ESO RIIO2 Business Plan 2 (2023-25)

Q1 2024-25 Incentives Report

23 July 2024

ESO

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Introduction

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

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

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

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

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

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

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

Please see our website for more information.

Summary of Notable Events

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

- On 27 June, we held the Balancing Programme Engagement Event in London, which was attended by 65 industry representatives from 48 organisations. Stakeholders had the opportunity to contribute to shaping future balancing and forecasting product roadmaps, and there was a customer listening session to gather input on customer engagement and partnership approaches. The event received positive feedback, with an average score of 8.5 out of 10 for the overall event and individual agenda items scored between 4 and 4.5 out of 5.
- On 6 June, we released our Early View of Winter and Winter Review and Consultation documents. The Early View provides an initial assessment of the energy security of supply outlook for the upcoming winter, allowing industry participants to prepare in advance. The documents include an assessment of global energy markets, potential risks, and efforts to collaborate with relevant stakeholders. Additionally, we published a Winter Review and Consultation to share operational insights and lessons from the previous winter, aiding industry preparation for the upcoming season.
- In June, we announced the release of our Innovation Annual Summary 2023/24, showcasing the role of innovation in shaping the future of the ESO and the energy landscape. The summary provides an overview of our performance, key activities, and project case studies from the past year. Key highlights include 75 live projects, 74 project partners, 144 innovation ideas with a 33% approval rate at the big ideas stage, and an average stakeholder and customer satisfaction score of 8.63.
- On 26 June, we organised a Connections Compliance Seminar in Glasgow, which brought together over 100 compliance professionals, industry experts, and business leaders. The event focused on Grid Code compliance, and various breakout sessions were held to facilitate focused discussions on certain topics. The seminar concluded with a Q&A panel, allowing attendees to seek clarification and gain deeper insights. The event received positive feedback, with an average score of 8.6 out of 10.
- On 27 June, we published consultations on BM Quick Reserve (QR) and Dynamic Response products (DM/DC/DR). These consultations seek feedback on revised terms and the implementation of new reserve services by Autumn 2025. QR will be procured for both positive and negative volumes with a 1-minute delivery time. The consultations will close on 29 July 2024 and will be reviewed before submission to Ofgem for approval.

Summary of Metrics and RREs

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) for Q1 2024-25.

Table 1: Summary of Metrics

Monthly (M) and Quarterly (Q) Metrics

				Status			
Metric		**Performance**	M / Q	Apr	May	Jun	**Q1**
Metric 1A	**Balancing Costs**	June: £208m vs benchmark of £187m	M	●	●	●	●
Metric 1B	**Demand Forecasting**	June: Forecasting error of 565MW vs indicative benchmark of 534MW	M	●	●	●	●
Metric 1C	**Wind Generation Forecasting**	June: Forecasting error of 5.68% vs indicative benchmark of 4.43%	M	●	●	●	●
Metric 1D	**Short Notice Changes to Planned Outages**	June: 1.49 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	M	●	●	●	●
Metric 2Ai	**Phase-out of non-competitive balancing services** (% of services procured competitively, calculated by volume)	Frequency Response & Reserve: 19% procured non-competitively in Q1 vs benchmark of 20%	Q	n/a	n/a	n/a	●
		Reactive Power: 97% procured non-competitively in Q3 vs benchmark of 90%	Q	n/a	n/a	n/a	●
		Constraints: 0% procured non-competitively in Q3 vs benchmark of 55%	Q	n/a	n/a	n/a	●
Metric 2X	**Day-ahead procurement**	77% balancing services procured at no earlier than the day-ahead stage vs benchmark of 80%	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: 91.7% of actions taken in merit order	M
RRE 1F	**Zero Carbon Operability indicator**	Q1: Highest ZCO% of 92% after ESO operational actions	Q
RRE 1G	**Carbon intensity of ESO actions**	June: 12.31gCO_2/kWh of actions taken by the ESO	M
RRE 1H	**Constraints cost savings from collaboration with TOs**	Q1: £145m	Q
RRE 1I	**Security of Supply**	June: 1 instance where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	M
RRE 1J	**CNI Outages**	June: 0 planned and 0 unplanned system outages	M
RRE 2Aii	**Balancing services procured in a non-competitive manner**	Q1: £46.5m spend on non-competitive services. Volume of 10.3 TWH and 9.7 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 12%	M
RRE 3X	**Connection Offers**	Q1: 639 connection offers made within 3 months, 129 taking longer than 3 months. TEC queue stands at 547 GW.	Q
RRE 3Y	**Percentage of 'right first time' connection offers**	Q1: 92% of connections offers were right first time	Q

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

Hannah Kruimer

Interim Head of Regulation

Role 1 (Control Centre operations)

ESO

Metric 1A Balancing cost management

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

A new benchmark was 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 was derived using the historical relationships between those two drivers and balancing costs:

i. The benchmark was created using monthly data from the preceding 3 years.
ii. A straight-line relationship has been established between historic constraint costs, outturn wind generation and the historic wholesale day ahead price of electricity.
iii. A straight-line relationship has been established between historic non-constraint costs and the historic wholesale day ahead price of electricity.
iv. Ex-post actual data input into the equation created by the historic relationships to create the monthly benchmarks.

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

Non-constraint costs = 62.25 + (Day Ahead baseload x 0.478)
Constraint costs = -33.49 + (Day Ahead baseload x 0.39) + (Outturn wind x 23.51)

Benchmark (Total) = 28.76 + (Day Ahead baseload x 0.87) + (Outturn wind x 23.51)

**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 2024-25 performance

Figure: 2024-25 Monthly balancing cost outturn versus benchmark

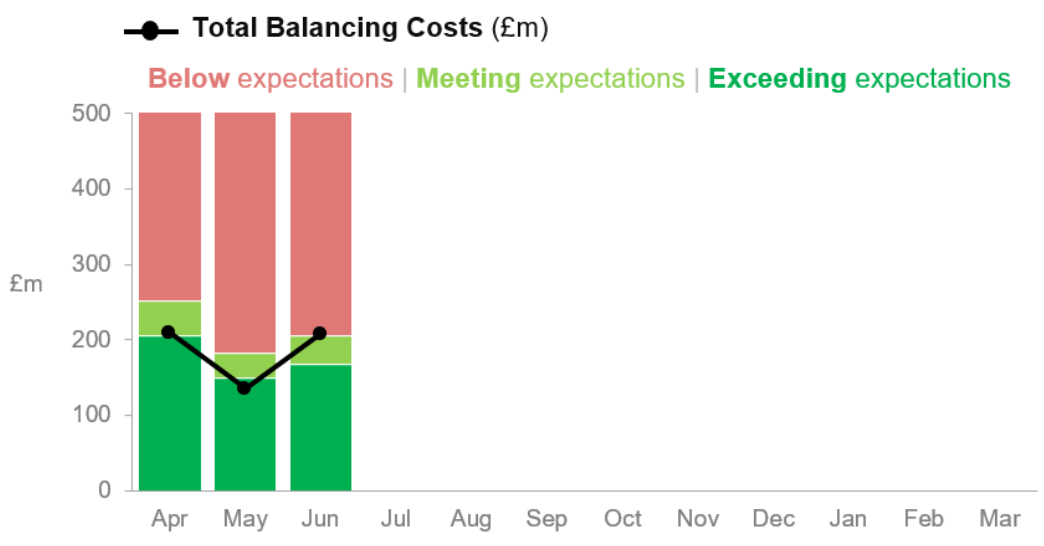


Table: 2024-25 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	6.3	3.2	3.9										13.4
Average Day Ahead Baseload (£/MWh)	59	72	76										n/a
Benchmark	228	167	187										581
Outturn balancing costs[1]	**209**	**135**	**208**										**552**
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

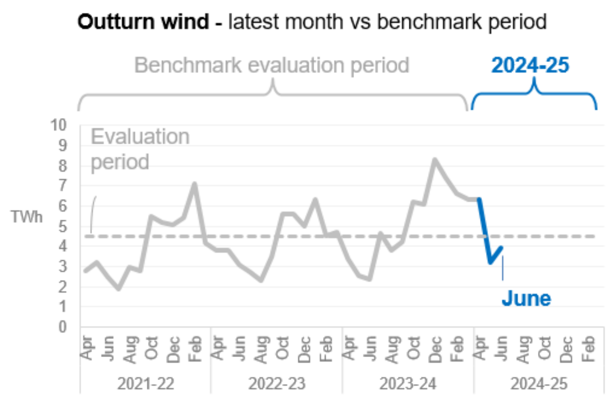
Supporting information

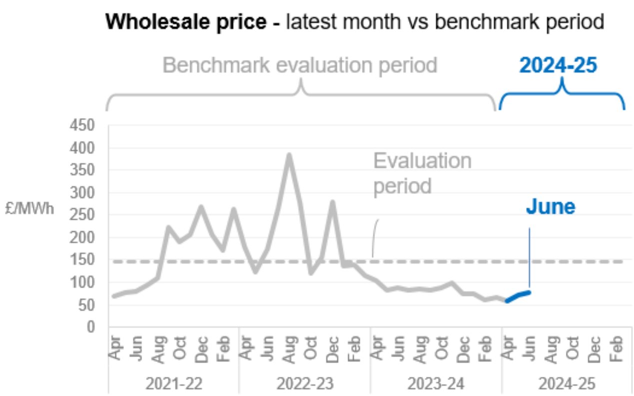
This month's benchmark

The June benchmark of £187m is £20m higher than May 2024 (£167m) and reflects:

- An **outturn wind** figure of 3.9TWh that is relatively low compared to the benchmark evaluation period (the last three years, where the average wind outturn is 4.5TWh) and is slightly higher than last month's figure (May 2024).
- An average monthly **wholesale price** (Day Ahead Baseload) that remains low compared to the benchmark evaluation period, although £4/MWh higher than last month's figure (May 2024).

The slight increase in both wind outturn and wholesale price contribute to the increase in the overall benchmark compared to last month.





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

June Performance

June's total balancing costs were £208m which is £21m (~11%) above the benchmark of £187m, and therefore performance is below expectations. June saw a 22% increase in overall wind generation compared to May. However, Scotland experienced a significant total increase of over 50% due to several high wind days throughout the month. This led to higher constraint costs in Scotland due to curtailment. In contrast, England and Wales saw only a 5% increase in wind generation. The volume weighted average price for bids has increased by £40/MWh compared to last month and is significantly higher than June 2023, whilst the volume weighted average offer price is in line with last month.

June's balancing costs were higher than both last month (May 2024) and the same month a year ago (June 2023) – with higher wind generation, resulting in higher constraint costs. Slightly higher wholesale prices with a minor increase in non-constraint costs than last month have also contributed to the higher costs between May 2024 and June 2024. However, lower wholesale prices compared to June last year have reduced non-constraint costs. The total constraint volumes have increased by 673 GWh in part due to the slightly higher wind generation, particularly in Scotland, resulting in more thermal constraint actions and ROCOF actions to support system inertia. The non-constraint costs are in line with May 2024 with a small increase of only £1m despite an increase of 258GWh volume of actions which were mainly from more actions for constrained margin compared to May 2024. We continue to make significant savings through optimising outages and trading activities.

Multiple occurrences of Sub-Synchronous Oscillation (SSO) have been observed in the Scotland area between May and June. To mitigate the effects of these low-frequency oscillations, additional measures were implemented to maintain stability. Historical data indicate that SSOs tend to occur during the early morning when demand and wind levels are low. In response, further defensive measures, such as running generators to provide inertia were implemented, particularly overnight. These measures aim to minimise the likelihood of SSO occurrence until the implementation of the Stability Pathfinder Phase 2 projects in summer 2024. We are quantifying the cost impact associated with SSOs and the results will be shared in the coming months.

The total savings from outage optimisation were £72.6m in June 2024, this represents an increase of £50.2m relative to May this year (£22.4m). The action that yielded the greatest value was related to the coordination of planned outages to fix hot joints[2] in the East of England. This significantly improved the transfer capacity of a thermal constraint in the area by roughly 1,200MW, delivering savings of roughly £23.7m. We continue to monitor the occurrence of hot joints in the system and their potential cost impact.

The Trading team were able to make a total saving of £56.7m in June through trading actions as opposed to alternative BM actions, representing a 53.5% increase on the previous month. This was driven by large volumes of downwards trading, which was needed for margins and managing constraints, coupled with the continuation of sell trading to help alleviate both the ESTEX and later BOLSELEX constraints against expensive wind bids and Emergency Instruction. Trading options were partly limited this month due to some outages and reduced capacity on the interconnectors, but the volumes needed to manage the constraints were secured. The day with the greatest spend on trades was 15 June with a cost of £1.6m, most of which was spent on voltage trading for the South of England (VSCENTRAL).

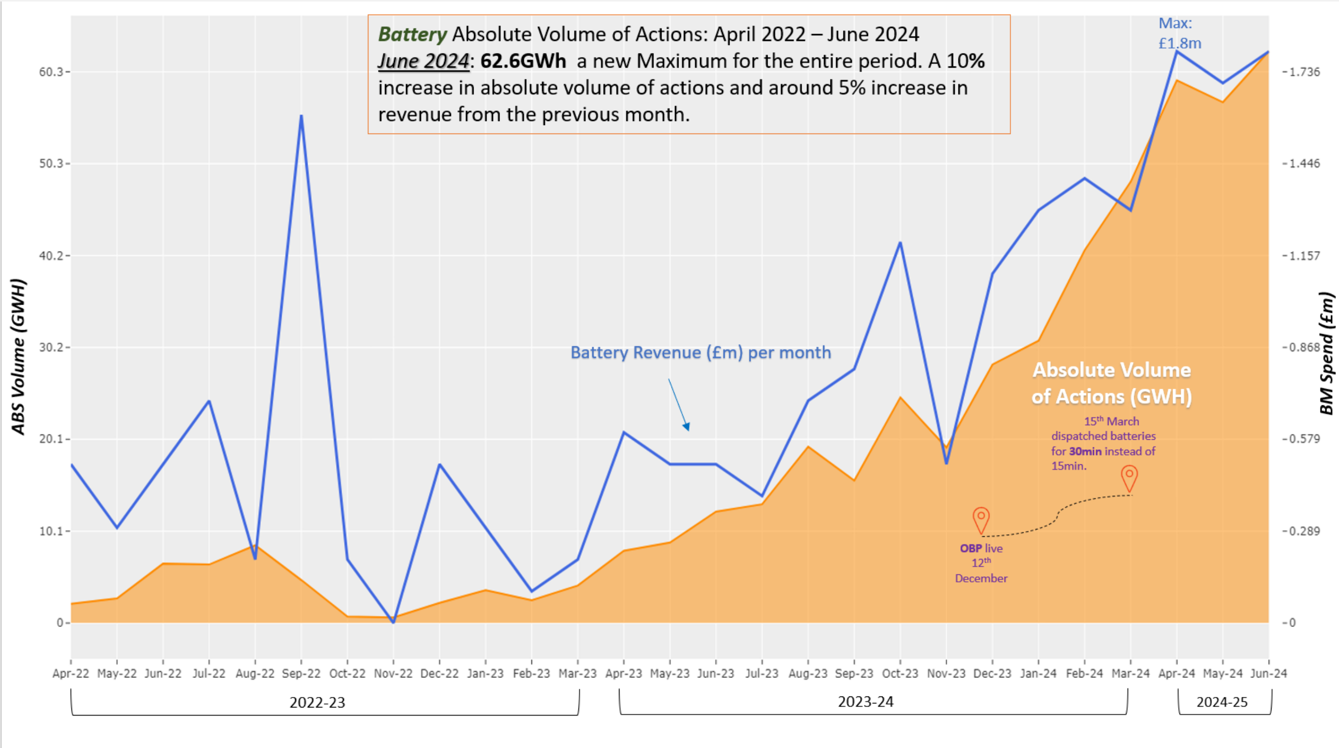
As discussed in December's incentives report, the first stage of our new platform to support the bulk dispatch of battery storage and small Balancing Mechanism Units, the Open Balancing Platform (OBP), went live on 12 December. Since then, our ability to dispatch a greater number of typically smaller BMUs within a settlement period has increased. This has unlocked greater capability to dispatch batteries in the Balancing Mechanism.

June had the highest battery dispatch absolute volume (63GWh) and the second highest battery (£1.79m) revenue since April 2022 in the Balancing Mechanism (BM), as shown on the graph below. This illustrates our commitment to maximising the flexibility of energy offered by battery storage and small BMUs over the last year.

[2] 'Hot-Joint' is a term used to describe a condition where high-voltage equipment, usually a connection point on a circuit, experiences elevated temperatures beyond what is considered safe for the equipment to sustain indefinitely. This can result in the reduction of a boundary's capability to transfer energy across it.

Monthly Absolute Volume of actions and spend for Batteries in the Balancing Mechanism

April 2022 to June 2024



Breakdown of costs vs previous month

Balancing Costs variance (£m): June 2024 vs May 2024

		(a) May-24	(b) Jun-24	(b) - (a) Variance	decrease ◄ ► increase Variance chart
Non-Constraint Costs	Energy Imbalance	0.3	5.9	5.6	
	Operating Reserve	9.0	6.0	(3.0)	
	STOR	3.5	3.8	0.2	
	Negative Reserve	0.4	0.2	(0.2)	
	Fast Reserve	15.9	16.2	0.4	
	Response	13.7	16.1	2.4	
	Other Reserve	2.9	2.6	(0.3)	
	Reactive	12.5	10.7	(1.8)	
	Restoration	2.4	2.2	(0.2)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	4.4	2.4	(2.1)	
Constraint Costs	Constraints - E&W	40.4	44.3	3.9	
	Constraints - Cheviot	0.3	1.6	1.3	
	Constraints - Scotland	16.0	68.4	52.4	
	Constraints - Ancillary	0.6	0.6	(0.0)	
	ROCOF	2.3	8.8	6.5	
	Constraints Sterilised HR	9.9	18.5	8.6	
Totals	Non-Constraint Costs - TOTAL	65.0	66.0	1.0	
	Constraint Costs - TOTAL	69.5	142.2	72.7	
	Total Balancing Costs	**134.5**	**208.2**	**73.6**	

As shown in the total rows from the table above, constraint costs increased by £72.7m and non-constraint costs increased by £1.0m, resulting in an overall increase of £73.6m (rounded to £0.1m) compared to May 2024.

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

- **Constraint-Scotland & Cheviot***: The constraint costs in Scotland and Cheviot increased by £53.7m in part due to significantly higher absolute curtailed volume of actions by 444 GWh than May 2024.
- **Constraint-England & Wales***: The constraint cost in England & Wales increased by £3.9m although the absolute volume of actions decreased by 47 GWh.
- **Constraint Sterilised Headroom***: £8.6m increase due to an increase of 634 GWh total volume of replacement energy. Windier conditions in Scotland compared to England & Wales this month resulted in more sterilised headroom.

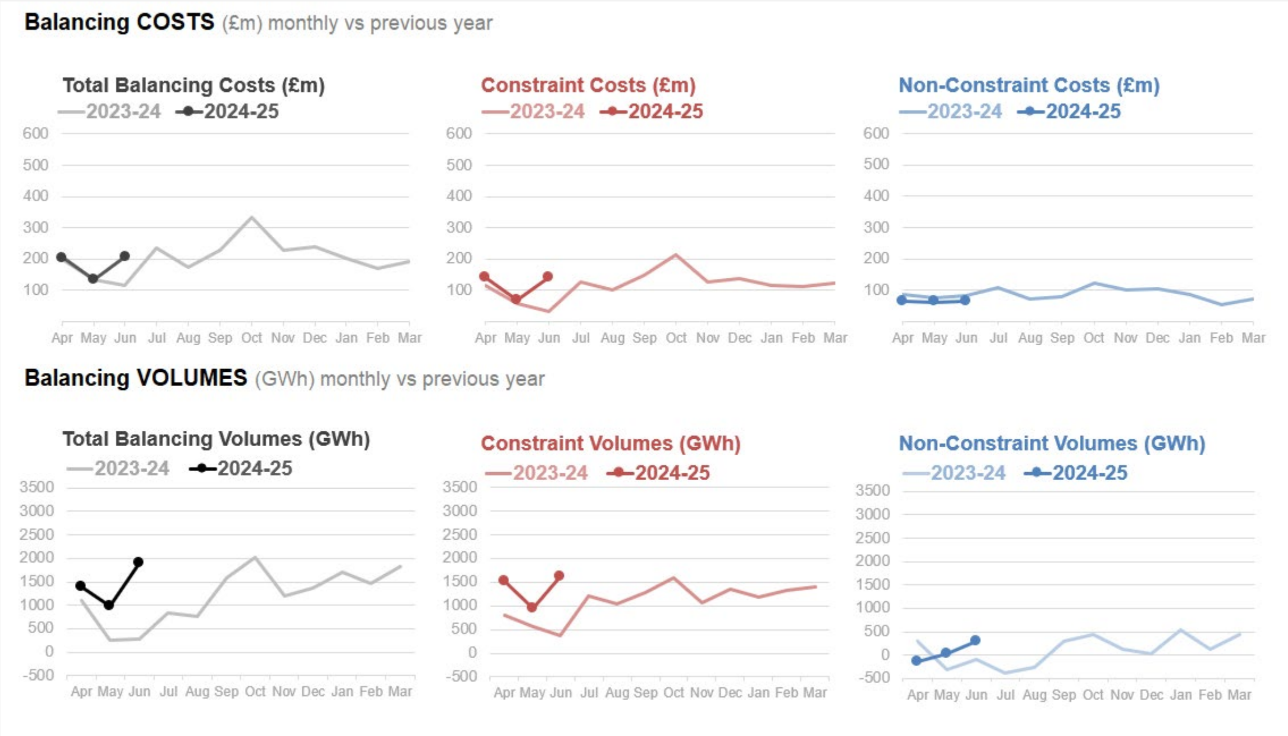
*This month saw a slight increase in the volume weighted average price for bids following a slightly higher electricity price.

Non-constraint costs*: The main driver of the variance this month is:

- **Energy Imbalance**: increased by £5.6m, despite a reduction of 14 GWh in the absolute volume of actions.
- **Operating Reserve**: £3.0m lower in cost despite an increase of 192 GWh reserve required to secure the system.
- **Fast Reserve**: £0.4m increase due to an increase of 11 GWh in volume.
- **Response**: £2.4m increase despite a decrease of 29 GWh in the absolute volume of actions.
- **Reactive**: £1.8m decrease due to a minor decrease in the volume average price from £3.5/MVAr to £3.4/MVAr compared to last month.

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

Constraint vs non-constraint costs and volumes



The cause of the minor components issue from last year, where the minor components category was capturing some costs which should be attributed to different categories, has been identified. Our research has shown that the operating reserve category is primarily affected. The months that are impacted demonstrate a strong correlation with higher-than-normal Trading activity. This poses challenges for the historical data classification system responsible for allocating total costs to different categories, particularly in distinguishing between actual constraint actions and actions taken for replacement energy.

This issue is a misallocation of costs due to the nature of the categorisation function in the ESO database. It occurs when trades are a high proportion of total actions. However, the total sum of costs is accurate.

The phenomenon is being monitored closely and similar behaviour has not occurred since April 2023. We are assessing how to remediate the categorisation in the database.

In summary, the total Constraint costs and non-constraint costs are featured below.

Constraint costs

Compared with the same month of the previous year:	We observe an increase of £110.9m in constraint costs compared to June 2023, due to an increase of 1,239 GWh in volume of constraint actions.
Compared with last month:	Constraint costs increased by £72.7m compared to May 2024, due to an increase of 673 GWh in volume of constraint actions, because of greater wind generation, particularly in Scotland.

Non-constraint costs**

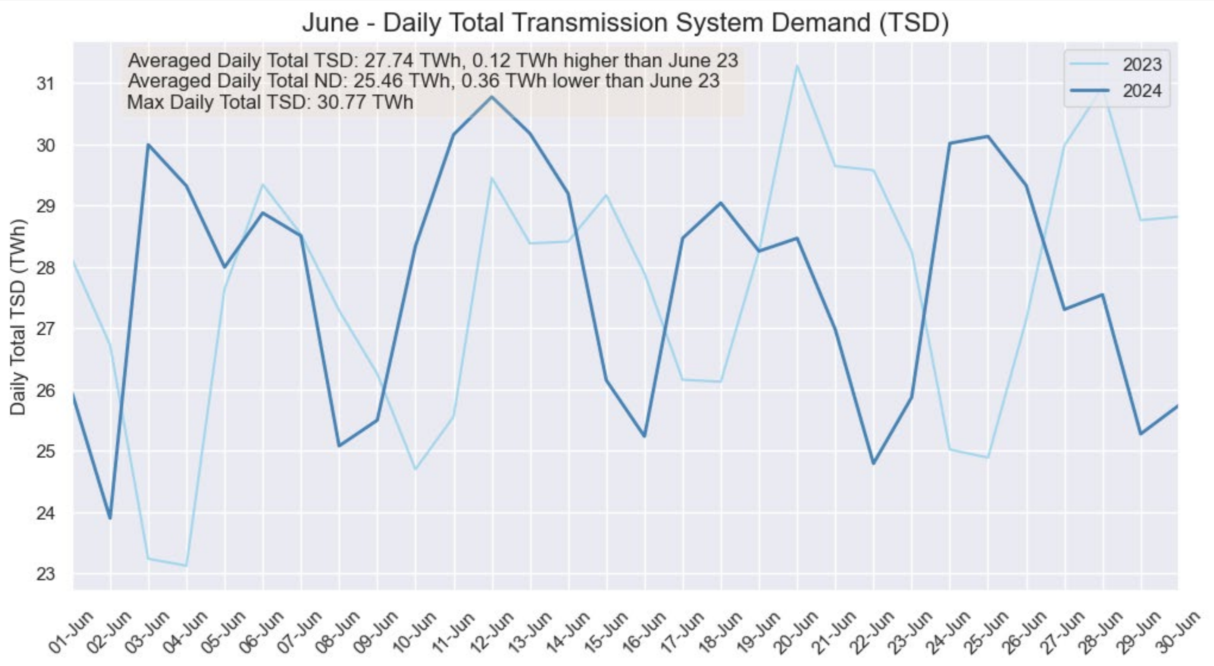
Compared with the same month of the previous year:	Non-Constraint costs were £18.1m lower than in June 2023 due to: • Slightly lower average wholesale prices* • The total volume has been raised from –100 GWh last June to 289 GWh this June, resulting in an increase of 389 GWh in net volume of actions and an increase of 189 GWh in absolute volume of actions.
Compared with last month:	Non-Constraint costs were £1.0m higher than May 2024, the total volume rose to 289 GWh in June, higher than 31 GWh in May as shown in the chart above, resulting in an increase of 258 GWh in volume of actions.

* Average wholesale price for June 24: £76/MWh compared to £87/MWh for June 23.

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

June daily Transmission System Demand (TSD*)

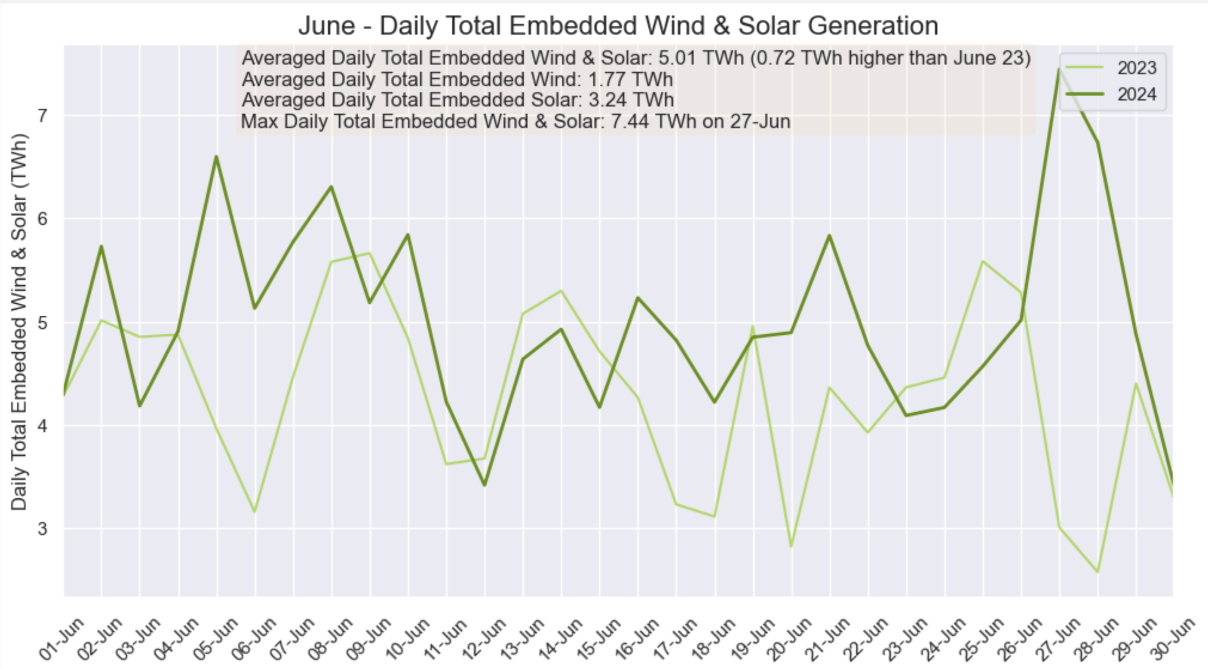
- Total Monthly National Demand (not shown below) was 0.36 TWh lower than June 2023.
- **Total Monthly Transmission System Demand*** was 0.12 TWh higher than June 2023.



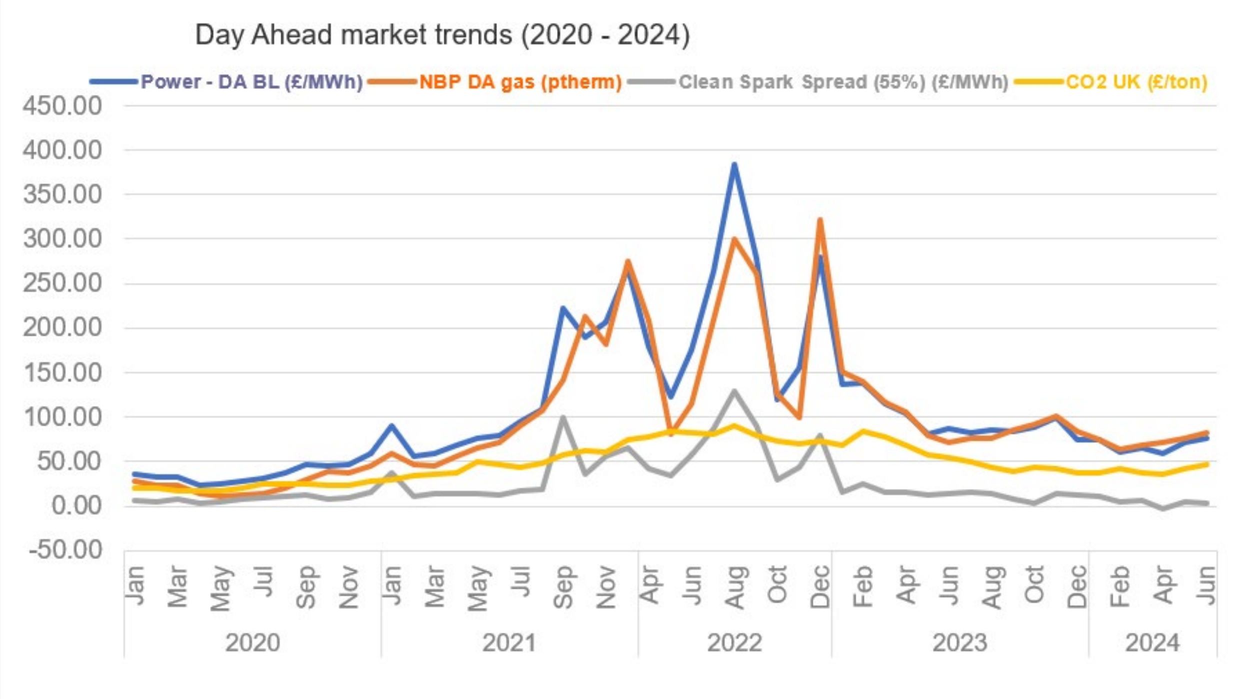
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand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

June daily Embedded Wind and Solar Generation

- **Monthly Total Embedded wind & solar generation** was 0.72TWh higher than in June 2023.
- The maximum daily total embedded wind & solar generation occurred on 27 June 2024 (7.44 TWh).



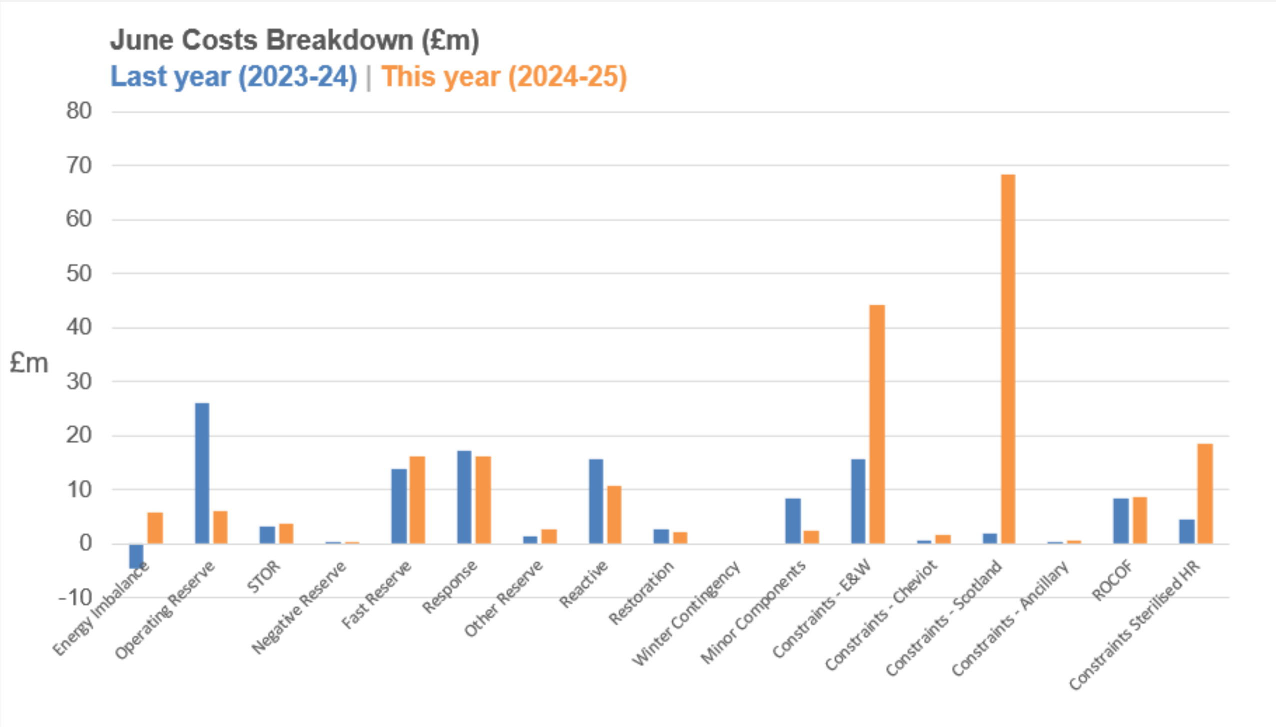
Price Trends in energy markets



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

Power, gas and CO2 had an upward trajectory compared to last month, with a consequent slight fall in the Clean Spark Spread price. Gas increased to 82.3p/therm compared to 71.2p/therm in June 2023 but all other trends remain lower compared to the previous year.

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



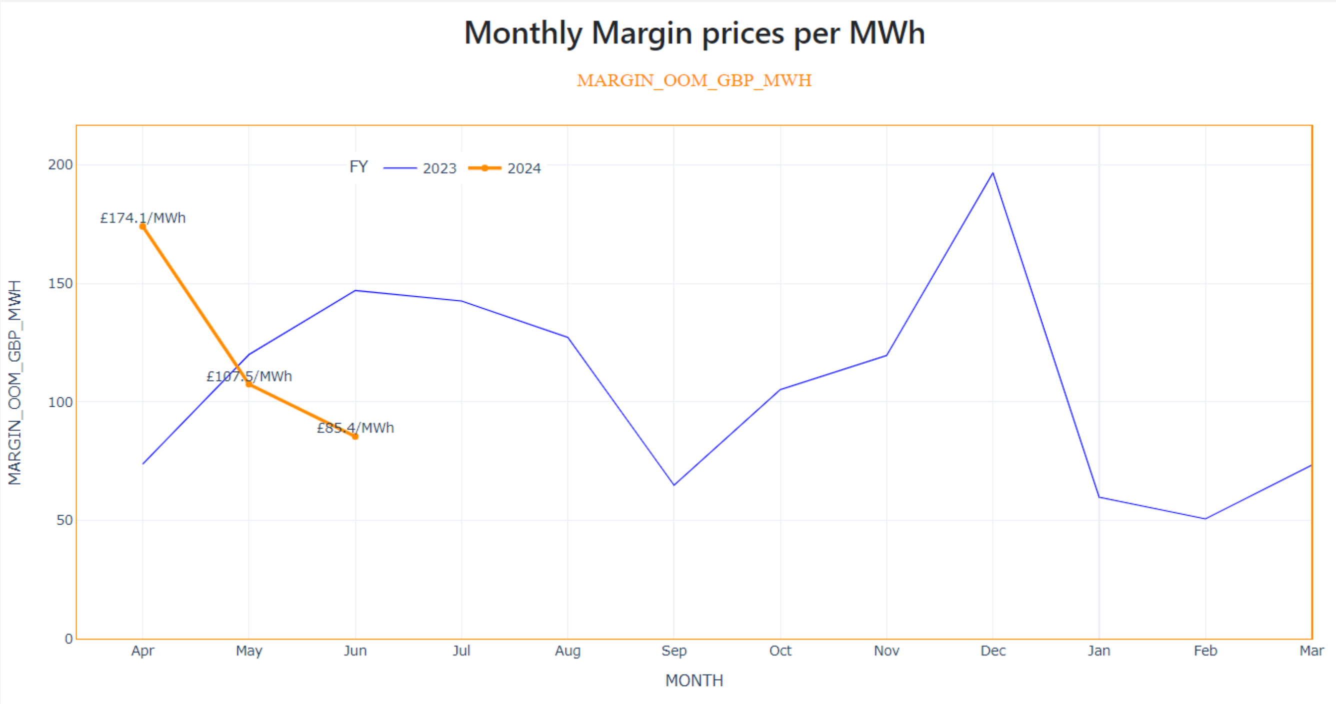
Comparing the non-constraint costs of June 2024 with those of June 2023, most categories showed a decrease or small deviation:

- **Reactive:** £5.1m decrease, due to the decrease in the weighted average price, from £4.7/MVAR to £3.4/MVAR.
- **Operating Reserve** £19.9m decrease despite an increase of 276 GWh of reserve required to balance the system. The reduced cost experienced this year can be attributed, in part, to the lower energy prices compared to June 2023. Additionally, the introduction of the balancing reserve service in March has the potential to decrease reserve prices in the Balancing Mechanism (BM). We are currently in the process of quantifying the benefits associated with this service, and the results will be shared in the coming months.
- **Response**: £1.2m decrease due to 80 GWh less volume of actions taken.
- **Energy Imbalance:** £10.4m increase due to a 26 GWh increase in the absolute volume of actions taken to balance the system.

Comparing the constraint costs of June 2024 with those of June 2023, all categories showed an increase:

- **Constraints – Scotland & Cheviot**: £67.5m increase due to 584 GWh more absolute volume of actions.
- **Constraints – E&W**: £28.6m increase despite taking 153 GWh less absolute volume of actions.
- **Constraints Sterilised Headroom***: £14.0m increase due to an increase of 1071 GWh total volume of replacement energy.

Drivers for unexpected cost increases/decreases



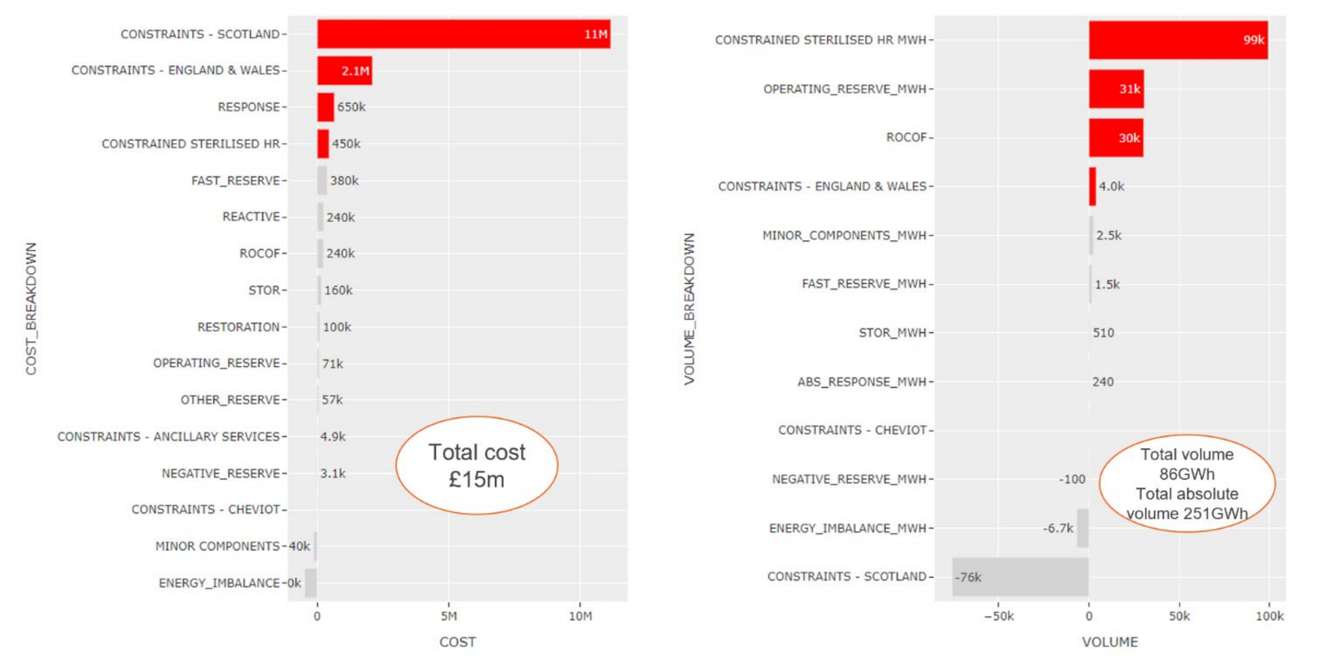
Margin prices (the amount paid for one MWh) fell to £85.4/MWh in June 2024 compared to £147.0/MWh in June 2023 and decreased compared to May 2024.

Daily Costs Trends

June’s balancing costs were £208m which is £74m higher than the previous month. 4 days had a daily total cost over £10m and 1 day had a daily total cost over £15m, resulting in an increase of the average monthly daily cost by £2.6m (from £4.3m to £6.9m).

The lowest total daily cost of £2.3m was observed on 25 June, whilst the highest total cost was observed on 28 June when the total spend was £15m. Thermal Export Constraints in Scotland dominated the cost breakdown on this day making up 73% of the daily cost. No individual action was expensive, but high volumes of wind curtailment contributed to the high total balancing costs for the day.

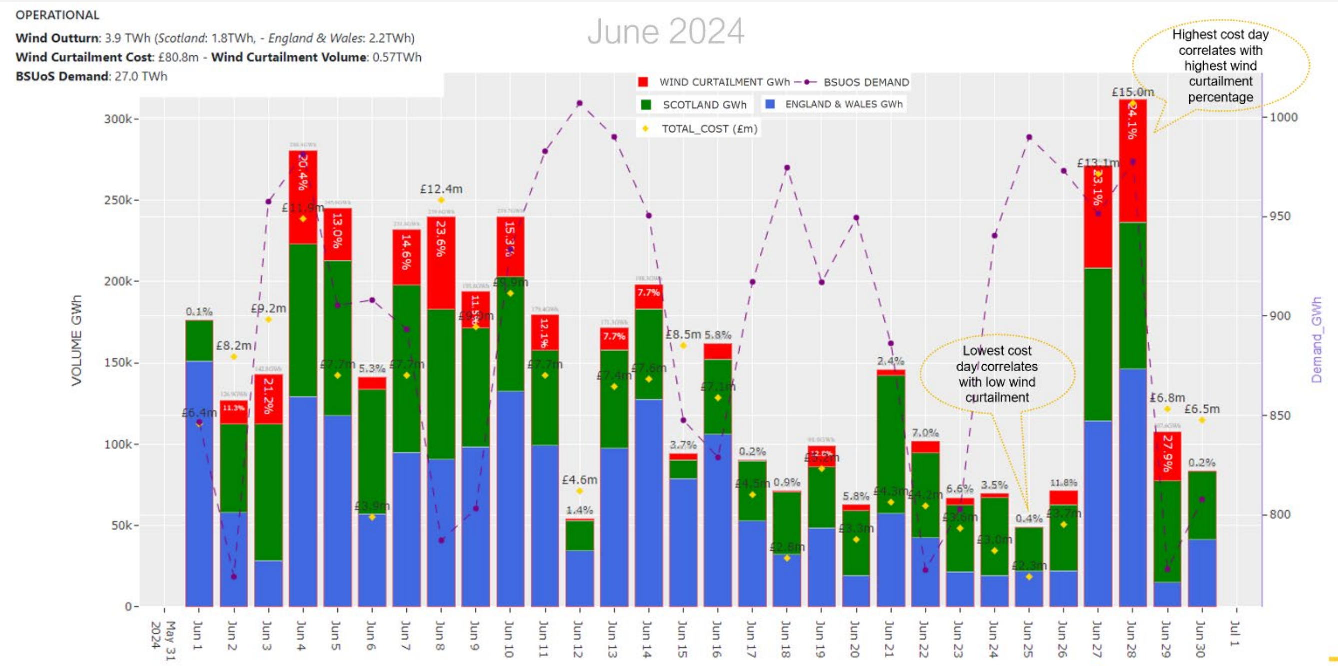
Cost breakdown for 28 June 2024



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

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

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



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

Metric 1B Demand forecasting accuracy

This metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[3]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each half hour period. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

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

In settlement periods where the Demand Flexibility Service (DFS) is instructed by the ESO, this will be retrospectively accounted for in the data used to calculate performance.

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 2024-25 performance

Indicative benchmark figures for 2024-25: Please note that the benchmark figures used below are indicative only. We have calculated these in line with the method specified by Ofgem, but we have not yet received the confirmed figures from Ofgem. We will update previous performance figures in subsequent reports once the benchmarks have been finalised.

Figure: 2024-25 Monthly absolute MW error vs Indicative Benchmark

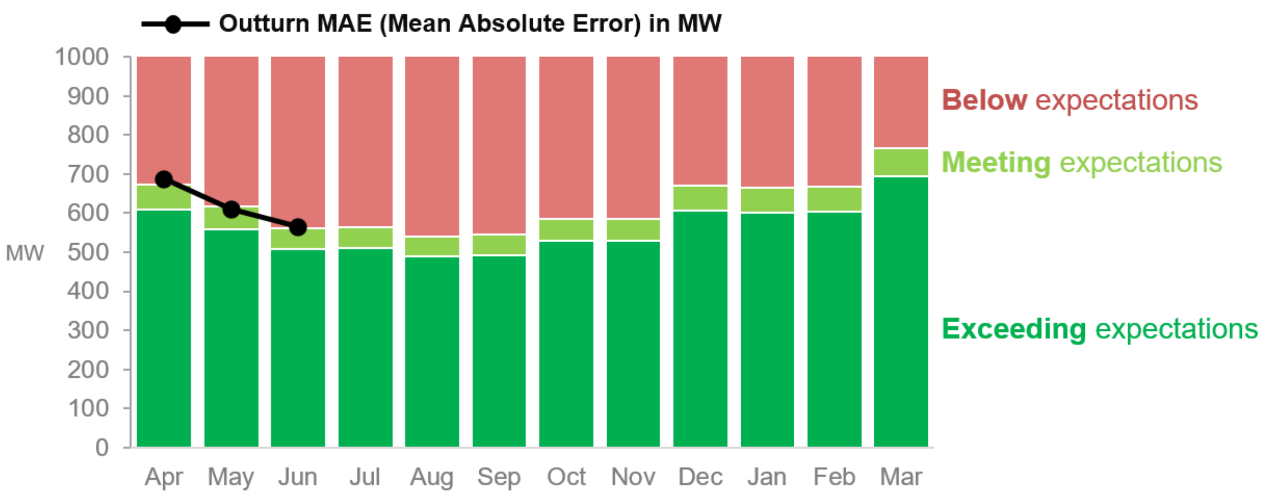


Table: 2024-25 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	642	588	534	538	515	519	558	557	639	632	636	730
Absolute error (MW)	**687**	**610**	**565**									
Status	🔴	🟢	🔴									

[3] Demand | BMRS (bmreports.com)

Performance benchmarks:

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

Supporting information

In June 2024, the mean absolute error (MAE) of our day ahead demand forecast was 565 MW compared to the indicative benchmark of 534 MW. The 5% range around this benchmark extends to 561 MW, meaning performance was below expectations this month June.

In contrast to May, the UK experienced a cooler than average June. There was a short-lived period of warm temperatures near the end of the month. Solar generation peaked at 10.7GW on 2 June.

The largest demand errors occurred on 4, 9 and 27 June and were mainly attributed to solar, with some contribution from wind. The peak demand error was 2.8GW, recorded on 4 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 (1296)
1000 MW	194	15%
1500 MW	71	5%
2000 MW	25	2%
2500 MW	6	0%

The days with largest MAE were June 4, 9, 27 and 28.

Missed / late publications

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

Triads

Triads run between November and February (inclusive) each year and therefore did not affect this month's performance.

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 2024-25 performance

Indicative benchmark figures for 2024-25: Please note that the benchmark figures used below are indicative only. We have calculated these in line with the method specified by Ofgem, but we have not yet received the confirmed figures from Ofgem. We will update previous performance figures in subsequent reports once the benchmarks have been finalised.

Figure: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmark

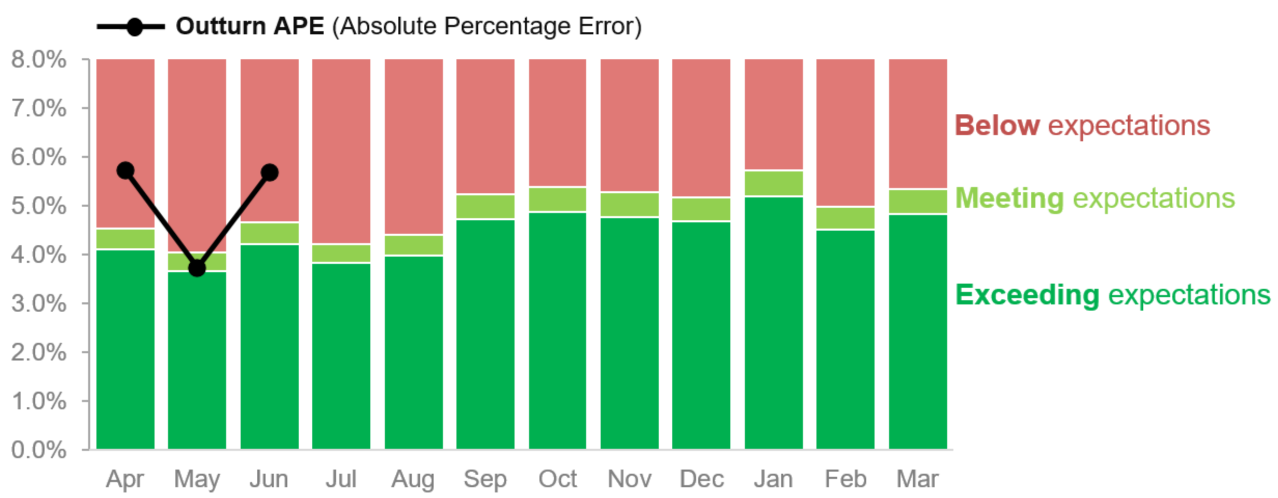


Table: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmarks

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.32	3.85	4.43	4.02	4.19	4.98	5.13	5.02	4.93	5.46	4.74	5.09
APE (%)	**5.10**	**3.69**	**5.65**									
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.

Alternative view of BMU Wind Generation Forecast APE

We have agreed with Ofgem that for 2024-25, alongside the above monthly figures we will include a post-report updated APE% view which aims to exclude some of the factors that are outside of our control. This view excludes sites that have redeclared to zero, and incorporates Initial Settlement Runs (+16 Working Days). Both the benchmark and APE% reported below used this approach. A performance status is shown here, however this is for information only and is not part of the 2024-25 incentives assessment.

Please note that this new approach has also been proposed in the Consultation on Associated Documents to the proposed NESO licences – regulatory framework documents, which will come into effect when ESO transitions into NESO.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.34	3.82	4.45	3.98	4.22	4.99	5.13	5.07	4.89	5.44	4.73	5.05
APE (%)	**4.60**	**3.68**	**5.40**									
Status	●	●	●									

Supporting information

In June 2024, the mean absolute percentage error (APE) was 5.65%, which is more than 5% higher than the benchmark of 4.43% and therefore below expectations.

The alternative APE (corrected for redeclarations to zero and revisions to Settlement Metering) is currently reported as 5.40% against the corresponding benchmark of 4.45% for June, which is also below expectations.

Monthly error was strongly affected by three extraordinarily large error days on 8, 9 and 15 June. Investigations are ongoing, but provisional indications are an exceptionally large error in the Met Office weather data (wind speed), combined with some CfD activity due to negative energy prices on 9 June (~2GW for 6 hours). Note: During the period of CfD activity, we observed some windfarms only declaring down to low output levels and not zero.

The tactical manual entry of outage data continues to be a source of forecast error, of which the process is largely dictated by limitations of our legacy system and the quality and consistency of the outage data.

Offshore forecasts, particularly in the North Sea, remain challenging. The quality of the weather data continues to be variable in this region and contributes to most of the metric error.

The highest wind error (over-forecast) was 5.5GW on 9 June, occurring during Settlement Period 40. Allowing for processing time, the original weather forecast data for this 1C outturn period is approaching two days old.

Withdrawal of wind units

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

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 2024-25 performance

Figure: 2024-25 Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

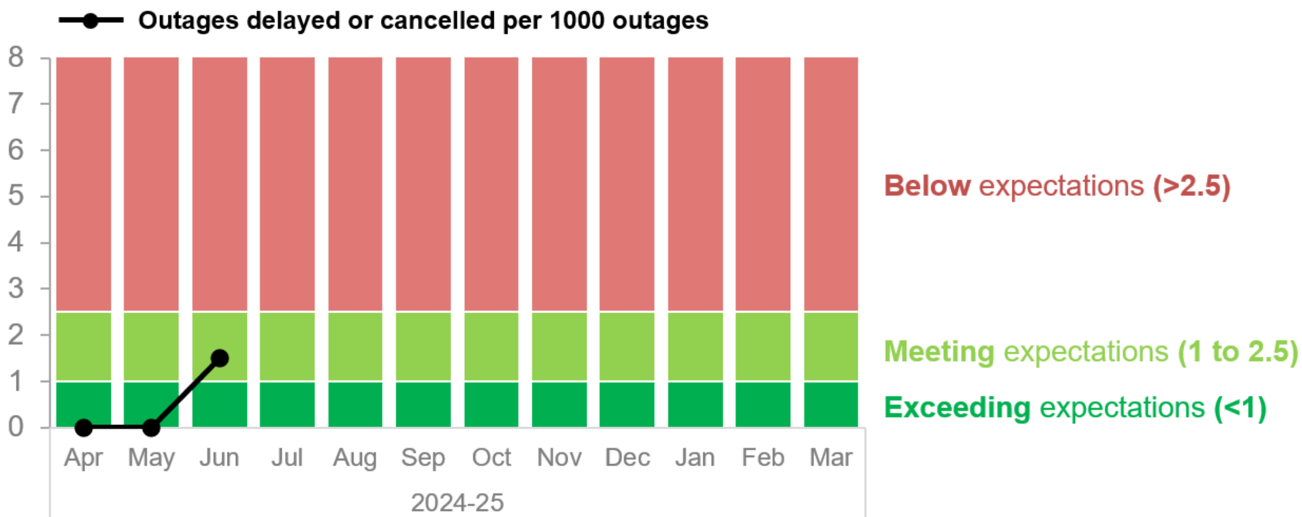


Table: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	673	614	670										1957
Outages delayed/cancelled due to ESO process failure	0	0	1										1
Number of outages delayed or cancelled per 1000 outages	0	0	1.49										0.51
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 670 outages. There was one delay or cancellation due to an ESO process failure. The number of stoppages or delays per 1000 outages for June was 1.49, which is within the 'Meets Expectations' target of less than 2.5 delays or cancellations per 1000 outages. The single event is summarised below:

- There was a delay on an outage where the network constraint limit calculated when the assessment was conducted in medium term timescales had significantly dropped when it was rechecked prior to handing the plan over to the ESO Control Room. The constraint reduction was substantial and it was decided to postpone the outage until the root cause could be identified. An investigation confirmed a modelling issue which was then rectified before the outage could be released. The modelling issue resulted in a constraint limit that had not been passed through the ESO outage sanctioning process. An Operational Learning Note (OLN) has been written to outline the requirements for all scenarios to consider when planning outages in this geographical area and best practice to be followed. An Operational Learning Note (OLN) has been written to outline the requirements for all scenarios to consider when planning outages in this geographical area and best practice to be followed.

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 2024-25 performance

Figure: 2024-25 Percentage of balancing actions taken in merit order to meet requirements in the Balancing Mechanism

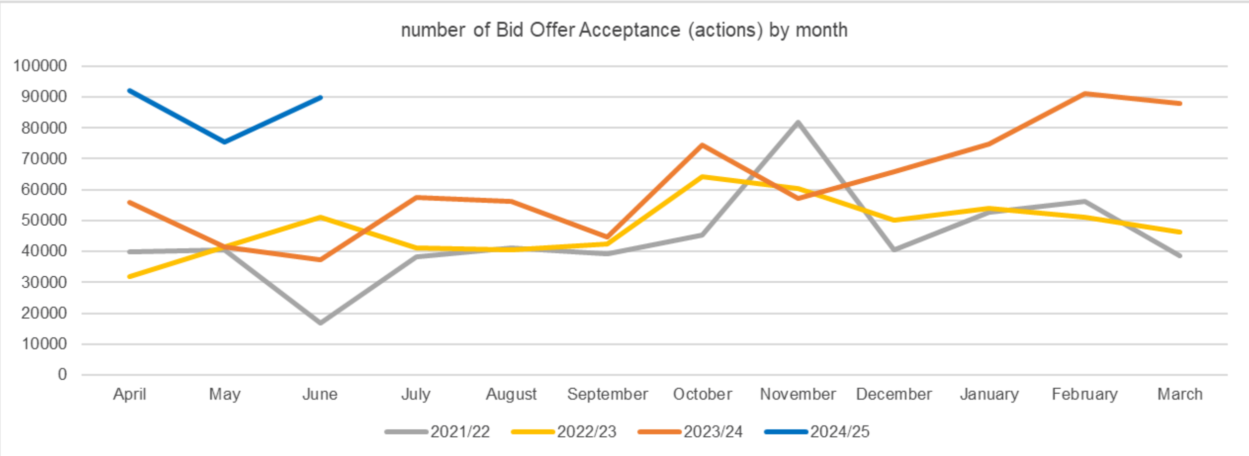
Table: Percentage of balancing actions taken outside of merit order in the BM

	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)	90.9%	90.9%	91.7%									
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.4%	99.5%	99.4%									
Percentage of actions with no category applied or reason group identified	0.6%	0.5%	0.6%									

Supporting information

June performance

This month 91.7% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 7.7% of actions were allocated to reason groups for the purposes of our analysis, and the percentage of actions with no category applied or reason group identified remained in line with previous months. During June, there were 89,709 BOA (Bid Offer Acceptances) and of these, only 542 remain with no category or reason group identified, which is 0.6% of the total.



Other activities

As mentioned previously we commissioned an independent report from LCP Delta. An unanticipated delay in their data processing has had a subsequent knock-on impact on the necessary data validation and report assurance activities. Unfortunately, this has caused a delay in us receiving the report to be able to share with the industry.

LCP Delta is progressing with the ESO to further quality assure the product and we’re committed to delivering this report to industry as soon as we are able.

A new date for the webinar will be shared as soon as possible. Regular further updates will continue at the OTF.

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: 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 prior to the start of BP2 was 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 Q2 2023-24 was 98% on 28 September 2023, settlement period 8. However, for that period the final ZCO dropped to 80% 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: Q1 maximum zero carbon generation percentage by month (2024-25)

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	92.3%	94.7%	15 Apr SP29
May	83.4%	93.8%	12 May SP28
June	86.1%	88.6%	4 Jun SP28

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

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

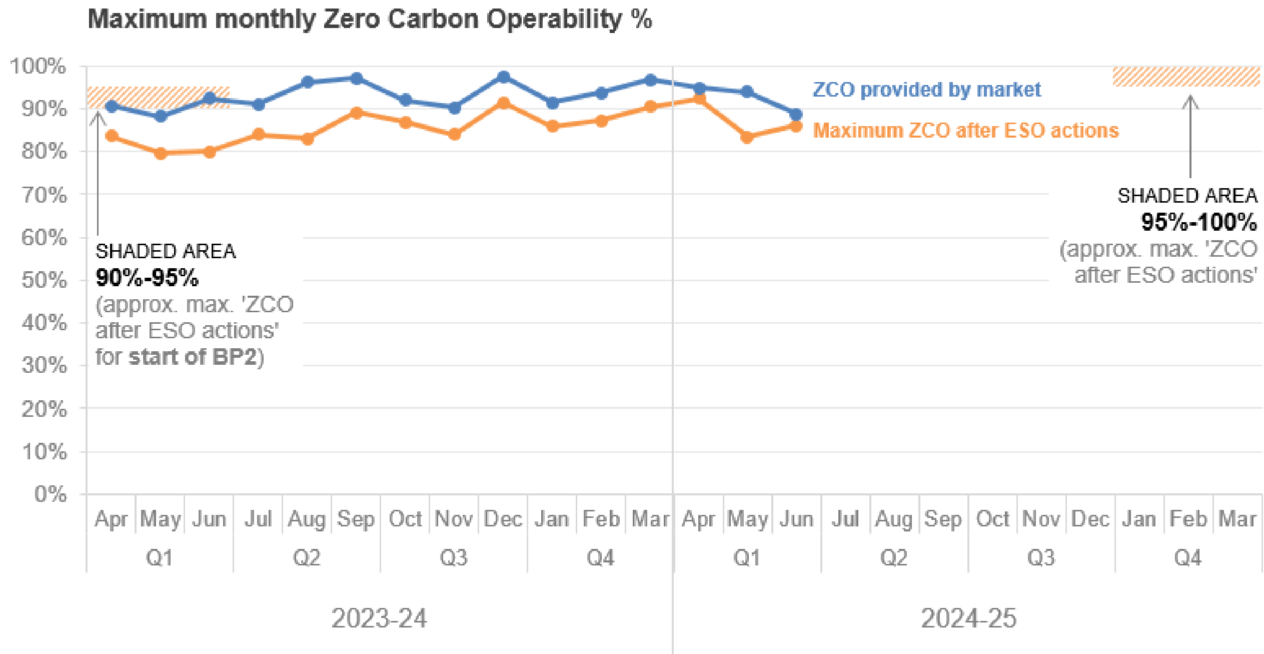
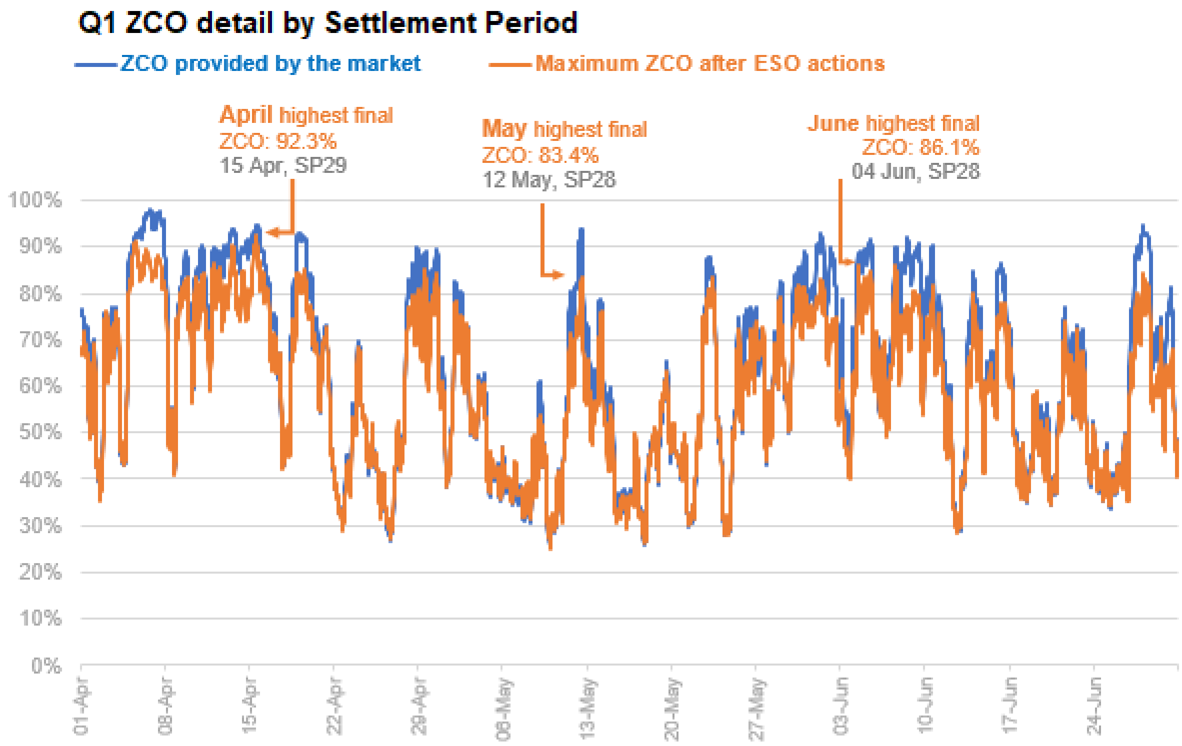


Figure: Q1 2024-25 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

In Q1 2024-25, we have continued to increase the Zero Carbon Operability indicator, setting a new record in April and operating at a higher ZCO% on average than Q4 2023.

In April the highest ZCO% performance for a single settlement period was 92% setting a new record. Zero Carbon generation totalled 19.2GW, with 1.61GW from carbon emitting sources. This beats the previous record of 91% previously achieved on 28 Dec 2023. Only three carbon emitting generators were needed for voltage levels; one self-dispatched, and two were instructed on by ESO. Future reactive power provision from new connections, Transmission Operator assets, and Network Service Procurement is expected to negate the need for these units in future.

For May's highest ZCO day, transmission connected wind output was forecast to remain fairly stable at between 8GW and 9GW. Circuits in the South East had been downrated by the Transmission Operator resulting in significant restrictions and large volumes of actions to create negative reserve. Demand was ~5GW lower than the April day above, meaning more generators were required to manage voltage levels.

On June's highest day, transmission connected wind rose rapidly from 7GW at 08:00 hours to reach 15.2GW by 17:00. Around 2.5GW of wind was constrained in Scotland and replaced by carbon emitting generation further south. Power flows into the South West activated a constraint and required generation to be instructed on to resolve.

Highest final ZCO by month vs previous year

Quarter	Month	2023	2024	Difference
Q1	April	83.6%	92.2%	+8.6%
	May	79.6%	83.4%	+3.8%
	June	79.9%	86.1%	+6.2%
Q2	July	83.9%		
	August	82.9%		
	September	89.1%		
Q3	October	86.8%		
	November	84.0%		
	December	91.3%		
Q4	January	85.8%		
	February	87.1%		
	March	90.5%		

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 2024-25 performance

Figure: 2024-25 Average monthly gCO2/kWh of actions taken by the ESO (vs 2023-24)

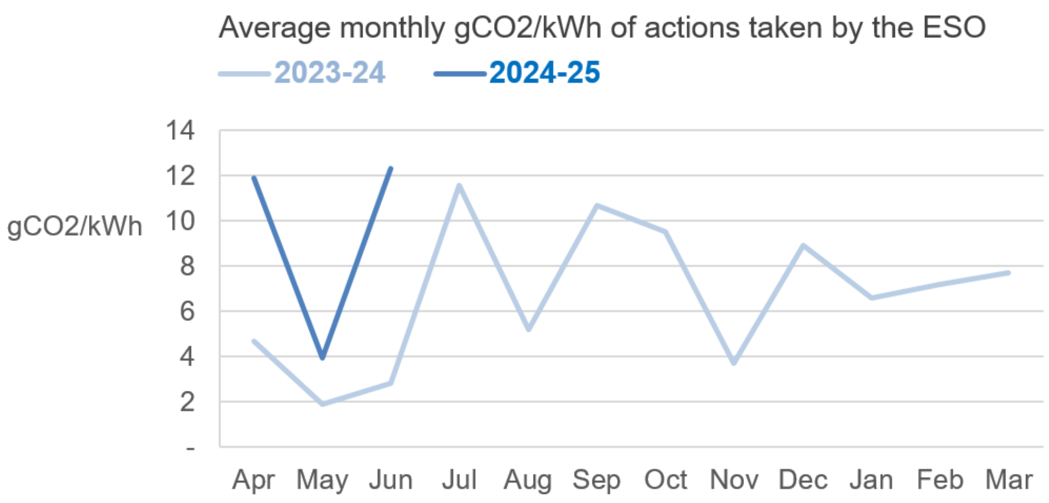


Table: Average monthly gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	11.87	3.93	12.31									

Supporting information

In June 2024, Carbon Intensity from ESO actions was 12.31gCO2/kWh an increase of 8.38gCO2/kWh from May 2024 and an increase of 9.5gCO2/kWh from June 2023 (2.81gCO2/kWh).

Differences peaked on 2 June at 0630 (47.45gCO2/kWh) where there were numerous planned outages across England, Scotland and Wales.

The largest impact occurred on 27 June at 0900 (43.44gCO2/kWh) and continued throughout the weekend into the morning of 30 June (0900 peaked at 65gCO2/kWh).

Significant outages at multiple sites took place over 29/30 June creating a consistent increase of carbon intensity from our actions over this period. The Open Balancing Platform presented errors during this period and batteries were dispatched using VERGIL Voltage management across the South West was highlighted by the Control Room as particularly difficult during this weekend.

England also played Slovakia in the men's European Football Championships, during this period with pickups at half time and full time at 1GW (17:45) and 1.2GW (19:00) respectively and a more gradual 1.2GW after extra time.

If the above period was removed from calculations the average of difference for Carbon Intensity would have been lower at 9.71 gCO2/kWh for June 2024.

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.

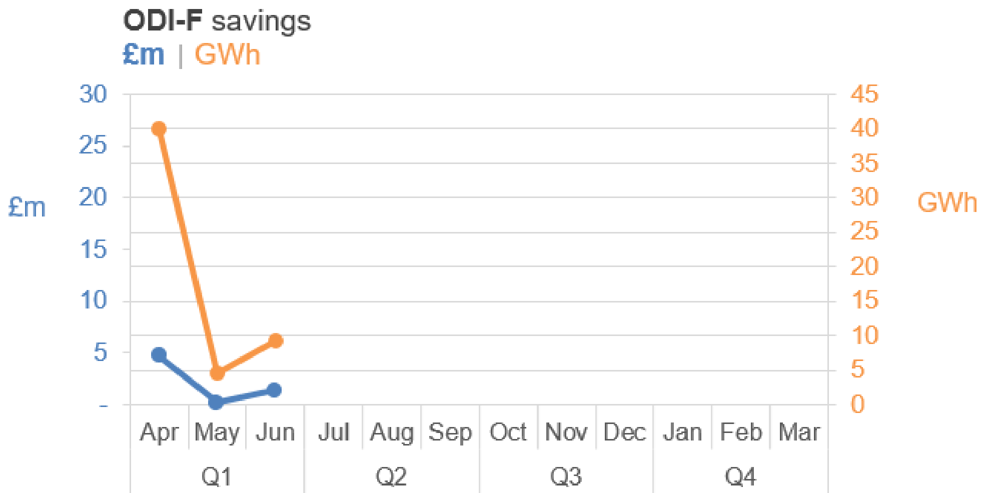
There are two ways the ESO can work with the TOs to minimise constraint costs. We will report on both for RRE 1H:

- 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[4] 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.
- 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: Estimated £m savings in avoided constraints costs (ODI-F) – 2024-25

(Estimated savings in GWh are also shown for context)



[4] 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: Estimated £m savings in avoided constraints costs (Other)

(Estimated savings in GWh are also shown for context)

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

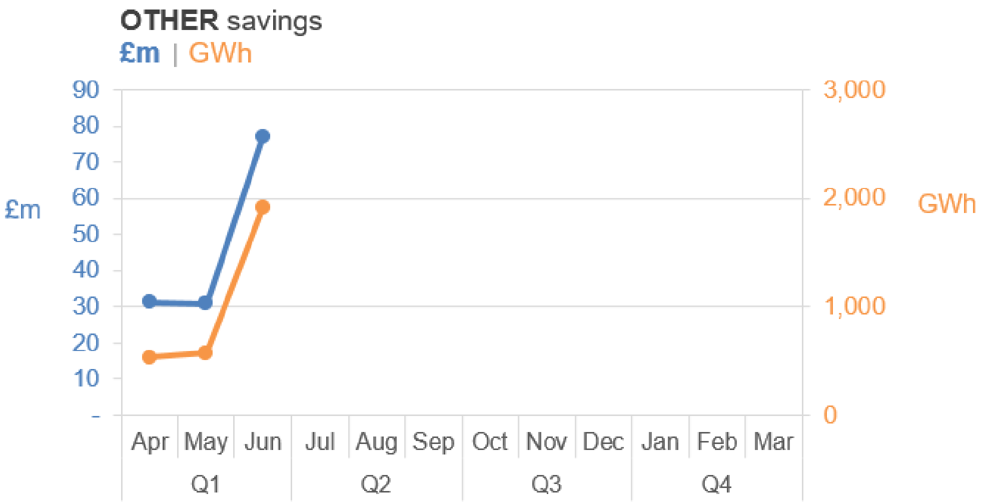


Table: Monthly estimated £m savings in avoided constraints costs (2024-25)

	ODI-F savings	**Other** savings	**ODI-F** savings	**Other** savings
	£m	£m	GWh	GWh
Apr	4.7	31.3	39.9	533.6
May	0.2	30.8	4.6	576.6
Jun	1.4	76.9	9.3	1908.5
Jul				
Aug				
Sep				
Oct				
Nov				
Dec				
Jan				
Feb				
Mar				
YTD	**6.3**	**139.0**	**53.8**	**3018.7**

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 £36 per MWh are used for conventional generation and £75 per MWh for renewable generation.

Supporting information

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

The Network Access Planning (NAP) team has progressed and completed **14** approved enhanced service provisions from TO's through STCP 11.4 that provide constraint cost savings this quarter. Some of these provisions are highlighted below:

- In April, NGET and NAP agreed an enhancement on Tynemouth - West Boldon 275kV circuit to facilitate an outage on South Shields - West Boldon 275kV circuit, for undertaking routine maintenance works on this circuit. This enhancement yielded a saving of **25.1 GWh** circa **£4 million** to the end consumer.

- In May, an enhancement on the Burwell Main – Pelham 1 400kV circuit was agreed between NGET and NAP to facilitate an outage on Burwell Main – Pelham 2 400kV circuit, which was needed on outage to undertake an investigation associated with the protection issues. With this enhancement in place, a total saving of **3.22 GWh** and **£0.16 million** to the end consumer was achieved for the duration of the outage.

- In June, NGET and NAP agreed a weather-based increase in ratings, based on the installed line vison technology on the Kirkby – Washway Farm – Penwortham 2 circuits, to facilitate an outage on Kirkby - Washway Farm - Penwortham 1 275kV circuit, needed for routine maintenance and system construction works. This enhancement saved the end consumer **7.83 GWh** and **£1.3 million**.

In Q1 2024-25, NAP has realised **53.8 GWh** and approximately **£6.3 million** of cost savings through STCP 11-4. This is because only started and completed enhancements have been reported. There are several ongoing enhancements which will be included in the next quarterly reports once they have successfully completed.

Other Savings (Customer Value Opportunities (CVO)):

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 **43 instances this quarter,** where the ESO's actions directly resulted in adding value to the end consumers, and its innovative ways of working facilitated increased generation capacity to the connected customers.

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

Some examples of these instances include:

- NAP received a system access request in April from NGET on the Harker - Hutton 1 400kV circuit for one week, needed as a proximity for SF6 leak repairs on one of the Harker 400kV transformers. However, within the same period both Torness generators were out of service, and this outage would put the B6 boundary on a single circuit risk. Therefore, NAP proposed to NGET for this outage to be replanned at a time when there less impact on the B6 boundary capability. The outage was then replanned and completed in the last week of April, and this in turn equated to a saving of **0.94 TWh** and approximately **£7.1 million** to the end consumer.
- In May, NAP received a two-week outage request on Alyth - Kincardine 1 275kV circuit from SHET, for reconductoring and re-insulation works. However, assessment of the sanctioning costs was pending. So, following NAP's outage review, a more economical option was proposed to SHET to be align this outage with the Kintore – Fetteresso 2 275kV outage in November. This action in turn would save an approximate of **0.2 TWh** and **£12.6 million** to the end customer.
- In June, NAP received a request from NGET for Bulls Lodge – Rayleigh Main 400kV circuit as proximity for the completion of works on Rayleigh Main disconnectors. However, this outage request would clash with a planned outage of Elstree – Sundon 1 400kV circuit, thus dropping the boundary capability of the LE1 boundary. NAP proposed for a better placement of the Bulls Lodge – Rayleigh Main, by replanning it to start when the Elstree – Sundon 1 400kV returns to service

late October. This action saved an approximate of **0.4 TWh** and circa **£15.8 million** to the end consumer.

The above and many more customer value opportunities represent a total of **3.02 TWh** approximately **£139 million** of extra generation capacity across Q1, which would have otherwise been constrained at a cost to the end consumer.

The £/MWh figure for savings is calculated per outage. £50 per MWh is used for savings on conventional generation, £75 per MWh is used for renewable generation. Where full commercial cost benefit analysis assessment is available these figures are used instead. Due to the high price per MWh in fully costed CVOs and the increase in renewable generation on the network, the average price per MWh is approximately £65.

RRE 1I Security of Supply

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

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

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

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

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

June 2024-25 performance

Table: Frequency and voltage excursions (2024-25)

	2024-25											
	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[5]	0	0	0									

Supporting information

June performance

There were no reportable voltage or frequency excursions that breached the statutory limits in June.

On 24 June 2024 @18:32, there was one frequency event. An interconnector tripped while importing 1000MW to GB. The frequency reached a maximum deviation of 49.661Hz and returned to the operational limit 49.8Hz within 5 minutes and 50Hz within 15 minutes.

[5] 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.

June 2024-25 performance

Table: 2024-25 Unplanned CNI System Outages (Number and length of each outage)

	2024-25											
Unplanned	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: 2024-25 Planned CNI System Outages (Number and length of each outage)

	2024-25											
Planned	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									

Supporting information

June performance

There were no outages, either planned or unplanned, encountered during June 2024 and throughout Q1 2024-2025.

Notable events during June 2024

Balancing Programme event – 27 June

On 27 June we were joined by 65 Industry representatives from across 48 different organisations at the latest Balancing Programme Engagement Event in London.

The focus of the day was on delivering for society, the importance of partnerships, and proactive collaboration in developing product roadmaps beyond 2025. We provided details of the new balancing functionality being delivered into the Control Room, as part of current system upgrades and our ongoing Open Balancing Platform (OBP) delivery.

There were updates on forecasting products and planned activity as we transition to the new Platform for Energy Forecasting (PEF), ESO innovation projects and how these will enhance and future-proof Control Room operations, and details of optimisation developments and enhancements.

There was an interactive, future-looking session which enabled stakeholders to input into and shape balancing & forecasting product roadmaps beyond 2025, and a customer listening session where we heard how stakeholders would like to see the Balancing Programme evolve its approach to customer engagement and partnership working.

The event was extremely well received by stakeholders with attendees giving an average score of 8.5 out of 10 for the overall event, marking our highest event score to date! Induvial agenda items scored between 4 and 4.5 out of 5, again an increase from our previous event.

Stakeholders commented:

“These sessions have evolved over the years and you can see the changes from feedback given previously. Keep up the good work.”

"Excellent event - really appreciated the forward planning / look head sections, and the interactive feedback session.”

“Great, very useful - all the ESO team were very helpful and willing to listen and help."

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 the 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 the benchmark • Competitive procurement of Reactive Power through Market mechanisms will be understood later in 2024 – through the Reactive Power Market Reform. • There will continue to be specific regional requirements, and these will be procured through market mechanisms where feasible.
Constraints	Year 1: 65% Year 2: 55%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for the 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 Constraint Management Intertrip Service (EC5 CMIS) and Local Constraint Market (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	• Static FFR (Firm Frequency Response) • Dynamic Containment Low and High • Dynamic Moderation Low and High • Dynamic Regulation Low and High	• Mandatory Frequency Response (Primary, Secondary and High) • Fast Start
Reserve	• Day-Ahead STOR (Short Term Operating Reserve)	• Long Term STOR • Optional Fast Reserve • Super SEL (Stable Export Limit) (Footroom)
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 & EC5 Constraint Management Intertrip Service	• Strike Price

Overall performance – All services

Q1 2024-25 performance

Figure: Percentage of volume procured non-competitively vs benchmark

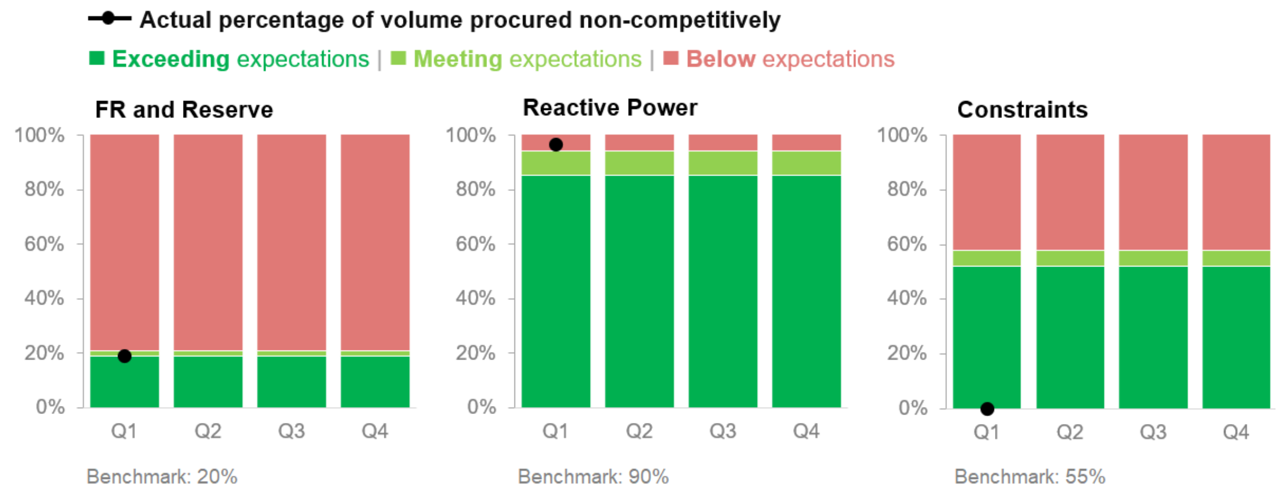
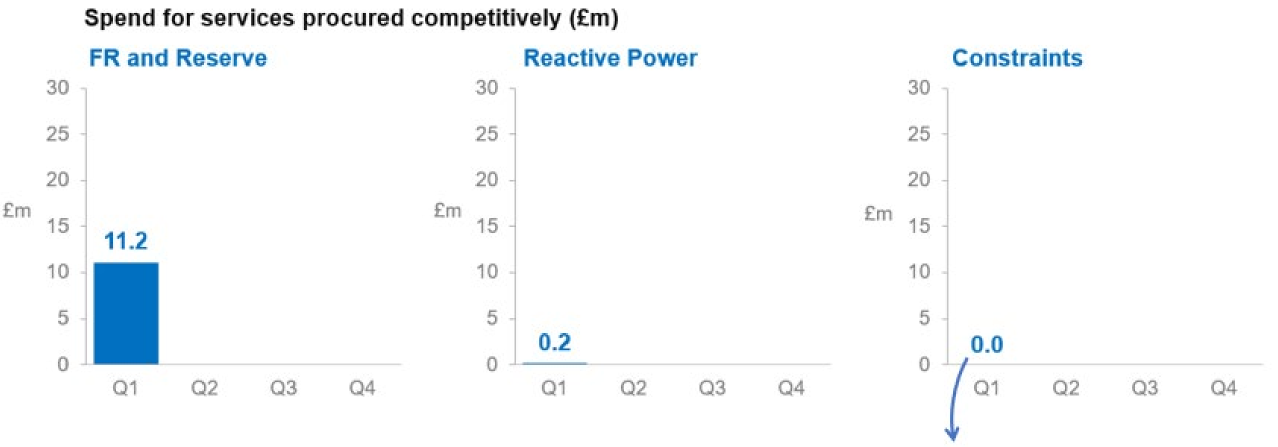


Figure: Quarterly competitive spend by service



For Constraints, the graph above on a scale of £m shows ***£0.0m****. This rounded figure reflects spend of* ***£6,000*** *procured competitively (as shown in the Constraints section further down).*

SO-SO trades made during Q1

Historically SO-SO Trades were available to us across the IFA & IFA2, Nemo Link, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & Nemo Link, the current required notice period is longer than the hourly gates provide, and so we can no longer use this service. EWIC & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. We do not trade via third Parties and therefore only have access to CBB.

Trades for Q1 totalled £0m consisting of 0 trades on 0 interconnector/s.

ℹ	**Data content Information:**	Data consists of final settlement data for the first two months of the most recent quarter with the third month to be provided within the next submission of the report.

1. Frequency Response and Reserve

Q1 2024-25 performance

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

Frequency Response & Reserve		Unit	Q1	Q2	Q3	Q4	Full Year
Volume	Total volume procured	GWh	10451				10451
	Volume procured non-competitively	GWh	1999				1999
	Percentage of volume procured non-competitively	%	19%				19%
	Year 2 benchmark	%	**20%**				**20%**
	Status	n/a	●				●
Spend	Total spend	£m	25.6				25.6
	Spend for volume procured competitively	£m	11.2				11.2
	Spend for volume procured non-competitively	£m	14.4				14.4

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, 19% of Frequency Response and Reserve volume was procured non-competitively, which is within 5% of the benchmark of 20%, and therefore meeting expectations.

With the growth in response and reserve competitive markets we are able to procure more of our requirements at day-ahead so have less reliance on non-day-ahead 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.

For detail on year 1 of BP2, please see our previous reports on our website.

2. Reactive Power

Q1 2024-25 performance

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

Reactive Power		Unit	Q1	Q2	Q3	Q4	Full Year
Volume	Total volume procured	GVARh	10137				10137
	Volume procured non-competitively	GVARh	9786				9786
	Percentage of volume procured non-competitively	%	**97%**				**97%**
	Year 2 benchmark	%	**90%**				**90%**
	Status	n/a					
Spend*	Total spend	£m	38.2				38.2
	Spend for volume procured competitively	£m	0.2				0.2
	Spend for volume procured non-competitively	£m	37.9				37.9

*Rounding: Spend figures in £m are rounded to the nearest 1 decimal place, therefore Total spend may differ slightly from the sum of competitive and non-competitive spend.

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, which is more than 5% higher than the benchmark of 90% and therefore below expectations. The benchmark was established late in the BP1 period, on the expectation that by BP2 we would have a Reactive Market in place. The development of that market was postponed in 2022 and subsequently restarted in May 2023.

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 long-term Mersey Pathfinder awarded two contracts to meet a need in this region: the Peak Gen shunt reactor service went live in Q1 2022-23 and the Zenobe Battery live in Q4 2022-23. In January 2022 we also awarded contracts to meet reactive needs in the Pennines region that are due to commence in 2024-26 which will decrease the percentage of reactive power services procured and utilised through non-competitive means. Two of those three Pennines solutions delivered by NGET are now operational, with the remaining reactor is expected to come online in Q2 2024/25.

A Reactive market is being established based on initial market design from NIA project in 2022. We have completed our work on the long-term reactive power market and plan to launch the first tender in Q2 of

2024/25 for service delivery in 2029. Implementing the long-term market will drive locational investment and enable greater competition in the delivery of reactive power service provision.

We are continuing to assess the consumer benefit impact that a mid-term (Y-1) and short-term (D-1) can deliver.

For detail on year 1 of BP2, please see our previous reports on our website.

3. Constraints

Q1 2024-25 performance

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

Constraints		Unit	Q1	Q2	Q3	Q4	Full Year
Volume	Total volume procured	GWh	3				3
	Volume procured non-competitively	GWh	0				0
	Percentage of volume procured non-competitively	%	0%				0%
	Year 2 benchmark	%	**55%**				**55%**
	Status	n/a	●				●
Spend	Total spend	£m	0.006				0.006
	Spend for volume procured competitively	£m	0.006				0.006
	Spend for volume procured non-competitively	£m	0				0

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

During Q1 the intertrip service had low utilisation with only arming instructions for the EC5 boundary. The B6 region had multiple outages on the west coast throughout the quarter along with outages ongoing across B4, with control room unable able to push enough power down through Central Scotland to constrain B6, therefore resulting in no arming of the boundary.

For detail on year 1 of BP2, please see our previous reports on our website.

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.

Whilst 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:	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 2024-25 performance

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

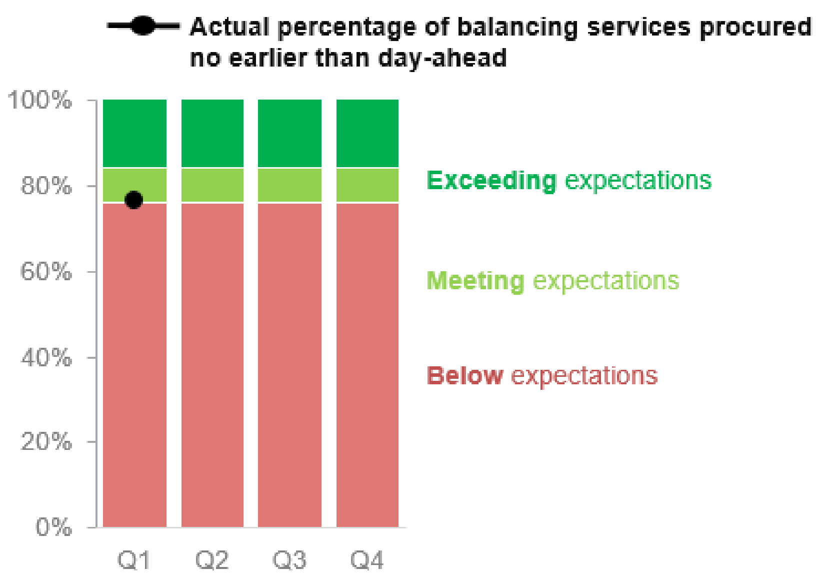


Table: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4	Full Year
Total volume of balancing services procured	MW	8371				8371
Volume procured no earlier than day-ahead	MW	6419				6419
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	77%				77%
Benchmark	%	80%				80%
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 content Information: Data consists of final settlement data for first two months of the most recent quarter with 3rd month to be provided within the next submission of the report.

Supporting information

In Q1, 77% of balancing services volume was procured no earlier than day-ahead, compared to the benchmark of 80%, and therefore meeting expectations.

Please note that because of the performance benchmark range for Exceeding Expectations changing from 55% to 80%, this has meant that with 77% our scores are now in the Meeting Expectation range.

The meeting expectations performance for day-ahead procurement of services is due to several factors across the markets. Since their launches 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 which was phased out with last delivery of the service in November 2023 and these volumes are going into 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.

For detail on year 1 of BP2, please see our previous reports on our website.

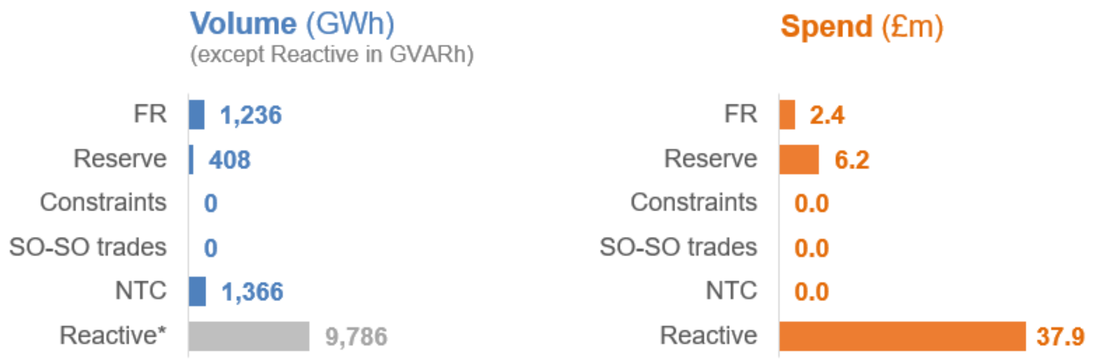
RRE 2Aii Balancing services procured in a non-competitive manner

This Regularly Reported Evidence (RRE) 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. Mandatory Frequency Response). 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 2024-25 performance

Figure: 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: Volume and spend for non-competitive services

	Service	Unit	Q1	Q2	Q3	Q4	Full Year
VOLUME	Frequency Response****	GWh	1236				1236
	Reserve****	GWh	408				408
	Constraints***	GWh	0				0
	SO-SO trades	GWh	0				0
	Net Transfer Capacity (NTC)	GWh	1366				1366
	Total Volume in GWH	GWh	**3010**				**3010**
	Reactive (in GVARh)	GVARh	9786				9786
SPEND	Frequency Response	£m	2.4				2.4
	Reserve -	£m	6.2				6.2
	Constraints	£m	0				0
	SO-SO trades *	£m	0				0
	Net Transfer Capacity (NTC)**	£m	0				0
	Reactive	£m	37.9				37.9
	Total spend	£m	**46.5**				**46.5**

*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.

**NTC cost was updated for Q1 to show payments to provider only – this logic to be used going forward

***For Q2 - Super SEL category has moved from Constraints to Reserve

****Total non-competitive procurement for Frequency Response and Reserve in RRE 2Aii will not align with volume stated in Metric 2Ai. This is because Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded from RRE 2Aii as per the agreed methodology.

Data content Information:	Data consists of final settlement data for first two months of the most recent quarter with 3rd month to be provided within 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 and 2025.

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

Super SEL, which is now included as a Reserve service, 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 in this metric to reflect utilisation. We have previously reported the contract values and not actual utilisation.

Constraints

There were minimal arming instructions throughout Q1 due to low wind and certain outage conditions.

SO-SO Trades

Historically SO-SO Trades were available to us across the IFA & IFA2, Nemo Link, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & Nemo Link, the current required notice period is longer than the hourly gates provide, we can no longer use this service.

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.

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 (NTC) and this reduction is defined as a non-frequency ancillary service.

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

On 28 September 2023, Ofgem granted us a derogation against C28 for NTCs until 30 September 2026. This follows a request we sent to Ofgem to extend this derogation in August. They also approved our revised NTC Commercial Consultation Methodology, which applies from 1 October 2023. This gives our Control Room certainty that they can use this vital tool when required for system security over the coming years.

NTCs are our 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:

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

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

Methodology

<table>
<tr><th colspan="2">Product</th><th>Methodology</th></tr>
<tr><td rowspan="6">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="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 Containment (DC)</td></tr>
<tr><td>Dynamic Moderation (DM)</td></tr>
<tr><td>Dynamic Regulation (DR)</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="5">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>Super SEL (Footroom)</td><td>We report on contracted volumes for all contracts that are live for any part of the month.</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>
<tr><td rowspan="3">Reactive</td><td>Mandatory Reactive</td><td rowspan="3">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).</td></tr>
<tr><td>Stability Reactive</td></tr>
<tr><td>Synchronous Compensation</td></tr>
</table>

	Mersey & Pennine Pathfinder	
Constraints	Strike Price	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.
	B6 & EC5 Intertrip	

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

Data content Information:	Data consists of final settlement data for the first two months of the most recent quarter with the third month to be provided within the next submission of the report.

Figure: Total contracted volumes by service type for Q1

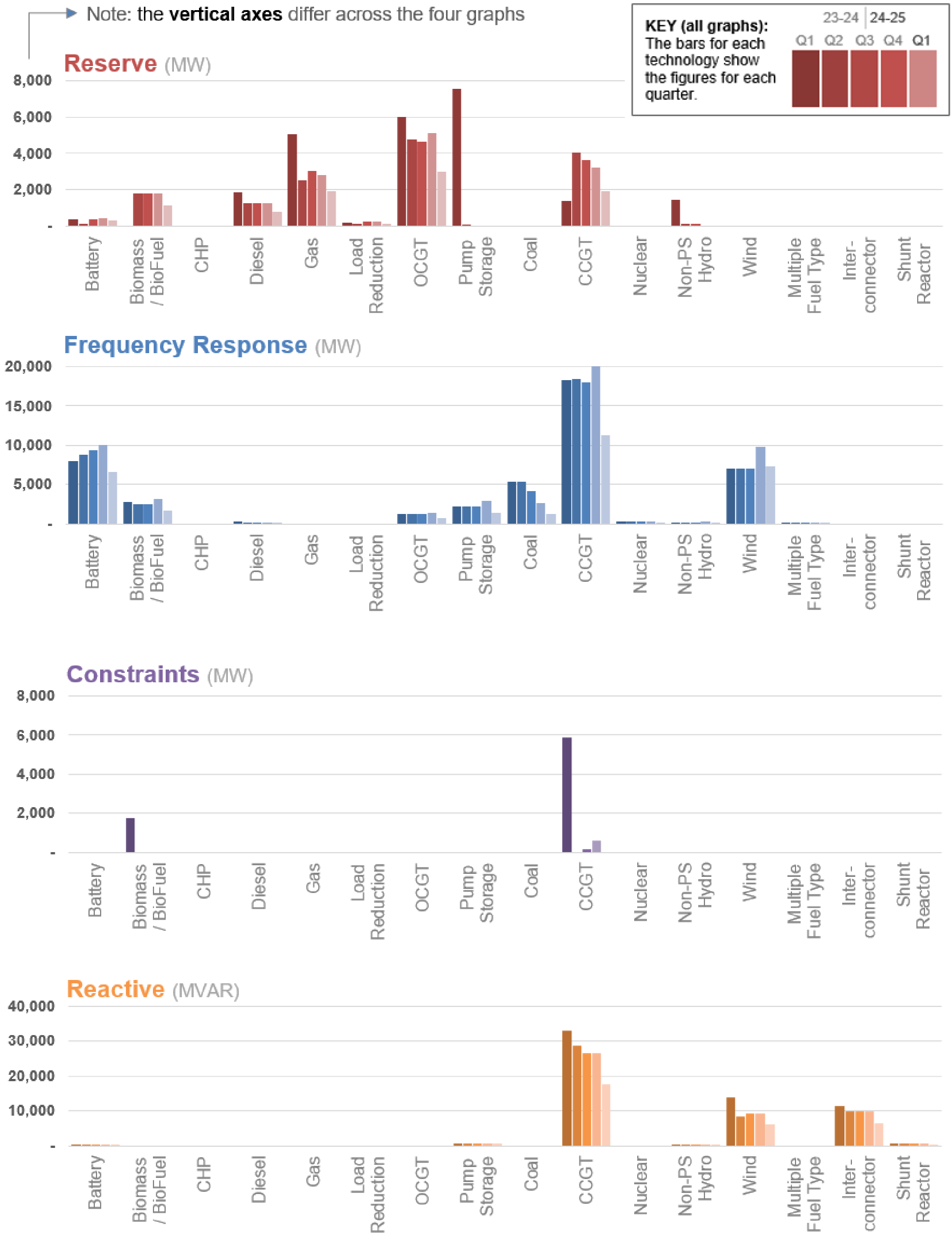


Table: Monthly contracted volumes provided to the ESO by service type

Reserve

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Q1	Q2	Q3	Q4	Q1
Total	8,017	8,022	8,022	5,038	5,105	4,793	5,009	5,029	5,184	5,360	4,947	4,663	4,739	4,646	-	24,062	14,936	15,222	14,970	9,385
Battery	134	134	134	40	24	88	135	105	125	133	112	213	168	189	-	401	152	365	458	357
Biomass/BioFuel	19	19	19	595	595	595	595	595	595	595	595	595	595	595	-	58	1,785	1,785	1,785	1,190
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	628	627	627	426	421	423	424	427	432	432	432	429	411	423	-	1,882	1,270	1,283	1,293	834
Gas	1,690	1,691	1,691	910	831	773	1,023	1,034	984	948	922	940	1,032	922	-	5,073	2,514	3,041	2,810	1,954
Load Reduction	70	70	70	54	55	52	69	87	101	100	86	86	78	68	-	210	161	257	272	146
OCGT	2,001	2,003	2,003	1,497	1,762	1,485	1,535	1,562	1,578	1,875	1,830	1,430	1,485	1,479	-	6,008	4,744	4,675	5,135	2,964
Pump Storage	2,516	2,519	2,519	100	-	-	-	-	-	-	-	-	-	-	-	7,554	100	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	465	466	466	1,416	1,417	1,227	1,228	1,219	1,219	1,277	970	970	970	970	-	1,397	4,060	3,666	3,217	1,940
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	490	490	490	-	-	150	-	-	150	-	-	-	-	-	-	1,470	150	150	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Frequency Response

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Q1	Q2	Q3	Q4	Q1
Total	15,161	15,436	15,203	15,501	15,324	15,467	15,451	15,673	14,057	14,173	24,843	14,454	15,400	15,438	-	45,800	46,292	45,181	53,470	30,838
Battery	2,596	2,767	2,695	3,017	2,820	2,956	2,960	3,162	3,254	3,368	3,413	3,298	3,311	3,349	-	8,058	8,793	9,376	10,079	6,660
Biomass/BioFuel	957	937	837	837	837	837	817	837	837	837	1,554	837	837	837	-	2,731	2,511	2,491	3,228	1,674
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	112	112	56	36	56	56	56	56	54	56	57	56	54	54	-	280	148	166	169	108
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	443	443	443	443	443	443	443	443	362	362	724	362	362	362	-	1,329	1,329	1,248	1,448	724
Pump Storage	728	728	728	728	728	728	728	728	728	728	1,456	728	728	728	-	2,184	2,184	2,184	2,912	1,456
Coal	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	650	650	1,300	650	650	650	-	5,346	5,346	4,214	2,600	1,300
CCGT	6,024	6,148	6,148	6,148	6,148	6,155	6,155	6,155	5,662	5,662	11,324	5,662	5,662	5,662	-	18,320	18,451	17,972	22,648	11,324
Nuclear	92	92	92	92	92	92	92	92	92	92	184	92	92	92	-	276	276	276	368	184
Non-PS Hydro	70	70	70	70	70	70	70	70	70	70	140	70	70	70	-	210	210	210	280	140
Wind	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	4,686	2,694	3,629	3,629	-	7,029	7,029	7,029	9,723	7,258
Multiple Fuel Type	14	14	9	5	5	5	5	5	5	5	5	5	5	5	-	37	15	15	15	10
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Constraints

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Q1	Q2	Q3	Q4	Q1
Total	2,300	3,605	1,795	-	-	-	-	-	200	200	200	200	-	-	-	7,700	-	200	600	-
Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass/BioFuel	595	595	595	-	-	-	-	-	-	-	-	-	-	-	-	1,785	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pump Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	1,705	3,010	1,200	-	-	-	-	-	200	200	200	200	-	-	-	5,915	-	200	600	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Reactive

MVARs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Q1	Q2	Q3	Q4	Q1
Total	19,921	19,921	19,921	16,174	16,174	16,174	15,702	15,839	15,747	15,794	15,719	15,702	15,702	15,702	-	59,763	48,522	47,288	47,215	31,404
Battery	32	32	32	16	16	16	49	65	49	49	66	49	49	49	-	96	48	163	164	98
Biomass / BioFuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pump Storage	235	235	235	235	235	235	235	235	235	235	235	235	235	235	-	705	705	705	705	470
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	11,021	11,021	11,021	9,579	9,579	9,579	8,832	8,832	8,832	8,832	8,832	8,832	8,832	8,832	-	33,063	28,737	26,496	26,496	17,664
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	93	93	93	72	72	72	72	72	72	72	72	72	72	72	-	279	216	216	216	144
Wind	4,573	4,573	4,573	2,813	2,813	2,813	3,055	3,176	3,100	3,147	3,055	3,055	3,055	3,055	-	13,719	8,439	9,331	9,257	6,110
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	3,767	3,767	3,767	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	-	11,301	9,777	9,777	9,777	6,518
Shunt Reactor	200	200	200	200	200	200	200	200	200	200	200	200	200	200	-	600	600	600	600	400

Supporting information

The commentary below is similar to previous reports as the diversity of providers that provide balancing services didn’t change significantly through BP1 and is not expected to change much in BP2 unless otherwise stated.

Frequency Response

Frequency services are delivered by providers who have a Mandatory Services Agreement (MSA) or who are awarded contracts through a competitive tendering process (which includes the daily auctions). Mandatory Frequency Response is primarily provided by providers with MSA registered transmission connected Units. For frequency response procured through competitive tendering 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 growth in MWs from batteries providing tendered frequency services, with this asset type now making up the vast majority of the MWs provided by frequency services procured through competitive tendering. Static FRR has seen the generation mix diversify further since moving to day-ahead procurement with increased DER, Domestic and Battery assets now regularly participating in the service.

Reserve

Procurement volumes and technology mix in Q1 remain consistent with historical STOR data, building upon the introduction of EV charging within the service in the previous quarter, we continue to see expansion with this type of asset with a view of including NHH settled MPANs in the future, another milestone for the legacy service.

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 (now called Network Services Procurement – NSP) has seen the delivery of a new shunt reactor service that went live in Q1 2022-23 which 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 2025-26. Additionally, NGET are providing three reactors under the Pennines tender. Two of these are now live and delivering. The final one is due to go live in Q2 2024/25.

Constraints

Constraint costs occur when we pay 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 and EC5 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 and implemented in April 2023. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) were forecast for the year ahead, and two 6-month tariffs were set to cover the 2023/24 charging year.

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

June 2024-25 performance

Figure: 2024-25 Monthly BSUoS forecasting performance (Absolute Percentage Error)

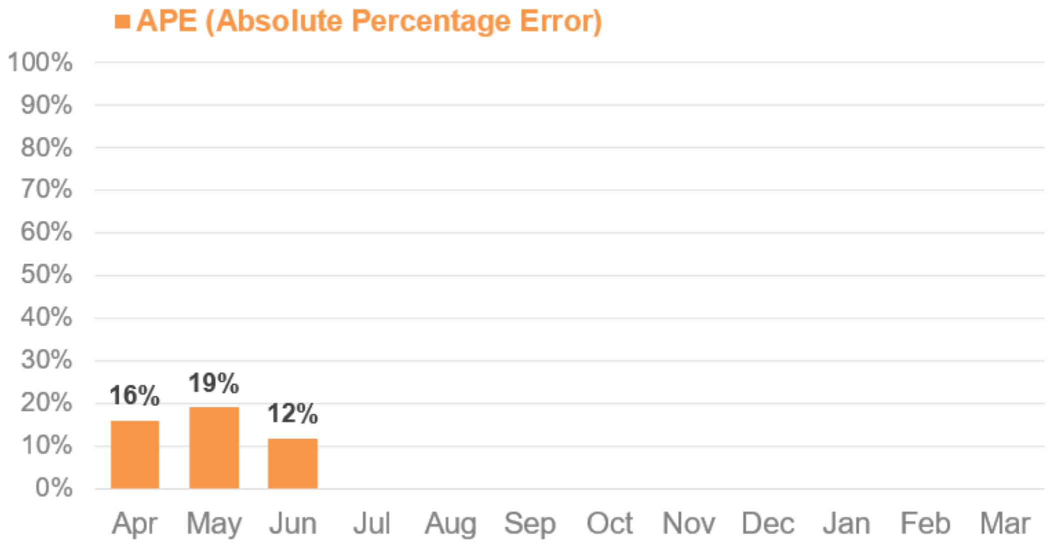


Table: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[6] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	11.5	8.5	12.7									
Month-ahead forecast (£ / MWh)	9.7	10.2	11.2									
APE (Absolute Percentage Error)[7]	**16.0**	**19.0**	**11.8**									

[7] 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 above forecast for June, with an Absolute Percentage Error of 11.8%. Costs were above forecast. A data error with the forecast June volume has also been identified, which resulted in an over-forecast of volume.

Costs:

June outturn costs were around the 60th percentile of the forecast produced at the beginning of May, primarily driven by constraint costs out turning 22% above forecast. Wholesale electricity prices for June were also higher than forecast, out turning at an average £77/MWh against the forecast £65/MWh.

Volumes:

A data error was identified by us in the volumes used in the June forecast. June forecast volume as published on the 15 May 2024 was 20.7TWh; a new version was published on the 16 July 2024 to show the corrected volume forecast of 19.5TWh. We are taking additional steps going forward to prevent similar errors from occurring in future publications.

Forecast for June made at the start of May: 20.7

Corrected forecast for June: 19.5

June Outturn: 19.5

Notable events during June 2024

Early View of Winter Outlook

On 6 June we published our Early View of Winter and Winter Review and Consultation documents. The Early View contains our initial assessment of the energy security of supply outlook for the coming winter. We provide early visibility of this analysis to give energy industry participants time to prepare for the coming winter.

The Early View assesses the ability of de-rated capacity to meet average peak demand during a cold spell, with an associated assessment of the Reliability Standard to be maintained. Our analysis shows that the margin under our base case is 5.6GW (9.4%), higher than the 4.4GW (7.4%) published in the Winter Outlook for 2023/24. The associated Loss of Load Expectation (LOLE) is below 0.1 hours which is within the Reliability Standard. It also includes an early indication of where the tightest periods are most likely to occur through the publication of an operational surplus time-series. Our analysis shows sufficient operational surplus throughout winter, though there may still be some tight days where we need to use our standard tools including the use of system notices. Alongside these two key measures we provide our current assessment of global energy markets, potential market risks and the resilience of interconnected markets. We assess global markets to be showing signs of stability and finding a new equilibrium but recognise that uncertainties remain. We continue to work closely with Government, Ofgem and National Gas to establish necessary actions and continue close and active engagement with neighbouring transmissions system operators to identify risks.

We publish a Winter Review and Consultation to help inform industry of the operational experience of last winter. We review our analysis and reflect on last winter, informing industry of any lessons, in preparation for the winter ahead.

Response and Reserve consultations

On the 27 June we published our BM Quick Reserve (QR) consultation and our Dynamic Response products (DM/DC/DR) consultation. The DM/DC/DR product terms have undergone revision and change based on requirements from the ESO and others developed with engagement with our stakeholders. The QR consultation is the first consultation for our new reserve services which will all be developed and implemented by Autumn 2025. QR will be procured for both positive and negative volumes (ie generation and demand turn up and turn down) with an expected full delivery in one minute. It will be implemented for BM providers first, aligning with our strategic delivery roadmap and realising consumer benefits.

The consultations will close on the 29 July 2024 and following a review of responses will be sent to Ofgem for their ultimate approval.

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 has been running, we have been reporting:

- 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 9 months, after counter signature of the step one offer; and
    - the number of any connection offers that took longer than the above timeframes.

The two-step process concluded on 31 May 2024 and therefore reporting on the two-step offer process will not run past the end of Q1 in Year 2 (2024-25).

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: Quarterly connection offers by time taken

Area	Connection offers issued:	Q1	Q2	Q3	Q4	Total
NGET (England and Wales)	(Standard offer) Within 3 months	157				
	(One-step) Within 3 months	-				
	(Two-step) Within 9 months*	335				
	Longer than the above timeframes	115				
	Total	607				
SPT (Scotland)	(Standard offer) Within 3 months	54				
	Longer than 3 months	2				
	Total	56				
SHET (Scotland)	(Standard offer) Within 3 months	93				
	Longer than 3 months	12				
	Total	105				
TOTAL	Within 3 months / 9 months*	**639**				
	Longer than 3 months	**129**				
	Total	768				

* after counter-signature of the step one offer

Figure: Connections queue in MW split by time from offer acceptance to connection: Q1 (30 June 2024) vs Q2 (30 Sep 2024) vs Q3 (31 December 2024 vs Q4 (31 March 2025)

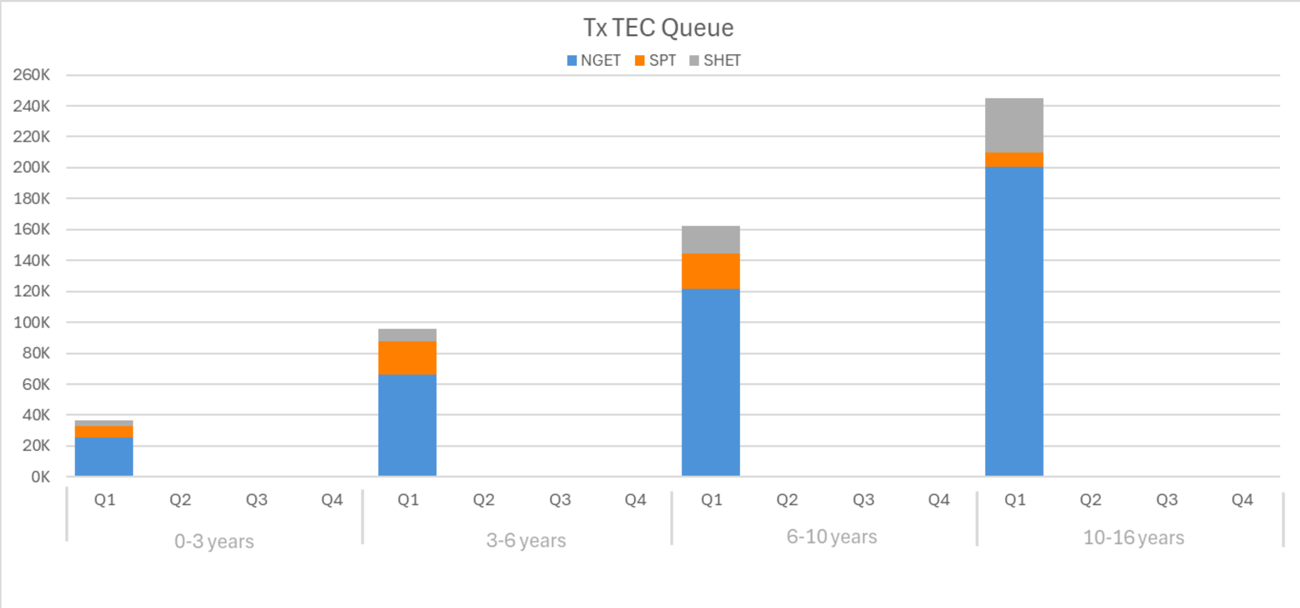


Table: Connections queue in MW split by time from offer acceptance to connection

Host TO	Unit	0-3 years	3-6 Years	6-10 Years	10-16 Years	Total*
NGET	MW	25,284	66,022	121,895	200,486	**413,686**
SPT	MW	7,556	21,737	22,305	9,527	**61,125**
SHET	MW	3,818	7,836	18,127	34,856	**64,637**
Total*	MW	**36,658**	**95,594**	**162,328**	**244,868**	**539,448**

*Timescale MW values are rounded up in this table but Totals are reflective of the unrounded base figures and therefore might appear slightly lower than the sum of the columns or rows.

Figure: Connections queue in MW by technology type (30 June 2024)

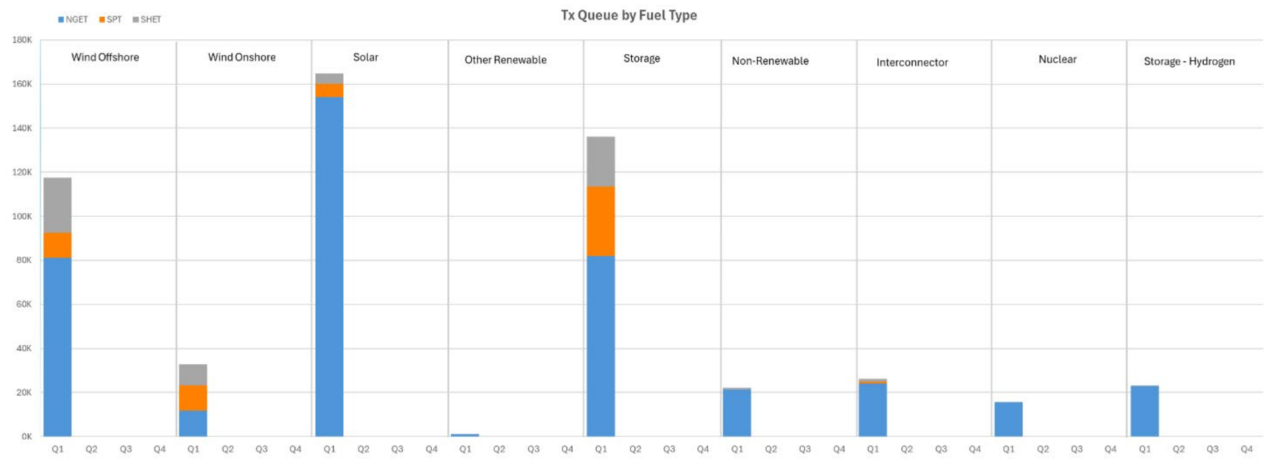


Figure: Connections queue in MW by technology type (30 June 2024)

Host TO	NGET	SPT	SHET	Total*
Wind Offshore	81,146	11,356	24,968	**117,470**
Wind Onshore	11,803	11,320	9,735	**32,857**
Solar	154,015	6,069	4,688	**164,772**
Other Renewables	904	-	327	**1,231**
Storage	81,860	31,681	22,607	**136,147**
Non-Renewable	21,263	-	910	**22,173**
Interconnector	24,083	730	1,400	**26,183**
Nuclear	15,620	-	-	**15,620**
Storage - Hydrogen	22,992	-	2	**22,994**
TOTAL*	**413,686**	**61,126**	**64,637**	**539,447**

*Technology Type MW values are rounded up in this table but Totals are reflective of the unrounded base figures and therefore might appear slightly lower than the sum of the columns or rows.

Supporting information

Timeliness of connection offers

Application volumes continue to increase in comparison with 2023-24 and this is reflected in the number of offers being sent out across all three TOs.

50 Standard Offers and 79 2nd Step Offers were covered by the extension granted by Ofgem for all Offers received between 27th November 2023 and 29 February 2024 being sent outside of standard time scales.

Connections queue

The Connections queue continues to increase, moving from 534GW at the end of Q4 2023-24 to 547GW at the end of the Q1. The vast majority of this increase is due to new connection applications from battery storage developers. A large increase in connection dates for the 6-10 year and 10-16 year periods can be seen, which is in line with average connection timescales of 10 years in E&W and 7 years in Scotland.

CUSC modification CMP376 (Inclusion of Queue Management process within the CUSC) was approved and implemented in November 2023. This introduces queue management milestones into connection contracts and allows the ESO to terminate contracted projects which are not progressing against agreed milestones. This is a significant step towards being able to reduce the size of the overall queue and remove stalled projects. Our connections reform proposals (to go live from January 2025) will go further and faster towards reducing the overall queue by removing stalled projects.

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.

The two-step process concluded on 31st May 2024, however as Right First Time reporting is measured on when the offer was signed, we are likely to see 2nd Step offers reflected in this table until the end of Q3.

Table: 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	0				
	Percentage right first time	**0%**				
	Total Full / Step 2 offers signed	86				
	Number right first time	75				
	Percentage right first time	**94%**				
SPT	Total connection offers signed	54				
	Number right first time	44				
	Percentage right first time	**93%**				
SHET	Total connection offers signed	68				
	Number right first time	52				
	Percentage right first time	**90%**				
TOTAL	Total connection offers signed	209				
	Number right first time	172				
	Percentage right first time	**92%**				

Table: Connection offer that needed reissuing by reason

Area	**One-step** connection offers	Q1	Q2	Q3	Q4	Total
NGET	Customer driven	5				
	ESO driven	5				
	TO driven	2				
	Total	**11***				
SPT	Customer driven	6				
	ESO driven	4				
	TO driven	4				
	Total	**10***				
SHET	Customer driven	7				
	ESO driven	8				
	TO driven	2				
	Total	**16***				
TOTAL	Customer driven	19				
	ESO driven	16				
	TO driven	8				
	Total	**37***				

* 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, with ESO driven re-offers accounting for just under half of the re-offers issued.

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.

Overall performance for the first quarter of this year at 92% right first time is similar to the same period last year which was 93%.

Notable events during June 2024

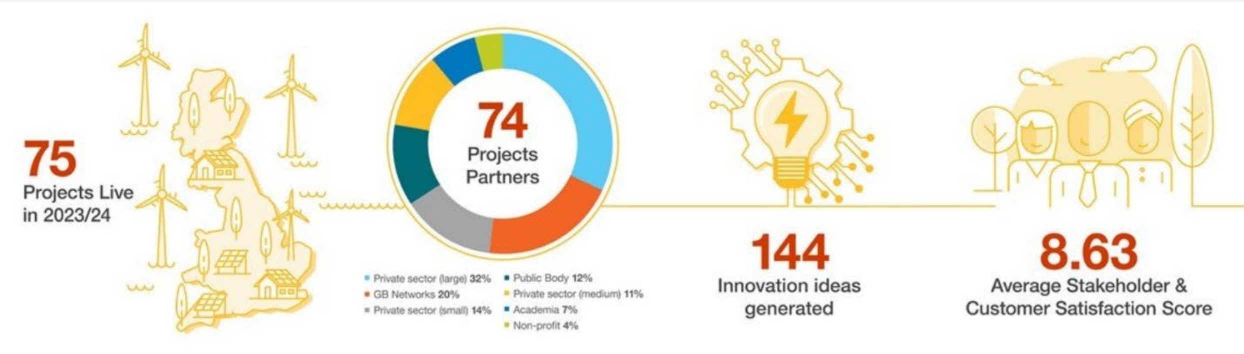
Publication of our Innovation Annual Summary 2023/24

In June, we announced the publication of our Innovation Annual Summary 2023/24. Innovation, and the new solutions and technologies it generates, is playing an important role in shaping the ESO and energy landscape of the future. The summary includes our performance, key activities and project case studies from the past year.

We have grown our capabilities, and our team, making full use of the Network Innovation Allowance (NIA) and Strategic Innovation Fund (SIF) to address our strategic priorities. We're demonstrating our values and accelerating progress as we have launched the highest number of innovation projects in any year to date. We've also included a section on 'What happened next' exploring some of our past and mature innovation projects and the impact they are having for us and the wider industry.

Key highlights:

- 75 live projects
- 74 project partners
- 144 innovation ideas and 33% approved
- 8.63 average stakeholder and customer satisfaction score



Some of our featured projects:

- **Dynamic Reserve Setting** – Started trialling machine learning to set reserve levels dynamically, at the day ahead stage, saving us from buying unnecessary reserve.
- **Consumer Building Blocks** – A set of industry-standard archetypes to help with our Future Energy Scenario modelling and to better understand our consumers.
- **Solar PV Nowcasting** – Used machine learning to build a tool for the ESO control room which can predict short-term solar generation more accurately, up to 36 hours ahead.
- **Powering Wales Renewably** – Setting the groundwork for a digital twin of Wales's power network to assist in future planning and operations.
- **Scenarios for Extreme Events –** Developing a tool which can simulate the impact of extreme events on the electricity and gas networks and quantify how this will affect homes, businesses and vital services.

Connections Compliance seminar – 26 June

On 26 June 2024, we hosted an insightful and engaging Connections Compliance Seminar in Glasgow. This was our first such event and it brought together over 100 compliance professionals, industry experts and business leaders to discuss the process and current challenges in the realm of grid code compliance.

We held several breakout sessions which saw participants split into smaller groups for focussed discussions, some of these included:

- Modelling – Root Mean Square (RMS) and Electromagnetic Transient (EMT) – This session covered what, how and why we are expecting model submissions and gave us the opportunity to listen to the challenges around this.
- Sub synchronous Oscillations and Grid Forming – This breakout session covered events around the oscillation incidents in 2023 and gave ESO the opportunity to share learning with the industry.
- Compliance Conversations – Here we covered the overall compliance process and listened to the challenges around this and how we can further improve.

The seminar concluded with a dynamic Q and A panel featuring the day's speakers. Attendees had the chance to pose their questions, seek clarification and gain deeper insights into the topics discussed throughout the day. The event received positive feedback from delegates with an average score of 8.6 out of 10.

In the days that followed, attendees received an FAQ document to address questions and any additional information to support their ongoing compliance efforts. We look forward to hosting future events and collaborating with customers to enhance their compliance journey.