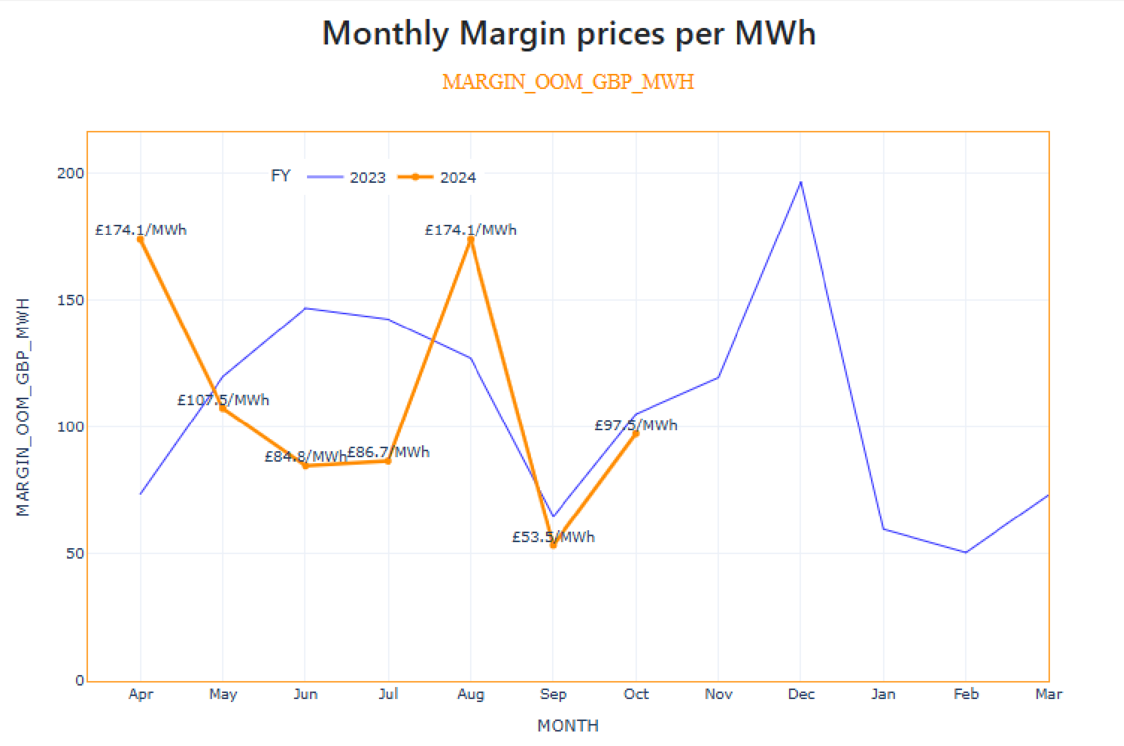


Synchronisation costs are associated with specific actions required to support voltage in the system. These actions involve units that are instructed to provide MVArs and maintain voltages within SQSS limits. It is a highly location-dependent issue, so only a limited set of assets are effective in voltage support, depending on their location. In October, synchronisation costs amounted to £12.5m, which is an increase of £0.6m compared to September 2024. In comparison to 2023, synchronisation costs have experienced a four-month period with lower costs. Factors contributing to this include:

- Machines required for voltage support are self-dispatched, providing MVArs without requiring actions in the Balancing Mechanism (or very few of them, resulting in lower volumes).
- Economic assets commissioned through voltage pathfinders. This includes the ones allocated on Mersey (a 38 MVAr battery at Capenhurst and a 200 MVAr reactor in Frodsham) and Pennines (reactors at Bradford West – 100 MVAr, Stocksbridge – 200 MVAr and Stalybride – 200 MVAr).
- Stability assets commissioned through stability pathfinders. Twelve synchronous compensators received contracts through Phase 1, providing roughly 12.3 GVA.s of inertia to the system, in addition to 1.06 GVAr of absorption and 950 MVAr of injection capacity.
- Variations in offer prices in the Balancing Mechanism, particularly for CCGTs.

Reserve Costs/Volumes

Margin prices increased to £97.5/MWh in October compared to £53.9/MWh in September 2024. This is aligned with increased volumes compared to the previous month and linked to higher wholesale prices.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£0.4m **Fast Reserve: -£0.8m** There was a 305 GWh increase in the volume of Operating Reserve required to secure the system compared to September.	**Operating Reserve: -£14.6m** **Fast Reserve: +£1.9m** The reduced operating reserve cost experienced this year can be attributed, in part, to the lower energy prices compared to October 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 Balancing Reserve, and the results will be shared in the coming months.

Response Costs/Volumes

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

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£2.9m There was a 17.3 GWh increase in the absolute volume of actions compared to September.	**-£6.4m** The volume of actions taken for response reduced 14.6 GWh compared to October 2023.

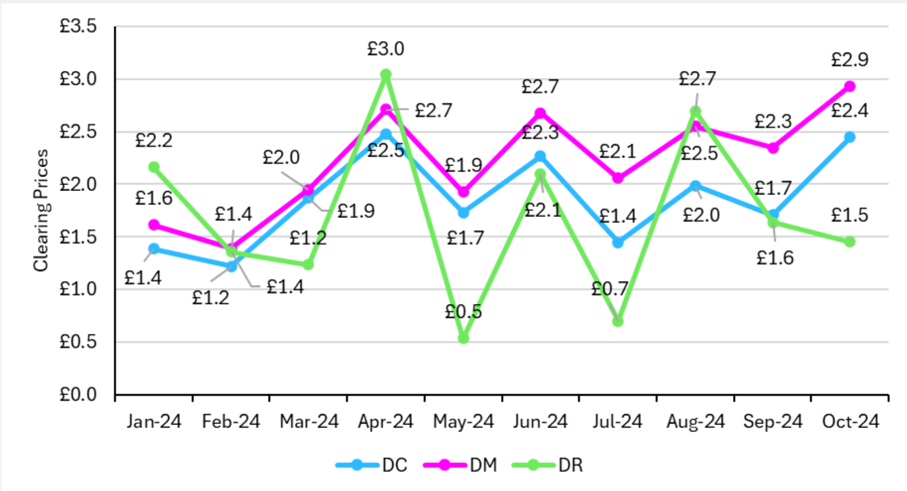
Dynamic Services Average Clearing Prices: October 2024 vs September 2024

		(a) Oct-24	(b) Sep-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	2.4	1.7	0.7	
	DM	2.9	2.3	0.6	
	DR	1.5	1.6	(0.2)	

Dynamic Services Average Clearing Prices: October 2024 vs October 2023

		(a) Oct-24	(b) Oct-23	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	2.4	3.2	(0.8)	
	DM	2.9	4.7	(1.7)	
	DR	1.5	5.5	(4.0)	

Average clearing prices for DC and DM increased in October compared to September 2024, but there was a decrease in DR prices over the same period. When compared to October 2023, all three Dynamic Services experienced a decline, with a significant decrease observed for DR. DR High prices were particularly low (approximately -£5.77/MWh in October 2024), which is commonly utilised by batteries for charging patterns. This results in minimal charging costs due to the Applicable Balancing Services Volume Data (ABSVD). The design and introduction of these services by NESO have increased liquidity and competition in the provision of these services, driving down costs. It is also worth mentioning that Frequency Risk and Control Report (FRCR) 2024 allowed for an increase of 100 MW of DC procurement during October.



Reactive Costs/Volumes

The volume-weighted average price for reactive power was £3.8/MVAr in October 2024.

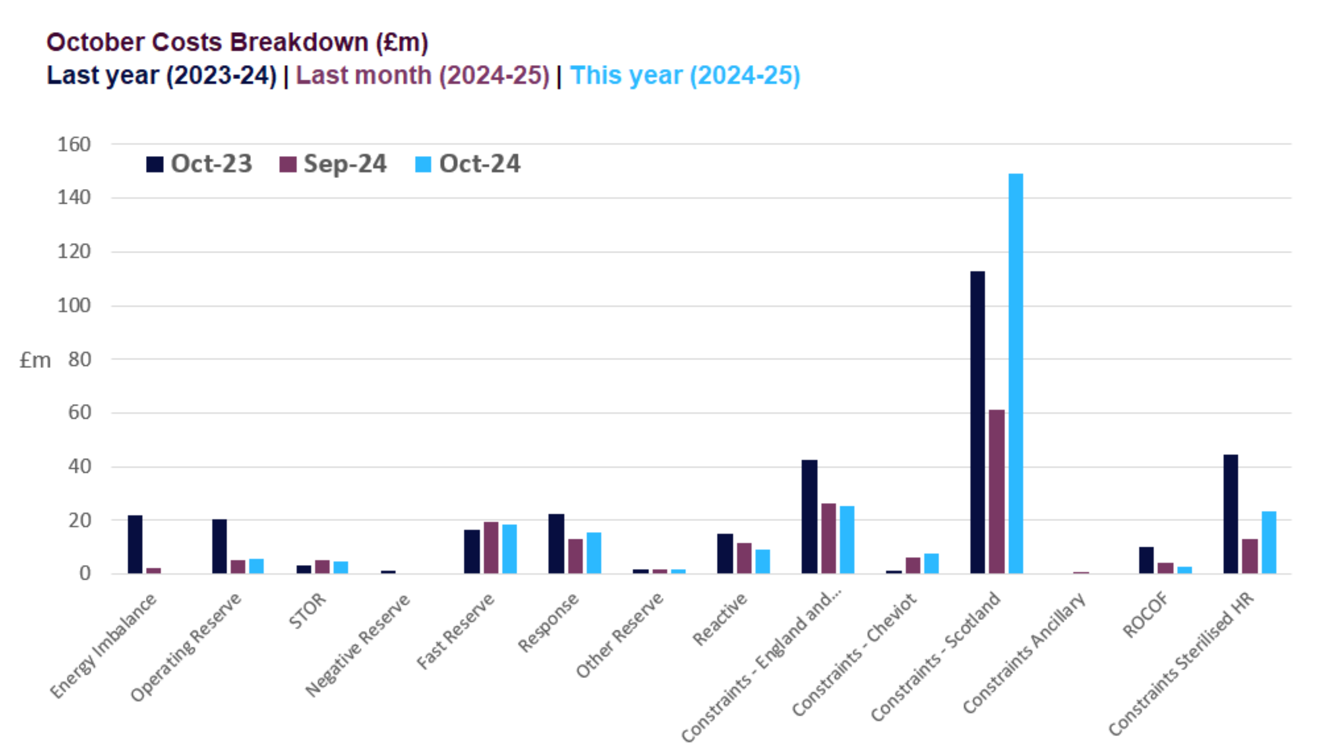
Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£2.2m Reactive volumes reduced by 12% compared to September 2024. The system is dominated by the need for absorption volumes, but these tend to vary according to the system operation conditions.	**-£6m** The volume-weighted average price decreased from £4.3/MVAr to £3.8/MVAr compared to last year.

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

Comparison breakdown

The Scottish constraint component was the main driver of increased costs compared to last month. Constraint costs overall were up by £96.2m on last month and were reduced by £4.2m on last year. All categories for non-constraint costs showed a decrease or small deviation compared to last month. Overall non-constraint costs were down £35.3m on last month and £93.6m on last year.

Thermal constraints currently dominate constraint costs. NESO is progressing several initiatives to reduce thermal constraint volumes/costs including the Constraints Collaboration Project and Constraint Management Intertrip Service. The ongoing review of electricity market arrangements (REMA) is also considering options that could alleviate thermal constraints over the long term such as zonal pricing. Network Service Procurement projects for voltage and stability are also helping to provide solutions for network management at lowest cost.



COST SAVINGS

Cost Savings – Outage Optimisation

The total savings from outage optimisation were roughly £122.8m in October 2024, this represents a reduction of £225.2m relative to September this year (£348m). The action that yielded the greatest value was the rating enhancement of a 400kV circuit in Scotland during the outage of its parallel, enabling the Western Link to run above the threshold that arms the Run Back Scheme. This increased the transfer capacity for B6 and B7 by roughly 600MW for a duration of 12 days. The estimated cost savings for this action are around £13m.

Cost Savings – Trading

The Trading team were able to make a total saving of £11.0m in October through trading actions as opposed to alternative BM actions, representing a 16.8% decrease on the previous month. Over October the interconnectors were mostly importing, and due to a number of outages on them trading options were reduced causing a considerable number of trades to be conducted against Emergency Instruction. Savings from voltage trading have remained similar mainly due to low wind generation. The days with the greatest saving on trading were the 27th and 28th October at £1.7m and £1.6m respectively, most of which was due to trades for downwards regulation. The day with the greatest spend on trades was on the 14th October at a cost of £8.9m with the greatest component being for margin. This was due to tight margins and interconnector outages, coupled with a Capacity Market Notice being issued at midday which meant that the remaining volumes required were purchased on the interconnectors that weren't importing at the day ahead stage. Along with very high European market prices this led to prices in excess of £1000/MWh which were traded against EI.

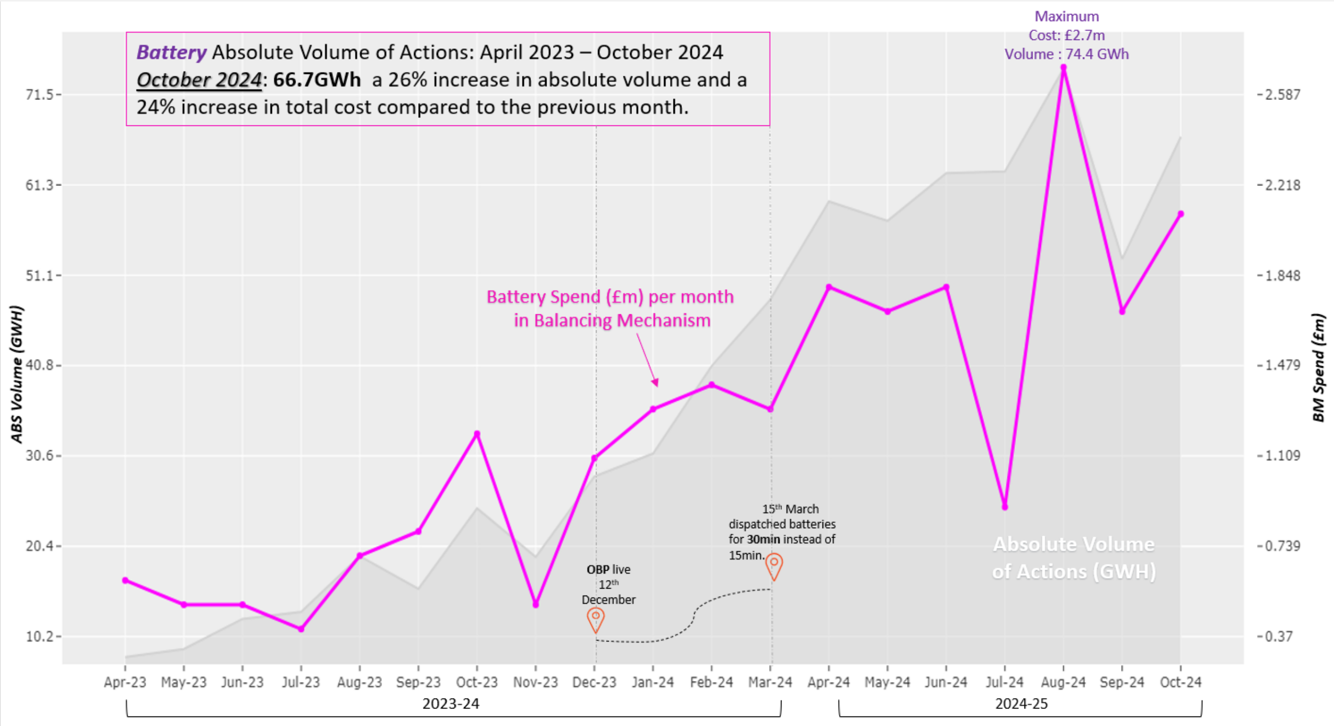
Cost Savings – Network Services Procurement (NSP)

NESO is using Network Services Procurement (NSP) 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 Constraint Management Intertrip Service, Voltage Mersey, and Stability Phase 1 have delivered approximately £231m in savings since April 2023. This represents the first set of live NSP projects, with savings for other live and future projects also undergoing development and implementation, such as Voltage Pennines and Stability Phase 2.

NOTABLE EVENTS

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

April 2023 to October 2024



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

The total absolute volume of actions and cost have both increased compared to the previous month (September 2024), due to higher absolute volume of Bid Offer Acceptances (BOA's) in a higher volume weighted average price for Bids and Offers.

DAILY CASE STUDIES

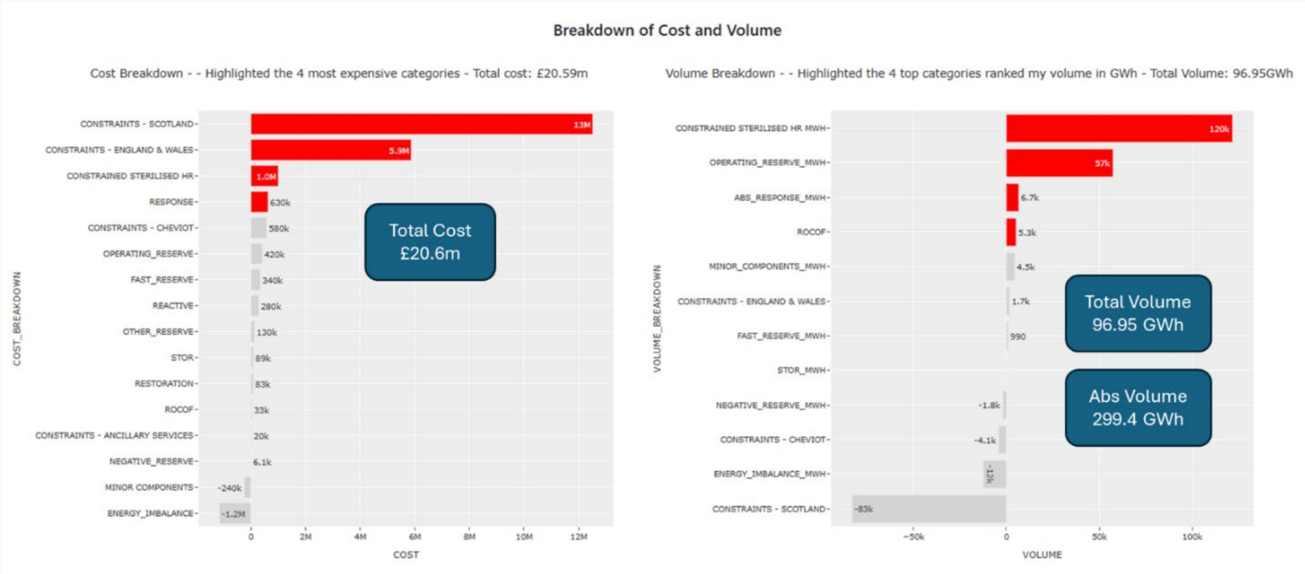
Daily Costs Trends

October's balancing costs were £272m which is £96m higher than the previous month. Six days were recorded with costs above £15m (9th, 20th, 21st, 23rd, 24th and 31st) and six days had a daily total cost over £10m (12th,14th, 18th, 22nd, 26th and 27th) resulting in an increase in the average monthly daily cost by £2.9m (to £8.7m from £5.8m).

Low-cost days were observed on October 3rd, 17th and 25th with a total balancing cost of approximately £2.7m, £3.1m and £3.1m respectively. The highest total cost was observed on the 20th October when the total spend was £20.6m (see 'Daily wind outturn' chart below). Thermal Export Constraints dominated the cost breakdown on this day, with Scottish constraints making up 63% of the daily cost and England & Wales constraints contributing to a further 28%. Storm Ashley led to high wind output of roughly 5.8GW, with 2GW of wind with CfD contracts taken off due to negative pricing. No individual action was expensive, but high volumes of wind curtailment at bids between -£6/MWh to -

£126/MWh (80% of the total system action bids taken that day) and a heavily constrained system resulted in high total balancing costs for the day.

High-Cost Day – 20th October 2024

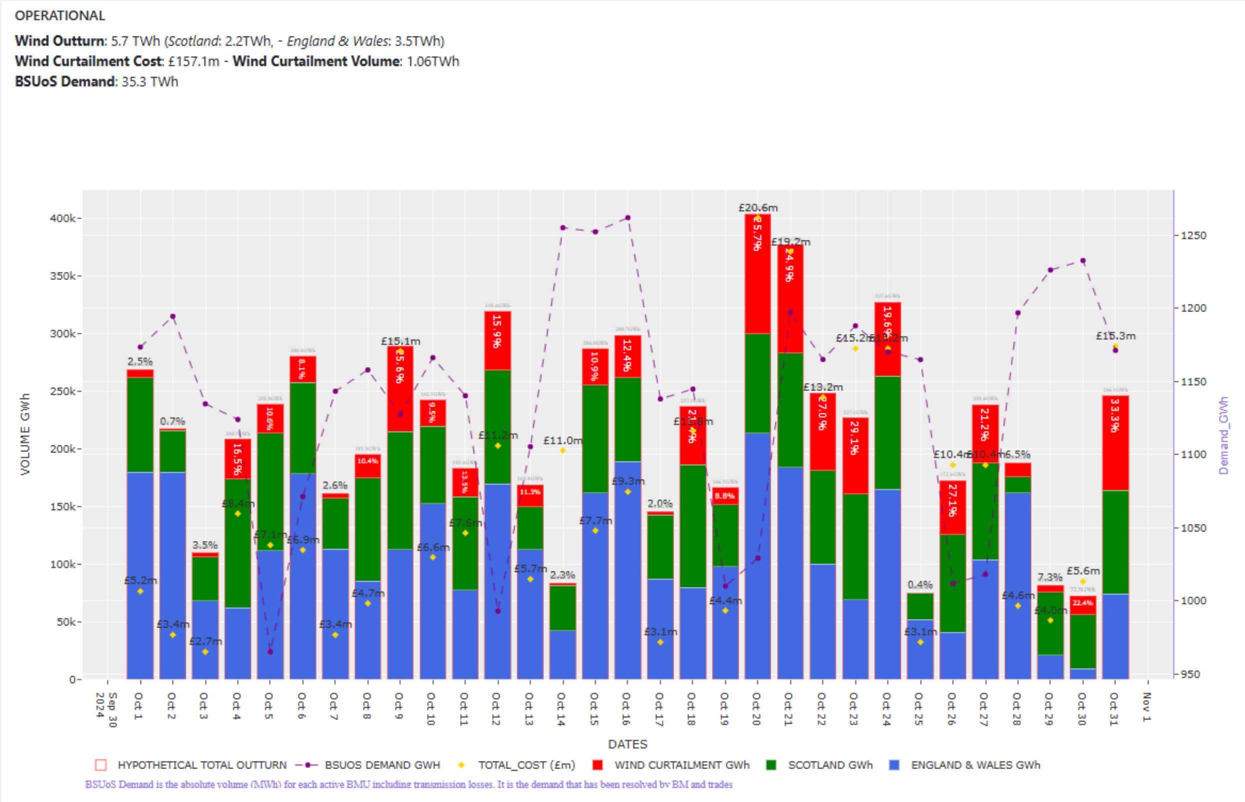


October Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUoS Demand

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.

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 NESO, 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 NESO will report against these each month to provide transparency of its performance through the year.

October 2024-25 performance

Indicative monthly benchmark figures now confirmed: We have now received confirmation of the monthly indicative benchmark figures from Ofgem. There are some small changes compared to the indicative figures we previously reported, but the overall benchmark for the year does not change.

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

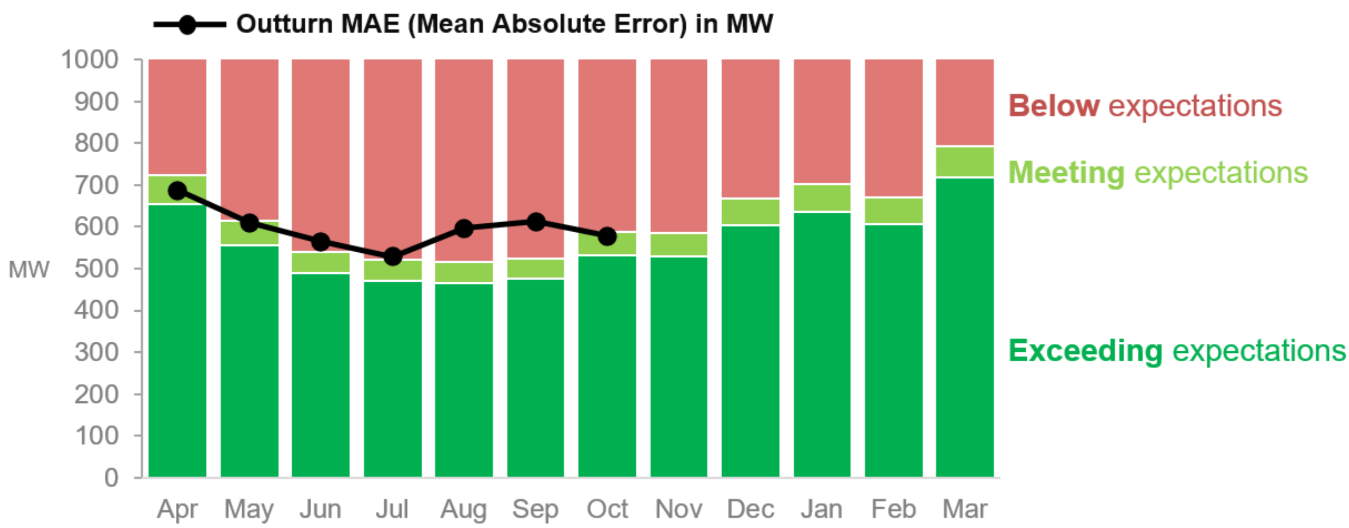


Table: 2024-25 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	690	584	514	496	491	500	559	557	635	669	637	756
Absolute error (MW)	**687**	**610**	**565**	**528**	**596**	**612**	**578**					
Status	●	●	●	●	●	●	●					

[2] Demand | BMRS (bmreports.com)

Performance benchmarks:

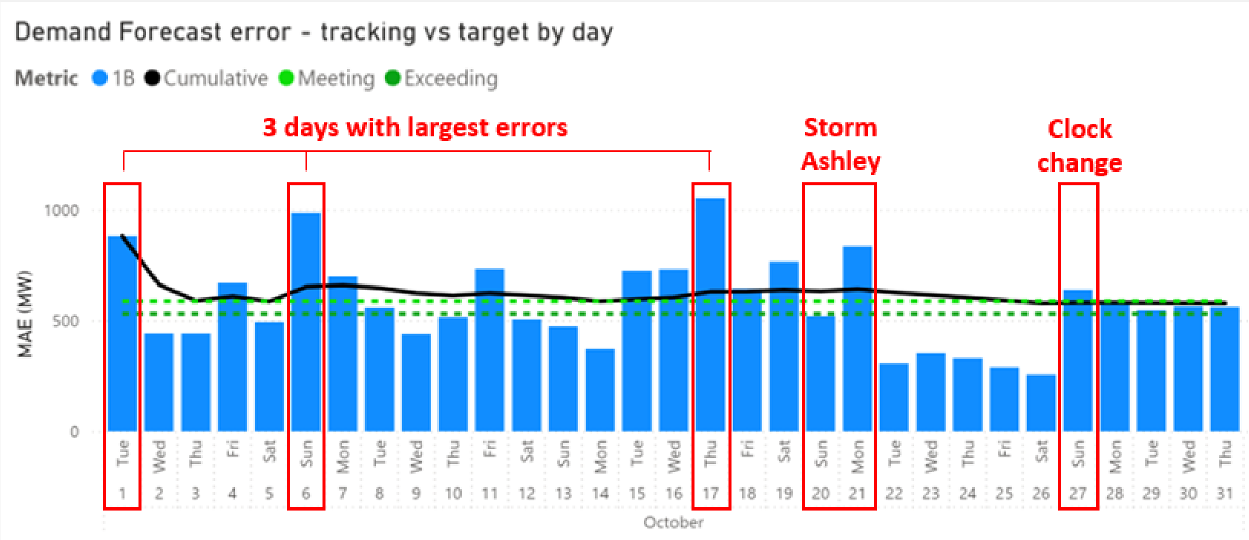
- **Exceeding expectations:** >5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** >5% higher than 95% of average value for previous 5 years

Supporting information

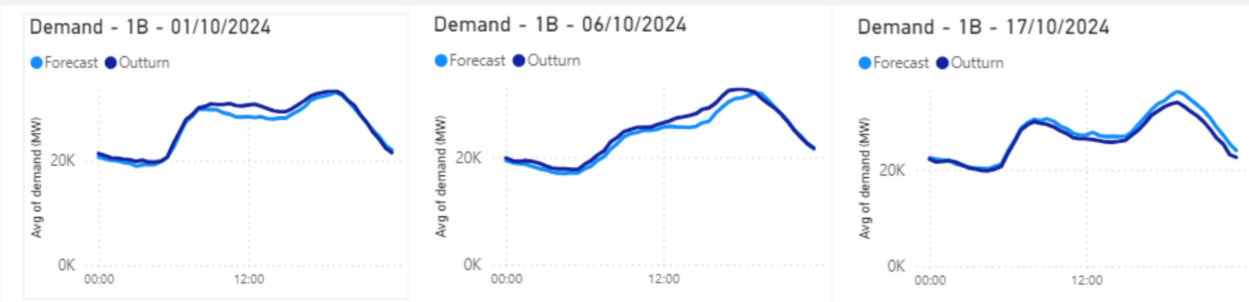
In October 2024, the mean absolute error (MAE) of our day ahead demand forecast was 578 MW compared to the indicative benchmark of 559 MW. The 5% range around this benchmark extends to 587 MW, meaning our performance met expectations for October.

The Met Office reports that October saw a mix of settled conditions due to high-pressure systems as well as wet and windy weather from a succession of low-pressure systems. These included Storm Ashley, the first named storm of the 2024/25 season, which brought heavy rain and strong winds to Scotland and northern parts of England and Wales on the 20th and 21st.

Sunday, 27th October, saw the clock change from BST to GMT. This was followed by a week of school holidays in most local authorities, which was unusual as October half term holidays usually precede clock change. The initial period following any clock change is always challenging, as trained models re-adjust.



Below are details of the three days with the largest errors:



The errors on 1 and 6 October are all during the daylight hours, which reflects known challenges with our current solar forecasting. Errors on 17 October extend into the evening.

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 (1490)
1000 MW	265	18%
1500 MW	101	7%

2000 MW	39	3%
2500 MW	6	0%

The days with largest MAE were October 1, 6, and 17.

Day	Error (MAE)	Major causal factors
1 Oct	881	Errors in the solar forecast (indicated by the variance in the middle of the day in the above graph for 1 October) and in the temperature input data.
6 Oct	987	Inaccurate temperature input data and other factors in our model and profiling.
17 Oct	1054	Factors other than weather input data in our model and profiling.

Missed / late publications

There was 1 occasion of missed or late publication in October, which was caused by IT updates due to the move to NESO.

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 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:

1) did not have a bid-offer acceptance (BOA);
2) 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.

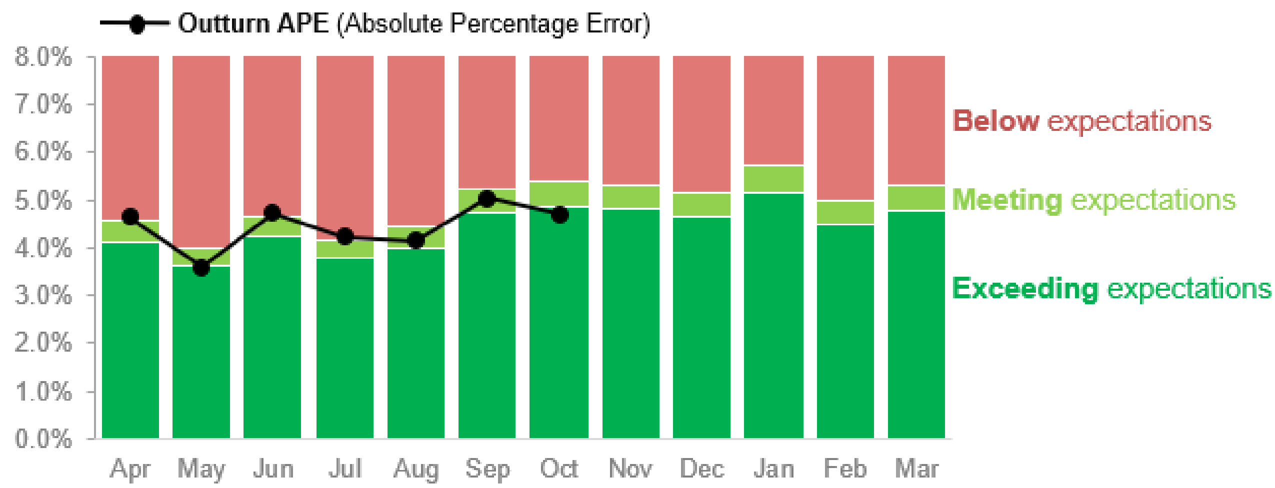
Sites deemed to have withdrawn availability are those that:

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

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.

October 2024-25 performance

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



Change to methodology from 18-Month Report onwards

In line with the NESO Performance Arrangements Governance Document, from the 18-Month Report (published in October 2024), the APE% that we report excludes some of the factors that are outside of our control. This view excludes sites that have redeclared to zero and incorporates Initial Settlement Runs (+16 Working Days). This approach applies to the figures reported for the whole of 2024.

	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**	**4.15**	**5.04**	**4.70**					
Status	●	●	●	●	●	●	●					

ESORI view of BMU Wind Generation Forecast APE (Previous Method)

Below, we report the APE% and benchmark based on the method described in The Electricity System Operator Reporting and Incentives (ESORI) Arrangements: Guidance Document. This applied prior to the transition to NESO on 1 October 2024, up to and including the figures reported in August 2024. This view includes sites that have redeclared to zero and does not incorporate Initial Settlement Runs (+16 Working Days).

A performance status is shown in the table below, however for the figures reported for September 2024 onwards, this is for information only and is not part of the 2024-25 incentives assessment.

Table: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmarks (ESORI method)

	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**	**4.60**	**4.97**	**4.77**					
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.

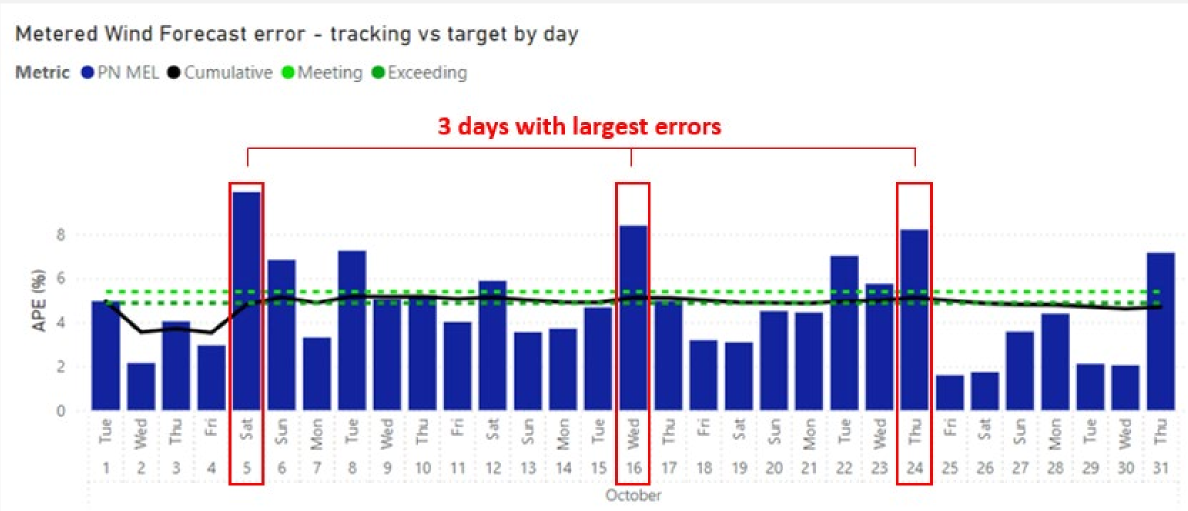
Supporting information

In October 2024, the mean absolute percentage error (corrected for redeclarations to zero and revisions to Settlement Metering) is currently reported as 4.70% against the corresponding benchmark of 5.13% for October. The 5% range around this benchmark extends from 4.87% to 5.39%, meaning our performance exceeded expectations for October.

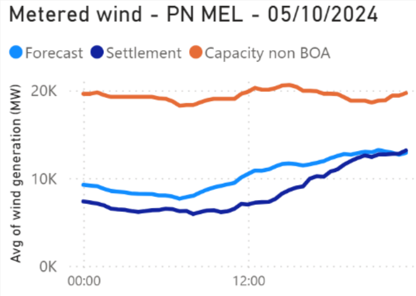
The mean absolute percentage error for the original 1C metric was 4.77%, compared to the monthly benchmark of 5.13%. The 5% range around this benchmark extends from 4.87% to 5.39%. which is also exceeding expectations.

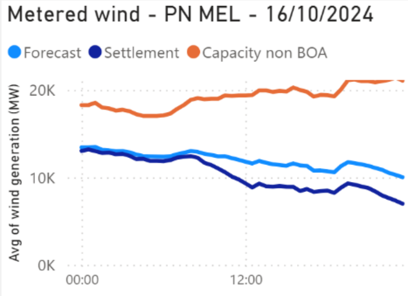
Monthly error was brought up by three larger error days on 5, 16, and 24 October, which were over-forecast. These were mainly caused by missing settlement data as well as poor wind speed input data in some regions; in addition, on 16 and 24 October, outages impacted wind forecast accuracy.

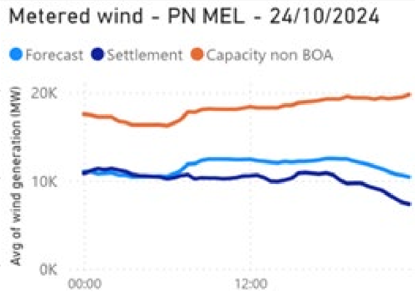
The largest individual settlement period forecast error this month was 4.0GW (over-forecast) on 22 October, settlement period 48.



Below are details of the three days with the largest errors:







The errors on 5th October were largely down to weather (wind speed) errors in Scotland and missing Settlement Metering data. For both 16th and 24th October, missing Settlement Metering and unprocessed outage profiles were the main factors.

Note: September performance has been recalculated with the full month of Settlement Final (SF) run settlement data (rather than partially using the Interim Information (II) Settlement Run view available at the time)[3]. This recalculated performance (mean APE corrected for redeclarations to zero and revisions to Settlement Metering) has improved from 5.21% to 5.04%, which is still meeting expectations for the month. The recalculated mean APE for the original 1C metric has improved from 5.19% to 4.98%, still meeting expectations.

PEF Wind (R5) Go-live

On 7 November we released our latest Wind Power Forecasting model, on a new Azure (PEF v2) platform. This platform will provide the foundation for the development and release of all future Energy Forecast products. The Wind Power model's initial benefits are:

- Use of richer weather (Numerical Weather Prediction, NWP) data.
- 24 forecasts per day (increased from 8).
- Ensemble models, using a range of "equally likely" weather scenarios.
- Automatic adjustments for declared windfarm outages, submitted via the REMIT (Elexon)/eGAMA (NESO) systems.
- Capability for sustained improvements to 1C performance.

Missed / late publications

There were two occasions of missed or late publications in October, which were caused by IT updates due to the move to NESO.

[3] II run: Interim Information Settlement Run, is the earliest settlement data available from Elexon.
SF run: Settlement Final Run, is the first settlement run that results in money changing hands. Note that this is not the last run.

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 NESO'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 NESO to address and reduce the need for actions to be taken out of merit order.

October 2024-25 performance

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

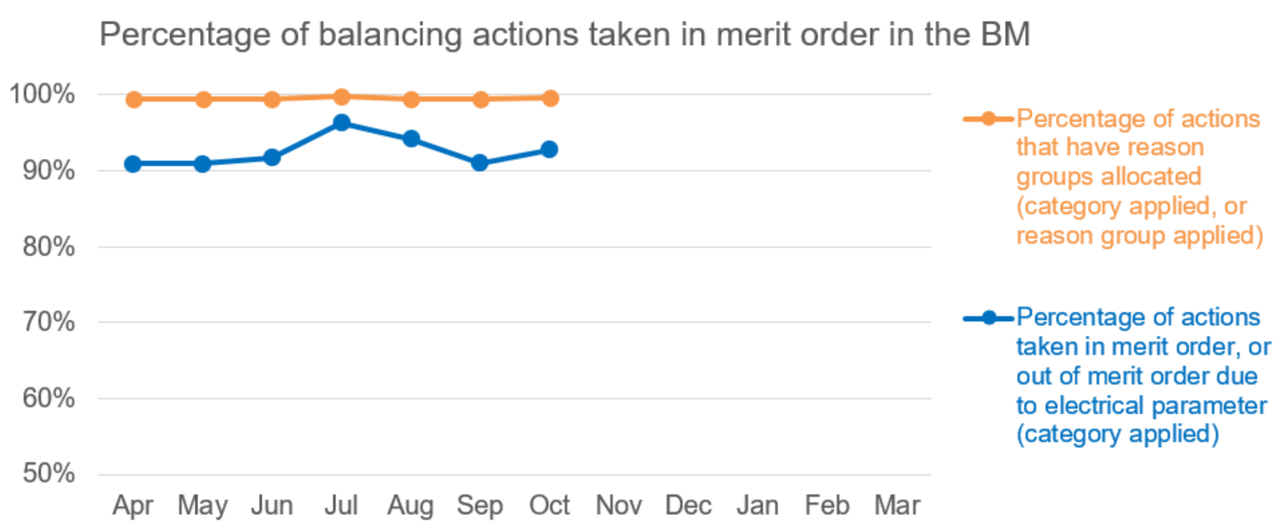


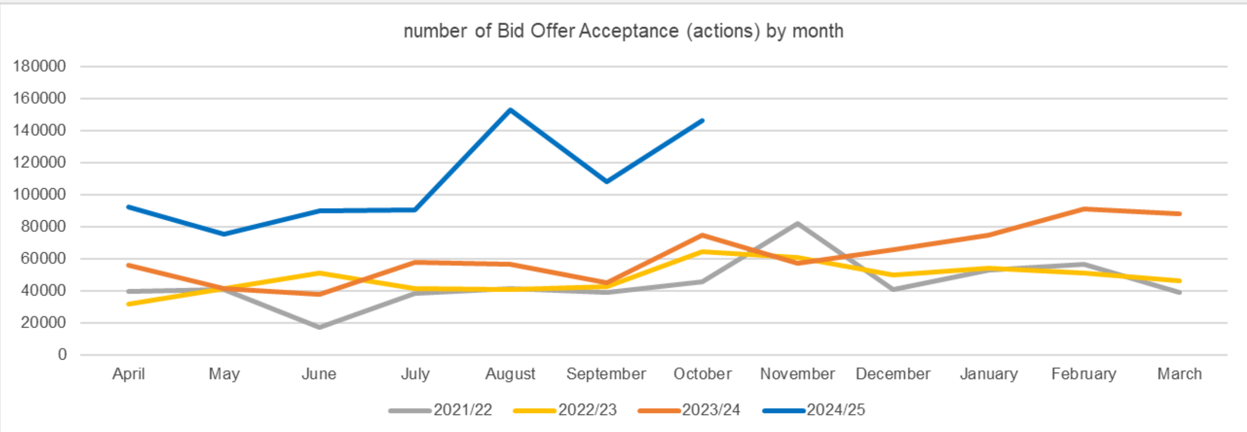
Table: Percentage of balancing actions taken outside of merit order in the BM

	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%	91.0%	92.8%					
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.4%	99.5%	99.4%	99.8%	99.5%	99.4%	99.6%					
Percentage of actions with no category applied or reason group identified	0.6%	0.5%	0.6%	0.2%	0.5%	0.6%	0.4%					

Supporting information

October performance

This month 92.8% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 6.8% 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 October, there were 146,570 BOA (Bid Offer Acceptances) and of these, only 592 remain with no category or reason group identified, which is 0.4% of the total. The number of BOAs in October increased to a similar level seen in August.



Other activities

On Thursday 7th November we hosted a webinar on the LCP Delta methodology for skip rates, which attracted over 150 attendees. We are hosting industry surgery sessions from 13th November to 27th November to provide an opportunity to explore the methodology in more detail. We will also be hosting an inaugural battery storage forum in-person event on 4th December to collaborate with industry on improving dispatch efficiency.

RRE 1G Carbon intensity of NESO 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 NESO for operability reasons increase the carbon intensity of the generation mix. More information about NESO's operability challenges is provided in the Operability Strategy Report.

October 2024-25 performance

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

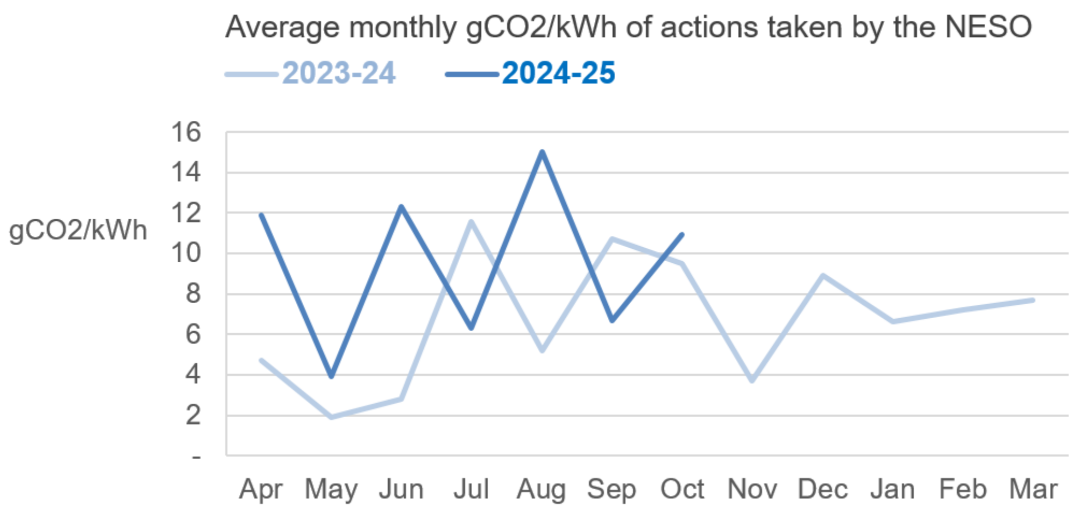


Table: Average monthly gCO2/kWh of actions taken by NESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	11.87	3.93	12.31	6.33	15.02	6.69	10.92					

Supporting information

In October 2024, the average monthly carbon intensity from NESO actions was 10.92g/CO2/kWh. This is 1.34g/CO2/kWh higher than the 2024 YTD average of 9.58g/CO2/kWh.

The maximum difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the BM and the equivalent profile with balancing actions applied was 59.39g/CO2/kWh which took place on 12 October at 1900. This is 2.02g/CO2/kWh lower than September's highest difference of 61.41g/CO2/kWh.

On 12 October transmission connected wind output was forecast to increase throughout the day, from 9.4 GW at 06:00 in the morning to 17.2 GW at 21:00 in the evening resulting in increased NESO actions. During this time NESO actions also included close management of the voltage profile for the South West peninsular.

On 19 October at 1500 the carbon intensity from NESO actions peaked with a negative difference of -16.21g/CO2/kWh. With Storm Ashley forecast and transmission connected wind output forecast to be very high, the strategy required a significant amount of intervention by NESO, by 0730 on 20 October the difference had risen to 56.71g/CO2/kWh.

This month’s carbon intensity from NESO actions is in line with October 2023, when the average monthly carbon intensity from NESO actions was 9.5g/CO2/kWh.

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.

October 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	0	0					
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0	1					
Voltage Excursions defined as per Transmission Performance Report[4]	0	0	0	0	0	0	0					

Supporting information

October performance

There were no reportable voltage or frequency excursions that breached the statutory limits in October.

On 8th October 2024 @8:48, there is one frequency event. An interconnector tripped while importing 1424MW to GB. The frequency reached a maximum deviation of 49.594Hz and returned to the operational limit 49.8Hz within 5 minutes and 50Hz within 15 minutes.

[4] https://www.neso.energy/industry-information/industry-data-and-reports/system-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.

October 2024-25 performance

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

Unplanned	2024-25											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	0	0	0					
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0					

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

Planned	2024-25											
	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	0	0					
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0					

Supporting information

October performance

There were no outages, either planned or unplanned, encountered during October 2024.

Role 2

(Market developments and transactions)

Metrics and RREs: Please note there are no metrics or monthly RREs for Role 2

Notable events during October 2024

Winter Outlook 2024 Published

Each year we published our Winter Outlook 2024, detailing our assessment of the electricity security of supply outlook for the coming winter. This report builds on the initial analysis shared in the Early View. The report is structured around two metrics of adequacy:

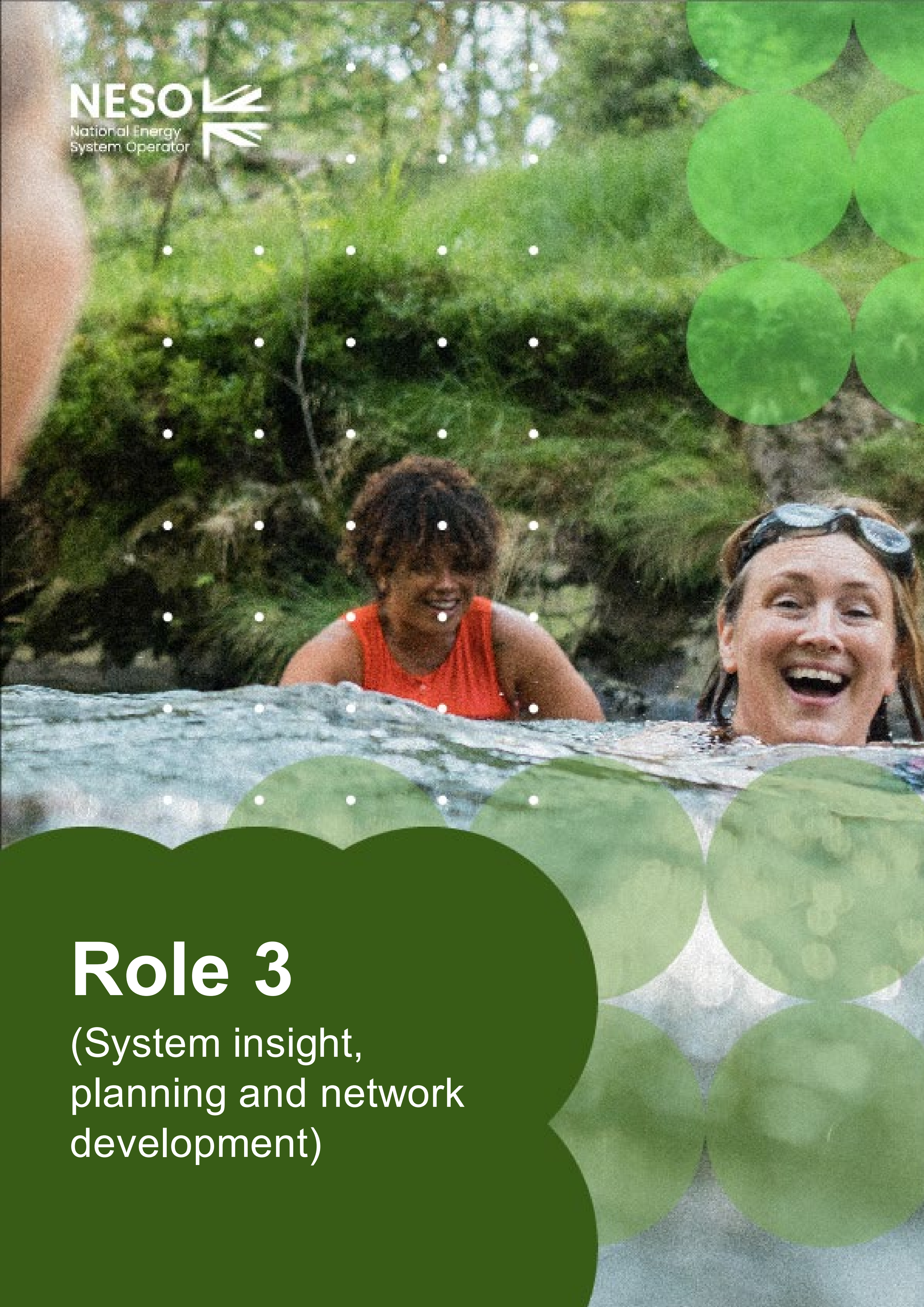
- The de-rated margin is an assessment of the remaining supply available once peak average cold spell demand and reserve requirements have been met. This generates an associated Loss of Load Expectation (LOLE) to compare against the Reliability Standard. Our analysis shows that the margin under our base case is 5.2GW (8.8% of peak demand), higher than the 4.4GW (7.4%) published in the Winter Outlook for 2023/24 and the highest since 2019/20. The associated Loss of Load Expectation (LOLE) is below 0.1 hours which is within the Reliability Standard of 3 hours.

- The Operational Surplus is a time series of the expected operational headroom which reflects public generator availability, potential future generation losses, renewable generation variability and demand variation under 30,000 simulations. It is intended to provide an indication of where the tightest periods are most likely to occur. Our analysis shows sufficient operational surplus throughout winter, although there may still be some tight days where we need to use our standard tools including the use of system notices.

Alongside these two key measures we provide our current assessment of global energy markets. Markets continue to show signs of finding a new equilibrium giving confidence in interconnector import availability this winter. Structural changes in European gas markets have strengthened the resilience of the whole energy system and suggest reduced risks to primary fuel acquisition relative to recent winters.

Notwithstanding these encouraging signs the report details our winter preparations and plans including steps to ensure mutual support with neighbouring TSOs, minimise generation restrictions due to network outages, new products' plans and systems to ensure balancing costs are minimised. The report also highlights our continued close engagement with Government, Ofgem and National Gas to establish any necessary steps that would be required to build resilience.

We published this year's report on 8 October and presented at a range of internal and industry events, as well as in security of supply dialogues with neighbouring Transmission System Operators (TSOs). Please see our website page for more information.



NESO
National Energy System Operator

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 October 2024

Connections 360 goes live

On 28 October, the Connections Digital team, successfully launched the new Connections 360 application.

Connections 360 will provide customers with greater insight into the GB connections landscape and greater access to connections information before submitting applications to the business, empowering customers to make more informed applications to the Connections Operations department and cut down on the volume of speculative applications. Furthermore, Connections 360 will assist internal business users with data and scenario modelling, and aid in the answering of detailed governmental and regulatory queries.

Connections 360 is integrated with the single sign-on process, meaning customers who have an existing NESO digital account are able to access the application with their existing credentials. As of the time of writing, we have had over 500 customers log in and use the application with some very positive feedback received at the London 2024 Connections Customer Seminar.

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