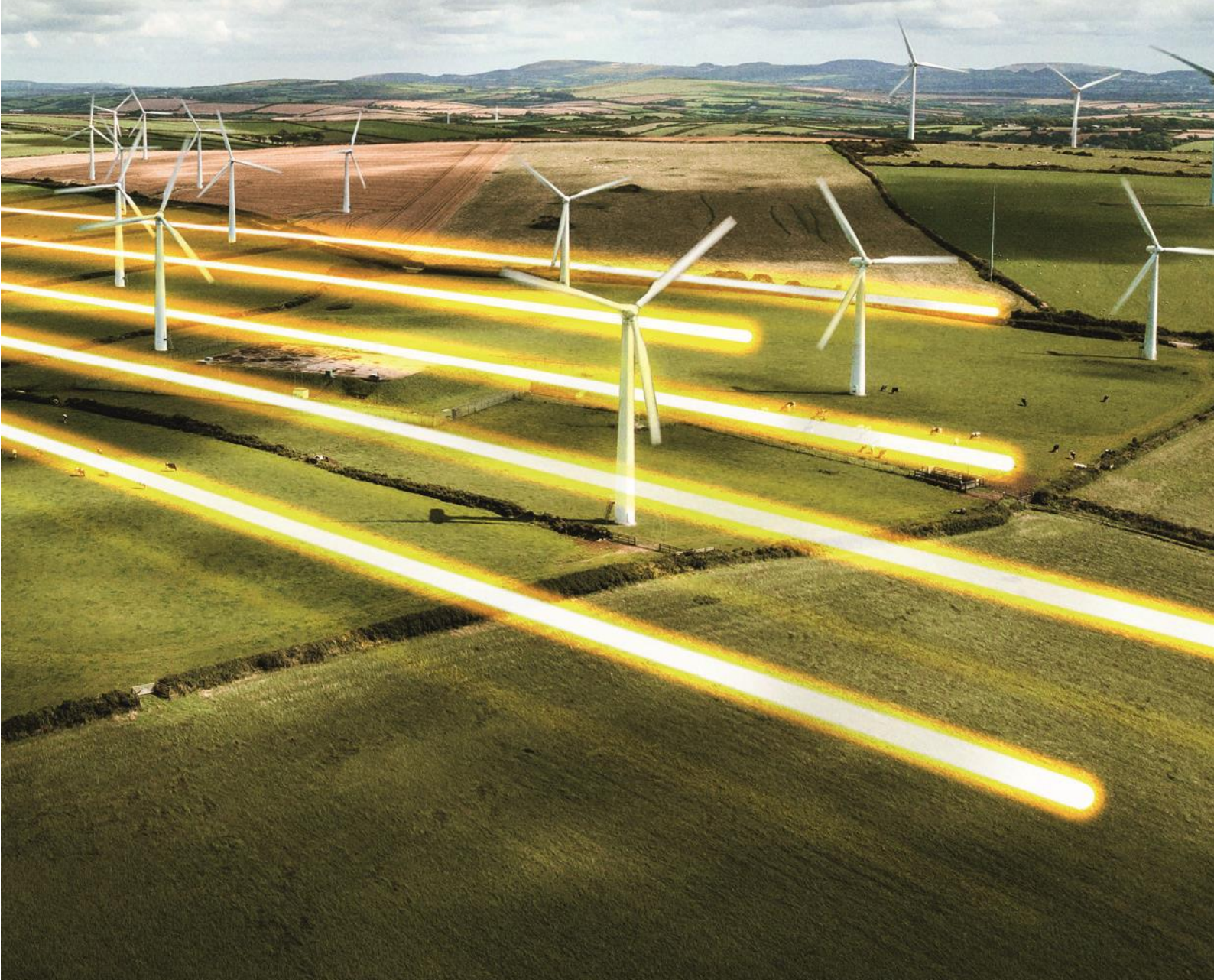


ESO RII02 Business Plan 1 (2021-23)

November 2022-23 Incentives Report

23 December 2022



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Introduction

The ESO's [RIIO-2 Business Plan](#), submitted to Ofgem in December 2019, sets out our proposed activities, deliverables, and investments for 2021-26 to enable the transition to a flexible, net zero carbon energy system.

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 1" period, which runs from 1 April 2021 to 31 March 2023.

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 [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. 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](#).

Every six months, we produce a more detailed report covering all of the criteria used to assess our performance.

Please see our [website](#) for more information.

Summary of Notable Events

In November we have successfully delivered the following notable events and publications:

- A new daily wind record was set on 2nd November. Wind generated more than 20GW for the first time in UK history, providing over half of our daily electricity.
- Our Demand Flexibility Service launched on 4 November which will allow businesses and the public to be paid for the first time to reduce/move their electricity use out of peak hours following a signal from the ESO. A collaborative effort across industry enabled the launch of this innovative service at pace to tackle the unique challenges of this winter
- The ESO has secured new contracts worth £1.3bn to provide network stability services without the use of carbon between 2025 and 2035. These contracts represent a cost benefit of £14.9bn between 2025 and 2035 and bring us one step closer to delivering a net-zero electricity system.
- On November 24th and 29th the ESO's Net Zero Market Reform (NZMR) programme hosted two workshops with stakeholders across 144 different organisations. The purpose of these workshops was to gather views from these stakeholders on ESO commissioned work from the business and technology consultancy Baringa. Baringa are working with the NZMR team to provide an independent assessment of market reform options and packages.
- Head of National Control, Craig Dyke held a call with the CEO of the Ukrainian TSO, Volodymyr Kudrytskyi, during November. The call was to discuss how ESO can assist them going forward after missile strikes destroyed major parts of Ukraine's infrastructure.
- On the 22nd of September 2022 the ESO (in partnership with the TO's and Ofgem) launched the first TEC (Transmission Entry Capacity) Amnesty since 2013 giving customers the opportunity to Terminate or reduce TEC with a reduced or no cost. Following industry feedback, it has now been decided to extend the expression of interest window for the TEC Amnesty from the 30th November 2022 to the end of April 2023.
- The Market Monitoring team has produced a new 12 month review which shares details of the team's role and how they monitor the market, plus insight into the last year of market activity.
- The second tender for the B6 Constraint Management Pathfinder (CMP), aimed at reducing constraint costs, has concluded and contracts have been successfully awarded. Four contracts were able to start early from the previous tender and saved £30m in the first four months of operation.
- Following a government independent review of net-zero, which questioned whether the United Kingdom is on track to achieve net zero in the most economic, efficient, and pro-growth way. ESO have submitted a response highlighting the need for decarbonisation to accelerate growth in the UK, by increasing the development of flexible technologies alongside the right markets, whole system strategic planning and an independent system operator.

Table 1: Summary of Metrics and RREs for Role 1

This table summarises our Metrics and Regularly Reported Evidence (RRE) performance for November 2022.

| Metric/Regularly Reported Evidence | | Performance | Status |
|------------------------------------|---|--|--------|
| Metric 1A | Balancing Costs | £502m vs benchmark of £176m | ● |
| Metric 1B | Demand Forecasting | Forecasting error of 2.3% vs benchmark of 1.8% | ● |
| Metric 1C | Wind Generation Forecasting | Forecasting error of 5.5% vs benchmark of 5% | ● |
| 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 | 88.4% of actions taken in merit order | N/A |
| RRE 1G | Carbon intensity of ESO actions | 6.0gCO 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 13% | N/A |

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

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

Gareth Davies

ESO Regulation Senior Manager

Role 1 Control Centre operations

Metric 1A Balancing cost management

November 2022 Performance

This metric measures our balancing costs based on a benchmark that has been calculated using the previous three years' costs and outturn wind generation. It assumes that the historical relationship between wind generation and constraint costs continues, recognising that there is a strong correlation between the two factors. Secondly, it assumes that non-constraint costs remain at a calculated historical baseline level. A more detailed explanation follows:

At the beginning of the year the non-adjusted balancing cost benchmark is calculated using the methodology outlined below. The final benchmark for each month is based on actual outturn wind, but an indicative view is provided in advance based on historic outturn wind.

- i. Using a plot of the historic monthly constraints costs (£m) against historic monthly outturn wind (TWh) from the 36 months immediately preceding the assessment year, a best fit straight-line continuous relationship is set to determine the monthly 'calculated benchmark constraints costs'.
- ii. Using a plot of historic monthly total balancing costs (£m) against historic monthly constraint costs from the 36 months immediately preceding the assessment year, a best fit straight-line continuous relationship is set, with the intercept value of that straight line used to determine the monthly 'calculated benchmark non-constraints costs'.
- iii. An equation for the straight-line relationship between outturn wind and total balancing costs is then formed using the outputs of point (i.) and point (ii.).
- iv. The historic 3-year average outturn wind for each calendar month is used as the input to the equation in point (iii). The output is 12 ex-ante, monthly non-adjusted balancing cost benchmark values. The sum of these monthly values is the initial 'non-adjusted annual balancing cost benchmark'. The purpose of this initial benchmark is illustrative as it will be adjusted each month throughout the year.

$$\text{Total Balancing Costs}^1 (\text{£m}) = (\text{Outturn Wind (TWh)} \times 25.254 (\text{£m/TWh})) + 15.972 (\text{£m}) + 50.4 (\text{£m})$$

A monthly ex-post adjustment of the balancing cost benchmark is made to account for the actual monthly outturn wind. This is done by following the process described in point (iv.) above but using the actual monthly outturn wind instead of the historic 3-year average outturn wind of the relevant calendar month. The annual balancing cost benchmark is then updated by replacing the historic value for the relevant month with this actual value.

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](#).

¹ This is the benchmark formula for 2022-23. The benchmark for 2021-22 was calculated as: (Outturn Wind (TWh) x 12.16 (£m/TWh)) + 19.75 (£m) + 41.32 (£m)

Figure 1: Monthly balancing cost outturn versus benchmark – two-year view

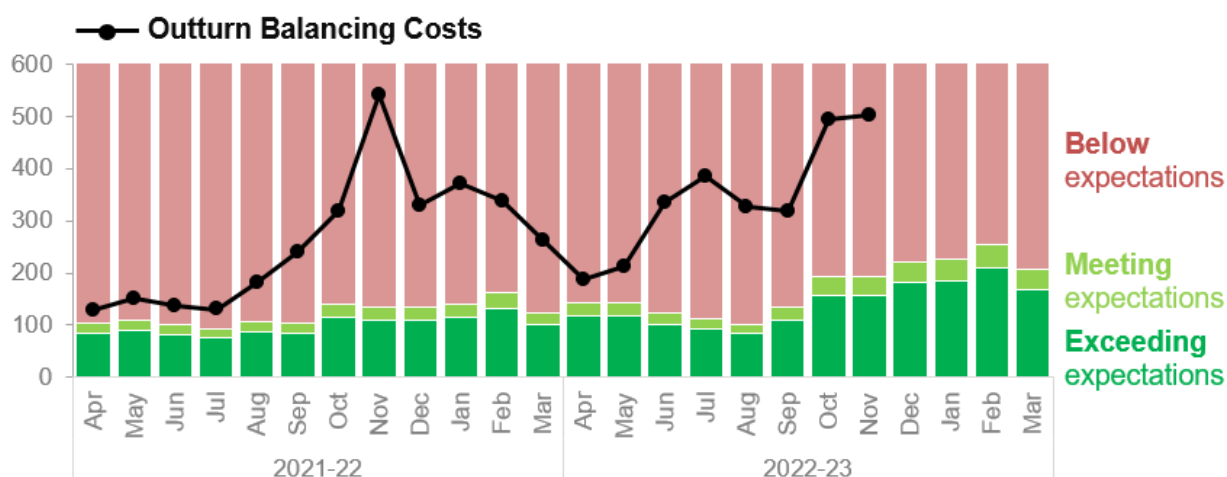


Table 2: Monthly balancing cost benchmark and outturn

| All costs in £m | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | YTD |
|--|------------|------------|------------|------------|------------|------------|------------|------------|-----|-----|-----|-----|-------------|
| Benchmark: non-constraint costs (A) | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | | | | | 403 |
| Indicative benchmark: constraint costs (B) | 97 | 89 | 90 | 81 | 101 | 107 | 146 | 133 | | | | | 844 |
| Indicative benchmark: total costs (C=A+B) | 147 | 139 | 140 | 132 | 152 | 158 | 196 | 183 | | | | | 1247 |
| Outturn wind (TWh) | 3.8 | 3.8 | 3.1 | 2.8 | 2.3 | 3.5 | 5.6 | 5.6 | | | | | 30.4 |
| Ex-post benchmark: constraint costs (D) | 80 | 80 | 62 | 52 | 42 | 73 | 125 | 125 | | | | | 640 |
| Ex-post benchmark (A+D) | 130 | 130 | 113 | 130 | 93 | 123 | 176 | 176 | | | | | 1043 |
| Outturn balancing costs² | 188 | 213 | 335 | 385 | 327 | 318 | 493 | 502 | | | | | 2761 |
| Status | ● | ● | ● | ● | ● | ● | ● | ● | | | | | ● |

Rounding: monthly figures are rounded to the nearest whole number, with the exception of outturn wind which is rounded to one decimal place.

Performance benchmarks

- **Exceeding expectations:** 10% lower than the balancing cost benchmark
- **Meeting expectations:** within ±10% of the balancing cost benchmark
- **Below expectations:** 10% higher than the balancing cost benchmark

² Please note that previous months' outturn balancing costs are updated every month with reconciled values

Supporting information

Data issue: Please note that due to a data issue on a few days over the previous months, the Minor Components line in Non-Constraint Costs is capturing some costs on those days 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.

November performance

The Balancing costs for November 2022 were £502m, which is an increase of £9m from October 2022.

A new cost category, Winter Contingency, has been added to the non-constraint costs from October 2022. In response to the disruption of gas supplies to Europe, the Secretary of State approached ESO to secure additional non-gas capacity over winter 2022/23. The ESO has contracted five generation units across three coal fired power stations to stay available across this winter to provide extra generation should it be needed to ensure electricity security of supply. These contracts began in October 2022 and are the main driver of the significant increase in non-constraint costs since September 2022.

The underlying non-constraints costs (excluding Winter Contingency) decreased this month but remained higher than last year. Constraint costs showed a slight decrease this month and is significantly lower than last year.

Even though the total volume of actions was higher this month compared to November 2021, the total cost from this month decreased compared to the corresponding period last year, due to lower wholesale prices than last year.

Breakdown of costs vs previous month

Balancing Costs variance (£m): November 2022 vs October 2022

| | (a) | (b) | (b) - (a) | decrease ◀ increase ▶ | |
|----------------------|------------------------------|--------------|--------------|-----------------------|---|
| | Oct-22 | Nov-22 | Variance | Variance chart | |
| Non-Constraint Costs | Energy Imbalance | -9.2 | -8.9 | 0.3 | |
| | Operating Reserve | 64.1 | 59.2 | (4.9) | █ |
| | STOR | 5.6 | 13.4 | 7.8 | █ |
| | Negative Reserve | 0.4 | -0.5 | (0.9) | |
| | Fast Reserve | 17.1 | 17.2 | 0.1 | |
| | Response | 27.4 | 21.5 | (5.9) | █ |
| | Other Reserve | 2.5 | 1.5 | (1.0) | |
| | Reactive | 41.4 | 36.2 | (5.2) | █ |
| | Restoration | 3.5 | 4.5 | 1.0 | |
| | Winter Contingency | 62.0 | 60.0 | (2.0) | █ |
| | Minor Components | 21.5 | 47.9 | 26.5 | █ |
| Constraint Costs | Constraints - E&W | 53.9 | 51.6 | (2.3) | █ |
| | Constraints - Cheviot | 5.7 | 4.0 | (1.7) | █ |
| | Constraints - Scotland | 36.0 | 33.5 | (2.4) | █ |
| | Constraints - Ancillary | 1.3 | 3.1 | 1.8 | █ |
| | ROCOF | 23.8 | 0.0 | (23.8) | █ |
| | Constraints Sterilised HR | 136.1 | 157.7 | 21.6 | █ |
| Totals | | | | | |
| | Non-Constraint Costs - TOTAL | 236.2 | 252.0 | 15.8 | █ |
| | Constraint Costs - TOTAL | 256.8 | 250.0 | (6.8) | █ |
| | Total Balancing Costs | 493.0 | 502.0 | 9.0 | █ |

As shown in the total rows above, the total balancing costs this month was slightly higher than last month, and this variance was due to non-constraint spend which increased by almost £16m. Constraint costs were down by almost £7m.

Against the constraint category, the breakdown shows that RoCoF and Constraints Sterilized Headroom were the key factors behind this difference, as all the other categories showed a decrease or minor variance.

Within the Non-Constraint costs, an increase was seen in the STOR and Minor Components, whilst all the other categories either decreased or showed little variance from the previous month.

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

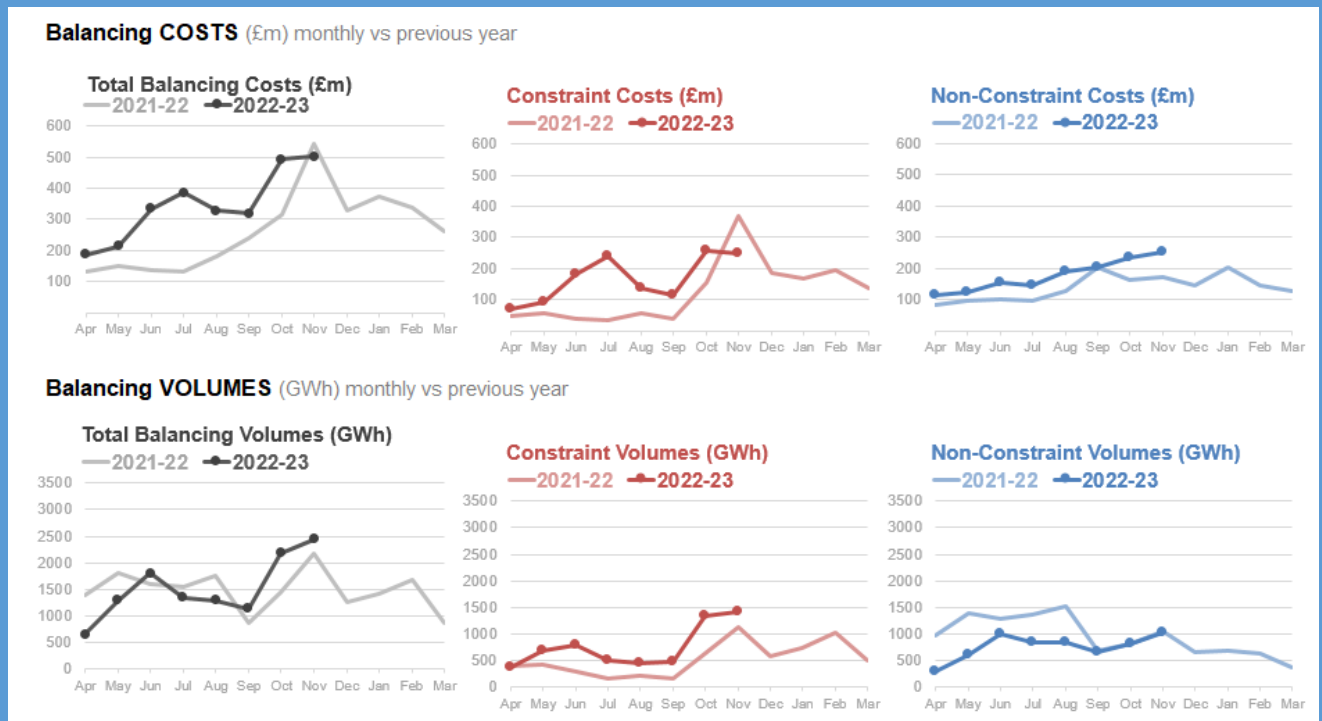
- **RoCoF: £23.8m decrease.** Decrease driven by the inertia requirements being met by synchronised generation, whether self-dispatched or instructed for voltage or another requirement.
- **Constraint Sterilised HR: £21.6m increase.** As more generation was restricted behind constraints, the higher spend was to replace the additional energy available on constrained generators elsewhere outside the constraint.

Non-constraint costs: The main drivers of the biggest variances this month are detailed below:

- **Minor components: £26.5m increase.** We have identified that £14m in this category should be in the Operating reserve category. It will be corrected once the data issue is resolved.
- **STOR: £7.8m increase** due to tightening margins and high wholesale prices which are reflected in STOR participants submitted bids and hence the cleared costs of procuring the service has increased

Constraint vs non-constraint costs and volumes

Restoration: Please note that the 2020-21 incentivised balancing cost figures did not include costs for restoration, but from April 2021 these are included. To enable a direct comparison, in the graphs below these restoration costs are included for both 2020-21 and 2021-22.



Please note that a portion of the **Minor Components** spend contributing to non-constraint cost and volume is actually 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 ~£119m lower than in November 2021 due to lower volume of actions and significantly lower wholesale prices compared with last year.

Compared with last month:

- Constraint costs shown a little variance (£7m lower) from October 2022 due to slightly lower volume of actions.

Non-constraint costs

Compared with the same month of the previous year:

Non-Constraint costs were around £79m higher than in November 2021 due to:

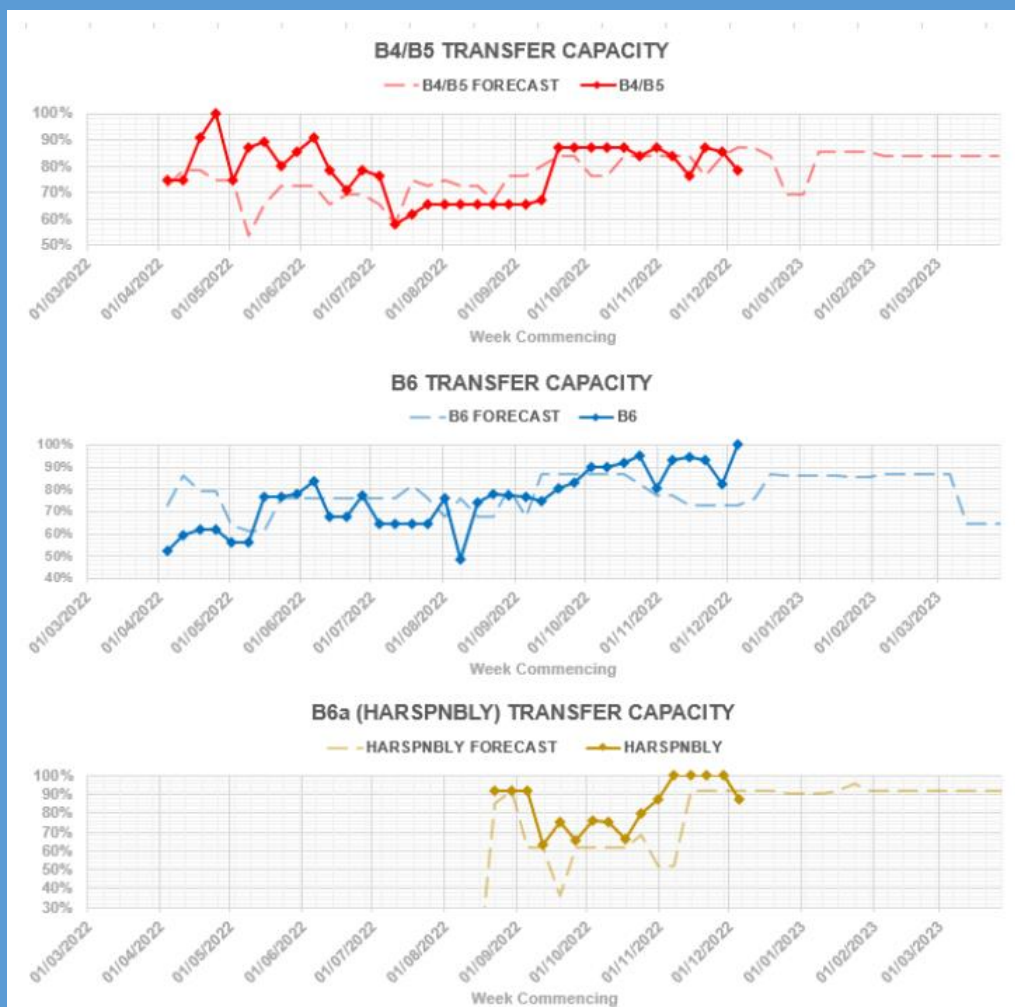
- Winter contingency contracts
- Higher volume of actions

Compared with last month:

Non-Constraint costs were £16m higher than in October 2022 due to:

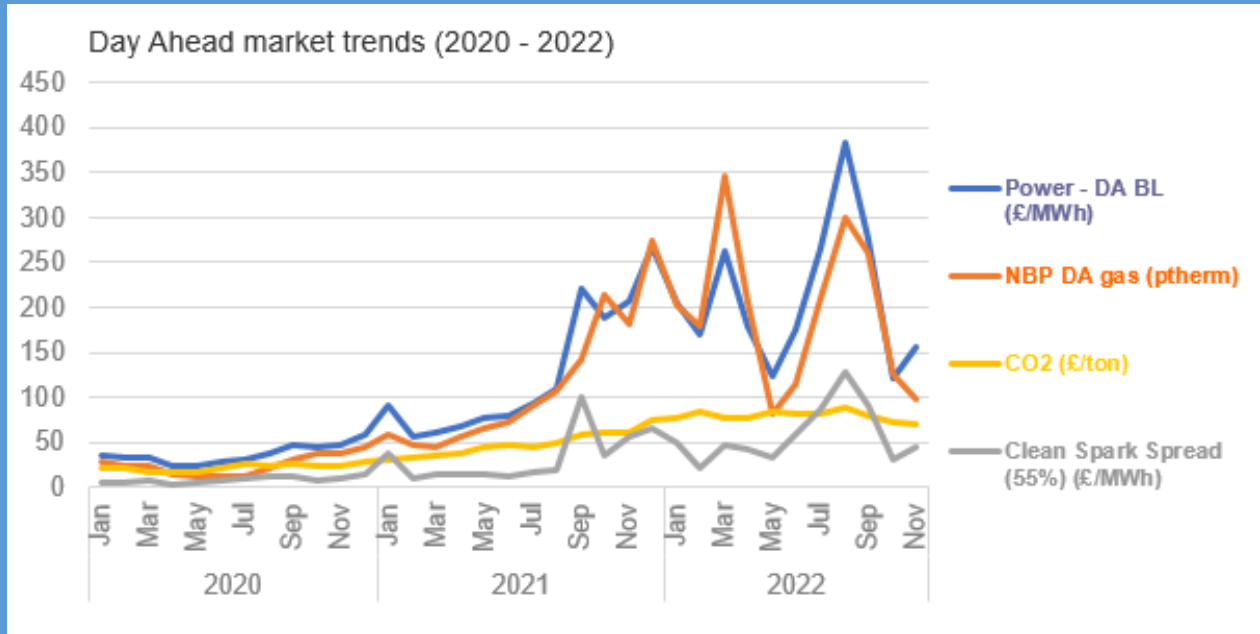
- Winter contingency contracts
- Higher volume of actions

Network availability 2022-23



Please note that transfer capacity is discussed in more detail at each week's Operational Transparency Forum. Details of how to sign up, and recordings of previous meetings are available [here](#).

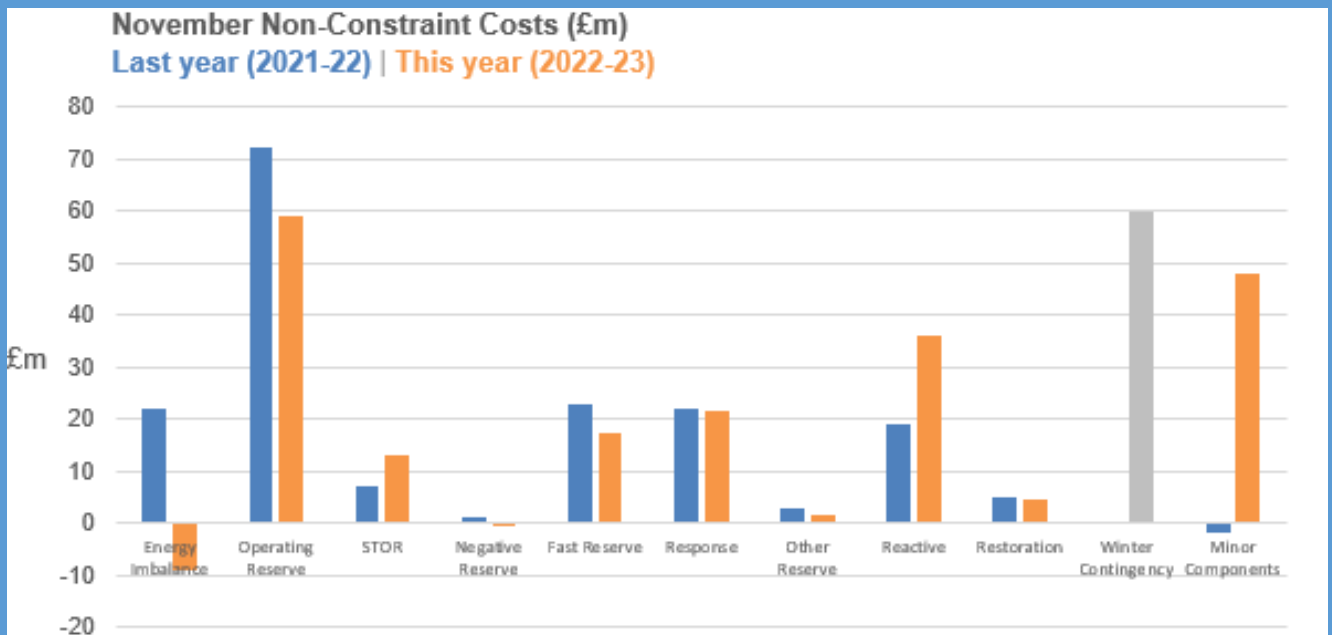
Changes in energy balancing costs



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

Power day ahead prices increased in November but remain below than the previous year levels. The day ahead gas prices have followed an opposite trend and significantly lower in comparison with the previous year. Carbon prices slightly lower than the previous month and slightly lower than the same period of 2021 but higher than 2020. Clean Spark Spread prices have increased slightly this month.

Cost trends vs seasonal norms

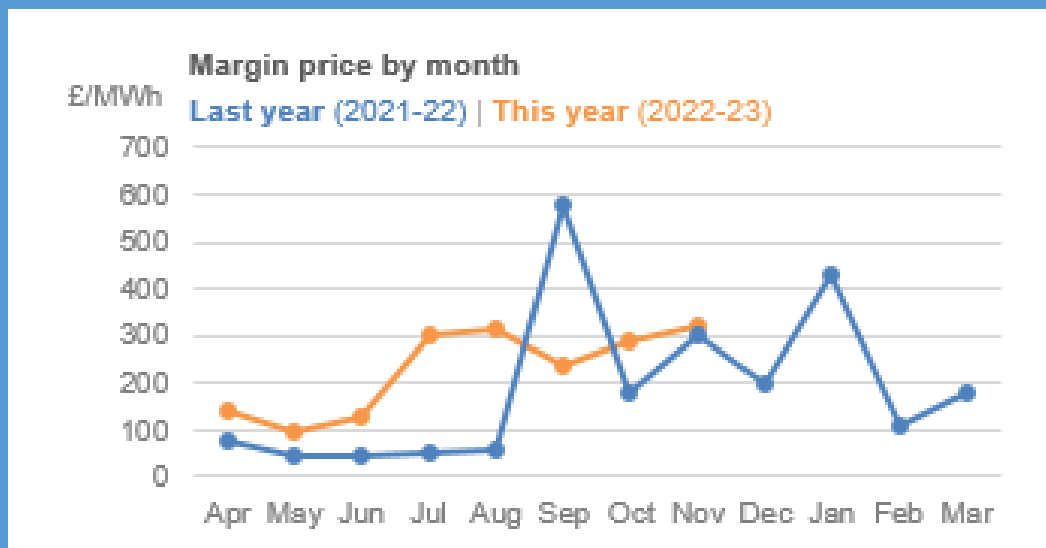


Comparing the non-constraint costs of November 2022 with those of November 2021, we can see that there has been an increase in STOR, Reactive and Minor Components. Winter Contingency costs were introduced

this year so show a significant increase. All other categories showed a small variation. We do not cover the variation in Minor Components here as it is driven by the data issue referenced earlier and the

- **STOR costs are £6.2m higher.** Tightening margins and high wholesale prices are reflected in STOR participants submitted bids and hence the cleared costs of procuring the service has increased
- **Reactive costs are £16.9m higher.** Volumes from the relevant ancillary services are not available at the time of writing this report
- **Winter Contingency: £60m higher.** Due to the winter contingency contracts that started last month. See introduction to this section for more details.

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for a single MWh) have increased slightly since October and are slightly higher than the same month last year

Daily costs trends

Friday 04 November was the least expensive day in the month with a daily spend of almost £8m and Thursday 10 November was the most expensive day in month with the daily cost slightly over £30m.

Friday 11 and Tuesday 15 November were other expensive days with a daily outturn £26.7m and £23.7m respectively.

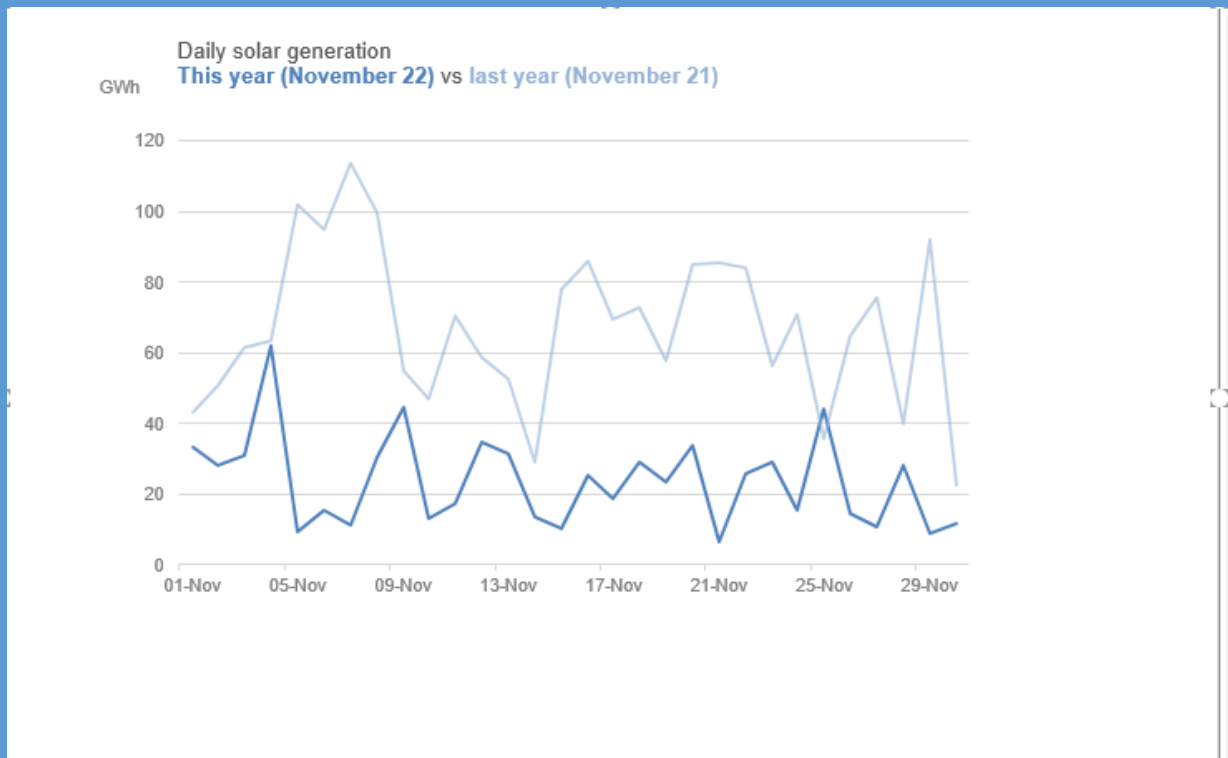
The average daily cost of the month was £16.8m.

The main drivers behind the high-cost days of the month, were large volume of BM actions to reduce generation to manage thermal constraints* and to support voltage control and the system stability.

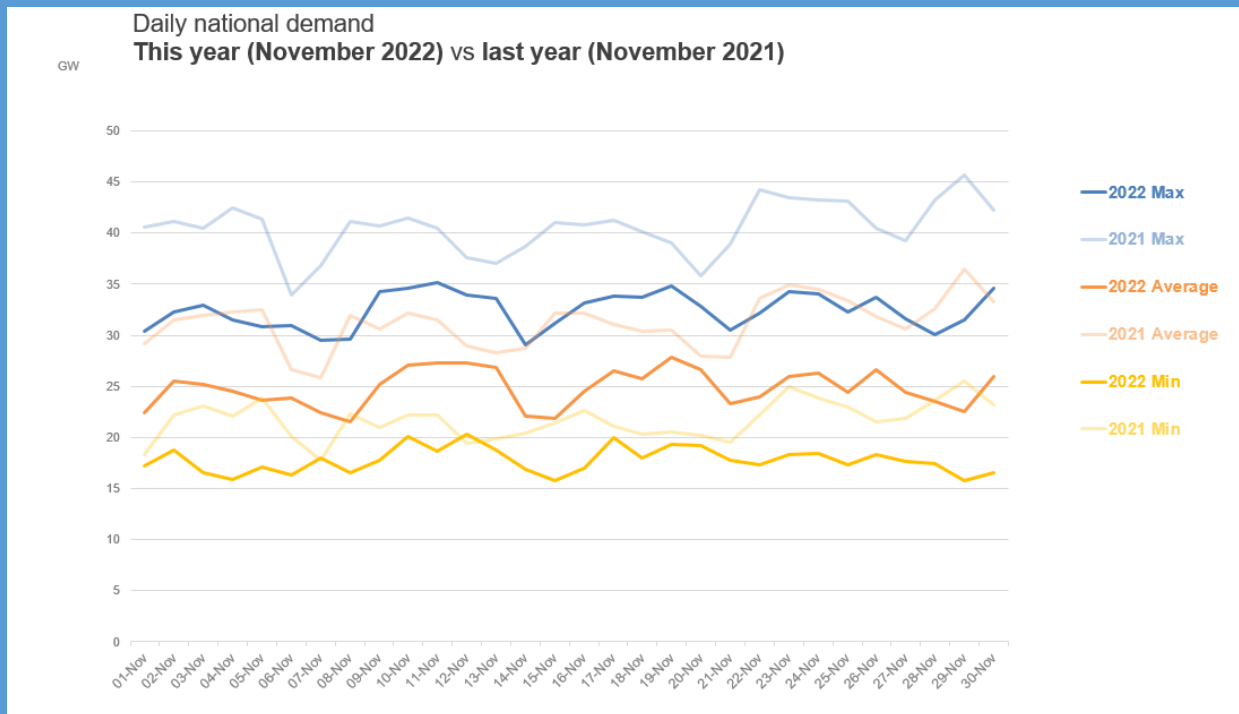
*When a bid is taken to resolve a constraint, the energy on the system must then be replaced. When a large volume of BM bids is required to manage the flow on a boundary to below the constraint limit, that volume of energy needs to be procured in the BM to rebalance.

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 actions

Solar generation - November 2022 vs November 2021



Outturn Demand – November 2022 vs November 2021



Metric 1B Demand forecasting accuracy

November 2022 Performance

This metric measures the average absolute percentage error (APE) between day-ahead forecast demand and outturn demand for each half hour period. The benchmarks are drawn from analysis of historical forecasting errors for the five years preceding the performance year.

If the Optional Downward Flexibility Management (ODFM) service is used, it will be accounted for in the data used to calculate performance. The ESO will publish the volume of instructed ODFM.

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

Performance will be assessed against the annual benchmark of 2.1%, but monthly benchmarks are also provided as a guide. The ESO will report against these each month to provide transparency of its performance during the year.

Figure 2: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark – two-year view

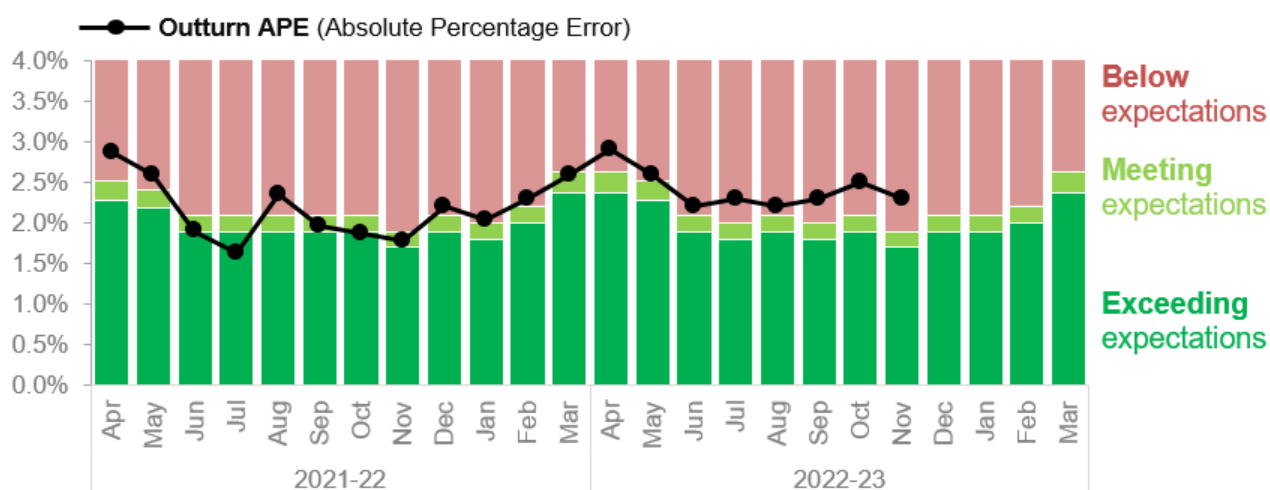


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Full Year |
|--------------------------|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----------|
| Indicative benchmark (%) | 2.5 | 2.4 | 2.0 | 1.9 | 2.0 | 1.9 | 2.0 | 1.8 | 2.0 | 2.0 | 2.1 | 2.5 | 2.1 |
| APE (%) | 2.9 | 2.6 | 2.2 | 2.3 | 2.2 | 2.3 | 2.5 | 2.3 | | | | | |
| Status | ● | ● | ● | ● | ● | ● | ● | ● | | | | | |

Performance benchmarks

- **Exceeding expectations:** >5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** $\pm 5\%$ 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

For November 2022, the mean absolute percentage error (MAPE) of our day ahead demand forecast was 2.3% compared to the indicative performance target of 1.8%, and therefore below expectations.

National demand has continued to fall year on year, and this is still noticeable in November 2022. Part of this drop can be explained by milder than normal weather at the beginning of winter, and possible price related avoidance. This greatly reduced national demand has the effect of increasing the percentage errors.

The end of the month started to see the onset of lower temperatures that had been missing compared to previous years. This changing weather and more variable weather forecasts led to some errors, especially around the 3B and DP cardinal points. 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 | 302 | 21% |
| 1500 MW | 88 | 6% |
| 2000 MW | 7 | 0% |

The days with largest MAPE were 28, 2, 22, 13 and 12 November.

Generally, this month had smaller errors spread across the day rather than large errors in small sections of the day.

The SPs with largest MAPE were SP33 and 34, though there was much less distinction than previous months.

DFS tests were run on 15, 22 and 30 November. Our processes are still being updated to fully account for these.

From November, we increased the amount of weather data we receive from the Met Office and feed into our models. Prior to this change, we received weather forecasts at 111 locations around Great Britain, and this increased to 259 locations. As a result, the average distance between a forecast location and population centres, wind farms or solar capacity has approximately halved.

Model improvements will be developed and implemented over the winter period to take advantage of this expanded dataset. Given the normal day-to-day variability in forecast error, it will take time to collect enough data to robustly measure the impact of these forecast improvements (at least one full quarter), so accuracy improvements won't be seen immediately.

Triads

November is the first month of the 2022-23 triad season. 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, especially around the Darkness Peak (DP) which is between settlement periods 34 and 39. See our [website](#) for more detail on triads.

In November we saw approximately 3700MW of triad avoidance behaviour, occurring on 22 and 28 November.

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

Metric 1C Wind forecasting accuracy

November 2022 Performance

This metric measures the average absolute percentage error (APE) between day-ahead forecast and outturn wind generation for each half hour period as a percentage of capacity for BM wind units only. 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 $\pm 5\%$ of that value is required to meet expectations.

Figure 3: BMU Wind Generation Forecast APE vs Indicative Benchmark – two-year view

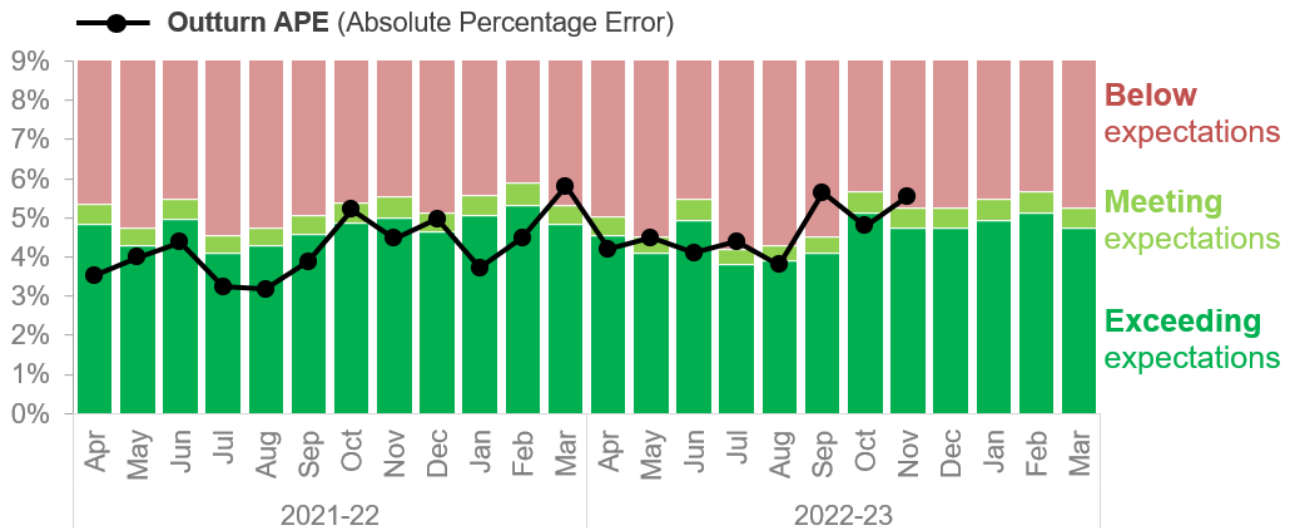


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2022-23)

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Full Year |
|--|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----------|
| BMU Wind Generation Forecast Benchmark (%) | 4.8 | 4.3 | 5.2 | 4.0 | 4.1 | 4.3 | 5.4 | 5.0 | 5.0 | 5.2 | 5.4 | 5.0 | 4.8 |
| APE (%) | 4.2 | 4.5 | 4.1 | 4.4 | 3.8 | 5.7 | 4.8 | 5.5 | | | | | |
| Status | ● | ● | ● | ● | ● | ● | ● | ● | | | | | |

Performance benchmarks

- **Exceeding expectations:** <5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** $\pm 5\%$ 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

For November the wind power forecast accuracy achieved was 5.5% against a target of 5.0%, which is below expectations.

November is normally the month when Winter really gets underway. Immediately post clock change with the evenings drawing in and the temperatures falling. Unusually this November began with very mild conditions for the time of year. According to the Met Office this was the third warmest November on record and produced 130% of average rainfall due to frequent bands of rain.

Notable weather events in November were as follows: On the 15th a frontal system associated with the remnants of Storm Nicole moved Eastwards across the UK. The remnants of tropical storms can be difficult to forecast accurately because the intricate nature of storm decomposition is harder to calculate. On 27 November the global model at ECMWF (European Centre of Medium range Weather Forecasting) had difficulty resolving accurately the low pressure system and associated rain fall which was the main cause of weather forecast error across the south east on that day.

Lightning was a feature of November in different areas on seven days in November. Lightning is a good indication of atmospheric stability which can be an indication of wind power forecast error.

November wind power forecasting is normally difficult because it represents the transition from the Autumn to the more stormy Winter weather patterns. We are regularly revising our wind power forecasting models to incorporate the latest behaviour from new wind farms. We have also been working with the Met Office to investigate whether ensemble forecasting techniques provides a good route to improved forecasting accuracy. Ensemble forecasting gives greater information about the uncertainty that future weather has. The weather companies do this by producing multiple weather forecasts (ensemble members) with slightly different starting conditions. The spread of these ensemble members then represents the spread of possible weather scenarios.

The Intermittent Market Reference price was negative for 2 hours on the 11 November. It is unlikely that this resulted in any wind farms reducing output for economic reasons. Wind farms with CFD contractual arrangements switch off for commercial reasons while prices are negative for 6 hours or more. Market Price Data for August can be downloaded from here. <https://www.emrsettlement.co.uk/settlement-data/settlement-data-roles/>

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

Metric 1D Short Notice Changes to Planned Outages

November 2022 Performance

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

Figure 4: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages – two-year view

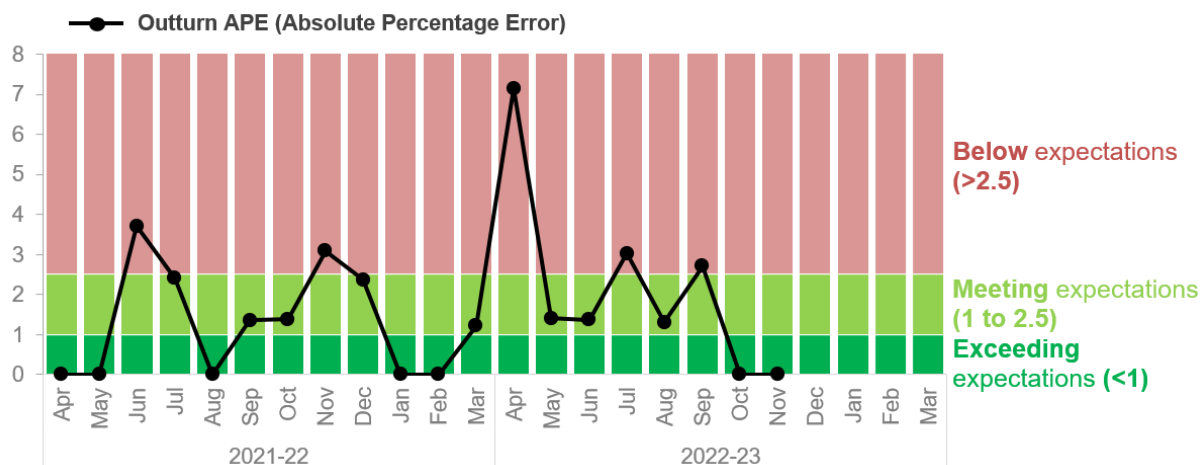


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | YTD |
|---|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|------|
| Number of outages | 700 | 709 | 730 | 660 | 766 | 739 | 684 | 635 | | | | | 5623 |
| Outages delayed/cancelled | 5 | 1 | 1 | 2 | 1 | 2 | 0 | 0 | | | | | 12 |
| Number of outages delayed or cancelled per 1000 outages | 7.1 | 1.4 | 1.4 | 3.0 | 1.3 | 2.7 | 0 | 0 | | | | | 2.1 |
| 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 635 outages and there have been no delays or cancellations due to an ESO process failure. This is within the 'Exceeds Expectation' target of less than one delay or cancellation per 1000 outages. The number of outages released in November 2021 was 648 and has decreased in November 2022 to 635, this is due to the reduced number of outage requests received from the TOs/DNOs for this period. The cumulative number of short changes per 1000 outages is now back into the 'Within Expectation' target of less than 2.5 per 1000 outages. 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

November 2022 Performance

This Regularly Reported Evidence (RRE) shows % 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 where 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.

The Dispatch Transparency dataset, first published at the end of March 2021, has already sparked many conversations amongst market participants. It is anticipated that as we continue to publish this dataset, we will be able to provide additional insight into the actions taken in the Balancing Mechanism and help build trust as we become more transparent with our decision making.

Figure 5: Percentage of balancing actions taken in merit order in the BM – two-year view

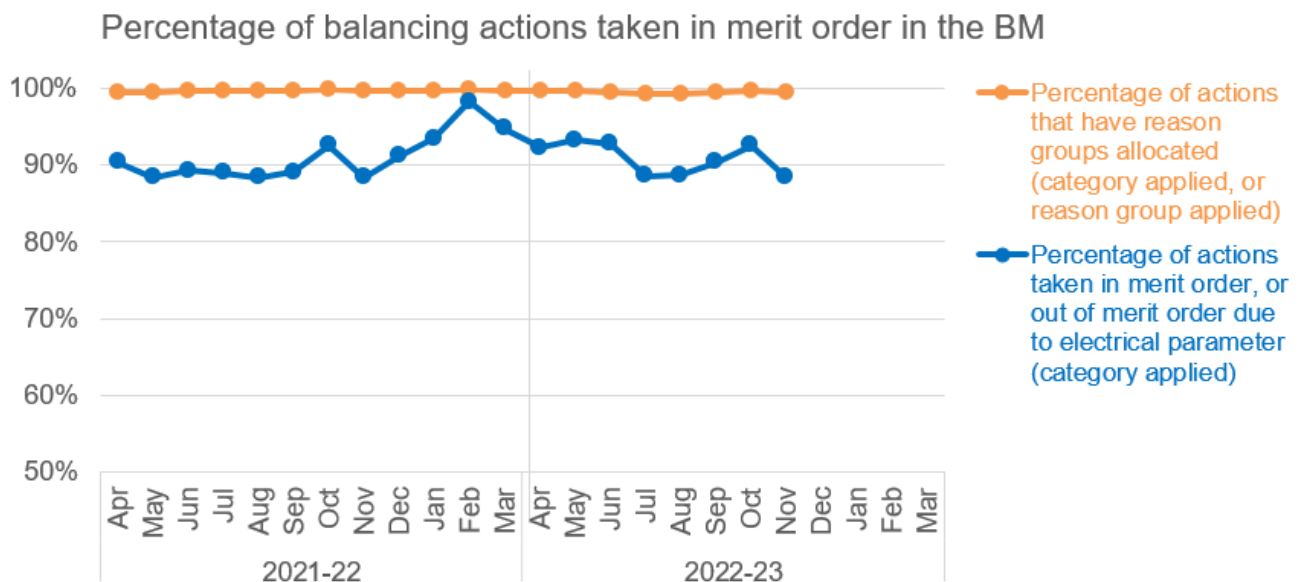


Table 6: Percentage of balancing actions taken outside of merit order in the BM

| | 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) | 92.3% | 93.3% | 92.8% | 88.6% | 88.7% | 90.4% | 92.6% | 88.4% | | | | |
| Percentage of actions that have reason groups allocated (category applied, or reason group applied) | 99.7% | 99.7% | 99.6% | 99.4% | 99.4% | 99.6% | 99.7% | 99.6% | | | | |
| Percentage of actions with no category applied or reason group identified | 0.3% | 0.3% | 0.4% | 0.6% | 0.6% | 0.4% | 0.3% | 0.4% | | | | |

Supporting information

This month 88.4% of actions were taken in merit order or taken out of merit order due to an electrical parameter.

For the remaining actions, where possible, we allocate actions to reason groups for the purposes of our analysis.

During November 2022, we sent 60,519 BOAs (Bid Offer Acceptances) and of these, only 229 remain with no category or reason group identified, which is 0.4% of the total.

Data issue: As mentioned in our October report, we recently identified an issue with the data used to support this metric. The impact of this issue is minor and is very unlikely to affect the reported figures.

- Over the 19-month period from April 2021, 11 days were not captured by the dataset.
- We have identified the cause in the data which is provided by an ESO legacy tool and we have implemented countermeasures to ensure any future missing days are flagged promptly and included into the dataset.
- We are unable to recreate the previous missing days due to the time elapsed.

RRE 1G Carbon intensity of ESO actions

November 2022 Performance

This 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](#).

Figure 6: Average monthly gCO₂/kWh of actions taken by the ESO - two-year view

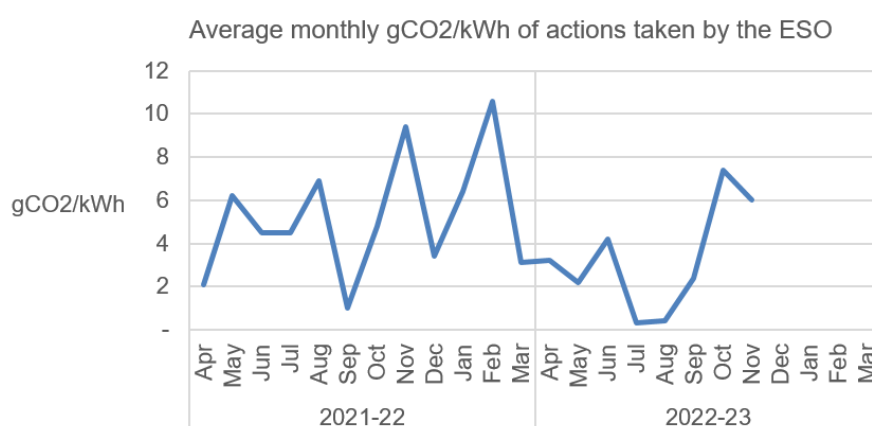


Table 7: Average monthly gCO₂/kWh of actions taken by the ESO

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar |
|--|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| Carbon intensity (gCO ₂ /kWh) | 3.2 | 2.2 | 4.2 | 0.3 | 0.4 | 2.4 | 7.4 | 6.0 | | | | |

Supporting information

In November, the average carbon intensity of balancing actions was 6.0 gCO₂/kWh. This was a decrease from October but is relatively normal for this time of year as temperatures drop and the demand rises. In addition, wind levels have meant that we have had to constrain off wind generation due to thermal export constraints and replace the missing energy with carbon generation. This increases the carbon intensity of our actions.

For Q1 and Q2, the average carbon intensity was 3.2 gCO₂/kWh and 1.0 gCO₂/kWh respectively. Q2 saw a reduction in the carbon intensity as we were taking significantly fewer operational actions compared with previous months. In addition, carbon generation has been supporting the increased exports from GB and they also provide the needed network ancillary services. This reduces ESO interventions and means that if we do take operational actions pulling back carbon generation, the market carbon figures for this RRE will also reduce significantly.

In November, the largest decrease in carbon intensity due to ESO's actions was at 00:00 on 4 November with a minimum intensity of ESO actions at -22.5 gCO₂/kWh. The minimum for the year so far is -26.2 gCO₂/kWh on 29 May.

RRE 1I Security of Supply

November 2022 Performance

This Regularly Reported Evidence (RRE) shows when the frequency of the electricity transmission system deviates more than $\pm 0.3\text{Hz}$ 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 $\pm 0.3\text{Hz}$ 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.

Table 8: Frequency and voltage excursions (2022-23)

| | 2022-23 | | | | | | | | | | | |
|--|---------|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| | 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 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | | | | |
| Voltage Excursions defined as per Transmission Performance Report ³ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |

Supporting information

There were no reportable voltage or frequency excursions in November.

³ <https://www.nationalgrideso.com/research-publications/transmission-performance-reports>

RRE 1J CNI Outages

November 2022 Performance

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.

Table 9: Unplanned CNI System Outages (Number and length of each outage) – two-year view

| Unplanned | 2021-22 | 2022-23 | | | | | | | | | | | |
|--|---------|---------|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| | TOTAL | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar |
| Balancing Mechanism (BM) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |
| Integrated Energy Management System (IEMS) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |

Table 10: Planned CNI System Outages (Number and length of each outage) – two-year view

| Planned | 2021-22 | 2022-23 | | | | | | | | | | | |
|--|------------------------|---------|-----|-----|-------------------------|-----|-----|-----|-------------------------|-----|-----|-----|-----|
| | TOTAL | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar |
| Balancing Mechanism (BM) | 3 ⁴ outages | 0 | 0 | 0 | 1 outage 186 minutes | 0 | 0 | 0 | 1 outage 165 minutes | | | | |
| Integrated Energy Management System (IEMS) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |

Supporting information

In November 2022 there was one planned CNI system outage. The outage was part of regular planned maintenance activities and major software delivery on the BM production systems, and impacted the key BM Suite components used for scheduling and dispatch of generation.

⁴ July 2021: 1 outage, 216 minutes.
November 2021, 1 outage, 215 minutes.
March 2022, 1 outage, 196 minutes.

Notable events during November 2022

New Daily Wind Record

On 2 November wind generated more than 20GW for the first time in UK history, providing over half of our daily electricity. Throughout November wind provided 37.6% of generation demonstrating how we can begin to rely on more green energy to run the system.

Another great achievement towards decarbonising our energy system is our reliance on coal, which has dropped significantly from five years ago, with only 0.7% of generation coming from coal in November compared to 11.3% during the same month in 2017. This allowed us to achieve 158 consecutive hours without coal in November.

Throughout November, 51% of electricity came from zero carbon sources, peaking at 82%. Overall this has been a great green month moving us ever nearer towards our 2025 target of being able to run 100% zero carbon generation for short periods.

A conversation with the Ukrainian System Operator

As part of our ongoing support of system operators around the world, and the support we're providing Ukraine, we held a call with the CEO of the Ukrainian TSO, Volodymyr Kudrytskyi, last week and Craig wanted to update you on what they shared with us.

The call from Ukraine was made from a room that had been bombed just a week ago, but the team were continuing to work as normal, showing the incredible commitment and bravery that these international colleagues are demonstrating every day. Ukraine has already seen some rolling blackouts this year, that's before winter has even begun. This put into perspective the work we do, and also the challenges system operators are facing around the world. We are also working with ENTSO-E to help Ukraine with system operation support.

Extending the TEC Amnesty

In September 2022 we, in collaboration with Transmission Owners, led the industry communication of a new strategy to address the current challenges observed with electricity transmission connections. Namely a growing Transmission Entry Capacity (TEC) Queue and long lead timescales for connections.

TEC Amnesty is a process whereby we invite all parties with Connections Agreements listed on the TEC register (e.g., Generation developers) to confirm whether they would be willing to terminate their agreement at minimal or no cost, or reduce their TEC.

Originally this process was due to run until end of November 2022, however we decided to investigate the extension of the expression of interest window to enable us to align with other key events or initiatives taking place across the energy industry. Initial uptake of the amnesty had been low (just over 1GW initially) and so an extension was also investigated to encourage a greater number of amnesty participants. Alignment to events and initiatives listed below:

- Completion of HND1 contract update
- Further progress on the Construction and Planning Assumptions optimisation exercise
- Completion of interconnector Cap and Floor review
- CMP376: Introduction of Queue Management milestones to connections contracts
- Conclusion of latest Capacity Market Auction

The window was successfully extended until the end of April 2023, with agreement and support from TOs and OFGEM

Since the extension of TEC Amnesty window, another 4GW of contracted connections have come forwards to terminate their contract. We shall continue to work with and support our Customers, partners and TOs as we look to ensure this initiative is a success as we continue to remain focused on the delivery of our Net Zero commitments.

TEC Amnesty is one of a number of initiatives that we are working on as part of the need to improve the connections process and connection timescales, ahead of a more fundamental

reform of the GB Connections. You can find out more about this on our Business Plan 2. You can find out more about it [here](#).

Market Monitoring 12 Month Review 2022

In early November, the Market Monitoring team published the 12 month review [document on the ESO website](#). The document gives an overview of the team's first 12 months in existence, outlining the purpose of the team, an explanation of what we are looking for and how we do it, and how we work with Market Participants. Within the document we also give some headline figures demonstrating the number of alerts that we review and the number of investigations that we conduct.

Whilst drafting the document we engaged Ofgem's REMIT team to ensure they were comfortable with its content and publication.

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

November 2022 Performance

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.

Figure 7: Monthly BSUoS forecasting performance (Absolute Percentage Error) – two-year view

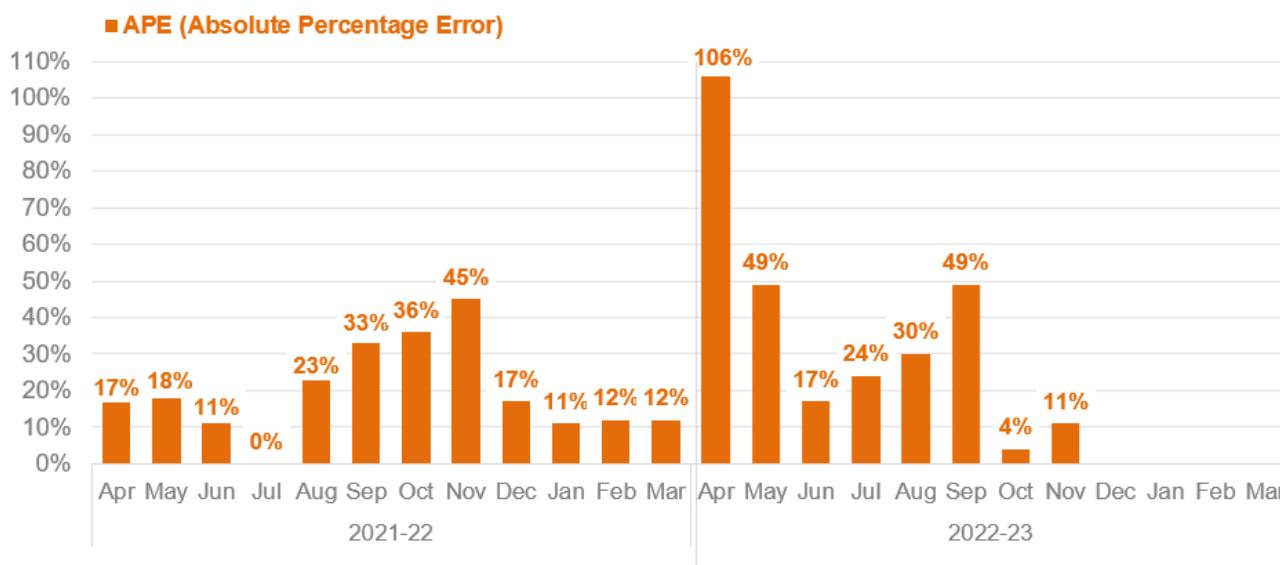


Table 11: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance⁵ - one-year view

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar |
|--|-------------|------------|------------|------------|------------|------------|-----------|------------|-----|-----|-----|-----|
| Actual | 5.3 | 6.0 | 9.4 | 10.3 | 9.2 | 8.5 | 12.5 | 11.7 | | | | |
| Month-ahead forecast | 11.0 | 9.0 | 7.7 | 7.8 | 11.9 | 12.7 | 12.1 | 13.0 | | | | |
| APE (Absolute Percentage Error)⁶ | 106% | 49% | 17% | 24% | 30% | 49% | 4% | 11% | | | | |

Supporting information

The BSUoS charge (£/MWh) depends on the total BSUoS cost and the total volume.

The BSUoS cost forecast 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 is below the 50th percentile of the cost forecast,

⁶ 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.

then we expect the actual BSUoS charge to be lower than the forecast provided the actual volume is at or above the estimate (and vice versa).

November performance

Costs:

November outturn costs were around the 35th percentile of the forecast produced at the beginning of October.

This was mainly due to the wholesale electricity prices being 72% lower in outturn (£147/MWh) than the forward market prices available at the beginning of October (£522/MWh).

Total cost was £502 million (£442 million plus winter contingency cost of £60m)

Volumes:

November actual BSUoS volume was only 6% higher than the estimate. (46.05 TWh instead of the estimate 43.5 TWh)

Notable events during November 2022

Demand Flexibility Service launched on 4 November

Following Ofgem approval of the Electricity Balancing Reserve (EBR) Article 18 Consultation for the Demand Flexibility Terms and Conditions, the Demand Flexibility Service (DFS) is now live and runs until the 31st March 2023. [Key Documents are available on our website](#). A collaborative effort across industry enabled the launch of this innovative service.

The number of providers (e.g. energy suppliers and aggregators) participating in DFS events has been growing since the service launched, with 26 providers now on our [Approved Providers List](#). More than one million households and businesses have now signed up to DFS.

To ensure maximum volume this winter, the ESO offered all providers the maximum 12 DFS tests subject to all onboarding steps being completed by 18 November. There will be two regular tests each month the service is live and each provider will have two onboarding tests during their first month in the service. The number of tests available for providers is subject to the onboarding completion date.

In November the ESO initiated three demonstration events, successfully delivering consumer demand flexibility at scale, enabling consumers and businesses across the country to benefit from shifting their electricity use away from a specific time period.

| Date of Delivery | Period | Max Requested (MW) |
|-------------------|----------------|--------------------|
| 15 November, 2022 | 17:00 to 18:00 | 200 |
| 22 November, 2022 | 17:30 to 18:30 | 200 |
| 30 November, 2022 | 17:30 to 18:30 | 250 |

DFS Test 15 November

4 providers participated in the first test. There was an average 76MW in accepted bids at £3,000 MWh (which is the Guaranteed Acceptance Price). An average 54MW in rejected bids ranging up to £6,000 MWh. The first test delivered an average 121 MW.

DFS Test 22 November

13 providers participated in this test. There was an average 140 MW in accepted bids at 3,000MWh. An average 63 MW in rejected bids ranging up to £6,000. This test delivered an average 188 MW.

Data from the first two events show that consumer engagement has exceeded expectations, with consumers overdelivering by over 35% against targets on both occasions. Data for the 30 November test will be published in due course. The ESO has created an area on the Data Portal to share updates on the Demand Flexibility Service, this can be accessed via [this link](#). There are two sections, one for DFS Tests and one for DFS Live Events. It is possible to register to receive updates from these webpages to know when information on the DFS has been published. To register for SMS updates from the Data Portal, [this webpage](#) explains how to set this up and subscribe for Data Portal notifications.

Net zero market reform webinars.

On November 24th and 29th the ESO's Net Zero Market Reform (NZMR) programme hosted two workshops with stakeholders across 144 different organisations. The purpose of these workshops was to gather views from these stakeholders on ESO commissioned work from Baringa which considered an assessment of market design and policy packages. There was a presentation of the current approach and findings, before a Q&A session, and finally moving into small breakout groups to allow as many stakeholders as possible to express their views.

Baringa is a business and technology consultancy, and they are working with the NZMR team to provide an independent assessment of market reform options and packages.

The stakeholder feedback will feed into Baringa's final assessment which will be published in the new year and ultimately inform the ESO's own assessment of net zero market packages to be published in 2023. In addition, the ESO will share a summary of the event to those who attended and wider industry in December.

Feedback on content and delivery was very positive. There were comments about the need for more time to discuss the key points in the breakouts in the first session. As a result, we lengthened the breakouts in the second session and will take this feedback into consideration for future engagement events.

Role 3 System insight, planning and network development

Please note there are no metrics for Role 3

B6 Constraint Management Pathfinder (CMP) 2024-25 tender concluded

The B6 Constraint Management Pathfinder (CMP) is seeking tenders for a post-fault intertrip that rapidly (sub-150ms) disconnects selected generators in the event of a network fault on one of the circuits that the intertrip scheme monitors. It aims to reduce network constraint costs across the Anglo-Scottish (B6) boundary.

On Friday 25th November, the results of the latest B6 CMP tender were released to industry. Contracts were successfully awarded for the second B6 CMP tender to 15 generators for service delivery between October 2024 and September 2025. The B6 CMP 2024-25 tender is predicted to save the consumer £70m in constraint costs over the contract period.

ESO announces new contracts to deliver over £14bn in savings to consumers

In December 2021 ESO launched the invitation to tender for its Stability Pathfinder Phase 3. This tender set out to procure short circuit level (SCL) and inertia across five regions of need in England and Wales.

On 23 November 2022 ESO announced the results of this tender by sharing a [blog post](#) and posting the results table on the [Stability Pathfinder Phase 3 webpage](#). A total of 29 contracts were awarded to six suppliers for provision of stability services between 2025 and 2035. It is expected these contracts will deliver £14bn cost benefit across the same 10-year period.

The Business, Energy and Industrial Strategy (BEIS) secretary of state will review the report at the end of December, which summarises the evidence gathered from across the energy sector.

ESO supporting the government's net zero review

The ESO submitted a response to the Government's independent review of net-zero, led by Chris Skidmore MP, which questioned whether the United Kingdom is on track to achieve net zero in the most economic, efficient, and pro-growth way. Our evidence highlighted the need for decarbonisation to accelerate growth in the UK, by increasing the development of flexible technologies alongside the right markets, whole system strategic planning and an independent system operator.

The ESO organised a roundtable discussion with the Net Zero Review Secretariat, where we walked through our evidence in more detail and answered questions.

The Business, Energy and Industrial Strategy (BEIS) secretary of state will review the report at the end of December, which summarises the evidence gathered from across the energy sector.