ESO RIIO2 Business Plan 2 (2023-25)

Q1 2023-24 Incentives Report

25 July 2023

Contents

Introduction

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

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

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

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

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

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

Please see our website for more information.

Summary of Notable Events

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

- We hosted our latest Dispatch Transparency event on Friday 2 June and published the slides, webinar recording and Q&A document on the OTF webpage.
- We held our third Balancing Programme quarterly engagement event on 15 June where we presented more detail on the benefits and value we have delivered to date through BP1 and what can be expected to be delivered through BP2.
- At the beginning of June we published the final report for the Powerloop trial, which we ran with Octopus Energy in 2022. The trial was the first of its kind for the Great Britain energy system, linking actions taken in the Electricity National Control Centre (ENCC) to domestic household Electric Vehicles (EVs) charge points.
- To support the energy industry's preparations for Winter 2023/2024, on 15 June we published our Early View of Winter Outlook report, to give organisations across the UK energy industry time to prepare for the coming winter.
- We continued engagement with industry and delivered improvements to Demand Flexibility Service (DFS), Balancing Reserve (BR) and Enduring Auction Capability (EAC).
- We published a press release titled "ESO announces urgent action to speed up electricity grid connections by up to 10 years". This announced to industry our plans for ensuring projects with a pre-2026 Connection Agreement are adhering to their milestones.
- On 27 June, a Balancing Mechanism system release was successfully delivered which included a number of enhancements to support our control room in operating the network.

Summary of Metrics and RREs

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) for Q1 2023-24.

Table 1: Summary of Metrics

Monthly (M) and Quarterly (Q) Metrics

Metric		Performance	Status				
			M / Q	Apr	May	Jun	Q1
Metric 1A	**Balancing Costs**	June: 115m vs benchmark of £158m	M	●	●	●	●
Metric 1B	**Demand Forecasting**	June: Forecasting error of 546MW vs indicative benchmark of 503MW	M	●	●	●	●
Metric 1C	**Wind Generation Forecasting**	June: Forecasting error of 4.50% vs indicative benchmark of 4.21%	M	●	●	●	●
Metric 1D	**Short Notice Changes to Planned Outages**	June: 0 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	M	●	●	●	●
NEW **Metric 2Ai**	**Phase-out of non-competitive balancing services** (% of services procured competitively, calculated by volume)	Frequency Response & Reserve: 23% procured non-competitively in Q1 vs benchmark of 25%	Q	n/a	n/a	n/a	●
		Reactive Power: 97% procured non-competitively in Q1 vs benchmark of 90%	Q	n/a	n/a	n/a	●
		Constraints: 98% procured non-competitively in Q1 vs benchmark of 65%	Q	n/a	n/a	n/a	●
NEW Metric 2X	**Day-ahead procurement**	64% balancing services procured at no earlier than the day-ahead stage vs benchmark of 55%	Q	n/a	n/a	n/a	●

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

Table 2: Summary of RREs

RREs don't have performance benchmarks (with the exception of 2C and 2D which are reported annually).

Monthly (M) and Quarterly (Q) RREs

RRE		Performance	M / Q
RRE 1E	**Transparency of Operational Decision Making**	June: 98% of actions taken in merit order	M
RRE 1F	**Zero Carbon Operability indicator**	Q1: Highest ZCO% of 84% after ESO operational actions	Q
RRE 1G	**Carbon intensity of ESO actions**	June: 2.8gCO_2/kWh of actions taken by the ESO	M
RRE 1H	**Constraints cost savings from collaboration with TOs**	Q1: £395m	Q
RRE 1I	**Security of Supply**	June: One instance where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	M

RRE 1J	**CNI Outages**	June: 1 planned and 0 unplanned system outages	M
NEW **RRE 2Aii**	**Balancing services procured in a non-competitive manner**	Q1: £94m spend on non-competitive services. Volume of 19 TWH and 15 TVARH	Q
RRE 2B	**Diversity of service providers**	*See report for details*	Q
RRE 2E	**Accuracy of Forecasts for Charge Setting**	June: Month ahead BSUoS forecasting accuracy (absolute percentage error) of 43%	M
NEW **RRE 3X**	**Connection Offers**	Q1: 357 connection offers made within 3 months, none taking longer than 3 months. TEC queue stands at 343 GW.	Q
NEW **RRE 3Y**	**Percentage of 'right first time' connection offers**	Q1: 93% of connections offers were right first time	Q

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

Adelle Wainwright
Acting ESO Regulation Senior Manager

Role 1 (Control Centre operations)

ESO

Metric 1A Balancing cost management

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

A new benchmark has been introduced for BP2. Analysis has shown that the two most significant measurable external drivers of balancing costs are wholesale price and outturn wind generation. The new benchmark has been derived using the historical relationships between those two drivers and balancing costs:

1. The benchmark has been created using monthly data from the preceding 3 years.

2. A straight-line relationship has been established between historic constraint costs, outturn wind generation and the historic wholesale day ahead price of electricity.

3. A straight-line relationship established between historic non-constraint costs and the historic wholesale day ahead price of electricity.

4. Ex-post actual data inputted into the equation created by the historic relationships to create the monthly benchmarks.

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

Non-constraint costs = 54.48 + (Day Ahead baseload x 0.52)
Constraint costs = -32.66 + (Day Ahead baseload x 0.34) + (Outturn wind x 25.72)

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

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

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

June 2023-24 performance

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

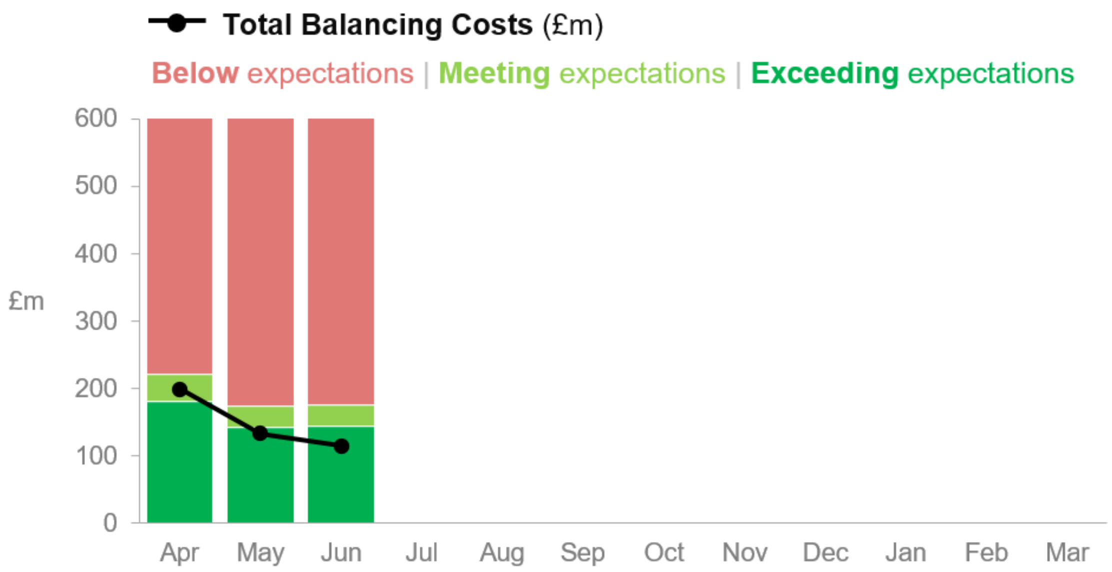


Table 3: 2023-24 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	3.4	2.6	2.4										8.3
Average Day Ahead Baseload (£/MWh)	105	81	87										274
Benchmark	200	157	158										516
Outturn balancing costs[1]	**198**	**132**	**115**										**446**
Status	●	●	●										●

Previous months' outturn balancing costs are updated every month with reconciled values. Figures are rounded to the nearest whole number, except outturn wind which is rounded to one decimal place.

Performance benchmarks:

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

Supporting information

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

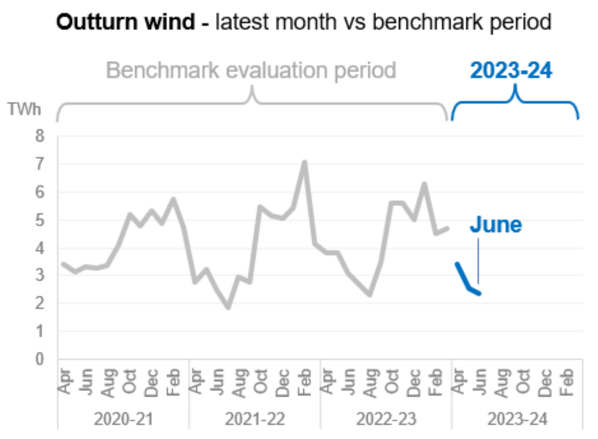
We continue to investigate and will advise when we have a resolution.

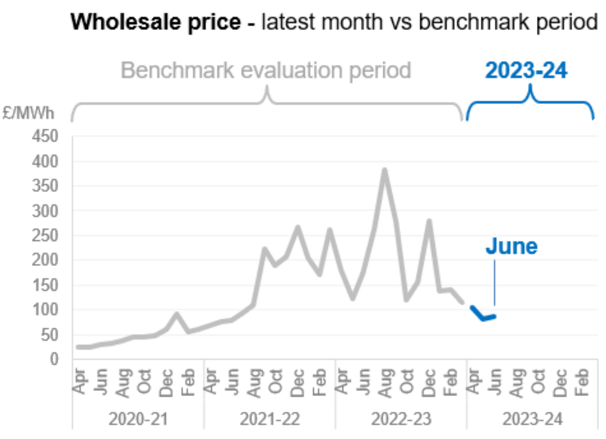
This month's benchmark

The benchmark of £158m reflects:

- a relatively low average **outturn wind** figure compared to the benchmark evaluation period (the last three years). Wind is seasonal and generally at its lowest at this time of year.
- a relatively low average monthly **wholesale price** (Day Ahead Baseload) compared to the benchmark evaluation period (the last three years).

[1] Outturn balancing costs excludes Winter Contingency costs for comparison to the benchmark as agreed with Ofgem. However, in the rest of this section we continue to include those costs for transparency and analysis purposes.





June performance

June's total balancing costs were £115m which is £43m below the benchmark of £158m, and therefore exceeding expectations. As you can see from the above graphs, this month the average wholesale price and outturn wind both remained low relative to the benchmark period, with neither changing significantly from last month. Therefore, all other things being equal, we would not expect a significant change in actuals between May and June. This is broadly the case, with actual balancing costs of £115m in June compared to £132m in May.

Breakdown of costs vs previous month

Balancing Costs variance (£m): June 2023 vs May 2023

		(a) May-23	(b) Jun-23	(b) - (a) Variance	decrease ◂▸ increase Variance chart
Non-Constraint Costs	Energy Imbalance	-3.9	-4.5	(0.6)	
	Operating Reserve	17.6	26.0	8.3	
	STOR	2.8	3.2	0.4	
	Negative Reserve	0.1	0.1	0.0	
	Fast Reserve	12.0	12.1	0.2	
	Response	17.5	17.6	0.2	
	Other Reserve	1.5	1.4	(0.1)	
	Reactive	19.3	15.7	(3.6)	
	Restoration	2.8	2.6	(0.2)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	6.3	9.5	3.2	
Constraint Costs	Constraints - E&W	33.7	15.7	(18.0)	
	Constraints - Cheviot	0.0	0.7	0.7	
	Constraints - Scotland	8.2	1.8	(6.5)	
	Constraints - Ancillary	2.5	0.2	(2.4)	
	ROCOF	2.9	8.4	5.5	
	Constraints Sterilised HR	9.6	4.5	(5.1)	
Totals	Non-Constraint Costs - TOTAL	76.0	83.6	7.6	
	Constraint Costs - TOTAL	57.0	31.3	(25.7)	
	Total Balancing Costs	**133.0**	**114.9**	**(18.1)**	

As shown in the total rows from the table above, the non-constraint costs increased by £7.6m, while the constraint cost fell by £25.7m, resulting in an overall drop of over £18m compared to May 2023.

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

- **Constraint-England & Wales**: £18m decrease, due to lower volume of actions*
- **Constraint-Scotland**: £6.5m decrease, due to lower volume of actions*.

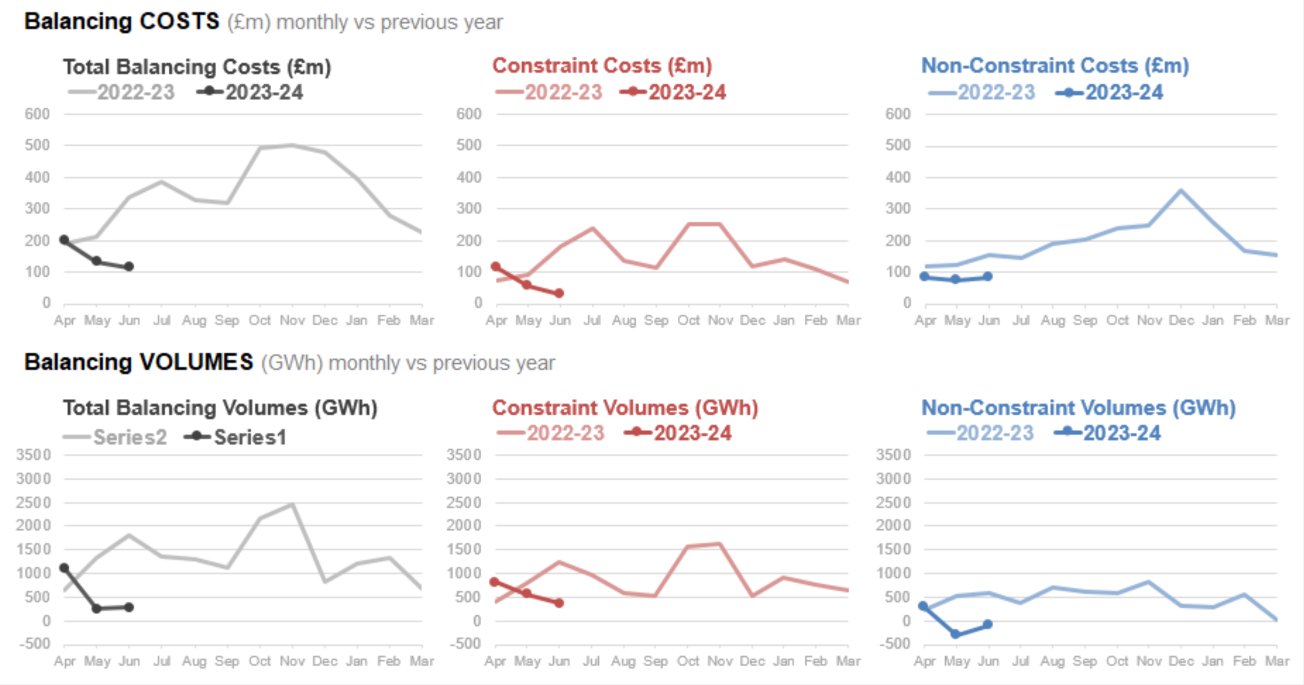
- **Constraints Sterilised Headroom**: £5.1m decrease. Cost decrease is in line with the decreasing of constraint actions because less headroom had to be replaced using BM actions on the system outside the constraint.

* More than 130 fewer planned outages and less wind generation in June compared with May resolved a lower volume of constraint actions.

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

- **Operating Reserve**: £8.3m increased, due to a higher volume weighted average of each action.

Constraint vs non-constraint costs and volumes



Please note that a portion of the **Minor Components** spend contributing to non-constraint cost and volume is 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 £150m lower than in June 2022 due to: • Significantly lower volume of actions taken (700 GWh less wind generation and more than 100 less planned outages) • Lower average wholesale prices (this June £86 /MWh instead of £157 /MWh from the previous year)
Compared with last month:	Constraint costs were £25.7m lower than in May 2023 due to: • Significantly lower volume of actions (182GWh lower than last month)

Non-constraint costs

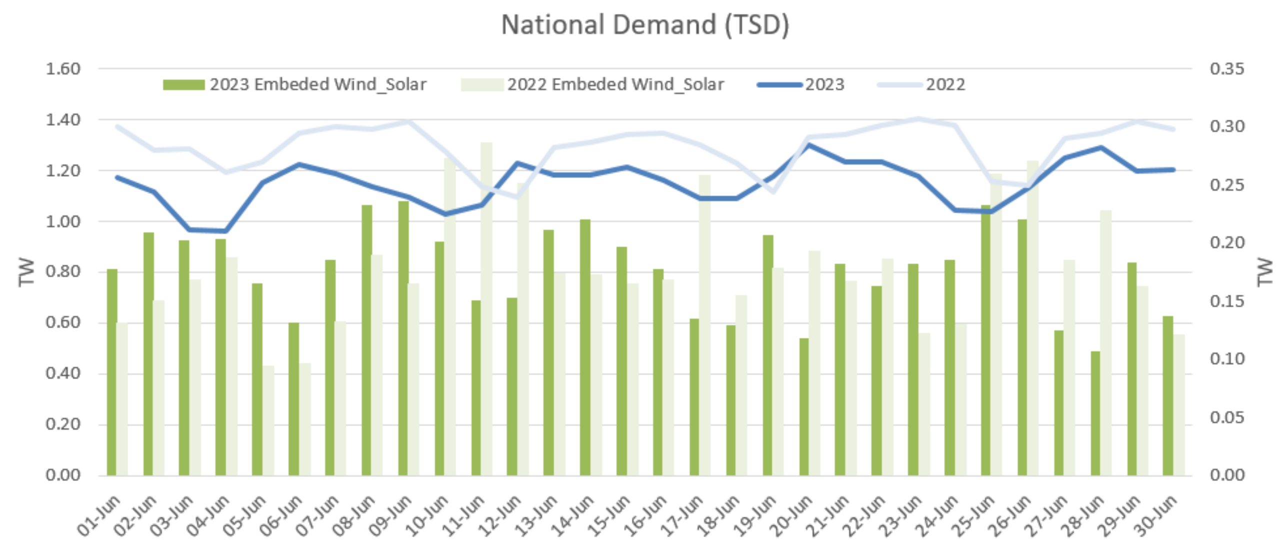
Compared with the same month of the previous year:	Non-Constraint costs were £70.8m lower than in June 2022 due to: • Significantly lower volume of actions (70 GWh less than the previous year) • Lower average wholesale prices (this June £86 /MWh instead of £157 /MWh from the previous year)

Compared with last month:	Non-Constraint costs were £7.6m higher than in May 2023 due to: • higher* volume of actions * The No-Constraint category consists of several subcategories. Small changes to each of these led to the final result. It is not easy to distinguish the most influential category in this increased of the volume.

June daily National Demand (TSD*), Embedded Wind and Solar Generation

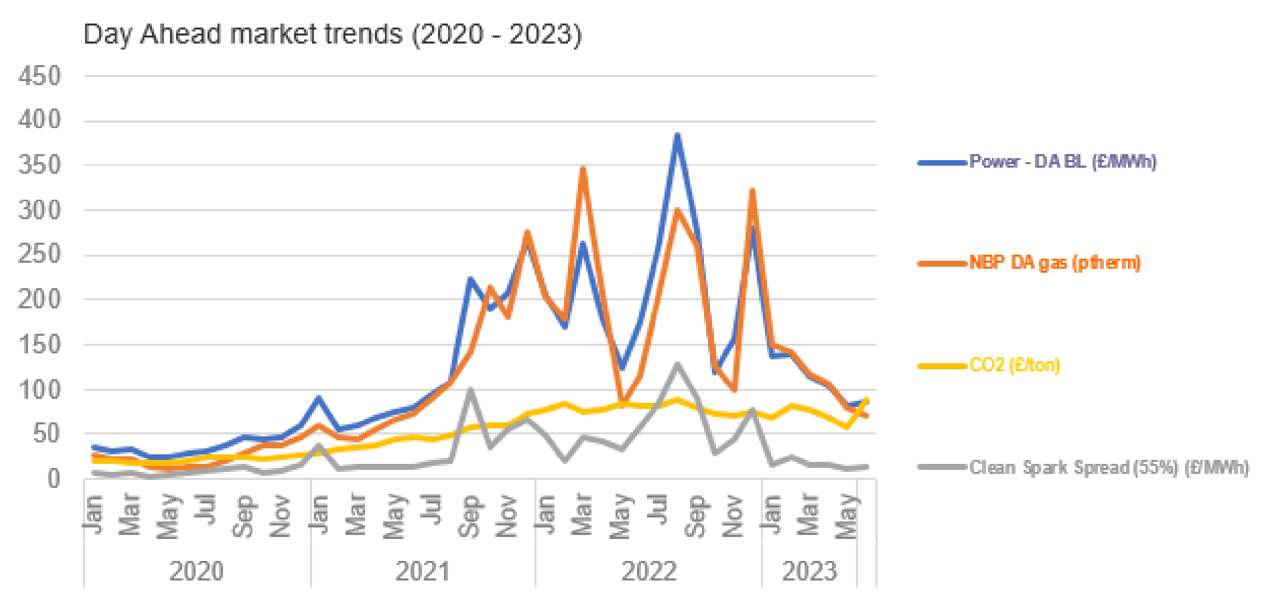
National Demand and embedded wind & solar generation are significantly lower than from the same period last year.

(National Demand: 4.4TW lower – Embedded Generation: 56GW lower)



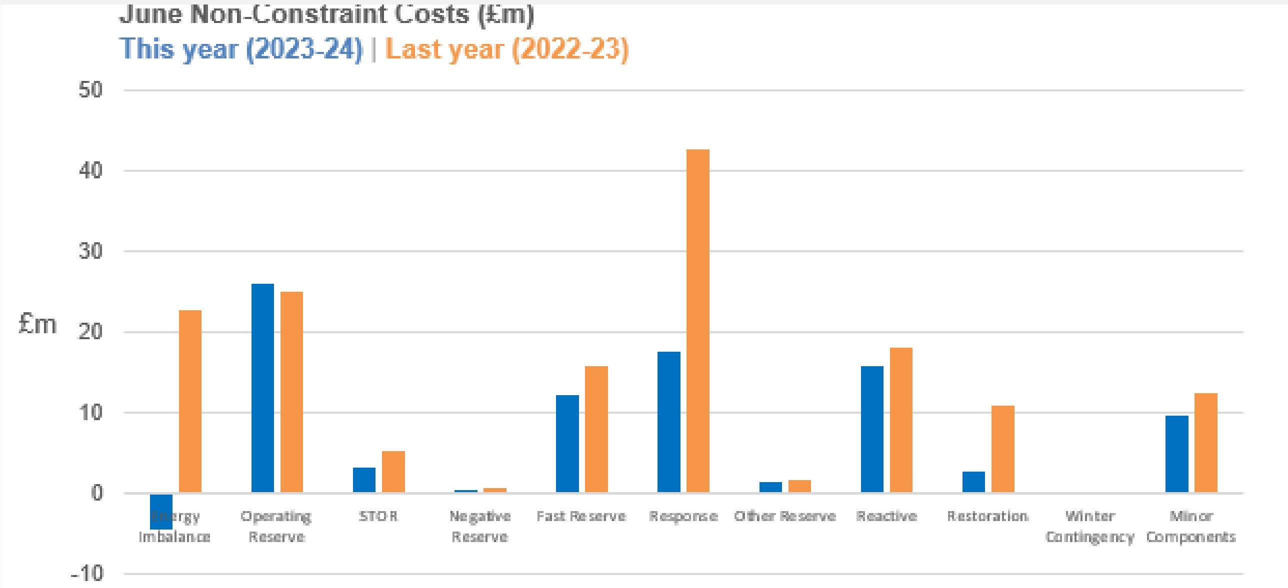
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand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

Changes in energy balancing costs



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

Apart from the Carbon prices which rose in higher levels compared to last month and previous years and Power Day ahead prices which showed a slight increase compared to the last month but remain lower than the previous years the other trends (Day Ahead Gas prices & Clean Spark Spread) decreased from last month and remain lower compared to the previous year.



Comparing the non-constraint costs of June 2023 with those of June 2022, all the categories showed a decrease or a small deviation.

- **Energy Imbalance** over £27m decrease because market was long throughout the month
- **Response decreased** by £25.2m, due to lower average wholesale prices

Drivers for unexpected cost increases/decreases

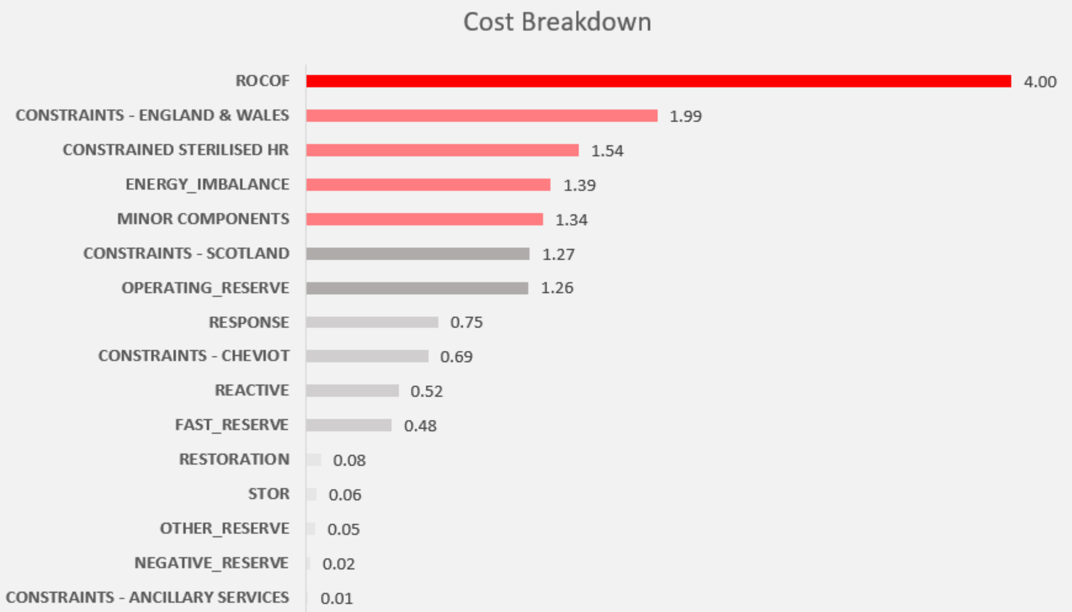
Margin prices (the amount paid for one MWh) have increased compared to May 2023 and the corresponding period of the previous year which is consistent with the increase we saw in the Operating reserve category.

Daily Costs Trends

As mentioned above, June’s balancing costs were slightly more than £18m lower than the previous month due to a significant drop in the volume of actions taken to manage constraints.

At the date of publication, we have recorded 1 day with a spend of more than £10m:

On Sunday 25 June when costs were around £15m, the major cost components were driven by wind forecast errors exceeding 5GW (for more information on this see Metric 1C below) combined with low demand and system management actions. Up to 1.5GW of wind was bid off and up to 2GW of trades were enacted on Continental Interconnectors for downward regulation in addition a large amount of plant was required for RoCoF.



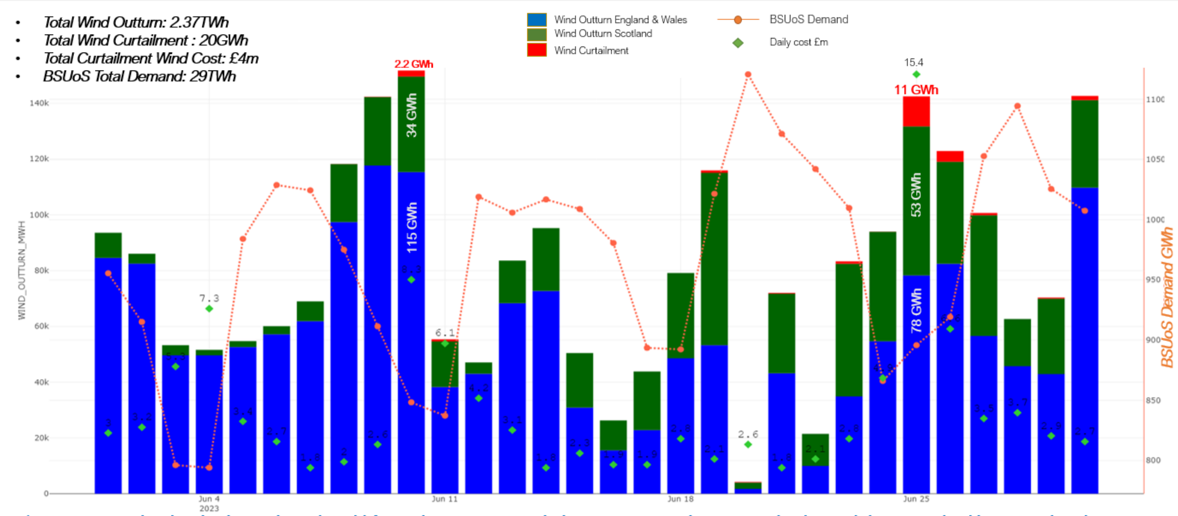
The minimum cost of £1.8m was observed on 7 June.

The average daily spent for the month was £3.8m, a £0.5m decrease from the previous month.

Daily Wind Outturn – Wind Curtailment and BSUoS Demand

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

With this graph one can trace for example the relationship that may exist in how wind performance and low demand affect the cost of each day. However, any direct correlation of wind generation (or BSUoS demand) and the daily costs has not been identified.



*BSUoS Demand is the absolute volume (MWh) for each active BMU including transmission losses. It is the demand that is resolved by BM and trades.

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

Metric 1B Demand forecasting accuracy

This metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS19) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each half hour period. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

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

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

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

June 2023-24 performance

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

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

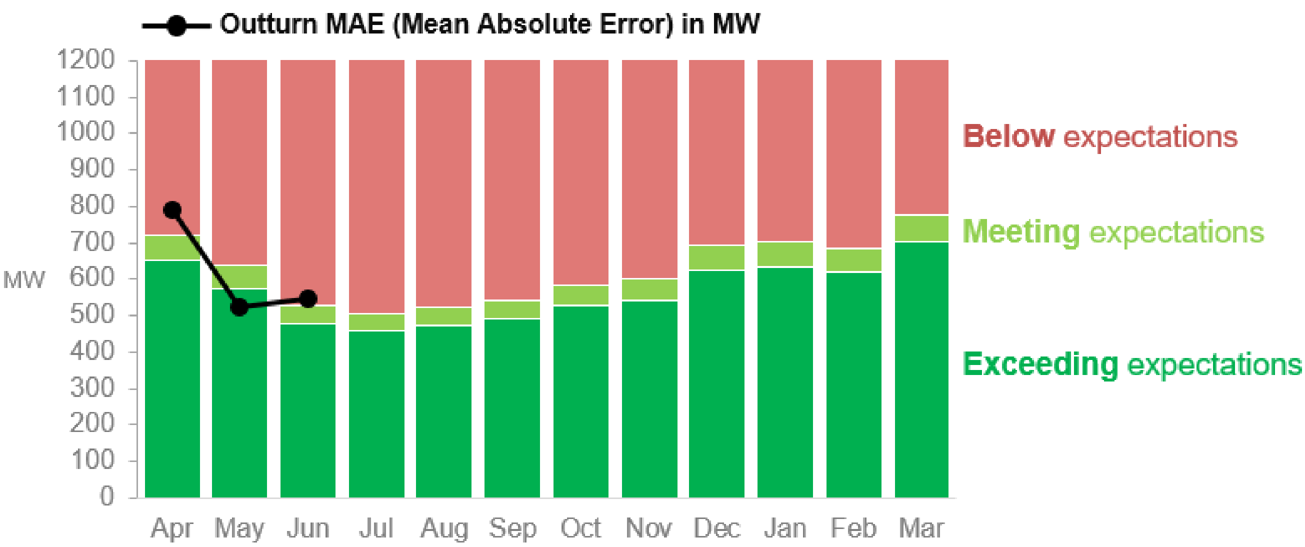


Table 4: 2023-24 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	687	606	503	481	497	516	554	571	659	669	651	738
Absolute error (MW)	**791**	**524**	**546**									
Status	●	●	●									

Performance benchmarks:

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

Supporting information

In June 2023, the mean absolute error (MAE) of our day ahead demand forecast was 546 MW compared to the indicative benchmark of 503 MW, and below expectations.

Solar output in June was high compared to both previous months this year, and to previous Junes in the metric benchmark period (approximately 18% increase). With this higher output comes an increased possibility of high errors. These errors are usually caused by changes in cloud cover which can be very difficult for weather forecasters even at a timescale of hours ahead. This embedded solar generation error translates into demand forecast error, as embedded generation is seen as a drop in demand.

The handful of days in the month with relatively larger errors were all affected by solar generation errors, which suggests this was the main driver of the variance from benchmark this month. On 6 June in particular, large amounts of cloud cover was expected to ‘boil’ off, however this did not happen. The total average error across all settlement periods for this day was 1250MW which was much larger than any other day in June.

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

Error greater than	Number of SPs	% out of the SPs in the month (1440)
1000 MW	232	16%
1500 MW	84	6%
2000 MW	26	2%
2500 MW	7	0%
3000 MW	1	0%

The days with largest MAE were June 6, 7, 17 and 25.

Missed / late publications

There were 0 occasions of missed or late publications inJune.

Triads

Triads only take place between November and February and therefore did not impact on forecasting performance during Q2.

Metric 1C Wind forecasting accuracy

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

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

June 2023-24 performance

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

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

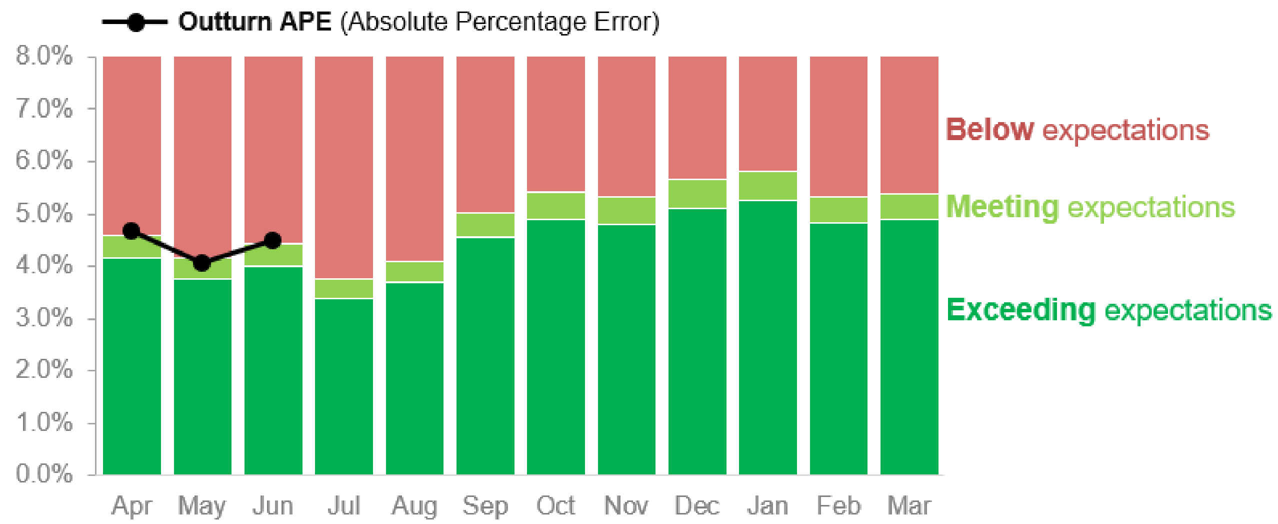


Table 5: 2023-24 BMU Wind Generation Forecast APE vs Indicative Benchmarks

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

Performance benchmarks:

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

Supporting information

In June, average absolute percentage error for our wind power forecast was 4.5% against a benchmark of 4.21% and therefore below expectations.

June tends to be the month of the lightest winds.

Market activity on wind farms with CFD contractual arrangements was observed on several (weekend) occurrences. Windfarms operating under these arrangements, tend to shut down in advance, using forecast negative market prices (declared @ 1100hrs D-1). Cfd is a function of increasing installed capacity and how windy and sunny is on a particular day, combined with the level of electricity demand at the time. The occurrence of negative prices has been steadily growing over the past few years and is therefore an increasing source of forecasting error.

Numerous disturbances on the electricity network were observed this month, resulting in several windfarms shutting down as a tactical defensive action. Disturbances of this nature are extremely rare and are not forecastable in advance. When a wind farm switches off in these circumstances, all of the forecasted output for that wind farm appears as forecasting error.

25 June was a particularly extraordinary day, with wind errors exceeding 5GW. This day alone, was responsible for the June 1C metric being below expectation, with the maximum error recorded being 33% of installed capacity. Investigations are ongoing, but the root causes appear to be significant weather forecast errors from our external weather forecast provider, CfD activity, and actions by windfarm protection systems. CfD is a relatively new phenomenon and so would not appear consistently over the past 5 years.

Withdrawal of wind units

There is no indication that any wind units withdrew their capacity in June, purely for technical reasons. However, there was clear evidence of capacity being withdrawn (PN to zero) for commercial (CfD) purposes.

Missed / late publications

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

Metric 1D Short Notice Changes to Planned Outages

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

June 2023-24 performance

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

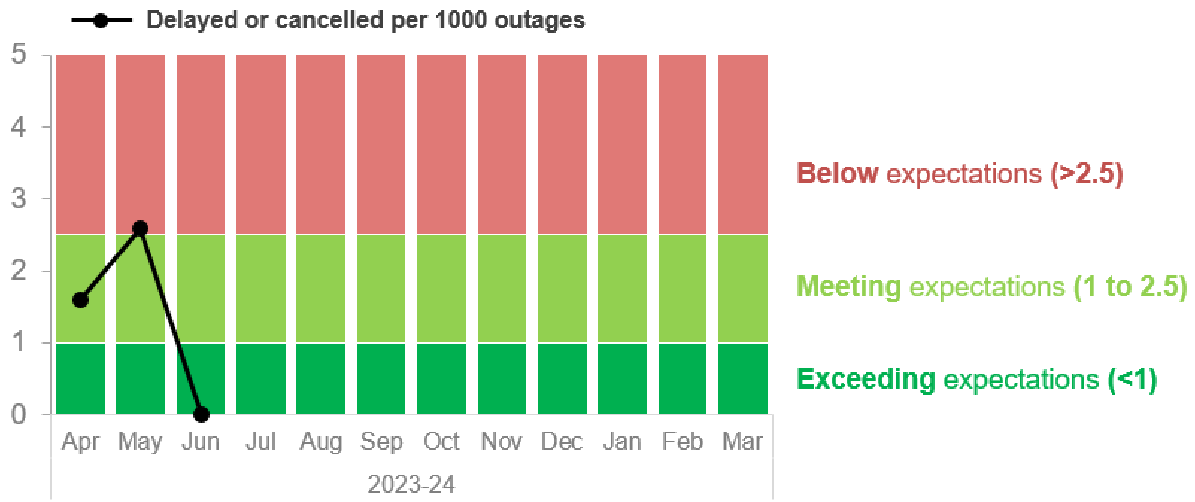


Table 6: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	624	739	645										2008
Outages delayed/cancelled due to ESO process failure	1	2	0										3
Number of outages delayed or cancelled per 1000 outages	1.6	2.6	0										1.5
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 June, we successfully released 645 outages and there were no delays or cancellations that occurred due to an ESO process failure. The number of stoppages or delays per 1000 outages is 0, which is inside the 'exceeding expectations' target of less than 1 delays or cancellations per 1000 outages.

The number of outages reduced in June this year (645) is a decrease compared to June 2022 (730). This is due to the reduced number of outage requests received from the TOs/DNOs for this period. Overall, we are continuing to liaise with the TOs and DNOs to effectively facilitate system access through weekly or monthly liaison meetings to maximize system access.

Please note that we have revised the previously reported number of outages for April (from 664 to 624) and May (from 772 to 739). There is no change to the statuses for either month.

RRE 1E Transparency of operational decision making

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

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

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

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

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

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

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

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

June 2023-24 performance

Figure 5: 2023-24 Percentage of balancing actions taken in merit order in the BM

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	94.1%	90.9%	98.0%									
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.6%	99.9%									
Percentage of actions with no category applied or reason group identified	0.3%	0.4%	0.1%									

Supporting information

June performance

This month 98.0% 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 June 2023, there were 37,378 BOAs (Bid Offer Acceptances) and of these, only 34 remain with no category or reason group identified, which is 0.1% of the total.

Dispatch Transparency Event

We held a Dispatch Transparency Event on 2 June. Participants in the event provided constructive feedback on the event itself which have indicated there is a need for us to address stakeholder expectations for:

- understanding of the Balancing Mechanism
- explanation of ESO operational decision making
- more deep dives to promote understanding of the decisions made in specific circumstances
- opportunities for bilateral discussion of specific concerns
- engagement with customer groups and trade associations to explore common concerns
- changes to ESO systems and tools including expectations for their impact on "skip rates"

Please see Role 1 Notable Events for more details of the feedback we received.

Other activities

During June we met bilaterally with some individual customers to answer their questions and discuss their concerns.

We have identified specific concerns for a particular customer segment which we recognise will need to be addressed through coordinated engagement by teams from across the ESO.

We also held the Balancing Programme quarterly engagement event on 15 June, see Role 1 Notable Events for details.

RRE 1F Zero Carbon Operability Indicator

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, battery 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 BP2

Below we define the approximate maximum ZCO limit (using a reasonable approximation of likely operating conditions), the system can accommodate at the start and end of BP2, explaining which deliverables are critical to increasing the limit.

Table 8: Forecast maximum ZCO% after our operational actions

BP2 2023-25	Maximum ZCO limit	Calculation and rationale
Start of BP2 (Q1 2023-24)	**90% - 95%**	The maximum ZCO% achieved to date is 90%, set in January 2023. New frequency products and voltage and stability pathfinders are the main projects delivering increased ZCO% during the early part of BP2. The methodology for calculating ZCO% is consistent with BP1 and our continued delivery of projects and programmes increases the opportunity to operate the system at higher ZCO%.
End of BP2 (Q4 2024-25)	**95% - 100%**	We expect that our remaining projects, products and programmes will enable us to operate at 100% ZCO in 2025. Our operational strategy is set to deliver some key projects which will increase the maximum ZCO% over the BP2 period. These key deliverables are the deployment of our full suite of response and reserve products, voltage and stability pathfinders, further reduction of minimum inertia requirement via the Frequency Risk and Control methodology (FRCR) and improved tools for monitoring system inertia. These deliverables are either enabling zero carbon providers of ancillary services or increasing the window in which we can operate the system securely.

Part 2 – Regular reporting on actual ZCO

Every quarter we report 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, battery 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.

The graphs further below show the underlying data by settlement period and highlight when the maximum monthly values occurred.

Table 9: Q1 maximum zero carbon generation percentage by month (2023-24)

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	84%	91%	10 Apr / 36
May	80%	88%	4 May / 24
June	80%	92%	10 Jun / 33

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

Figure 6: Maximum monthly ZCO% after ESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred) – two-year view

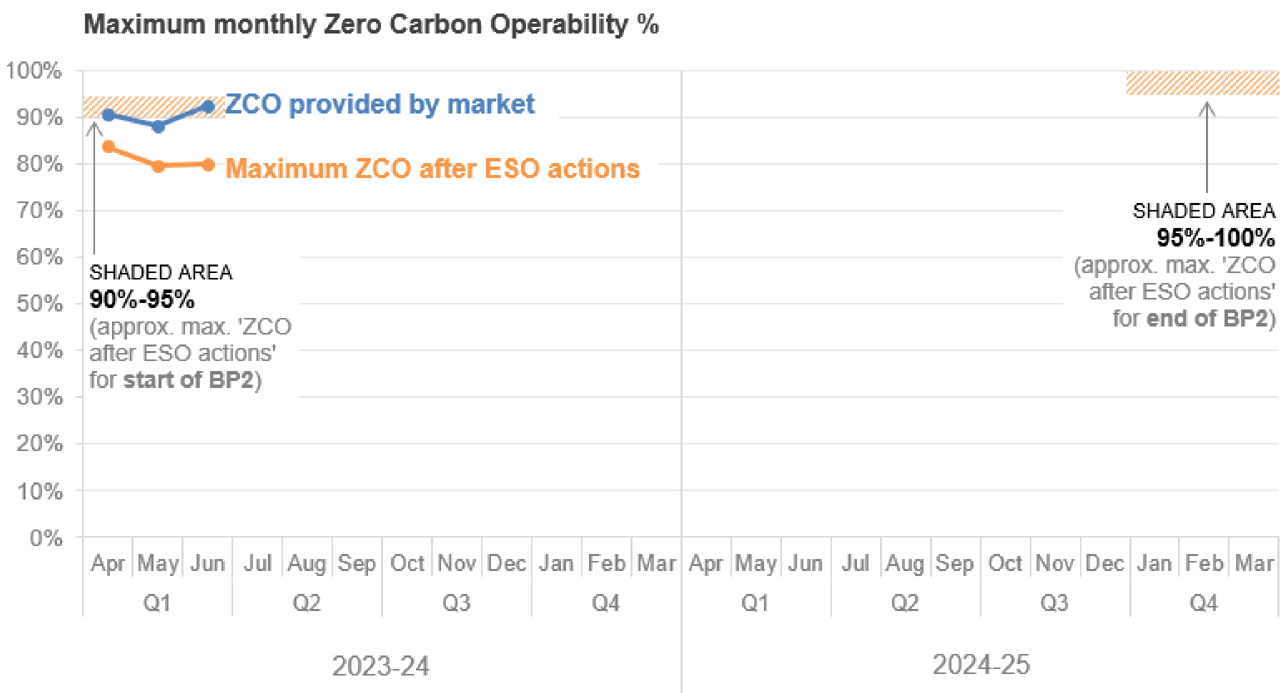
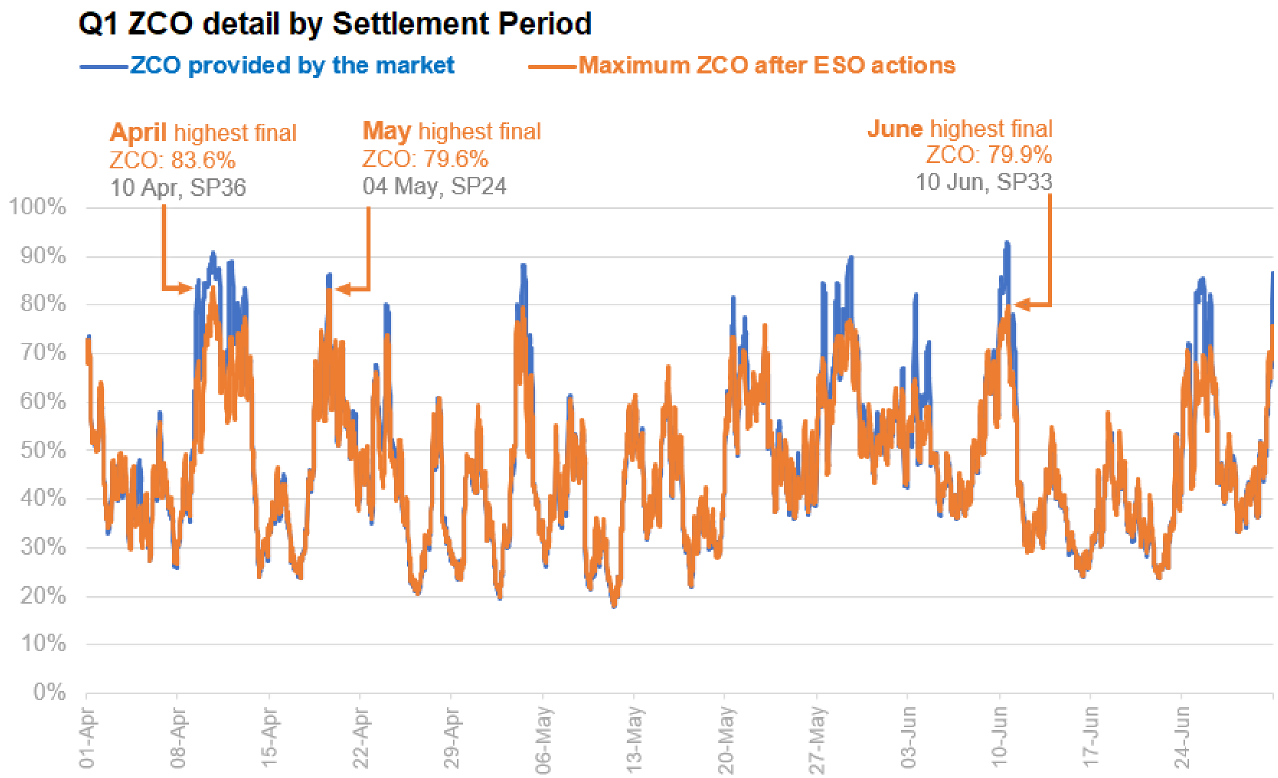


Figure 7: Q1 2023-24 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

In this first quarter of BP2 new records have been broken, getting us ever closer to zero carbon operation. Generation from Solar PV peaked at 10.1GW on 20 April and carbon intensity was at its lowest of 33g CO_2/KWh on 10 April.

The highest ZCO% for May and June is higher than it was in the same months last year; evidence that our innovative approach to system operation and new ancillary service products are enabling the transition to net zero. Whilst the highest ZCO% in Q1 (83.6%) is lower than in Q4 2022-23 (84.8%), this is because of the different challenges introduced to system operation during lower demands. Lower demands during the summer months mean that system strength is reduced, and this requires more ESO actions on carbon emitting generation to provide services which increase that system strength. It reflects our view that zero carbon operation in 2025 is likely to be during spring/autumn rather than summer.

Highest final ZCO by month vs previous year

Month	2022	2023	Difference
April	83.7%	83.6%	-0.2%
May	78.5%	79.6%	1.1%
June	76.7%	79.9%	3.2%

RRE 1G Carbon intensity of ESO actions

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

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

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

June 2023-24 performance

Figure 8: 2023-24 Average monthly gCO2/kWh of actions taken by the ESO (vs 2022-23)

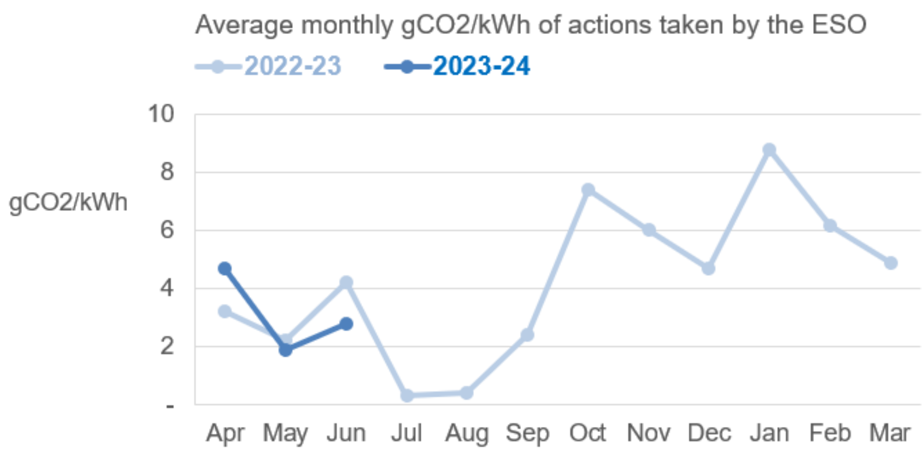


Table 10: Average monthly gCO2/kWh of actions taken by the ESO

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

Supporting information

In June 2023, the average carbon intensity of balancing actions was 2.8 gCO2/kWh. This is 1.4g lower than June 2022.

Across the month, our actions reduced the carbon intensity in 56% of settlement periods. The greatest impact of our actions on carbon intensity was seen throughout the day on 25 June, at its highest from mid-morning to mid-afternoon, and peaking at +69.5 gCO2/kWh. During the early morning generation was synchronised to provide voltage and stability services, and generating margin. From mid-morning to mid-afternoon, generation was synchronised for stability and margin, and to cover the short market position.

RRE 1H Constraints Cost Savings from Collaboration with TOs

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.

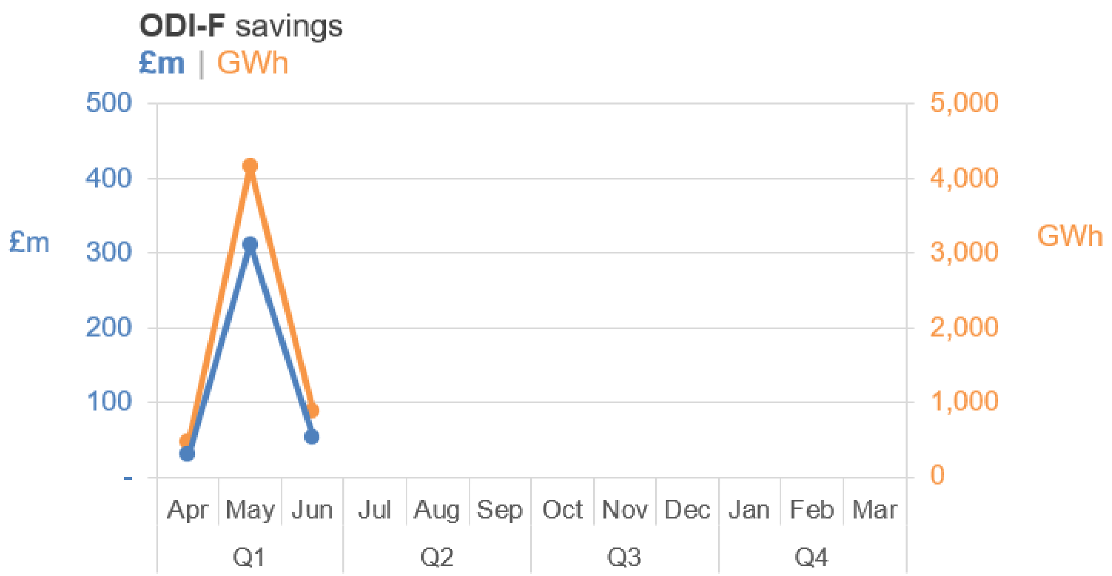
This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

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[2] 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 9: Estimated £m savings in avoided constraints costs (ODI-F) – 2023-24

(Estimated savings in GWh are also shown for context)



[2] 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 10: Estimated £m savings in avoided constraints costs (Other) – two-year view

(Estimated savings in GWh are also shown for context)

*Note **vertical axes scales** differ from the ODI-F graph above.*

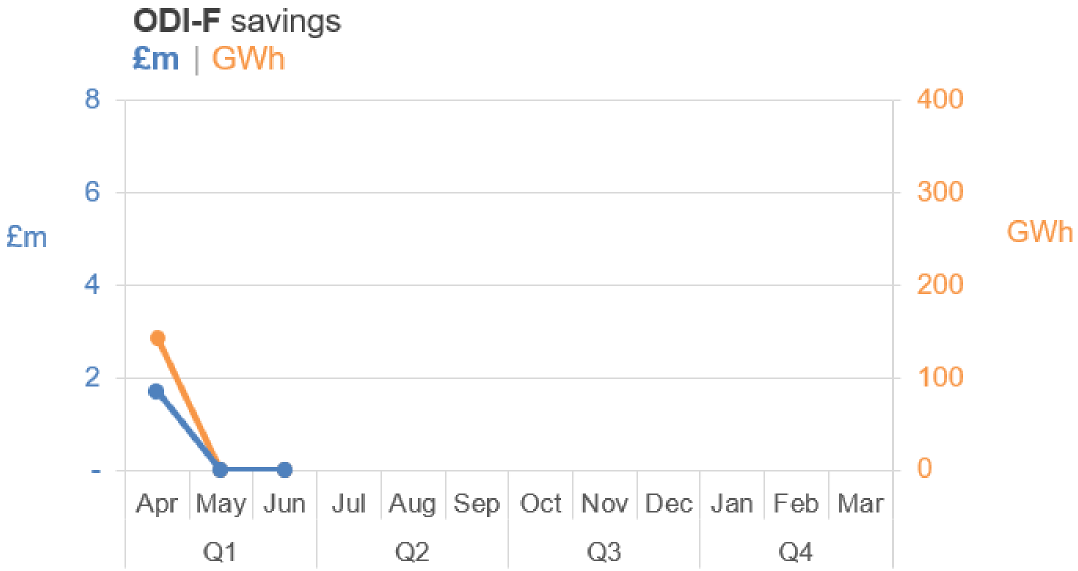


Table 11: Monthly estimated £m savings in avoided constraints costs (2023-24)

	ODI-F savings	Other savings	ODI-F savings	Other savings
	£m	£m	GWh	GWh
Apr	1.7	29	142	474
May	-	311	-	4,161
Jun	-	53	-	884
Jul				
Aug				
Sep				
Oct				
Nov				
Dec				
Jan				
Feb				
Mar				
YTD	**1.7**	**393**	**142**	**5,520**

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

In Q1 the Network Access Planning (NAP) team has progressed and approved 14 enhanced service provisions from TO's through STCP 11.4 that provide constraint cost savings. These include:

1. A thermal limit circuit enhancement was agreed with the TO, in the Northwest of England. This enhancement provided 142.2 GWh of energy saving and has been through full commercial costing to show that this saved £1.73 million to the end consumer.
2. Several thermal enhancements for circuits in the Northwest and Northeast of England have been approved. These are still ongoing and are pending completion and outturn cost assessment. Up to 234 GWh could be saved from these enhancements.
3. A dynamic line rating has been approved under STCP 11.4 for a circuit in Southwestern England. Unfortunately, this enhancement was no required to be used and so outturn costing is at 0 MWh saved.

In Q1 NAP has realised above **£1.73 million of constraint cost savings** through STCP 11.4. This is as the result of only 1 fully completed and outrun costed STCP 11.4 opportunity in this time. There are a number of ongoing enhancements expected to be completed and included in future quarterly reports.

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 **46 instances this quarter** where our actions directly resulted in adding value to the end consumers and where our 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 for Q1 include:

- SPT submitted a request into the year ahead plan to take two major scheme work outages together around Kilmarnock South. Both works impacted key export circuits for generation in the Ayrshire region of Scotland. NGESO suggested alternate placing for these schemes across years 24/ 25 and 25/26 to de-clash these schemes and working closely with SPT have produced an optimised plan for delivery of the schemes whilst maintain security at reduced cost to the Ayrshire region. The initially proposed plan would have required an additional 2.7 TWh of generation to be bought off in Ayrshire against the new plan. This generation reduction would have been required to prevent unacceptable thermal overloading post fault with the change saving approximately £202 million to the end consumer.
- At day-ahead timeframes, non-standard running arrangement changes were made by ESO planning in the Aire Valley to improve constraint limits in the North of England based on system conditions. In total, 168,000 MWh of energy savings were made equating to £12.6 million saved for the end consumer
- A cross boundary outage alignment was arranged by ESO planning working closely with NG and SPT. This aligned outages from both TOs across the B6 boundary. The alignment saved 47,250 MWh in energy that would have to be constrained by the originally proposed outages. This resulted in £3.5 million savings to the end consumer

These and many more represent a total of **5.5 TWh (approximately £393M)** of extra generation capacity, which would have otherwise been constrained at a cost to the consumer.

A note on updated costings, the conversion from MWh saving to £ saved is now done assuming 30% effectiveness of all optimisations and using bid off plus replacement energy costs on the current system as £120/ MWh for conventional generation and £250/ MWh for renewable generation.

Therefore, wind-based constraint enhancements are converted at £75/ MWh, gas-based constraint enhancements are converted at £36/ MWh, and demand improvements are converted at £50/ MWh.

RRE 1I Security of Supply

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

The frequency is more than ± 0.5Hz away from 50 Hz for more than 60 seconds

The frequency was 0.3Hz - 0.5Hz away from 50Hz for more than 60 seconds.

There is a voltage excursion outside statutory limits. For nominal voltages of 132kV and above, a voltage excursion is defined as the voltage being more than 10% away from the nominal voltage for more than 15 minutes, although a stricter limit of 5% is applied for where voltages exceed 400kV.

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

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

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

June 2023-24 performance

Table 12: Frequency and voltage excursions (2023-24)

	2023-24											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz for over 60 seconds)	0	0	0									
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1									
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0									

Supporting information

There were no reportable voltage or frequency excursions in June. There was one instance where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds, as follows:

On 8 June, 2023 @11:38, NSL tripped while importing 1321MW from Norway. The frequency dropped to 49.624 Hz but returned to operational limits, 48.8Hz by 11:42. The reason behind the trip is yet to be identified.

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

RRE 1J CNI Outages

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

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

Q1 2023-24 performance

Table 13: 2023-24 Unplanned CNI System Outages (Number and length of each outage)

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

Table 14: 2023-24 Planned CNI System Outages (Number and length of each outage)

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

Supporting information

June performance

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

Additional information

In addition, on 7th June 2023 there was one outage to one of the ESO infrastructure systems, which supports data flow to and from the BM. Although this is not a CNI outage, the industry was impacted and market messages via BMRS were sent. We include details here for transparency of our activities, recognising the impact this had on market participants.

During this outage, the BM system remained functional and resilient throughout, but the result was a lack of availability to users, both internal and external. The outage was communicated to the market at the time via BMRS and email notifications, in line with our obligations to report these events.

Whilst working to re-establish full system availability to all users, the ESO implemented a number of established contingency measures to ensure continued data submission and instructions to users.

In summary, the infrastructure outage lasted 150 minutes, and restricted the use of the BM system to both internal and external users for a total period of 245 minutes. We are conducting an internal investigation into this unplanned outage to identify and implement learnings from this into our future activities.

Notable events during June 2023

Dispatch Transparency event held on 2 June

We held our first Dispatch Transparency event at Wokingham on 5 December 2022. Feedback from participants was overall very positive. Our wider stakeholder group asked us to provide an online event to provide greater accessibility. We hosted an online event about Dispatch Transparency on Friday 2 June and published the slides, webinar recording and Q&A document on the OTF webpage.

From the in-event poll, stakeholders rated the event at 7.2. The comments we received covered a wide range, such as:

"Great deep dive into how ESO takes balancing and trading actions/ decisions."

"Quite a high barrier to entry in understanding (e.g. lots of acronyms, concepts not explained). But really useful in general"

"The initiative is great, but the time/space to answer questions is clearly insufficient. We need to have the ability to have public back-and-forths about such topics, presenting examples, counter examples etc. We understand this takes precious time on the NGESO side, but it's critical to have open conversations."

"You are filling in some of the background details of how BM dispatch is actioned which are almost impossible to gather from published sources. More events like this please."

The in-event poll and post event survey have provided constructive comments and questions which we will use in the further development of our approach to Dispatch Transparency.

Balancing Programme quarterly engagement event

The Balancing Programme is transforming our Electricity National Control Centre Balancing Capabilities. On 15 June, we held our third quarterly engagement event in London, where we presented more detail on the benefits and value we have delivered to date through BP1 and what can be expected to be delivered through BP2. We had colleagues join us from our ESO Networks and Markets teams to show the linkages across our roadmaps and how we enable benefits within different areas. We also provided an update and demonstration of the functionality of our new system, the Open Balancing Platform (OBP), which will go live later this year. At each of our breakout sessions we sought feedback from industry to ensure we are prioritising capabilities that provide the greatest benefit.

Overall, stakeholders rated the event 8 out of 10. Our breakout sessions averaged 4 out of 5. Some of the comments we received included:

"Thank you for putting on these events it is a great way to collaborate."

"Just keep it going, very challenging but important"

"There is so much work that goes on behind the scenes; and it shows up on the day; consistently. Q and A answered all my questions."

"Interesting topics, most presenters experienced and knowledgeable."

Materials from the day are available on our website: https://www.nationalgrideso.com/what-we-do/electricity-national-control-centre/balancing-programme

Publication of Powerloop report (EV'S in the BM trial)

At the beginning of June we published the final report for the Powerloop trial, which we ran with Octopus Energy in 2022. The trial was the first of its kind for the Great Britain energy system, linking actions taken in the Electricity National Control Centre (ENCC) to domestic household Electric Vehicles (EVs) charge points. It explored how altering charging and discharging schedules of individual households could offer us a greener, cheaper way to balance the energy system, whilst protecting customers' preferences. The trial was a proof-of-concept piece, the high level conclusions were:

Economic value for consumers – Octopus Energy reported customers participating in the Powerloop Vehicle-to-Grid (V2G) trial realised a saving of up to £180/y compared to smart charging, or £840/y compared to unmanaged charging on a flat tariff, when adjusted to an annual mileage of 10,000 miles.

Reduced balancing costs – Through live tests with consumers, it has been shown that V2G enabled EVs could offer a cheaper option to balance the system than current alternatives in the Balancing Mechanism, decreasing all consumer bills whilst reducing reliance on carbon intensive fuel sources.

Capability of aggregating V2G enabled EVs – Through trial sessions with households, we have shown the ability for the ENCC to alter (dis)charge patterns to meet energy balancing requirements, whilst still protecting end consumers' desired charging preferences. The trial demonstrated that, when aggregated, these domestic assets have the potential to meet the data requirements necessary for the BM, as well as consuming and delivering energy in response to an instruction.

Viability of entry into the BM – Several barriers have been highlighted in the requirements of the current BM market framework and registration process. The majority of these were deemed to be short term barriers, such as minimum threshold and aggregation requirements, which will be overcome as the market for V2G enabled EVs grows over time. However, the current operational metering standards to enter the BM, in particular the types of measurements required and the accuracy an asset must take readings at, has been highlighted as a key blocker that needs addressing to unlock this new energy resource for balancing actions.

Although the trial centred on V2G enabled EVs, the findings and conclusions drawn from the report are applicable to all types of EV smart charging, as well as offering a good insight into other flexible domestic assets.

Role 2 (Market developments and transactions)

ESO

Metric 2Ai Phase-out of non-competitive balancing services

This metric measures the percentage of services procured by the ESO that are procured on a non-competitive basis. For the purpose of this metric, we consider a ‘non-competitive’ service to be either a bilateral contract or a service with significant barriers to entry. It excludes SO-SO trades, which are trades made between system operators of connected countries. These are used to determine the direction of electricity flow over interconnectors. The volumes reported in this metric are those delivered within the time period.

There are benchmarks for the following categories: Frequency Response (FR) and Reserve, Reactive Power, and Constraints.

Benchmarks are set based on the ESO’s current and projected procurement for each of these services:

Category	Benchmark	Assumptions applied in BP2 benchmark
FR and Reserve	Year 1: 25% Year 2: 20%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for Benchmark • Reserve will continue to be procured competitively until the implementation of new reserve services
Reactive power	Year 1: 90% Year 2: 90%	• Historical data was analysed from the previous reporting period (BP1) and no uplift applied for Benchmark • Competitive procurement of Reactive Power through Market mechanisms will be understood later in 2023 – through the Reactive Power Market Reform. • There will continue to be specific regional requirements, and this will procured through market mechanisms
Constraints	Year 1: 65% Year 2: 55%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for Benchmark • B6 Commercial Intertrip service was the first Constraint service to be delivered competitively. More will be delivered through market mechanisms in BP2, such as EC5 and LCM

The non-competitive percentage is calculated on a volume basis, which is measured in MWs, with the exception of Reactive Power which is measured in MVAr.

These expectations are set for the current suite of products and may be revised if new products are introduced.

Category	Services procured **competitively**	Services procured **non-competitively**
Frequency Response	• FFR (Firm Frequency Response) Secondary, High and Static • Dynamic Containment Low and High • Dynamic Moderation Low and High • Dynamic Regulation Low and High	• Mandatory Frequency Response (Primary, Secondary and High) • Enhanced Frequency Response • Fast Start
Reserve	• Day Ahead STOR (Short Term Operating Reserve)	• Long Term STOR • Optional Fast Reserve
Reactive Power	• Mersey Reactive Power Pathfinder • Pennines Pathfinder	• Reactive • Mandatory Reactive Lead & Lag • Stability Reactive Lead & Lag • Reactive Sync Comp, Comp Lead and Comp Lag • Inertia (Stability)
Constraints	• B6 Intertrip	• Super SEL (Stable Export Limit) (Footroom) • Strike Price

Overall performance – All services

Q1 2023-24 performance

Figure 11: Percentage of volume procured non-competitively vs benchmark

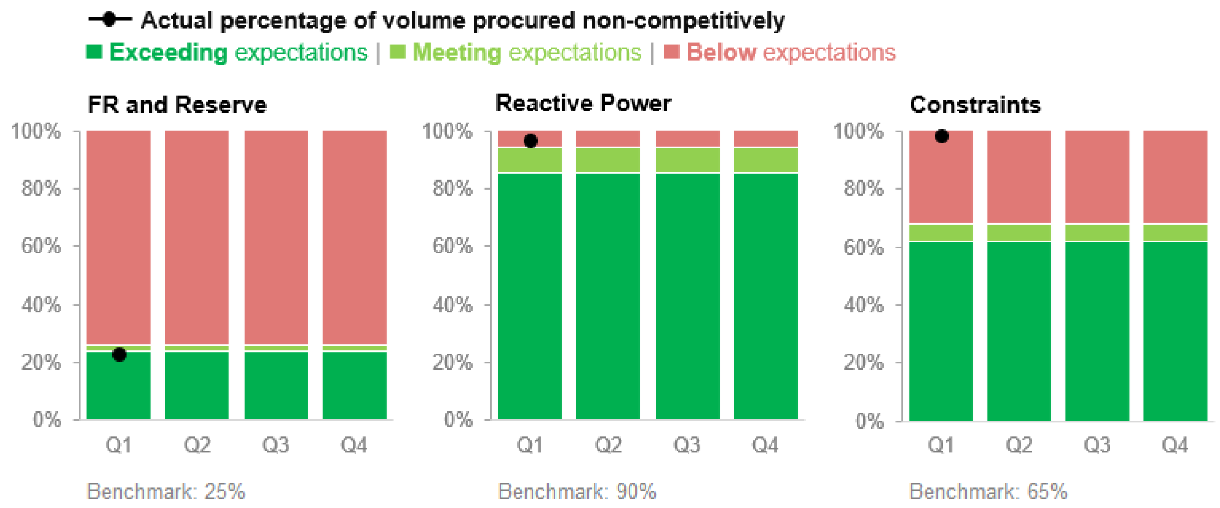
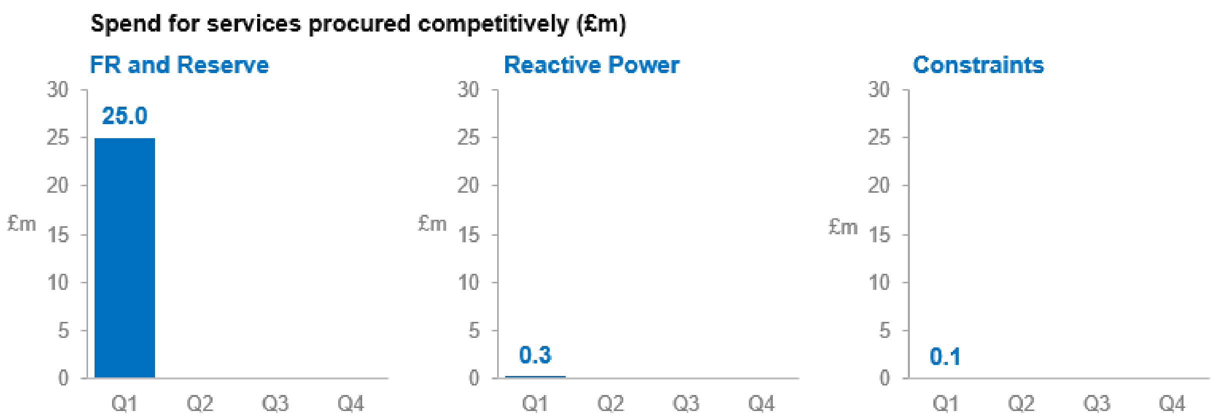


Figure 12: Quarterly competitive spend by service



SO-SO trades made during Q1

Historically SO-SO Trades were available to the ESO across the IFA & IFA2 , NEMO, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & NEMO, the current required notice period is longer than the hourly gates provide, this service can no longer be used by the ESO. EWIC & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. The ESO does not trade via 3rd Parties and therefore only has access to CBB.

Trades for Q1 totalled £0.06m consisting of 2 trades on Moyle interconnector

Data consists of final settlement data for 1st and 2nd month, with preliminary data used on 3rd month, which will be updated with final data on the next submission of the report.

1. Frequency Response and Reserve

Q1 2023-24 performance

Table 15: Frequency Response and Reserve percentage of services procured on a non-competitive basis, and spend.

Frequency Response & Reserve		Unit	Q1	Q2	Q3	Q4
Volume	Total volume procured	GWH	13,013			
	Volume procured non-competitively	GWH	2,941			
	Percentage of volume procured non-competitively	%	**23%**			
	Year 1 benchmark	%	25%	25%	25%	25%
	Status	n/a	●			
Spend	Total spend	£m	45.3			
	Spend for volume procured competitively	£m	25.0			
	Spend for volume procured non-competitively	£m	20.3			

Performance benchmarks:

- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5% or more higher than the annual procurement benchmark

The benchmark for Year 2 is 20%

Supporting information

In Q1, 23% of Frequency Response and Reserve volume was procured non-competitively compared to the benchmark of 25%, and therefore exceeding expectations.

With the growth in response and reserve competitive markets the ESO is able to procure more of its requirements at the day ahead so has a lesser reliance on non-competitive procured services. As more reserve services are introduced to day ahead procurement we expect to see further reductions in the Frequency Response and Reserve volumes that are procured non-competitively. For Long Term STOR, we remain committed to the legacy ~ 400MW volume of contracts which expire in April 2025. This volume will then be replaced by volumes procured at day ahead through the new reserve products.

2. Reactive Power

Q1 2023-24 performance

Table 16: Reactive Power percentage of services procured on a non-competitive basis, and spend.

Reactive Power		Unit	Q1	Q2	Q3	Q4
Volume	Total volume procured	GVARH	15,168			
	Volume procured non-competitively	GVARH	14,644			
	Percentage of volume procured non-competitively	%	97%			
	Year 1 benchmark	%	90%	90%	90%	90%
	Status	n/a	●			
Spend	Total spend	£m	76.4			
	Spend for volume procured competitively	£m	0.3			
	Spend for volume procured non-competitively	£m	76.1			

Performance benchmarks:

- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5% or more higher than the annual procurement benchmark

The benchmark for Year 2 remains at 90%

Supporting information

In Q1 97% of Reactive Power volume was procured non-competitively compared to the benchmark of 90%, and therefore below expectations.

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 Balancing Mechanism (BM).

The percentage of services delivered by non-competitive means in this quarter is similar to the previous quarter and will be in future quarters of 2023/24 as we establish the Reactive Power future market. This re-started in May 2023 and we are now working on assessing the feasibility of implementing the proposed market design with a commitment to sharing a plan for how this will be implemented by the end of 2023.

The launch of the short- and long-term Voltage Pathfinders previously has proven that distribution network providers can also be effective to meet a transmission need. The long-term Mersey Pathfinder awarded two contracts, the Peak Gen shunt reactor service went live in Q1 2022-23 and the Zenobe Battery live in Q4 2022-23, to meet a need in this region. In January 2022 we also awarded contracts to meet reactive needs in the Pennines region that are due to commence in 2024-25 which will decrease the percentage of reactive power services procured and utilised through non-competitive means.

To meet a short-term need because of planned outages we launched a competitive tender for reactive power services to provide voltage support in the East Anglia region for the period of 31 March to 26 April, extended to 9 May. We awarded two contracts to RyeHouse and Little Barford Power Station and these were optional contracts to run overnight.

3. Constraints

Q1 2023-24 performance

Table 17: Constraints percentage of services procured on a non-competitive basis, and spend.

Constraints		Unit	Q1	Q2	Q3	Q4
Volume	Total volume procured	GWH	158			
	Volume procured non-competitively	GWH	155			
	Percentage of volume procured non-competitively	%	98%			
	Year 1 benchmark	%	65%	65%	65%	65%
	Status	n/a	●			
Spend	Total spend	£m	4.9			
	Spend for volume procured competitively	£m	0.1			
	Spend for volume procured non-competitively	£m	4.8			

Performance benchmarks:

- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5 or more higher than the annual procurement benchmark

The benchmark for Year 2 is 55%

Supporting information

In Q1 98% of Constraints volume was procured non-competitively compared to the benchmark of 65%, and therefore below expectations.

There were no arming instructions throughout April and June for the Intertrip service. 2% was competitively procured in May, this was due to low wind and no requirement to call upon the service for the other two months.

We continue to assess opportunities to utilise the intertrip service across the B6 boundary dependant on system conditions and will look to extend this to the East Anglia EC5 CMIS service when it becomes live.

Strike price was procured non-competitively to the end of May with no further activity throughout June

Super SEL is an active but optional contract that a number of generators can provide as a backup to other solutions. Super SEL has not been utilised since early 2022 and so we have reported 0GWH within this metric to reflect utilisation. We have previously reported the contract values and not actual utilisation.

Metric 2X Day-ahead procurement

This metric measures the percentage of balancing services procured at no earlier than the day-ahead stage, i.e. those procured at day-ahead or closer to real time. We report on total contracted volumes (mandatory and tendered) in megawatts (MWs). Expectations are set for all relevant services that are currently procured by the ESO and may be revised if new products are introduced.

Benchmarks are set based on expected product expirations, and expectations for new procurement volumes:

Note that in line with the terms of a derogation from the requirements of Article 6(9) of the Electricity Regulation, the ESO is required to procure at least 30% of services no earlier than day-ahead stage

Whist the ESO set out the daily requirements for Day ahead procurement, when these requirements are not met through competitive day ahead tendering the outstanding requirement could be met through other means such as bi lateral agreements and mandatory markets.

The following services are included in the figures for this metric:

Day ahead: Short-Term Operating Reserve (STOR), Dynamic Containment, Dynamic Moderation, Dynamic Regulation, Static Firm Frequency Response

Non-day ahead: Firm Frequency Response Monthly, Mandatory Frequency Response, Long Term STOR

Services newly introduced during BP2 should only be included in this metric if they displace those procured earlier than day-ahead.

Q1 2023-24 performance

Figure 13: Quarterly percentage of balancing services procured at no earlier than day-ahead

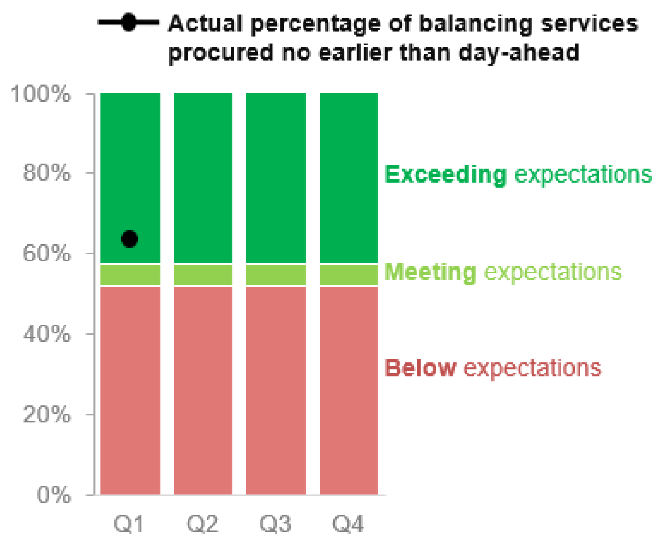


Table 18: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4
Total volume of balancing services procured	MW	12447			
Volume procured no earlier than day-ahead	MW	7910			
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	64%			
Benchmark	%	55%	55%	55%	55%
Status	n/a	●			

Performance benchmarks:

- **Exceeding expectations:** 5% or more higher than annual day-ahead procurement benchmark
- **Meeting expectations:** within ±5% of the annual day-ahead procurement benchmark
- **Below expectations:** 5% or more lower than the annual day-ahead procurement benchmark

For year 2, the benchmark increases to 80%

Data consists of final settlement data for 1st and 2nd month, with preliminary data used on 3rd month, which will be updated with final data on the next submission of the report.

Supporting information

In Q1 64% of balancing services volume was procured no earlier than day ahead, compared to the benchmark of 55%, and therefore exceeding expectations.

The exceeding expectations performance for day ahead procurement of services is due to several factors across the markets. Over the past 12 months the response and reserve markets have matured resulting in greater market liquidity and greater competition. Reducing volumes in non-day ahead service such as Dynamic Firm Frequency response as it is being phased out and these volumes going services procured at day ahead.

Going forward we would expect to see this performance increase as legacy services are fully phased out and new services go live.

RRE 2Aii Balancing services procured in a non-competitive manner

This Regularly Reported Evidence measures the volume and spend for non-competitive services for contracts. For the purpose of this metric, we have included volumes where the decision to instruct non-competitive services is made after 31 March 2023, even if the contract terms were signed before (e.g. MFR). Figures are reported in GWH/GVARH for the contracted month, which is calculated as the contracted volume in MW multiplied by the number of contracted hours.

Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded. However, all SO-SO trades and NTC application, as well as any other non-competitively procured services with contract award after this date, are included.

Q1 2023-24 performance

Figure 14: Volume and spend for non-competitive services for contracts

*Reactive volume is measured in GVARH and is not directly comparable to the other services measured in GWH, but is included in the graph with this caveat.

Table 19: Volume and spend for non-competitive services

	Service	Unit	Q1	Q2	Q3	Q4
VOLUME	Frequency Response	GWH	1,895			
	Reserve	GWH	506			
	Constraints	GWH	155			
	SO-SO trades	GWH	10,920			
	Net Transfer Capacity (NTC)	GWH	5,242			
	Total Volume in GWH	GWH	**18,718**			
	Reactive (in GVARH)	GVARH	14,644			
SPEND	Frequency Response	£m	4.0			
	Reserve -	£m	8.7			
	Constraints	£m	4.8			
	SO-SO trades *	£m	0.06			
	Net Transfer Capacity (NTC)	£m	0.38			

	Reactive	£m	76.1			
	Total spend	£m	**93.7**			

*SO-SO trades, trade volumes and costs for services provided to the ESO by another country's system operator have been included. Services provided by ESO to another country's System Operator are excluded.

Data consists of final settlement data for 1st and 2nd month, with preliminary data used on 3rd month, which will be updated with final data on the next submission of the report.

Supporting information

Frequency Response

The volume of non-competitive services procured in Frequency Response is Mandatory Frequency Response (MFR). MFR is used as an element of our response holding that can be instructed within operational timescales. We are considering alternatives to MFR to reduce this volume in future.

Reserve

This volume of non-competitive Reserve is made up of the intra-day Optional Fast Reserve product, where prices for the service can be updated by providers per Settlement Period close to real-time. The Optional Fast Reserve product will be phased out with the introduction of the new day ahead procured reserve products as they are introduced through 2024.

Optional Fast Reserve is used for short-term frequency management outside of contracted fast reserve windows e.g., periods where wind may have shortfalled unexpectedly or demand has pulled (increased) more than anticipated. Note that day ahead procured STOR is to replace the largest loss and thus utilisation should always be quite low)

Constraints

Strike price was procured non-competitively to the end of May with no further activity throughout June

Super SEL is an active but optional contract that a number of generators can provided as a backup to other solutions. Super SEL has not been utilised since early 2022 and so we have reported 0GWH within this metric to reflect utilisation. We have previously reported the contract values and not actual utilisation.

SO-SO Trades

Historically SO-SO Trades were available to the ESO across the IFA & IFA2 , NEMO, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & NEMO, the current required notice period is longer than the hourly gates provide, this service can no longer be used by the ESO.

EWIC & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. The ESO does not trade via 3rd Parties and therefore only has access to CCB.

The volume of available SO-SO trades is high compared to payment, the service was only utilised 2 times in quarter with payment only made upon utilisation and not availability.

Net Transfer Capacity (NTC)

A capacity management process is used to ensure secure system operation for both Interconnectors and onshore TSOs. This process can result in the reduction in capacity through the application of a Net Transfer Capacity and this reduction (NTC) is defined as a non-frequency ancillary service.

Standard Licence Condition C28 requires ESO to procure non-frequency balancing services using market-based procedures. NTC is not procured through marketbased procedures and therefore requires a derogation from this requirement The procurement of NTC cannot be market-based due to technical parameters and that alternative actions are not sufficient or economically efficient.

NTC's are the ESO's only way of guaranteeing system security in real-time. As a result, they are as near-to real-time calculated values as the market structure allows. Any restrictions are based on the forecast system conditions for that particular real-time period and are reflective of the limits of GB system security.

RRE 2B Diversity of Service Providers

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:

1. Frequency Response (MFR, sFFR, dFFR, DC, DM, DR, FFR Auction, EFR)
2. Reserve (STOR, Fast Reserve)
3. Reactive
4. 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

<table>
<tr><th colspan="2">Product</th><th>Methodology</th></tr>
<tr><td rowspan="8">Frequency Response</td><td>Mandatory Frequency Response (MFR)</td><td>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).</td></tr>
<tr><td>Static Firm Frequency Response (sFFR)</td><td rowspan="2">We report on the highest volume for each unit that has contracted for a particular service block for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Dynamic Firm Frequency Response (dFFR)</td></tr>
<tr><td>Dynamic Containment (DC)</td><td rowspan="4">We report on the highest volume for each unit that has been contracted for a particular Electricity Forward Assessment (EFA) block for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Dynamic Moderation (DM)</td></tr>
<tr><td>Dynamic Regulation (DR)</td></tr>
<tr><td></td></tr>
<tr><td>Enhanced Frequency Response (EFR)</td><td>We report on contracted MW. This will not change from month to month unless a contract ends.</td></tr>
<tr><td rowspan="4">Reserve</td><td>Short Term Operating Reserve (STOR)</td><td>We report on the highest volume for each unit that has been contracted for a particular service window for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Fast Reserve</td><td>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.</td></tr>
<tr><td>Quick Reserve</td><td rowspan="2">We report on the highest volume for each unit that has been contracted for a particular service window for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Slow Reserve</td></tr>
</table>

Reactive	Mandatory 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).
	Stability Reactive	
	Synchronous Compensation	
	P9 Pathfinder	
Constraints	Super SEL (Footroom)	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.
	Strike Price	
	B6 Intertrip	

Firm Frequency Response Auction – this service is excluded as it ended in 2021-22.

Data consists of final settlement data for 1st and 2nd month, with preliminary data used on 3rd month, which will be updated with final data on the next submission of the report.

Figure 15: Total contracted volumes by service type for Q1

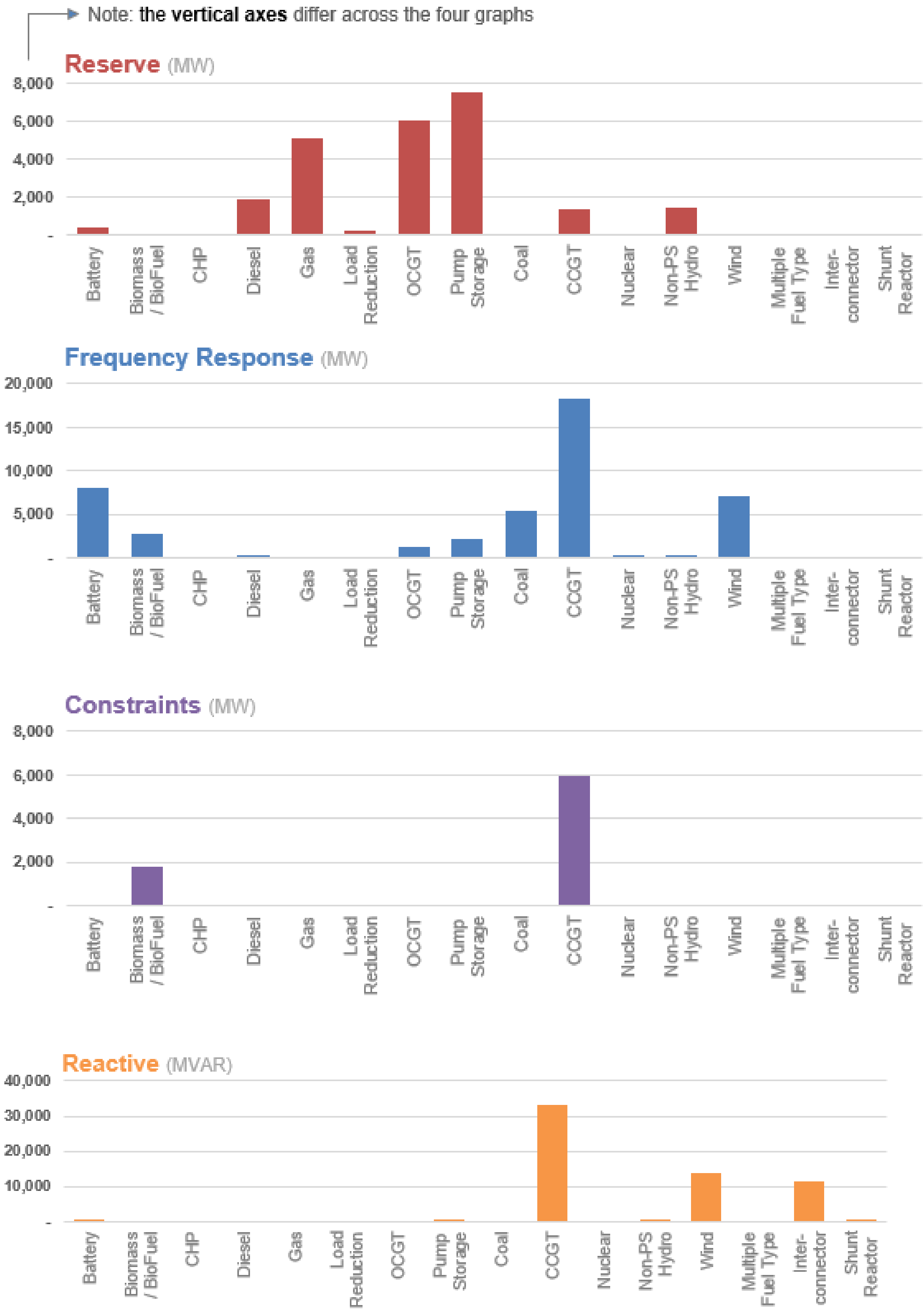


Table 20: Monthly contracted volumes provided to the ESO by service type

Reserve

MWs	Apr-23	May-23	Jun-23	Q1
Total	8,017	8,022	8,022	24,062
Battery	134	134	134	401
Biomass/BioFuel	19	19	19	58
CHP	-	-	-	-
Diesel	628	627	627	1,882
Gas	1,690	1,691	1,691	5,073
Load Reduction	70	70	70	210
OCGT	2,001	2,003	2,003	6,008
Pump Storage	2,516	2,519	2,519	7,554
Coal	-	-	-	-
CCGT	465	466	466	1,397
Nuclear	-	-	-	-
Non-PS Hydro	490	490	490	1,470
Wind	-	-	-	-
Multiple Fuel Type	3	3	3	9
Interconnector	-	-	-	-
Shunt Reactor	-	-	-	-

Constraints

MWs	Apr-23	May-23	Jun-23	Q1
Total	2,300	3,605	1,795	7,700
Battery	-	-	-	-
Biomass/BioFuel	595	595	595	1,785
CHP	-	-	-	-
Diesel	-	-	-	-
Gas	-	-	-	-
Load Reduction	-	-	-	-
OCGT	-	-	-	-
Pump Storage	-	-	-	-
Coal	-	-	-	-
CCGT	1,705	3,010	1,200	5,915
Nuclear	-	-	-	-
Non-PS Hydro	-	-	-	-
Wind	-	-	-	-
Multiple Fuel Type	-	-	-	-
Interconnector	-	-	-	-
Shunt Reactor	-	-	-	-

Frequency Response

MWs	Apr-23	May-23	Jun-23	Q1
Total	15,161	15,436	15,203	45,800
Battery	2,596	2,767	2,695	8,058
Biomass/BioFuel	957	937	837	2,731
CHP	-	-	-	-
Diesel	112	112	56	280
Gas	-	-	-	-
Load Reduction	-	-	-	-
OCGT	443	443	443	1,329
Pump Storage	728	728	728	2,184
Coal	1,782	1,782	1,782	5,346
CCGT	6,024	6,148	6,148	18,320
Nuclear	92	92	92	276
Non-PS Hydro	70	70	70	210
Wind	2,343	2,343	2,343	7,029
Multiple Fuel Type	14	14	9	37
Interconnector	-	-	-	-
Shunt Reactor	-	-	-	-

Reactive

MVARs	Apr-23	May-23	Jun-23	Q1
Total	19,921	19,921	19,921	59,763
Battery	32	32	32	96
Biomass / BioFuel	-	-	-	-
CHP	-	-	-	-
Diesel	-	-	-	-
Gas	-	-	-	-
Load Reduction	-	-	-	-
OCGT	-	-	-	-
Pump Storage	235	235	235	705
Coal	-	-	-	-
CCGT	11,021	11,021	11,021	33,063
Nuclear	-	-	-	-
Non-PS Hydro	93	93	93	279
Wind	4,573	4,573	4,573	13,719
Multiple Fuel Type	-	-	-	-
Interconnector	3,767	3,767	3,767	11,301
Shunt Reactor	200	200	200	600

Supporting information

The commentary below may look similar to previous reports as the diversity of providers that provide balancing services has not changed too much throughout BP1 and is not expected to change much in BP2 unless otherwise stated.

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 distribution connected, however we are starting to also see transmission 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.

Reserve

Procurement volumes and technology mix remain consistent with historical data within BP1.

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 addition of the Peak Gen shunt reactor service that went live in Q1 2022-23 has further diversified the type of providers. In January 2022 we also awarded contracts to meet reactive needs from an offshore windfarm in the Pennines region due to commence in 2024-25.

Constraints

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.

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

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

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

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

Q1 2023-24 performance

Figure 16: 2023-24 Monthly BSUoS forecasting performance (Absolute Percentage Error)

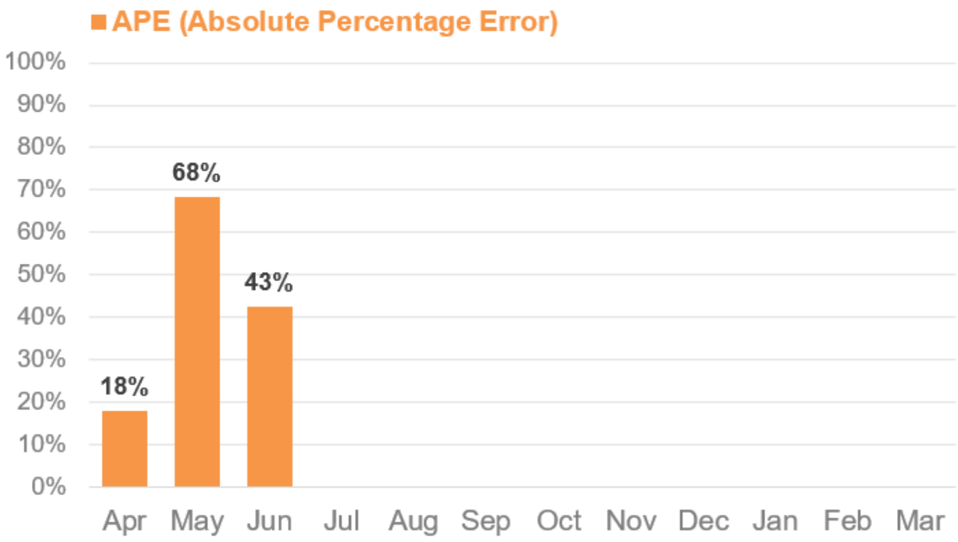


Table 21: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[4] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	10.8	8.2	7.5									
Month-ahead forecast (£ / MWh)	12.7	13.8	10.8									
APE (Absolute Percentage Error)[5]	**18.0**	**68.4**	**42.5**									

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

Supporting information

June Performance:

Actuals out-turned below forecast again in June 2023, but the Absolute Percentage Error (APE) decreased from 68% in May 2023 to 43% in June 2023. The main driver was costs being significantly lower than forecast, with volumes broadly in line.

Costs:

June outturn costs were around the 15th percentile of the forecast produced at the beginning of May.

This is firstly due to the wholesale electricity prices being 5% lower in outturn (£83/MWh) than the forward market prices available at the beginning of May (£88/MWh).

Secondly, the proportion of demand met by renewable generation was lower in outturn (20%) than the forecast at the beginning of May (28%). The proportion of demand met by renewables is a main driver in BSUoS costs, as a high proportion of renewables tends to drive higher constraint costs.

Forecast for June made at the start of May: £183m

Outturn costs for June: £113m

Volumes:

June actual volume was slightly below forecast.

Forecast BSUoS volume (made at the start of May): 20.3TWh

June actual BSUoS volume: 19.7TWh

Notable events during June 2023

We have published our Early View of Winter Outlook report

To support the energy industry's preparations for Winter 2023/2024, on 15 June we published our Early View of Winter Outlook report, to give organisations across the UK energy industry time to prepare for the coming winter.

This year's Early View uses a Base Case scenario to assess the availability of operational margins under average weather and normal weather conditions. This year's report finds that the de-rated margin in this Base Case scenario is 4.8 GW (around 8%). This is slightly higher than this time last year but is relatively in-line with margins across previous winters.

As with previous years, a more in-depth Winter Outlook report will be published later in the year to provide more up to date information relating to the coming winter.

A formal consultation process has just begun to determine the final terms of this years' service and is open until 17 July 2023. The main focus of the consultation is on the terms and conditions of a revised Demand Flexibility Service for this coming winter, and we are proposing several developments to the 2022/23 service. Following a request from the Government we are also continuing to have discussions on the availability of two of the five coal contingency units that were used last winter.

We have continued engagement with industry and delivered improvements to Demand Flexibility Service (DFS), Balancing Reserve (BR) and Enduring Auction Capability (EAC)

Following on from the success of the Demand Flexibility Service (DFS) for Winter 22/23 (delivery of just under 300MW of demand flexibility across 1.6 million homes & businesses), we are now exploring the potential use of the DFS as a winter contingency and a commercial service for the future and to build on its past successes. We are actively consulting with industry and consumers to establish how this world leading service, or a similar flexibility product, can be developed further and support the continued evolution of consumer flexibility in the UK and its role in the power system of the future. We have collaborated with industry to develop the proposals for the continued use of the DFS for Winter 23/24. We have run three two-hour deep dive DFS workshops, two of which were interactive sessions and we encouraged external participation using an interactive whiteboard tool. These were very well received with more than 150 participants and over 300 feedback items and questions. The consultation for DFS has now been launched.

A similar approach has been followed for re-evaluating of the design for Balancing Reserve to create a fit-for-the-future, compliant product after Ofgem raised certain reservations on the previous design. The team engaged with market participants through multiple webinars and issued a 'call for input' which was well received, and multiple providers participated in the opportunity to put their issues forth. The study provides key insights on the parameters of the service, thereby influencing what the final service design appears to be. We ran an industry Webinar at the end of June to share the service design and our plan for delivery. Our engagement plan with the industry is now being developed so that further updates to service procurement, consultation and implementation is aligned with internal and external stakeholders.

Enduring Auction Capability has had multiple webinars to discuss the market design, User interface and the various functionality going live. We have received valuable feedback from market participants, and it has been worked into the final solution being developed. The program continues to provide updates and support to market providers through drop-in sessions to ensure that all queries can be responded to, and providers can be onboarded and are able to use the system with as much ease as is possible.

Role 3
(System insight, planning and network development)

ESO

RRE 3X Timeliness of Connection Offers

This Regularly Reported Evidence (RRE) reports on the number of connection offers made within 3 months of clock start date, and the number of connection offers made that took longer than 3 months.

We provide this information separately for the England and Wales area, the Scotland area and by Transmission Owner (TO) area:

- England and Wales: National Grid Electricity Transmission (NGET)
- Central and Southern Scotland: SP Transmission (SPT)
- North of Scotland: Scottish & Southern Electricity Networks (SHET)

In year 1 (2023-24), in England and Wales, while the two-step offer process is running we will report:

- The number of standard offers issued within 3 months.
- For two-step offers, the number of (one-step) offers issued within 3 months.
- the number of two-step offers issued within nine months, after counter signature of the step one offer;
- and the number of any connection offers that took longer than the above timeframes.

We also report on the scale of the connection queue in terms of GW and time from offer acceptance to connection date. We include a breakdown of assets in the connection queue by size, technology type, and TO area.

Please note these figures are consistent with the Connections monthly data submission provided to Ofgem.

Table 22: Quarterly connection offers by time taken

Area	Connection offers issued:	Q1	Q2	Q3	Q4	Total
NGET	(Standard offer) Within 3 months	162				
	(One-step) Within 3 months	23				
	(Two-step) Within 9 months*	0				
	Longer than the above timeframes	0				
	Total	**185**				
SPT	(Standard offer) Within 3 months	77				
	Longer than 3 months	0				
	Total	**77**				
SHET	(Standard offer) Within 3 months	95				
	Longer than 3 months	0				
	Total	**95**				
Scotland total	(Standard offer) Within 3 months	172				
	Longer than 3 months	0				
	Total	**172**				
TOTAL	Within 3 months	**357**				
	Longer than 3 months	**0**				
	Total	**357**				

* after counter signature of the step one offer

Figure 17: Connections queue in MW split by time from offer acceptance to connection (30 June 2023)

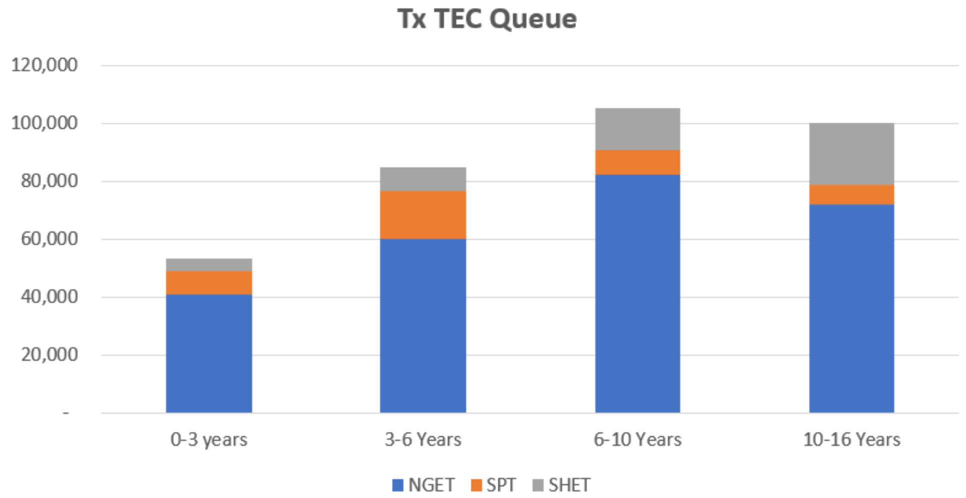


Table 23: Connections queue in MW split by time from offer acceptance to connection

Host TO	Unit	0-3 years	3-6 Years	6-10 Years	10-16 Years	Total
NGET	MW	40,966	59,925	82,180	72,104	**255,175**
SPT	MW	8,091	16,619	8,398	6,531	**39,639**
SHET	MW	4,275	8,404	14,516	21,381	**48,576**
Total	MW	**53,331**	**84,949**	**105,094**	**100,016**	**343,390**

Figure 18: Connections queue in MW by technology type (30 June 2023)

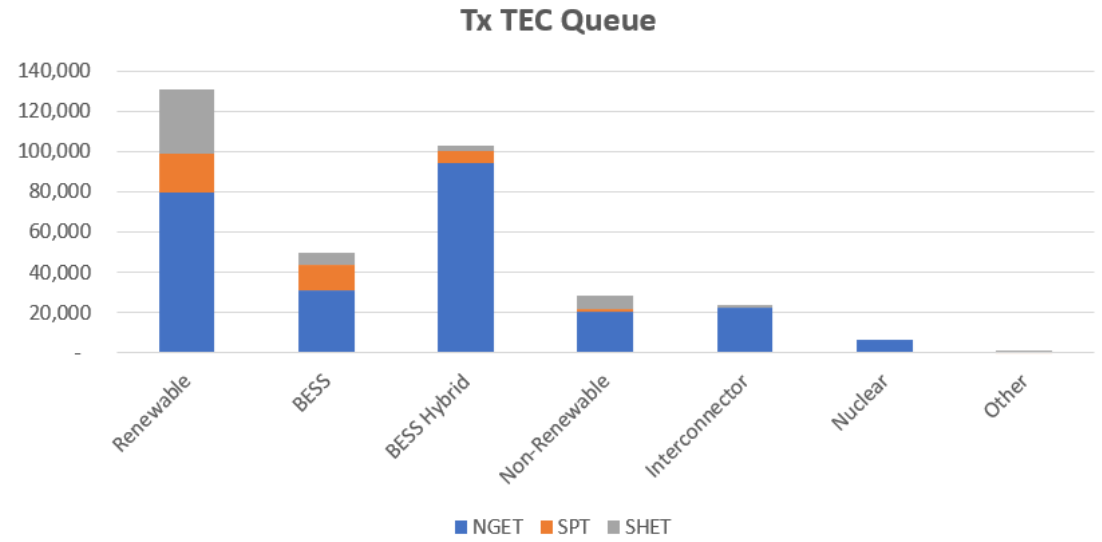


Figure 19: Connections queue in MW by technology type (30 June 2023)

Host TO	Unit	NGET	SPT	SHET	Total
Renewable	MW	79,179	19,210	31,964	**130,892**
BESS	MW	30,917	13,066	6,030	**50,013**
BESS Hybrid	MW	94,569	5,572	2,837	**102,979**
Non-Renewable	MW	20,735	1,290	6,286	**28,311**
Interconnector	MW	22,554	0	1,400	**23,954**
Nuclear	MW	6,680	0	-	**6,680**
Other	MW	1	500	59	**560**
TOTAL	MW	**255,175**	**39,639**	**48,576**	**343,390**

Supporting information

Timeliness of connection offers

Application volumes continue to increase in comparison with 2022/23 and this is reflected in the number of offers being sent out across all 3 TOs.

We have requested and are awaiting approval on 6 extensions to CUSC timescales relating to connection offers during Q1. The new proposed dates for sending these offers all fall within Q2 and will be reported as sent outside of CUSC timescales in the Q2 submission. There are no offers issued outside of CUSC timescales for Q1.

Connections queue

The Connections queue continues to increase moving from 280GW at the start of May 2023 to 343GW at the end of the quarter. The vast majority of this increase is due to new connection applications from battery storage developers.

RRE 3Y Percentage of 'right first time' connection offers

This RRE measures the % of connection offers made which did not need reissuing. For those that needed reissuing, we break these down by reason.

We include details of the number of connection offers made for the England and Wales area, and the Scotland area, in addition to by TO area. During the period where the 2-step offer process is in place, we will report this separately for step 1 and step 2 offers.

Table 24: Quarterly % of 'right first time' connection offers

Area	Connection offers	Q1	Q2	Q3	Q4	Total
NGET	Total Step 1 offers signed	1				
	Number right first time	1				
	Percentage right first time	**100%**				
	Total Full / Step 2 offers signed	222				
	Number right first time	182				
	Percentage right first time	**95%**				
SPT	Total connection offers signed	50				
	Number right first time	38				
	Percentage right first time	**88%**				
SHET	Total connection offers signed	46				
	Number right first time	36				
	Percentage right first time	**91%**				
TOTAL	Total connection offers signed	319				
	Number right first time	257				
	Percentage right first time	**93%**				

Table 25: Connection offer that needed reissuing by reason

Area	**One-step** connection offers	Q1	Q2	Q3	Q4	Total
NGET	Customer driven	18				
	ESO driven	12				
	TO driven	24				
	Total	**40***				
SPT	Customer driven	6				
	ESO driven	6				
	TO driven	3				
	Total	**12***				
SHET	Customer driven	4				
	ESO driven	4				
	TO driven	4				
	Total	**10***				
TOTAL	Customer driven	28				
	ESO driven	22				
	TO driven	31				
	Total	**62***				

* Please note that re-offers can be driven by more than one factor. Therefore the totals can be lower than the sum of the figures for each reason

Supporting information

Numbers of re-offers are spread across the TOs relative to the number of offers signed within the period, and the drivers for the re-offers are fairly evenly distributed with ESO driven re-offers coming in a little lower than the others.

There are a variety of reasons leading to an offer being re-issued such as amendments to appendices, charging statements and offer documents following post-offer discussions.

The number of ESO Driven re-offers directly affects our performance percentage, which is calculated by looking at the number of offers Right First Time not due to an ESO re-offer. Re-issued offers and the reasons for them are continuously reviewed.

Notable events during June 2023

We announced urgent action to speed up electricity grid connections by up to 10 years

In February we launched our 5 point plan, which is a set of tactical initiatives ahead of the wider connections reform which is due to be delivered by 2025.

The five point plan consists of TEC Amnesty, changes to the Construction Planning Assumptions, modelling energy storage a 0MW, the introduction of Queue Management (code modification CMP 376: Inclusion of Queue Management process within the CUSC) into Transmission connection agreements and offering non-firm agreements for energy storage.

In June 2023 we published a press release titled "ESO announces urgent action to speed up electricity grid connections by up to 10 years". This announced to industry our plans for ensuring projects with a pre-2026 Connection Agreement are adhering to their milestones.

It is worth noting that we will not be trying to implement CMP376 into agreements ahead of Ofgem making a decision on queue management. The press release also discussed how we are going to allow energy storage to connect non-firm, potentially speeding up connections for up to 95GW of energy storage projects in the pipeline. We are doing this within the current provisions in the industry codes.

Balancing Mechanism IT system release to support Constraint Management Pathfinder

On 27 June, a Balancing Mechanism system release was successfully delivered which included a number of enhancements to support our control room in operating the network. Within these were new tools to support the Constraint Management Pathfinder that will provide greater visibility of the contracted units, as well as functionality to reduce manual effort for both ESO and service providers. These will help us to better optimise the use of the Constraint service, in turn reducing consumer costs and allowing a greater amount of renewable power to be generated.

Further changes are planned in the next release that will deliver additional enhancements and capabilities.