ESO RIIO2 Business Plan 1 (2021-23)

Q3 2022-23 Incentives Report

25 January 2023

Contents

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 December we have successfully delivered the following notable events and publications:

- Dispatch Transparency (skip rate) event on 5 December. Twenty-nine industry colleagues joined us in Wokingham for a transparent discussion about the decisions we make in the control room on which balancing services need to be used and who should provide them.
- ESO published findings from its new Demand Flexibility Service. So far, we've run five planned demonstration test events of the Demand Flexibility Service, successfully delivering consumer demand flexibility at scale for the first time in British history. More than 1 million households and businesses have now signed up to participate and 26 providers are currently involved.
- OFGEM approval of CMP361/362 which implements fixed ex-ante BSUoS for April 2023. Connection and Use of System Code (CUSC) Modification Proposal (CMP) 361/362 introduces a fixed ex-ante Balancing Use of System Charges (BSUoS) tariff to be implemented from 1 April 2023 alongside CMP308, which following its approval in April 2022 will move BSUoS charges to final demand only.
- We have launched the GB Connections Reform project to fully understand the challenges and develop solutions for our connections process. Our case for change sets out these challenges before we move to the design stage in January, with implementation expected to start in spring 2023.
- Operability Strategy Report (OSR) was published on 21st December. This year's report explains the challenges we face in operating a rapidly changing electricity system. The report describes what capabilities we need to resolve these challenges and to enable a zero-carbon electricity system in 2035.
- By 31st January the Future Energy Scenarios (FES) 2023 Stakeholder Feedback Document will be sent to Ofgem to meet the ESO's Standard Licence condition C11.15. This document sets out the proposed FES scenario framework and scenarios for 2023 and shares the detail of our engagement that has taken place from springtime 2022 to date and how we are taking it forward.

These are some of the highlights that we have successfully delivered earlier in Q3:

- We published our Winter Outlook 2022-23 on 6 October 2022, building on the Winter Outlook - Early View we published in July 2022. It presents our view of the electricity system between October 2022 and March 2023 and is published to inform the energy industry and support its preparations for the winter ahead.
- We successfully completed a software upgrade which allows us to share data more effectively with DNOs. This supports our Regional Development Programmes, where we're working with partner DNOs to deliver whole system solutions to facilitate the connection of Distributed Embedded Resources.
- 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 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.

Table 1: Summary of Metrics

This table summarises our performance for December 2022 and Q3. Monthly (M) and Quarterly (Q) Metrics.

Metric		Performance December figure for monthly Metrics, Q3 figure for quarterly Metrics	M / Q	Status Oct	Nov	Dec	Q3
Metric 1A	**Balancing Costs**	Dec: £477m vs benchmark of £161m	M	●	●	●	●
Metric 1B	**Demand Forecasting**	Dec: Forecasting error of 2.3% vs (benchmark of 2.0%)	M	●	●	●	●
Metric 1C	**Wind Generation Forecasting**	Dec: Forecasting error of 5.8% vs (benchmark of 5.0%)	M	●	●	●	●
Metric 1D	**Short Notice Changes to Planned Outages**	Dec: 0 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	M	●	●	●	●
Metric 2A	**Competitive procurement**	Q3: 37% of services procured by competitive means (vs Year 2 benchmark of 65%-75%)	Q	n/a	n/a	n/a	●

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

Table 2: Summary of RREs

This table summarises our performance for December 2022 and Q3. Monthly (M) and Quarterly (Q) RREs

Regularly Reported Evidence		Performance December figure for monthly RRE's, Q3 figure for quarterly RRE's	M / Q
RRE 1E	**Transparency of Operational Decision Making**	Dec: 89.1% of actions taken in merit order	M
RRE 1F	**Zero Carbon Operability indicator**	Q3: the system accommodated a maximum 84.8% zero carbon transmission connected generation	Q
RRE 1G	**Carbon intensity of ESO actions**	Dec: 4.7gCO_2/kWh of actions taken by the ESO	M
RRE 1H	**Constraints cost savings from collaboration with TOs**	Q3: £692m avoided costs	Q
RRE 1I	**Security of Supply**	Dec: 0 instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. 0 voltage excursions	M
RRE 1J	**CNI Outages**	Dec: 0 planned and 0 unplanned system outages	M
RRE 2B	**Diversity of service providers**	Q3: Varying diversity of providers across the different markets	Q
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Dec: Month ahead BSUoS forecasting accuracy (absolute percentage error) of 2%	M

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

Q3 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.

Total Balancing Costs[1] ***(£m)*** = (Outturn Wind *(TWh)* x 25.254 *(£m/TWh)*) + 15.972 *(£m)* + 50.4 *(£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

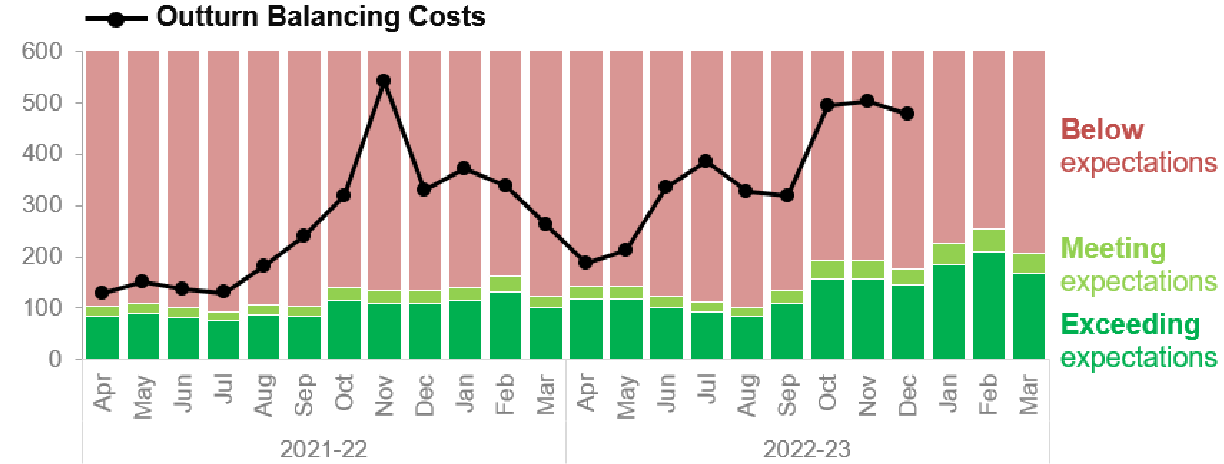


Table 2: Monthly balancing cost benchmark and outturn

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	50				454
Indicative benchmark: constraint costs (B)	97	89	90	81	101	107	146	133	151				**995**
Indicative benchmark: total costs (C=A+B)	147	139	140	132	152	158	196	183	201				**1448**
Outturn wind (TWh)	3.8	3.8	3.1	2.8	2.3	3.5	5.6	5.6	5.0				**35.4**
Ex-post benchmark: constraint costs (D)	80	80	62	52	42	73	125	125	110				**750**
Ex-post benchmark (A+D)	130	130	113	130	93	123	176	176	161				1204
Outturn balancing costs[2]	**188**	**213**	**335**	**385**	**327**	**318**	493	502	477				3238
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 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.

December performance

The Balancing costs for December 2022 were £477m, which is a decrease of £22m from November 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.

Although the non-constraint volume of actions was lower than the previous month and the same period last year, the underlying non-constraints costs (excluding Winter Contingency) significantly increased and remain higher than last year.

Constraint costs decreased this month and remain lower than last year.

Even though the total volume of actions was lower this month compared to December 2021, the total cost showed a notable increase compared to the corresponding period last year, due to the number of tight margin days in the first half of the month leaving the Control Room to take high-priced actions, combined with high renewable penetration in the second half of the month.

Q3 performance

The total balancing costs for the third quarter of the year (£1,467m) was higher than last year's outturn Q3 spend (£1,190m). Monthly balancing costs were steady in the range coming at slightly below £500m for this quarter, with November's balancing spend the highest for this financial year and the second highest on the record. December's balancing costs decreased compared to October and November this year.

Although the non-constraint volume of actions was slightly lower in the third quarter compared to the same period last year, the non-constraint costs were significantly higher. The significant increase in non-constraint costs compared with last year was the result of the winter contingency contracts (£185m), tight system margins and price scarcity.

The decrease in constraint costs, was in line with the overall reduction in the constraint volume of BM actions compared to October and November.

Breakdown of costs vs previous month

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

		(a) Nov-22	(b) Dec-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-8.9	-11.0	(2.1)	
	Operating Reserve	59.2	134.2	75.0	
	STOR	12.8	26.8	14.0	
	Negative Reserve	-0.5	0.2	0.8	
	Fast Reserve	17.3	21.4	4.1	
	Response	22.0	14.0	(8.0)	
	Other Reserve	1.6	1.9	0.4	
	Reactive	36.6	36.5	(0.1)	
	Restoration	4.5	3.3	(1.2)	
	Winter Contingency	60.0	62.9	2.9	
	Minor Components	44.0	68.3	24.3	
Constraint Costs	Constraints - E&W	41.5	20.3	(21.2)	
	Constraints - Cheviot	4.0	3.1	(0.9)	
	Constraints - Scotland	33.5	1.9	(31.6)	
	Constraints - Ancillary	3.1	1.7	(1.4)	
	ROCOF	10.1	17.3	7.1	
	Constraints Sterilised HR	157.7	73.7	(84.0)	
Totals	Non-Constraint Costs - TOTAL	248.5	358.6	110.1	
	Constraint Costs - TOTAL	250.0	118.0	(132.0)	
	Total Balancing Costs	**498.6**	**476.7**	**(21.9)**	

As shown in the total rows from the table above, the non-constraint costs increased by £110m this month. Constraint spends showed a significant reduction of £132m.

All the constraint categories fell this month or showed little variance from the previous month. Constraints Sterilized Headroom showed a marked decrease of £84m.

Within the Non-Constraint costs, there was an increase in Operating Reserve, STOR and Minor Components, while all other categories experienced a decrease in cost or showed little variance from the previous month.

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

- **Constraint Sterilised Headroom: £84m decrease.** The cost reduction is in line with the reduction of constraint actions because less headroom had to be replaced elsewhere outside the constraint through BM actions.
- **Constraint-Scotland: £32.6m decrease.** No costs were incurred to resolve constraints within Scotland for one third of days of December, resulting in an overall reduction in the volume of BM actions compared to November.

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

- **Operating Reserve: £75m increase.** Tight margins in the first half of the month, combined with high renewable penetration in the second half of the month required higher volumes of reserve than in November which combined with acceptance of higher prices to be the main driver behind this increase.
- **Minor components: £24.3m increase.** We have identified that £53.4m in this category should have been allocated to the Operating reserve category. It will be corrected once the data issue is resolved.

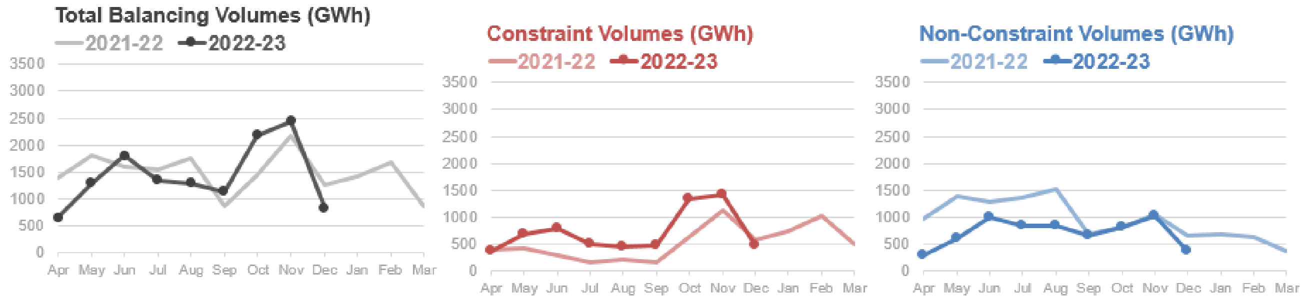
ROCOF: a processing error meant that in last month's report (November), the ROCOF costs for November in the table above were incorrectly showing as zero. This was identified and corrected when updating the November and December costs for this report. November's corrected figure for ROCOF is £10.1m. Although the original ROCOF figure was incorrect, all other figures including the total constraint costs and total balancing costs were correct. We have also confirmed no previous months were affected.

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.

Balancing COSTS (£m) monthly vs previous year

Balancing VOLUMES (GWh) monthly vs previous year



Please note that a portion of the **Minor Components** spend contributing to non-constraint cost and volume is 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.

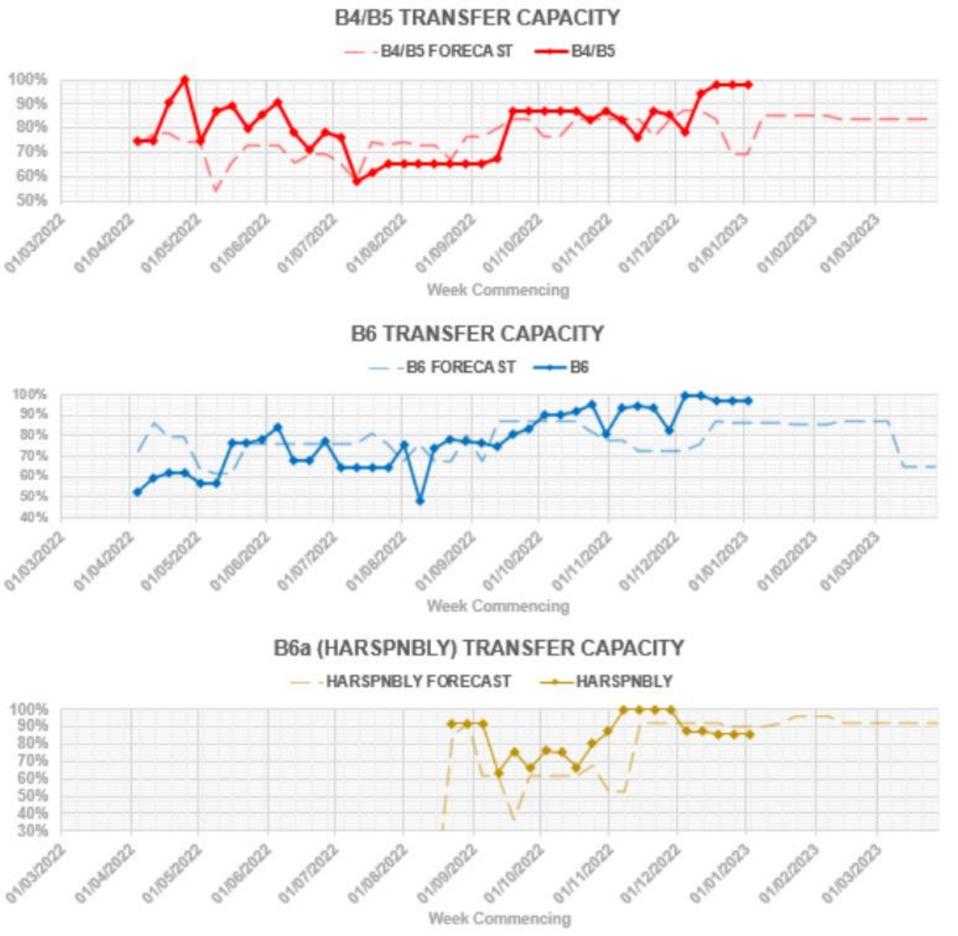
Constraint costs

Compared with the same month of the previous year:	• Constraint costs were ~£67m lower than in December 2021 due to lower volume of actions and lower wholesale prices compared with last year
Compared with last month:	• Constraint costs showed a significant decrease (£132m lower) from November 2022 due to lower volume of actions.

Non-constraint costs

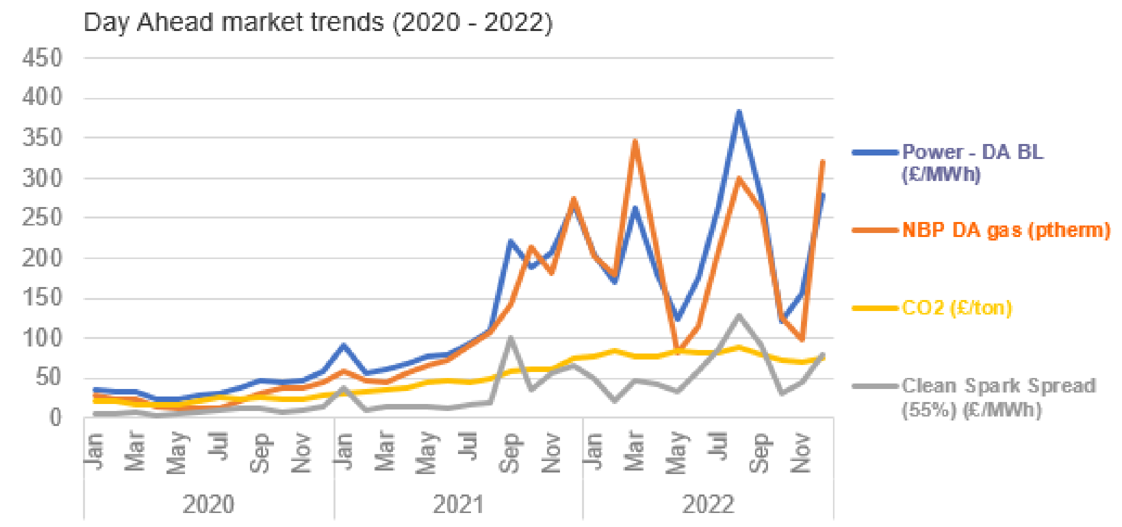
Compared with the same month of the previous year:	Non-Constraint costs were around £214m higher than in December 2021 due to: • Winter contingency contracts • Operating Reserve • STOR • Reactive
Compared with last month:	Non-Constraint costs were £110m higher than in November 2022 due to: • Winter contingency contracts • Operating Reserve • STOR

Network availability 2022-33



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

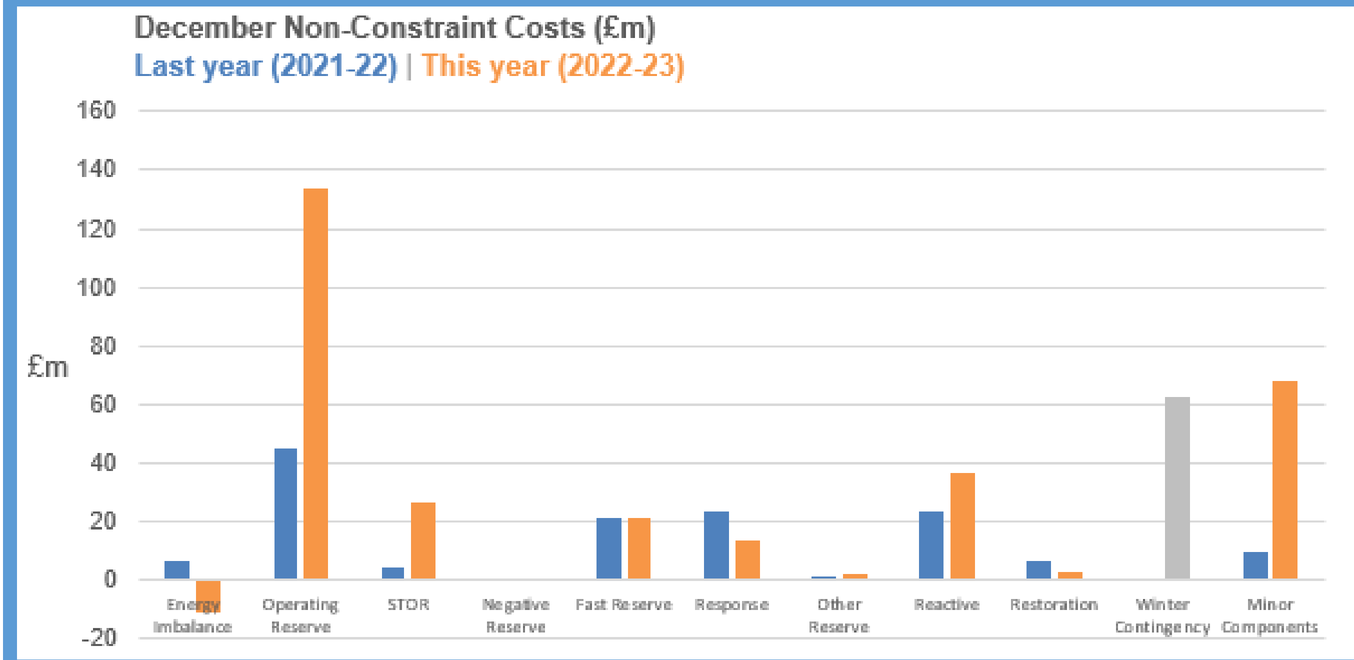


DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Power day ahead prices have increased in December but remain lower compared to the previous year.

The day ahead gas prices rose in December following November's trend and remain higher in compared to December 2021. Carbon prices shown a stability throughout 2022 and Clean Spark Spread prices have increased this month.

Cost trends vs seasonal norms



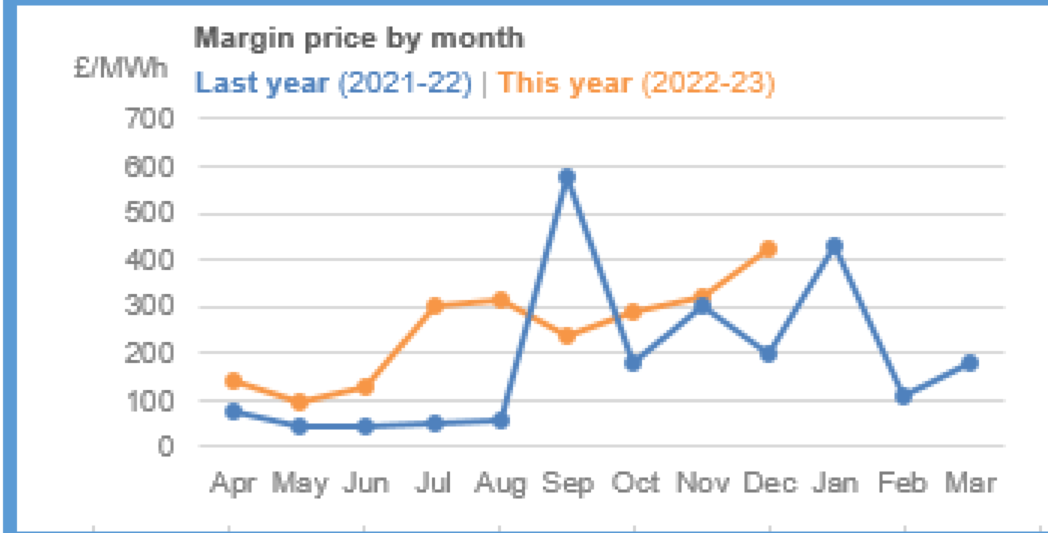
Comparing the non-constraint costs of December 2022 with those of December 2021, we can see that there was an increase in Operating Reserve, STOR, Reactive and Minor Components.

Winter Contingency costs were introduced this year. All other categories showed a small variation.

- **Operating Reserve:** £90m increase, due to higher volume of actions.
- **STOR** £22.3m increase. Tightening margins are reflected in STOR participants' submitted prices, hence the cleared costs of procuring the service have increased
- **Reactive** costs are £13m higher. Volumes from the relevant ancillary services are not available at the time of writing this report

- **Winter Contingency:** £63m higher. Due to the winter contingency contracts that started on October 2022. See introduction to this section for more details.
- Minor components: £58.4m increase. We have identified most of the cost in this category should have been allocated to the Operating reserve category. It will be fixed once the data issue is resolved.

Drivers for unexpected cost increases/decreases



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

Daily costs trends

As discussed above, December balancing costs were £22m lower than the previous month. However, we counted four days that recorded a spend of more than £20m.

Tight margin days in the first half of the month, combined with high renewable penetration in the second half, were the main drivers behind the expensive days.

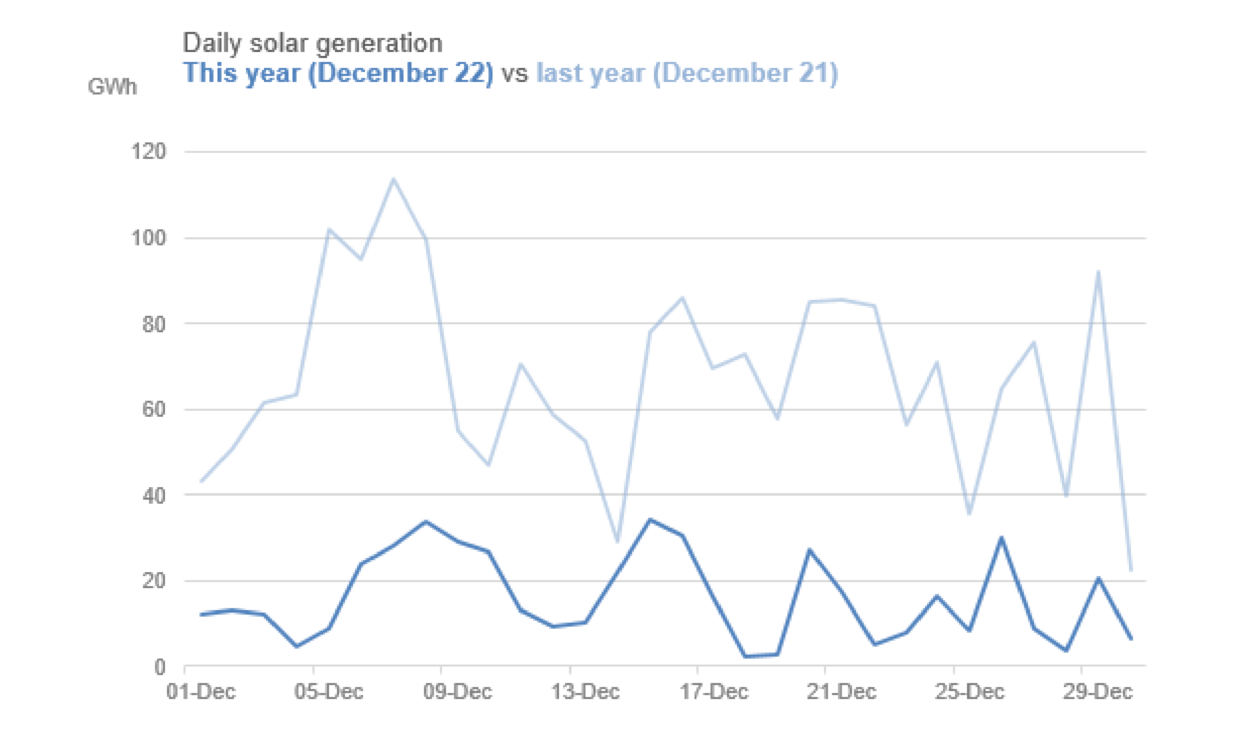
On Thursday 12 December when outturned costs exceeded £32m, the major cost component was the Operating Reserve due to tight margins.

There was a similar picture for the other expensive days, namely 14, 19 & 25 December, £25m, £23m & £21m respectively, with tight margins and thermal constraints being the main drivers behind costs.

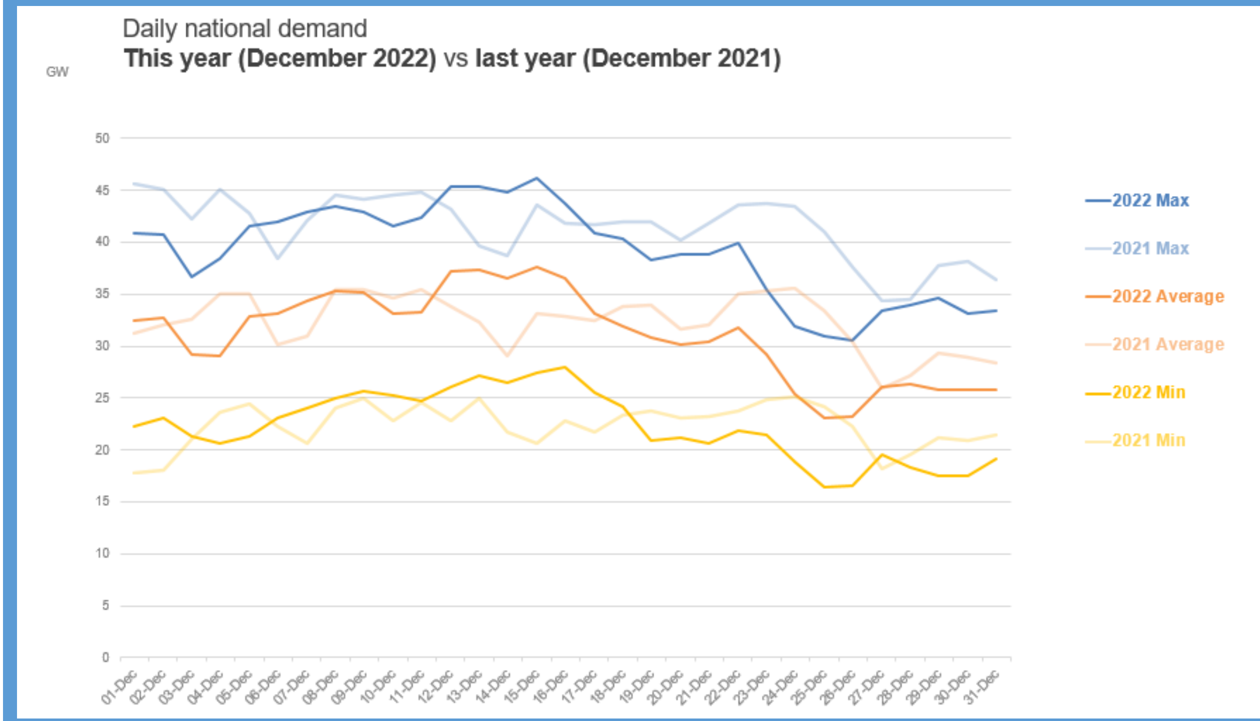
The average daily cost of the month was £15.4m, a £1.4m decrease from the previous month.

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 - December 2022 vs December 2021



Outturn Demand – December 2022 vs December 2021



Metric 1B Demand forecasting accuracy

Q3 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 ±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

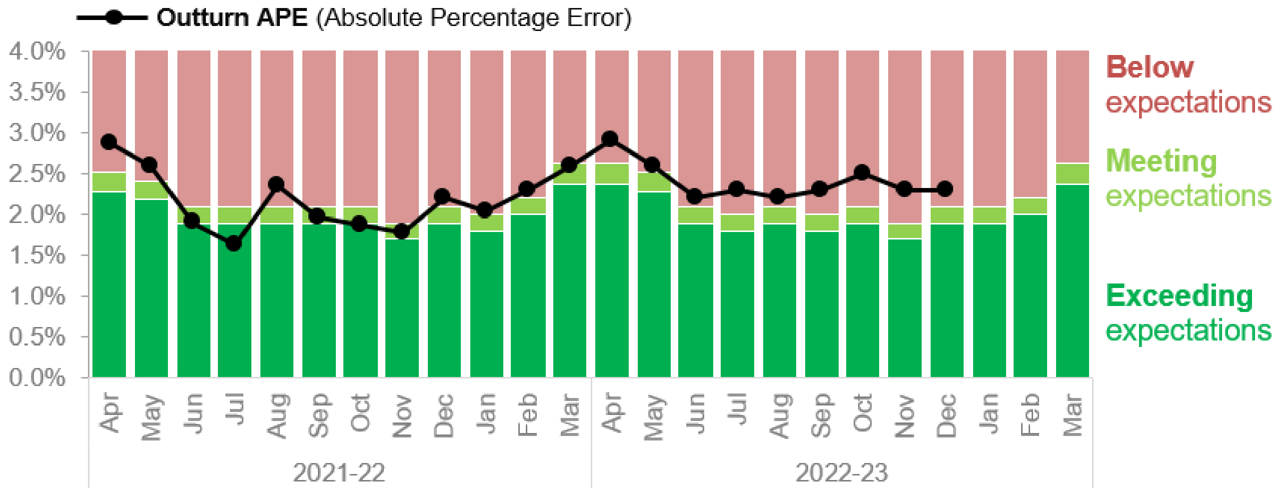


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

	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	2.3				
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

For December 2022, the mean absolute percentage error (MAPE) of our day ahead demand forecast was 2.3% compared to the indicative performance target of 2.0%, and therefore below expectations.

National demand has continued to fall year on year, and this reduced national demand has the effect of increasing the percentage errors.

The month started with a cold snap, according to the MET Office “the coldest start to meteorological winter since 2010”. This was followed by a dramatic change to much milder conditions. Even with these large swings in weather conditions, errors seemed to be dominated by human behaviour related factors.

December is a difficult month for forecasting, especially due to the variable human behaviours around the Christmas period. This month was affected by a few large error days; excluding 25 and 26 Dec the monthly MAPE would be 2.01.

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 (1488)
1000 MW	332	22%
1500 MW	124	8%
2000 MW	56	4%
2500 MW	18	1%
3000 MW	3	0%

The days with largest MAPE were December 26, 25 and 18.

DFS tests were run on December 1, 12, 21 and 23. These events introduce additional uncertainty in both forecast and outturn.

From November, we increased the amount of weather data we receive and feed into our forecast models. Model improvements are currently being developed, though this will take time to collect enough data to robustly measure the impact of these forecast improvements (at least one full quarter), and accuracy improvements won’t be seen immediately.

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

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.

In December we saw 7 days affected by triad avoidance behaviour, totalling approximately 15,000 MW.

Metric 1C Wind forecasting accuracy

Q3 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 ±5% of that value is required to meet expectations.

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

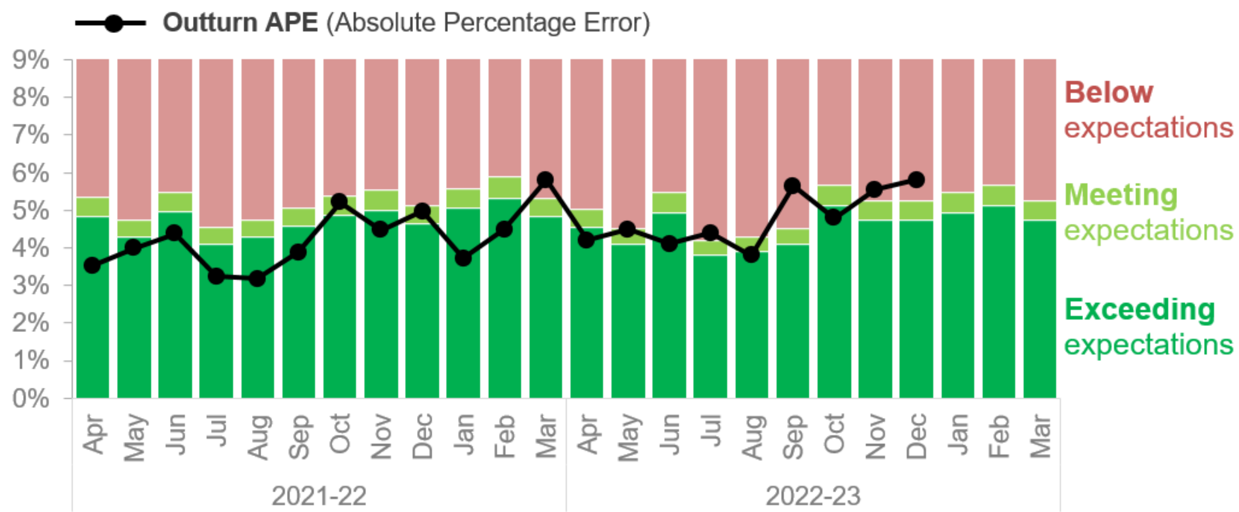


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2022-23)

	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	5.8				
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

For December the wind power forecast accuracy achieved was 5.84% against a target of 4.96%, which is below expectations.

The first two weeks of December 2022 were dominated by a prolonged spell of very cold, dry and calm weather. This gave way to milder, wetter and winder conditions in mid to late December. There were no storms strong enough to be classified as of ‘medium’ or ‘high’ impact by the Met Office.

The December wind forecasts underpredicted the metered generation on some days and overpredicted on others. The largest errors were seen on the 27th December, where the forecast overpredicted the metered wind power output by as much as 4.9 GW. This error was associated with the transition between a relatively short-lived ridge of high pressure giving way to a decaying low pressure weather system. Even with the latest numerical weather prediction models at their disposal, predicting the precise timing and magnitude of such complex meteorological phenomena remains a significant challenge to weather forecast providers.

The Intermittent Market Reference price was negative for over 6h in the early hours of 29th December. This resulted in some wind farms with CFD contractual arrangements reducing output for economic reasons. The Energy Forecasting team at the ESO are currently investigating ways to warn the control room 12-24 hours in advance of these events, however ESO may not be able to publish price-corrected forecasts to the market as this may in turn feedback by itself influencing the market price.

The Energy Forecasting team at the ESO began receiving additional weather data from the Met Office on 24th November, more than doubling the number of forecast locations for which we receive weather forecasts. Over the coming months, this additional data will be assimilated into the ESO forecasting models to enable increased forecast accuracy. In addition, the Energy Forecasting team at the ESO will be improving our wind power forecasting software infrastructure over the coming months to enable the development of more advanced models.

Metric 1D Short Notice Changes to Planned Outages

Q3 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

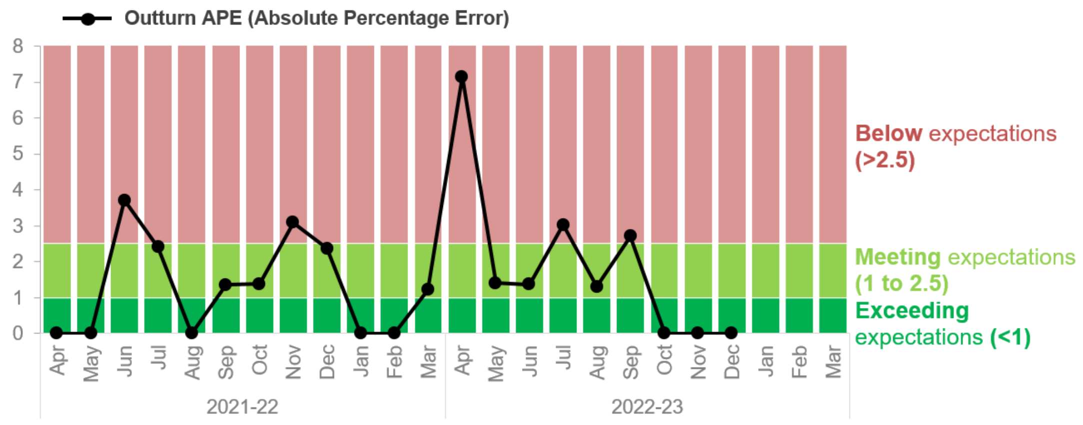


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	700	709	730	660	766	739	684	635	441				6064
Outages delayed/cancelled	5	1	1	2	1	2	0	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	0				2.0
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 Q3, the ESO has been able to successfully release 1760 Planned Outages with zero delays or cancellations. This is within the 'Exceeds Expectations' target of less than one delay or cancellation per 1000 outages. The cumulative number of cancellations or delays per 1000 outages has reduced to 1.98 which is within the 'Meets Expectations' target.

Comparing the 2021/22 performance for Q3, the ESO has released a similar volume of outages at 1794 in 2021/22 against 1760 in 2022/23. However, in 2021/22 there was three cancelations or delays which resulted in the cumulative number of cancellations or delays per 1000 outages at 1.50 by the end of Q3. Therefore, the Q3 performance in 2022/23 has exceeded that of 2021/22 with zero events, but overall the cumulative score is lower than 2021/22 due to the worse performance in Q1.

RRE 1E Transparency of operational decision making

Q3 2022-23 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) orhere 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

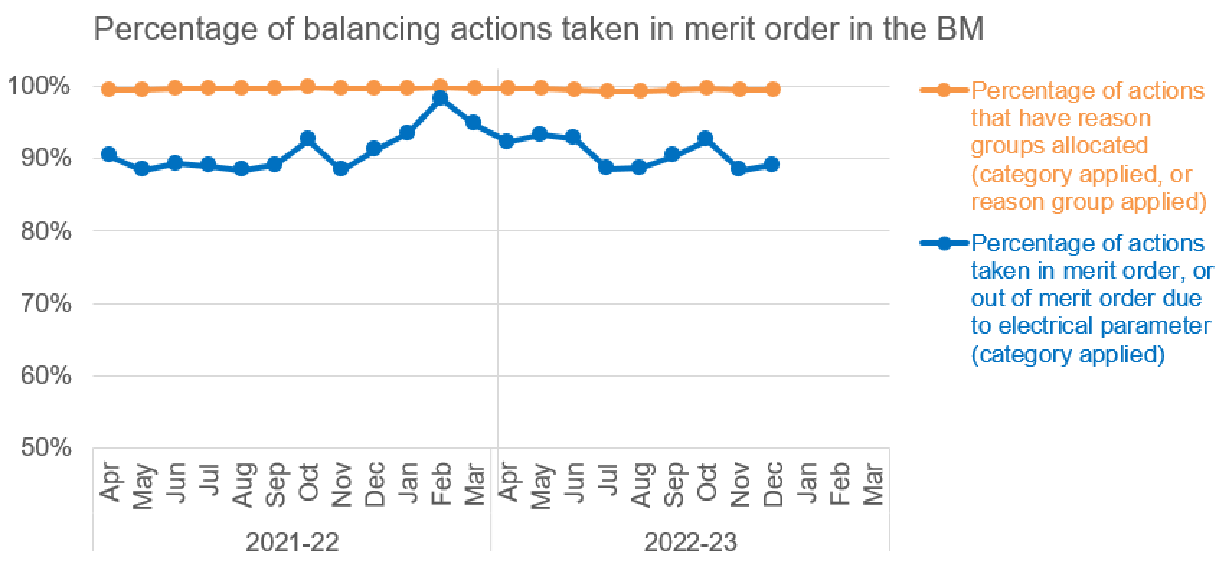


Table 6: Percentage of balancing actions taken outside of merit order in the BM

	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%	89.1%			
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%	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%	0.4%			

Supporting information

This month 89.1% 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 December 2022, we sent 49,995 BOAs (Bid Offer Acceptances) and of these, only 213 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 1F Zero Carbon Operability Indicator

Q3 2022-23 Performance

This Regularly Reported Evidence (RRE) provides transparency on progress against our zero-carbon operability ambition by measuring the proportion of zero carbon transmission connected generation that the system can accommodate.

For this RRE, each generation type is defined as whether it is zero carbon or not. Zero carbon generation includes hydropower, nuclear, solar, wind and pumped storage technologies. As this RRE relates to the ESO's ambition to be able to operate a zero carbon transmission system by 2025, only transmission connected generation is included and interconnectors are excluded (as EU generation is out of scope of our zero carbon operability ambition). Note that the generation mix measured by RRE 1F and RRE 1G differs.

The Zero Carbon Operability (ZCO) indicator is defined as:

$$ZCO(\%) = \frac{(Zero\ carbon\ transmission\ connected\ generation)}{(Total\ transmission\ connected\ generation)} \times 100$$

Part 1 – Defining the maximum ZCO limit for BP1

The ESO will define the approximate maximum ZCO limit (using a reasonable approximation of likely operating conditions), the system can accommodate at the start and end of BP1, explaining which deliverables are critical to increasing the limit.

Table 8: Forecast maximum ZCO% after our operational actions

BP1 2021-23	Maximum ZCO limit	Calculation and rationale
Start of BP1 (Q1 2021-22)	**80% - 85%**	The calculation of the maximum ZCO limit for the start of BP1 is based on the generation plant mix. We assume that the zero-carbon generation output is high, i.e. it is windy with significant contributions from nuclear, pumped storage and hydro, and then overlay system constraints. This overlay reduces the final ZCO as we remove zero carbon generation and add on carbon-producing generation such as CCGT or biomass to meet our response, inertia and voltage requirements. This range is compared with real-world system data to ensure consistency.
End of BP1 (Q4 2022-23)	**85% - 90%**	The forecast of the maximum ZCO limit that the system can accommodate at the end of BP1 uses a very similar methodology. However, we factor in our forecast changes to the generation mix and significant operational developments. These developments are in line with our operational strategy and more detail is set out in our Operability Strategy Report. The most significant developments that impact ZCO will be improvements to our new response products, the stability pathfinders, the Accelerated Loss of Mains Change Programme, the implementation of the Frequency Risk and Control methodology and the voltage pathfinders. All of these developments are increasing our ability to operate a zero carbon system by either increasing the operability envelope where secure system operation is possible, or by enabling new zero carbon providers of ancillary services.

Part 2 – Regular reporting on actual ZCO

Every quarter, the ESO will report the data on the ZCO provided by the market versus the ZCO following ESO actions. This is presented at a monthly granularity.

The table below is calculated according to the formula for ZCO for each settlement period for every day over the reporting period. ZCO is a percentage of the zero-carbon transmission generation (hydropower, nuclear, solar, wind and pumped storage technologies) divided by the total transmission generation. Two figures are calculated: one represents the system conditions before ESO interventions are enacted, the other is after. This indicator measures progress against our zero-carbon operability ambition by showing the proportion of zero carbon transmission generation that the system can accommodate.

For each month, the settlement period that has the highest ZCO figure after our operational actions were enacted is displayed. The corresponding market ZCO figure is also included. It is worth noting that this market ZCO figure might not necessarily be the maximum ZCO that the market provided over the month. For example, the maximum ZCO provided by the market in June 2022 was 95% on 11 June, settlement period 29. However, for that period the final ZCO dropped to 74% after our operational actions were taken into account, meaning that this was not the highest final ZCO of the month.

Figures 5 and 6 further below shows the underlying data by settlement period and highlights when the maximum monthly values occurred.

Table 9: April to December maximum zero carbon generation percentage by month (2022-23)

Month	**Highest ZCO% in the month** (after ESO operational actions)	**ZCO% provided by the market** (during the same day and settlement period)	Date / Settlement Period
April	83.7%	92.3%	23 Apr / 28
May	78.5%	89.7%	27 May / 8
June	76.7%	72.5%	25 Jun / 9
July	73.9%	78.5%	24 Jul / 22
August	67.3%	75.3%	03 Aug / 7
September	73.5%	74.3%	17 Sep / 30
October	77.6%	83.9%	01 Oct / 31
November	74.3%	82.7%	02 Nov / 7
December	84.8%	88.1%	26 Dec / 34
January			
February			
March			

Note that the values can change between reporting cycles as the settlement data is updated by Elexon.

Figure 5: Maximum monthly ZCO% after ESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred) – Two-year view

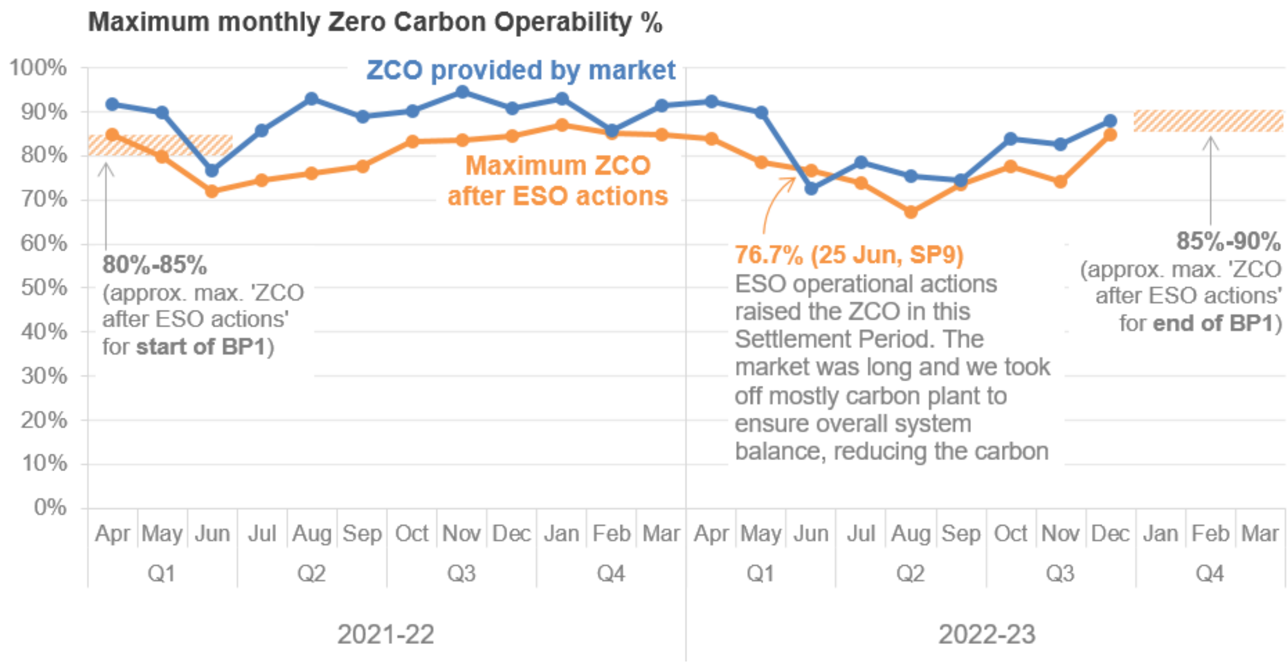
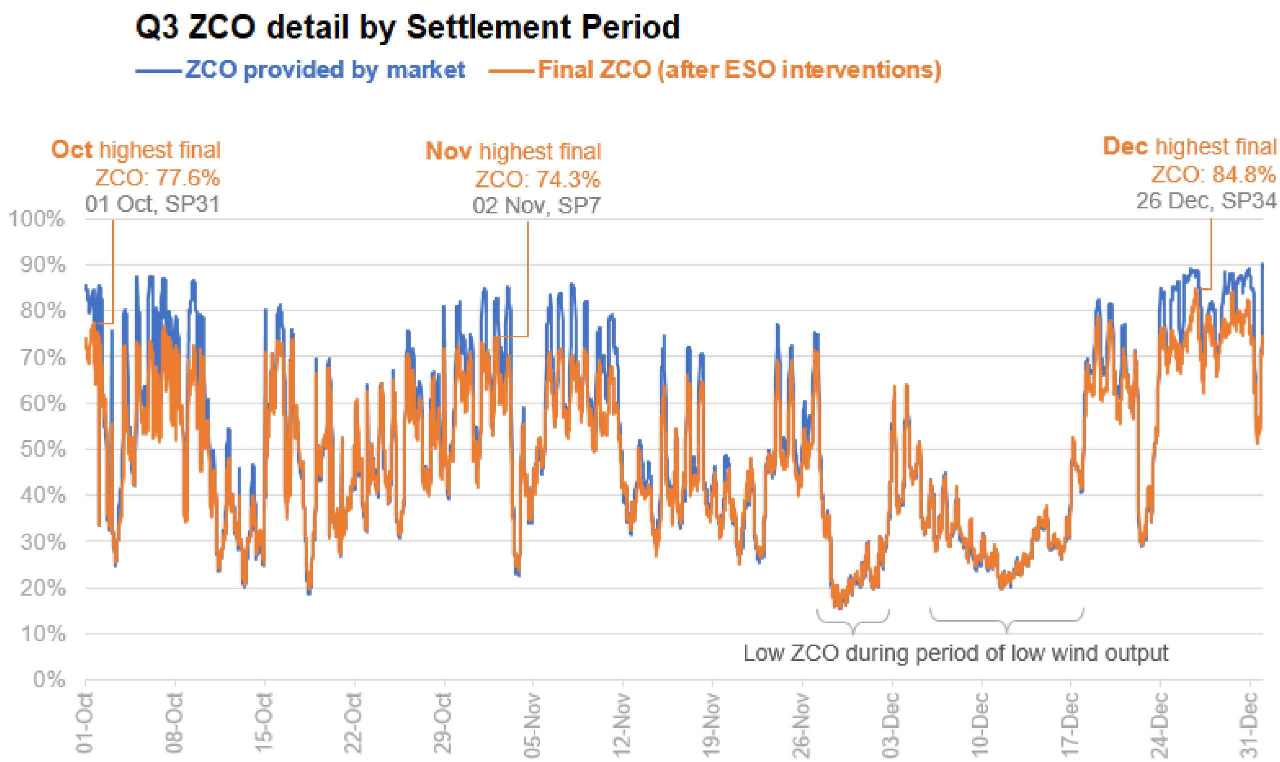


Figure 6: Q3 2022-23 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

In Q3 the highest zero carbon percentage outturn following ESO actions was 84.8%, on 26 Dec 2022, Settlement Period (SP) 34. This is less than the highest ever zero carbon percentage outturn that the system has achieved which remains at 87.1% on 5 January 2022, SP 5. During that SP the market provided 93.0% ZCO, with actions taken by the ESO to manage the system reducing the final figure to 87.1%.

The key message for this quarter is that ZCO numbers are less than last year. This is because the market has dispatched an increased amount of carbon generation to support the increased interconnector exports. This increased scheduling of carbon generation reduces the ZCO provided by the market and hence the final ZCO numbers after our operational actions.

Since April 2021, four Stability Pathfinder Phase 1 service providers have gone live at Rassau, Deeside, Keith and Killingholme. Together they increase system inertia by ~7.2GVAs, which could potentially remove the need to synchronise 2-3 Combined Cycle Gas Turbine (CCGT) units for inertia. This usually occurs over the summer and shoulder months and would increase the ZCO figure by around 2.5% (depending on system conditions at the time). Going forward we expect to see further increases in ZCO as the other Stability Pathfinder Phase 1 projects go live.

As expected, the Q3 ZCO figures have increased since Q2 2022-23. Q2 figures are lower than Q3 because the demand (not shown on the graph above) was lower due to the warmer weather. When the demand is low but the renewable output remains high, the ZCO after ESO actions is often lower. This is because we still have to take similar sets of actions (to manage operability constraints such as voltage) but these actions represent a larger proportion of the overall amount of generation. In a similar manner, ZCO will drop at times of high solar output. This is because the majority of solar generation is embedded and hence excluded from ZCO. Therefore, at times of high solar output operational actions will still be needed, even though the ZCO figure provided by the market will appear relatively low as it will not include the solar generation.

In June, the highest ZCO following ESO actions was 76.7% on 25 June, SP9. During this SP, operational actions actually increased the ZCO figure compared with the value provided by the market (72.5%). This means our operational actions reduced the carbon impact of the electricity network. This is because the market was long and we took off mostly carbon plant to ensure overall system balance. Effectively this raises the ZCO.

The other point to note is how closely linked the ZCO figure is with wind output - the low wind spells at the end of April through to the start of May are clearly visible on the graph above, where the ZCO% drops to ~30%. Conversely, the maximum ZCO figures align with settlement periods of high renewable output, such as when it is windy.

RRE 1G Carbon intensity of ESO actions

Q3 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

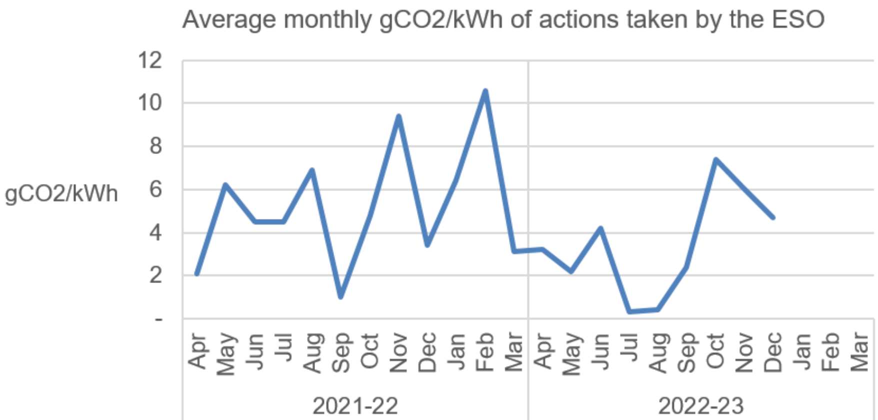


Table 7: Average monthly gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	3.2	2.2	4.2	0.3	0.4	2.4	7.4	6.0	4.7			

Supporting information

In December, the average carbon intensity of balancing actions was 4.7 gCO2/kWh. This was a decrease from November 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, Q2 and Q3, the average carbon intensity was 3.2 gCO2/kWh, 1.0 gCO2/kWh and 6.1gCO2/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 December, the largest decrease in carbon intensity due to ESO's actions was at 17:00 on 25th December with a minimum intensity of ESO actions at –30.1 gCO2/kWh. This was the biggest reduction for the year.

RRE 1H Constraints Cost Savings from Collaboration with TOs

Q3 2022-23 Performance

The Transmission Operators (TOs) need access to their assets to upgrade, fix and maintain the equipment. TOs request this access from the ESO, and we then plan and coordinate this access. We look for ways to minimise the impact of outages on energy flow and reduce the length of time generation is unable to export power onto the network.

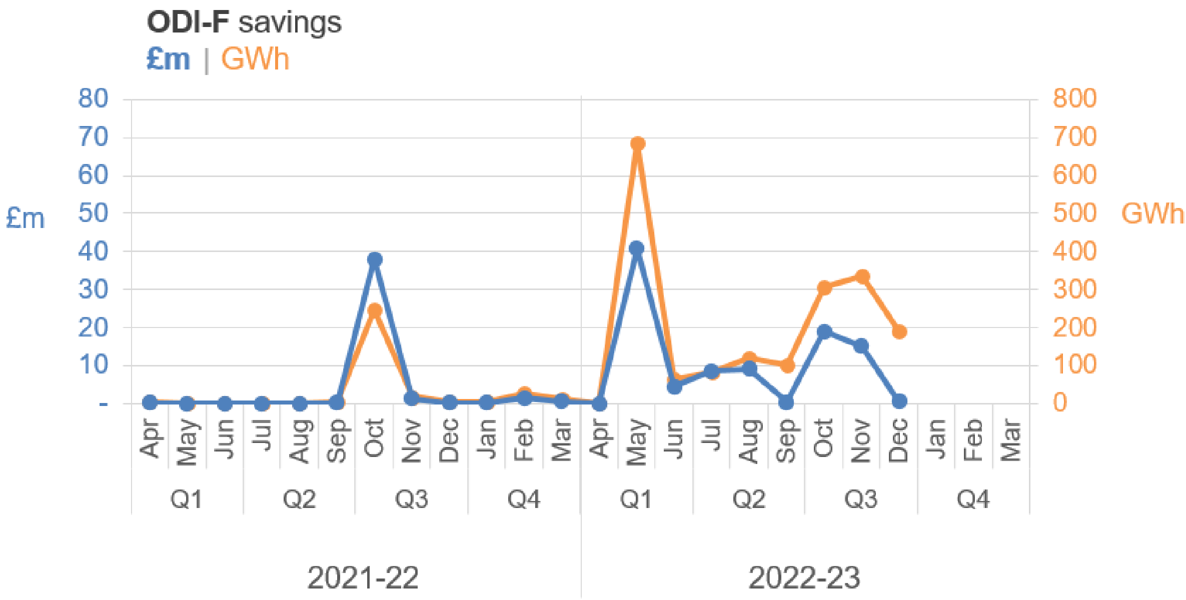
This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

There are two ways the ESO can work with the TOs to minimise constraint costs. We will report on both for RRE 1H:

1. ODI-F savings: Actions taken through the System Operator: Transmission Owner (SO:TO) Optimisation ODI-F
    - Output Delivery Incentives (ODIs) are incentives that form part of the TOs' RIIO-2 framework. They are designed to encourage licensees to deliver outputs and service quality that consumers and wider stakeholders want to see. These ODIs may be financial (ODI-F) or reputational (ODI-R).
    - One of these ODIs, the SO:TO Optimisation ODI-F, is a new two-year trial incentive to encourage the Electricity Transmission Owners (TOs) to provide solutions to the ESO to help reduce constraint costs according to the STCP 11-4[3] procedures. The ESO must assess the eligibility of the solutions that the TOs put forward in line with STCP 11-4, and must deliver the solutions in order for them to be included as part of the SO:TO Optimisation ODI-F and this RRE 1H.
    - For RRE 1H, where constraint savings are delivered through the SO:TO Optimisation ODI-F, the savings are calculated in line with the methodology for that incentive.
2. Other savings: Actions taken separate from the SO-TO Optimisation ODI-F
    - The ESO also carries out other activities to optimise outages. In these cases, the assumptions used for estimating savings will be stated in the supporting information.

Figure 7: Estimated £m savings in avoided constraints costs (ODI-F) – two-year view

(Estimated savings in GWh are also shown for context)



[3] The STCP 11-4 'Enhanced Service Provision' procedure describes the processes associated with the ESO buying a service from a TO where this service will have been identified as having a positive impact in assisting the ESO in minimising costs on the GB Transmission network.

Figure 8: Estimated £m savings in avoided constraints costs (Other) – two-year view

(Estimated savings in GWh are also shown for context)

Note **vertical axes scale** below is different from the ODI-F graph above.

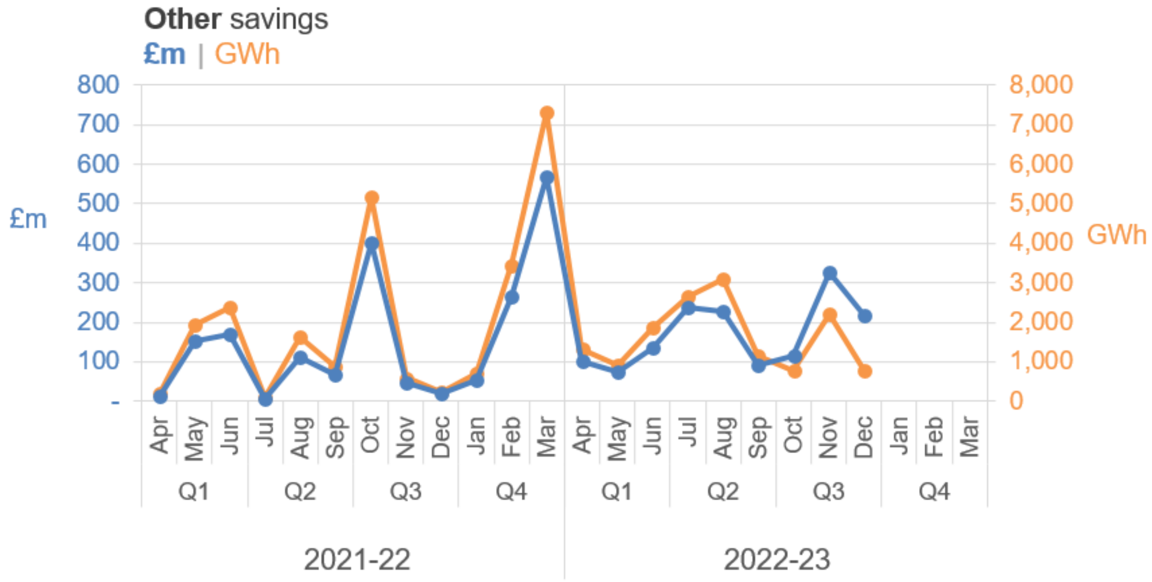


Table 11: Monthly estimated £m savings in avoided constraints costs (2022-23)

	ODI-F savings	Other savings	ODI-F savings	Other savings
	£m	£m	GWh	GWh
Apr	-	101	-	1,316
May	41	74	685	913
Jun	5	135	64	1,870
Jul	9	237	83	2,651
Aug	9	227	120	3,107
Sep	0.4	92	102	1,149
Oct	19.1	116	305	784
Nov	15.2	325	337	2,219
Dec	0.7	216	192	793
Jan				
Feb				
Mar				
YTD	**98**	**1,523**	**1,888**	**14,802**

Note that figures from previous quarters may change as some savings are updated retrospectively with costs that were not available at the time that the activities were carried out. Prices of £55 per MWh are used for conventional generation and £77 per MWh for renewable generation.

Supporting information

ODI-F (STCP 11-4) Constraint Cost Savings

The Network Access Planning (NAP) team has progressed and approved 16 enhanced service provisions from TO's through STCP 11.4 that provide constraint cost savings this year. Some of these provisions are highlighted below:

1. In October, a rating enhancement on a circuit in the Northeast of England was established. This enhancement assisted with B7 constraints. This is expected to save 101,700 MWh and realise around £0.4M of cost savings.

2. In November, a rating enhancement on a circuit in North Wales was established for a month. This enhancement assisted with easing boundary constraints on and behind NW3. This is expected to save 131,040 MWh and realise around £3M of cost savings.

3. In November, a rating enhancement on a key circuit in the southwest of England was delivered. This enhancement assisted with boundary constraints on and behind B12 for an expected saving of 141,600 MWh and £8M.

In Q3 2022-23, NAP has realised approximately £35M of constraint cost savings through STCP 11.4 from 834,200 MWh of extra capacity released.

At the time of this report, there are 9 enhanced service provisions awaiting outturn cost provision. Therefore, ESO have provided forecast savings as 935,940 MWh of savings and approximately £35.4 million for the period September – December. These will be updated in Q4 once more accurate cost figures are available. There is an additional 1 ongoing enhanced service provision that will be reported in quarter 4.

Other Savings (Customer Value Opportunities):

The Network Access Planning team has made good progress over the last three months. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded 51 instances this quarter, and 171 instances in the past 9 months, where the ESO's actions directly resulted in adding value to the end consumers and its innovative ways of working facilitated increased generation capacity to the connected customers.

Such actions include moving outage dates, splitting/separating outages, reducing return to service times, obtaining enhanced ratings from TOs, re-evaluating system capacity, identifying and facilitating opportunity outages, aligning outages with customer maintenance and generator shutdowns, proposing, and facilitating alternative solutions for long outages that impact customer, and many more.

Some examples of these instances include:

- In November, ESO facilitated an extremely complex outage combination in the South of England to improve the LE1 boundary/ Southeast import constraint by 800 MW. There is additional benefit from this work into the future to achieve higher East Anglia Exports as new generation connects in the coming years. This combination took over a year of planning efforts across the industry to deliver, with ESO playing a key role in facilitating the delivery. Plans for this began in 2019, with NGESO working closely with NGET to establish a sequence of outages that would always maintain maximal security by always maintaining one 400kV line in service. Despite this solution, there remained significant further issues to surmount that could not be avoided through outage sequencing. ESO worked with UKPN to change protection settings on sites in the area to reduce demand risk from protection maloperation in the onerous network topology required to deliver this work. ESO engaged with NGET to resolve unmanageable voltage issues in the area resulting in NGET commissioning an innovative temporary over-voltage scheme at Tilbury substation. ESO requested innovative system configurations through close liaison with NGET and UKPN to ensure clean shutdown of demand groups and clear restoration strategies in the case of the worst fault. In 2020 and 2021, studies showed that high volume of reactive equipment was required to release this outage. ESO and NGET liaised to determine that best placement for this outage combination would be in 2022, where reactive availability would be better. It was also identified that an October/ November placement would help further to reduce voltages due to higher demands. Additional non-related outages known to reduce system volts were also aligned to help alleviate high volts. Finally, ESO found that certain busbar faults would result in high volts. ESO identified these to NGET who were able to put in place countermeasures to remove the risk. Overall, this was costed as a £252M saving due to 1,008,000 MWh increased capacity released. This assumes the constraint is active 12 hours a day for 5 days a week. The very significant and innovative approaches taken by NGET to enable the outages and UKPN who assisted despite no direct benefit to themselves should also be noted.

- In November, an unplanned double circuit outage in the Northwest of England was realised and caused reduction on B7a, as well as simultaneous constraints on B16 and B17. ESO Network Access Planning had 24-hour notice of the double circuit outage and took 3 actions in that time to increase network capacity. Network Access Planning arranged a post-fault circuit offload to increase capacity on B17 by 900 MW; changed a running arrangement in the Northwest to improve the B7a constraint by 600 MW; and established a circuit enhancement through negotiations with NGET to improve the B16 limit by 760 MW. In total this allowed for the release of an additional 542,400 MWh of extra capacity that would otherwise have to be curtailed as a result of the emergency works. This was a saving of approximately £29.8M to the end consumer.
- In December, an outage request for a super grid transformer on the main interconnected system in the North of England was rejected for the requested dates and re-scheduled for a date in Spring 2023. This was done to increase network security for the winter period and reduce unnecessary cost to the end consumer for work that should be performed at a less onerous time of year. This resulted in an increase on the B7 limit by 1000 MW. There is expected to be no such constraint for the new dates. In total, an extra 456,000 MWh of savings were forecast in this case equating to around £114.0M of savings to the end consumer given the high price of generation at this time. Due to the higher price £250 per MWh was used in this instance.

8 previous Network Access Planning customer value opportunity actions had their MWh and £ savings calculated in the last quarter. This has led to increased savings registered in Q1 and Q2.

These and many more represent a total of 14,801,804 MWh (approximately £1,522M) of extra generation capacity, which would have otherwise been constrained at a cost to the consumer.

RRE 1I Security of Supply

Q3 2022 Performance

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 ± 0.3Hz 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
$49.2 \le f < 49.5$	up to 60 seconds	2 times per year
$48.8 < f < 49.2$	Any	1-in-22 years
$47.75 < f \le 48.8$	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	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	0			
Voltage Excursions defined as per Transmission Performance Report[4]	0	0	0	0	0	0	0	0	0			

Supporting information

There were no reportable voltage or frequency excursions in December.

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

RRE 1J CNI Outages

Q3 2022-23 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	0			
Integrated Energy Management System (IEMS)	0	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[5] outages	0	0	0	1 outage 186 minutes	0	0	0	1 outage 165 minutes	0			
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0			

Supporting information

In Q3 2022-23 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.

There were no other planned outages during Q3.

There were no unplanned outages during Q3.

[5] July 2021: 1 outage, 216 minutes.
November 2021, 1 outage, 215 minutes.
March 2022, 1 outage, 196 minutes.

Notable events during December 2022

Dispatch Transparency (skip rate) event on 5 December

Twenty-nine industry colleagues joined us in Wokingham for a transparent discussion about the decisions we make in the control room on which balancing services need to be used and who should provide them. This included the topic of "skip rate" (see explanation below)

We talked about:

- How the ESO currently dispatch in an interactive session developing the cumulative dispatch challenges face by our control engineers.
- The future of dispatch provided an overview of the Open Balancing Platform roadmap highlighting how progress will improve transparency and support the control room to manage the dispatch challenges.
- Current ESO Dispatch Transparency methodology explained reasons behind the control room accepting bids or offers which appear to be more expensive; or not accepting those which appear to be cheaper. Included discussion of risk management actions.

Attendees also had the opportunity to view the control room and engage in a Q&A session.

We have published the material and Q&A from the event on our website and invited attendees to give feedback on the event, including how we might improve the event and adapt it to present the information online.

Explanation of "skip rate"

- A skip is a BOA (Bid Offer Acceptance) instruction sent by the ESO control Room to increase or decrease the output of a generator but at a price that was higher than an alternative option. The ESO "skipped" an option that appears to be more economic.
- Skip Rate refers to the number of times a skip occurs in a given period such as a day.

Why are they of concern?

- The ESO has a license condition to operate efficiently and economically and a target to reduce the balancing cost as much as possible.
- There are genuine skips where alternative instructions could have been sent for a lower cost. However, most actions that appear to be skips in data analysis are taken for operational reasons and are not preventable.
- The ESO strives for zero preventable skips.

Role 2 Market development and transactions

Metric 2A Competitive Procurement

Q3 2022-22 Performance

This metric measures the overall % of services procured through competitive means (auctions and tenders) calculated by £ expenditure.

Please note the following points when interpreting the data for this metric:

For **Restoration**, For Restoration, following the competitively run Tenders in 2018 for the South West and Midlands region and in 2019 for the Northern regions, 11 of the successfully awarded contracts have commenced their services from Q1 2022. These new contracts are now providing restoration requirements alongside the historic bi-lateral contracts from before these tenders. From the competitive tenders, the last remaining station to commence service will come live in Q4. In Q2 2022, brand new regional competitive tenders were launched, and we should see the outcome of these contracts in 2025.

For **Frequency Response** (FR), a lower '% of services procured through competitive means (auctions and tenders)' may appear to indicate that the market has become less competitive but can actually be a sign of the opposite. When the market becomes more competitive, the market price drops. This can lead to a reduction in overall competitively procured spend and therefore a lower percentage of total services that are competitively procured.

SO/SO Trades are, by their nature, bilateral and therefore will always be reported as being bilaterally contracted. This means that in those quarters where more SO/SO trades are enacted, the percentage of Constraints & SO/SO Trades competitively procured is likely to reduce.

Figure 9: Percentage of £m spend by procurement method (October 2022 to December 2022)

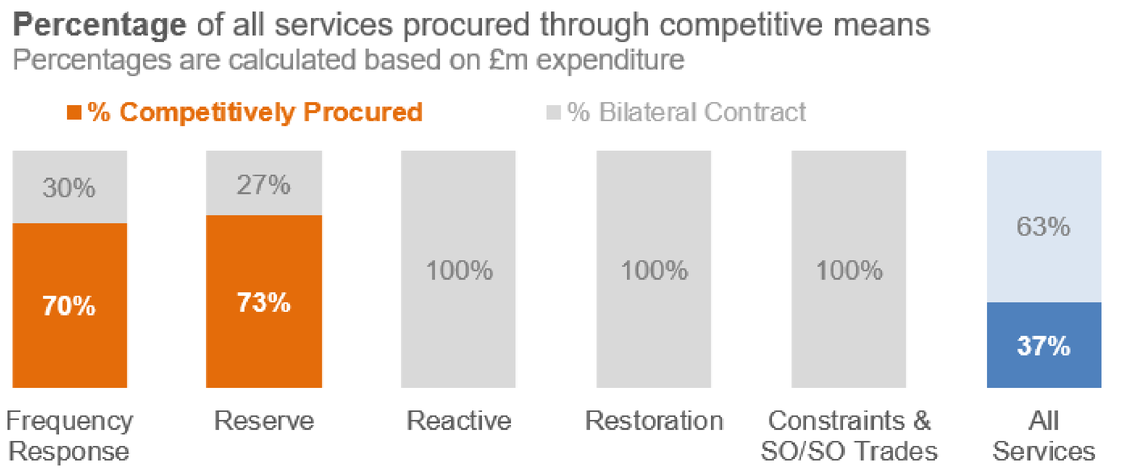


Figure 10: Absolute £m spend by procurement method (October 2022 to December 2022)

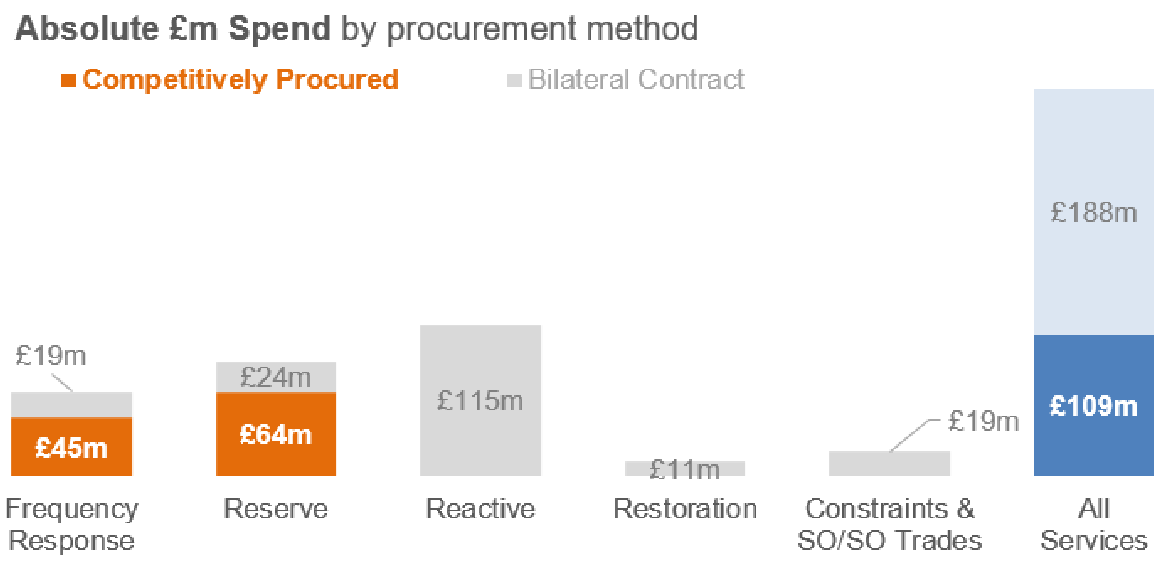


Table 15: Percentage of services procured through competitive means by Quarter

Year	2021-22					2022-23				
Services	**Q1**	**Q2**	**Q3**	**Q4**	**Full Year**	**Q1**	**Q2**	**Q3**	**Q4**	**YTD**
Frequency Response	91%	83%	84%	82%	85%	82%	76%	70%		76%
Reserve	61%	62%	62%	66%	63%	60%	70%	73%		68%
Reactive	0%	0%	0%	0%	0%	0%	0%	0%		0%
Restoration	0%	0%	0%	0%	0%	0%	0%	0%		0%
Constraints & SO/SO Trades	89%	376%[6]	42%	52%	118%[7]	29%	1%	0%		10%
All services	**57%**	**61%**	**46%**	**44%**	**51%**	**46%**	**47%**	**37%**		**39%**
Status (All services)	●	●	●	●	●	●	●	●		●

Performance benchmarks - **Year 1**

- ● **Exceeding expectations:** >60%
- ● **Meeting expectations:** 50-60%
- ● **Below expectations:** <50%

Performance benchmarks - **Year 2**

- ● **Exceeding expectations:** >75%
- ● **Meeting expectations:** 65-75%
- ● **Below expectations:** <65%

[6] The figure is greater than 100% as Bilateral contract spend is negative (due to sending additional energy to Ireland via interconnectors in September). Absolute figures could be used instead, however this would be inconsistent with previously provided data. For reference, the absolute figures for Constraints & SO/SO Trades in Q2 2021-22 were: £15m competitively procured, -£11m bilateral contract.

[7] The figure is greater than 100% as Bilateral contract spend is negative (due to sending additional energy to Ireland via interconnectors in September). Absolute figures could be used instead, however this would be inconsistent with previously provided data. For reference, the absolute figures for Constraints & SO/SO Trades for full year 2021-22 were: £30m competitively procured, -£5m bilateral contract.

Supporting information

Q3 performance: Below expectations

The percentage of services procured through competitive means is 37%, which is in the 'below expectations' range of <65%. This is largely driven by increased spend on reactive.

Within our spend on Restoration and Reactive services, there are contracts that have gone live recently that were procured via competitive tenders, which is not currently reflected within the figures reported here. We are working on assigning these figures correctly in time for the end of scheme report. We don't expect this to have a material effect on scoring for the overall metric.

Average Market Prices

	Q1	Q2	Q3	Q4
Dynamic Containment Low Frequency (DCL) (£/MW)	23.5	21.1	8.2	
Dynamic Containment High Frequency (DCH) (£/MW)	4.1	3.6	3.2	
Dynamic Moderation Low Frequency (DML) (£/MW)	5.2	5	4.6	
Dynamic Moderation High Frequency (DMH) (£/MW)	7.9	11.9	7.5	
Dynamic Regulation (£/MW) Low Frequency (DRL) (£/MW)	25.6	29.6	15.7	
Dynamic Regulation (£/MW) High Frequency (DRH) (£/MW)	26.2	18.4	11.8	
Optional Fast Reserve (£/MWh)	228.8	423.4	270.18	
STOR DA (£/MW)	4.6	10	23.91	

Frequency Response

The new frequency response product suite consists of Dynamic Moderation (DM), Dynamic Regulation (DR) and Dynamic Containment (DC). Although DM and DR services are less than a year old the market growth in this time has created a competitive market place and we predict this growth to continue as Dynamic Firm Frequency Response (FFR) is phased out. The volume of prequalified MWs across the tendered Frequency Response products has continued to increase since their launch, resulting in greater market liquidity.

Reserve

The average clearing price rose to £20.71/MW/h. Across the quarter the average contracted volume was 1289MW against a requirement of 1350MW, the average offered capacity was 1975MW. The STOR market remains liquid with the offered capacity always exceeding requirements during this quarter. Over the months of November and December we saw lower volumes offered in the daily auctions, when system margins were tight or when day ahead power prices spiked. The highest clearing price was £175 with offered prices on the same day peaking at £995, this resulted in the lowest cleared volume of the quarter with only 282MW being cleared. The market over the winter has become increasingly reactive to forward margin and price signals with parties seeking to maximise revenue opportunity.

Reactive

We continue to develop our thinking around market-based procurement of Reactive Power and are working with a partner company to explore potential reactive market designs through an innovation project. The Reactive Market Design Project phase 1 was concluded in March 2022 with the initial version of design and all outputs are shared on our website[8]. The next focus of the project is to assess the feasibility of implementing an enduring reactive market, and analyse what solutions are required to be developed. We will work with the stability market design project to further analyse some common questions on subjects such as Transmission Owner competition and broader asset eligibility. The output will then be used to inform a proposal about the plan on how the enduring reactive market can be delivered.

Currently the Reactive Power Market project team is reallocated to the Balancing Reserve project to provide support on the development of the service, lead industry engagement, run the consultation process and deliver the implementation of the service. The Reactive Power Market project was chosen due to the low immediate impact the project has on ESO costs for this winter. The project team will continue working on the Reactive market design after the new Balancing Reserve service is delivered.

Restoration

Q3 Restoration spend is higher than before because we are paying the works contribution payments for the new contracts from the South West and Midlands Tender 2018 and Northern Tender 2019, that have commenced their services in 2022.

The competitive Electricity Restoration Service (ESR) Tenders for the Northern region launched on 17 October 2022 which covered the five DNO licence areas for the North East and North West of England plus, North Scotland and South Scotland. This tender, like the one launched in the South East region in June 2022, also incorporated technical requirements for distribution-led restoration services from Distributed Energy Resources (DER) alongside the usual primary restoration services from transmission-led generators.

When the Expressions of Interest for the Northern Tender closed on 11 November 2022, we received 202 unique offerings from 65 different providers representing 7 technology types. This number surpassed our forecast immensely and in comparison, the South East Tender EOIs were 48 unique offerings.

In Q3, for the other two ESR Tenders - South East region and the one-off wind specific Tender that is targeting wind generators capable of providing the technical solutions equivalent to primary service requirements at transmission level, are both on track and we have shortlisted providers from EOI to the first stage of Feasibility Studies. For the South East Tender, we have collaborated with the DNO - UKPN and identified potential Distribution Restoration Zones (DRZ) which comprise of an Anchor Generator and Top up Service generators - if successful to contract, this will be a pioneering first - from the innovation project Distributed ReStart to BAU. In the Wind Tender, we have had a great level of interest from both onshore and offshore wind generators, which is promising for our Net Zero ambition as we aim to demonstrate that wind has the capability of providing primary service technical requirements which historically was fulfilled by large scale fossil-fuel based generators.

These three Tenders are aiming for service go-live by Q3 2025 for five year contract to 2030.

Constraints & SO/SO Trades

Since April we have had four parties signed up to a Commercial Intertrip on the B6 constraint boundary. All parties have offered different arming fees. Instead of paying constraint costs to turn off generation when there is the risk of a fault, this technology provides an option of allowing generation to continue for longer, by increasing the constraint limit, resulting in reduced constraint costs which would ultimately be paid for by consumers. Across April – December 2022 we have reported consumer savings of over £30m. The remaining parties awaiting TO connection are on schedule to be fully connected by October 2023, we have also contracted with additional generators to connect to the scheme for a service start of October 2024/25 with Framework agreements signed December 2022

RRE 2B Diversity of Service Providers

Q3 2022-22 Performance

This Regularly Reported Evidence (RRE) measures the diversity of technologies that provide services to the ESO in each of the markets covered by performance metric 2A (Competitive procurement). We report on total contracted volumes (mandatory and tendered) in megawatts (MWs) or megavolt amperes of reactive power (MVARs).

There are four services we report on below:

- Frequency Response (MFR, EFR, FFR, DC, DM & DR)
- Reserve (STOR, Fast Reserve)
- Reactive
- Constraints

Data on Restoration services is not included in this report due to the sensitive nature of the information, which will be provided to Ofgem separately.

Methodology

Service	Sub Service	Methodology
Frequency Response	MFR	We report on contracted volumes for every unit. Figures only apply to a single day, not the whole month. For example, a 20MW MFR contract is only recorded as 20MW in the report, not as 600 MW (20MW x 30days).
	FFR	We report on the highest volume for each unit that has been contracted for a particular EFA block for the relevant month. The sum of those values is what we present on the monthly report.
	Dynamic Regulation	
	Dynamic Containment	
	Dynamic Moderation	We report on contracted MW. This doesn't change from month to month unless a contract starts or ends.
Reserve	STOR (Short Term Operating Reserve)	We report on contracted volumes rather than delivered volumes for any contracted unit that could be instructed or awarded a tender each month.
	Fast Reserve	We report on contracted volumes. We record the highest available volume for each unit for each month. Available volumes can change throughout the month for a unit. For example, a unit can be available at 60MW for 29 days in a month, and at 70MW for 1 day of the same month.
Reactive	Reactive	We report on contracted volumes for every unit. Figures only apply to a single day and not the whole month. For example, a 20MW Reactive contract is only recorded as 20MW in the report, not as 600MW (20MW x 30days).
Constraints	Constraints	We report on contracted volumes for all contracts that are live for any part of the month. Some are live for the whole month whereas others are live for part of the month. The highest available volume on a specific day for each unit for the relevant month is captured. The sum of those values is what we present in the monthly report.

Figure 11: Total contracted volumes by service type by quarter – two-year view

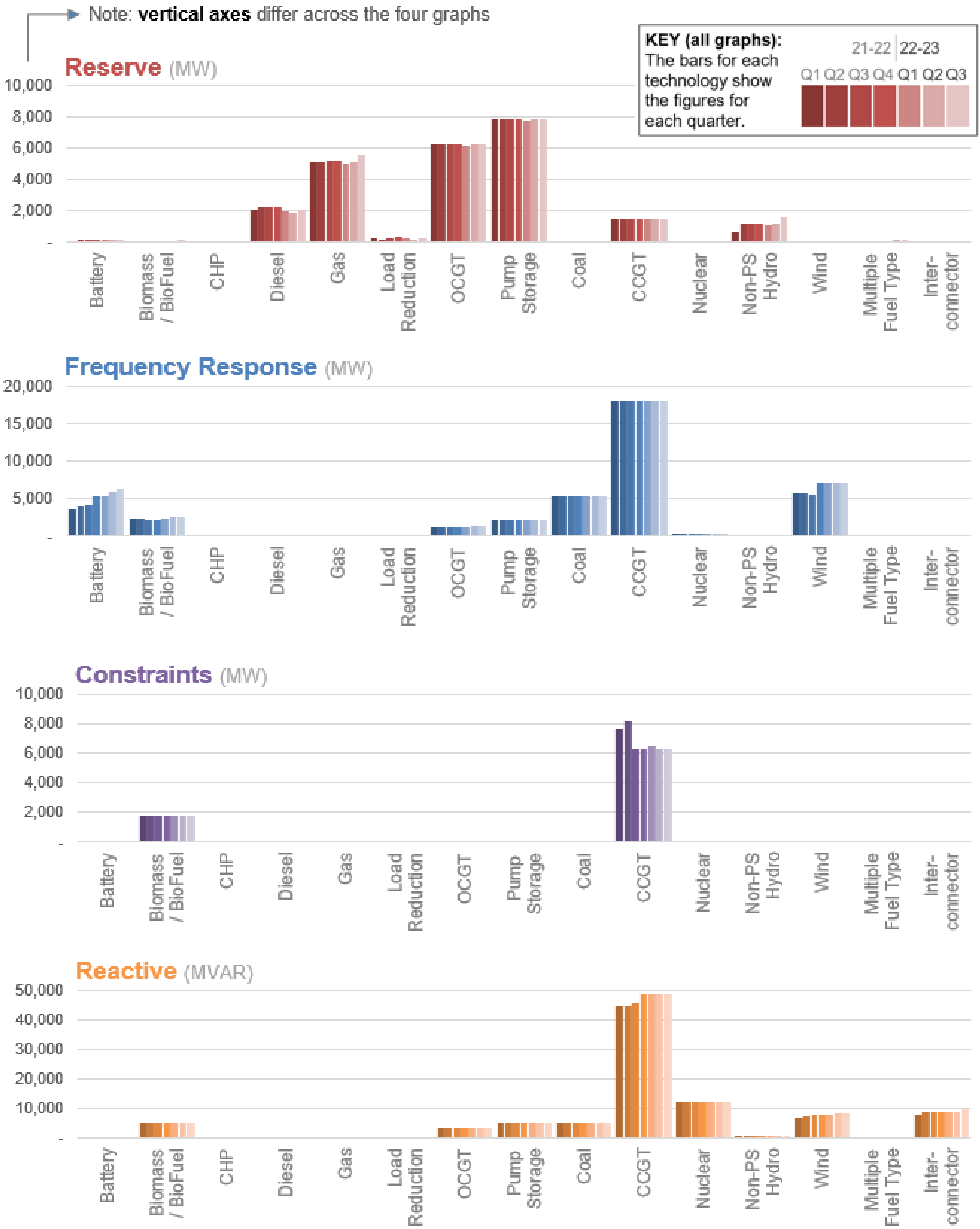


Table 16: Monthly contracted volumes provided to the ESO by service type

Reserve

				2021-22				2022-23				
MWs	**Oct-22**	**Nov-22**	**Dec-22**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**2021-22**	**2022-23**
Total	8,286	8,287	8,287	23,360	24,001	24,143	24,276	23,576	23,731	24,860	95,781	72,167
Battery	45	45	45	-	60	74	135	134	135	135	269	404
Biomass/BioFuel	20	20	20	-	-	-	-	-	-	60	-	60
CHP	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	669	670	670	2,063	2,182	2,205	2,217	1,890	1,864	2,009	8,668	5,763
Gas	1,836	1,836	1,836	5,085	5,073	5,133	5,133	4,964	5,031	5,508	20,424	15,503
Load Reduction	65	65	65	216	150	195	255	225	150	195	816	570
OCGT	2,061	2,061	2,061	6,183	6,183	6,183	6,183	6,117	6,183	6,183	24,732	18,483
Pump Storage	2,600	2,600	2,600	7,800	7,800	7,800	7,800	7,716	7,800	7,800	31,200	23,316
Coal	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	481	481	481	1,437	1,437	1,437	1,437	1,427	1,443	1,443	5,748	4,313
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	506	506	506	576	1,116	1,116	1,116	1,104	1,116	1,518	3,924	3,738
Wind	-	-	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	3	3	3	-	-	-	-	-	9	9	-	18
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-

Frequency Response

				2021-22				2022-23				
MWs	**Oct-22**	**Nov-22**	**Dec-22**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**2021-22**	**2022-23**
Total	14,359	14,376	14,730	39,001	39,296	39,343	41,967	42,282	43,150	43,465	159,607	128,897
Battery	1,990	2,007	2,366	3,644	3,979	4,126	5,336	5,382	5,986	6,363	17,085	17,731
Biomass/BioFuel	837	837	817	2,375	2,319	2,191	2,151	2,351	2,511	2,491	9,036	7,353
CHP	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	43	43	56	130	130	192	188	183	147	142	640	472
Gas	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	443	443	443	1,119	1,119	1,119	1,119	1,189	1,329	1,329	4,476	3,847
Pump Storage	728	728	728	2,184	2,184	2,184	2,184	2,184	2,184	2,184	8,736	6,552
Coal	1,782	1,782	1,782	5,346	5,346	5,346	5,346	5,346	5,346	5,346	21,384	16,038
CCGT	6,024	6,024	6,024	17,997	17,997	17,997	18,047	18,072	18,072	18,072	72,038	54,216
Nuclear	92	92	92	276	276	276	276	276	276	276	1,104	828
Non-PS Hydro	70	70	70	210	210	210	210	210	210	210	840	630
Wind	2,343	2,343	2,343	5,643	5,643	5,617	7,029	7,029	7,029	7,029	23,932	21,087
Multiple Fuel Type	7	7	9	77	93	85	81	60	60	23	336	143
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-

Constraints

				2021-22				2022-23				
MWs	**Oct-22**	**Nov-22**	**Dec-22**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**2021-22**	**2022-23**
Total	2,705	2,705	2,705	9,499	9,863	8,055	8,055	8,309	8,115	8,115	35,472	24,539
Battery	-	-	-	-	-	-	-	-	-	-	-	-
Biomass/BioFuel	595	595	595	1,785	1,785	1,785	1,785	1,785	1,785	1,785	7,140	5,355
CHP	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-	-	-	-
Pump Storage	-	-	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	2,095	2,095	2,095	7,645	8,070	6,225	6,225	6,455	6,285	6,285	28,165	19,025
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	-	-	-	-	-	-	-	-	-	-	-	-
Wind	15	15	15	69	8	45	45	69	45	45	167	159
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-

Reactive

MVARs	Oct-22	Nov-22	Dec-22	2021-22 Q1	2021-22 Q2	2021-22 Q3	2021-22 Q4	2022-23 Q1	2022-23 Q2	2022-23 Q3	2021-22	2022-23
Total	32,512	32,512	32,512	89,467	91,602	92,938	95,661	95,685	96,546	97,536	369,668	289,767
Battery	-	-	-	-	-	-	-	-	-	-	-	-
Biomass / BioFuel	1,734	1,734	1,734	5,202	5,202	5,202	5,202	5,202	5,202	5,202	20,808	15,606
CHP	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	967	967	967	2,901	2,901	2,901	2,901	2,901	2,901	2,901	11,604	8,703
Pump Storage	1,630	1,630	1,630	4,890	4,890	4,890	4,890	4,890	4,890	4,890	19,560	14,670
Coal	1,731	1,731	1,731	5,193	5,193	5,193	5,193	5,193	5,193	5,193	20,772	15,579
CCGT	16,164	16,164	16,164	44,496	44,496	45,820	48,468	48,492	48,492	48,492	183,280	145,476
Nuclear	4,095	4,095	4,095	12,285	12,285	12,285	12,285	12,285	12,285	12,285	49,140	36,855
Non-PS Hydro	189	189	189	567	567	567	567	567	567	567	2,268	1,701
Wind	2,743	2,743	2,743	6,576	7,311	7,323	7,398	7,398	8,259	8,229	28,608	23,886
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	3,259	3,259	3,259	7,357	8,757	8,757	8,757	8,757	8,757	9,777	33,628	27,291

Supporting information

Reserve

Procurement volumes and technology mix remain consistent with historical data within Quarter 3.

Frequency Response

Frequency services are delivered by providers who are awarded contracts through a competitive tendering process (which includes the daily auctions) that take place on a daily basis. The unit base is a mix of BM and Non-BM, primarily DNO connected, however we are starting to see TO connected storage assets that are providing frequency services. There is a continued increase in MWs from batteries providing tendered frequency services, with this asset type now making up the majority of the MWs provided by frequency services.

Constraints & SO/SO Trades

Constraint costs occur when the ESO pays generators to constrain their output due to network capacity limitations and typically for them to increase or decrease MWs on the system. Historically, this service has been limited to the providers that are connected to the transmission network and by requiring providers to change their MW generation levels. The Constraint Management Pathfinder reduces the actions required by the ENCC to manage the constraint across the B6 boundary.

Reactive

The reactive power service is delivered primarily by providers who have Mandatory Service Agreements and are typically connected to the Transmission Network. These providers would also be in the BM. The launch of the Voltage Pathfinders has proven that distribution network providers can also be effective to meet a transmission need. The Peak Gen shunt reactor service went live in Q1 2022-23, and we expect the Zenobe Battery to start delivering in Q4 2022-23 to meet a need in the Mersey region. In January 2022 we also awarded contracts to meet reactive needs in the Pennines region that are due to commence in 2024-25.

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

Q3 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

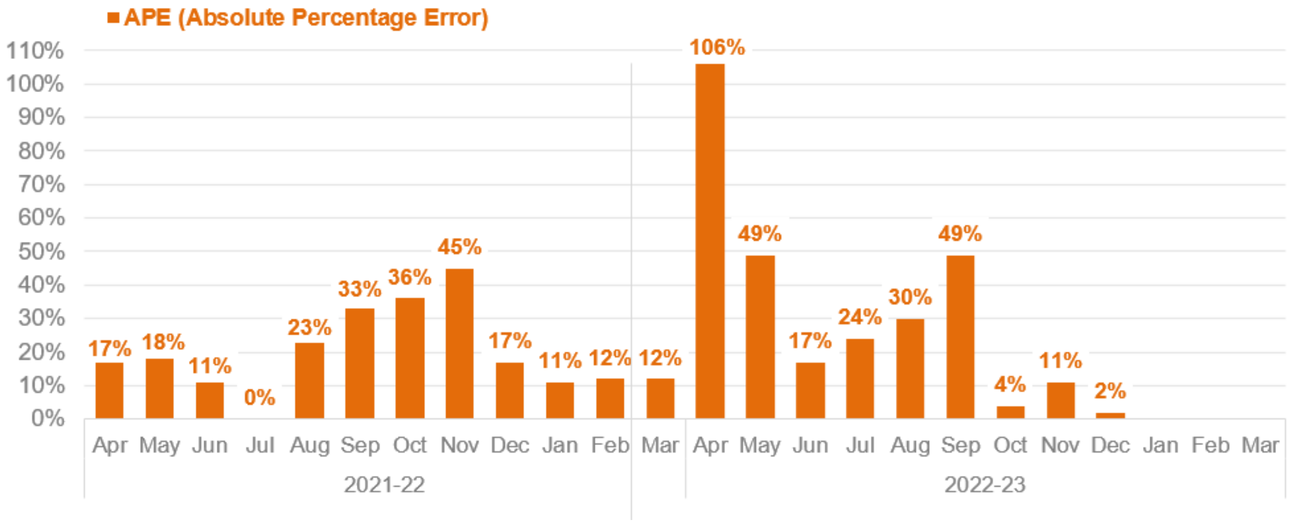


Table 11: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[8] - one-year view

	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	10.5			
Month-ahead forecast	11.0	9.0	7.7	7.8	11.9	12.7	12.1	13.0	10.3			
APE (Absolute Percentage Error)[9]	**106%**	**49%**	**17%**	**24%**	**30%**	**49%**	**4%**	**11%**	**2%**			

Supporting information

Context for monthly commentary:

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, 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).

[9] 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.

December performance

The BSUoS outturn cost and BSUoS volume for this month had a similar deviation (both ~8% higher) from the predicted values for the month. That's why this month's absolute percentage error of 2% is the lowest recorded error in at least the last 2 years.

Costs:

December outturn costs were around the 80th percentile of the forecast produced at the beginning of October. This was mainly due to tight margin days in the first half of the month, combined with high renewable penetration in the second half of the month.

Total cost was £477 million (£414m plus winter contingency cost of £63m)

Volumes:

December actual BSUoS volume was 8% higher than the estimate. (49.52 TWh instead of the estimate 45.9 TWh)

Notable events during December 2022

ESO publishes findings from its new Demand Flexibility Service

In November 2022 the ESO launched the Demand Flexibility Service (DFS). DFS has been developed to allow the ESO to access additional flexibility when the national demand is at its highest – during peak winter days – which is not currently accessible to the ESO. This innovative service supports suppliers/aggregators to incentivise end consumers (domestic and Industrial & Commercial (I&C)) for voluntarily reducing/flexing their electricity usage. The service design includes a number of tests of the service, where providers have access to participate in two regular tests per month and two onboarding tests, across November and December the ESO ran 8 tests (a mixture of onboarding and regular). Confirmed delivery from the 8 test events between 15-Nov and 23-Dec 2022 amounts to 1.18 GWh with a settled cost of £3.54m. For each of these tests, the volume delivered by customers has surpassed the procured volumes.

We have seen increased participation from providers as the service progresses through the winter with 26 approved providers who have over 1 million MPANs (individual households & I&C sites) participating in the service.

OFGEM approval of CMP361/362 which implements fixed ex-ante BSUoS for April 2023

Connection and Use of System Code (CUSC) Modification Proposal (CMP) 361/362 introduces a fixed ex-ante Balancing Use of System Charges (BSUoS) tariff to be implemented from 1 April 2023 alongside CMP308, which following its approval in April 2022 will move BSUoS charges to final demand only. The option approved includes a 9 month notice period for the tariff, a 6 month fix period for the tariff, and no BSUoS industry fund. The BSUoS tariffs for the first two 6 month periods (1 April 2023 to 30 September 2023 and 1 October 2023 to 31 March 2024) will be published by the end of January 2023.

The approval of an option with no industry fund was considered necessary as BSUoS costs are significantly higher and more volatile than when the modification was first assessed, resulting in an estimated industry fund of c.£2.1bn on top of the ESO’s c.£300m of working capital ringfenced to fixing BSUoS. As the industry fund is ultimately financed by consumers, it would erode the benefits of fixing BSUoS. We worked proactively with OFGEM and industry to ensure fixed BSUoS could be implemented for 1 April 2023 in a way that supports consumers, including running additional workshops to develop the solution.

Within their decision, OFGEM state "Should further CUSC Modification Proposals be brought forward, we would encourage industry to consider the appropriate Notice Period. As per our minded-to decision, we continue to believe that a 3-month Notice Period strikes the appropriate balance between providing Suppliers with sufficient advance notice of charges, and mitigating the risk of inaccuracy in a forecast set in advance of the timeframe to which it relates." Therefore, we will be looking at how we raise an additional CUSC modification to update the notice period for the tariff to 3 months.

We will also be investigating what an enduring fixed BSUoS solution may look like, such as whether a longer fixed period or the creation of a BSUoS industry fund to lower the risk of reset of tariffs within period would be beneficial. This would consider the modelled probability tariffs would need to be reset within the fixed period, which impacts the size of the fund and costs to consumers. We will continue to work with OFGEM and industry to develop solutions which have an overall industry and consumer benefit.

Role 3 System insight, planning and network development

Please note there are no metrics for Role 3

Launched the GB Connections Reform project

In October 2022 we launched the GB Connections Reform Project, a project that looks to address the challenges faced by our Connections Customer, Network Companies and ESO as we come together to support the drive for delivering Net Zero in GB of a no longer fit for purpose Transmission Connections Process. The challenges faced are: significantly increasing application volumes, new types of connection customers, significant changes to the mix of technologies, greater interaction between Transmission and Distribution, greater complexity and uncertainty over network investment planning, and an ever-increasing need for a holistic, whole systems approach to planning network investment to ready Great Britain for Net Zero

In December 2022 we published a Case for Change Report which was the product of a number of sessions held with 100 customers, stakeholders, network operators and internal ESO Stakeholders that took place between October and November. The Case for Change report looks to provide a summary of the key findings of the sessions with regards to failings or shortfalls of the process, thus enabling for outline of the strategy and objectives for phase 2 of the project.

Phase 2, the stage where we shall look to carry out design and development of proposals, with engagement and support from representatives from across the industry, for what the new process shall look like and implementation strategy, is now under way. This phase is planned to be completed by end of April 2023, with specific dates for engagement and follow up reports or publication to the industry to be confirmed.

The current timeline of this project presents an acceleration of 6 months against original plan, a response from the ESO to the urgency to address the need to change and evolve the current transmission connections process.

Operability Strategy Report (OSR) published on 21st December

On the 21st December the OSR was published. This year's report explains the challenges we face in operating a rapidly changing electricity system. The report describes what capabilities we need to resolve these challenges and to enable a zero carbon electricity system in 2035. The link to the report can be found here.

The report focuses on the five traditional security workstreams that have been discussed in previous editions of the OSR: Stability, Thermal, Voltage, Frequency and Restoration. Two new workstreams have been added this year to reflect the new challenges we will experience when operating a zero carbon network: Within-day Flexibility and Adequacy.

On the 24th January we are holding an industry wide webinar to discuss the key messages from the OSR, to receive opinions on future deep-dive topics and to answer any questions from industry.

FES Stakeholder Feedback Document to Ofgem for their review

By the 31st January 2023 we will be formally submitting the Future Energy Scenarios (FES) 2023 Stakeholder Feedback Document to Ofgem to meet the ESO's Standard Licence condition C11.15. This document sets out the proposed FES scenario framework and scenarios for 2023 and shares the detail of our engagement that has taken place from springtime 2022 to date and how we are taking it forward. Engagement is fundamental to the annual FES cycle and together with our research, modelling and expertise allows us to set out the credible pathways to the future of energy. We show in the document a summary of the views and evidence we have heard from stakeholders, how we will consider taking these forward and the decisions we have arrived out. Further into the document we will provide a detailed breakdown of insights gathered from stakeholders and our communication and engagement activities. We also take a look back at what we said we would do for FES 2022, both from a modelling perspective as well as our engagement and communications, providing an update on those actions and improvements we set out in last year's Stakeholder Feedback Document. Ofgem then have up to 28 days to respond to the document.

BP1 Deliverables - Milestones no longer valid

Referring to section 5.6 of the ESORI guidance 'If any changes are made to the delivery schedule during the business planning cycle they should be clearly identified and outlined in the reporting documents (e.g. in a separate sub-section), so it is clear where additional amendments have been made in comparison to the original Business Plan. This can ensure Ofgem, stakeholders and the Performance Panel understand the reasons for any changes to plans in advance of its evaluation of the ESO's performance.' – below is a view of those changes.

Below are details of milestones that have become no longer valid over the last quarter:

Role	Sub-activity	Deliverable	Milestone	Reason no longer valid
2	A5.1 Electricity Market Reform (EMR) Delivery Body	An improved prioritisation process in how we implement change in the EMR Delivery Body. This is about embedding the process and not the delivery of specific changes for each year.	EMR Delivery Body runs informal consultation with industry to refine the improved prioritisation process for changes that are deliverable and ensure transparency of those that are not.	In light of Ofgem's plans to establish a Capacity Market Advisory Group (CMAG) with industry in October 2022, the ESO will not undertake a separate engagement exercise regarding the prioritisation process with industry. We are also mindful that BEIS is now reviewing the wider EMR policy and change governance, incl. the CM Policy Board and RCAB. The Delivery Body will therefore capture rule improvement ideas based on feedback received from customers and feed this into the CMAG process as appropriate where these can be discussed with industry.
2	A5.1 Electricity Market Reform (EMR) Delivery Body	An improved prioritisation process in how we implement change in the EMR Delivery Body. This is about embedding the process and not the delivery of specific changes for each year.	Improved change prioritisation process is published by EMR Delivery Body.	In light of Ofgem's plans to establish a Capacity Market Advisory Group (CMAG) with industry in October 2022, the ESO will not undertake a separate engagement exercise regarding the prioritisation process with industry. We are also mindful that BEIS is now reviewing the wider EMR policy and change governance, incl. the CM Policy Board and RCAB. The Delivery Body will therefore capture rule improvement ideas based on feedback received from customers and feed this into the CMAG process as appropriate where these can be discussed with industry.
2	A5.1 Electricity Market Reform (EMR) Delivery Body	An improved prioritisation process in how we implement change in the EMR Delivery Body. This is about embedding the process and not the delivery of specific changes for each year.	Industry take part in prioritisation process.	In light of Ofgem's plans to establish a Capacity Market Advisory Group (CMAG) with industry in October 2022, the ESO will not undertake a separate engagement exercise regarding the prioritisation process with industry. We are also mindful that BEIS is now reviewing the wider EMR policy and change governance, incl. the CM Policy Board and RCAB. The Delivery Body will therefore capture rule improvement ideas based on feedback received from customers and feed this into the CMAG process as appropriate where these can be discussed with industry.

2	A6.1 Code management / market development and change	Continued facilitation of industry changes to the Grid Code, Connection and Use of System Code (CUSC), System Operator Transmission Owner Code (STC) and Security and Quality of Supply Standards (SQSS). Also, delivery of Great Britain driven regulatory change through the open governance process.	Submit Access and Forward Looking Charges Modification Proposals to Authority	Ofgem have changed the scope of the Access SCR, it is no longer expected that any TNUoS related modifications are required at this stage as a result of the SCR. Therefore, this milestone is no longer required and is being re-drafted following the agreed process.
3	A15.9 Identify Future operability needs across whole energy system	Commence RDP approach to whole energy system challenges – build on the RDP approach used in the electricity sector to develop cross sector operability solutions	initial scoping for this activity to take place in 2023/24 so no milestones applicable here	This activity was scheduled to start after BP1. It has subsequently been removed from our BP2 business plan submission..
3	A15.9 Identify Future operability needs across whole energy system	Second whole energy system RDP launched	work to commence on this activity in 2024/25	This activity was scheduled to start after BP1. It has subsequently been removed from our BP2 business plan submission.