ESO RIIO2 Business Plan 2 (2023-25)

November 2023-24 Incentives Report

19 December 2023

Contents

Introduction

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

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

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

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

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

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

Following our Business Plan 2 (BP2) submission, Ofgem outlined the requirement for a Cost Monitoring Framework (CMF). The objective of the CMF is to provide visibility of our BP2 Digital, Data and Technology (DD&T) delivery progress and cost management, and the value being delivered across the BP2 DD&T investment portfolio. As per the ESORI guidance, we are required to provide quarterly reports directly to Ofgem as part of the CMF. We feel it is important to share updates with our external stakeholders and industry as part of the framework. So, we'll be including a summary of the CMF update every six months alongside our incentives reporting.

Please see our website for more information.

Summary of Notable Events

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

- On 28 November we hosted our fourth Balancing Programme engagement event, where we confirmed the launch of the Open Balancing Platform (OBP). The event was extremely well received by stakeholders with attendees giving an average score of 8.3 out of 10 for the overall event, marking an improvement on our previous score for the June event of 7.8.
- On 8 November we held our annual Markets Forum, which was attended by 150 industry stakeholders. We also announced that we now plan to hold the Markets Forum four times a year. Two of these events will consist of a virtual pre-recorded webinar with a live Q&A session a week later, and two will be in person with the facility to livestream the main presentation.
- On 16 November we activated the first test Demand Flexibility Service (DFS) event of the winter and on 29 November we activated the first live DFS event of the winter. By the time of the live event there were over 1.8million households and businesses able to participate in DFS through 20 providers.
- On 2 November, the first round of auctions on the new Enduring Auction Capability (EAC) platform took place. We received bids from 23 participants with a total of 109 units, with co-optimisation and overholding delivering great results.
- On 13 November, Ofgem approved new rules for the ESO to proactively manage the connections queue. Our Director of the Electricity System Operator, Fintan Slye, provided an open letter to the industry. This enables us to proactively manage the connections process with the ability to terminate projects that are not progressing against their project milestones. This is a key component of our five-point plan to speed up grid connections.

Summary of Metrics and RREs

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) for November 2023.

Metric/RRE		Performance	Status
Metric 1A	**Balancing Costs**	£224m vs benchmark of £264m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 526MW vs indicative benchmark of 571MW	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 5.16% vs indicative benchmark of 5.06%	●
Metric 1D	**Short Notice Changes to Planned Outages**	6 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	●
RRE 1E	**Transparency of Operational Decision Making**	86.6% of actions taken in merit order or driven by an electrical parameter	N/A
RRE 1G	**Carbon intensity of ESO actions**	3.7gCO_2/kWh of actions taken by the ESO	N/A
RRE 1I	**Security of Supply**	0 instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	1 planned and 0 unplanned system outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 0.04%	N/A

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

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

Adelle Wainwright
Acting ESO Regulation Senior Manager

Role 1 (Control Centre operations)

Metric 1A Balancing cost management

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

A new benchmark has been 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 has been 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 established between historic non-constraint costs and the historic wholesale day ahead price of electricity.
iv. Ex-post actual data inputted 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 = 54.48 + (Day Ahead baseload x 0.52)
Constraint costs = -32.66 + (Day Ahead baseload x 0.34) + (Outturn wind x 25.72)

Benchmark (Total) = 21.82 + (Day Ahead baseload x 0.86) + (Outturn wind x 25.72)

**Constants in the formulas above are derived from the benchmark model*

ESO Operational Transparency Forum: The ESO hosts a weekly forum that provides additional transparency on operational actions taken in previous weeks. It also gives industry the opportunity to ask questions to our National Control panel. Details of how to sign up and recordings of previous meetings are available here.

November 2023-24 performance

Figure 1: 2023-24 Monthly balancing cost outturn versus benchmark

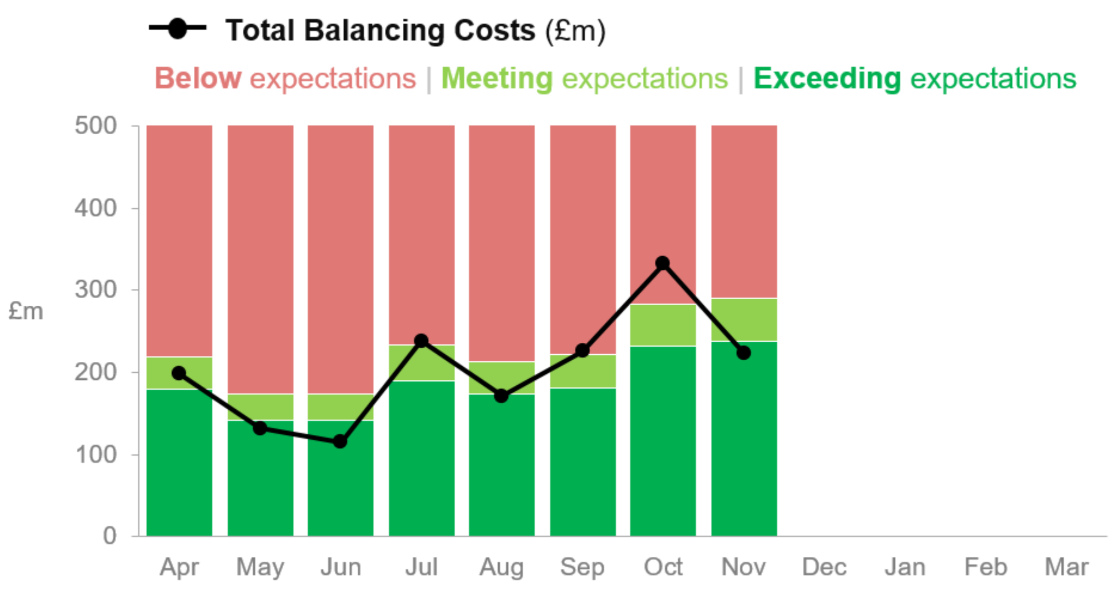


Table 1: 2023-24 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	3.4	2.6	2.4	4.6	3.8	4.2	6.2	6.1					33.28
Average Day Ahead Baseload (£/MWh)	105	81	87	82	86	83	89	99					n/a
Benchmark	200	157	158	212	194	201	258	264					1643
Outturn balancing costs[1]	**198**	**132**	**115**	**238**	**171**	**226**	332	224					**1637**
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

Ongoing data issue:

Please note that due to a data issue, over the previous months the Minor Components line in Non-Constraint Costs is capturing some costs which should be attributed to different categories. It has been identified that a significant portion of these costs should be allocated to the Operating Reserve Category. Although the categorisation of costs is not correct, we are confident that the total costs are correct in all months.

We continue to investigate and will advise when we have a resolution.

[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.

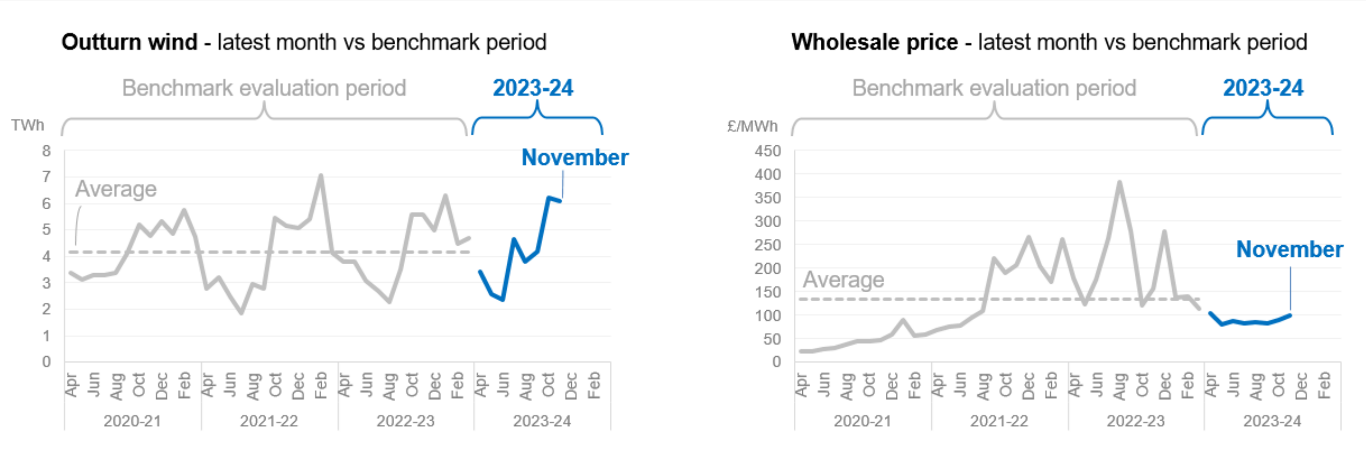
This month's benchmark

As noted in the introduction to this section, a new benchmark was introduced for BP2. The benchmark is derived using the historical relationships between two drivers (wholesale price and outturn wind generation) and balancing costs.

The November benchmark of £264m is the highest so far in 2023-24, and this reflects:

- an **outturn wind** figure that fell slightly this month but remains very high compared to the benchmark evaluation period (the last three years). Only two months in the entire benchmark period had higher outturn wind than the last two months.

- a continued relatively low average monthly **wholesale price** (Day Ahead Baseload) compared to the benchmark evaluation period (the last three years), although this month's figure is the highest since April 2023.



November performance

November's total balancing costs were £224m which is £40m (18%) below the benchmark of £264m, and therefore performance is exceeding expectations. Although November's overall outturn wind was broadly in line with October, wind output in Scotland decreased significantly, which was offset by a big increase in England and Wales. As a result of the lower wind in Scotland, there were significantly lower constraint costs in November compared to October. October was a particularly difficult month in managing constraints, with major storms and significant forecasting errors for wind generation. Scottish thermal constraints were ~£153m in October compared to ~£76m in November. There were two high-cost days that occurred in November (22nd and 23rd), which were a result of particularly high wind generation in Scotland, and Scottish boundary reductions (B4/5 boundary was at ~50% capacity and B6 boundary was at 70%) resulting in 19% wind curtailment on the 22nd.

This ongoing performance is possibly due to our commitment to minimising costs to consumers through all Control Room decisions in operational timescales which is enabled by the wide range of activities outlined in our balancing costs strategy and portfolio of activities. This includes trading outside of the balancing mechanism for which benefits total £47m this month and optimising network outages for which benefits total £55m this month. For example, the ESO team that manages outage optimisations managed to improve a circuit configuration during a specific outage that improved a boundary capacity at Keadby by 800 MW in November. This produced calculated savings of nearly £3.5m. Our trading team was able to save just over £34m this month from margin trades, and a further £13m in voltage trades.

Breakdown of costs vs previous month

Balancing Costs variance (£m): November 2023 vs October 2023

		(a) Oct-23	(b) Nov-23	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	21.7	5.2	(16.6)	
	Operating Reserve	19.9	23.4	3.5	
	STOR	3.1	3.2	0.1	
	Negative Reserve	1.2	1.0	(0.2)	
	Fast Reserve	16.8	14.6	(2.2)	
	Response	22.2	19.3	(2.8)	
	Other Reserve	1.6	1.6	0.0	
	Reactive	15.0	14.4	(0.6)	
	Restoration	7.9	2.9	(5.0)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	12.3	11.6	(0.8)	
Constraint Costs	Constraints - E&W	42.1	33.0	(9.1)	
	Constraints - Cheviot	1.5	3.7	2.2	
	Constraints - Scotland	112.7	54.7	(58.0)	
	Constraints - Ancillary	0.2	0.1	(0.1)	
	ROCOF	10.4	6.6	(3.9)	
	Constraints Sterilised HR	44.5	28.9	(15.6)	
Totals	Non-Constraint Costs - TOTAL	121.6	97.1	(24.5)	
	Constraint Costs - TOTAL	211.4	127.1	(84.3)	
	Total Balancing Costs	**333.1**	**224.2**	**(108.8)**	

As shown in the total rows from the table above, both non-constraint & constraint costs decreased by £24.5m & £84.3m respectively, resulting in an overall decrease of £108.8m compared to October 2023.

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

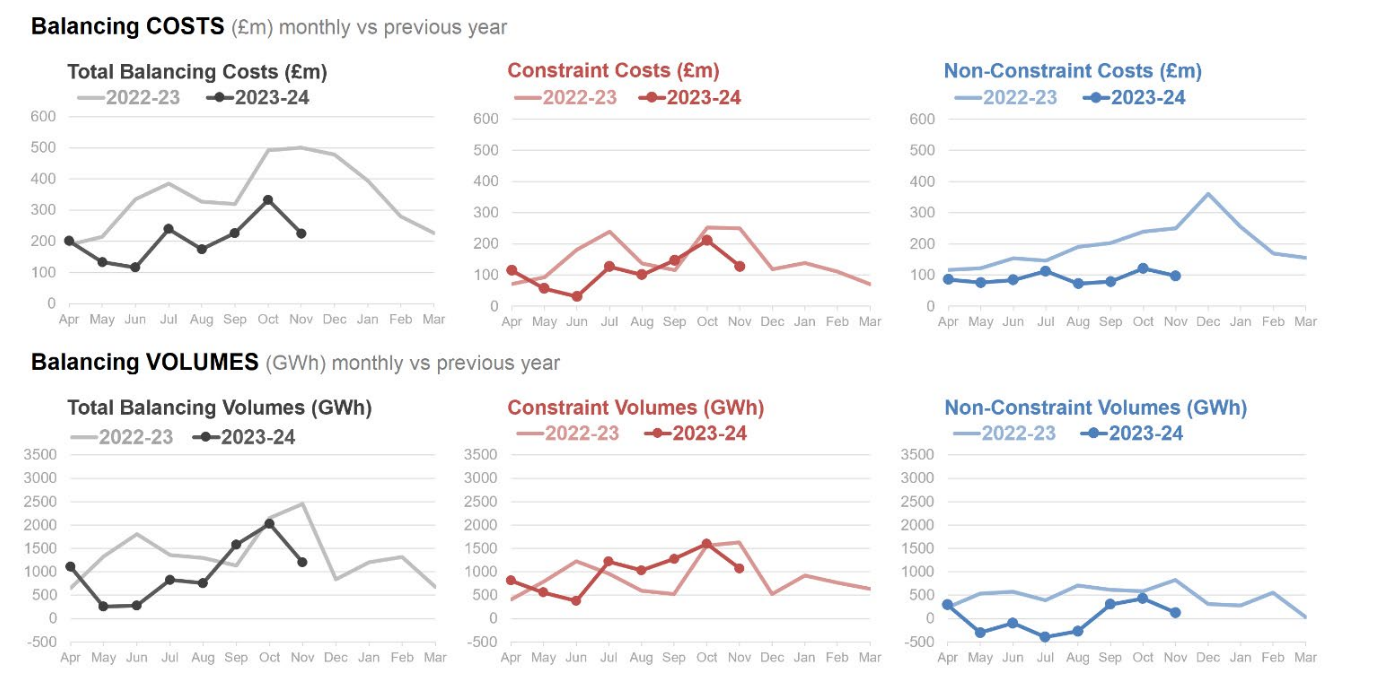
- **Constraint-Scotland & Cheviot***: £55.8m decrease, as lower wind generation in Scotland (~1GWh) resulted in a lower volume of thermal constraint actions (~400GWh) than the previous month.
- **Constraint-England & Wales***: £9.1m decrease, around 123GWh less than the previous month.
- **Constraints Sterilised Headroom**: £15.6m decrease. Cost decrease is in line with the decrease of constraint actions because less headroom had to be replaced using Balancing Mechanism (BM) outside the constraint.

*33 fewer outages compared to last month

Non-constraint costs: The main driver of the biggest difference this month is:

- **Energy Imbalance**: £16.6m decrease, due to 16GWh less from the absolute amount of energy required to balance the system this month compared to the previous month.
- **Operating Reserve**: £3.5m increase due to 4GWh more reserve required to secure the system.

Constraint vs non-constraint costs and volumes



Please note that a portion of the **Minor Components** spend contributing to non-constraint cost and volume is mainly Operating Reserve cost and volume. The narrative below discusses the broad themes of spend. The figures will be revised once the data issue is resolved.

Constraint costs

Compared with the same month of the previous year:	Constraint costs were £123m lower than in November 2022, due to: • Lower average wholesale prices* • Lower Volume of actions (557 GWh less – despite the fact of 36 more outages).
Compared with last month:	Constraint costs were £84m lower than in October 2023 due to: • A decrease in volume of actions, 526GWh less were required to manage constraints • 33 outages fewer

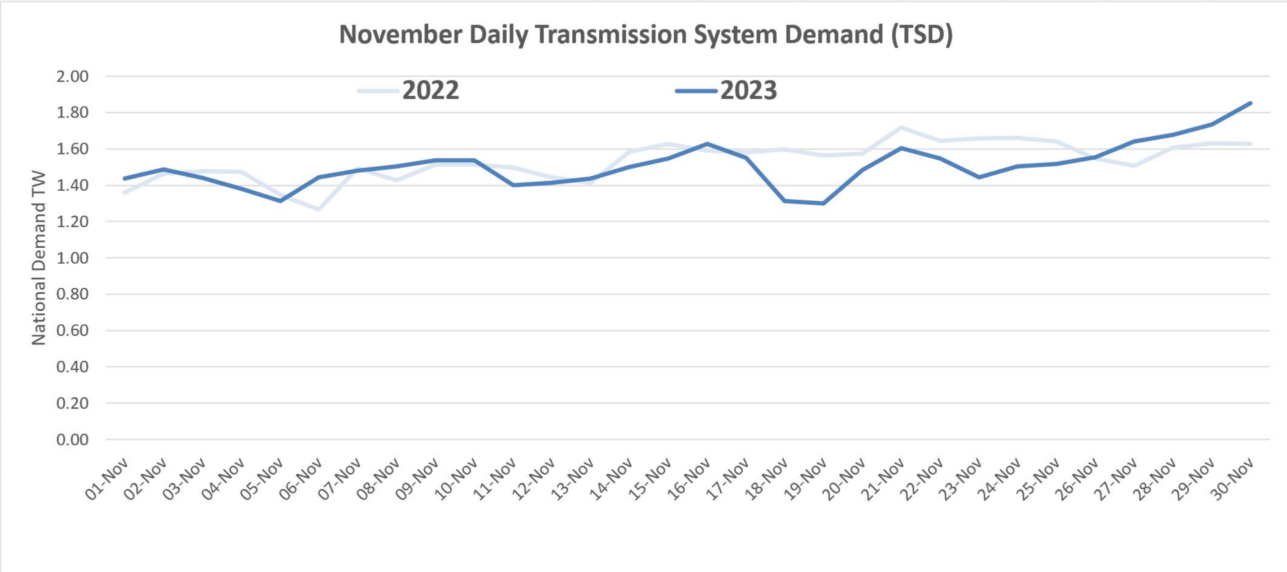
Non-constraint costs

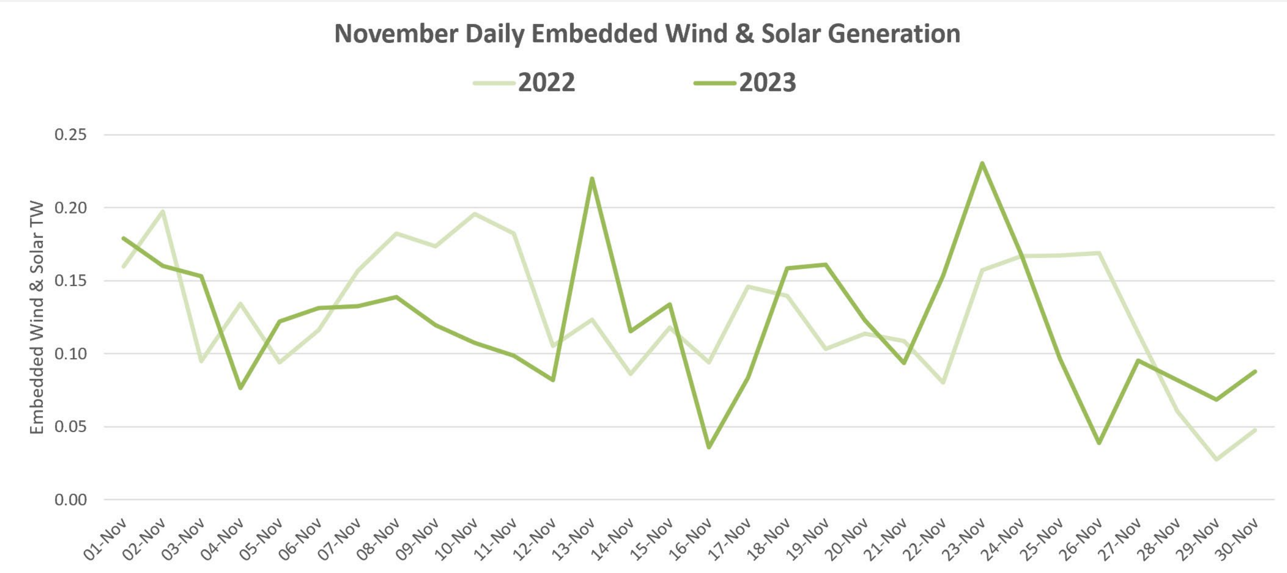
Compared with the same month of the previous year:	Non-Constraint costs were £153m lower than in November 2022 due to: • Lower average wholesale prices* • 692 GWh lower Volume of actions
Compared with last month:	Non-Constraint costs were £25m lower than in October 2023 due to: • 302 GWh lower** volume of actions ** The Non-Constraint category consists of several subcategories including energy imbalance, response, reserve, and restoration.

* Average wholesale price for November-23 is £91/MWh compared to £136/MWh for November-22.

October daily Transmission System Demand (TSD*), Embedded Wind and Solar Generation

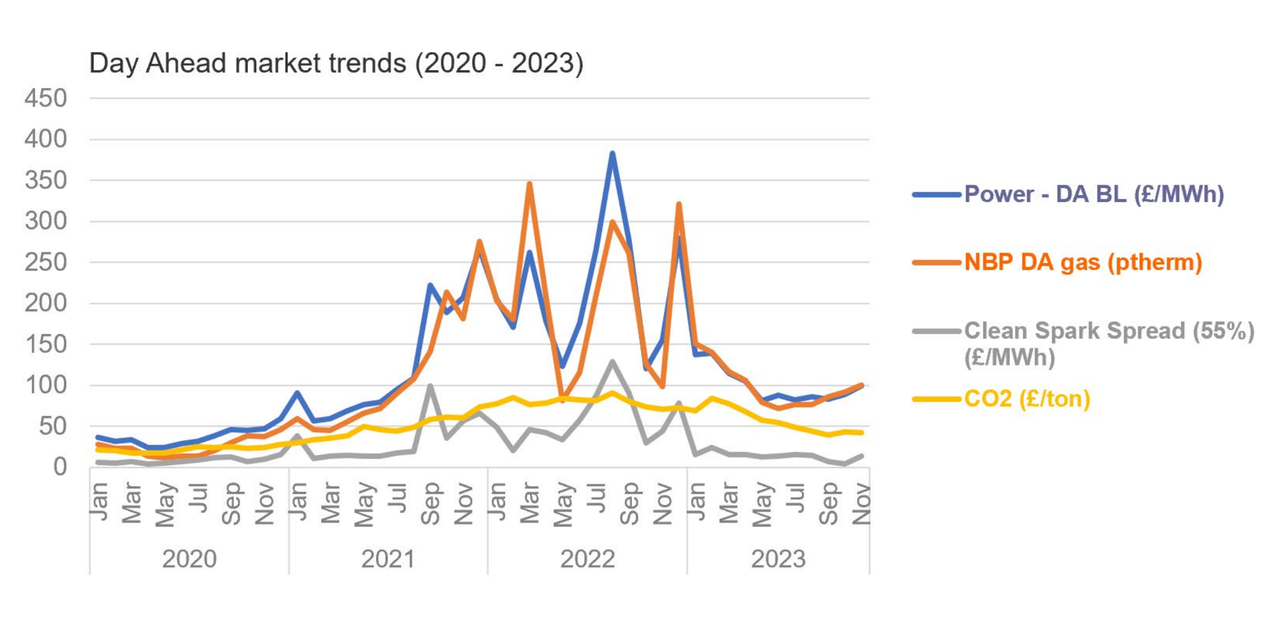
- **National Demand** (not shown below) was 2.4TW higher than the same period last year
- **Transmission System Demand*** was 850GW lower than November 2022.
- **Embedded wind & solar generation** was 169GW lower than the corresponding period last year.





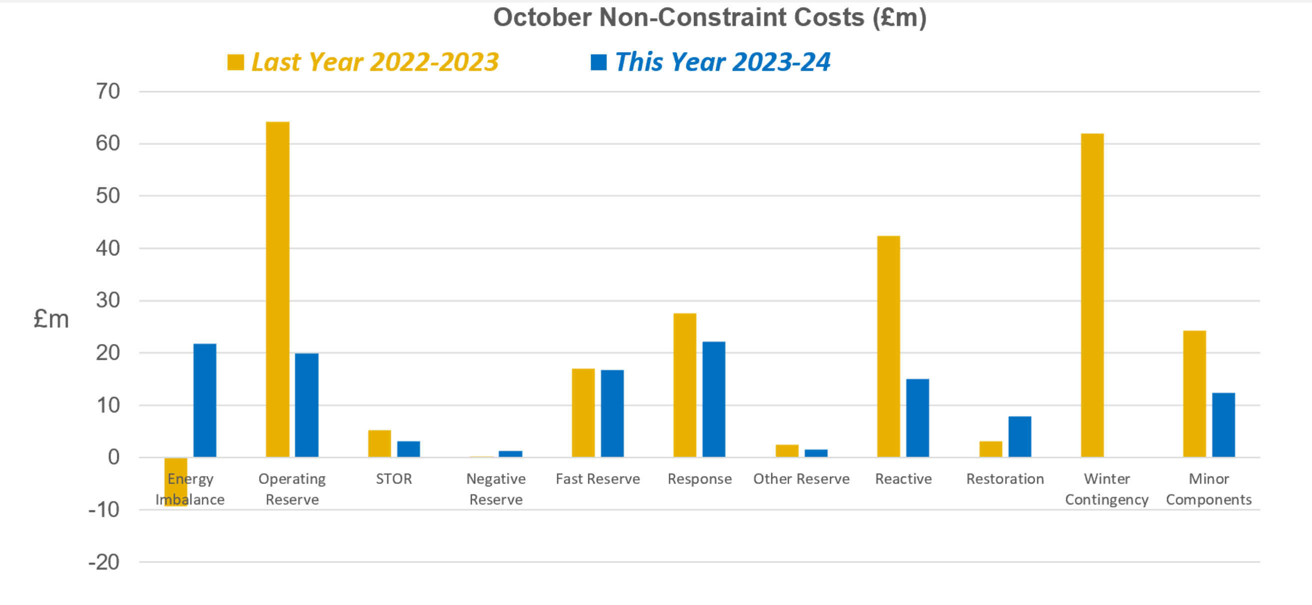
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand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

Changes in energy balancing costs



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

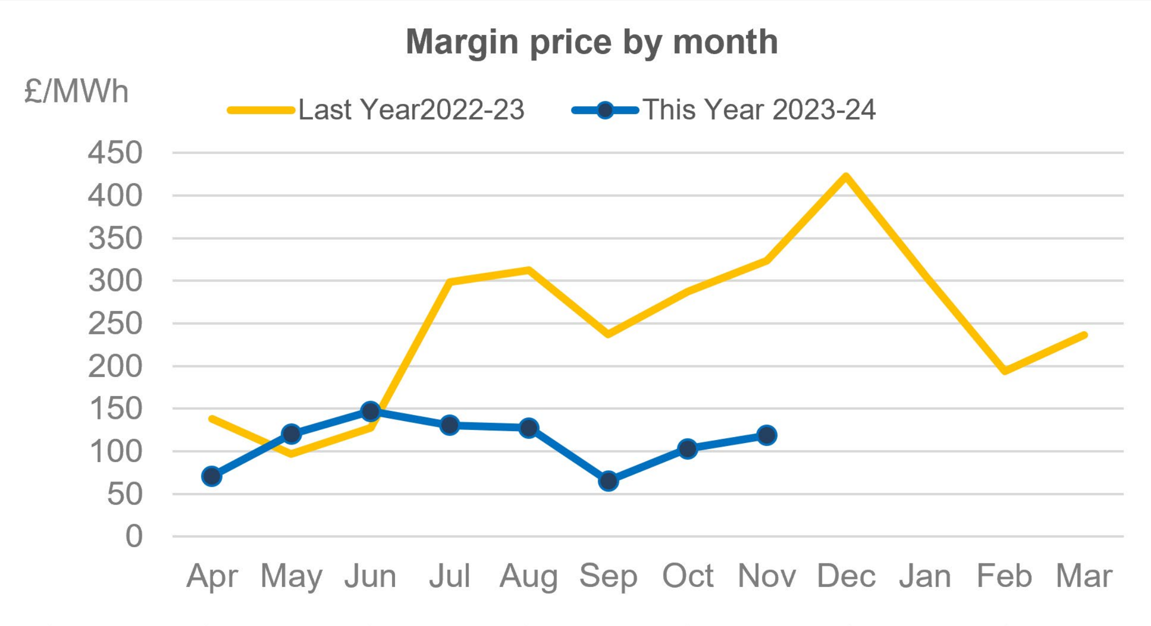
Most of the trends had a small upward deviation compared to last month with a slight increase (£10/MWh) in the Clean Spark Spread (CSS). They all remain lower compared to the previous year.



Comparing the non-constraint costs of November 2023 with those of November 2022, most categories showed a decrease:

- **Energy Imbalance** £14.1m increase due to ~96GWh more volume of actions taken to balance the system.
- **Operating Reserve** £36.4m decrease due to ~250GWh less volume of actions taken to secure the system and the lower average wholesale prices.
- **Reactive** £22.6m decrease despite the higher volume of MVAR required this November, due to a significant drop in the weighted average price (from £12.5 per MVAR to £4.7 per MVAR)
- **Minor Components** decreased by £31.4m. Last year's excessive cost contained incorrectly allocated cost from operating reserve that we have identified in the last end of the year report.

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for one MWh) have increased compared to October 2023, but it is significantly lower than the corresponding period of the previous year.

Daily Costs Trends

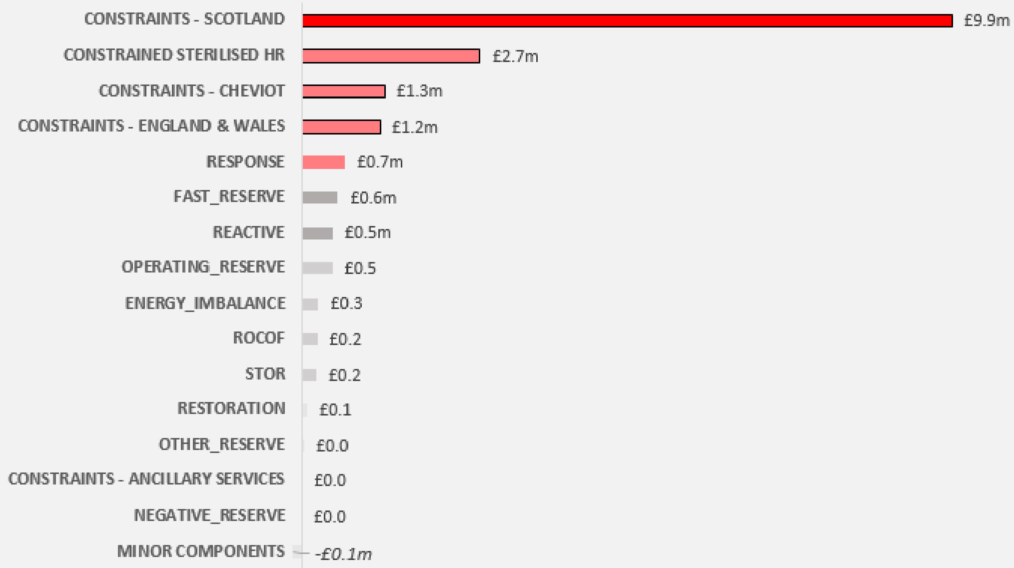
As stated above, November's balancing costs were £108.8m lower than the previous month.

At the date of publication, we have recorded two days with a spend of more than £15m (~16% of the total spent of the month).

The two high-cost days that occurred in November were a result of particularly high wind generation and Scottish boundary reductions (B4/5 boundary was at ~50% capacity and B6 boundary was at 70%) resulting in 19% wind curtailment on the 22nd.

The highest total cost observed on 22 November when the total spend was £17.9m, the major cost components were the thermal constraints driven by high renewable generation. No individual action was expensive, but high volumes of wind curtailment resulted in high total balancing costs.

Cost breakdown for 22 November 2023



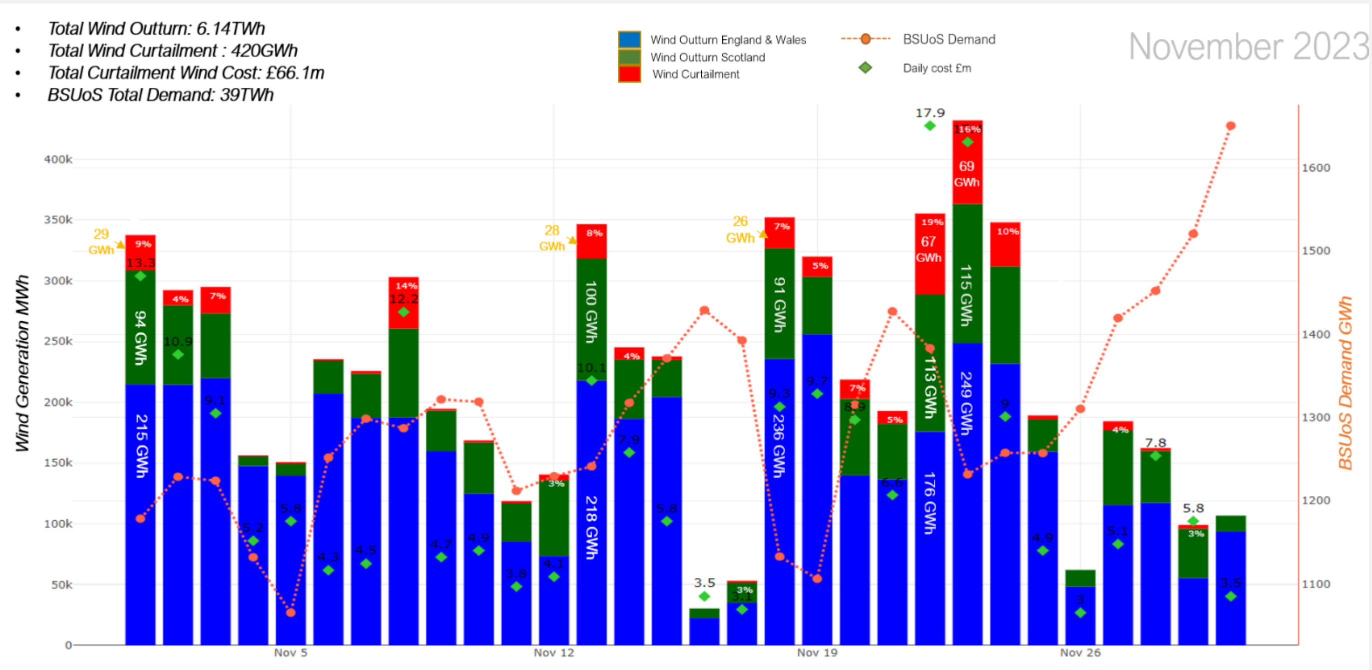
A minimum daily cost of £3m was observed on 26 November.

The average daily spend for the month was £7.5m, a £3.2m decrease from the previous month.

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

The chart below serves the purpose of supporting the transparency and the narrative above. It is the daily "tour" of wind performance (wind generation: **blue** & **green** bars, and wind curtailment: **red** bars), demand (resolved by the balancing mechanism and trades – **orange** dotted line) and daily cost (**green** diamonds).

With this graph one can trace for example the relationship that may exist in how wind performance and low demand affect the cost of each day.



High-cost days and balancing cost trends are discussed every week at the Operational Transparency Forum to give ongoing visibility of the operability challenges and the associated ESO control room action.

Metric 1B Demand forecasting accuracy

This metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each half hour period. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

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

In settlement periods where Optional Downward Flexibility Management (ODFM) and/or Demand Flexibility Service (DFS) are instructed by the ESO, this will be retrospectively accounted for in the data used to calculate performance. The ESO shall publish the volume of instructed ODFM to enable this to be done.

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

November 2023-24 performance

Indicative benchmark figures for 2023-24: Please note that the benchmark figures used below are indicative only. We have calculated these in line with the method specified by Ofgem, but we have not yet received the confirmed figures from Ofgem. We will update previous performance figures in subsequent reports once the benchmarks have been finalised.

Figure 2: 2023-24 Monthly absolute MW error vs Indicative Benchmark

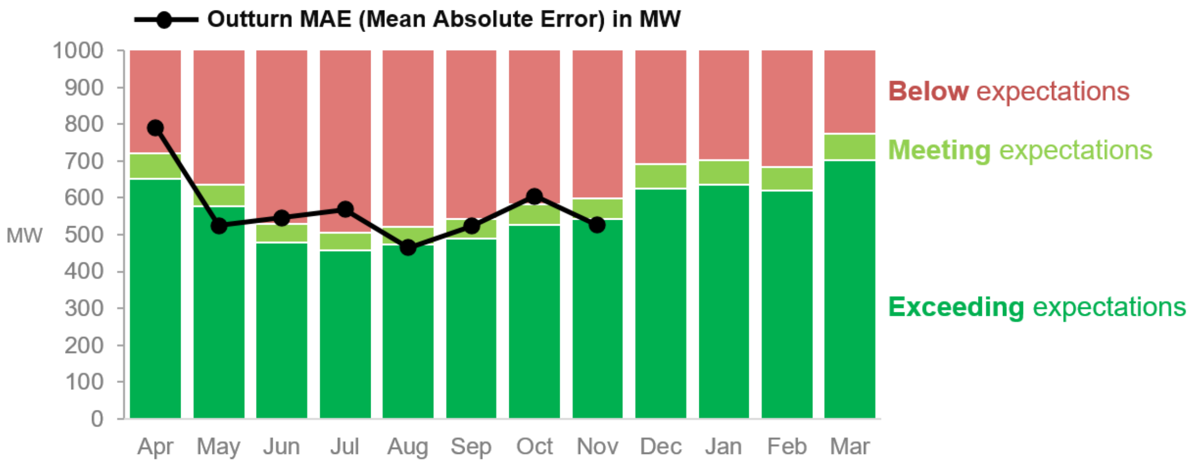


Table 2: 2023-24 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	687	606	503	481	497	516	554	571	659	669	651	738
Absolute error (MW)	**791**	**523**	**546**	**569**	**465**	**523**	**604**	**526**				
Status	●	●	●	●	●	●	●	●				

[2] Demand | BMRS (bmreports.com)

Performance benchmarks:

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

Supporting information

In November 2023, the mean absolute error (MAE) of our day ahead demand forecast was 526 MW compared to the indicative ‘meeting expectations’ target of 600 MW, and indicative ‘exceeding expectations’ target of 542 MW.

November can typically be a difficult month for forecasting, often due to lower temperatures hitting in earnest and difficult wind conditions. This year however, forecasting accuracy was relatively high for the month, with an average error below the ‘exceeding expectations’ target.

Storm Ciaran didn’t hit the UK as much as originally forecast, and wind speed forecast errors – through their impact on embedded wind generation - did contribute to the slightly higher average error on 2 November.

Though shorter daylight hours do mean less embedded solar generation, particularly difficult weather conditions can still contribute to larger demand errors, as seen on 6 and 7 Nov.

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	193	13%
1500 MW	39	3%
2000 MW	4	0%

The days with largest MAE were Nov 2,6,7,8.

DFS was run on 29 Nov, and a DFS test was run on 16 Nov. These will have affected the national demand outturn but are not included in our forecasts.

Missed / late publications

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

Triads

Triads are the three half-hour settlement periods of highest demand on the GB electricity transmission system between November and February (inclusive) each year. They are separated by at least ten clear days to avoid all three triads potentially falling in consecutive hours on the same day, for example during a particularly cold spell of weather. We use the triads to determine TNUoS demand charges for customers with half-hourly meters. The triads are designed to encourage demand customers to avoid taking energy from the system during peak times if possible. This can lead to some uncertainty in forecasting peak demands over the winter months. See our website for more detail on triads.

Triad season introduces higher uncertainty over the demand during the Darkness Peak (DP) which is between settlement periods 34 and 39. At the time of the 1B forecast publication, i.e. by 09:15 on D-1, the forecast shows the national demand without any triad avoidance expectation. Each evening during the triad season we run an automatic assessment of triad activity, to establish if it occurred and how much avoidance there was over the settlement periods during the Darkness Peak. For the purpose of the 1B metric reporting, national demand outturn is adjusted by the estimated triad avoidance. All data is submitted as part of the reporting.

Triad charges have been reduced this year, and for this reason it is expected that triad avoidance behaviour will be lower than in previous years. However, there are likely other factors that may be contributing to reduced demand over the higher winter peaks (e.g. increased energy costs) resulting in a similar ‘demand shaving’ over the peak demand times. This will likely make determining the amount of triad avoidance more difficult, as there is more overlap of these effects and less ‘unaffected’ days to use as a comparison.

In November we observed 1 day affected by triad avoidance behaviour – 28 Nov, where there was an average of 750MW suppression over the darkness peak window.

Metric 1C Wind forecasting accuracy

This metric measures the average absolute percentage error (APE) between day-ahead forecast (between 09:00 and 10:00, as published on ESO Data Portal here) and outturn wind generation (settlement metering as calculated by Elexon) for each half hour period as a percentage of capacity for BM wind units only. The data will only be taken for sites that did not have a bid-offer acceptance (BOA) during the relevant settlement period.

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

November 2023-24 performance

Indicative benchmark figures for 2023-24: Please note that the benchmark figures used below are indicative only. We have calculated these in line with the method specified by Ofgem, but we have not yet received the confirmed figures from Ofgem. We will update previous performance figures in subsequent reports once the benchmarks have been finalised.

Figure 3: 2023-24 BMU Wind Generation Forecast APE vs Indicative Benchmark

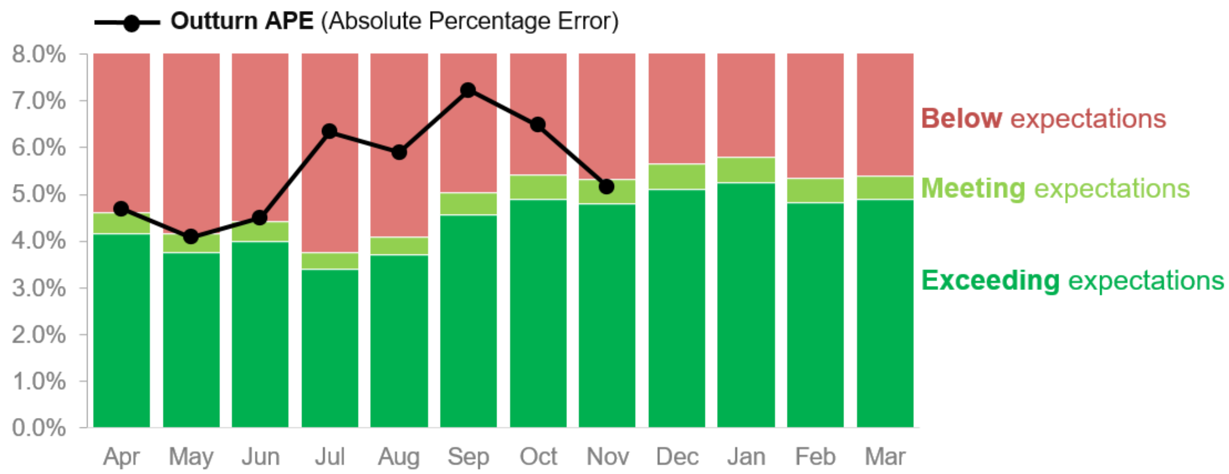


Table 3: 2023-24 BMU Wind Generation Forecast APE vs Indicative Benchmarks

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.38	3.95	4.21	3.57	3.89	4.79	5.15	5.06	5.38	5.53	5.08	5.14
APE (%)	**4.69**	**4.08**	**4.50**	**6.34**	**5.90**	**7.23**	**6.48**	**5.16**				
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

The weather in November started with a powerful Jet stream directing low pressure weather systems in the direction of the UK, bringing three major named storms. These weather systems bring wet, windy and unsettled weather and increase the likelihood of wind power forecast errors.

Forecasting accuracy significantly improved in the second half of the month, once the final batch of updated wind models had been released into production. The updated models, alongside the portfolio and systems-alignment work, has improved general 1C performance.

Significant forecast errors still exist on certain days, but they appear to be attributed to a few, albeit very large offshore windfarms. Work continues to better understand and resolve the underlying causes, but they seem to be predominantly weather-data accuracy and telemetry related.

Legacy systems will continue to be a significant constraint on the forecast accuracy, until such time that we can use Numerical Weather Prediction (NWP) data in our new wind models, functioning on the forthcoming cloud platform. This is expected in mid-2024. Similarly, new large windfarms (during their commissioning and early lifecycle) provide forecasting challenges, as there is no historic data available to train new models with.

Work continues to improve forecasting accuracy, through the use of outage data and improved High Speed Cut-Off modelling. Storms that create cut-off conditions are unusual, which limits the amount of available data to validate at BMU level. Outage data provided by wind market participants appears to be limited and inconsistent.

Following a sustained period of poor performance, the month of November the wind power forecast accuracy was narrowly achieved with 5.16%, against a target of 5.31%.

Withdrawal of wind units

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

Missed / late publications

In November there were no occasions of late or missing publications of the forecast.

Metric 1D Short Notice Changes to Planned Outages

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

November 2023-24 performance

Figure 4: 2023/24 Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

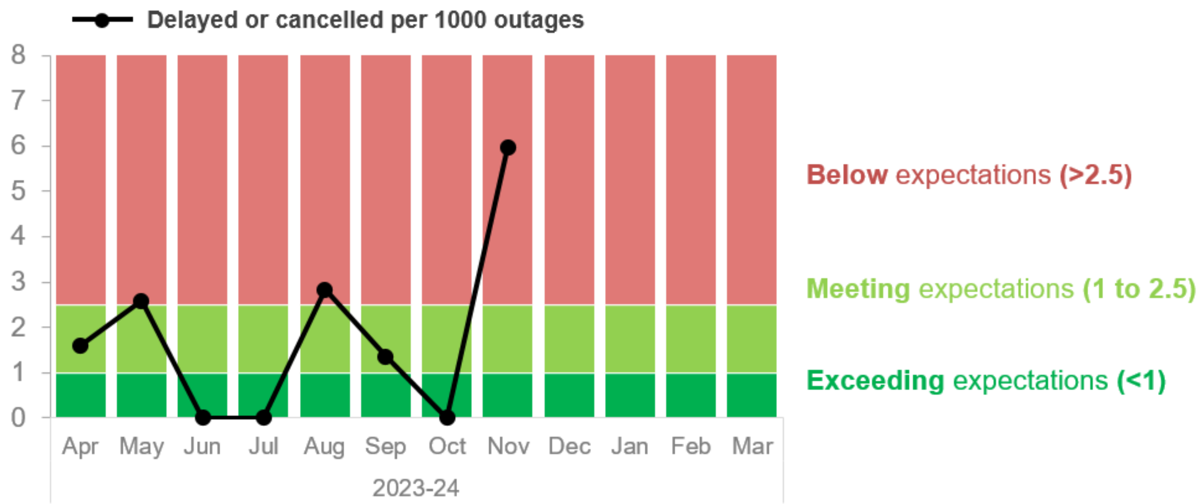


Table 4: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	624	739	645	644	706	734	704	671					5467
Outages delayed/cancelled due to ESO process failure	1	2	0	0	2	1	0	4					10
Number of outages delayed or cancelled per 1000 outages	1.6	2.6	0	0	2.8	1.4	0	6					1.83
Status	●	●	●	●	●	●	●	●					●

Performance benchmarks:

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

Supporting information

For November, the ESO has successfully released 671 outages. There were four delays or cancellations due to an ESO process failure. The number of stoppages or delays per 1000 outages for November was 5.96, which is outside the 'Meets Expectations' target of less than 2.5. The cumulative number of stoppages or delays per 1000 outages to date is 1.83 which is within 'Meets Expectations' target.

The four events can be summarised below:

The first delay occurred on a 275kV circuit outage where a change in a substation running arrangement was proposed, and resulted in demand at risk that was not identified within planning timescales. This meant the demand at risk process was not highlighted to identify potential contingencies and post-fault actions. Therefore, the impacted Distribution Network Operator (DNO) was not aware or agreeable to this risk at short notice. The ESO control room identified this issue and were able to propose a different running arrangement after a short period of time which was able to mitigate the risk. An operational learning note (OLN) has been written to capture the sequence of events with a proposed additional check on running arrangements as a preventative action, this has been shared with the wider department.

The second event occurred due to an outage on a different 275kV circuit that coincided with some existing faults and limitations on the network. As a result, for a particular contingency the demand group was no longer securable. The standard outage planning assessment process was followed with all contingencies being checked. However, when it reached the ESO control room they were seeing overloads on the network where they could not secure the demand group due to higher demands. This led to the outage being cancelled and was sent back to the planning team to investigate demand transfers or to request the Transmission Owner (TO) to return some of the faulted equipment before the outage could proceed. A comprehensive OLN has been written and will be circulated to highlight the challenges on the outage and a number of corrective actions.

The third event occurred due circuit outage which required a substation running arrangement to be modified to re-secure the site. The proposed running arrangement was not achievable due to a technical limitation on an isolator that prevented re-selecting the substation. This was not identified within planning timescales. As a consequence, the limited running arrangement would result in DNO demand at risk who had not been made aware or were agreeable to this risk. An OLN has been written to capture the sequence of events and two corrective actions and has been distributed to the wider department.

The final delay occurred on a 400kV circuit outage where it was identified by the ESO control room that the network could not be secured for a particular set of contingencies. The planning team assessed the outage and did not see any overloads in their offload studies. However, it was identified retrospectively that it the assessment assumed one of the interconnectors to be importing into GB. On the day of the outage, the interconnector was exporting from GB and this scenario had not been studied by the planning team due to human error. An OLN is being written to capture what assumptions and scenarios should be assessed before an outage can be agreed. This is to ensure that outages can be secured under a wide range of situations.

RRE 1E Transparency of operational decision making

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

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

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

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

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

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

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

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

November 2023-24 performance

Figure 5: 2023-24 Percentage of balancing actions taken in merit order to meet requirements in the Balancing Mechanism

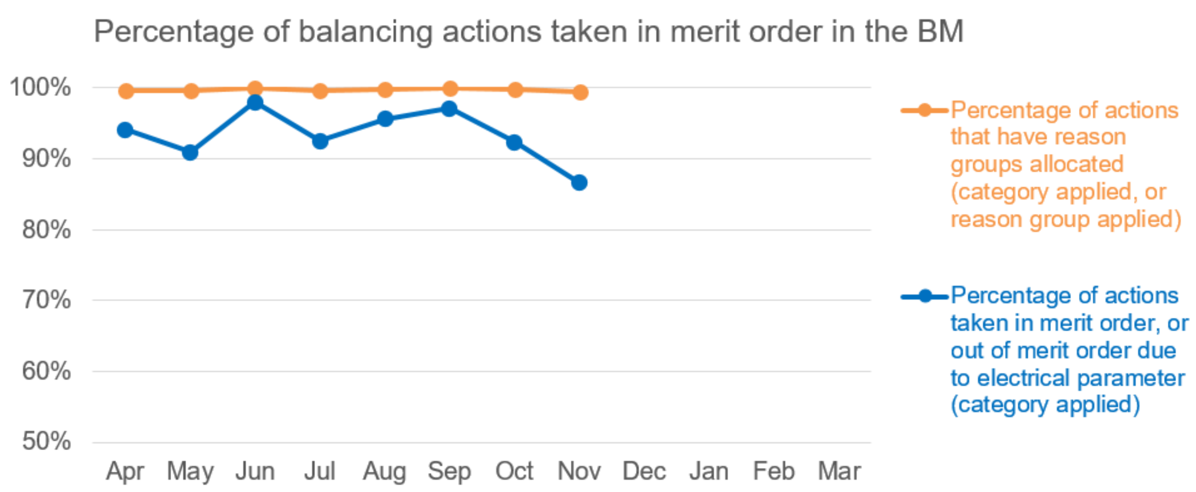


Table 5: Percentage of balancing actions taken outside of merit order in the BM

	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)	94.1%	90.9%	98.0%	92.5%	95.6%	97.1%	92.3%	86.6%				
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.6%	99.9%	99.7%	99.8%	99.9%	99.8%	99.5%				
Percentage of actions with no category applied or reason group identified	0.3%	0.4%	0.1%	0.3%	0.2%	0.1%	0.2%	0.5%				

Supporting information

November performance

This month 86.6% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 12.9% 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 November 2023, there were 57030 BOAs (Bid Offer Acceptances) and of these, only 297 remain with no category or reason group identified, which is 0.5% of the total.

Other activities

During November we have continued to provide data and support to LCP Delta in their independent analysis of the dispatch transparency dataset.

We provided a brief update to industry at the Balancing Programme event on 28 November. We will include our high-level roadmap for improvements for Dispatch Transparency data in the ESO Transparency Roadmap due to be published before the end of December. More information on our roadmap and how we intend to engage with wider industry going forward and on an enduring basis will be provided at the follow-up storage event in January.

We continue working to identify the missing data periods from the published dataset and are developing a reliable method to retrieve or reconstruct these sections for a comprehensive dataset. We are also carrying out a code review of the automated process and checks on reference data sources within the other ESO systems to identify and resolve additional root causes. We are committed to maintaining and improving the current Dispatch Transparency tool while we work with industry to build on LCP's recommendation and co-create a new Dispatch Transparency dataset. We will be sharing more details about the work on the existing and replacement datasets at the event in January.

RRE 1G Carbon intensity of ESO actions

This Regularly Reported Evidence (RRE) measures the difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the Balancing Mechanism (BM) and the equivalent profile with balancing actions applied.

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO2/kWh associated with it. For full details of the methodology please refer to the Carbon Intensity Balancing Actions Methodology document. The monthly data can also be accessed on the Data Portal here. Note that the generation mix measured by RRE 1F and RRE 1G differs.

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

November 2023-24 performance

Figure 6: 2023-24 Average monthly gCO2/kWh of actions taken by the ESO (vs 2022-23)

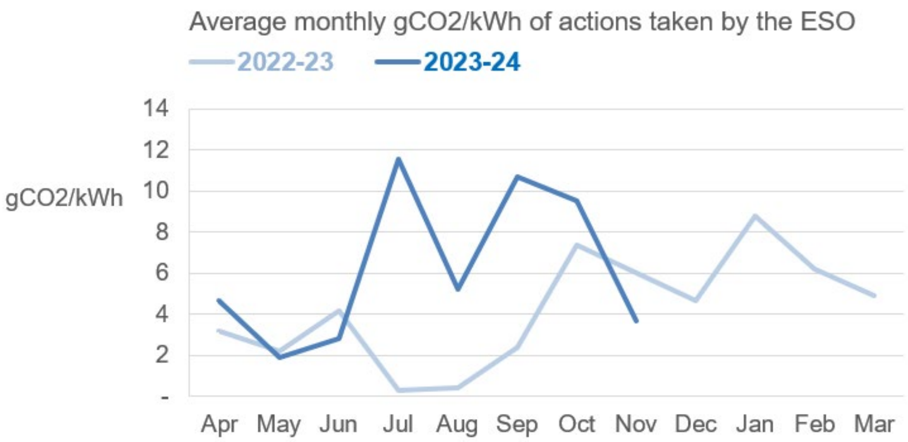


Table 6: Average monthly gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	4.7	1.9	2.8	11.6	5.2	10.7	9.5	3.7				

Supporting information

Data issue: Last month we reported that the October data was missing nine (9) days. We have been able to update the data to reduce the number of missing days to 4, and have updated the reported figure. We also have identified one day missing from the September figure, and 8 days' incorrect data in August. We have put a temporary fix in place which has meant that November data is complete, and are working to correct and update the Aug-Sep data.

In November 2023, the average carbon intensity of balancing actions was 3.7gCO2/kWh. This is 2.3g lower than Nov 2022 (which was 6.0gCO2/kWh).

Across the month, ESO actions reduced the carbon intensity in 49% of settlement periods.

The greatest impact of ESO actions on carbon intensity was seen over two nights on 22-23 and 23-24 November, raising the carbon intensity by 40g on average across the overnight periods (peaking at +55g). The lowest carbon intensity provided by the market would have been during this period. There were multiple network constraints across GB requiring up to 2500MW of wind bids to solve and up to 9 fossil fuelled units were synchronised for voltage and stability needs. Additional wind bids were required behind one boundary to allow a fossil fuelled unit on for necessary voltage support. Coal units were also kept on through the night of the 23-24 Nov for inertia and voltage needs as they were cheaper than other available gas units.

On 19 Nov, further actions were required to create downward margin on fossil fuelled units by reducing wind generation and interconnector imports. This was in addition to synchronising fossil fuelled units for voltage and stability requirements. The result was an average increase to carbon intensity of 23g during the overnight period.

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 2023-24 performance

Table 7: Frequency and voltage excursions (2023-24)

	2023-24											
	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	0	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 excursions in November.

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

RRE 1J CNI Outages

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

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

November 2023-24 performance

Table 8: 2023-24 Unplanned CNI System Outages (Number and length of each outage)

	2023-24											
Unplanned	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 9: 2023-24 Planned CNI System Outages (Number and length of each outage)

	2023-24											
Planned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	1 outage (185 mins)	0	0	1 outage (265 mins)	1 outage (145 mins)	1 outage (170 mins)				
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0				

Supporting information

November performance

In November 2023 there was one planned CNI system outage. The outage was to introduce enhanced system functionality, in addition to regular maintenance activities on the BM production systems, and impacted the key BM Suite components used for scheduling and dispatch of generation.

There were no other planned outages during November.

There were no unplanned outages during November.

Notable events during November 2023

We hosted our Balancing Programme engagement event 28 November

On 28 November we hosted our fourth Balancing Programme engagement event, where we confirmed the launch of the Open Balancing Platform (OBP). The OBP went live on 12 December and will replace current balancing systems. This first release of OBP provides enhanced dispatch capability within the control room for two zones - Batteries and Small BMU's - and is the foundation for all future system developments. Improving this capability is a big step forward along our journey to enabling a zero-carbon system.

The event attracted 69 representatives from 42 different organisations and allowed the Balancing Programme to proactively engage, collaborate and seek feedback from our stakeholders on our Balancing Transformation Plans. It also gave us a chance to update these stakeholders on our progress to date through a range of interactive presentations and breakouts. The day began with an overview of the OBP release schedule out to Summer 2025, capturing details of the capabilities being delivered and anticipated benefits. This was followed by a series of interactive breakout sessions.

The event was extremely well received by stakeholders with attendees giving an average score of 8.3 out of 10 for the overall event, marking an improvement on our previous score for the June event of 7.8.

Stakeholders commented**:**

- “Genuinely incredibly useful, great people attending to answer questions”
- “Excellent program and presentations. Nice to get so much time with people from National Grid”.
- "Very good, much more polished, open and collaborative."
- "Very clear and structured event"
- "Great to gather interested parties in one room; layout of timeline very useful."

Role 2 (Market developments and transactions)

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

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

The BSUoS charge (£/MWh) is now based upon a fixed tariff that was published in January 2023. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) were forecast for the year ahead, and two 6-month tariffs were set to cover the 2023/24 charging year.

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

November 2023-24 performance

Figure 7: 2023-24 Monthly BSUoS forecasting performance (Absolute Percentage Error)

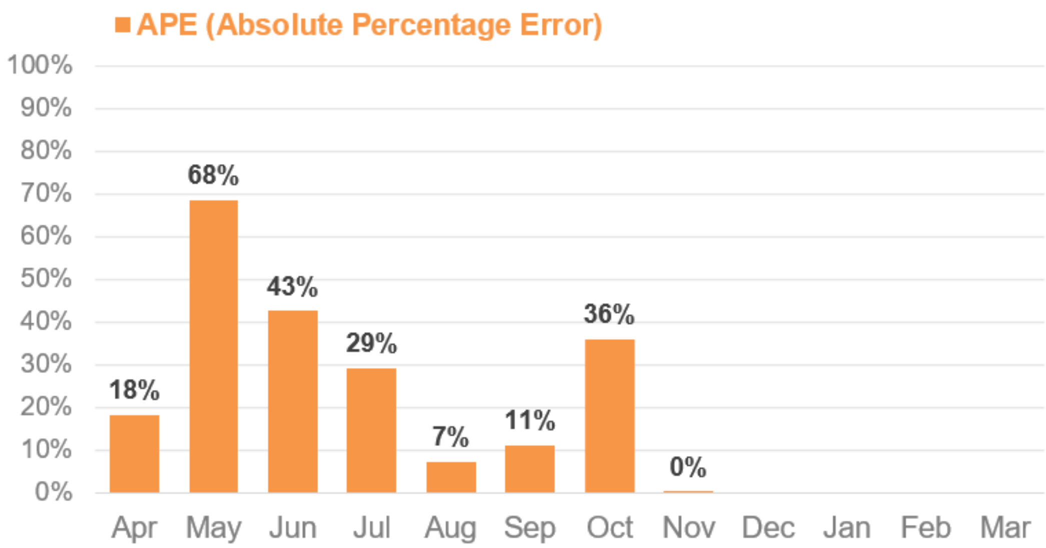


Table 10: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[4] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	10.8	8.2	7.5	13.7	10.4	12.8	16.5	10.5				
Month-ahead forecast (£ / MWh)	12.7	13.8	10.8	9.7	9.7	11.4	10.6	10.5				
APE (Absolute Percentage Error)[5]	**18.0**	**68.4**	**42.5**	**29.1**	**7.2**	**11.0**	**36.0**	**0.0**				

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

Supporting information

November Performance:

Actuals out-turned in line with forecast for November 2023, with the Absolute Percentage Error decreasing from 36% in October to 0.04% in November. Both cost and volume out turned slightly above forecast, bringing the £/MWh outturn in line with our month-ahead forecast.

Costs:

November outturn costs were around the 55th percentile of the forecast produced at the beginning of October. Despite a 4% decrease in the average wholesale electricity price between the October forecast for November (£100/MWh) and November outturn (£96/MWh), this was offset by a 5% increase in constraint costs (£121m in October forecast and £127m for November outturn)

Volumes:

November actual volume was slightly above the October forecast.

Forecast for November made at the start of October: 24.2TWh

Outturn volume for November: 24.6TWh

Notable events during November 2023

Markets Forum held in London on 8 November

On 8 November we held our annual Markets Forum where updated industry of our strategy and plans over the short-, medium- and longer-term horizon. The forum included formal presentations, collaborative breakout sessions, teach ins and much appreciated networking time for industry colleagues. The event was attended by 150 industry peers and highlights noted were the time and transparency provided for questions, collaboration conversations on key topics and networking.

A commitment was also made to transform the Markets Forum based on industry feedback, both in terms of content and cadence and as such industry were asked to provide feedback on a few proposals.

We are now pleased to announce that shaped by industry feedback we now plan to hold the Markets Forum four times a year. Two of these events will be virtual pre-recorded webinars with a live Q&A session a week later and two will be in person with the facility to livestream the main presentation.

Timeline for future Markets Forums

2023-24	Q3	Wednesday 8 Nov	In person - London
		26th February: Markets Roadmap publication	
	Q4	Thursday 7 March	Webinar release date
		Thursday 14 March	Live Q&A
2024-25	Q1	Tuesday 14 May	In person - Glasgow
		All Energy 2024 in Glasgow 15/16 May	
	Q2	Thursday 12 September	Webinar release date
		Thursday 19 September	Live Q&A
	Q3	Thursday 21 November	In person - London

Demand Flexibility Service (DFS) runs first test and live events in 2023/24

DFS incentivises households with smart meters, as well as industrial and commercial users, to voluntarily flex the time they use their electricity to help manage the system this winter during periods where margins are tightest.

Alongside potential live uses of the service to balance the network this winter, we will endeavour to run 12 test events that consumers can participate in. Electricity suppliers, aggregators and businesses who directly contract with us will receive a guaranteed acceptance price of £3/kWh for at least six of the test events.

On 16 November we activated the first test DFS event of the winter. Around 1.4million households and businesses had signed up to take part through 17 providers (which includes aggregators with multiple consumer-facing propositions). There are 3 procurement timelines that are available to use – day-ahead, within-day morning, within-day afternoon. This test was triggered at the day-ahead stage.

On 29 November we activated the first DFS live event of the winter. By this stage there were over 1.8million households and businesses able to participate in DFS through 20 providers (which includes aggregators with multiple consumer-facing propositions).

Data from test and live events can be viewed and downloaded from the ESO Data Portal.

Enduring Auction Capability (EAC) Platform: First live auctions

On 2 November, the first live auction successfully took place on our new Enduring Auction Capability (EAC) platform.

The EAC helps us to procure Dynamic Containment (DC), Dynamic Regulation (DR) and Dynamic Moderation (DM) Response Services which work together to control system frequency. The new platform allows market providers to access multiple markets at the same time and offer multiple day-ahead Frequency Response and Reserve Services simultaneously. Ultimately this makes the procurement of balancing services more efficient and allows us to select the option that provides the best value.

The first round of auctions on the EAC platform took place on 2 November. We received bids from 23 participants with a total of 109 units, with co-optimisation and overholding delivering great results. Clearing prices in almost all Dynamic Frequency Response markets fell with an average clearing price of £2.46 (35% lower than the average clearing price for the previous 7 days). The cleared volume remained stable as before.

As we continue to work with market providers, we plan to start procuring our newly reformed reserve services through the EAC as they are developed.

For more information on this new platform and its benefits please see the attached link.

Role 3
(System insight, planning and network development)

ESO

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

Notable events during November 2023

New rules for managing the connections queue approved

On 13 November, Ofgem approved new rules for the ESO to proactively manage the connections queue. Our Director of the ESO, Fintan Slye, provided an open letter to the industry. A summary of that letter is below.

We are delighted that new rules have been approved by Ofgem for the ESO to proactively manage the connections process (through a code change to the CUSC known as CMP376) with the ability to terminate projects that are not progressing against their project milestones – a key component of our five-point plan to speed up grid connections.

These changes mean that queue management milestones will be inserted into all transmission grid connection contracts with a connection date post November 2025 and any new connection applications we receive. Projects will have six months to apply for a more realistic connection date or face being terminated by the ESO.

Currently, there are 232 projects accounting for c.45GW of capacity that are due to connect by the end of 2025. We have classified 144 of these projects potentially at high risk of not meeting their contractual connection date, accounting for c.29GW of capacity.