23 November 2026

Incentives October 2026 Report

NESO1 Business Plan (2026-28)



NESO
National Energy System Operator

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Introduction

NESO1 is our first two-year Business Plan as the National Energy System Operator, covering April 2026 to March 2028. It explains how we will deliver our strategic aims, provide value for money, and support a secure, affordable and sustainable energy system. We published our plan in November 2025, structured around six Performance Objectives that set out how we would deliver over the period. In its Final Determinations, Ofgem added a seventh Performance Objective focused on providing customers with a high-quality, independent and trusted service. The final set of Performance Objectives are:

- Planning a Clean Energy Future
- Operating an Intelligent, Real-Time Grid
- Enabling Smarter, Cleaner Markets
- Delivering a Decarbonised, Operable Grid
- Driving Whole-System Resilience
- Building a Digitally Connected Energy System
- Providing Customers with a High-quality, Independent and Trusted Service

In line with the requirements set out in the NESO Performance Arrangements Governance Document (PAGD), this report provides transparency on a range of Reported Metrics covering operational outcomes, performance drivers and trends over time.

The Reported Metrics form part of NESO's regular performance reporting and provide visibility of key operational measures across the organisation.

Quarterly reports provide additional narrative on progress against NESO's Performance Outcomes, including evidence against Ofgem Expectations, associated Success Measures and Major Deliverables, while six-monthly and annual reports also include stakeholder survey results and updates on value for money.

Please see our incentives website for more information on the scheme, our reporting requirements, and to access our reports.

You can stay up to date with our latest news and events on the NESO website or by subscribing to our weekly newsletter.

Reported Metrics



Summary of Reported Metrics

The table below summarises our Reported Metrics for October 2026:

	Reported Metric	Performance
1	**Balancing Costs**	Oct: **£745m**
2	**Demand Forecasting**	Oct: Forecasting error of **731MW**
3	**Wind Generation Forecasting**	Oct: Forecasting error of **4.0%**
4	**Skip Rates**	Oct: Post System Action (PSA) Offers: **42%** Bids: **40%** Combined: **41%**
5	**Security of Supply**	Oct: **0** frequency excursions, **0** frequency instances and **0** voltage excursions
6	**CNI Outages**	Oct: **1** planned, **0** unplanned system outages.

1. Balancing Costs

Under NESO1 (April 2026 to March 2028), we publish NESO's outturn balancing costs (including Electricity System Restoration costs) as a Reported Metric to provide clear, accessible transparency on balancing cost outturns, key operational drivers of balancing costs and trends over time. Where we include comparative indicators, these are provided for context only.

We are using a new benchmark methodology for NESO1, which has been developed and expanded from the previous BP3 methodology. The new methodology continues to use the relationship between wholesale prices and monthly balancing costs; however outturn wind has been replaced with a new variable, hypothetical wind penetration.

Hypothetical wind penetration is defined as the ratio of unconstrained wind to national demand. This provides a normalised, objective measure of system stress from wind.

Other changes to the benchmark methodology include:

- Instead of using monthly data points in our calculations, we are using daily data points which allow for a greater sample volume. This increases the number of points from 36 to 1000+.
- We use a daily monthly average cost estimation (an average of the days across the month) multiplied by the number of days in the month, to normalise the data and to eliminate biases from the length of the month, which varies.

The model development process follows a structured train–validation–test framework to ensure robustness, generalisation, and full transparency. Initially, the model was trained on daily data spanning Apr-2018 to Mar-2024 and is retrained again every 6 months on the full dataset (currently **Apr-2018** to **Sep-2026**) to maximise the use of available information.

The NESO1 benchmark uses two main external drivers:

1. Unconstrained Wind Penetration

Unconstrained wind penetration = Unconstrained wind MWh / National demand MWh

Where:

Unconstrained wind MWh = actual wind output + curtailed wind
National demand MWh = daily total electricity demand

This variable captures system stress before operational decisions are made. In the dataset, this appears as:

wind_penetration_mean = daily average unconstrained wind penetration

2. Day-Ahead EPEX Price (APX)

Daily APX price = average day-ahead APX price in GBP/MWh

This variable captures the market price environment in which balancing actions occur.

In the dataset, this appears as:

day_ahead_price_mean = daily average APX price

Further details on our benchmark methodology and additional supporting information on monthly balancing costs and drivers are also available on our Balancing Cost page here.

October 2026 performance

Figure: 2026-27 Monthly balancing cost outturn versus benchmark

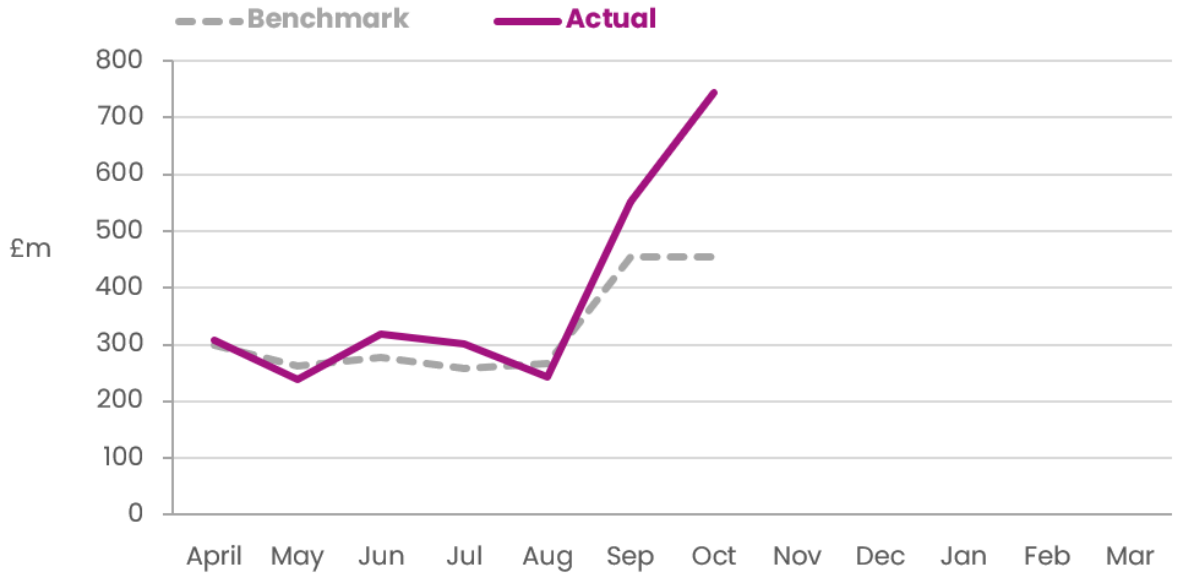


Table: 2026-27 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Unconstrained Wind Penetration	0.21	0.15	0.18	0.15	0.14	0.25	0.24						0.19
Day Ahead APX (£/MWh)	82.5	104.8	100.2	106.7	127.1	134.4	145.1						115.27
Benchmark*	299	262	278	257	266	455	455						2272
Outturn balancing costs[1]	**307**	**239**	**319**	**301**	**242**	**553**	**745**						**2707**

Previous months' outturn balancing costs are updated every month with reconciled values. Benchmark and outturn balancing costs are rounded to the nearest £m.

[1] Outturn balancing costs exclude 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.

Supporting information

BALANCING COSTS METRIC & PERFORMANCE

This month's benchmark

October's benchmark of £455m was closely aligned with the same value for September due to relatively similar system conditions considered – wind penetration and day ahead power prices.

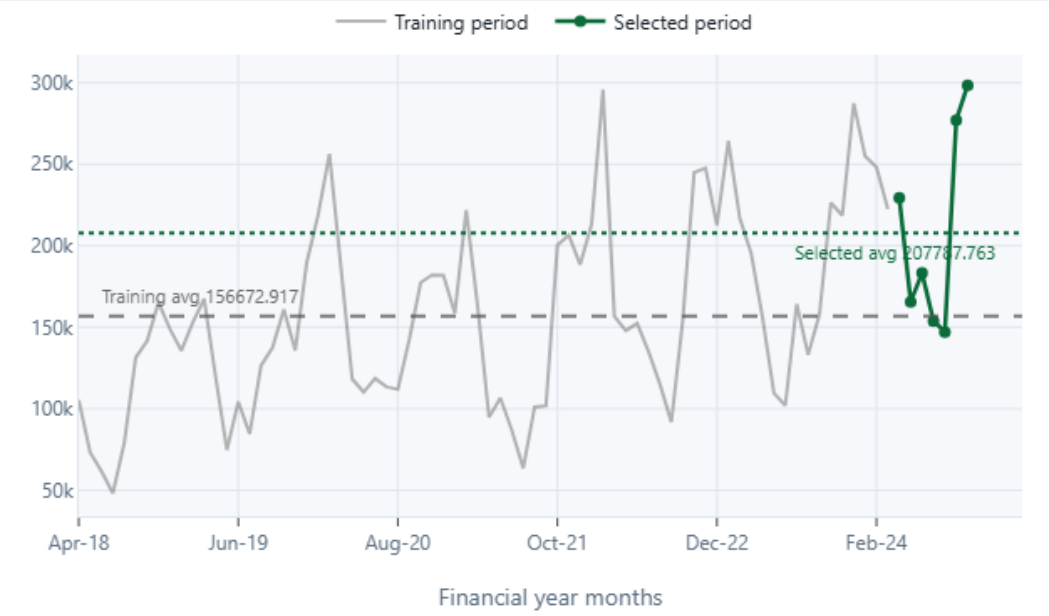
The benchmark model does not capture all system conditions that can influence balancing costs. In October, the unusually high level of outages and the interaction of these outages with lower demand created additional balancing requirements and costs that are not fully represented by the two model variables. Consequently, the benchmark explains part of the October cost movement but does not fully capture the exceptional system conditions experienced during the month.

Wind penetration (October ↓ vs September): Wind penetration was slightly lower in October than in September, as there was an increase in hypothetical wind generation, but also an increase in demand. These higher levels of wind penetration seen in Autumn/Winter are associated with greater variability in balancing costs, largely due to increased system constraints.

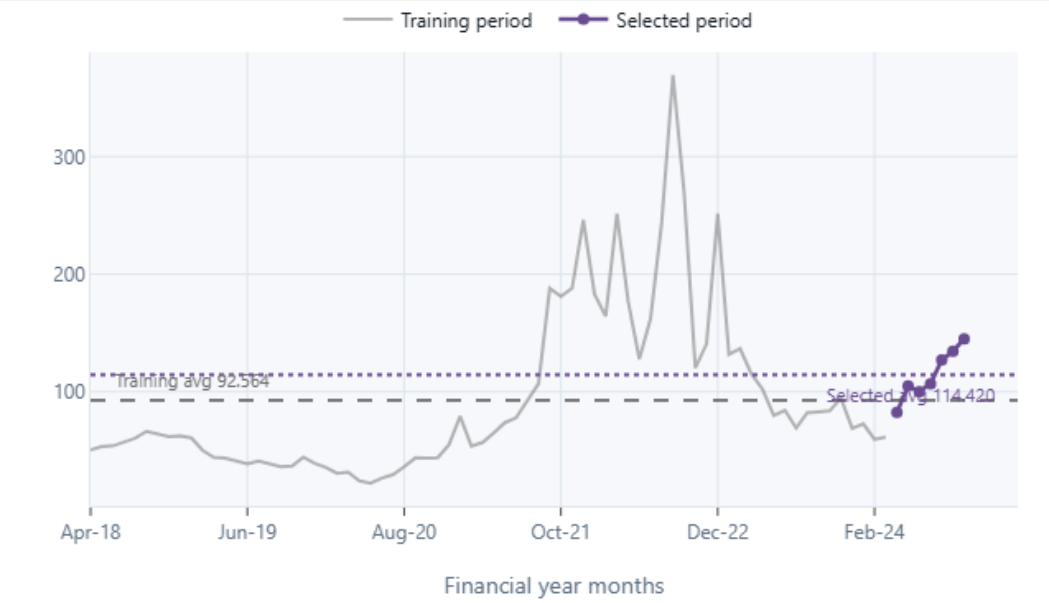
Day-ahead price (October ↑ vs September): October experienced higher day-ahead wholesale electricity prices compared with September, reflecting a more expensive underlying market environment. Day-ahead price is one of the key explanatory variables within the benchmark model and contributes materially to the estimation of average daily balancing costs

Overall, the benchmark remained comparable as the two key system conditions considered by the model had shifts in opposing directions creating a net-zero shift in cost expectations.

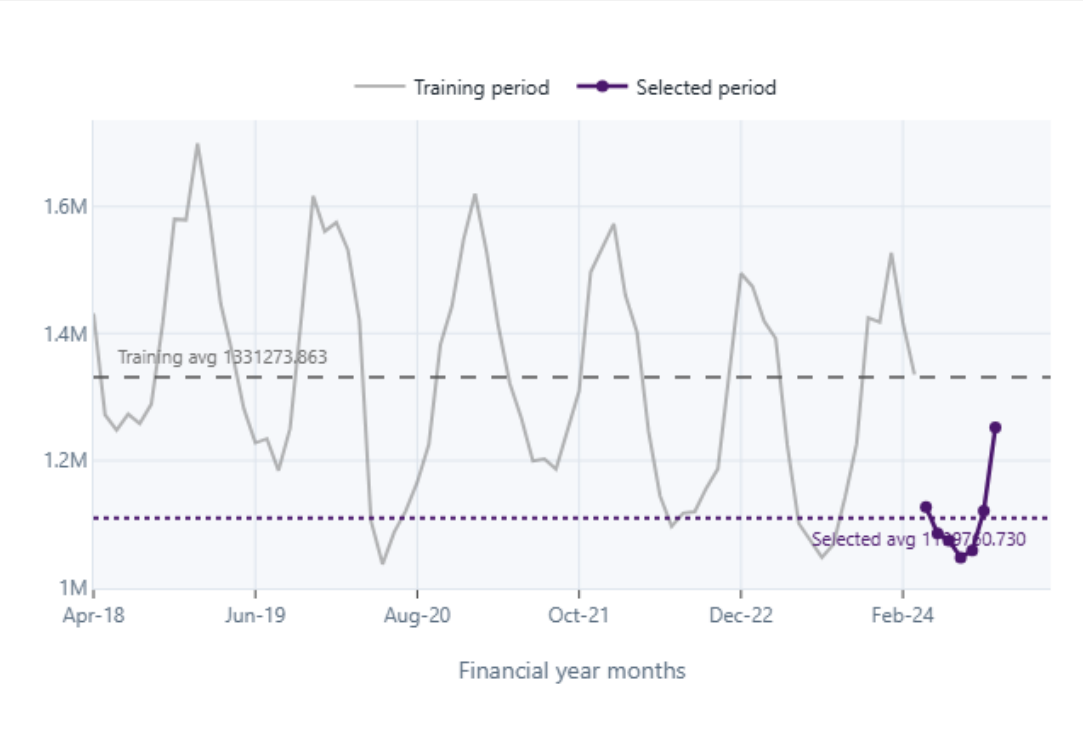
Wind Penetration



Day Ahead Price



National Demand



Balancing Costs - Overview

The total balancing cost for October was £745m, which is £290m (~64%) above the benchmark of £455m. October's benchmark remained broadly unchanged from September because movements in the two conditions captured by the model, unconstrained wind penetration and day-ahead power prices, broadly offset one another. However, the benchmark does not capture all system conditions that influence balancing costs. In October, high levels of network outages and restricted transfer capability, interacting with seasonally low demand, increased the volume of balancing actions required and contributed materially to costs above the benchmark.

October was the highest costing month on record, higher than the record set in September 2026 (£553m). Many of the conditions that drove September's high costs continued into October. Day ahead power and gas prices continued to increase, which drove up costs for replacement energy actions, typically taken on more traditional generators such as gas. October also saw record high wind curtailment volumes at 1,991GWh to manage network constraints and congestion on the system and maintain system security.

October costs were driven by:

Higher redispatch volumes. Sustained high wind generation, combined with seasonally low demand (comparative to previous years), transmission outages and multiple active thermal constraints, significantly increased redispatch requirements. Wind accounted for 40% of the generation mix, reaching 66% on 10 October, while a record 2.0 TWh of wind was constrained off during the month. Reduced transfer capability, particularly from Scotland, meant more wind had to be curtailed and replaced with generation closer to demand in the South.

Network outages and reduced transfer capability. Network outages were also a driver of October's thermal constraint costs. Outages affecting the B2 boundary in Scotland were the most significant with only around 48% capacity available, while outages in the Midlands were the second-most significant. Isolating the impact of individual outages is not done on an outturn basis, since it would require modelling a monthly counterfactual. As an indication of how much outages drive constraint costs, modelling for 2027 in our Annual Balancing Cost Report suggested that outages drives approximately 16% of constraint costs with the remainder caused by structural congestion.

In October the outages restricted the amount of electricity that could be transferred across the network at a time of high wind generation and relatively low demand. Reduced transfer capability, particularly from Scotland, meant more wind generation had to be curtailed and replaced with generation closer to demand in the South, increasing redispatch volumes and costs.

Higher cost of replacement generation. Gas prices were 171% higher year on year, increasing the cost of replacing curtailed wind with these actions typically taken on more traditional gas-fired units. The volume-weighted average offer price increased to £239.52/MWh, while the average bid price increased to £3.13/MWh, reflecting the high volume of wind curtailment. The positive bid price here reflects a net payment from generators to NESO. On several high-cost

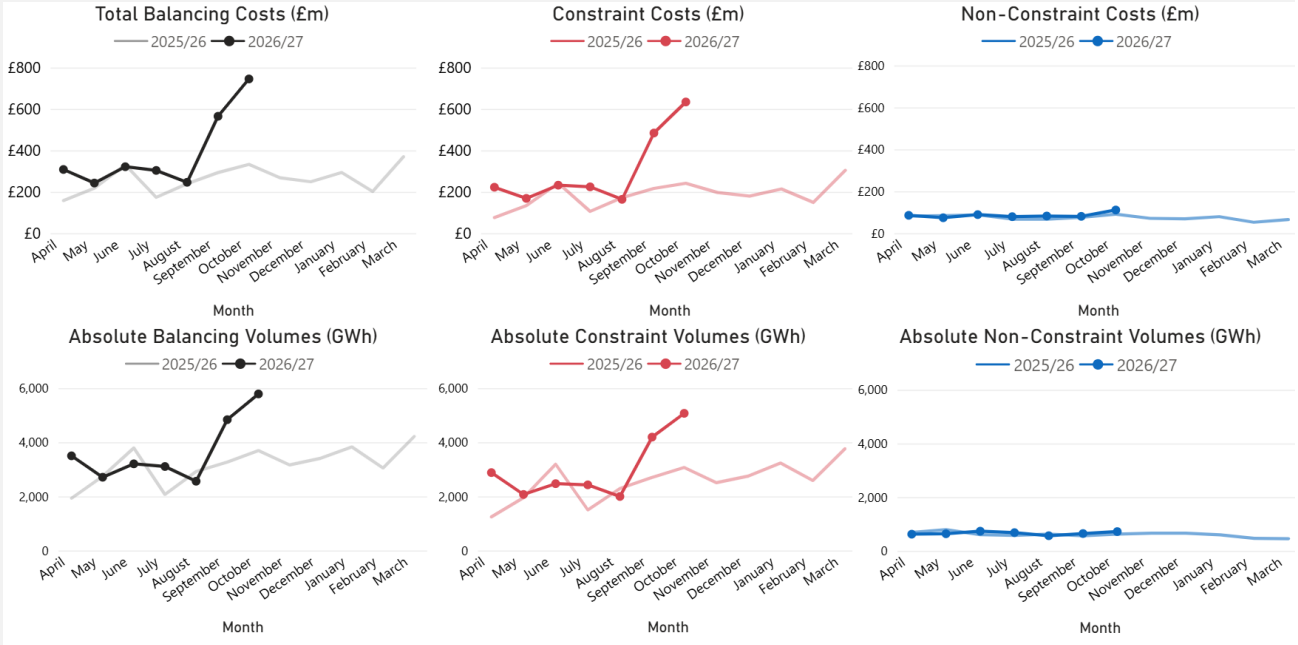
days, lower day-ahead prices reduced the incentive for gas generation to run in advance. NESO subsequently had to turn up generation through the Balancing Mechanism at higher prices. Restrictions on interconnector trading also limited the extent to which interconnectors could be used for replacement energy, increasing reliance on domestic generation, including gas.

The combined volume and price effects were sustained across the month. Very high-cost days occurred during Storm Austen and Boelo and the low-pressure system that followed, but elevated costs were seen across much of October, with more than half the month exceeding £15m per day. Constraint costs increased by £150m compared with September and accounted for much of the £192m increase in overall balancing costs. The repeated occurrence of high-cost days shows that October's increase was not driven by a single event, but by the sustained combination of high wind, network limitations and expensive replacement energy.

Non-constraint costs saw an increase month on month, with a total in October of £111m (£30m increase from September) with all categories of non-constraints increasing. This is due to more procurement of services moving into Winter, as well as these costs being influenced by the increased gas prices.

Total Balancing Costs (£m) and Balancing Volume (GWh)

monthly vs previous year



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

2. Demand Forecasting

Under NESO1 (April 2026 to March 2028), we publish demand forecasting as a Reported Metric to provide transparent reporting on forecast accuracy and how this is evolving over time. This supports our focus on high-quality system operation inputs and their effective use in real-time operational decision-making. For context, we also show comparisons with the previous year and the average of the previous five years for the same month.

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

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.

October 2026-27 performance

Figure: 2026-27 Monthly absolute MW error vs Indicative Benchmark

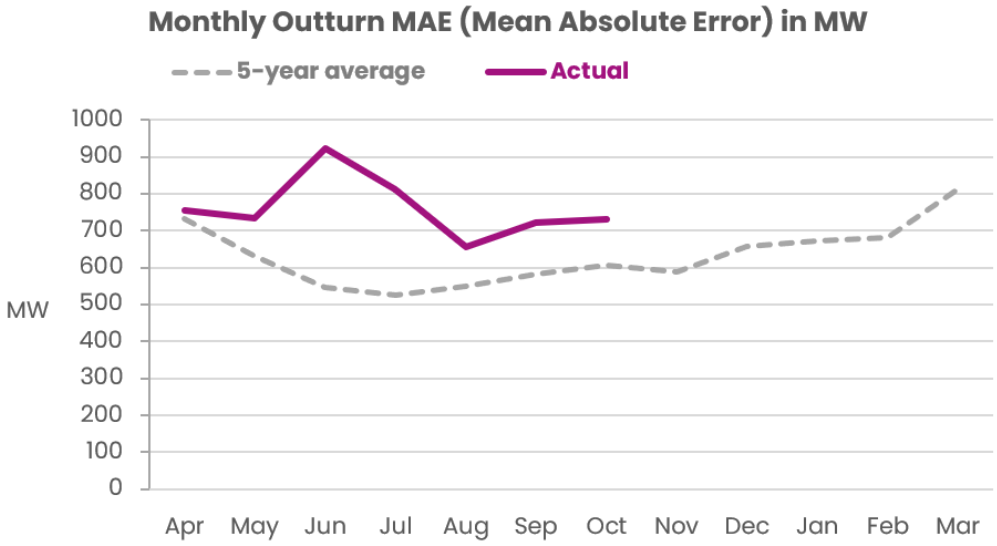


Table: 2026-27 Monthly absolute MW error vs Previous 5-year average

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Previous 5-year Average (MW)	732	630	546	525	548	583	606	588	657	671	680	813
Previous year outturn (MW)	671	692	616	584	579	702	720	641	626	662	717	985
Absolute error (MW)	**754**	**735**	**922**	**813**	**657**	**723**	**731**					

[2] Home | Insights Solution

Supporting information

In October 2026, demand forecasting error averaged 731MW, against the previous 5-year average of 606MW. YTD performance is currently 762MW, vs 5-year average of 596MW.

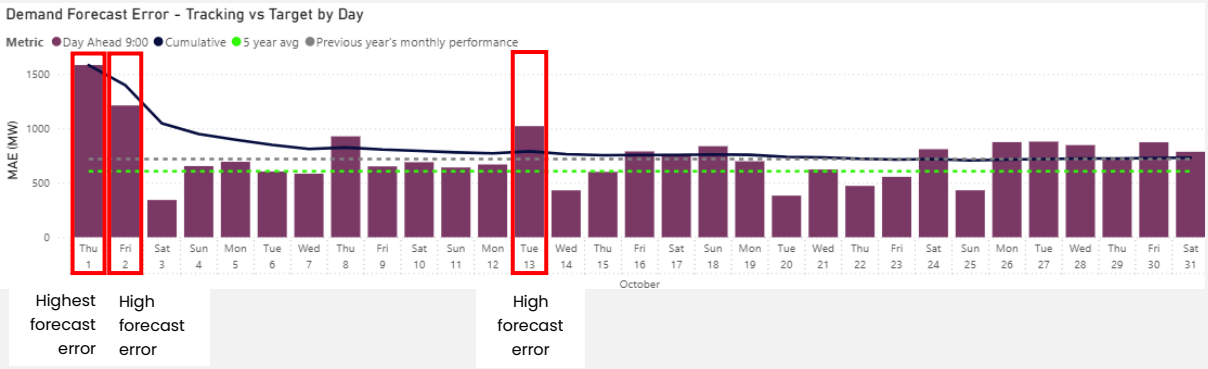
October was a mild but unsettled month. Frontal systems brought rain across much of the country throughout the first two weeks. Scotland witnessed the first snow of the season on 7 October. In the second half of the month, the first two named storms arrived; *Austen* (22-23 Oct) and *Boelo* (24-25 Oct) brought heavy rain and strong winds and disrupted supplies to many remote consumers. The last few days of the month saw fog and mist lingering in the morning, providing complex solar PV forecast conditions.

The clock change (25 October) and the coincident start of the school half-term holidays, brought the yearly forecasting uncertainty. This period is always challenging, until seasonal insights are established and machine learning models adapt.

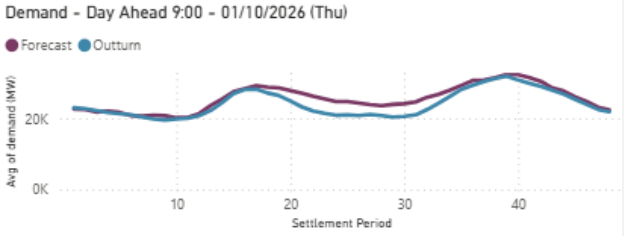
The minimum demand was 17.2GW on 4 October, SP12. The maximum demand was 37.4GW on 28 October, SP36. Solar generation peaked at 11.6GW, on 1 October, which was a record for October.

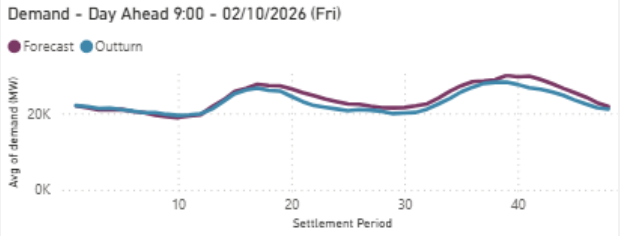
Work continues on validating our next-generation National Demand forecast models. These adopt Machine Learning/AI technology and will make use of the latest NWP (Numerical Weather Prediction) weather-grid data. NESO now aims to release the first model to production in Q3 2026-27.

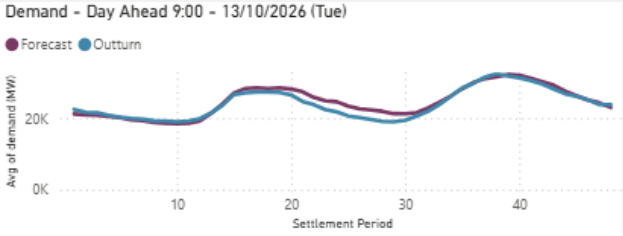
Solar continues to be the largest influence on the metric performance. The new solar models perform well under overcast or clear-sky conditions, but further weather and model improvements are necessary to cope with changing circumstances. NESO expects to release an upgrade in Q3 2026-27.



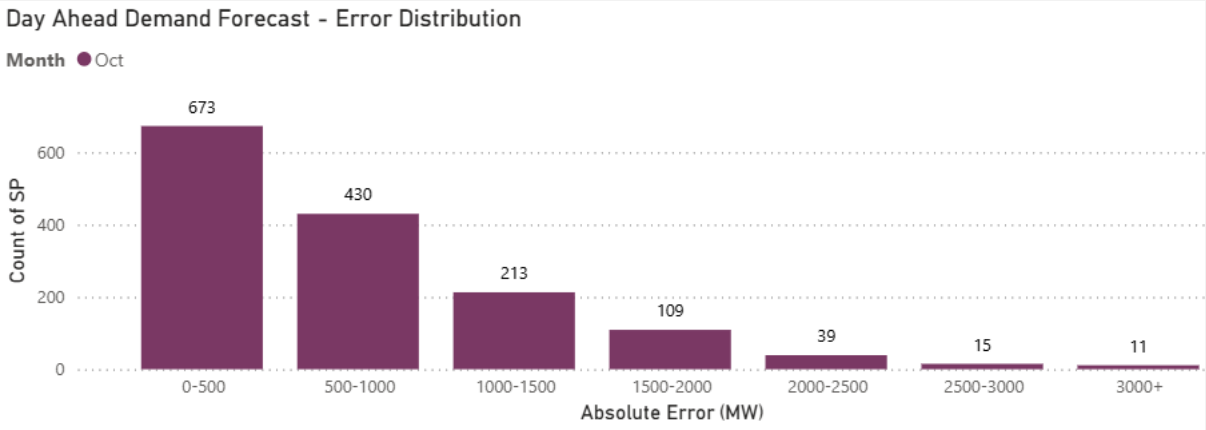
Days of Interest:



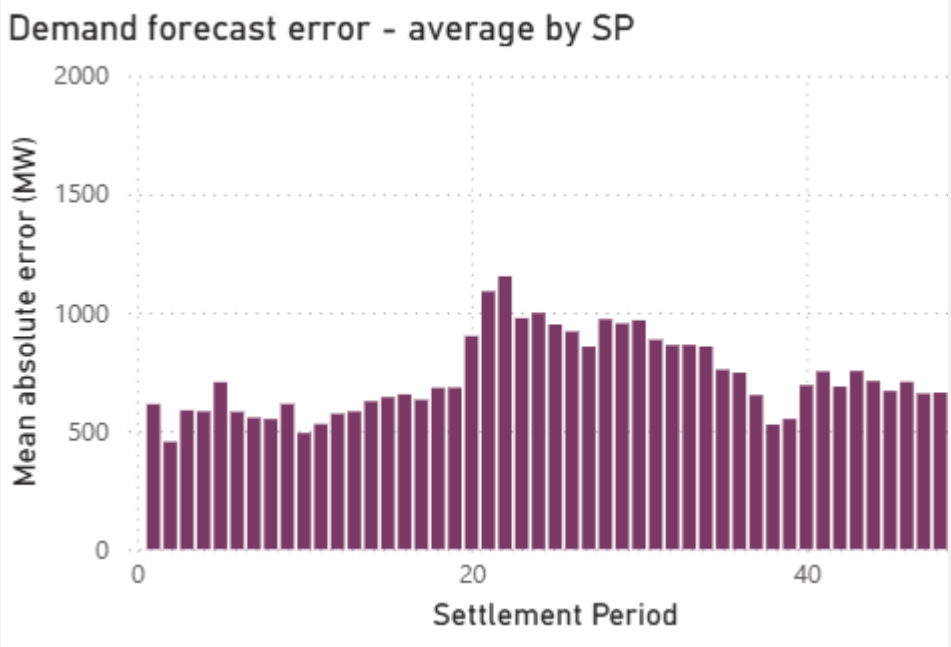




The distribution of settlement periods by error size is shown below:



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



Details of largest errors:

Day	Error (MAE)	Major causal factors
1	1584	Forecast errors due to solar PV forecast errors
2	1212	Forecast errors due to solar PV forecast errors, wind forecast errors and underlying demand

13	1022	Forecast errors due to solar PV forecast errors, wind forecast errors and underlying demand

Missed / late publications

There were no late publications in October.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 23 days in October, with an accumulated total of 3561MWh procured. These will nominally affect the national demand outturns but are not included in the day ahead forecast or metric correction.

3. Wind Generation Forecasting

Under NESO1 (April 2026 to March 2028), we publish wind generation forecasting as a Reported Metric to provide transparent reporting on forecast accuracy and how this is evolving over time. For context, we also show comparisons with the previous year and the average of the previous five years for the same month.

This Reported Metric measures the average absolute error between day-ahead forecast (between 09:00 and 10:00, as published on NESO data portal) and post-event outturn wind settlement metering (as published on the Elexon insights portal) for each half hour period as a percentage of capacity for BM wind units only. The data will only be taken for sites that:

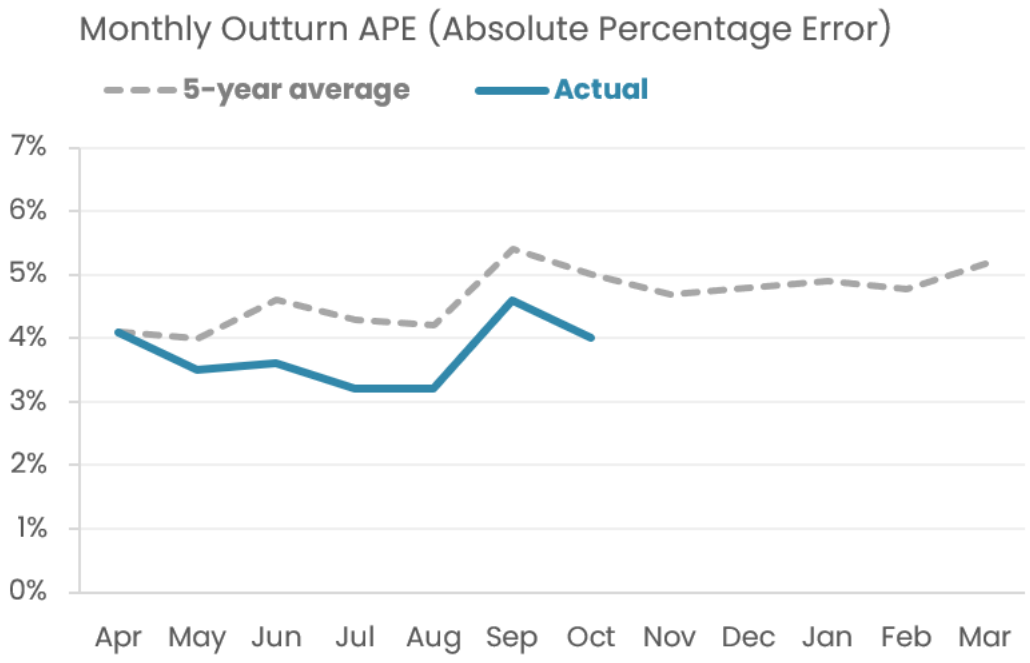
- did not have a bid-offer acceptance (BOA); and
- did not withdraw availability completely between time of forecast and time of metering; for the relevant settlement period. We publish this data on its data portal for transparency purposes.

Sites deemed to have withdrawn availability are those that:

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

October 2026-27 performance

Figure: 2026-27 BMU Wind Generation Forecast APE vs Indicative Benchmark



	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Previous 5-year average (%)	4.1	4.0	4.6	4.3	4.2	5.4	5.0	4.7	4.8	4.9	4.8	5.2
Previous year outturn (%)	3.9	4.1	5.6	3.8	4.1	5.7	4.4	5.3	4.4	4.9	4.7	4.2
APE (%)	**4.1**	**3.5**	**3.6**	**3.2**	**3.2**	**4.6**	**4.0**					

Supporting information

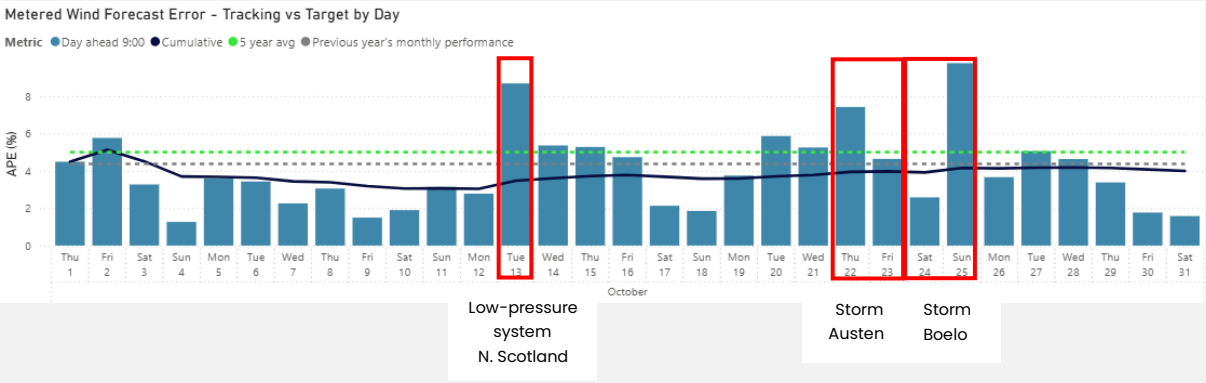
In October 2026, BMU wind forecasting error averaged 4.0%, against the 5-year average of 5.0%. YTD performance is currently 3.8%, vs 5-year average of 4.5%.

Metric-adjusted wind generation peaked at 17.2GW on 10 October, SP27.
Day Ahead Wind forecast absolute error peaked at 4.7GW on 15 October, SP45.

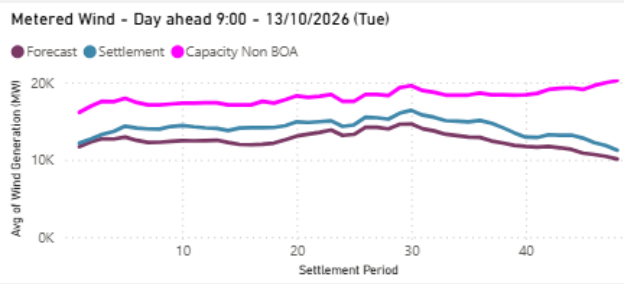
October brought the first named storms of the season, with Austen (22-23 Oct) and Boelo (24-25 Oct). Both experienced gusts >70mph across parts of the UK, with speeds exceeding 80mph during Boelo. High Speed Cut-Off values during Boelo, were forecast potentially up to 13GW.

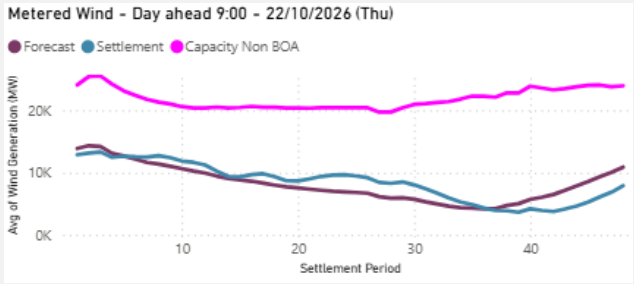
The wind models continue to perform well, but further weather-forecast and insight improvements are necessary to make significant performance gains.

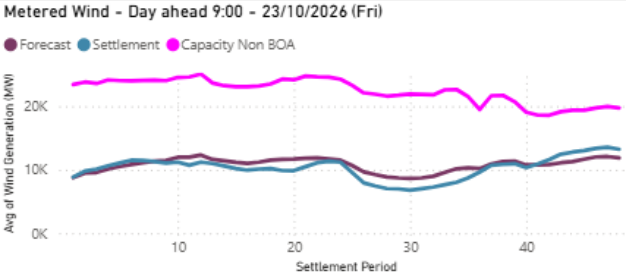
NESO aims to trial higher-resolution weather data in Q4 2026.

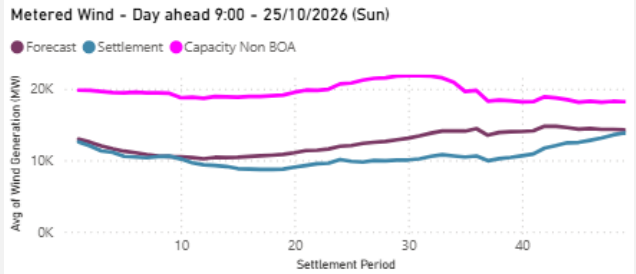


Days of Interest:

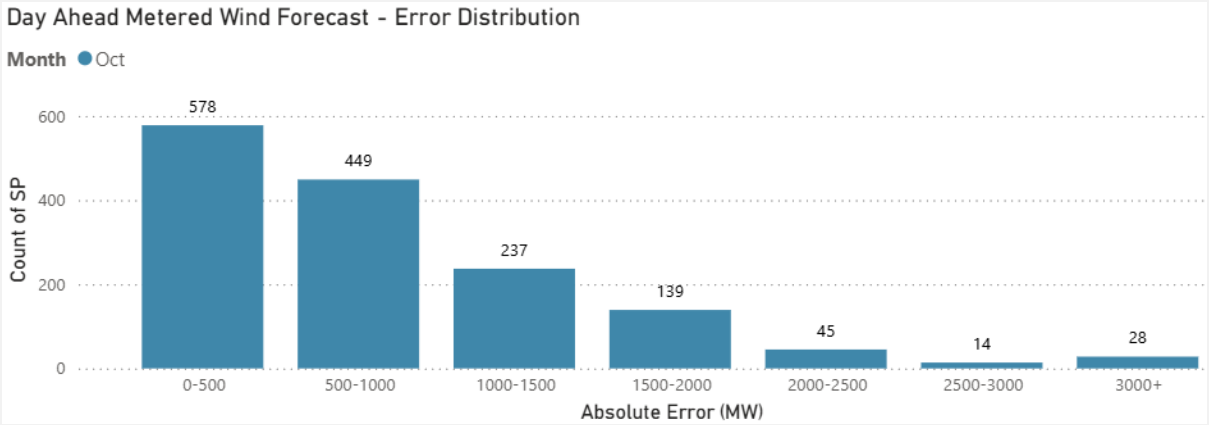




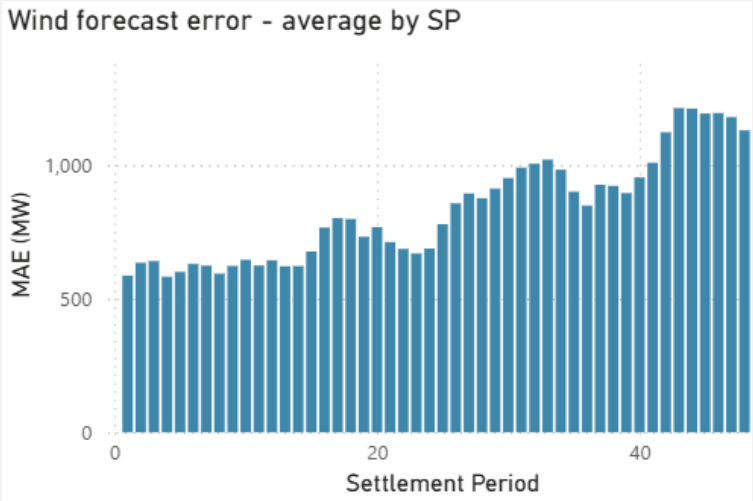




The distribution of settlement periods by error size is summarised below:



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



Details of largest errors:

Day	Error (APE)	Major causal factors
13	8.7	Wind speed forecast errors at day-ahead stage
22	7.4	Wind speed forecast errors at day-ahead stage
25	9.8	Wind speed forecast errors at day-ahead stage

Missed / late publications

There were no late publications in October.

4. Skip Rates

Under NESO1 (April 2026 to March 2028), we publish skip rates as a Reported Metric to provide transparent reporting on dispatch efficiency, key drivers of outcomes and trends over time. Alongside the data, we set out the actions we are taking, with industry, to improve performance and reduce avoidable skips.

NESO has an obligation to operate a safe, reliable and efficient system. In consultation with industry, we have developed the Energy Balancing skip rate (previously referred to as 'PSA') as a measure of dispatch efficiency of energy balancing actions. We also developed a methodology for measuring skip rates behind thermal constraints, which we will start reporting later in the year. A skip occurs when a non-economic dispatch decision is made due to the NESO Control Room sending an instruction via BOA (Bid Offer Acceptance) at a higher price than an alternative could have been taken. Some skips are unavoidable due to asset dynamics and transmission limits while others may occur as a result of optimising the lowest cost over the day.

Our aim is to provide transparency on dispatch decision-making and to work with industry to reduce avoidable skip rates over the NESO1 period, supporting efficient balancing actions and robust control room processes.

This Reported Metric currently measures the combined skip rate for bids and offers based on stage 5 of the Energy Balancing methodology. The previous target for this metric was an average rate of 30% from January to the end of June 2026. It is retained here for contextual comparison only. This methodology will be updated with necessary changes agreed with industry (e.g. incorporating new parameters as defined by GC0166). More information on the skip rate definition and methodology can be found here.

Graph: 2025-27 Monthly % Energy Balancing Skip rate Offers and Bids

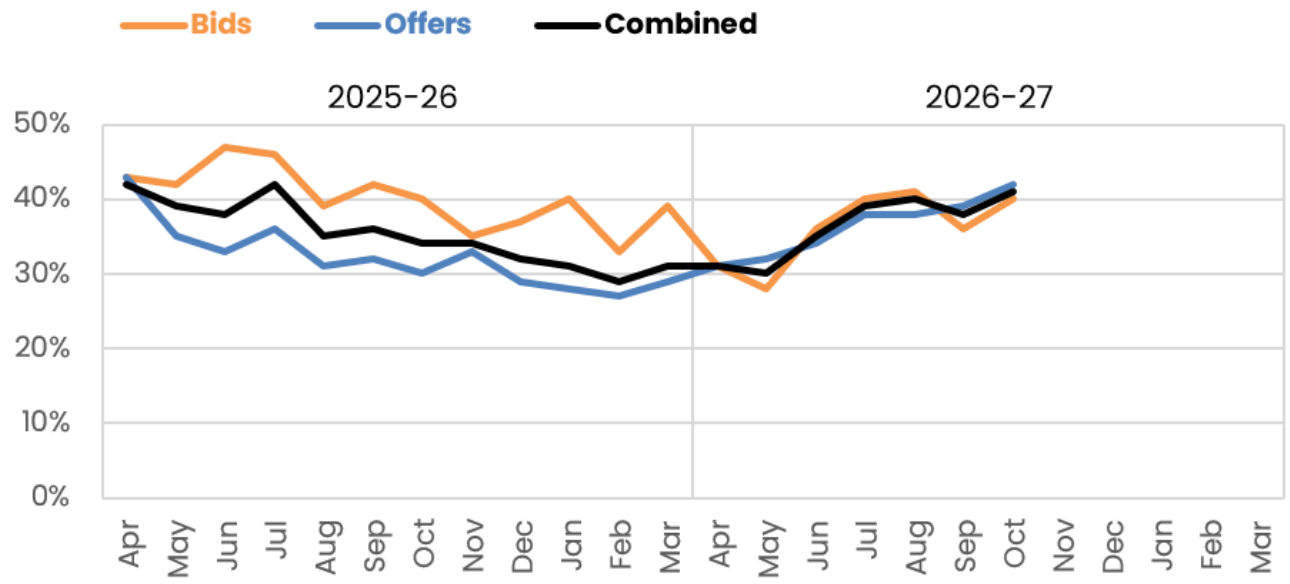


Table: 2026-27 Monthly % Energy Balancing Skip rate Offers and Bids

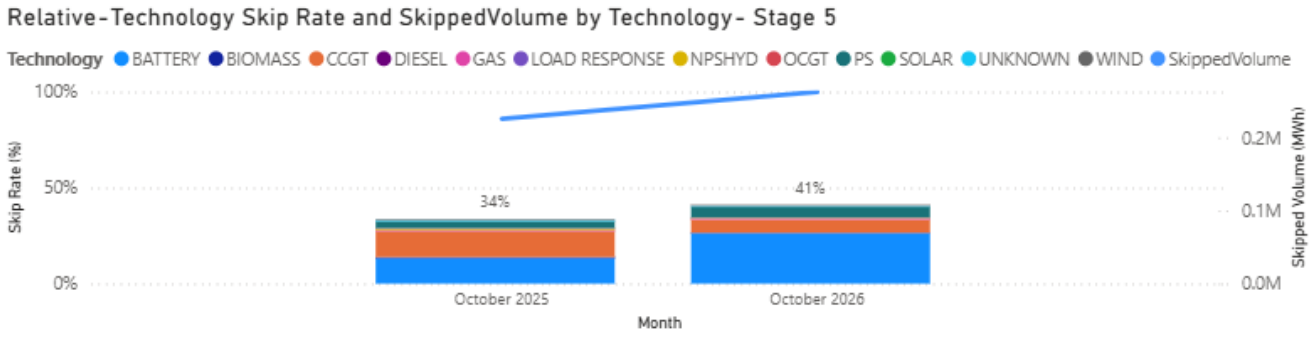
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Offers	31%	32%	34%	38%	38%	39%	42%					
Bids	31%	28%	36%	40%	41%	36%	40%					
Combined	31%	30%	35%	39%	40%	38%	41%					

Average skip rate January-June: (vs target of 30%): **31%**

Energy Balancing Skip Rate: October 2025 versus October 2026

The combined Energy Balancing skip rate increased from 34% in October 2025 to 41% in October 2026, a rise of 7 percentage points. Skipped volume increased by 16%, from 226 GWh to 262 GWh, while in-merit volume fell by 5%, from 672 GWh to 638 GWh. The increase therefore reflected both a higher volume being skipped and a smaller in-merit volume against which it was measured.

Beneath this headline, the technology mix changed substantially. Batteries account for a greater proportion of skipped volume, while CCGTs account for a smaller proportion. However, CCGT's technology-specific skip rate increased, illustrating that the smaller proportion of skipped volume is due to a similar reduction of in-merit volume.

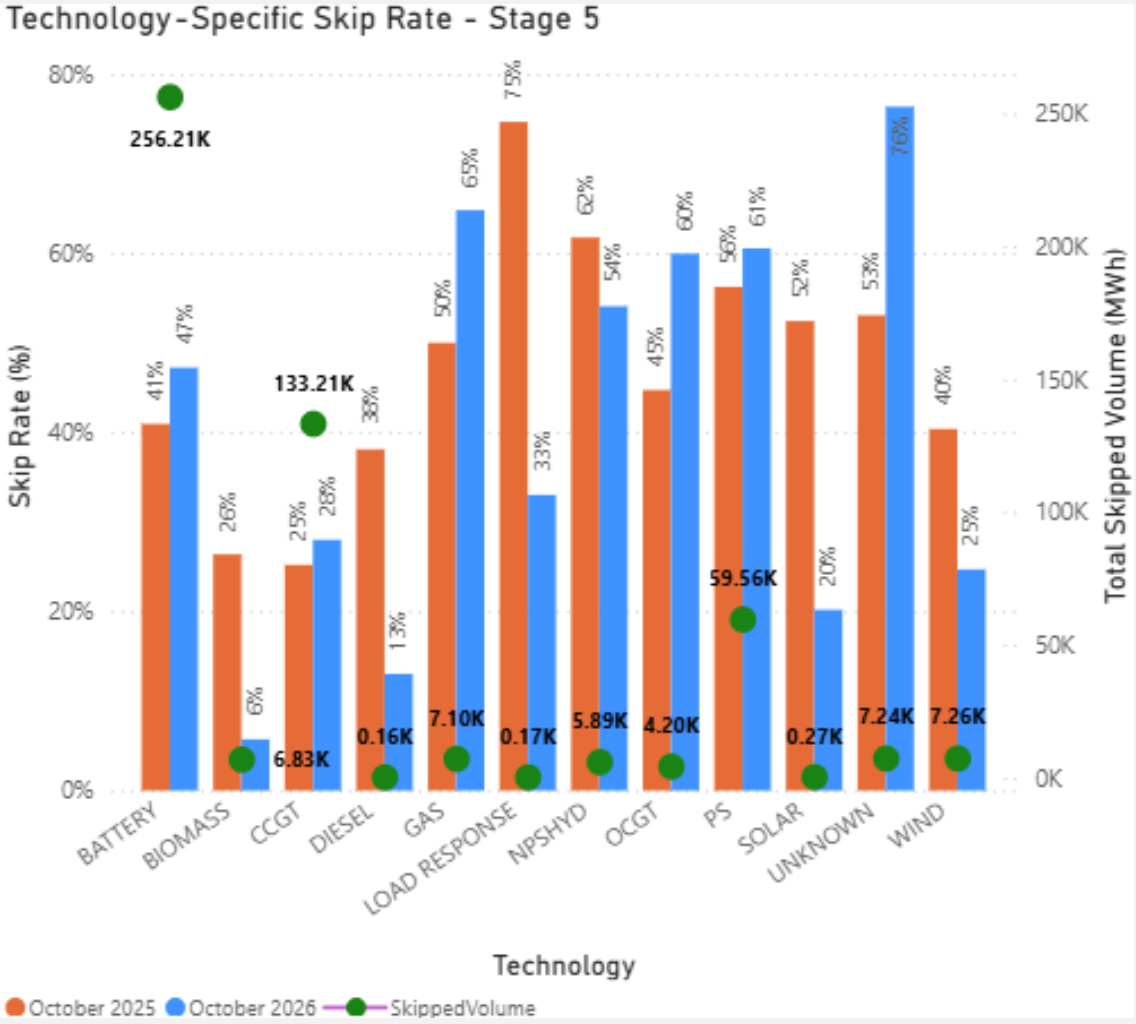


Supporting information

OCTOBER PERFORMANCE – COMBINED BIDS AND OFFERS

The combined bid and offer skip rate increased to 41% in October, from 38% in September. Overall balancing volumes remained broadly stable, with in-merit volume unchanged at around 638 GWh, while skipped volume increased by 9%, from 240 GWh to 262 GWh. As a result, the increase in skipped volume against stable in-merit activity drove the higher headline skip rate. The main driver behind the increase in skip rate was CCGTs being accepted out of merit. These units were typically instructed to create margin, across a month that had several days with high variation of demand, wind & solar forecast vs outturn. Operational decisions were also taken to deliberately skip Battery offers at times when they were charging to create positive headroom and preserve state of charge and flexibility for periods of greater system need.

At a technology level, battery bid volume remained broadly flat at 171 GWh, compared with 170 GWh in September. However, battery skipped volume increased by 8%, from 155 GWh to 168 GWh, with the technology-specific skip rate consequently rising from 43% to 47%. In contrast, CCGT skipped volume fell by 5%, from 45 GWh to 43 GWh, although its technology-specific skip rate increased from 24% to 28%. Pumped Storage saw an increase in balancing activity, with in-merit volume rising from 32 GWh to 58 GWh and skipped volume increasing from 19 GWh to 35 GWh. Despite these higher volumes, its technology-specific skip rate remained broadly stable at around 60%.



The combined technology-specific skip rate changed materially between October 2025 and October 2026. CCGT and Battery accounted for the largest skipped volumes in October 2025, at 91 GWh and 89 GWh respectively, but by October 2026 Battery had become the clear largest contributor. Battery's skip rate increased from 41% to 47% (+6pp), as in-merit volume rose from 217 GWh to 355 GWh (+64%) and skipped volume increased from 89 GWh to 168 GWh (+89%). In contrast, CCGT activity reduced substantially: in-merit volume fell

from 359 GWh to 153 GWh (-58%) and skipped volume from 91 GWh to 43 GWh (-53%), although its skip rate increased from 25% to 28% (+3pp).

Conclusion

The combined skip rate increased from 38% in September to 41% in October 2026, against a mixed picture across individual technologies. Battery remained the largest contributor to skipped volume, with its skip rate increasing from approximately 43% to 47% (+4pp). Its skipped volume rose from 155 GWh to 168 GWh, while in-merit volume decreased slightly from 361 GWh to 355 GWh (-2%). CCGT also saw its skip rate rise from approximately 24% to 28% (+4pp). This coincided with a 17% reduction in in-merit volume, from 184 GWh to 153 GWh, compared with a smaller 5% reduction in skipped volume, from 45 GWh to 43 GWh. Gas recorded the largest increase among these technologies, with its skip rate rising from approximately 55% to 65% (+10pp).

Note: In the technology specific skip rate graph 'Gas' refers to gas reciprocating units, which are typically small, aggregated units. 'Load Response' is based on the fuel type category used by Elexon. These are typically Demand Side Flexibility (DSF) units. We have published a dedicated dataset to report skip rates for DSF units and incorporated this into our external dashboard.

Please visit our website for the latest skip rates dashboard.

5. Security of Supply

Under NESO1 (April 2026 to March 2028), we publish security of supply as a Reported Metric to provide clear, accessible transparency on system security outcomes and trends over time. Reporting focuses on frequency and voltage excursions, the drivers behind them, and the actions we are taking to manage and mitigate risks to secure operation.

This Reported Metric shows when the frequency of the electricity transmission system deviates more than ± 0.3Hz away from 50 Hz for more than 60 seconds, and where voltages are outside statutory limits. On a monthly basis we report instances where:

- The frequency is more than ± 0.5Hz away from 50 Hz for more than 60 seconds
- The frequency was 0.3Hz - 0.5Hz away from 50Hz for more than 60 seconds.
- There is a voltage excursion outside statutory limits. For nominal voltages of 132kV and above, a voltage excursion is defined as the voltage being more than 10% away from the nominal voltage for more than 15 minutes, although a stricter limit of 5% is applied where voltages exceed 400kV.

Excursion events are categorised as Secured and Unsecured under SQSS:

Secured under SQSS:	Excursions resulting from events that the GB transmission system is secured against, i.e., voltage and frequency expected to remain within statutory and licence obligations.
Unsecured under SQSS	Excursions resulting from exceptional or catastrophic system contingencies, such as simultaneous or cascading trips and events caused by natural disasters, catastrophic infrastructure failures, among other causes that are explicitly outside the SQSS security criteria where system operation outside statutory and licence obligations is not preventable or secured for.

For context, the Frequency Risk and Control Report 2025 defines the appropriate balance between cost and risk, and sets out tabulated risks of frequency deviation as below:

Scenario	120 GVA.s	102 GVA.s
49.5 Hz event	3.48 times per year	3.49 times per year
49.2 Hz event	1-in-10.71 years	1-in-10.70 years
48.8 Hz event	1-in-27.94 years	1-in-27.87 years
50.5 Hz event	1-in-88.21 years	1-in-88.28 years

Also, for additional context here are the figures from the Frequency Risk and Control Report 2024:

Scenario	140 GVA.s	120 GVA.s	110 GVA.s	102 GVA.s
49.2 Hz event	1-in-27 years	1-in-27 years	1-in-27 years	1-in-27 years
48.8 Hz event	1-in-30 years	1-in-30 years	1-in-30 years	1-in-30 years

At the end of each year, we report on compliance with frequency control methodology and plans for any future changes to the methodology.

October 2026-27 performance

Table: Frequency and voltage excursions (2026-27)

		2026-27											
		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)	Secured under SQSS	0	0	-	0	0	0	0					
	Unsecured under SQSS	0	0	-	0	0	0	0					
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds*		0	1	-	0	0	0	0					
Voltage Excursions defined as per Transmission Performance Report2F.[3]	Secured under SQSS	0	0	-	0	0	0	0					
	Unsecured under SQSS	0	0	-	0	0	0	0					

*These frequency excursions do not fall under the statutory and licence reporting obligations but are provided for transparency.

+June data will be published on completion of Eversheds Sutherland International investigation and Ofgem review.

Supporting information

No reportable voltage or frequency excursions during October.

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

6. CNI Outages

Under NESO1 (April 2026 to March 2028), we publish CNI outages as a Reported Metric to provide clear, accessible transparency on service availability outcomes and trends over time. This reporting supports our focus on whole system resilience by helping stakeholders understand the number, duration and drivers of planned and unplanned outages, alongside the actions we are taking to reduce outage risk and improve resilience.

This Reported Metric shows the number and length of planned and unplanned outages to Critical National Infrastructure (CNI) IT systems.

The term 'outage' is defined as the total loss of a system, which means the entire operational system is unavailable to all internal and external users.

October 2026-27 performance

Table: 2026-27 Unplanned CNI System Outages (Number and length of each outage)

	2026-27											
Unplanned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	1 outage 125 mins	0	0					
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0					

Table: 2026-27 Planned CNI System Outages (Number and length of each outage)

	2026-27											
Planned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	1 outage 115 mins	1 outage 206 mins	0	0	1 outage 190 mins					
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0					

Supporting information

In October 2026 there was one planned CNI system outage. The outage was to implement enhanced functionality and carry out regular maintenance activities on the BM production systems and impacted the key BM Suite components used for scheduling and dispatch of generation.

This change took place 22 October, and was planned in advance, in collaboration with our control rooms to ensure it did not introduce a conflict with other known periods of high activity. Notifications are posted to the industry, via BMRA, at 7 days prior and 1 day prior.

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

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

There were no other planned outages during October.

There were no unplanned outages during October.

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