ESO RIIO2 Business Plan 2 (2023-25)

February 2023-24 Incentives Report

25 March 2024

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

- On 12 February, we hosted a ‘Enhancing Energy Storage in the BM’ webinar. This was a follow up to the plan we set out in October 2023 detailing how we would enhance the use of energy storage assets in the Balancing Mechanism. This webinar was attended by over 150 stakeholders from across the energy industry. It gave update on progress, including increased utilisation stats and overview of plans to change the 15-minute rule for batteries to 30 minutes.
- On 5 February, the Ancillary Service Reforms (ASR) Response Reform team held a webinar with Balancing Mechanism Units (BMU) providers to explain changes to reason codes for sending disarming and re-arming instructions to Dynamic Moderation (DM), Dynamic Regulation (DR) and Dynamic Containment (DC) providers. The webinar covered new reason codes, their implementation and testing, and received positive feedback with an average feedback score of 8.3/10.
- On 9 February, we hosted a teach-in session for the Balancing Settlement Code (BSC) Panel to provide insight into a proposed BSC modification, P462, which seeks to resolve an identified structural issue with the interaction between the Balancing Mechanism (BM) and support mechanism arrangements. The interactive session allowed for questions to be resolved and identified further topics to be explored within the workgroup process and received positive feedback from stakeholders.
- We are reviewing whether storage is treated appropriately within the charging methodology for Transmission Network Use of System (TNUoS) charges, which recover the cost of the investment in the UK electricity (High Voltage) transmission system. We have set up a storage subgroup to address potential anomalies and engage with industry to develop a fit-for-purpose charging methodology. On 14 February we hosted a Charging Futures webinar with industry, outlining the case for change, timelines, and the application process for becoming a subgroup member, and received positive feedback. We have shortlisted sub-group members and are applying for innovation funding to support industry with this work over the coming months.
- In October 2023, we published a request for input (RFI) to gather industry opinions on the development of an Interconnector Framework to enable consistency for interconnectors operating in GB markets and aid transparency. On 29 February we hosted an industry session to provide an overview of the RFI industry responses and discuss key opportunities, uncertainties, complexities, suggestions, and next steps for the workstream.
- The EMR Delivery Body ran the T-1 and T-4 Capacity Market auctions on 20 February and 27 February respectively. The Auction Monitor Reports for both auctions have been published by DESNZ, confirming that the Auctions were run in accordance with the CM Rules and Regulations.
- On 28 February, we held our Bridging the Gap webinar for 2024, which aims to make progress on areas of uncertainty concerning net-zero delivery through stakeholder engagement and dialogue. The team presented stakeholder views on how to accelerate progress on heat decarbonisation and highlighted the 6 bridges to cross, including strategic direction on heat and building consumer trust. 200 stakeholders attended the webinar and provided positive feedback on the content and presentation.
- The Early Competition team is in the final stages of implementing a model to introduce competition in the design, delivery, and operation of transmission assets, and working with Ofgem to draft tender regulations and new licence conditions. On 1 February we published an Early Competition Implementation (ECI) update, presenting final proposals for the model to Ofgem, and on 22 February, the Network Competition (NC) Team held a webinar to detail the updated commercial model for early competition, which received positive feedback.

Summary of Metrics and RREs

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

Metric/RRE		Performance	Status
Metric 1A	**Balancing Costs**	£168m vs benchmark of £244m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 606MW vs indicative benchmark of 651MW	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 5.08% vs indicative benchmark of 5.08%	●
Metric 1D	**Short Notice Changes to Planned Outages**	0 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**	89.6% of actions taken in merit order or driven by an electrical parameter	N/A
RRE 1G	**Carbon intensity of ESO actions**	7.2gCO_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**	0 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 39.9%	N/A

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

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

Adelle Wainwright
Head of Regulation

Role 1 (Control Centre operations)

ESO

Metric 1A Balancing cost management

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

A new benchmark 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 input into the equation created by the historic relationships to create the monthly benchmarks.

The formulas used are as follows (with Day Ahead Baseload being the measure of wholesale price):

Non-constraint costs = 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.

February 2023-24 performance

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

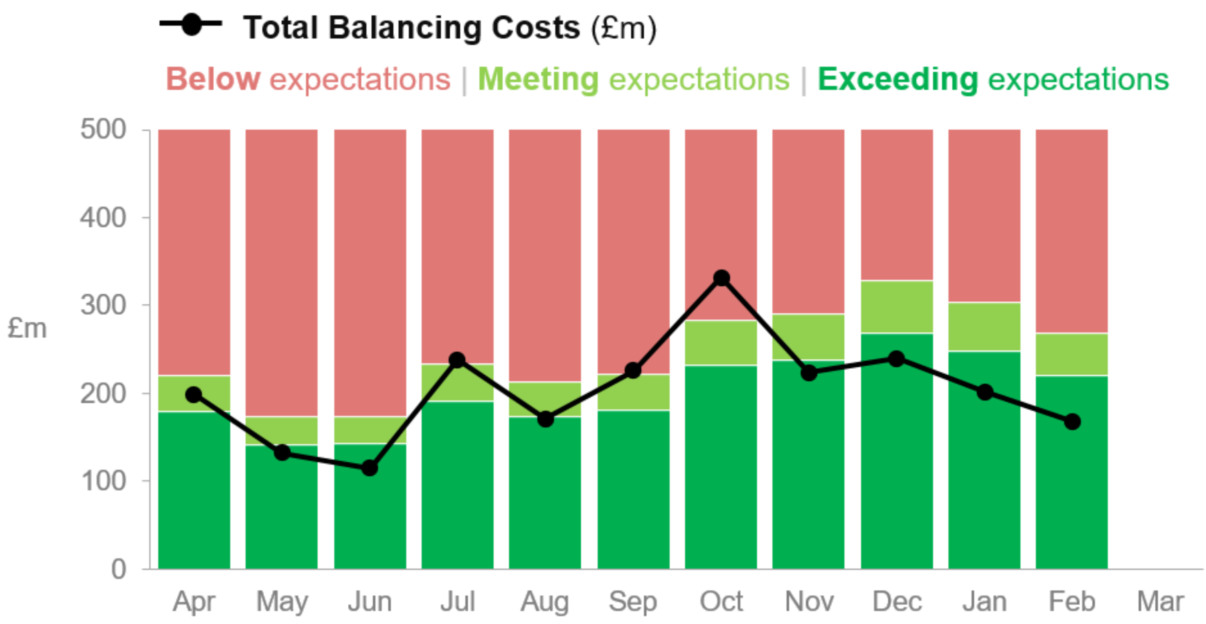


Table 3: 2023-24 Monthly breakdown of balancing cost benchmark and outturn

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	8.3	7.4	6.6		55.58
Average Day Ahead Baseload (£/MWh)	105	81	87	82	86	83	89	99	74	74	61		n/a
Benchmark	200	157	158	212	194	201	258	264	299	276	244		2462
Outturn balancing costs[1]	**198**	**132**	**115**	**238**	**171**	**226**	**332**	**224**	**240**	**202**	**168**		**2247**
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.

This month's benchmark

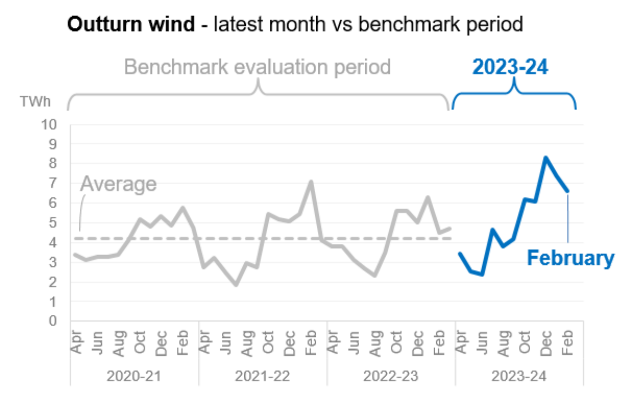
As noted in the introduction to this section, a new benchmark was introduced for BP2. The benchmark is derived using the historical relationships between two drivers (wholesale price and outturn wind generation) and balancing costs.

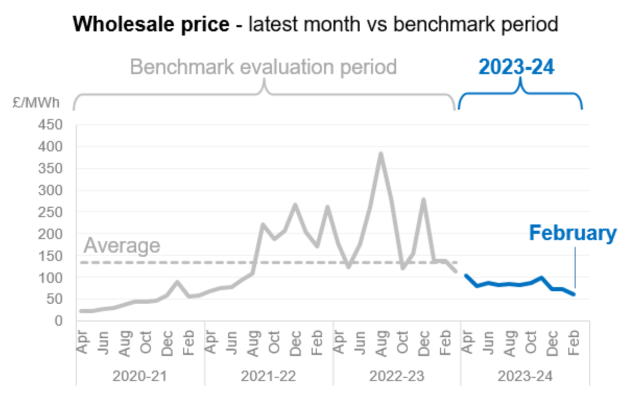
The February benchmark of £244m is the third lowest so far in 2023-24, and this reflects:

- an **outturn wind** figure that remains high compared to the benchmark evaluation period (the last three years), although slightly lower than last month. It is still higher than the highest outturn wind (7.1TWh) in the entire benchmark period.
- a drop of £13/MWh in the average monthly **wholesale price** (Day Ahead Baseload) this month compared to January 2024, remaining at the lowest point it's been so far in 2023-24. It is also relatively low compared to the benchmark evaluation period (the last three years).

The relatively lower levels of wind generation we observed this month is the main driver to the overall decrease of the benchmark this month compared to last month.

[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.



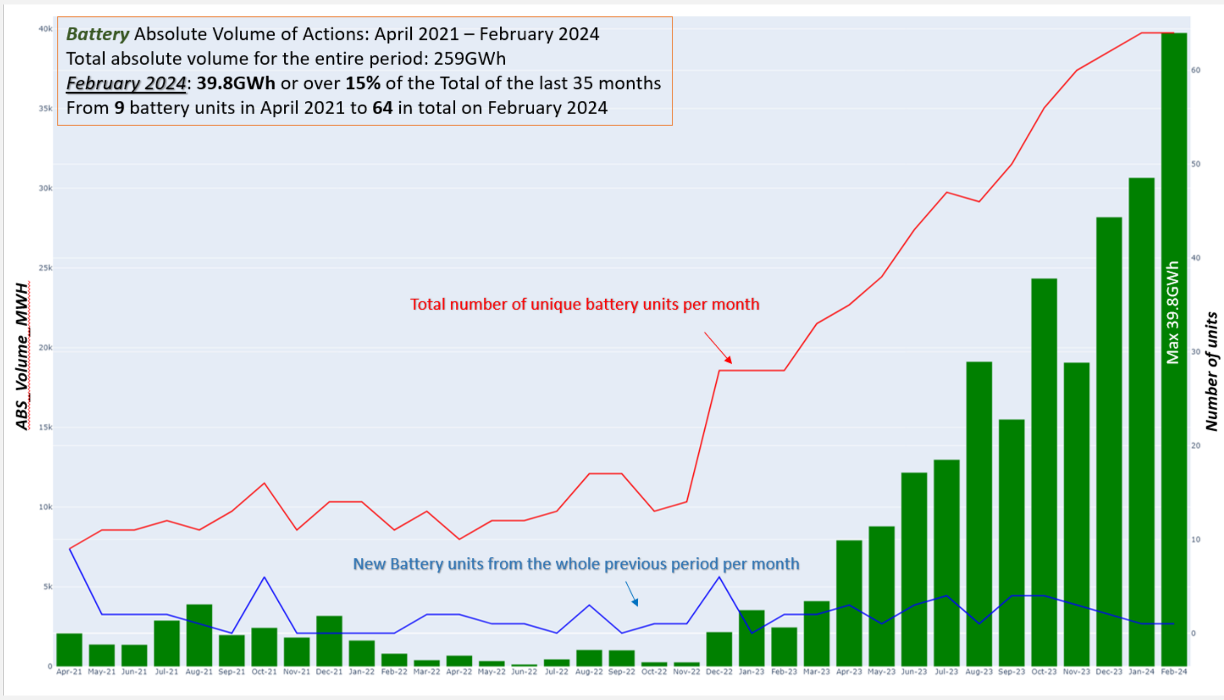


February Performance

February's total balancing costs were £168m which is £76m (~31%) below the benchmark of £244m, and therefore performance is exceeding expectations. This is the fourth consecutive month and seventh time that the ESO has 'exceeded expectations' since April 2023. February's overall outturn wind was slightly lower than January 2024, although still significantly high than the rest of the months in 2023-2024. The volume weighted average price for bids and offers have decreased compared to last month by £5 per MWh and £10 per MWh respectively and remains lower than the previous three months.

As discussed in December's incentives report, the first stage of our new platform to support the bulk dispatch of battery storage and small Balancing Mechanism Units, the Open Balancing Platform (OBP), went live on 12 December. February had the highest battery dispatch volume (~40GWh) since April 2021 as show on the graph below. This illustrates our commitment to maximising the flexibility of energy offered by battery storage over the last year.

April 21 to February 24 - Monthly Volume of actions for Batteries and number of unique units



Despite low-cost conditions for February 2024 – with less wind generation, and slightly higher total constraint volumes compared to January, the constraint cost in Scotland decreased by £5.9m and in Cheviot increased by £1.5m with a total increase of 82.3GWh by actions and decrease of £4.4m by costs. However, we were still able to make a significant total amount of savings through optimizing outages and trading activities.

The total savings from outage optimisation were £169m in February. Whilst still a largely significant amount of savings for February, this is a decrease of £278m from January outage savings. January's savings were particularly large due to many actions but most significantly the enabling of approximately 1.5 TWh of additional energy on the B6 boundary. In February, the most action that yielded the greatest value that was taken by the Outage Optimisation team was the rejection of two overlapping requests along the SCOTEX boundary. If these two outages had coincided, there would have been an additional restriction of 560 GWh along the SCOTEX boundary at a cost of approximately £42m.

The Trading team were also able to make significant savings through commercial decisions with interconnectors. A total of £26.9m was saved by taking these actions compared to alternative BM actions.

Work is still ongoing in quantifying the value of savings from the Operational Balancing Platform, but as can be seen from the figure above, a record volume of batteries (40 GWh) was dispatched through the Balancing Mechanism in February 2024.

Breakdown of costs vs previous month

Balancing Costs variance (£m): February 2024 vs January 2024

		(a) Jan-24	(b) Feb-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	8.7	-1.2	(10.0)	
	Operating Reserve	16.4	6.1	(10.3)	
	STOR	5.0	3.1	(1.9)	
	Negative Reserve	0.4	0.4	(0.0)	
	Fast Reserve	15.3	13.8	(1.5)	
	Response	14.8	11.7	(3.2)	
	Other Reserve	2.3	2.3	0.1	
	Reactive	13.9	12.3	(1.6)	
	Restoration	3.8	3.4	(0.4)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	5.5	2.8	(2.6)	
Constraint Costs	Constraints - E&W	21.3	19.4	(1.9)	
	Constraints - Cheviot	10.6	12.1	1.5	
	Constraints - Scotland	63.3	57.4	(5.9)	
	Constraints - Ancillary	0.2	0.7	0.5	
	ROCOF	1.3	3.3	2.0	
	Constraints Sterilised HR	18.6	20.6	2.0	
Totals	Non-Constraint Costs - TOTAL	86.1	54.7	(31.4)	
	Constraint Costs - TOTAL	115.3	113.6	(1.7)	
	Total Balancing Costs	**201.5**	**168.3**	**(33.1)**	

As shown in the total rows from the table above, both non-constraint & constraint costs decreased by £31.4m & £1.7m respectively, resulting in an overall decrease of £33.1m compared to January 2024.

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

- **Constraint-Scotland & Cheviot***: The constraint cost decreased by £4.4m, despite the volume of actions increased by 82.3GWh.
- **Constraint-England & Wales***: an increase of 85GWh in volume of the total actions with the constraint cost decreased by £1.9m, mainly due to a decrease in the import constraint actions by 86GWh for voltage control and to support system inertia.
- **Constraints Sterilised Headroom***: £2m increase, and the total volume of replacement energy increased by 36GWh.

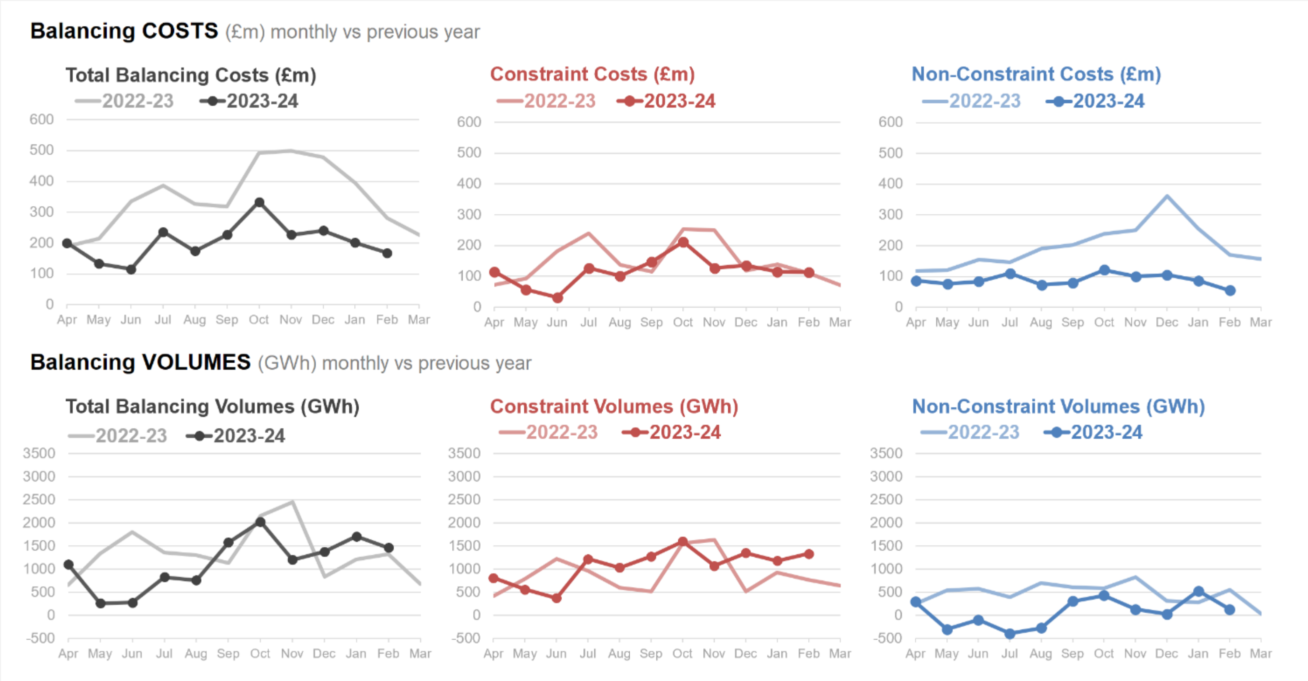
*73 more planned outages compared to last month yet remain lower than the previous months in 2023-2024. A relatively low number of planned outages tends to be the case during the winter months in preparation for peak demand conditions. This month also sees a slight decrease of the volume weighted average price for bids and offers following a downward trajectory of electricity prices of the month.

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

- **STOR**: £1.9m decrease, with a slight increase of 0.3GWh volume of actions from the BM*.
- **Operating Reserve**: £10.3m decrease due to using 248GWh less reserve required to secure the system.
- **Energy Imbalance**: £10.0m decrease despite using 140GWh more absolute volume of actions.

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

Constraint vs non-constraint costs and volumes



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 broad themes describing this cost are featured below. The figures will be revised once the data issue is resolved.

Constraint costs

Compared with the same month of the previous year:	We observe only a small increase of £2.7m in constraint costs compared to February 2023, despite the high increase of 562GWh in volume of constraint actions including the one extra day in February 2024.
Compared with last month:	Constraint costs were £1.7m lower than in January 2024, despite 153GWh more volume of constraint actions, driven by relatively high outturn wind.

Non-constraint costs**

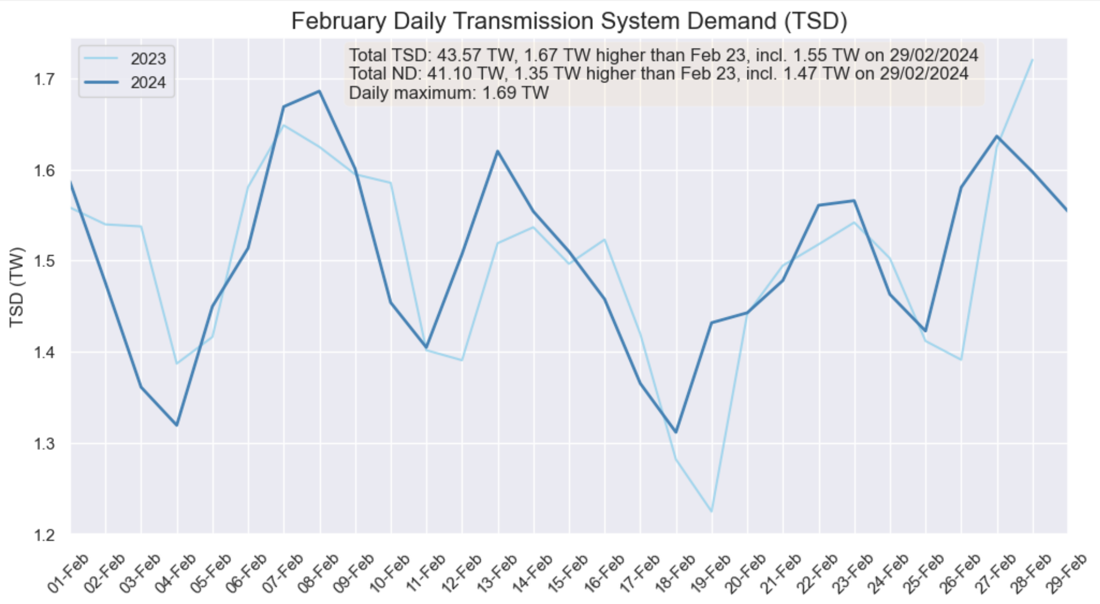
Compared with the same month of the previous year:	Non-Constraint costs were £115m lower despite the one extra day in February 2024 than in February 2023 due to: • Significantly lower average wholesale prices* • 420GWh lower Volume of actions.
Compared with last month:	Non-Constraint costs were £31.4m lower than in January 2024, due to 396GWh less absolute volume of actions were required to balance the system.

* Average wholesale price for February 24: £61/MWh compared to £139/MWh for February 23.

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

February daily Transmission System Demand (TSD*)

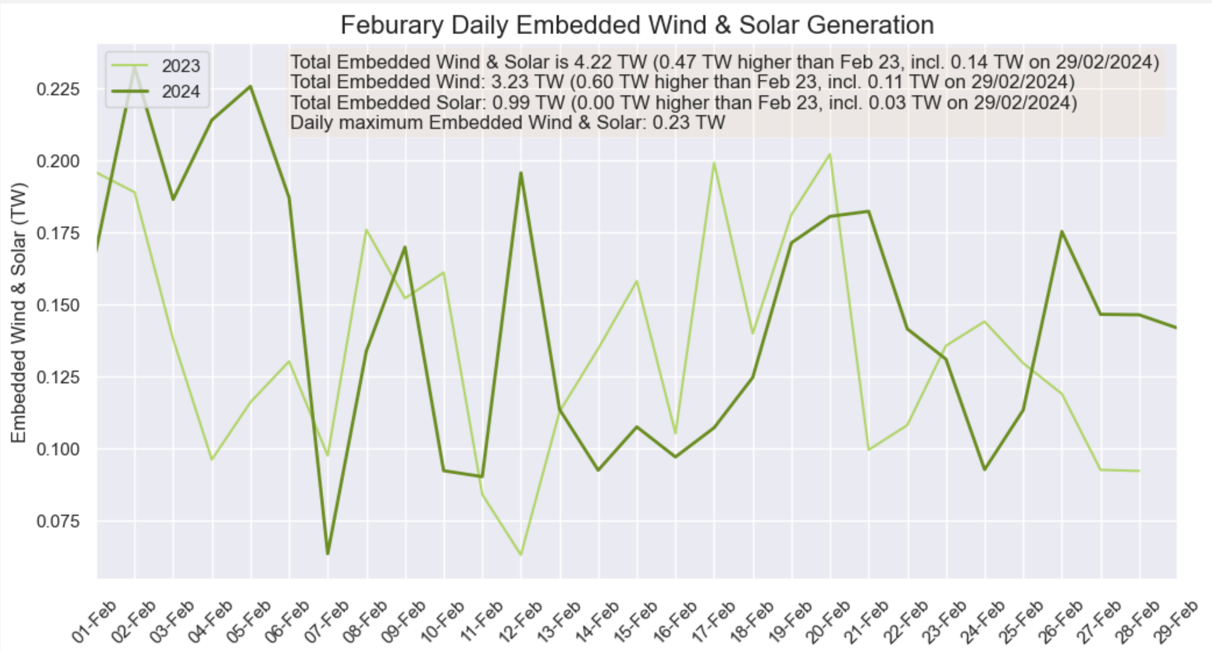
- **National Demand** (not shown below) was 1.4TW higher than February 2023, including 1.5TW for the extra day in February 2024.
- **Transmission System Demand*** was 1.7TW higher than February 2023, including 1.6TW for the extra day in February 2024.



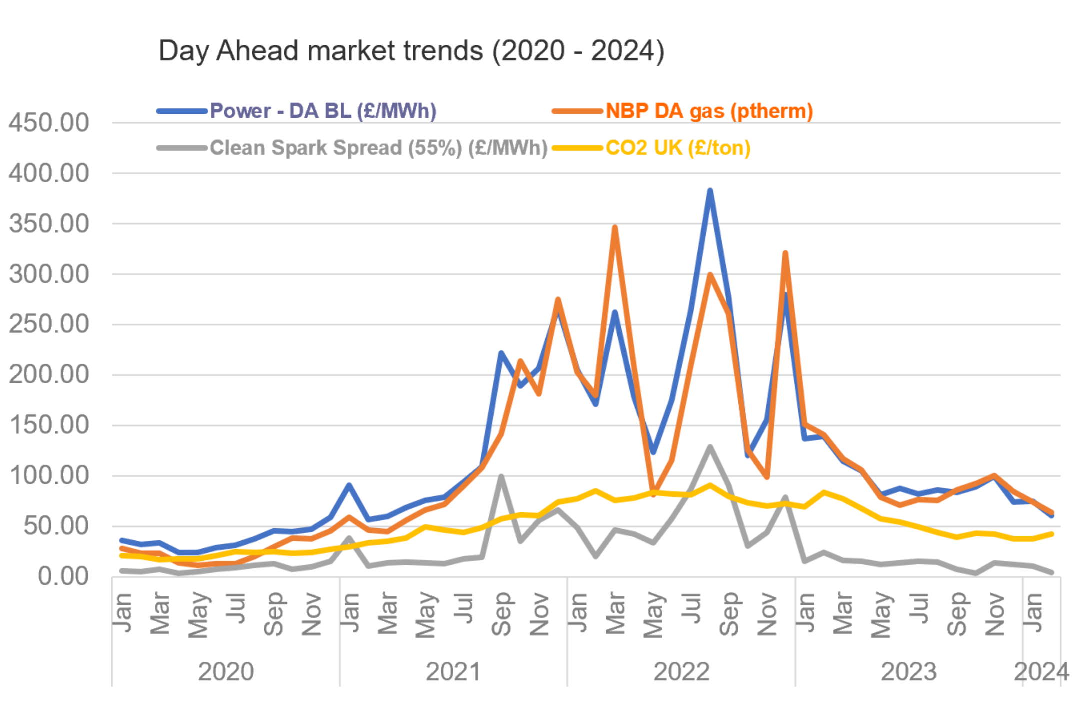
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand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

February daily Embedded Wind and Solar Generation

- **Embedded wind & solar generation** was 0.47TW higher than February 2023, including 0.14TW for the extra day in February 2024.
- The maximum embedded wind & solar generation occurred on 2nd February 2024 (0.23TW).



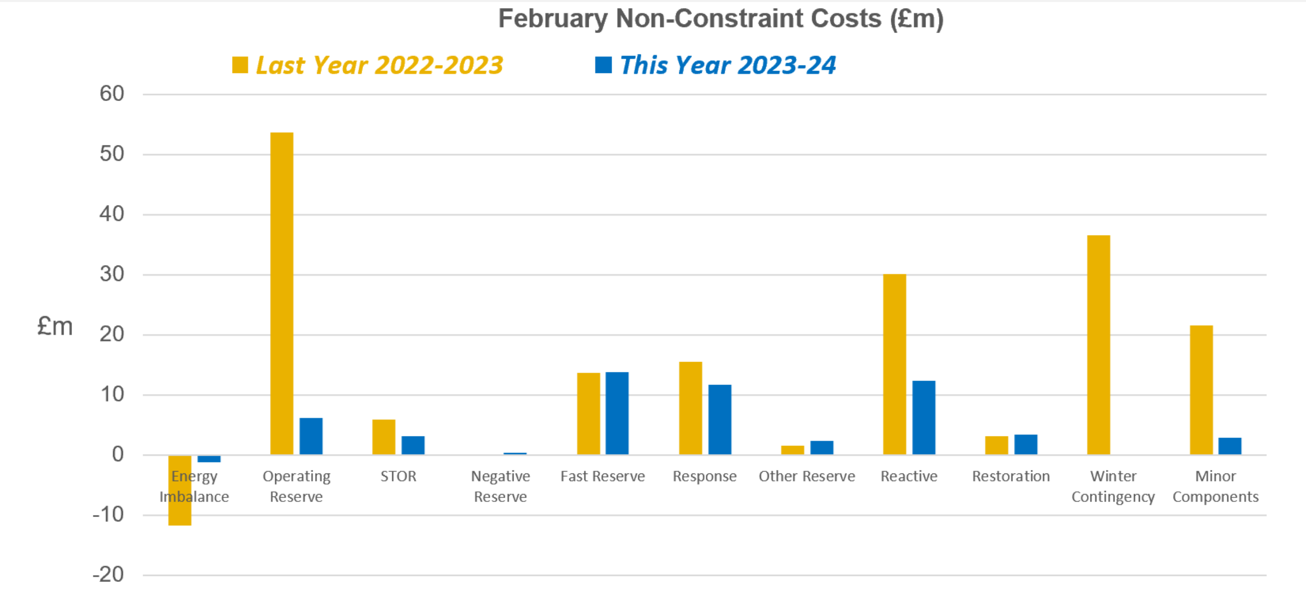
Price Trends in energy markets



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

Gas and power had a downward trajectory compared to last month with CO2 and Clean Spark Spread remain relatively steady. All trends remain lower compared to the previous year.

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

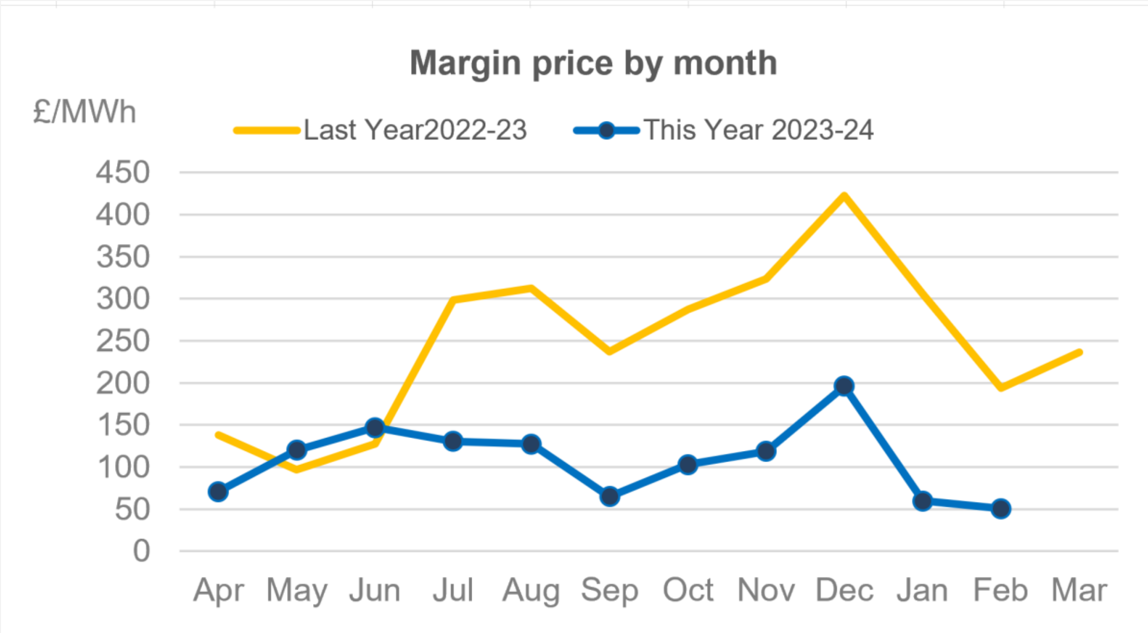


Comparing the non-constraint costs of February 2024 with those of February 2023, most categories showed a decrease or a small deviation:

- **Energy Imbalance** £10.6m increase due to 124GWh more volume of actions taken to balance the system.
- **Operating Reserve** £47.6m decrease mainly due to 104GWh less volume of reserve required to balance the system and the significant downward trajectory we have observed in all the energy related prices.

- **Reactive** £17.7m decrease, due to a significant drop in the weighted average price, from £11 per MVAR to £4.2 per MVAR.
- **Minor Components** decreased by £18.7m. 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



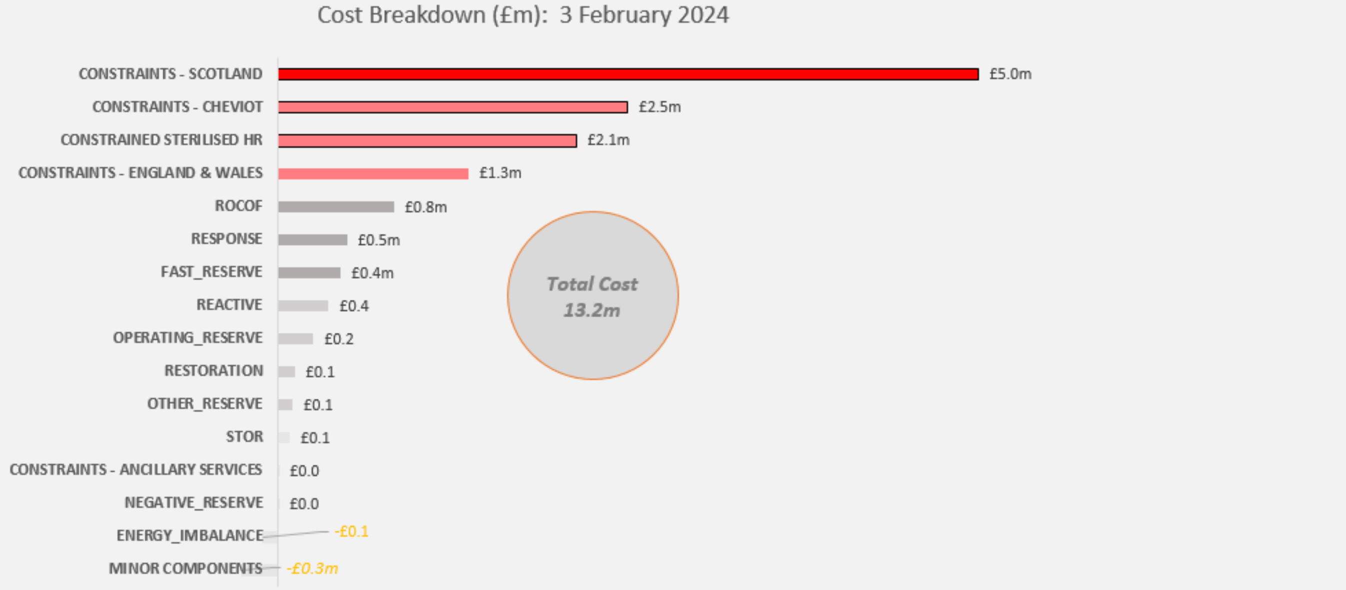
Margin prices (the amount paid for one MWh) have decreased compared to January 2024, and is also significantly lower than the corresponding period of the previous year.

Daily Costs Trends

February's balancing costs were £168m. £33m lower than the previous month, none of the days were recorded with costs above £15m with around 10% of the days had a daily total cost over £10m, resulting in a decrease of the average monthly daily cost by £0.7m (from £6.5m to £5.8m).

The lowest total daily cost of £2.1m was observed on 25 February, whilst the highest total cost was observed on 3 February when the total spend was £13.2m. Constraints in Scotland area were the major cost component driven by high renewable generation and low demand. No individual action was expensive, but high volumes of wind curtailment resulted in high total balancing costs for the day.

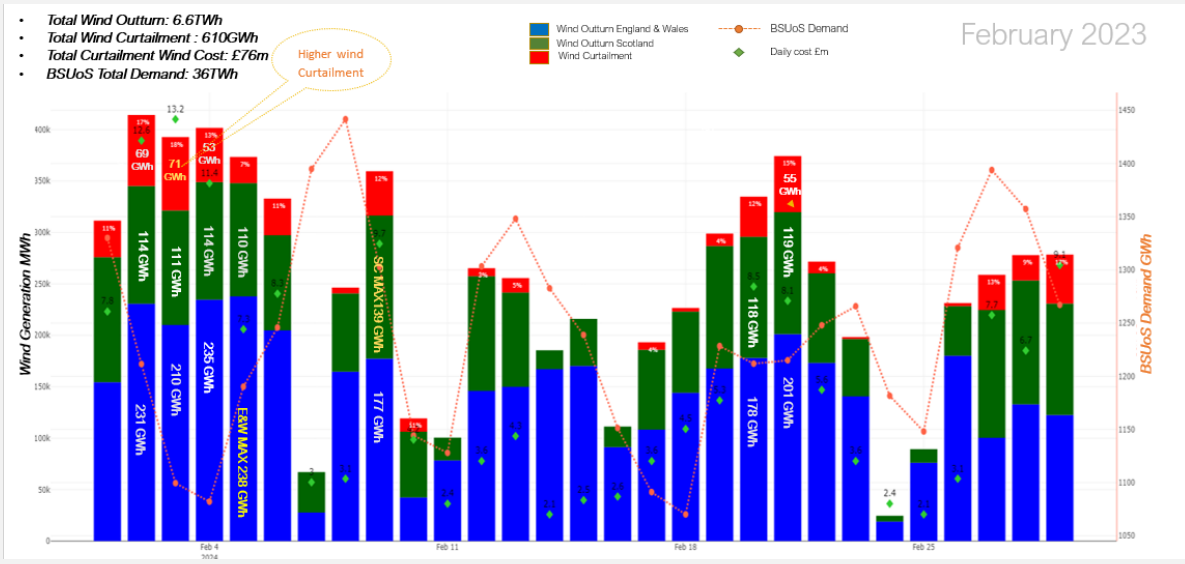
Cost breakdown for 3 February 2024



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

The chart below serves the purpose of supporting the transparency and the descriptions above. It is the daily "tour" of wind performance (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.

February 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

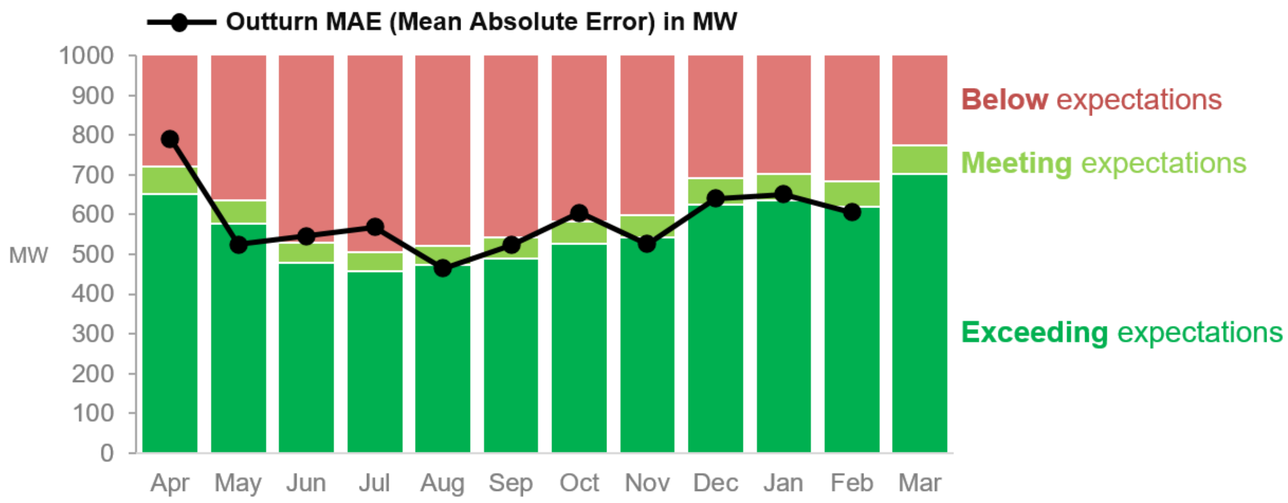


Table 4: 2023-24 Monthly absolute MW error vs Indicative Benchmark

	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**	**640**	**651**	**606**	
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 February 2024, the mean absolute error (MAE) of our day ahead demand forecast was 606 MW compared to the indicative ‘meeting expectations’ target of 684 MW, and indicative ‘exceeding expectations’ target of 618 MW.

The Met Office reports that February was one of the warmest and wettest on record, with generally unsettled weather but no named storms.

The February metric was largely influenced by only four significant error days, with 3GW being the greatest error recorded. February 12 was strongly affected by the solar forecast error (1.4GW), with 21 and 22 affected by the strong weather pattern which brought heavy rains and floods across England.

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 (1392)
1000 MW	240	17%
1500 MW	88	6%
2000 MW	23	2%
2500 MW	4	0%
3000 MW	1	0%

The days with largest MAE were Feb 12, 15, 21 and 22.

Demand Flexibility Service (DFS) tests were run on Feb 2, 8 and 29. 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 February.

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. The ESO uses 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 ESO runs 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 (eg. 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 February, we didn’t observe any dates affected by triad avoidance behaviour.

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.

February 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

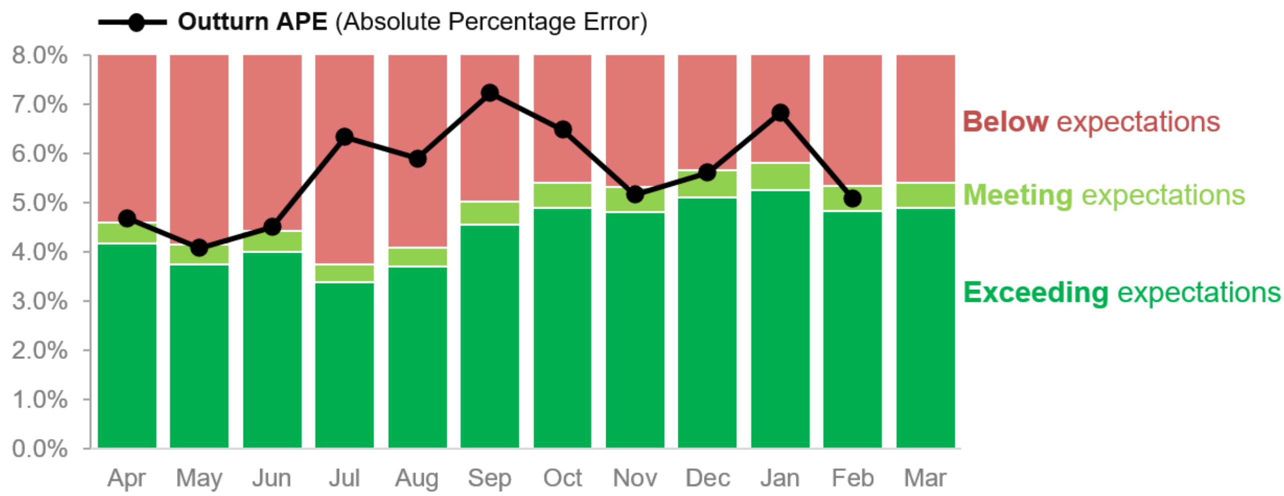


Table 5: 2023-24 BMU Wind Generation Forecast APE vs Indicative Benchmarks

	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	5.81	5.08	5.14
APE (%)	**4.69**	**4.08**	**4.50**	**6.34**	**5.90**	**7.23**	**6.48**	**5.16**	**5.61**	**6.82**	**5.08**	
Status	●	●	●	●	●	●	●	●	●	●	●	

Performance benchmarks:

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

Supporting information

In February, forecasting accuracy was largely affected by only three large-error days and the timing of weather systems passing over GB. The most unusual of the days (22) induced a low wind block in the North Sea, with wind production increasingly rapidly thereafter.

The general trend of performance continues to improve but remains largely sensitive due to poor quality weather data (available at Day Ahead) or rapidly changing weather patterns. The North Sea is proving to be a significant challenge, with a small number of windfarms routinely contributing to large errors on any given day.

Planned windfarm-outage events (where reported) are now used in the forecasts and we are exploring options to improve visibility of network-enforced (unreported) Power Park Module curtailment.

Dogger Bank A1 (300MW) came online this month and continue their commissioning.

For the month of February, the wind power forecast accuracy attained was 5.08%, against an indicative “meeting expectations” target of 5.33%.

Withdrawal of wind units

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

Missed / late publications

A system fault on 28 February, resulted in the Day Ahead forecast publication for 29 February being incorrectly reported. This issue was realised on 8 March, when the Settlement Metering data (for 29) was made available.

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.

February 2023-24 performance

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

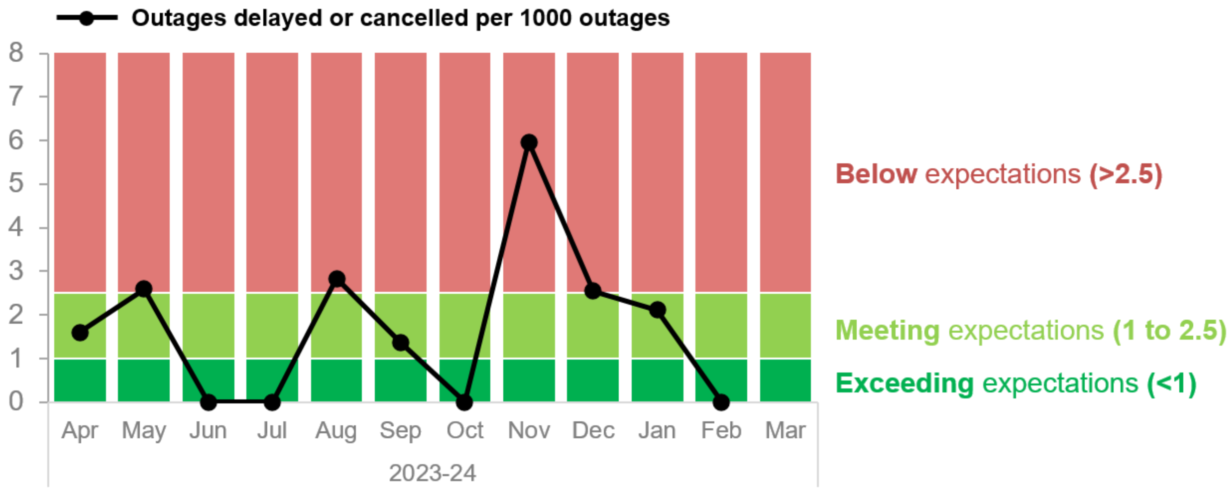


Table 6: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	624	739	645	644	706	734	704	671	393	472	545		6877
Outages delayed/cancelled due to ESO process failure	1	2	0	0	2	1	0	4	1	1	0		12
Number of outages delayed or cancelled per 1000 outages	1.6	2.6	0	0	2.8	1.4	0	6	2.5	2.1	0		1.74
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 February, the ESO has successfully released 545 outages and there has been zero delays or cancellations that occurred due to an ESO process failure. The number of stoppages or delays per 1000 outages is 0, which is inside the 'exceeds expectations' benchmark of less than 1 delays or cancellations per 1000 outages. The number of outages released in February 2023 was 512 and has increased in February 2024 to 545, this is due to an increased number of outage requests received from the TOs/DNOs for this period. Overall, the ESO is continuing to liaise with the TOs and DNOs to effectively facilitate system access through weekly or month liaison meetings to maximize system access.

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.

February 2023-24 performance

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

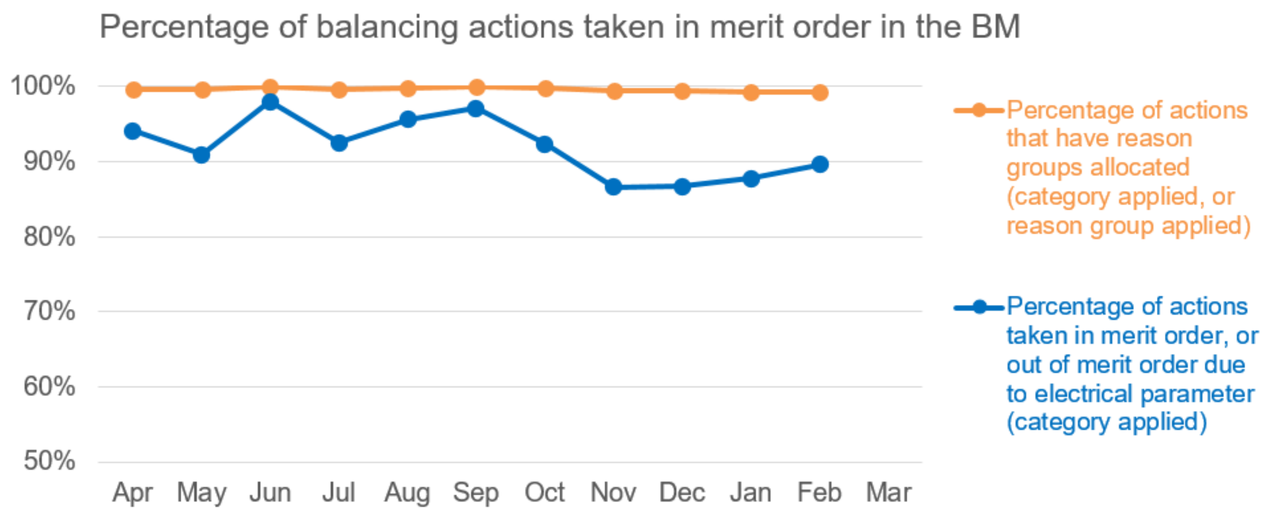


Table 7: Percentage of balancing actions taken outside of merit order in the BM

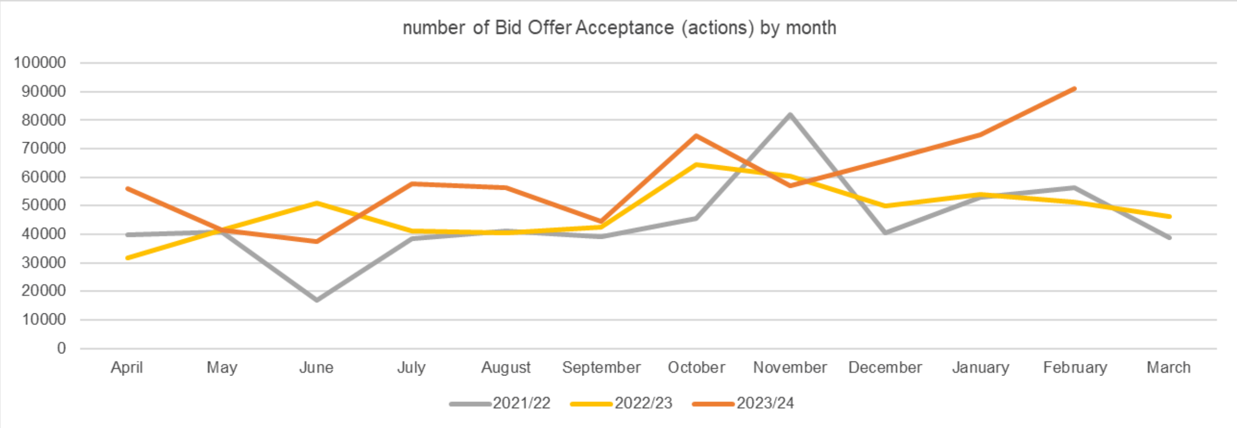
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	94.1%	90.9%	98.0%	92.5%	95.6%	97.1%	92.3%	86.6%	86.7%	87.8%	89.6%	
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.6%	99.9%	99.7%	99.8%	99.9%	99.8%	99.5%	99.5%	99.2%	99.3%	
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%	0.5%	0.8%	0.7%	

Supporting information

February performance

This month 89.6% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 9.7% 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 February, there were 91004 BOA (Bid Offer Acceptances) and of these, only 637 remain with no category or reason group identified, which is 0.7% of the total.

The number of BOA's will always vary from day to day and month to month in response to the system needs. However, numbers overall are significantly higher for the first 11 months of the current financial year at 14% higher than the previous year and 24% higher than the total of 2021/22. This appears to reflect the control engineers' increasing use of combinations of more economic smaller units to provide services within the Balancing Mechanism. We expect this trend to continue following the implementation of the Open Balancing Platform in December 2023.



Other activities

We continue to closely support LCP for the second phase of their independent analysis to provide greater insight into how the data can be used to identify and explain the reasons for out of merit despatch decisions.

We are developing the detailed plans for delivery of the improvements for Dispatch Transparency data, to incorporate the outcomes of the LCP analysis and continue to improve understanding and reporting. More information on this improvement timeline plus how we intend to engage with wider industry going forward and on an enduring basis will be provided at the follow-up storage webinar following LCP completion of the second phase work, expected March 2024.

We have identified the missing data periods from the published dataset for the current financial year (from 1 April 2023) and continue work to develop a reliable method to retrieve or reconstruct these sections to provide a comprehensive dataset. We are progressing with the 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.

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.

February 2023-24 performance

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

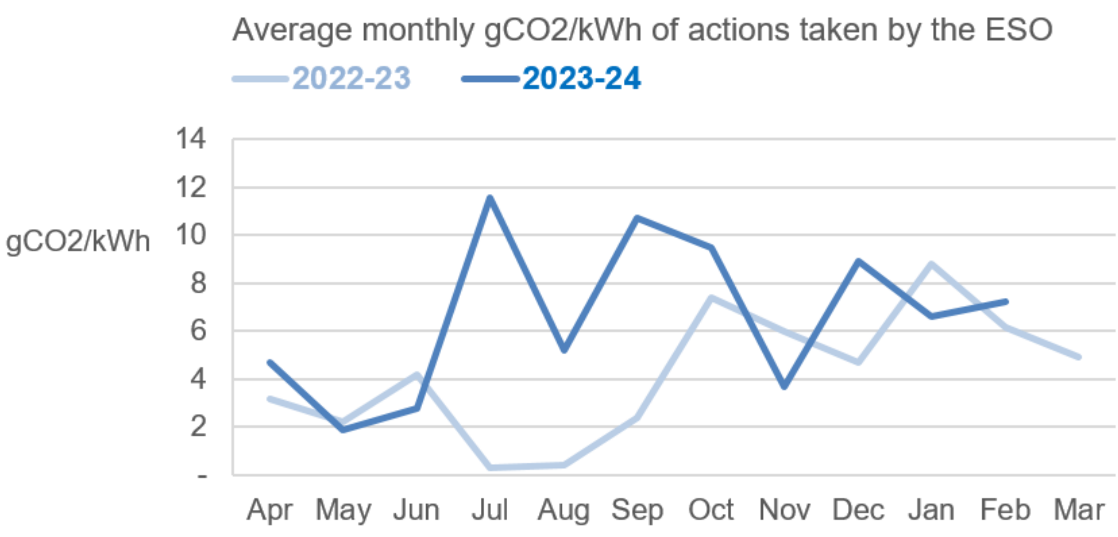


Table 8: Average monthly gCO2/kWh of actions taken by the ESO

	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	8.9	6.6	7.2	

Supporting information

***Data issue (Aug-Sep):** As reported previously there are eight days' incorrect data in August, one day's data missing in September and four in October. We have a temporary fix in place which means that data has been complete from November onwards. We're working to correct the August to October data and working on a permanent fix.

In February 2024, the average carbon intensity of balancing actions was 7.2gCO2/kWh. This is 1.0g lower than Feb 2023 (which was 6.2gCO2/kWh).

Across the month, ESO actions reduced the carbon intensity in 37% of settlement periods.

The majority of carbon intensity increase from ESO actions, was largely seen between 2-6 February during a period of high wind. Wind generation often delivered ~60% of the generation mix, peaking at 67.5%. This often required ~3GW of bids behind constraints in Scotland and Northern England, including the use of pump storage and batteries to reduce bid volumes on wind units. Use of pump storage and batteries mitigated further increases in carbon intensity. Specific outages also required limiting the Western HVDC link, resulting in 300MW of extra bids. Throughout the period, fossil fuel generation was required for both voltage and stability reasons. On the 28 February 2024, the minimum inertia requirement was reduced from 140 to 130 GVA.s. This should reduce the need to run fossil generation by approximately 3 units depending on system conditions.

The largest increase to carbon intensity was on 2 February 09:00-09:30. ESO actions increased the carbon intensity from 65 to 119gCO2/kWh. This was mainly due to increasing fossil fuel generation to balance the 3.9GW of bids which was needed to resolve constraints in Scotland and Northern England.

The lowest carbon intensity provided by the market was on the 4 February 14:00-14:30 (36gCO2/kWh) with high wind (~20GW) and other zero carbon sources providing around 75% of the generation mix (after ESO actions). Around 1GW of wind bids were required to solve constraints in Scotland and the North of England. This energy was replaced on coal and gas units, which raised the carbon intensity to 52gCO2/kWh.

RRE 1I Security of Supply

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

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

For context, the **Frequency Risk and Control Report** defines the appropriate balance between cost and risk, and sets out tabulated risks of frequency deviation as below, where ‘f’ represents frequency:

Deviation (Hz)	Duration	Likelihood
$f > 50.5$	Any	1-in-1100 years
$49.2 \leq f < 49.5$	up to 60 seconds	2 times per year
$48.8 < f < 49.2$	Any	1-in-22 years
$47.75 < f \leq 48.8$	Any	1-in-270 years

At the end of the year, we will report on frequency deviations with respect to the above limits and communicate any plans for future changes to the methodology.

February 2023-24 performance

Table 9: 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	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	1	0	0	
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0	0	0	0	0	0	0	0	

Supporting information

February performance

There were no reportable voltage or frequency excursions in February.

[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.

February 2023-24 performance

Table 10: 2023-24 Unplanned CNI System Outages (Number and length of each outage)

Unplanned	2023-24											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	0	0	0	0	0	0	0	
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0	

Table 11: 2023-24 Planned CNI System Outages (Number and length of each outage)

Planned	2023-24											
	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)	0	1 outage (203 mins)	0	
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0	

Supporting information

February performance

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

Notable events during February 2024

Enhancing Energy Storage in the Balancing Mechanism Webinar

In conjunction with colleagues across the ESO, we set out a plan in October 2023 detailing how we would enhance the use of energy storage assets in the Balancing Mechanism and held a stakeholder event to collaborate with industry on the plan.

Following on from this, on 12 February we hosted a follow up 'Enhancing Energy Storage in the BM' webinar, where we were joined by over 150 stakeholders from across the energy industry. The webinar was an opportunity to update industry on the progress to date on our actions to enhance the use of storage assets in our balancing activities, and future deliverables still to be implemented. We showcased how these actions have resulted in increased utilisation stats for volumes and instructions issued for Batteries and Small Balancing Mechanism Units, following the delivery of Release 1 of the Open Balancing Platform. We also presented additional measures integrated into the plan, including our proposal to change the 15-minute rule for batteries to 30 minutes from March 2024, in response to feedback received from industry and to enable longer instructions being issued to battery assets.

The slides and a recording of the session are available here. We have continued to provide updates on this work at the Operational Transparency Forum.

We have since published guidance on the changes to enable the transition to the 30-minute rule, and information for providers on how to engage with the ESO regarding asset transition plans.

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 and implemented in April 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. 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).

February 2023-24 performance

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

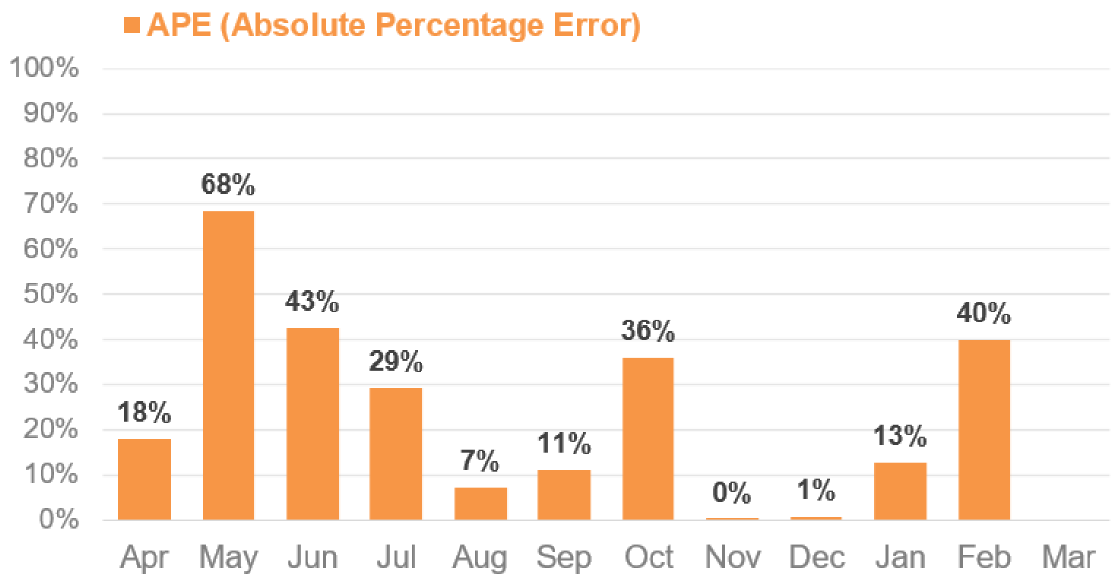


Table 12: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[4] - one-year view

	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	10.6	8.9	11.9	
Month-ahead forecast (£ / MWh)	12.7	13.8	10.8	9.7	9.7	11.4	10.6	10.5	10.6	10.0	8.5	
APE (Absolute Percentage Error)[5]	**18.0**	**68.4**	**42.5**	**29.1**	**7.2**	**11.0**	**36.0**	**0.0**	**0.7**	**12.7**	**39.9**	

[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

February Performance:

Actuals out-turned below forecast for February, with an Absolute Percentage Error of 39.9. The increase in absolute percentage error from last month was a result of below forecast costs.

Costs:

February outturn costs were around the 10th percentile of the forecast produced at the beginning of January. There was a 30% decrease in the average wholesale electricity price between the January forecast for February (£85/MWh) and February outturn (£59/MWh). As stated by Ofgem, electricity prices are heavily impacted by changing gas prices because of the importance of gas-fired power stations as the marginal unit to meet demand. Prices for forward delivery contracts of gas have continued to fall and these are a significant driver of the decrease in wholesale electricity prices we are seeing. Additional to the above constraints, outturn for the month were lower than forecast.

Volumes:

February actual volume was below the January forecast. This small variance could be due to weather and temperature fluctuations.

Forecast for February made at the start of January: 24.3TWh

Outturn volume for February: 23.8TWh

Notable events during February 2024

Frequency Response technical webinar

The Ancillary Service Reforms (ASR) Response Reform team held a webinar on 5 February with Balancing Mechanism Units (BMU) providers to explain the changes to the reason codes that are used in sending disarming and re-arming instructions to Dynamic Moderation (DM), Dynamic Regulation (DR) and Dynamic Containment (DC) providers. The webinar covered:

1. The details of the new reason codes and how, when, and why they will be used.
2. When they will be coming into effect and
3. What testing is available to the providers in advance of the move to the new codes.

We received positive feedback from the participants of the webinar resulting in average feedback score of 8.3/10.

Balancing Settlement Code (BSC) Panel teach in on P462 modification

On 9 February, we hosted a teach in session for the BSC Panel to provide further insight into an ESO proposed BSC modification, P462. The modification seeks to resolve an identified structural issue with the interaction between the Balancing Mechanism (BM) and support mechanism arrangements. The session's intent was to provide an in depth look at the identified issue and proposed solution, ahead of the modification assessment process. The highly interactive session allowed for questions to be resolved and identified further topics to be explored within the workgroup process. The session was well attended and highly engaging, with positive feedback from stakeholders.

You can follow the progress of P462 on the Elexon website.

Charging Futures webinar and set up Storage TNUoS subgroup

Transmission Network Use of System (TNUoS) charges recover the cost of the investment in the UK electricity (High Voltage) transmission system. The intent is to charge users of the system in a non-discriminatory and cost reflective manner, reflecting their load on and use of the network. Storage is currently aligned to generation within the charging methodology, however it operationally exhibits elements of behaviour of both generation and demand, so it doesn't align directly to either model. The increasing number of assets connecting with a storage component highlights a need to review whether storage is treated appropriately within the charging methodology.

Our engagement with industry to date has identified potential anomalies in the approach to TNUoS for electrical storage technologies. To address this feedback and potential anomalies, we have committed to setting up a storage subgroup. This subgroup will enable an engagement forum for industry to get ahead of technological developments and potential issues linked to charging, with the end goal being a fit for purpose charging methodology that is appropriate for storage.

On the 14 February, we hosted a Charging Futures webinar with industry, outlining the case for change, timelines, and the application process for becoming a subgroup member. We received positive feedback from those who attended the webinar, and it was recognised that the ESO is being proactive about acting on the need for change and working with industry to come up with recommendations rather than doing so in isolation.

We have now shortlisted a list of subgroup members and is in the process of applying for innovation funding to support industry with this work over the coming months.

Interconnector Framework external stakeholder event

In October 2023, we published a request for input (RFI) to hear from industry on the development of an Interconnector Framework. The aim of the framework is to enable consistency for interconnectors operating in GB markets and to aid transparency around how interconnectors operate and work with the ESO. Through the RFI, we gathered useful insight into industry's opinions on the creation of a framework and initial thoughts on potential scope of the framework. On the 29 February, we hosted an industry session to provide an overview of the RFI industry responses and provide a further opportunity for discussion with a wide range of stakeholders.

The session covered the following topics:

- Industry's view on the key opportunities of creating an Interconnector framework.
- Industry's current uncertainties.
- Industry's views on the key complexities when considering the scope of the framework.
- Industry's suggestions for what a 'Framework' could look like.
- Time for continued discussion on the key themes identified.
- Overview of next steps for the workstream.

The outcomes of the session are fundamental in supporting us in building a view on scope before further industry consultation and establishing key gaps where industry feels the ESO should provide a viewpoint. As we saw in the RFI some stakeholders continue to express strong support for the creation and implementation of a framework while other stakeholders have reservations as to whether a framework is required and do not feel there is a clear case for change. We will continue to engage with industry through a series of events over the coming months to refine the case for change and potential scope of any framework.

2024 Capacity Market auctions concluded

The Electricity Market Reform Delivery Body (EMR DB) assessed over 1,000 applications during the prequalification process over summer 2023 and rejected approximately 5% for failing to meet all the prequalification requirements. The most common reasons for rejection were because applicants misunderstood new regulatory requirements or because applications were of insufficient quality and missed information required under the Rules. During the Tier 1 disputes process, the EMR DB was able to prequalify the majority of applicants who had previously been rejected, following receipt of information or correction of errors to make the applications compliant with the CM Rules. Three applicants that were unsuccessful in their Tier 1 dispute raised Tier 2 disputes with Ofgem. Ofgem upheld the EMR DB’s decision on two of the disputes and overturned one of them. The EMR DB is working with Ofgem on a change to clarify the intent of the Rules associated with the overturned rejection.

On 20 February 2024, the EMR DB ran the T-1 Auction and on 27 February 2024, the EMR DB ran the T-4 Auction. The Auction Monitor Reports for both auctions have been published by DESNZ, confirming that the Auctions were run in accordance with the CM Rules and Regulations.

EMR new portal open for registration

The new EMR customer portal has been live since the 22 January for registration. Over 600 companies have registered so far representing ~97% of capacity under live contracts. Based on customers’ feedback, we have implemented two improvements to the system and process. We are opening the testing environment of the new portal on the 20 March for ~70 customers who registered interest in the customer familiarisation exercise. This will help us identify any issues as well as build customer’s confidence in using the new system before it goes live in May.

If you have any further questions about company and user registration and management, please get in touch with the Capacity Market Prequalification & Disputes Team via email box.emr.prequal@nationalgrideso.com.

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

Notable events during February 2024

Bridging the Gap webinar

Our Bridging the Gap webinar for 2024 took place on 28 February. Bridging the Gap aims to make progress on areas of uncertainty concerning net zero delivery through stakeholder engagement and dialogue. The team presented stakeholder views on how to accelerate progress on heat decarbonisation and highlighted the 6 bridges to cross include strategic direction on heat and building consumer trust. 200 stakeholders attended the webinar and provided positive feedback on the content and the webinar presentation. The webinar highlighted next steps forward including:

- Flowing findings into the Future Energy Scenarios for 2024 as well as the updating heat modelling
- Flowing findings into Flexibility Market reform and Ofgem's decision on the Market Facilitator role
- Flowing findings into the Strategic Energy Planning programme of work
- Further quantitative work to help inform the strategic direction on heat itself.

Early Competition Webinar and Publishing Implementation Update

The Early Competition team are now in the final stages of implementation of the model, working closely with Ofgem as they progress drafting of tender regulations and new licence conditions to allow the NESO to introduce competition in the design, delivery, and operation of transmission assets.

On 1 February we published our Early Competition Implementation (ECI) update, which details all the work we've done since the initial Early Competition Plan (ECP) document in 2022 and presents our final proposals for the model to Ofgem. On 22 February, the Network Competition team also held a webinar which detailed the updated commercial model for early competition, finishing with a short Q&A. The webinar was well received and had positive feedback. Watch the webinar here: Events and webinars | ESO (nationalgrideso.com)

The Network Competition team have been holding bilaterals to discuss the impact of early competition on the supply chain for onshore transmission projects, and to understand what market signalling is sufficient to enable the supply chain to respond the needs of future projects. Visit our website for more information on early competition.