Public

NESO RIIO2 Business Plan 2 (2023-25)

November 2024 Incentives Report

20 December 2024

NESO
National Energy System Operator

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

- On 7 November, we successfully launched PEF R5, marking a significant milestone in enhancing our energy forecasting capabilities. This achievement is the result of the collective efforts of the Balancing Programme's PEF Product team, Energy Forecasting team, and the Electricity National Control Centre (ENCC). PEF R5 allows for frequent improvements to wind forecasting, reducing uncertainty and boosting decision-making and operational efficiency. It also initiates the migration to a new Azure platform, with future enhancements planned for solar and demand forecasting models. Early data indicates an improvement in forecasting performance under various weather conditions, and we will continue to monitor its impact and develop further upgrades. This milestone underscores our commitment to continuous improvement and collaboration in delivering reliable energy solutions.
- In December 2023, we launched the first tender round under the Mid-Term (Y-1) Market to procure stability services, aiming to access inertia capability from existing assets on a high-availability basis. On 22 November, we awarded contracts worth an anticipated £25.4 million to five providers to deliver 5 GVA.s of inertia for the inaugural delivery year between October 2025 and September 2026. These contracts are expected to save consumers £47.3 million and contribute to the stability of the GB power system by providing cost-effective, zero-carbon solutions to increase system inertia during periods of shortfall.
- On 13 November, we presented a deep dive on our proposed Mid-Term reactive power market to update interested parties on our latest thinking and gather industry feedback. The event covered the need for a reactive power market, details of the proposed market design, and how we will assess it. With 215 attendees, the level of engagement was encouraging. We also launched a voluntary Market Engagement Request for Information (RFI) to capture feedback on the market design and additional thoughts.

Clean Power 2030

- In August, the Department for Energy Security & Net Zero (DESNZ) and Mission Control commissioned NESO to provide advice on achieving the Clean Power 2030 (CP30) target. On 5 November, we published our advice, please read our website here for the latest information.

Summary of Metrics and RREs

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

Metric/RRE		Performance	Status
Metric 1A	**Balancing Costs**	£220m vs benchmark of £243m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 591MW vs indicative benchmark of 557MW	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 3.55% vs indicative benchmark of 5.07%	●
RRE 1E	**Transparency of Operational Decision Making**	92.6% of actions taken in merit order or driven by an electrical parameter	N/A
RRE 1G	**Carbon intensity of NESO actions**	7.74gCO_2/kWh of actions taken by the NESO	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**	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

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.

November 2024-25 performance

Figure: 2024-25 Monthly balancing cost outturn versus benchmark

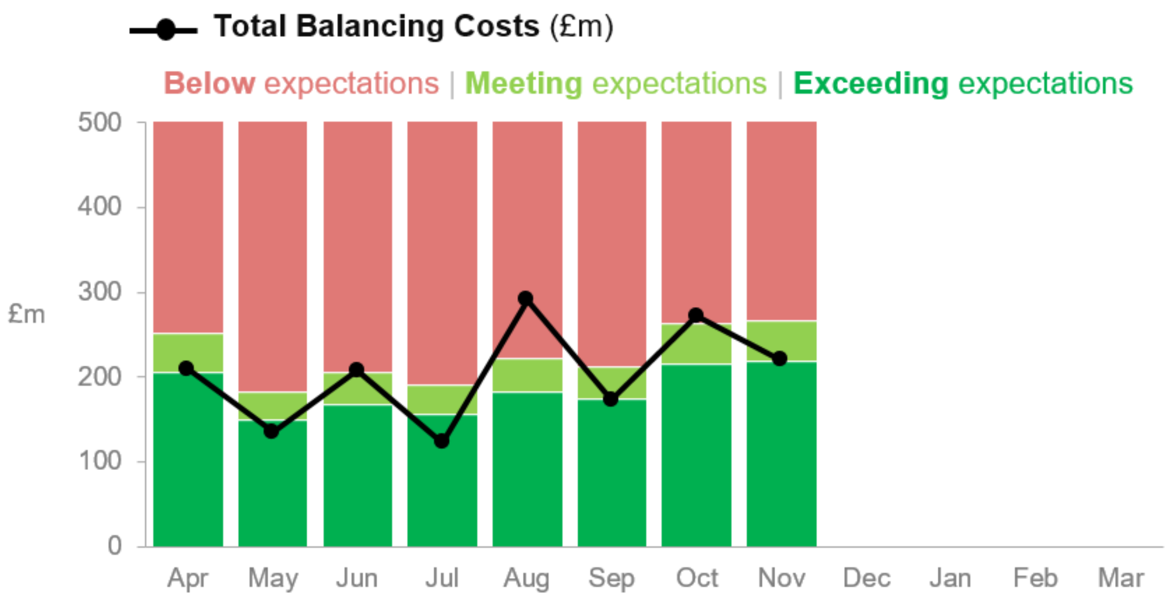


Table: 2024-25 Monthly breakdown of balancing cost benchmark and outturn

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	5.3					37.2
Average Day Ahead Baseload (£/MWh)	59	72	76	71	62	76	88	103					n/a
Benchmark	228	167	187	173	203	194	239	243					1633
Outturn balancing costs[1]	**209**	**135**	**208**	**123**	**291**	**173**	**272**	**220**					**1632**
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

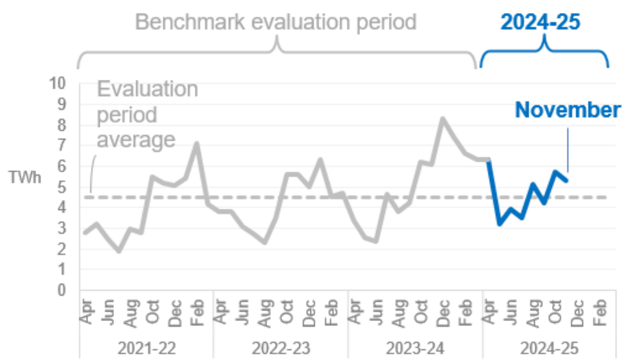
The November benchmark of £243m is £4m higher than October 2024 and reflects:

- An **outturn wind** figure of 5.3 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) but is lower than last month's figure (5.7 TWh).
- 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.

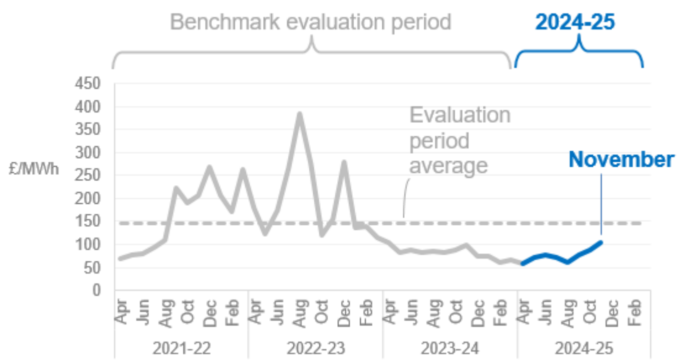
The elevated wholesale prices in November, coupled with high wind outturn, resulted in the highest overall benchmark so far in 2024-25.

[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.

Outturn wind - latest month vs benchmark period



Wholesale price - latest month vs benchmark period



Variable	November 2024	October 2024	November 2023
Average Wholesale Price (£/MWh)	**103**	**-14**	**-3.8**
Total Wind Outturn (TWh)	**5.3**	**+0.4**	**+0.8**
Benchmark (£m)	**243**	**-4**	**-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.

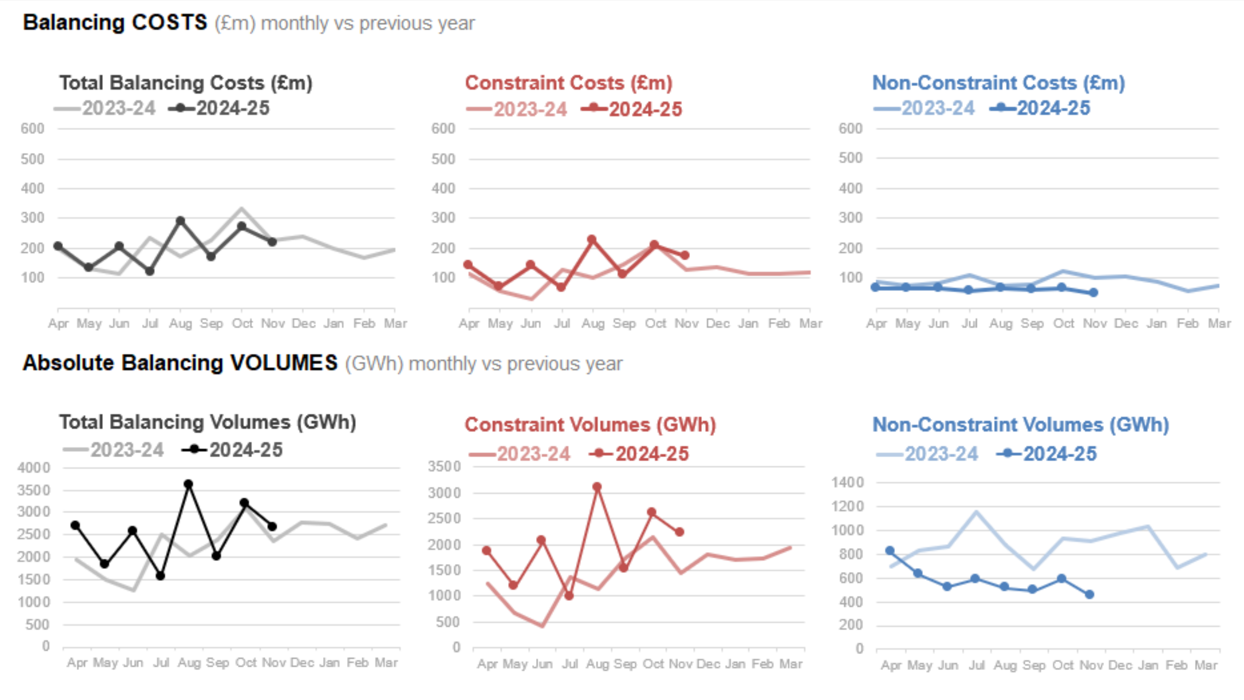
Balancing Costs - Overview

The total balancing costs for November were £220m, which is £23m below the benchmark of £243m. As the variance is within 10%, performance is meeting expectations.

Despite two named storms, Bert on 23 November and Conall on 26 November, overall wind outturn fell 7% compared to October, contributing to a £36.5m reduction in constraint costs month-on-month. The largest reduction in constraint costs came from England and Wales constraints which fell to their lowest level this financial year. In contrast, Scottish constraints remained high, although down £6m compared to October, with the transfer capacity at key boundaries in this region continuing to be impacted by several outages.

There was also particularly low wind and solar generation between 1 and 9 November, known as a dunkelflaute period. The daily average wind and solar generation mix was ~6%, reaching a low of 2.85% on 5 November. For comparison, in October solar and wind accounted for roughly 21% of the generation mix on average. During this period, there was a higher dependency on gas-fired generation and lower wind curtailment (averaging 8 GWh/day) compared to the rest of the month. As there is a strong correlation between balancing costs and wind curtailment, balancing costs remained relatively low during the dunkelflaute period, averaging £3.6m/day.

Average wholesale power prices were up £14/MWh compared to October 2024 and £3.8/MWh higher compared to November 2023. The volume weighted average price for bids increased £1/MWh compared to last month (from £120/MWh to £121/MWh). Similarly, the volume weighted average price for offers increased £9/MWh (from £124/MWh to £133/MWh). Non-constraint volumes decreased 60 GWh (mainly due to fewer actions to manage operating reserve and response) and costs were £16.6m lower compared to October.

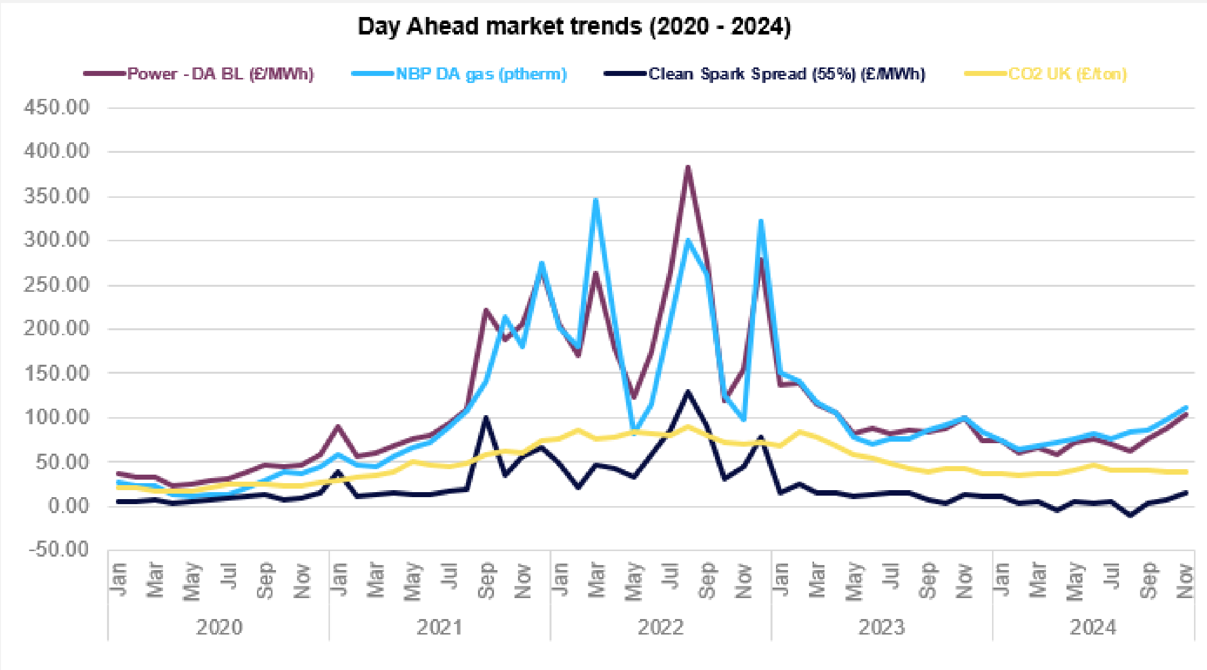


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

Market trends

Power and gas prices increased compared to last month, with a consequent rise in the Clean Spark Spread price. The CO_2 price remained close to its October 2024 level. Power and gas prices were also higher compared to last year whereas CO_2 remained lower compared to November 2023. Prices have continued their upwards trajectory heading into the winter period with below average temperatures in the second half of November resulting in increased gas for heating demand, and power prices remained closely correlated. CO_2 did not see a significant rise in November with higher wind outturn likely counteracting the impact of increase gas demand.



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

Wind Outturn

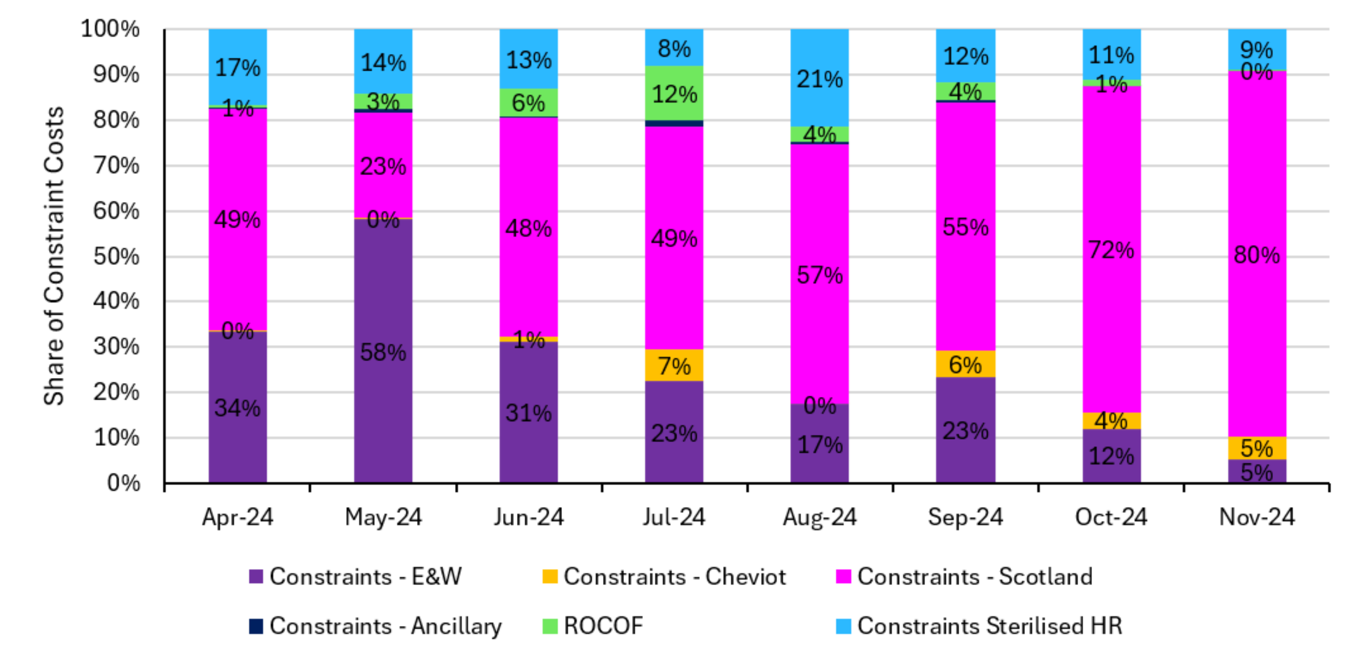
The first half of November saw relatively mild conditions. Between 1 and 9 November there was particularly low wind (offshore and onshore) and solar generation, known as a dunkelflaute period. Wind curtailment averaged just 8 GWh/day during this period which supported lower balancing costs early in the month.

The second half of November shifted to more wintery weather. On 23 November, Storm Bert brought wet and windy weather, particularly to south Wales and south-west England. Storm Conall then passed through on the 26 November, impacting the southern coast of England. Despite two named storms in November, overall wind outturn fell slightly to 5.3 TWh in November from 5.7 TWh in October, falling 9% in Scotland, and 6% in England and Wales month-on-month. Overall wind outturn was also 13% down on November 2023 but regionally there was a 33% increase in Scotland and 28% decrease in England and Wales compared to last year.

23 and 24 November saw the highest levels of wind curtailment for the month, coinciding with Storm Conall, with around 5GW of wind taken off behind constraints on each day. Weather conditions during this period also resulted in an increased number of circuit trips that required management.

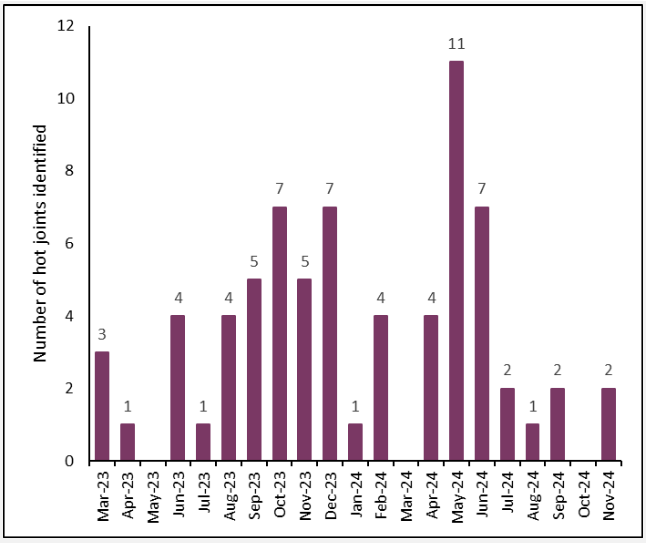
Constraints

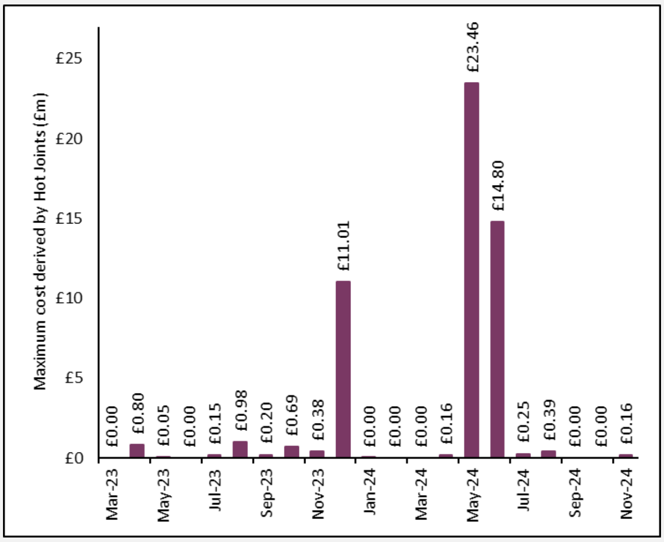
Constraint costs in November decreased by £36.2m compared to October 2024. Although the costs of all constraint components fell compared to the previous month, the largest reduction came from England and Wales constraints which fell to their lowest level this financial year. In contrast, Scottish constraints remained high (despite reducing 7% compared to October), due to ongoing outages reducing transfer capacity at key boundaries in this region. Scottish constraints made up 80% of constraint costs in November, a record high over the current financial year. Windy days, linked to storms, 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.



Network Availability

We continue to monitor the occurrence of hot joints in the system and their potential cost impact. Two hot joints were identified in November: one in the London and East Anglia region and the other in the West Midlands. The latter was resolved after six days, while the remaining hot joint is still active and is currently being addressed through network arrangements. No significant cost impact has been identified for either of the hot joints.





BALANCING COSTS DETAILED BREAKDOWN

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

		(a) Oct-24	(b) Nov-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	0.4	-7.4	(7.8)	
	Operating Reserve	6.3	3.6	(2.7)	
	STOR	4.7	5.5	0.8	
	Negative Reserve	0.5	0.4	(0.1)	
	Fast Reserve	17.2	15.6	(1.7)	
	Response	16.0	11.9	(4.1)	
	Other Reserve	1.7	1.4	(0.4)	
	Reactive	9.4	10.7	1.3	
	Restoration	2.7	2.9	0.3	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	4.3	2.3	(2.0)	
Constraint Costs	Constraints - E&W	25.3	9.3	(16.0)	
	Constraints - Cheviot	6.5	8.8	2.3	
	Constraints - Scotland	145.5	139.3	(6.2)	
	Constraints - Ancillary	3.4	0.3	(3.1)	
	ROCOF	2.9	0.8	(2.2)	
	Constraints Sterilised HR	26.3	15.2	(11.1)	
Totals	Non-Constraint Costs - TOTAL	63.2	46.8	(16.4)	
	Constraint Costs - TOTAL	209.9	173.6	(36.2)	
	Total Balancing Costs	**273.1**	**220.5**	**(52.6)**	

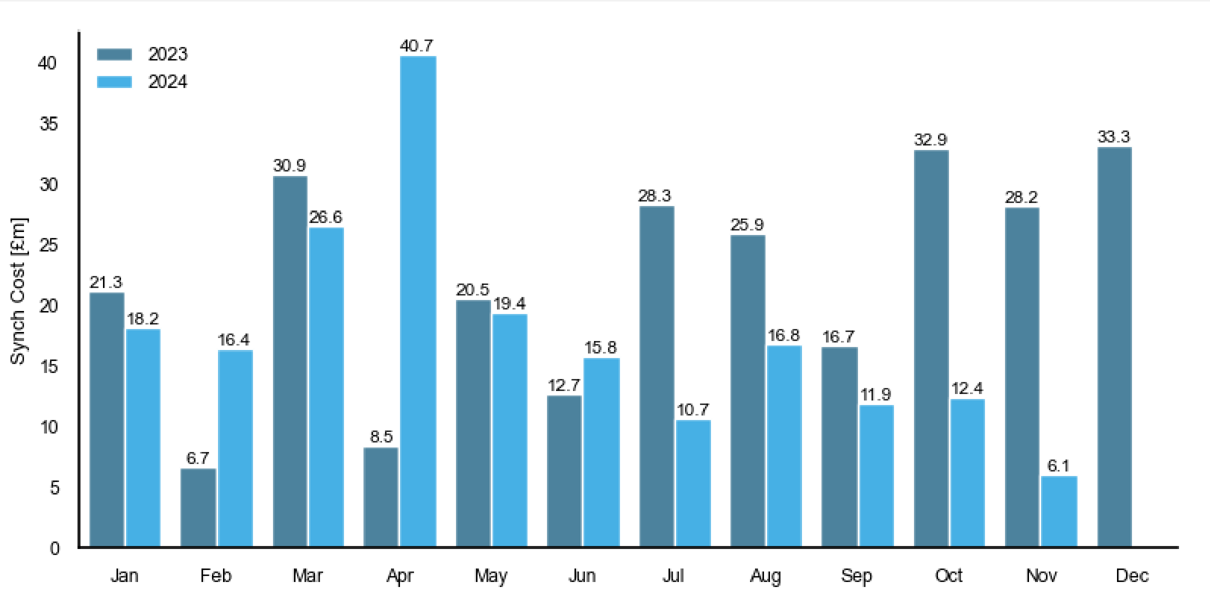
As shown in the totals from the table above, constraint costs decreased by £36.2m and non-constraint costs decreased by £16.4m, resulting in an overall decrease in balancing costs of £52.6m compared to October 2024.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: -£3.9m **Constraint – England & Wales: -£16.0m** **Constraint Sterilised Headroom: -£11.1m** Constraint costs have fallen by £36.2m compared to October 2024, coinciding with a 181 GWh decrease in the volume of actions. Slightly lower wind outturn has reduced costs month-on-month but Scottish constraint costs remain high due to significant outages leading	**Constraints – Scotland & Cheviot: +£90.0m** **Constraints – England & Wales: -£24.3m** **Constraints Sterilised Headroom: -£14.3m** Constraint costs have increased by £45.4m compared to last year, despite a 103 GWh reduction in volume of actions. Wind outturn in November 2024 was around 0.8TWh lower than November 2023, although wholesale prices this year were slightly higher.

to higher-than-expected costs in managing the constraints of the region.	Several outages also remain in effect impacting Scottish constraints compared to November last year.
ROCOF: -£2.2m In November, 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 20 GWh in the volume of action was observed during this period.	**ROCOF: -£5.9m** The expenditure on ROCOF tends to be marginal in the system. The implementation of the FRCR requirement reduction (140GVAs to 120GVAs) across February to 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 system cost of synchronisation actions for voltage control 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 November, the system costs of synchronisation costs amounted to £6.1m, which is a decrease of £6.3m compared to October 2024. In comparison to 2023, synchronisation costs have experienced a five-month period with lower costs.

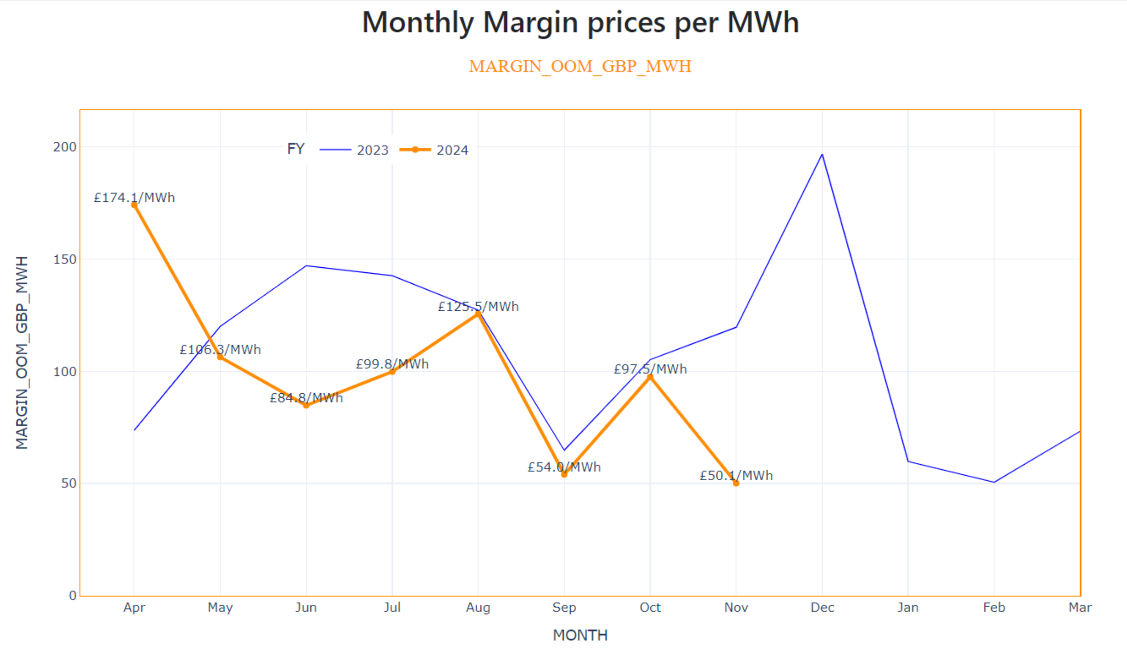
During the first half of November, the system experienced low wind and solar generation due to a Dunkelflaute period. This resulted in a higher reliance on gas-fired generation, which acted as a backup until wind generation began to ramp up again in the last days of the month, primarily driven by Storm Bert. Consequently, CCGTs that are typically instructed for voltage support in specific locations were already operational and providing reactive power, eliminating the need to buy them in the Balancing Mechanism and resulting in lower synchronisation costs.

Additional factors driving lower voltage management costs include:

- 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.

Reserve Costs/Volumes

Margin prices decreased to £50.1/MWh in November compared to £97.5/MWh in October 2024.This is aligned with decreased volumes compared to the previous month.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: -£2.7m **Fast Reserve: -£1.9m** There was a 72 GWh increase in the volume of Operating Reserve required to secure the system compared to October.	**Operating Reserve: -£20.1m** **Fast Reserve: -£0.67m** The introduction of the Balancing Reserve service in March has the potential to decrease reserve prices in the BM contributing to lower costs than last year.

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

Response Costs/Volumes

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

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£4.1m There was a 28.4 GWh decrease in the absolute volume of actions compared to October.	**-£6.6m** The volume of actions taken for response reduced 66.1 GWh compared to November 2023.

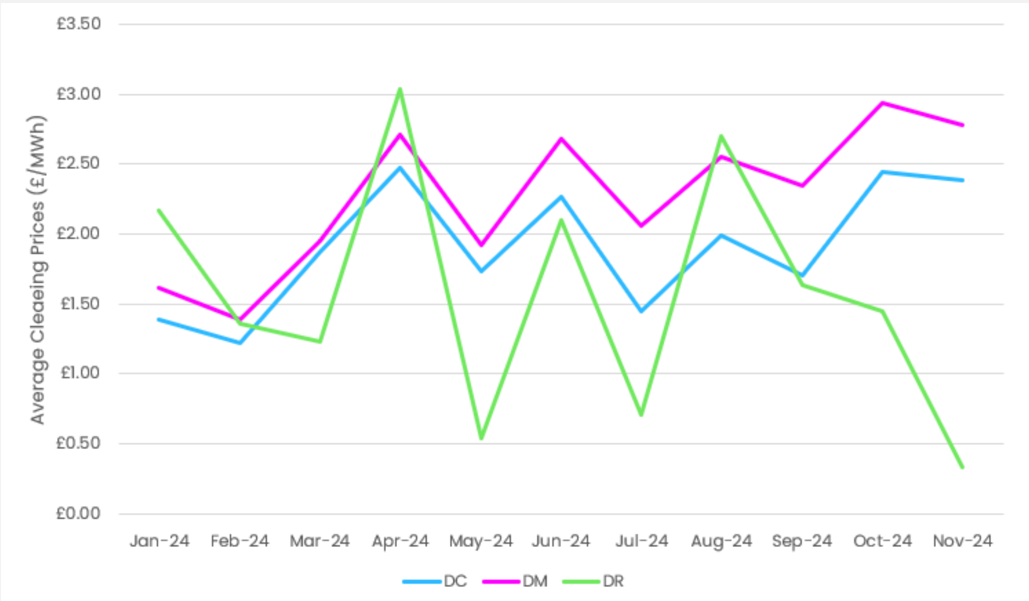
Dynamic Services Average Clearing Prices: November 2024 vs October 2024

		(a) Nov-24	(b) Oct-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	2.4	2.4	(0.1)	
	DM	2.8	2.9	(0.2)	
	DR	0.3	1.5	(1.1)	

Dynamic Services Average Clearing Prices: November 2024 vs November 2023

		(a) Nov-24	(b) Nov-23	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	2.4	2.0	0.4	
	DM	2.8	2.5	0.3	
	DR	0.3	4.1	(3.8)	

Average clearing prices for DC, DM and DR decreased in November compared to October 2024. When compared to November 2023, all three DC and DM saw a slight increase, whole DR experienced a significant decrease. DR High prices were particularly low (approximately -£7.79/MWh in November 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).



Reactive Costs/Volumes

The volume-weighted average price for reactive power was £3.9/MVAr in November 2024.

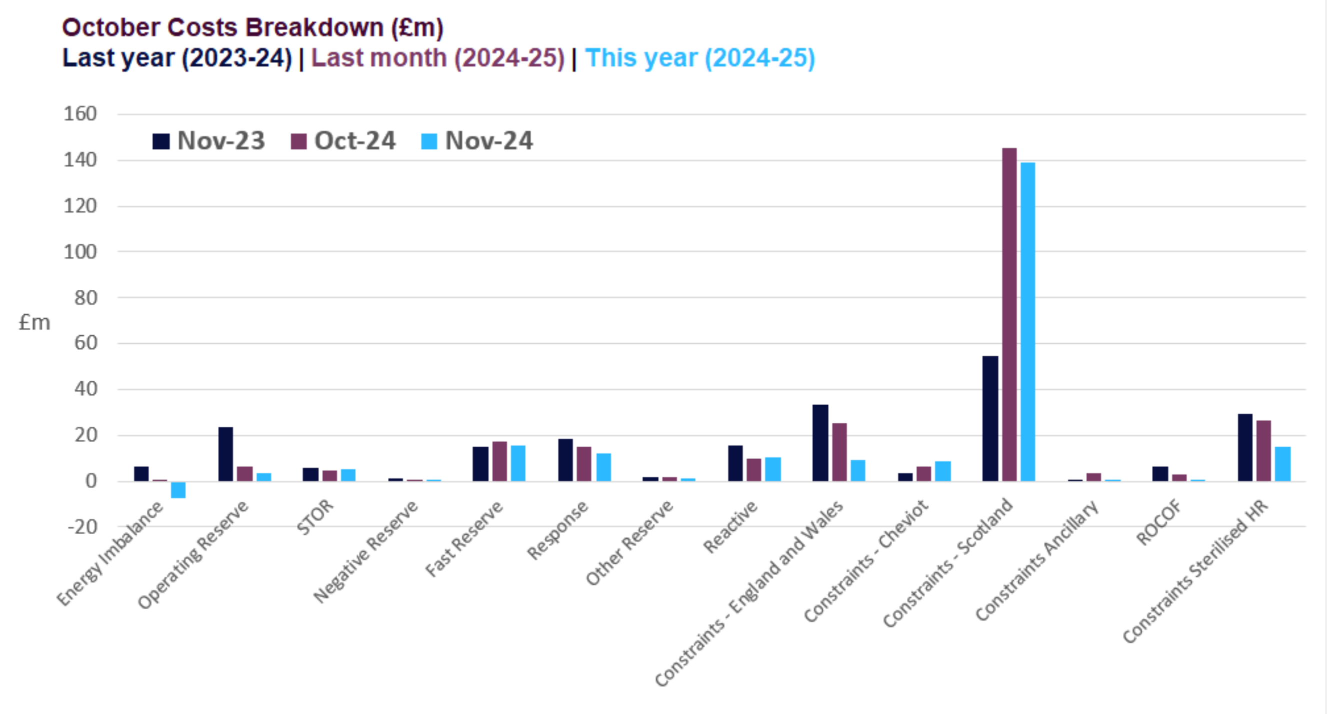
Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£1.3m Reactive volumes reduced by 15% compared to October 2024. The system is dominated by the need for absorption volumes, but these tend to vary according to the system operation conditions.	**-£4.8m** The volume-weighted average price decreased from £4.7/MVAr to £3.9/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 England and Wales constraint component was the main driver of reduced costs compared to last month. Constraint costs overall were down by £36.2 on last month. However, compared to last year constraint costs remain high, up £45.4m due to high costs from Scottish constraints. All categories for non-constraint costs showed a decrease or small deviation compared to last month. Overall non-constraint costs were down £16.6m on last month and £54.1m 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

Total savings from outage optimisation were roughly £47m in November 2024, this represents a reduction of £75m relative to October this year (£122.8m). The action that yielded the greatest value was the rejection of two concurrent planned outages in the South-West that would drop the transfer capacity of a constraint in the region by roughly 1210 MW. The optimisation over the outages' duration avoided the overlap and decreased the drop by roughly 550 MW. The estimated cost savings for this action are around £12.3m.

Cost Savings – Trading

The Trading team were able to make a total saving of £12.1m in November through trading actions as opposed to alternative BM actions, representing a 9.6% increase on the previous month. This was largely down to trading for thermal constraints in the South East. Various interconnectors were on unplanned and planned outages over November, however by the end of the month IFA1 and IFA2 were back to full capacity, which provided more trading options. Voltage savings remained consistent for this time of year, with average wind generation and higher demand. The day with the greatest spend on trades was on the 15 November at a cost of £1.99m with the greatest component being for managing the SEIMP constraint.

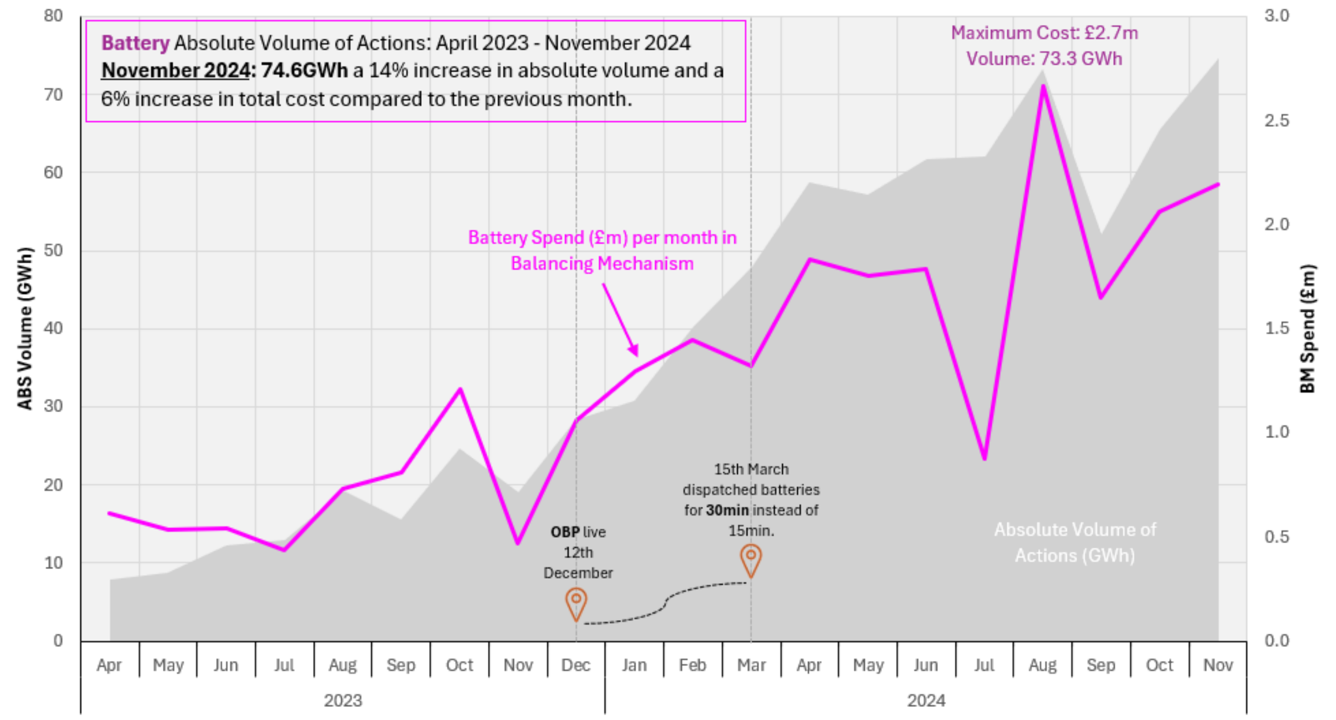
Cost Savings – Network Services Procurement (NSP)

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 £276m 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 November 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 (October 2024). Battery dispatch increased to a new record absolute volume, at 74.6GWh, illustrating our commitment to maximising the flexibility of energy offered by battery storage and small BMUs over the last year.

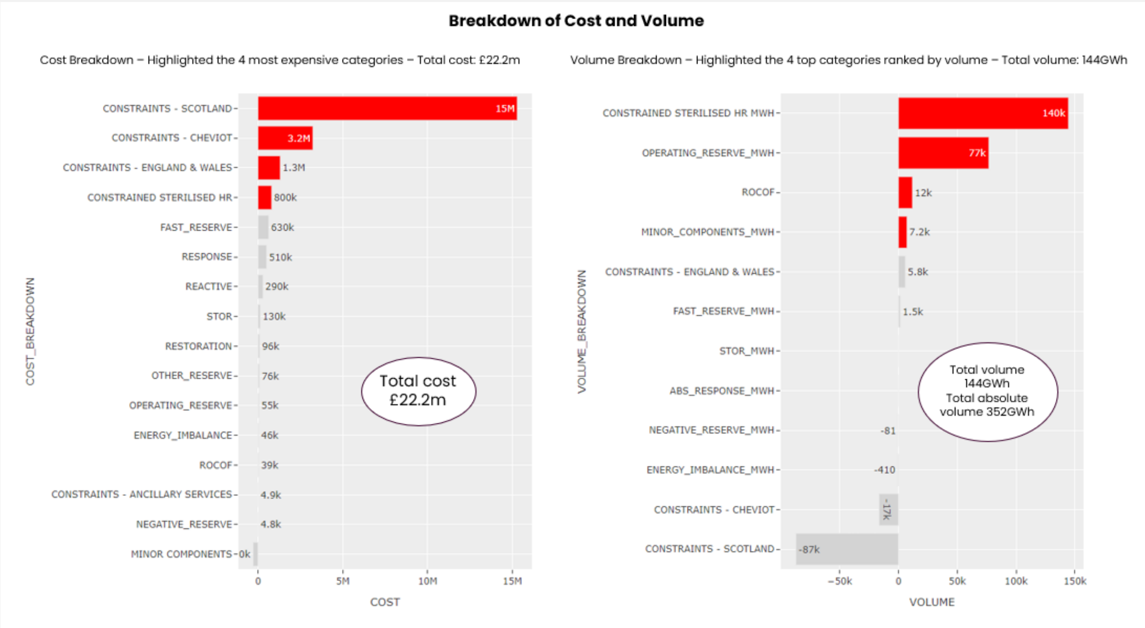
DAILY CASE STUDIES

Daily Costs Trends

November's balancing costs were £220m which is £52.6 lower than the previous month. Two days were recorded with costs above £15m (24 and 25) and an additional four days had a daily total cost over £10m (15,16, 23, 30). The daily average cost fell by £2.5m compared to October 2024 (to £6.2m from £8.7m).

Lowest-cost day was the 4 November with a total balancing cost of approximately £1.6m. The highest total cost was observed on the 25 November when the total spend was £20.4m, although the 24 saw a similar cost at £20.2m (see 'Daily wind outturn' chart below). Thermal Export Constraints dominated the cost breakdown on these days, with Scottish constraints making up ~70% of the daily costs. Storm Bert led to high wind output across both days resulting in high levels of wind curtailment, approximately 5GW each day, to manage Scottish constraints. No individual action was expensive, but high volumes of wind curtailment at bids up to -£178/MWh and a heavily constrained system resulted in high total balancing costs for the day.

High-Cost Day – 25 November 2024

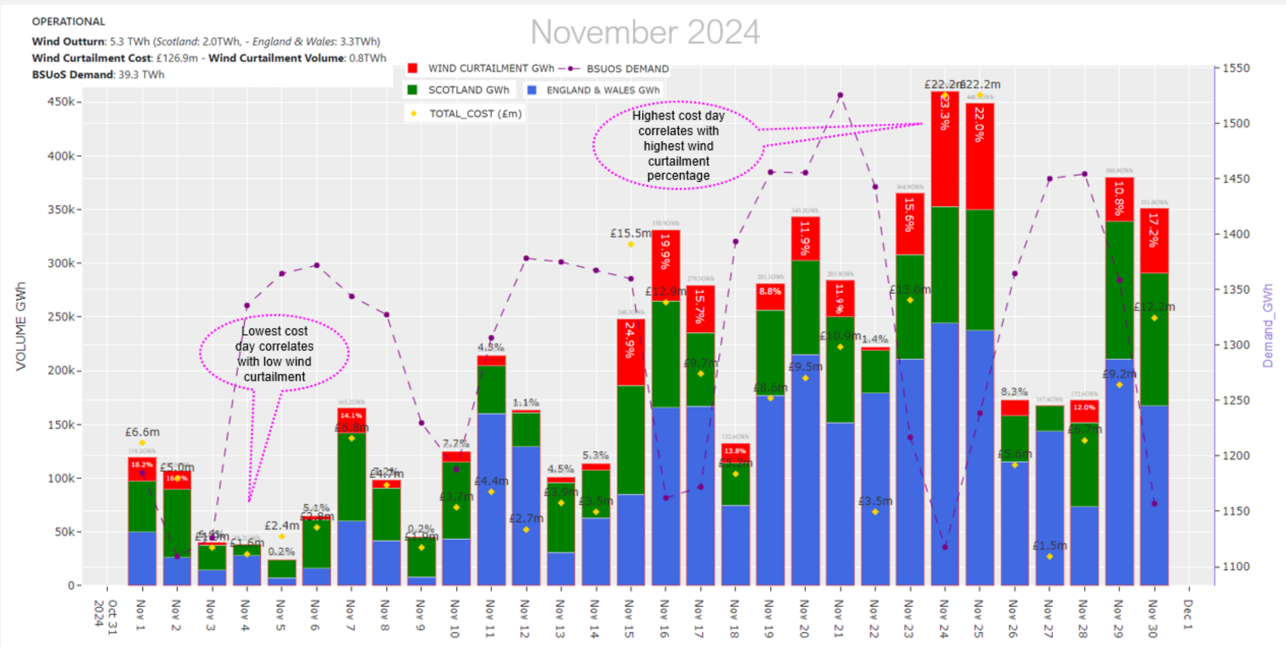


November Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUoS Demand

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.

November 2024-25 performance

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

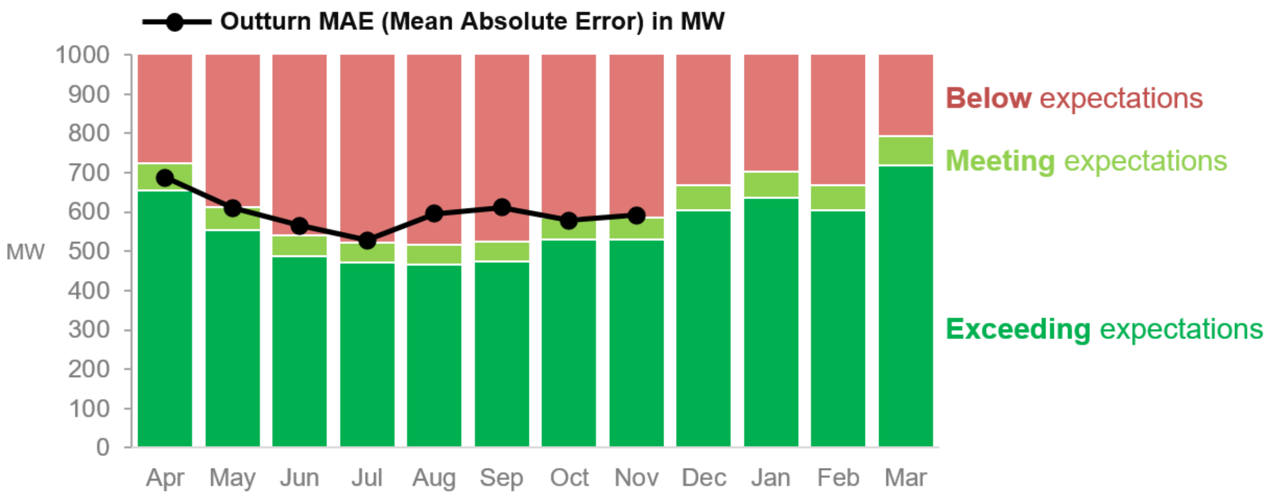


Table: 2024-25 Monthly absolute MW error vs Indicative Benchmark

	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**	**591**				
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

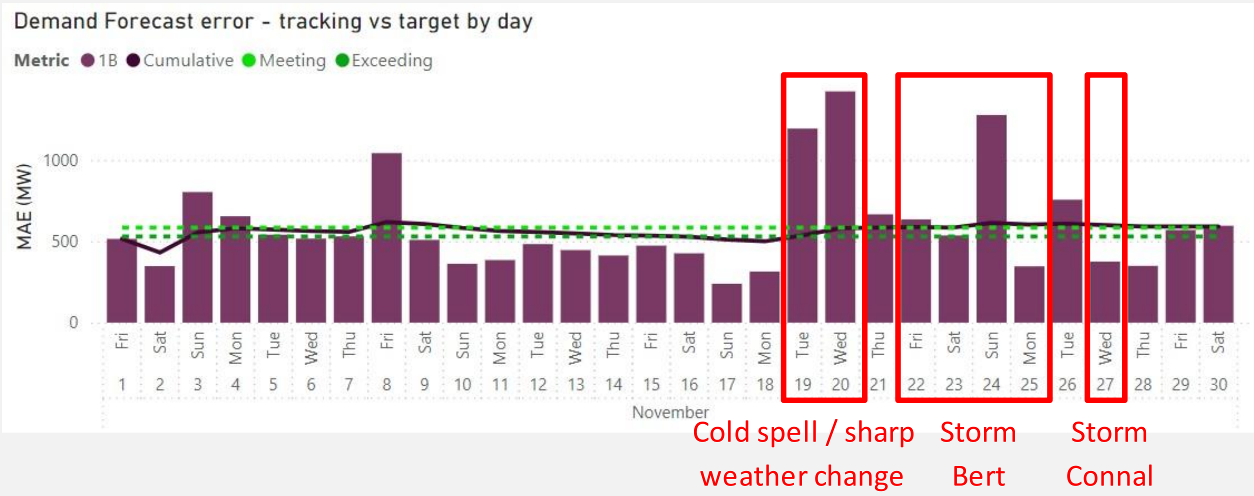
[2] Demand | BMRS (bmreports.com)

Supporting information

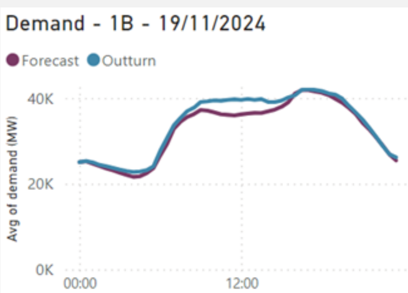
In November 2024, the mean absolute error (MAE) of our day ahead demand forecast was 591 MW compared to the indicative benchmark of 557 MW. The 5% range around this benchmark extends to 585 MW, meaning our performance narrowly missed expectations for November.

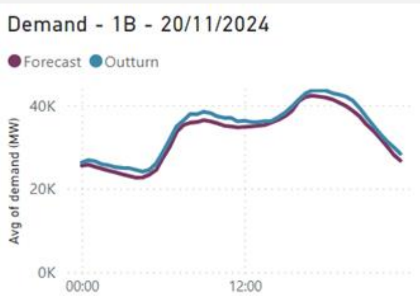
The Met Office reports that November began with very mild conditions and low sunlight, turning into a cold, wet and windy second half of the month including two named storms: Bert (22-25 November) and Conall (27 Nov).

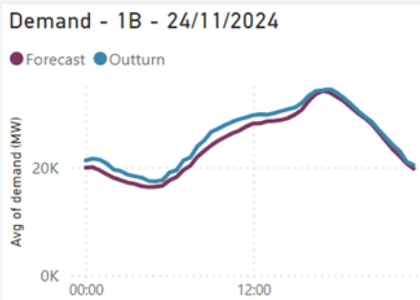
The sharp weather changes and cold spell around 19 and 20 November caused two of the largest error days, with solar generation being a large part of the error on 19 November. The other largest error day (24 November) was during Storm Bert, where weather conditions caused higher demand outturn than expected for the first three quarters of the Sunday.



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







The errors on 19 November were during daylight hours, attributed to solar forecast errors. Errors on 20 and 24 November were wind related, owing to conditions around storm Bert and Conall

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 (1440)
1000 MW	249	17%
1500 MW	102	7%
2000 MW	29	2%
2500 MW	10	1%
3000 MW	7	0%

The days with largest MAE were November 19, 20, and 24.

Day	Error (MAE)	Major causal factors
19 Nov	1193	Errors in the solar forecast (indicated by the variance in the middle of the day in the above graph for 19 November) and in the temperature input data.
20 Nov	1422	Process/Model/Profile error - Current diagnostics do not identify the distinctive causal factor
24 Nov	1277	Process/Model/Profile error - Current diagnostics do not identify the distinctive causal factor

Missed / late publications

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

Triads

Triads run between November and February (inclusive) each year.

Due to changes in charging methods, triads are expected to have a smaller effect than in previous years. However there may be other price related demand avoidance effects over the daily peaks.

Triad avoidance behaviour is predicted to have affected the following dates in November: 18, 19 and 27, totalling 3200MWh.

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:

- did not have a bid-offer acceptance (BOA);
- did not withdraw availability completely between time of forecast and time of metering; for the relevant settlement period. We publish this data on its data portal for transparency purposes.

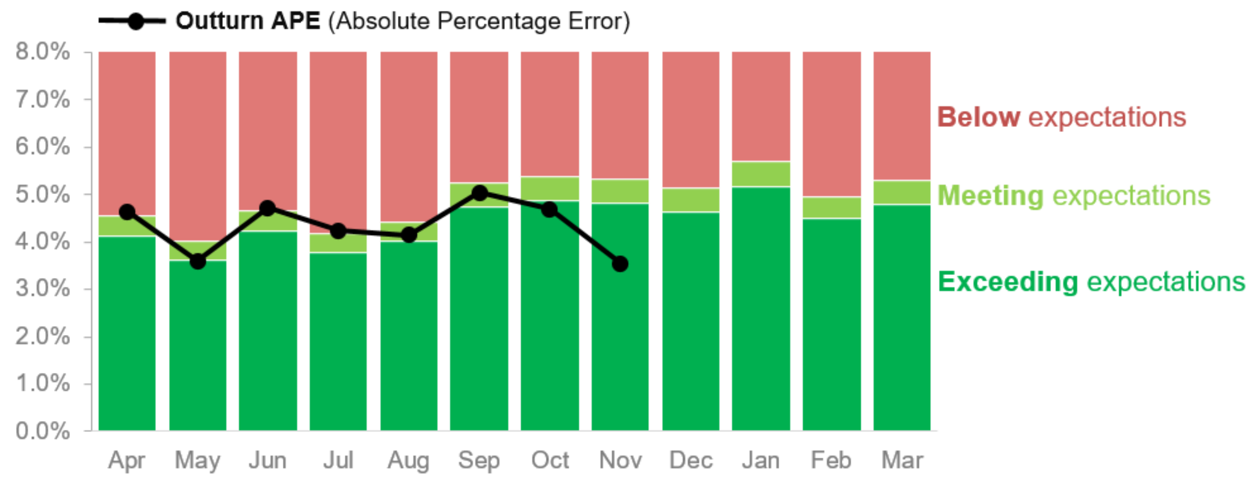
Sites deemed to have withdrawn availability are those that:

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

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.

November 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**	**3.55**				
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**	**4.98**	**4.77**	**3.51**				
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 November 2024, the mean absolute percentage error (corrected for redeclarations to zero and revisions to Settlement Metering) is currently reported as 3.55% against the corresponding monthly benchmark of 5.07%. The 5% range around this benchmark extends from 4.82% to 5.32%, meaning our performance exceeded expectations for November.

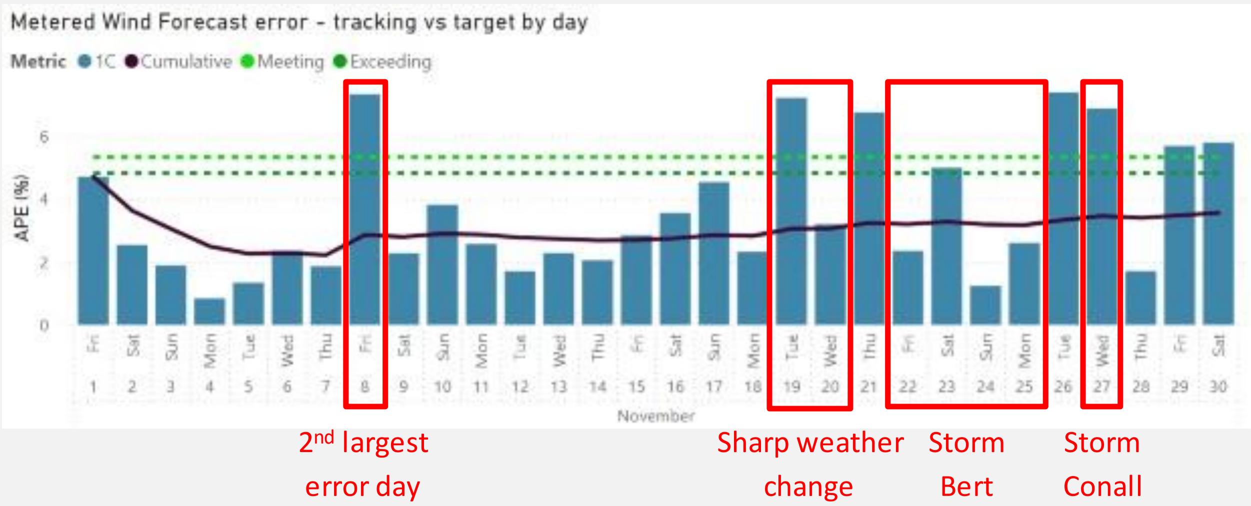
The mean absolute percentage error for the original 1C metric was 3.51%, compared to the monthly benchmark of 5.02%. The 5% range around this benchmark extends from 4.77% to 5.27%. meaning performance on this metric also exceeded expectations.

The first half of November was made up of mostly low, stable wind conditions, making accurate forecasting possible. The second half of the month brought stronger, more variable winds, as well as two named storms (Bert and Conall).

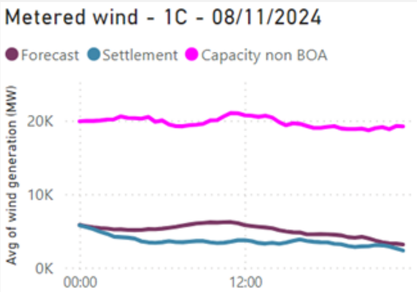
Monthly performance was brought up by larger error days on 8, 19, 21, 26, 27 November.

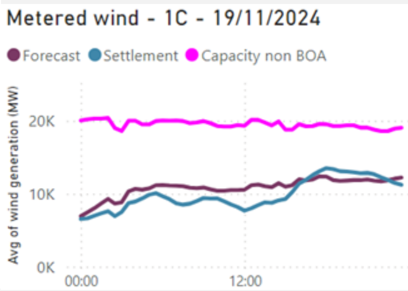
The largest forecast error this month was 3.2 GW on 21 November, settlement period 36.

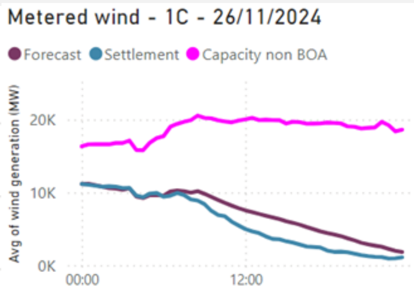
NESO's next-generation wind forecasting product (PEF R5) was released late on 7 November, with 9 November being the first reported 1C date with the new version. While it's early days, and we cannot directly test performance during this period with the old model, the data so far suggests an improvement in forecasting performance under all weather conditions. We'll continue to monitor the impact of PEF R5 in the coming months, in addition to developing and releasing further upgrades in due course.



The days with largest APE were 8, 19, and 26 November.







Day	Error (APE)	Major causal factors
8 Nov	7.33	Largely down to weather (wind speed) errors at day ahead – fast changing forecast. By 12 hours ahead, this error had dropped by over half and continued to reduce at shorter lead times.
19 Nov	7.22	Sharp weather change as the ‘anti cyclonic gloom’ system ended
26 Nov	7.39	Weather (wind speed) errors in the period directly between storms Bert and Conall, with complex wind conditions especially offshore.

Missed / late publications

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

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.

November 2024-25 performance

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

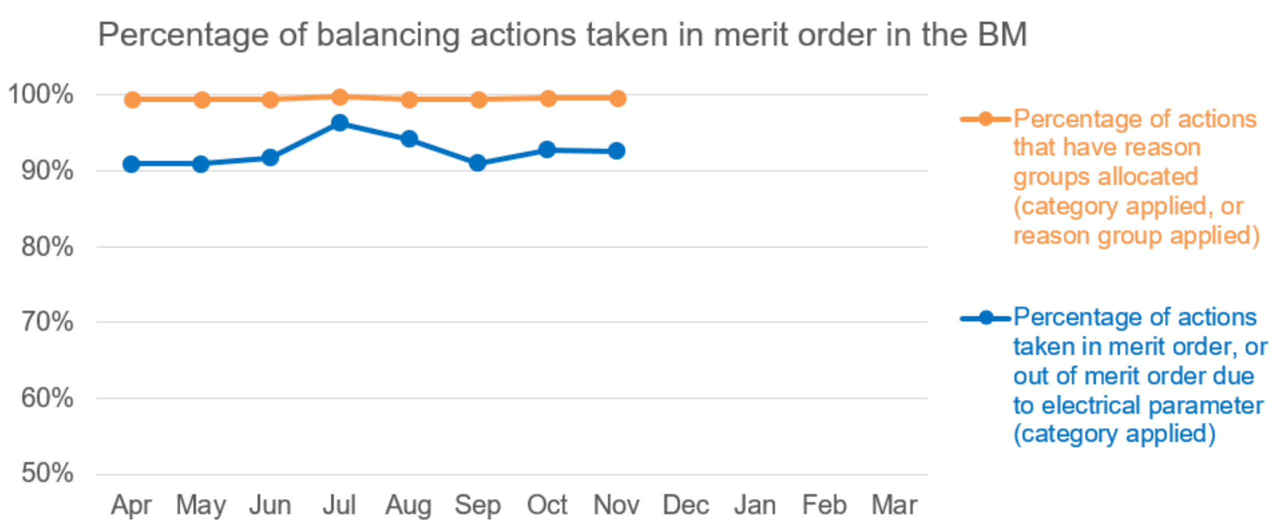


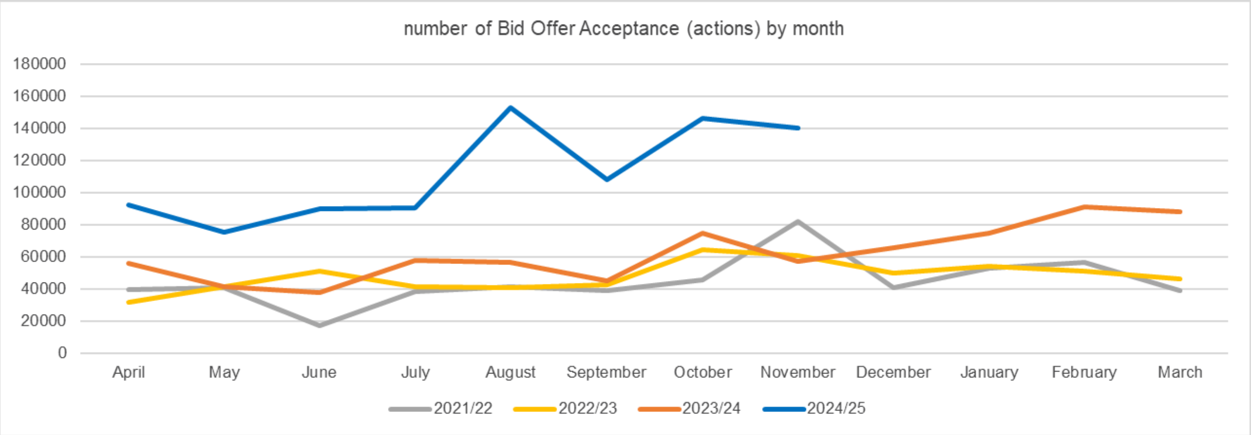
Table: Percentage of balancing actions taken outside of merit order in the BM

	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%	92.6%				
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%	99.7%				
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%	0.3%				

Supporting information

November performance

This month 92.6% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 7.1% 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 140,288 BOA (Bid Offer Acceptances) and of these, only 451 remain with no category or reason group identified, which is 0.3% of the total. The number of BOAs in November was in line with October.



Other activities

On 4 December we hosted the inaugural battery storage forum in-person event to collaborate with industry on improving dispatch efficiency. The event was attended by 35 customers from 23 organisations. We engaged on a variety of topics including NESO's roadmap to improve efficient battery dispatch, the methodology for calculating skip rates, Markets and Ancillary Services, forecasting and trading. We also gave an insight into our control room operations and our battery dispatch engineers, and included Q&A and networking opportunities so we could listen to and understand industry's views.

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 (Zero Carbon Operability Indicator) 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.

November 2024-25 performance

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

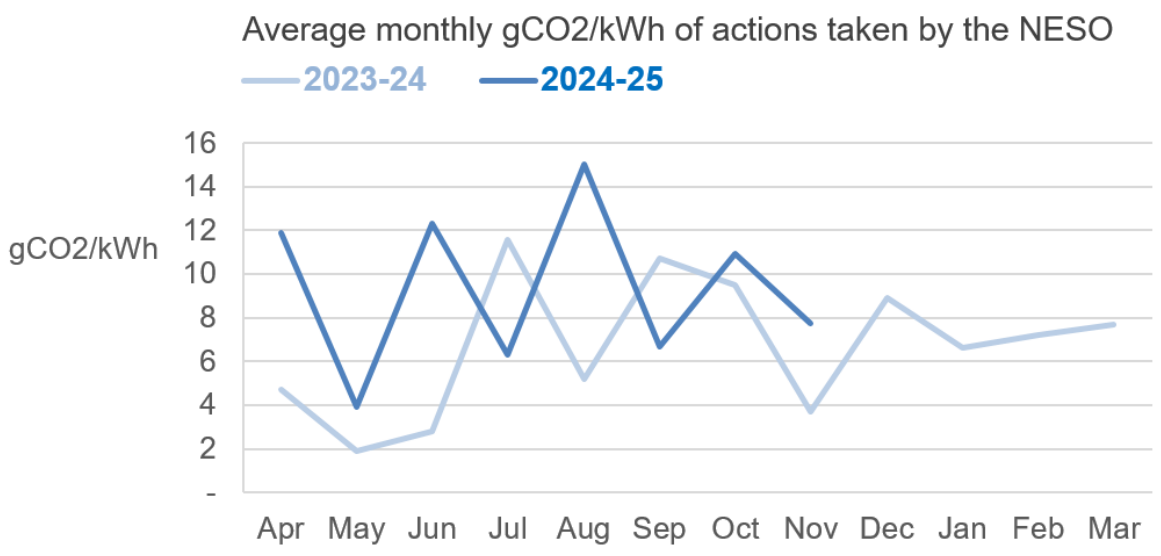


Table: Average monthly gCO2/kWh of actions taken by NESO

	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	7.74				

Supporting information

In November 2024, the average monthly carbon intensity from NESO actions was 7.74g/CO2/kWh. This is 1.61g/CO2/kWh lower than the 2024 YTD average of 9.35g/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 63.2g/CO2/kWh which took place on 24 November at 1630. This is 3.81g/CO2/kWh higher than October's highest difference of 59.39g/CO2/kWh.

On 24 November Storm Bert was affecting the UK with multiple weather warnings in place. Transmission connected wind output forecast was very high at 17GW with minimal solar generation forecast of 1.4GW. Management of this required a significant amount of action by NESO.

This month's carbon intensity from NESO actions is in line with November 2023, when the average monthly carbon intensity from NESO actions was 5.88g/CO2/kWh and the maximum difference peaked at a similar stage in the month on 23 November 2023.

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 ≤ f < 49.5	up to 60 seconds	2 times per year
48.8 < f < 49.2	Any	1-in-22 years
47.75 < f ≤ 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.

November 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	0				
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0	1	0				
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0	0	0	0	0				

Supporting information

November performance

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

[3] 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.

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

Supporting information

November performance

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

Notable events during November 2024

Platform for Energy Forecasting goes live

On 7 November, we successfully launched PEF R5, marking a significant milestone in enhancing our energy forecasting capabilities. This achievement is the result of the collective efforts and dedication of the Balancing Programme's PEF Product team, Energy Forecasting team, and the Electricity National Control Centre (ENCC).

PEF R5 empowers our Energy Forecasting team to make frequent and incremental improvements to their modelling capabilities, leading to more accurate wind forecasting for our control room. This advancement significantly reduces uncertainty and provides a substantial boost to our energy forecasting resources, resulting in better decision-making and operational efficiency.

PEF R5 also signifies the beginning of the new Azure platform with migration of current energy forecasting models, including Solar and both GSP and National Demand expected by the BP2 period.

Looking ahead, we envision continuing to provide an advanced and supported platform in Azure. This commitment ensures we have the necessary tools and resources to refine forecasting models over time. Our program of continuous improvement will incorporate new features that improve forecast accuracy and account for currently unmodeled generator behaviours. Improved forecasts will support more optimal control room actions, efficient risk management decisions, and better day-ahead electricity markets.

This achievement highlights the positive impact of our collaboration and shared commitment to excellence in delivering reliable and efficient energy solutions.

Role 2

(Market developments and transactions)

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

Notable events during November 2024

Conclusion of the first Mid-Term Stability Y-1 Market

In December 2023, we launched the first tender round under the Mid-Term (Y-1) Market to procure stability services. The Mid-Term (Y-1) Market was launched as a priority to access inertia capability from existing assets on a high-availability basis. Through annual contracts, this market provides revenue certainty for market participants whilst reducing risk for NESO as periods of low inertia become more frequent and unpredictable.

On 22 November, following a rigorous tender assessment process, we announced the award of contracts worth an anticipated £25.4 million to 5 providers to deliver 5 GVA.s of inertia for the Mid-Term (Y-1)'s inaugural delivery year between October 2025 and September 2026.

The first contracts to be awarded under the Mid-Term (Y-1) Stability Market will deliver an anticipated consumer saving of £47.3 million, between October 2025 and September 2026. As outlined in our Frequency Risk and Control Report, we must operate the power system above the minimum target inertia threshold (currently 120GVAs) at all times. The award of these contracts will help contribute to the stability of the GB power system by providing cost-effective, zero-carbon solutions which can be utilised to increase system inertia during periods of shortfall.

Webinar on Mid-Term Reactive Power Market

On 13 November, we presented a deep dive on our proposed Mid-Term reactive power market. In short, we wanted to update interested parties on our latest thinking of what this market may look like and provide an opportunity for industry feedback on the proposed design.

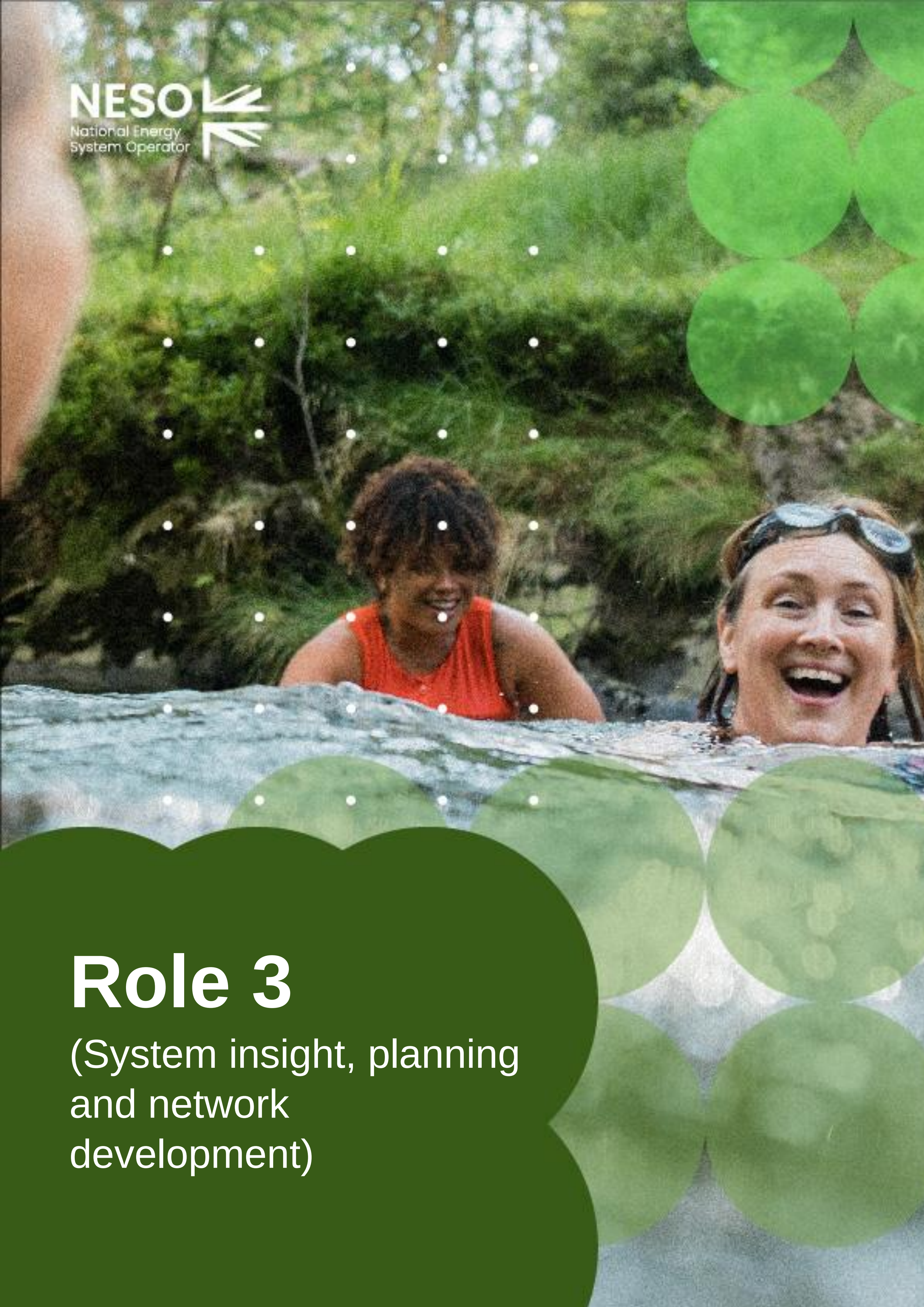
This event aimed to provide a deep dive on the following topics:

- Why does NESO need a reactive power market?
- A deep dive into NESO's proposed market design
- How we will be assessing our proposed design

Slides and a recording can be found on NESO's Future of Reactive Power webpage.

With 215 attendees, we were pleased by the level of engagement. During this webinar we also launched our voluntary Market Engagement Request for Information (RFI). This Market Engagement RFI aimed to capture interested parties feedback on the indicative market design, their assets and any additional thoughts. Though the RFI submission date has closed, queries can still be sent to box.voltage@nationalenergyso.com.

We intend to present an industry update in the early new year, before our conclusionary webinar in Q1 2025 (fiscal).



Role 3

(System insight, planning and network development)

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

NESO
National Energy
System Operator