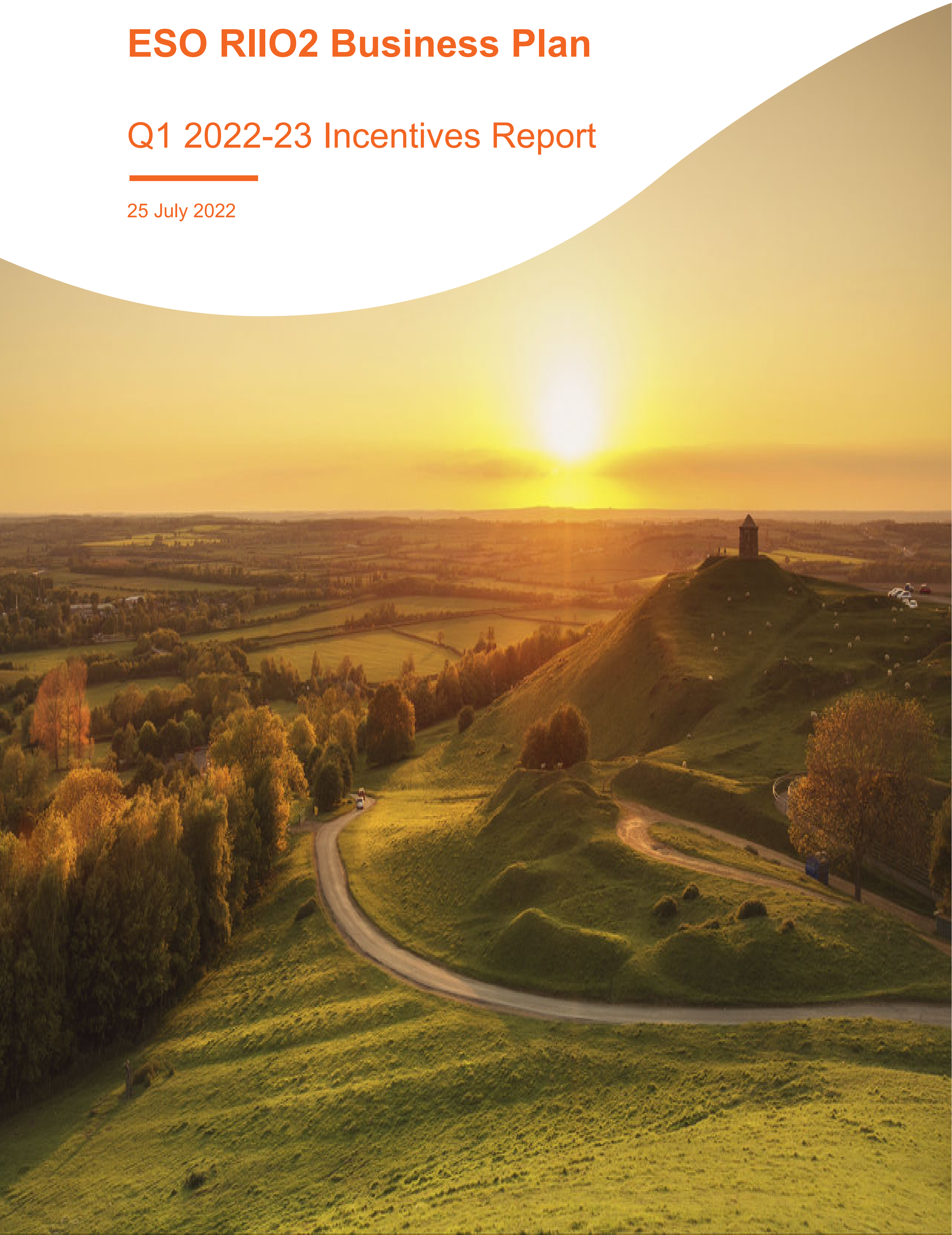
ESO RIIO2 Business Plan

Q1 2022-23 Incentives Report

25 July 2022



Contents

Introduction

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

The ESO's Delivery Schedule sets out in more detail what the ESO will deliver, along with associated milestones and outputs, for the "Business Plan 1" period, which runs from 1 April 2021 to 31 March 2023.

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

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

Every quarter, we report on a larger set of performance measures, and also provide an update on our progress against our Delivery Schedule in the RIIO-2 deliverables tracker.

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

Please see our website for more information.

Summary

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

- In June we launched the next set of tenders for new service provisions for Electricity System Restoration (ESR).
- Changes to the Balancing Mechanism (BM) have been successfully implemented through Release 1 in May and June
- Applications for the Transmission Network Use of System (TNUoS) Task Force closed on 21 June 2022. The ESO and Ofgem then reviewed these via a collaborative assessment process.
- The ESO worked with NGET to develop proposals for Grid Code modification GC083 which has gone to consultation in June, and GC084 which will now be further refined in an industry workgroup.
- We published the Winter Review and Consultation 2022 in June, providing a review of our 2021/22 Winter Outlook Report.
- Our Bridging the Gap flexibility tracker was published in June. This tracker has been developed to monitor progress against the key actions for the 2025 flexibility milestones.
- We have been working with NGET and UK Power Networks on a Regional Development Programme covering the East Anglia region. In June, we reached a conclusion for Burwell Grid Supply Point (GSP) and re-offered a connection agreement to UKPN to capture that solution.

These are some of the highlights that we have successfully delivered earlier in Q1:

- During April and May 2022, we completed a series of engagements with the industry, looking at co-creating a roadmap for our Balancing Programme.
- In May we announced that a successful trial, part of the three-year Ofgem-funded Distributed ReStart project in South-west Scotland, saw a hydro generator connected to the distribution network, self-start and power the local transmission and distribution network.
- GE Digital has developed a solution for the ESO which provides real-time monitoring and day-ahead inertia forecasting. Reactive Technologies (RT) has also developed a solution for us which provides GB-wide, real-time inertia monitoring.
- In April we shared a summary of our proposed product and service design for two new Reserve products: Negative Slow Reserve (NSR) and Positive Slow Reserve (PSR).
- Our new frequency response service Dynamic Moderation has held its first auction in May, completing the full suite of the new frequency response services, alongside Dynamic Containment and Dynamic Regulation.
- During May our Net Zero Market Reform Phase 3 Assessment and Conclusions was completed, finding that the current market design, based on a blanket national wholesale price for electricity, is no longer fit for purpose for a rapidly decarbonising system.
- In April we announced our innovation strategy, which has been developed in consultation with industry and is informed by the results of our Bridging the Gap work.
- Our latest Summer Outlook report was published in April, providing a view into the season ahead.
- The first of our voltage management projects went live in May, with the Mersey Reactive Power solution installed in Frodsham, Cheshire.

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) performance for Q1 2022-23.

Table 1: Summary of Metrics

Monthly (M) and Quarterly (Q) Metrics

Metric		Performance June figure for monthly Metrics, Q1 figure for quarterly Metrics	M / Q	Status Apr	May	Jun	Q1
Metric 1A	**Balancing Costs**	June: £327m vs benchmark of £113m	M	●	●	●	●
Metric 1B	**Demand Forecasting**	June: Forecasting error of 2.2% (vs benchmark of 2.0%)	M	●	●	●	●
Metric 1C	**Wind Generation Forecasting**	June: Forecasting error of 4.1% (vs benchmark of 5.2%)	M	●	●	●	●
Metric 1D	**Short Notice Changes to Planned Outages**	June: 1.4 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	M	●	●	●	●
Metric 2A	**Competitive procurement**	Q3: 46% of services procured by competitive means (vs Year 2 benchmark of 65%-75%)	Q	n/a	n/a	n/a	●

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

Table 2: Summary of RREs

RRE		Performance June figure for monthly RREs, Q1 figure for quarterly RREs	M / Q
RRE 1E	**Transparency of Operational Decision Making**	June: 92.8% of actions taken in merit order in the BM	M
RRE 1F	**Zero Carbon Operability indicator**	Q1: the system accommodated a maximum 83.7% zero carbon transmission connected generation	Q
RRE 1G	**Carbon intensity of ESO actions**	June: 4.2gCO2/kWh of actions taken by the ESO	M
RRE 1H	**Constraints cost savings from collaboration with TOs**	Q1: £324m avoided costs	Q
RRE 1I	**Security of Supply**	June: 1 instance where frequency was more than ±0.3Hz away from 50Hz, and 0 voltage excursions	M
RRE 1J	**CNI Outages**	June: 0 planned or unplanned outages	M
RRE 2B	**Diversity of service providers**	Q1: Varying diversity of providers across the different markets	Q
RRE 2E	**Accuracy of Forecasts for Charge Setting**	June: 17% forecasting error	M

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

Gareth Davies
ESO Regulation Senior Manager

Role 1 Control Centre operations

Metric 1A Balancing cost management

Q1 2022-23 Performance

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

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

i. Using a plot of the historic monthly constraints costs (£m) against historic monthly outturn wind (TWh) from the 36 months immediately preceding the assessment year, a best fit straight-line continuous relationship is set to determine the monthly 'calculated benchmark constraints costs'.

ii. Using a plot of historic monthly total balancing costs (£m) against historic monthly constraint costs from the 36 months immediately preceding the assessment year, a best fit straight-line continuous relationship is set, with the intercept value of that straight line used to determine the monthly 'calculated benchmark non-constraints costs'.

iii. An equation for the straight-line relationship between outturn wind and total balancing costs is then formed using the outputs of point (i.) and point (ii.).

iv. The historic 3-year average outturn wind for each calendar month is used as the input to the equation in point (iii). The output is 12 ex-ante, monthly non-adjusted balancing cost benchmark values. The sum of these monthly values is the initial 'non-adjusted annual balancing cost benchmark'. The purpose of this initial benchmark is illustrative as it will be adjusted each month throughout the year.

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

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

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

Updated benchmark for 2022-23: The benchmark for this metric has been updated for the period April 2022 to March 2023 in line with ESORI guidelines, and the figures have been confirmed by Ofgem.

Figure 1: Monthly balancing cost outturn versus benchmark (£m) – two-year view

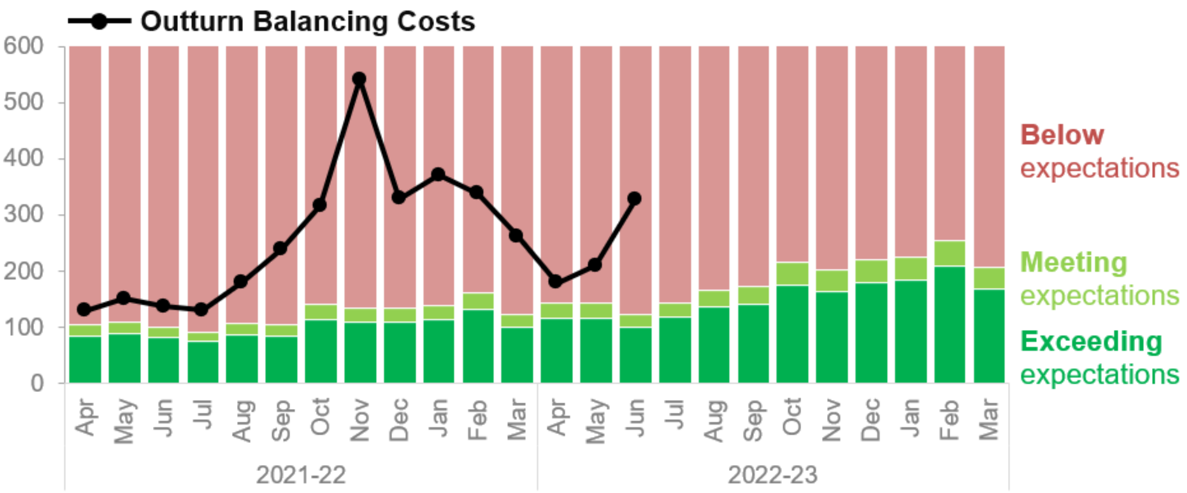


Table 3: 2022-23 Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	YTD
Benchmark: non-constraint costs (A)	50	50	50	50	50	50	151
Indicative benchmark: constraint costs (B)	97	89	90	81	101	107	276
Indicative benchmark: total costs (C=A+B)	147	139	140	132	152	158	427
Outturn wind (TWh)	3.8	3.8	3.1				10.7
Ex-post benchmark: constraint costs (D)	80	80	62				222
Ex-post benchmark (A+D)	130	130	113				374
Outturn balancing costs[1]	186	211	327				724
Status	●	●	●				●

Rounding: monthly figures are rounded to the nearest whole number, with the exception of outturn wind. Small variances in totals may arise as a result.

Performance benchmarks[2]

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

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

Supporting information

Data issue: Please note that due to a data issue on a few days over the last three months, the **Minor Components** line in Non-Constraint Costs is capturing some costs on those days which should be attributed to the Constraints Costs lines. This data issue is under investigation and although the categorisation of costs is not correct, we are confident that the total costs are correct in all months.

June performance

The Balancing costs for June 2022 were close to £327m, showing an increase from the previous month of slightly over £116m.

Both constraint and non-constraint costs have increased from the previous month and remain higher than June last year.

Persistent high gas prices are the key factors responsible for continued high prices compared to last year for Energy Imbalance, Operating Reserve, STOR, Response and Reactive. This resulted in significantly higher non-constraint costs despite a substantial decrease in the volume of related actions.

The significant constraint cost increase from last year is the result of continued very high wholesale prices. This in turn increases the cost of the Balancing Mechanism (BM) actions we are required to take in order to reduce generation behind constraints and replace it with alternative generation. This is particularly the case at times of high wind and reduced boundary capability due to system outages.

Q1 performance

The total balancing costs for April to June 2022 (£724m) were significantly higher than the outturn in Q1 last year (£420m). Balancing costs increased from April to May and showed a sharp increase between May and June.

Both overall constraint and non-constraint costs were higher than those for the same period of the previous financial year, with constraint costs showing a significant increment from the previous financial year in June.

The increase in non-constraint costs compared with the same period last year was the result of scarcity pricing, and high gas prices driving up prices for Operating Reserve, Response and Reactive.

Response costs are higher than last year due to the increased response requirements as a result of having access to fast acting response product Dynamic Containment to manage the change in approach to managing loss risks on the system, due to the implementation of the FRCR. Holding additional response reduces alternative actions to ensure system security e,g, RoCoF constraint actions which came to £15m in Q1 this year compared to £68m in Q1 last year.

The constraint costs increase compared with last year, particularly in June, was the result of continued very high wholesale prices, combined with higher wind levels and reduced boundary capability due to system outages. This required us to take a large volume of Balancing Mechanism (BM) actions to reduce generation behind constraints and replace it with alternative generation.

Breakdown of costs vs previous month

Balancing Costs variance (£m): June 2022 vs May 2022

		(a) May-22	(b) Jun-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	8.1	23.2	15.1	
	Operating Reserve	14.4	24.8	10.5	
	STOR	6.3	5.4	(0.9)	
	Negative Reserve	0.4	0.5	0.1	
	Fast Reserve	17.8	15.7	(2.0)	
	Response	31.5	41.3	9.8	
	Other Reserve	1.8	1.5	(0.3)	
	Reactive	23.7	17.0	(6.7)	
	Restoration	2.9	6.6	3.7	
	Minor Components	18.0	10.3	(7.7)	
Constraint Costs	Constraints - E&W	16.0	54.6	38.6	
	Constraints - Cheviot	8.8	30.6	21.7	
	Constraints - Scotland	33.7	45.3	11.6	
	Constraints - Ancillary	3.5	3.3	(0.1)	
	ROCOF	1.6	2.8	1.2	
	Constraints Sterilised HR	22.1	43.9	21.8	
Totals	Non-Constraint Costs - TOTAL	124.9	146.3	21.4	
	Constraint Costs - TOTAL	85.7	180.5	94.8	
	Total Balancing Costs	**210.6**	**326.8**	**116.2**	

As shown in the total rows above, this month's significant increase in costs came in both constraint and non-constraint costs which increased by £94.8m and £21.4m respectively.

For constraint costs, the breakdown shows that Constraint-Cheviot, Constraint-Scotland, Constraint-E&W and Constraint Sterilized Headroom and were the main cost increases.

For non-constraint costs, the main increases were in Operating Reserve, Energy Imbalance and Response.

The main drivers of the biggest constraint cost variances this month are detailed below:

- **Constraint-E&W: £38.6m increase.** A change in the outage pattern and generation pattern meant that more BM actions were needed to reduce generation in order to manage thermal constraint in England and Wales. Friday 10 June was the most expensive day for this category with a spend of nearly £14m.
- **Constraint-Cheviot: £21.7m increase.** The cost increase was driven by an increase in the volume of BM actions to manage power flow restrictions on the Scotland-England network boundary to solve thermal constraints. Saturday 11 June and Sunday 12 June were the most expensive days, with a daily cost of around £18m and £13m respectively.
- **Constraint Sterilized HR: £21.8m increase.** This is a cost associated with constraints. The significant increase is a result of reduced boundary capability (due to system outages), high wind levels and a resultant need to increase the generation constrained off behind a constraint. Headroom that was available on the constrained generation had to be replaced through actions in the BM, which are high cost actions.
- **Constraint-Scotland: £11.6m increase.** This increase was driven by an increase in the volume of BM actions to manage power flow restrictions in Scotland. Saturday 18 June and Sunday 19 June were the most expensive days for this category, with a daily spend of around £14m and £10m respectively.

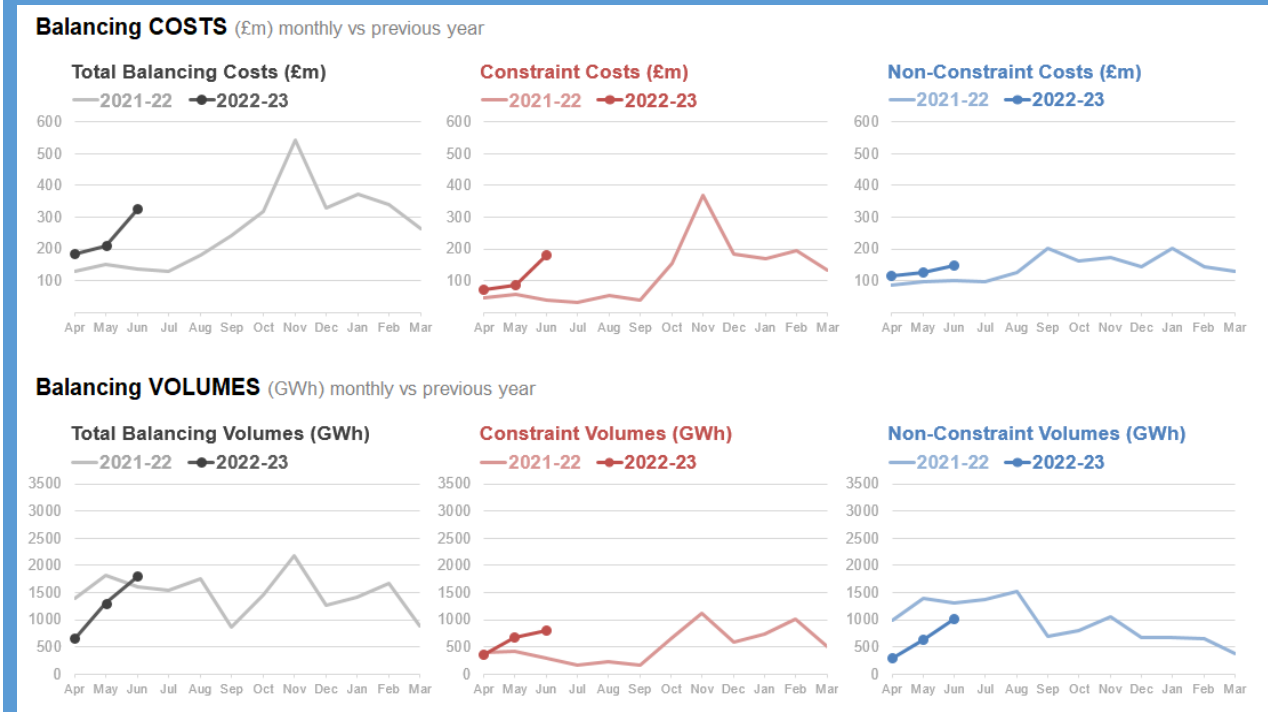
The main drivers of the biggest non-constraint cost variances this month are detailed below:

- **Energy Imbalance: £15.1m increase.** The market was mostly short in June 2022, whilst in May 2022 the market was mostly long.

- **Operating Reserve: £10.5m increase.** Larger volumes of Operating Reserve procured than in May 2022.

Constraint Costs vs Non-Constraint Costs

Restoration: Please note that the 2020-21 incentivised balancing cost figures did not include costs for restoration, but from April 2021 these are included. To enable a direct comparison, in the graphs below these restoration costs are included for both 2021-22 and 2022-23.



Please note that a portion of the Minor Components spend contributing to Non-Constraint Cost and Volume is actually Constraint Cost and Volume. The narrative below discusses the broad themes of spend, the figures will change once the data issue is resolved.

Constraint Costs

Compared with the same month of the previous year:

Constraint costs were £142m higher than in June 2021 due to

- The ongoing higher wholesale prices compared with last year, as well as he increased cost of actions to manage thermal constraints and network congestion during high wind periods, and the higher volume of actions which is in line with a higher wind generation level.

Compared with the previous month:

Constraint costs were £95m higher than in May 2022 due to:

- The increase in the volume of BM actions to reduce generation in order to manage thermal constraints. This is driven by a significant number of new outages.

Non-Constraint Costs

Compared with the same month last year:

Non-Constraint costs were £47m higher than in June 2021 due to:

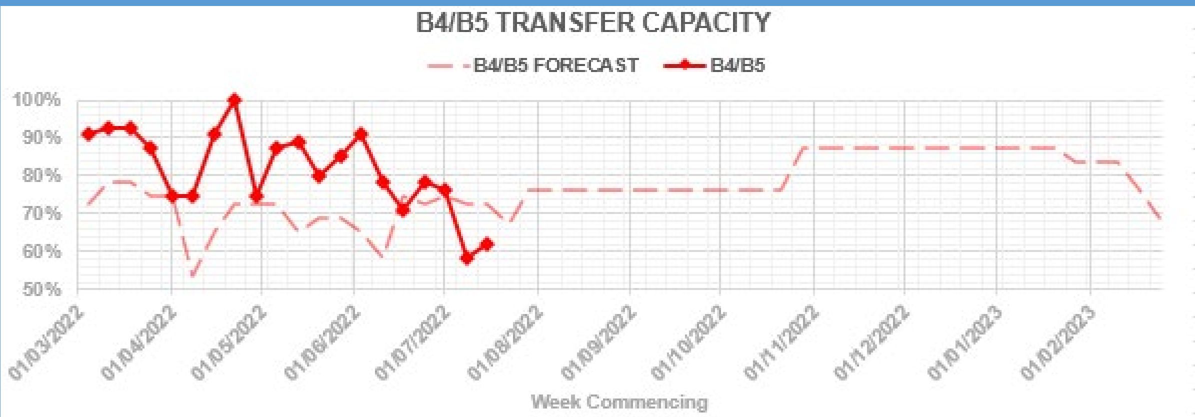
- The higher price of actions taken to manage the system. Particularly the price of offers in the BM which are higher due to increased wholesale costs. The volume of actions was lower than the previous year and this shows that it is the cost of the actions required rather than the volume which is driving the overall non-constraint cost.

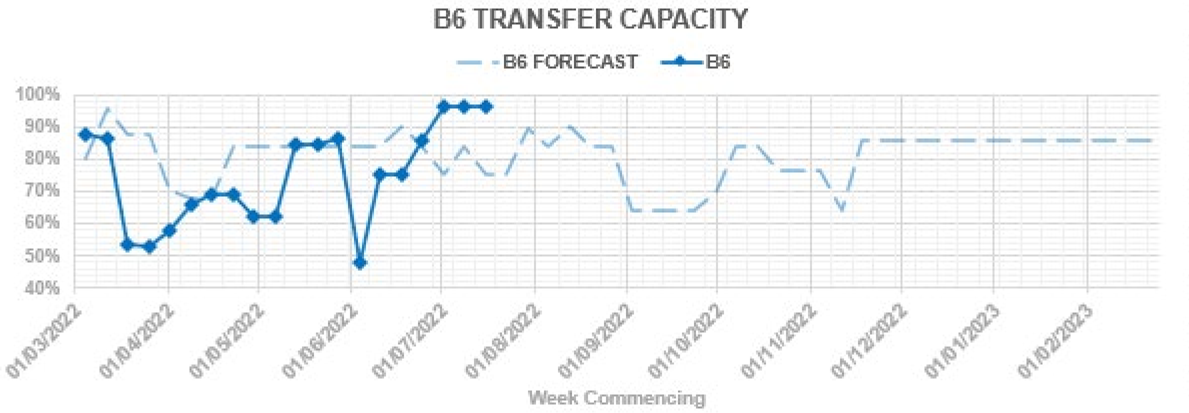
Compared with the previous month:

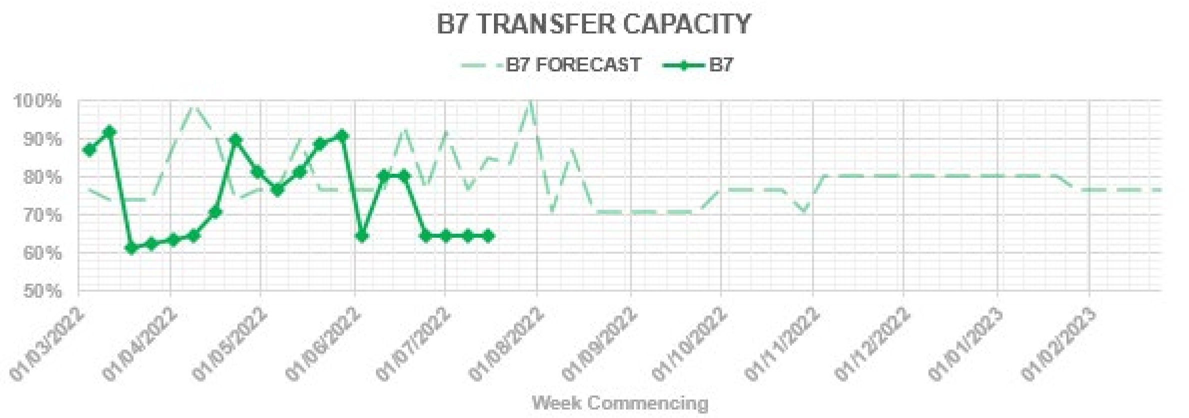
Non-Constraint costs were £21m higher than in May 2022 due to:

- Increased costs in Operating Reserve due to larger volume of Operating Reserve procured.
- Increased costs in Energy Imbalance due to the mostly short market in June 2022, compared to a mostly long market in June 2021.

Network availability 2022-23

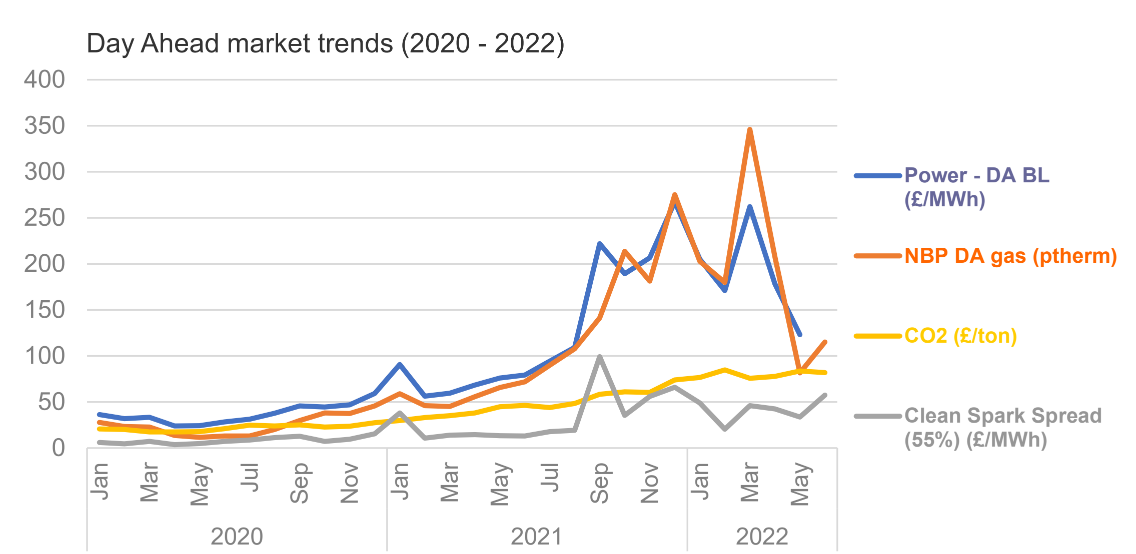






Please note that transfer capacity is discussed in more detail at each week's Operational Transparency Forum. Details of how to sign up, and recordings of previous meetings are available here.

Changes in energy balancing costs



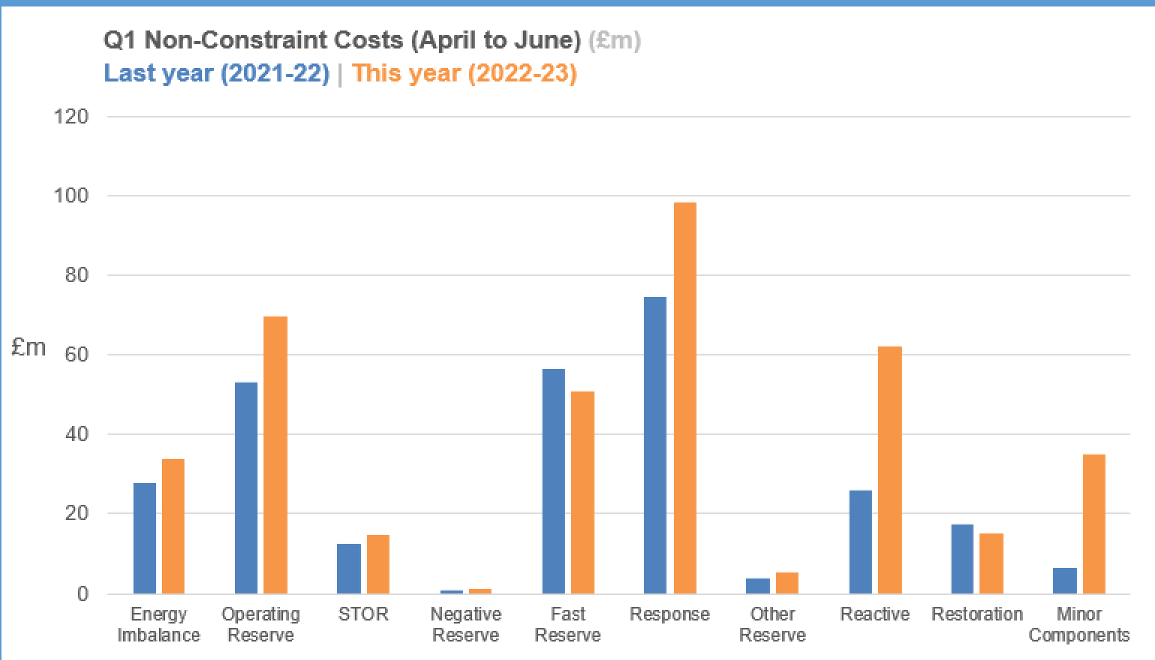
DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Power DA BL prices data is currently unavailable for June. We will update this when it becomes available.

The day ahead gas prices have increased compared with May, but remain much lower than they were for most of 2021/22. Carbon prices showed little variation from previous month and remain very high compared to the previous years. Clean Spark Spread prices have increased slightly this month.

These continued higher prices impact on both the buy (offer) and sell (bid) actions available to the ESO to manage our operability requirements. This demonstrates some of the external drivers of the underlying high prices available to ESO for balancing actions.

Cost trends vs seasonal norms



Comparing the Q1 (April 2022 - June 2022) non-constraint costs with those of the same period last year, we can see that there has been a rise in Energy Imbalance, Operating Reserve, Response and Reactive. The other categories either decreased or showed little variance.

- **Response** costs are £23.5m higher. With the introduction of the Dynamic Containment service this continues to be higher spend than the previous year but offsets some costs in other categories.
- **Operating Reserve** costs are £16.5m higher. High wholesale market prices leading to high cost of BM actions is the main driver behind the cost increase.
- **Reactive** costs are £36.3m higher. As the volume of actions taken is in line with seasonal norms, the increase in spend is driven by the increased cost of the actions taken and is therefore related to the continued high wholesale market prices.
- **Minor Components** appear higher than Q1 last year, however this is impacted by the data issue which we highlighted at the start of this section.

Drivers for unexpected cost increases/decreases

Margin prices (the amount paid for a single MWh) have increased since May and remain high when compared to last year. The margin prices for Q1 as a whole are also higher than the same period last year. This is due to the higher prices offered for actions required to be taken.

Daily costs trends

The monthly balancing costs in June outturned at £327m showing an increase from May of over £116m.

Throughout the month there were 16 days when the spend was around or above £10m, of which four days recorded a daily spend above £20m. The most expensive days were Saturday 11 June and Sunday 12 June, with a daily spend of £28m and £21m respectively, and Saturday 18 June and Sunday 19 June with a daily spend of £25m and £20m respectively.

Additionally, between Thursday 21 June and the last day of the month, the daily costs remained consistently around or above £10m. Periods of windy weather and a significant number of new outages requiring a larger volume of BM actions to reduce generation to manage thermal constraints were the main driver behind these expensive days. When a bid is taken to resolve a constraint, the energy on the system must then be replaced. When a large volume of BM bids are required to manage the flow on a boundary to below the constraint limit, that volume of energy needs to be procured in the BM to rebalance. The cost of the replacement energy is significantly higher than in previous years due to the ongoing high wholesale market prices.

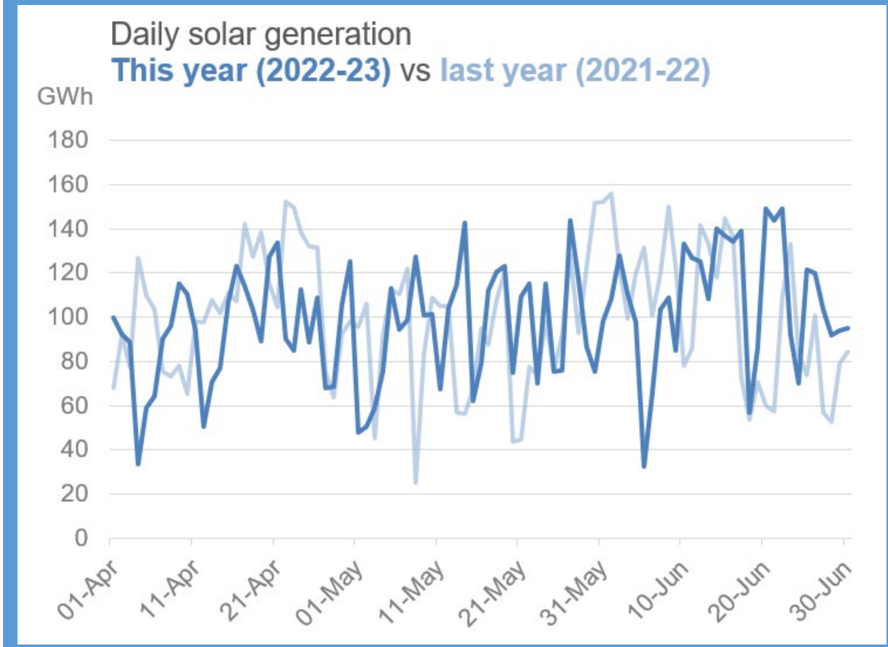
High-cost days and balancing cost trends are discussed every week at the Operational Transparency Forum to give ongoing visibility of the operability challenges and the associated ESO control room actions.

There has been a significant number of new outages which has led to an increase in BM actions needed to curtail generation to manage thermal constraints arising as a result.

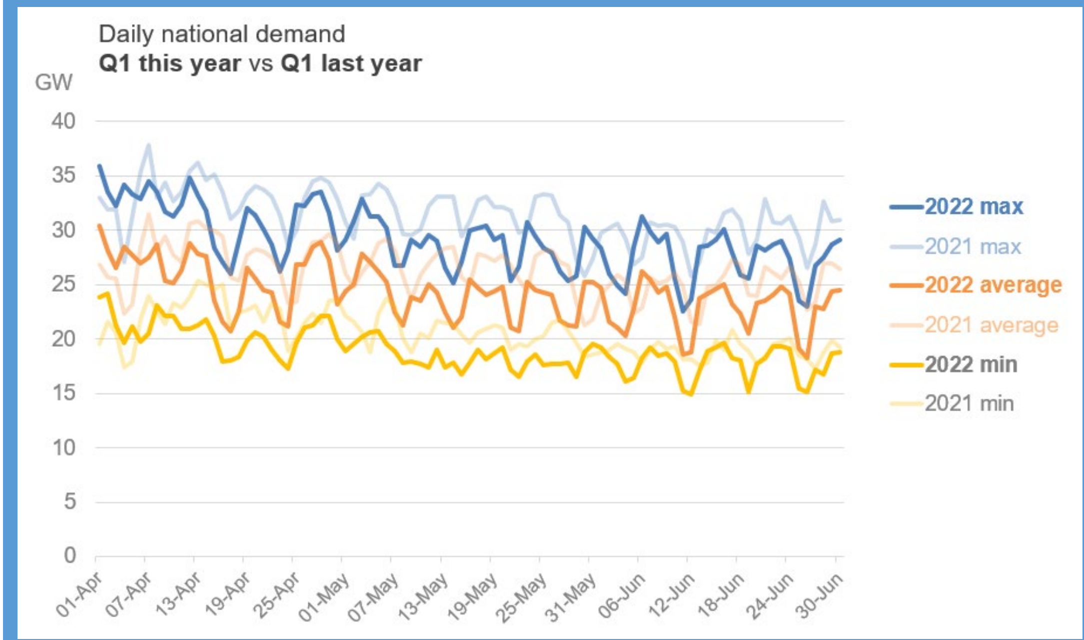
Significant events

There were no significant events during June.

Solar generation - comparison of Q1 this year vs Q1 last year



Q1 Outturn Demand vs Q1 2021-22



Metric 1B Demand forecasting accuracy

Q1 2022-23 Performance

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

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

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

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

Compared with 2020-21's reporting, there are two differences in relation to metric 1B. The first one is that the performance is reported as the mean absolute percentage error (APE) rather than mean average error expressed in MW. The second difference is that the accuracy is measured for each Settlement Period, rather than each Cardinal Point.

Updated benchmark for 2022-23: The benchmark for this metric has been updated for the period April 2022 to March 2023 in line with ESORI guidelines, and the figures have been confirmed by Ofgem.

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

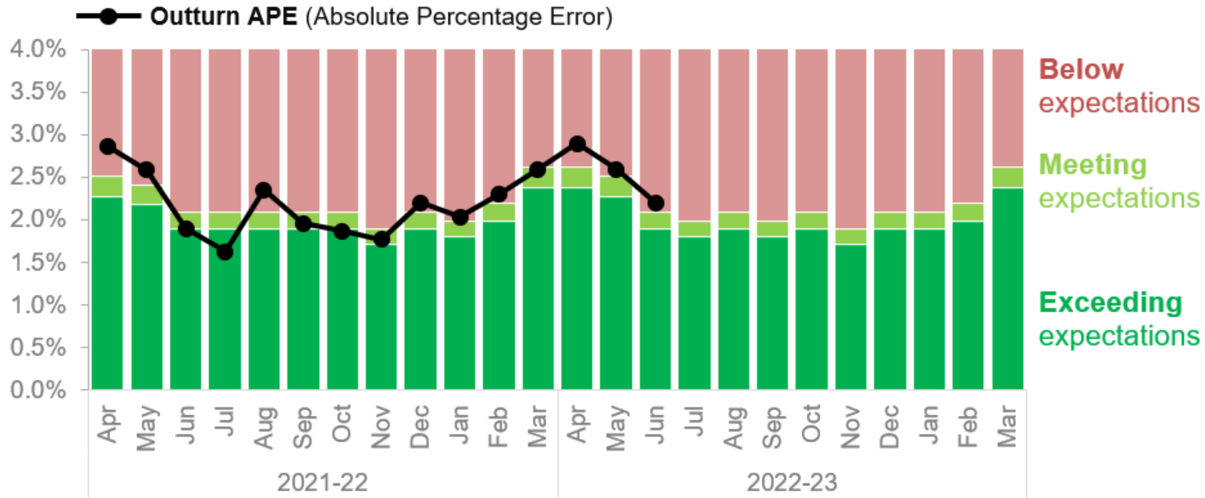


Table 4: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Indicative benchmark (%)	2.5	2.4	2.0	1.9	2.0	1.9	2.0	1.8	2.0	2.0	2.1	2.5	**2.1**
APE (%)	**2.8**	**2.6**	**2.2**										
Status	●	●	●										

Performance benchmarks

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

Supporting information

For **June 2022**, our MAPE (mean absolute percentage error) was 2.2% compared to the benchmark of 2.0%, and therefore below expectations.

The biggest challenges in June 2022 were the extreme temperatures that occurred in mid-June and the special extended bank holiday for the Queen's Platinum Jubilee. The last time that the late May bank holiday was moved to June was in 2012 which does not reflect the current demand behaviour. Therefore, it was difficult to find a good profile date for use.

Furthermore, solar generation forecasting inaccuracies and the extreme temperatures that occurred on 16 June and 17 June increased the uncertainty of the demand forecasting performance.

The biggest inaccuracies at the day ahead forecasting horizon were mostly observed between the settlement periods of SP20 and SP31 on 5, 21, 17, 19 and 6 June.

The monthly indicative performance by settlement period has been calculated for June 2022 and shown in the below table. 12% of the total settlement periods (1440) in June had an error greater than 1000MW and 1% had an error greater than 2500MW.

Error greater than	Number of SPs	% out of the SPs in the month (1440)
1000 MW	167	12%
1500 MW	57	4%
2000 MW	30	2%
2500 MW	11	1%

New solar forecasting model

We have developed a new solar forecasting model to improve our solar forecasting, and this is now being run in parallel to the existing model. The new model makes use of Grid Supply Point (GSP) level solar photovoltaics (PV) data provided by Sheffield Solar, and forecasts regional solar outturn which is then aggregated to national level. This differs from the current model, which does not use the GSP resolution data. In the autumn, we will have collected enough data to be able to make a reliable statistical comparison of the performance of the two models. At this point we would be able to assess which approach yields better results and decide which solar forecasting model to use moving forward.

Sheffield Solar are based at the University Of Sheffield. We have been working with them since 2015 on a variety on Network Innovation Allowance (NIA) funded projects to help us get a better understanding of the solar PV output in Great Britain.

Other upcoming forecasting improvements

We expect to see further improvements to our forecasting in the coming months as we increase the amount of weather data used as inputs to our models. From October, a significantly increased number of forecast locations will be used. This will provide additional weather information in areas with high concentrations of solar PV capacity, areas with high population density, and an expanded number of wind farm locations.

Associated improvements in forecast accuracy will be assessed in early 2023, by which time there should be sufficient data to make a reliable statistical assessment.

In June 2022 there were no instances of missed or late publication of national demand forecast data.

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

Metric 1C Wind forecasting accuracy

Q1 2022-23 Performance

This metric measures the average absolute percentage error (APE) between day-ahead forecast and outturn wind generation for each half hour period as a percentage of capacity for BM wind units only. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

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

Updated benchmark for 2022-23: The benchmark for this metric has been updated for the period April 2022 to March 2023 in line with ESORI guidelines, and the figures have been confirmed by Ofgem.

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

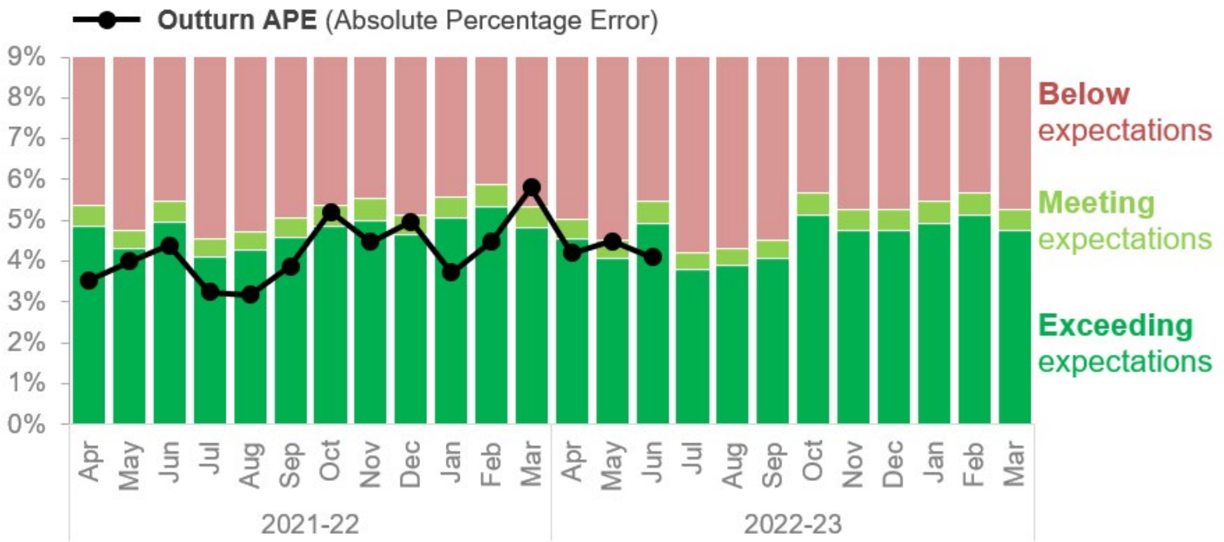


Table 5: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2022-23)

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

Performance benchmarks

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

Supporting information

For **June 2022**, our MAPE (mean absolute percentage error) was 4.1% compared to the benchmark of 5.2% and therefore exceeds expectations.

The month started off with areas of low pressure drifting in from the northwest of England and Wales, developing into the frontal system which saw heavy and thundery rain drift into the central and northern regions of England, bringing strong upper winds with it, by 5 June. Whilst rain does not affect wind power it is normally a good indicator of atmospheric turbulence which can make forecasting more difficult. Western regions of England and Wales experienced heavy rain up to 9 June due to remnants of the ex-Tropical Storm Alex. Throughout the middle of the month the country experienced periods of high pressure, bringing calmer, more consistent low wind speeds, which are easier to forecast.

Significant lightning activity was a factor for 11 of the 30 days in June. Most notably on: 4 June in southwest England, 18 June in southern England and Wales, and 29 June in the central midlands region of England. Lightning is a good indication of atmospheric stability which can be difficult to forecast, commonly leading to greater wind power forecast error.

Given the significant weather events that saw low pressure systems, thunderstorms, and lightning move over Britain early in the month, we would usually expect greater wind generation forecast error. Despite this, consistently low wind speeds later in the month, in addition to the continued effective use of our models, saw wind forecasting accuracy for June exceed expectations.

Wind farms with Contracts For Difference (CFD) arrangements switch off for commercial reasons when prices are negative for 6 hours or more. In June there were no occasions when the electricity price went negative for 6 hours or more. The electricity price used for this analysis is the Intermittent Market Reference Price. Market Price Data for June can be downloaded from here.

The weather information we used came from the following sources:
- https://www.metcheck.com/WEATHER/live_discussion_archive.asp#
- https://zoom.earth/#view=52.8,-15,4z/date=2019-10-02,pm
- http://en.blitzortung.org/historical_maps.php?map=12

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

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

Metric 1D Short Notice Changes to Planned Outages

Q1 2022-23 Performance

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

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

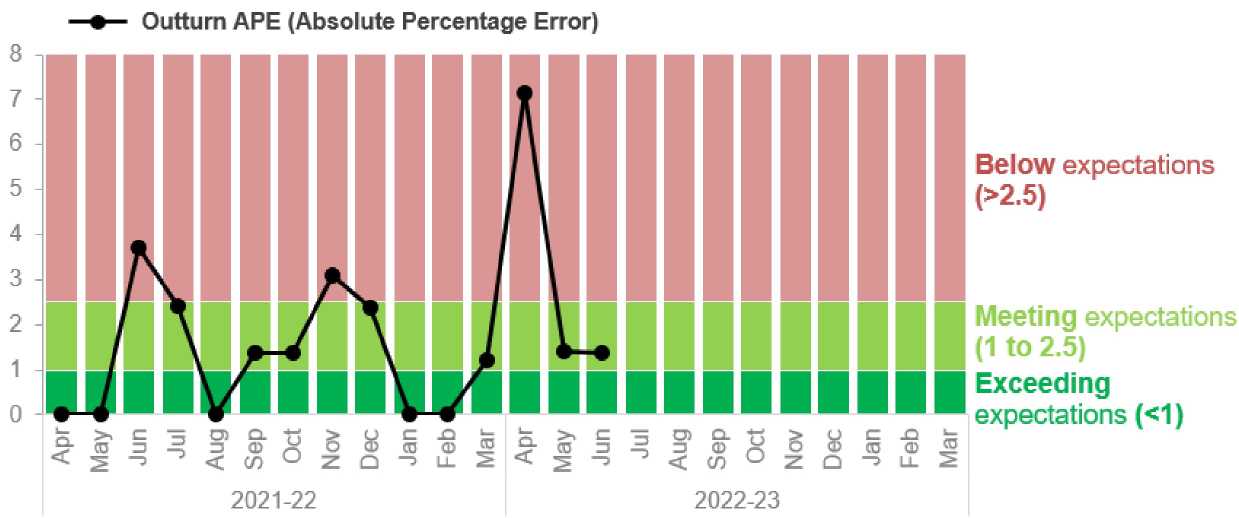


Table 6: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	700	709	730										2139
Outages delayed/cancelled	5	1	1										7
Number of outages delayed or cancelled per 1000 outages	7.1	1.4	1.4										3.3
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, the ESO successfully released 730 outages and there was one delay and no cancellations that occurred due to an ESO process failure. The number of stoppages or delays per 1000 outages is 1.37, which is within the 'Meeting Expectations' target of less than 2.5 delays or cancellations per 1000 outages.

For Q1 as a whole, we released 2139 outages and there was a total of 7 outages either delayed or cancelled due to an ESO process failure. This comes to 3.3 per 1000 outages and is therefore 'below expectations'.

The one delay in June is summarized below:

- A delay occurred where there was a misunderstanding on the outage request, and it was not clear what the impact to the network would be. As the information provided was incomplete, a full assessment on network security was not undertaken before this was passed to the ESO control room. Due to the incomplete assessment and a method statement not being provided, the outage was not taken until further information was obtained, and a detailed assessment to confirm there would be no adverse impact to the network. An Operational learning Note (OLN) has been written that has identified that the key information for these protection depletions is requested and that the work clearly outlines which party is carrying out the work. This will ensure all the requirements for a detailed assessment is clear.

RRE 1E Transparency of operational decision making

Q1 2022-23 Performance

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

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

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

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

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

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

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

We are regularly having conversations with market participants about 'skip rates'. This Dispatch Transparency dataset gives us the monthly 'skip rate' as shown below based on the categorisation and reason codes applied. We believe this outturn represents overall very efficient dispatch.

Table 7: Percentage of balancing actions taken outside of merit order in the BM (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	92.3%	93.3%	92.8%								
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.7%	99.6%								
Percentage of actions with no category applied or reason group identified	**0.3%**	**0.3%**	**0.4%**								

Supporting information

This month 92.8% of actions were taken in merit order or taken out of merit order due to an electrical parameter.

For the remaining actions, where possible, we allocate actions to reason groups for the purposes of our analysis. During June 2022, we sent 51,038 BOAs (Bid Offer Acceptances) and of these, only 212 remain with no category or reason group identified, which is 0.4% of the total.

RRE 1F Zero Carbon Operability Indicator

April – March 2021-22 Performance

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

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

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

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

Part 1 – Defining the maximum ZCO limit for BP1

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

Table 8: Forecast maximum ZCO% after our operational actions

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

Part 2 – Regular reporting on actual ZCO

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

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

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

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

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

Month	**Highest ZCO% in the month** (after ESO operational actions)	**ZCO% provided by the market** (during the same day and settlement period)	**Date / Settlement Period**
April	83.7%	92.3%	23 Apr / 28
May	78.5%	89.7%	27 May / 8
June	76.7%	72.5%	25 Jun / 9
July			
August			
September			
October			
November			
December			
January			
February			
March			

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

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

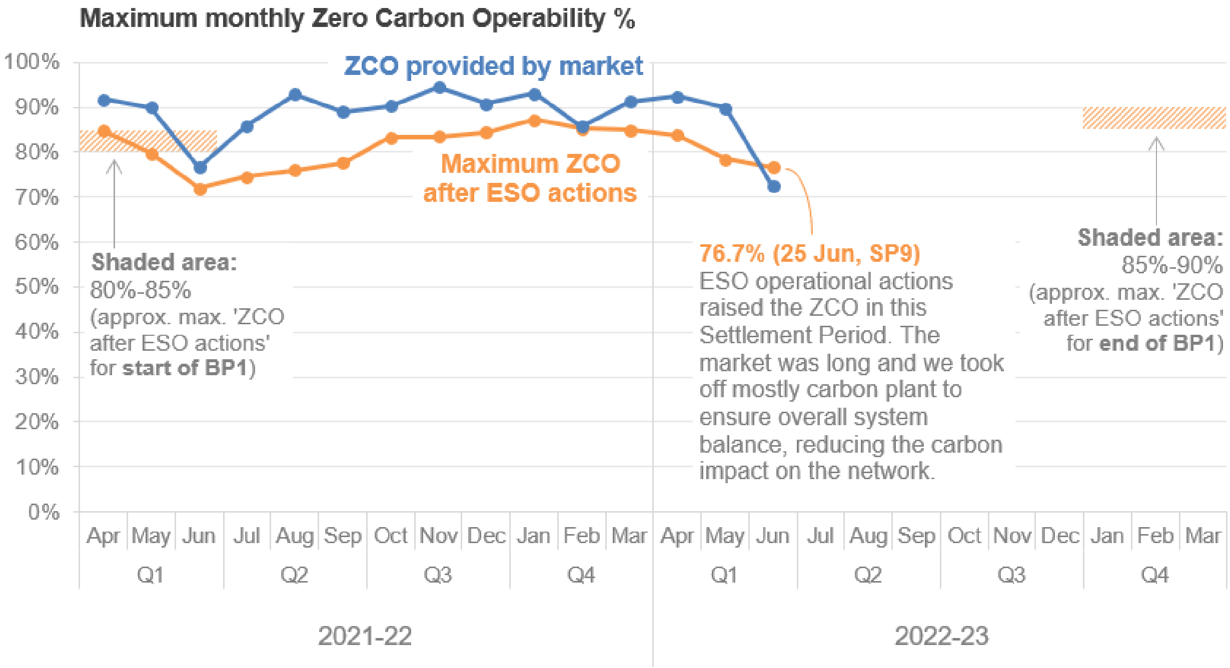
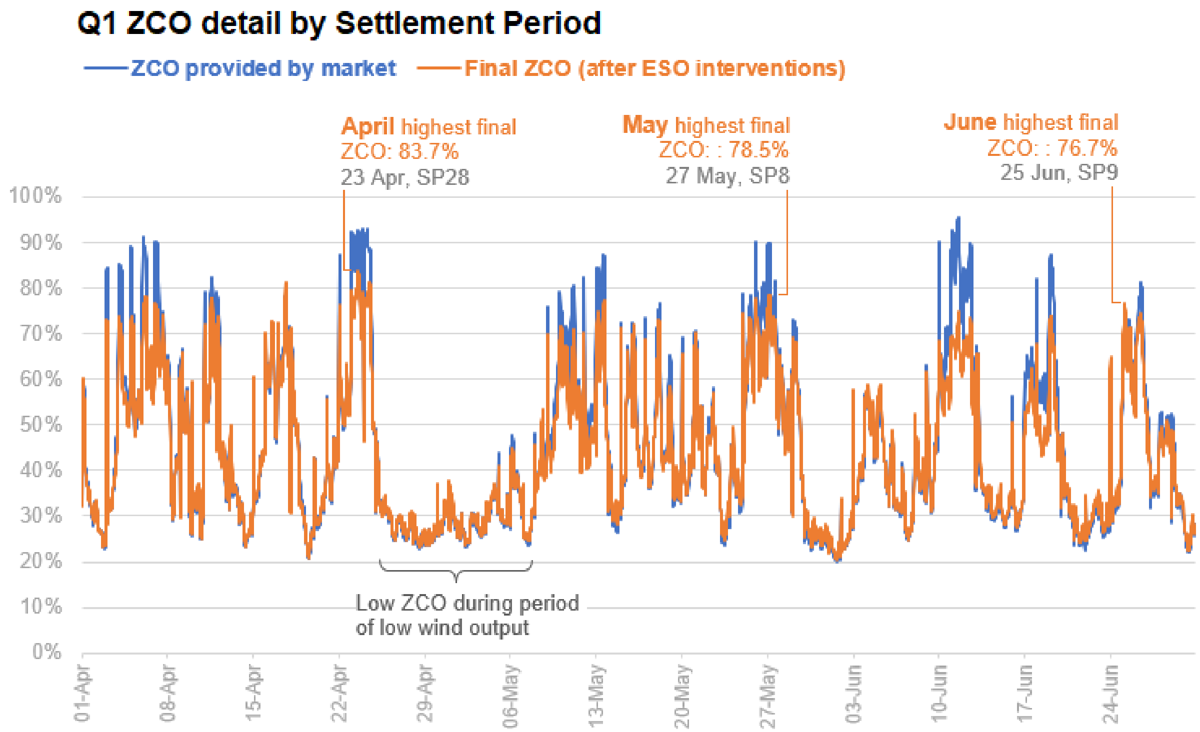


Figure 6: Q1 2022-23 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

In Q1 the highest zero carbon percentage outturn following ESO actions was 83.7%, on 23 April 2022, Settlement Period (SP) 28. This is less than the highest ever zero carbon percentage outturn that the system has achieved which remains at 87.1% on 5 January 2022, SP 5. During that SP the market provided 93.0% ZCO, with actions taken by the ESO to manage the system reducing the final figure to 87.1%.

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

As expected, the Q1 ZCO figures have dropped back since Q4 2021-22, and are similar to the levels seen in Q1 2021-22. Q1 figures are lower than Q4 because the demand (not shown on the graph above) was lower in Q1 due to the warmer weather. When the demand is low but the renewable output remains high, the ZCO after ESO actions is often lower. This is because we still have to take similar sets of actions (to manage operability constraints such as voltage) but these actions represent a larger proportion of the overall amount of generation. In a similar manner, ZCO will drop at times of high solar output. This is because the majority of solar generation is embedded and hence excluded from ZCO. Therefore, at times of high solar output operational actions will still be needed, even though the ZCO figure provided by the market will appear relatively low as it will not include the solar generation.

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

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

RRE 1G Carbon intensity of ESO actions

Q1 2022-23 Performance

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

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO_2/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.

Table 10: Monthly gCO_2/kWh of actions taken by the ESO (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO_2/kWh)	3.2	2.2	4.2									

Supporting information

In June 2022, the average carbon intensity of balancing actions was 4.2 gCO2/kWh. This was the highest monthly average in Q1. For Q1 the average carbon intensity was 3.2 gCO2/kWh.

In June, the time with the largest decrease in carbon intensity due to ESO's actions was at 00:00am on 10 June 2022 with a minimum of -16.6 gCO2/kWh. The Q1 minimum was -26.2 gCO2/kWh on 29 May 2022.

In June the highest carbon intensity increase was 53.8 gCO2/kWh at 10:00am 11 June 2022. This was the highest carbon intensity increase in Q1.

RRE 1H Constraints Cost Savings from Collaboration with TOs

April – March 2021-22 Performance

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

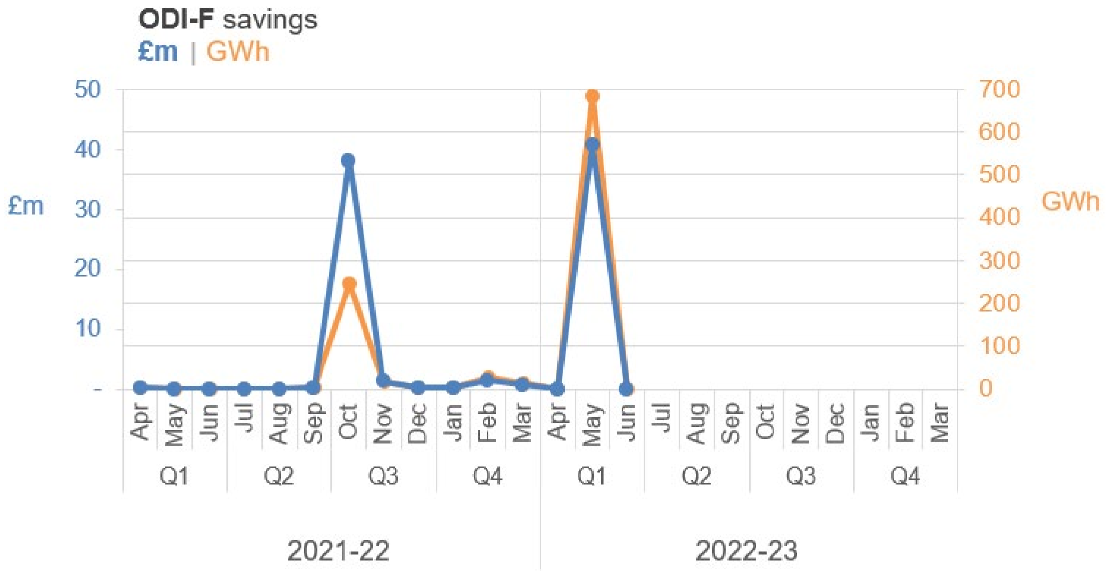
This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

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

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

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

(Estimated savings in GWh are also shown for context)



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

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

(Estimated savings in GWh are also shown for context)

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

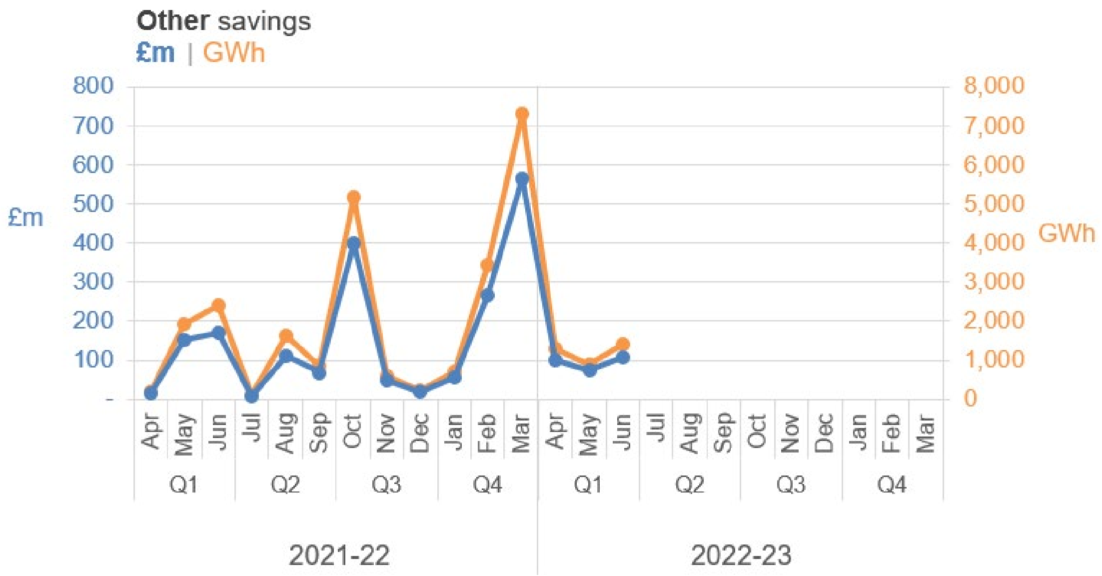


Table 11: Monthly estimated £m savings in avoided constraints costs (2022-23)

	ODI-F savings	Other savings	ODI-F savings	Other savings
	£m	£m	GWh	GWh
Apr	-	101	-	1316
May	41	74	685	911
Jun	-	109	-	1410
Jul				
Aug				
Sep				
Oct				
Nov				
Dec				
Jan				
Feb				
Mar				
YTD	**41**	**283**	**685**	**3637**

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.

Supporting information

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

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

1. A series of three switching actions were agreed, through STCP 11.4, with the TO, in the North of England, as Post-Fault Actions (PFA) which allowed voltage management of the network to within the security standards. These three switching actions were required to be completed within 15 minutes. The quoted time for one switching action is 10 minutes, therefore the TO had to operate above and beyond the usual procedure and carry the risks associated with this. The enhanced service provision from the TO included providing additional personnel on site and in the transmission network control centre (TNCC), enhanced mitigation checks, and dedicated monitoring equipment in place across a 275kV substations and two circuits. This proposal was approved, alleviating the need to agree a contract with conventional generation in the Northwest of England and saving £30m.
2. Forced cooling of super grid transformers for a substation in the North of England has been agreed by NGESO between 6 April 2022 and 30 March 2023. This is to be activated pre-fault during periods of high constraints on the B6 boundary in order to reduce constraint costs. The savings from this initiative span the entire year so have not been included in the reported figures for this quarter but will be prorated over the full 12 months at the end of the year.
3. The ESO, working with the TO, facilitated the extension of Spring thermal ratings on a circuit in the South of England thus increasing the limit on the South East boundary, LE1, for four days. This minimised constraint costs and improved network conditions for the four-day duration. The constraint was biting for the majority of this time. This action released approximately 139,200MWh of renewable generation to the market.
4. Dynamic line ratings have been approved through STCP 11.4 for three circuits in Southwestern England. Again, the savings from this initiative span the entire year so have not been included in the reported figures for this quarter but will be prorated over the full 12 months at the end of the year.

In Q1 2022-23 NAP has realised more than £30m of constraint cost savings through STCP 11.4. Some, as detailed in points 2 and 4 above cannot be captured in a single month in the ODI-F table above but rather will be prorated over the 12-month period at end of year.

STCP 11-4 opportunities (also proposed by ESO, and the TOs) that are in progress with the relevant TOs, and that will most likely be active in Q2 2022-23 include:

- Scope change to ECUP (East Coast Uprating project) in Northern Central Scotland to further benefit the B4 boundary by providing increased capacity and thus lowering constraint costs.
- Weather based rating enhancements on 3 circuits in Southern England.

Other Savings (Customer Value Opportunities):

The Network Access Planning team has made good progress over the last three months. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded over 42 instances where the ESO's actions directly resulted in adding value to end consumers, and where 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:

- Three running arrangement changes in England and Wales were made leading to 1,086,000MWh of savings against constraints in the South of England, creating considerable value for the end consumer.

- A current year outage clashed with another outage that was in the same geographical area. To secure this, the ESO would have needed to pull back 1650MW of generation on the Western Link. The ESO worked in partnership with the TO to review all possible options to deliver the work whilst reducing the impact on the system. After careful optimisation, the TO delayed one outage to align with outages on the same assets later in the year. This action released about 158,400MWh of renewable generation to the market.

These and many more represent a total of 3,637 GWh (approximately £283m) of extra generation capacity, which would have otherwise been constrained at a cost to the consumer.

RRE 1I Security of Supply

Q1 2022-23 Performance

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

The frequency is more than ± 0.3Hz away from 50 Hz for more than 60 seconds

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

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

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

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

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

Table 12: Frequency and voltage excursions (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz)	0	0	0									
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	1	1	1									
Voltage Excursions defined as per Transmission Performance Report[4]	0	0	0									

Supporting information

In Q1 there were three instances where the frequency was 0.3 to 0.5 Hz away from 50 Hz, one in each quarter.

- On 18 April 2022 @ 17:25 , Sizewell units trip caused frequency to drop 0.3 – 0.5 Hz away from 50Hz for more than 60 seconds.

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

- On 4 May 2022 @ 02:12 , IFA1 Bipole 2 tripped while exporting 1000 MW to France. The frequency reached 50.341Hz but returned to operational limits,50.2 Hz by 02:16. The root cause of the trip was due to protection issues which is now fixed.
- On 10 June 2022 @ 02:07, North Sea Link interconnector tripped while exporting 700MW to Norway. The frequency reached 50.318Hz but returned to operational limits,50.2Hz by 02:10. The root cause of the trip was a control value fault.

RRE 1J CNI Outages

Q1 2022-23 Performance

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

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

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

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 14: Planned CNI System Outages (Number and length of each outage)

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

There were no outages, either planned or unplanned, encountered during Q1 2022-2023.

Notable events during Q1

Balancing Strategy Capability Review

During April and May 2022 we have completed a series of eight engagements (six webinars and two in person events) with the industry looking at co-creating a roadmap for our Balancing Programme. This was undertaken collaboratively to ensure that our plans and delivery roadmaps meet our RIIO-2 strategic objectives, minimise balancing costs, deliver consumer benefits and create a foundation for future market changes and reform.

We were keen to receive views and input from a wide range of stakeholders, to ensure that further investment will enable us to:

- Meet our net-zero carbon operability ambition.
- Continue to remove barriers to entry for energy providers and encourage participation in the market.
- Operate within increasingly challenging system conditions.
- Efficiently and effectively transition between our current and future balancing capability.

We took extensive feedback and input from industry and jointly developed a delivery roadmap that combines industry needs and the needs of the ESO control room.

- **73 companies** represented in the whole process.
- **110 individual** attendees across the engagement process.
- **200 questions** received throughout process.
- **34 stakeholders** provided confidence votes on key areas of proposal.
- Very positive feedback around **transparency** and **collaboration**.

Content from the review including recording of our webinars and a mural board which shows outputs from in person workshops can be found on our website[5].

Successful Distributed ReStart trial in Galloway

On Thursday 19 May, we announced that a successful trial, part of the three-year Ofgem-funded Distributed ReStart project, in Galloway, South-west Scotland, saw a hydro generator connected to the distribution network self-start, power the local transmission and distribution network, and power wind turbines on two wind farms within an isolated test network. The trial's success could create a blueprint for incorporating distributed energy resources (DER) using green energy sources, to power Britain's electricity system in the "highly unlikely" event of electricity network shutdown. The Distributed ReStart project aims to show how utilisation of DERs would restore demand to localised areas of electricity network and establish Distribution Restoration Zones (DRZs).

Inertia Monitoring

GE Digital has developed a solution for the ESO which provides real-time monitoring and day-ahead inertia forecasting. This new tool was rolled out in June to the Control Room and supporting teams. It monitors the contribution from Scotland, extending to cover all of GB as NGET rollout Phasor Measurement Units (PMUs) at the required sites.

Reactive Technologies (RT) has also developed a solution for us which provides GB-wide, real-time inertia monitoring. Following a number of technical issues with the "ultracapacitor", which have delaying operation, commissioning testing has now been completed. Final remediation works have been undertaken and the ESO took ownership on 9th July of the ultracapacitor. A period of validation and confidence building in the data from this innovative solution is now underway ahead of a roll out to the Control Room in August following a period of data validation.

Electricity System Restoration (ESR)

In June the ESO launched the next set of tenders for new service provisions. The first of these cover the South East Restoration region, coinciding with the DNO licensed areas. There are 10 in East England, 12 in London and 19 in South East England.

We hosted a webinar on 05 May 2022 to provide an overview of the timescales of the tender, technical requirements, the process through to service go-live, and what's different this time round with the ESR procurement. Following on from the webinar, we announced that the Expression of Interest (EOI) stage had been launched for the South East (SE) region tender with a submission deadline of 08 July 2022.

Balancing Mechanism Release 1

We successfully deployed Release 1 to the Balancing Mechanism (BM) system in two drops on 24 May and 29 June. The benefits with this release that we have delivered are:

- Essential asset health improvements, including fixes to issues that have caused outages in test environments (representing a £17m cost saving if the issue were to occur in production).
- Fundamental re-architecting of a core BM process to provide performance stability and accommodate further growth in BMUs. This will also enable work that is planned for later releases.
- Performance improvements to ensure Electronic Dispatch Logging (EDL) and Electronic Data Transfer (EDT) data to and from market participants is handled quicker in our systems.
- Priority control room functionality improvements, to ensure they can continue to manage an increasingly challenging operational environment. This includes enhancements to the Automatic Instruction Repeater (AIR) functionality that was delivered in the R0 release in November 2021 and stability and user interface improvements to our bulk dispatch tool (VERGIL).
- Work that supports other initiatives across the ESO, including our Pennines High Voltage Pathfinder, the Modern Dispatch Adviser and Ancillary Services Reform.

This is the latest in a series of releases using our new release-based approach where multiple changes of different kinds are implemented together on a fixed date, rather than individually. This is improving openness and dialogue with impacted parties about upcoming changes and allowing time to plan and deliver the necessary business change activities, such as training and updating business processes, forecasting, and planning to secure already-busy resources in a sympathetic way, such as for User Acceptance Testing (UAT).

As a way of working, we have continued to adopt the Scaled Agile Framework (SAFe) wherever possible. With this release we introduced the sprint retrospectives and sprint demos into our ways of working. We also held more regular planning sessions to ensure alignment across the team. We have listened to feedback from the control room and improved our process for conducting UAT.

[5] https://www.nationalgrideso.com/industry-information/balancing-services/balancing-programme/strategic-capability-review

Role 2 Market development and transactions

Metric 2A Competitive Procurement

Q1 2022-22 Performance

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

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

For **Restoration**, there may be a significant lag time between when a contract is agreed and when it comes into effect. Therefore, in some cases actions we take in the current quarter may not impact Metric 2A until months or years later.

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

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

Figure 9: Percentage of £m spend by procurement method (April 2022 to June 2022)

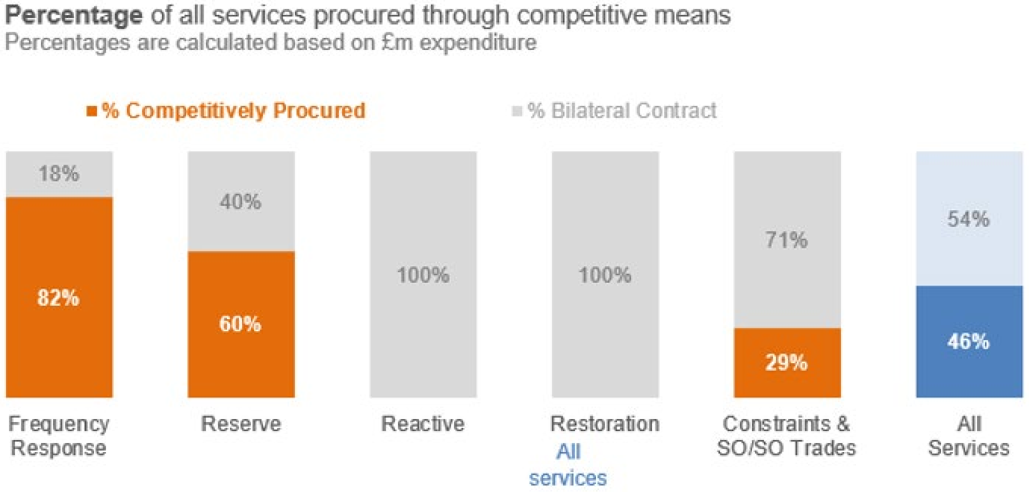


Figure 10: Absolute £m spend by procurement method (April 2022 to June 2022)

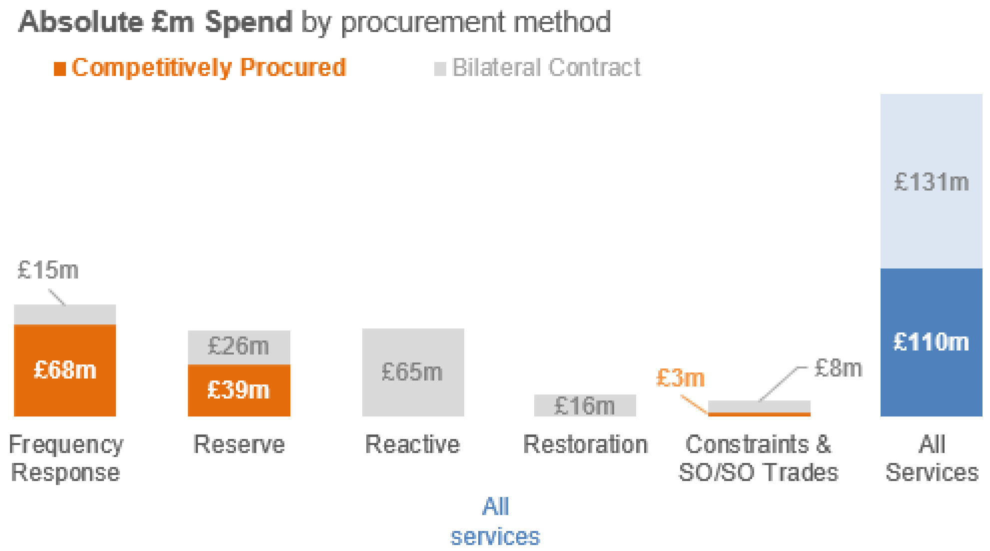


Table 15: Percentage of services procured through competitive means by Quarter

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

Performance benchmarks (Year 1)

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

Performance benchmarks (Year 2)

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

[6] The figure is greater than 100% as Bilateral contract spend is negative (due to sending additional energy to Ireland via interconnectors in September). Absolute figures could be used instead, however this would be inconsistent with previously provided data.

[7] The figure is greater than 100% as Bilateral contract spend is negative (due to sending additional energy to Ireland via interconnectors in September). Absolute figures could be used instead, however this would be inconsistent with previously provided data.

Supporting information

Q1 performance: Below expectations

The percentage of services procured through competitive means is 46%, which is in the 'below expectations' range of <65%.

Average Market Prices

	Q1	Q2	Q3	Q4
Dynamic Containment Low Frequency (DCL) (£/MW)	4.1			
Dynamic Containment High Frequency (DCH) (£/MW)	23.5			
Dynamic Moderation Low Frequency (DML) (£/MW)	5.2			
Dynamic Moderation High Frequency (DMH) (£/MW)	7.9			
Dynamic Regulation (£/MW) Low Frequency (DRL) (£/MW)	25.6			
Dynamic Regulation (£/MW) High Frequency (DRH) (£/MW)	26.2			
Optional Fast Reserve (£/MWh)	228.8			
STOR DA (£/MW)	4.6			

Frequency Response

The frequency response market saw the launch of the new Dynamic Moderation (DM) and Regulation (DR) service which, along with Dynamic Containment (DC), completes the suite of new responses services. The Volume of prequalified MW's across the tendered frequency response products has increased quickly since their launch over the last 18 months.

Reserve

The average availability price for Short Term Operating Reserve (STOR) dropped during Q1 to just under £5/MWh, more aligned with the average prices experienced before the wholesale electricity price volatility and instances of tight operating margins experienced through the winter period. The STOR market maintains liquidity with a large number of providers bidding in a large proportion of the total 230+ pre-qualified STOR units each day, in most instances offering well in excess of the daily required volume of STOR. For Fast Reserve, the average price for procuring the overall service has dropped slightly in Q1 from the winter spike. As we only procure the optional service (no firm procurement) the market has not changed in the last year and remains with a small volume of non-BM units.

Reactive

We continue to develop our thinking around market-based procurement of reactive power and are working with a partner company to explore potential reactive market designs through an innovation project. The Reactive Market Design Project phase 1 was concluded in March 2022 with the initial version of design and all outputs are shared on our website[8]. The team are now working on the next phase of the project to assess the market design including the feasibility study of implementing the design options analysis to understand what solutions are required and how they can be developed; further optimise market design if any changes are needed; and the implementation plan which will be shared with industry by the end of this financial year. In May a tender for reactive power in the Estuary region was run. An optional call off

[8] Reactive Reform – Market Design | National Grid ESO

contract from 01 June to 18 July was agreed with Grain Power station and a firm contract for 10 to 13 June was agreed with Coryton South Power Station.

Restoration

A competitive procurement event was launched for the South East region on 06 June 2022. This tender is the first time that Distributed Energy Resources (DER) can apply to provide Distribution-led restoration services to supplement the usual Transmission-led provisions. This tender round aims to bring the Distributed ReStart innovation project inputs into mainstream Electricity Restoration Service (ESR) process. Following on from this, more ESR tenders are planned. A one-off nationwide wind specific initiative in Q2 2022 and in Q3 2022, tenders for the whole Northern Region. The wind tender is mainly aimed at supplementing existing and new ESR provisions to help met our resilience standards by tapping into the 50GW of offshore wind generation forecasted by 2030.

Constraints & SO/SO Trades

Since April we have had four parties signed up to a Commercial Intertrip on the B6 constraint boundary. All parties have offered different arming fees, via a tender event, and the ESO can use the Intertrip as an alternative to bidding off generation when it results in lower overall constraints costs in managing the B6 boundary.

RRE 2B Diversity of Service Providers

Q1 2022-22 Performance

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

There are four services we report on below:

Frequency Response (MFR, EFR, FFR, DC, DM & DR)
Reserve (STOR, Fast Reserve)
Reactive
Constraints
Data on Restoration services is not included in this report due to the sensitive nature of the information, which will be provided to Ofgem separately.

Methodology

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

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

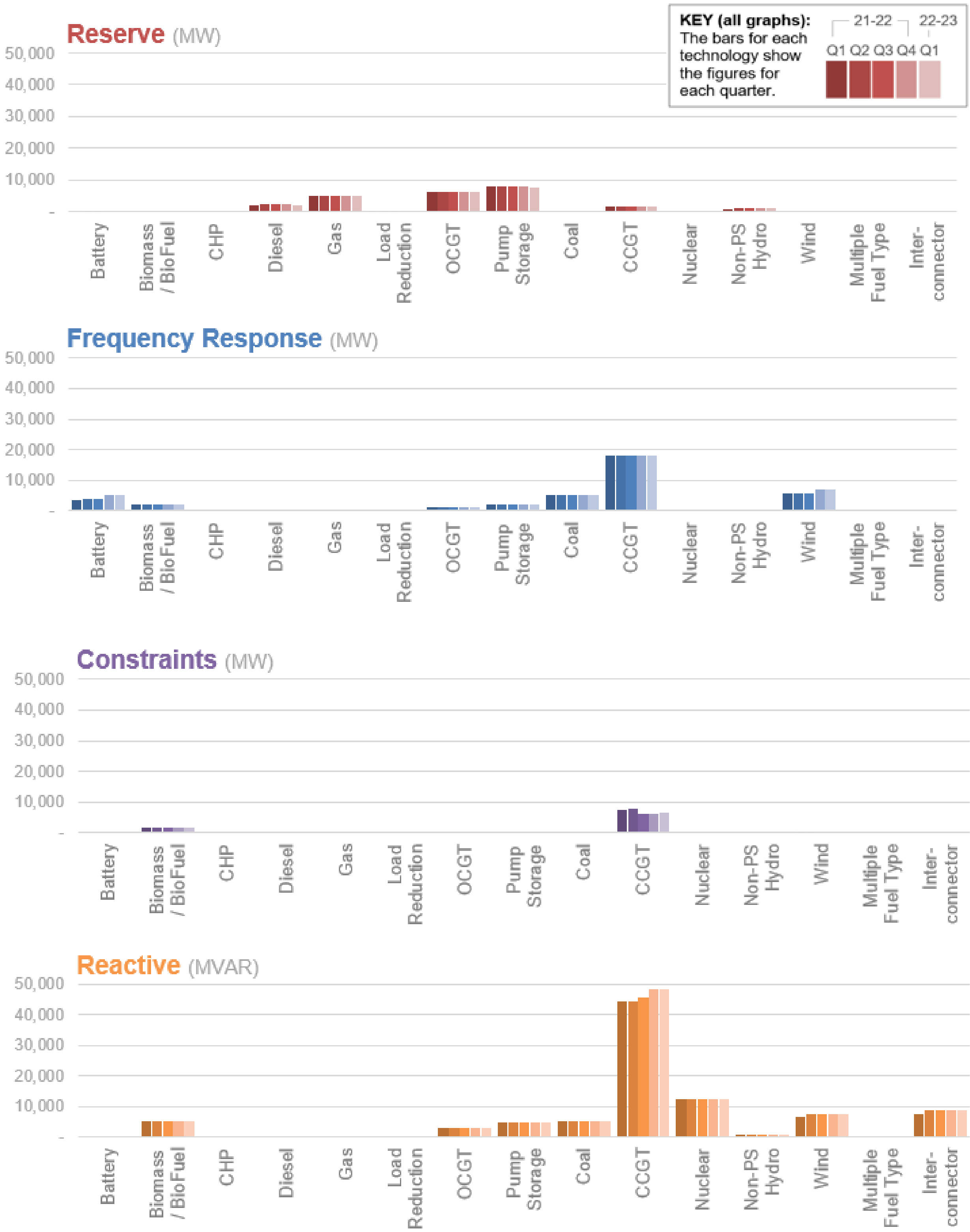


Table 16: Monthly contracted volumes provided to the ESO by service type

Reserve

MWs	Apr-22	May-22	Jun-22	2021-22 Q1	2021-22 Q2	2021-22 Q3	2021-22 Q4	2022-23 Q1	2021-22	2022-23
Total	7,939	7,937	7,700	23,360	24,001	24,143	24,276	23,576	95,781	23,576
Battery	45	45	44	-	60	74	135	134	269	134
Biomass/BioFuel	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
Diesel	638	636	615	2,063	2,182	2,205	2,217	1,890	8,668	1,890
Gas	1,667	1,667	1,630	5,085	5,073	5,133	5,133	4,964	20,424	4,964
Load Reduction	75	75	75	216	150	195	255	225	816	225
OCGT	2,061	2,061	1,995	6,183	6,183	6,183	6,183	6,117	24,732	6,117
Pump Storage	2,600	2,600	2,516	7,800	7,800	7,800	7,800	7,716	31,200	7,716
Coal	-	-	-	-	-	-	-	-	-	-
CCGT	481	481	465	1,437	1,437	1,437	1,437	1,427	5,748	1,427
Nuclear	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	372	372	360	576	1,116	1,116	1,116	1,104	3,924	1,104
Wind	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-

Frequency Response

MWs	Apr-22	May-22	Jun-22	Q1	Q2	Q3	Q4	Q1	2021-22	2022-23
Total	14,249	13,930	14,103	39,001	39,296	39,343	41,967	42,282	159,607	42,282
Battery	1,939	1,620	1,823	3,644	3,979	4,126	5,336	5,382	17,085	5,382
Biomass/BioFuel	817	817	717	2,375	2,319	2,191	2,151	2,351	9,036	2,351
CHP	-	-	-	-	-	-	-	-	-	-
Diesel	61	61	61	130	130	192	188	183	640	183
Gas	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-
OCGT	373	373	443	1,119	1,119	1,119	1,119	1,189	4,476	1,189
Pump Storage	728	728	728	2,184	2,184	2,184	2,184	2,184	8,736	2,184
Coal	1,782	1,782	1,782	5,346	5,346	5,346	5,346	5,346	21,384	5,346
CCGT	6,024	6,024	6,024	17,997	17,997	17,997	18,047	18,072	72,038	18,072
Nuclear	92	92	92	276	276	276	276	276	1,104	276
Non-PS Hydro	70	70	70	210	210	210	210	210	840	210
Wind	2,343	2,343	2,343	5,643	5,643	5,617	7,029	7,029	23,932	7,029
Multiple Fuel Type	20	20	20	77	93	85	81	60	336	60
Interconnector	-	-	-	-	-	-	-	-	-	-

Constraints

MWs	Apr-22	May-22	Jun-22	Q1	Q2	Q3	Q4	Q1	2021-22	2022-23
Total	2,693	2,693	2,923	9,499	9,863	8,055	8,055	8,309	35,472	8,309
Battery	-	-	-	-	-	-	-	-	-	-
Biomass/BioFuel	595	595	595	1,785	1,785	1,785	1,785	1,785	7,140	1,785
CHP	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-	-
Pump Storage	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-
CCGT	2,075	2,075	2,305	7,645	8,070	6,225	6,225	6,455	28,165	6,455
Nuclear	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	-	-	-	-	-	-	-	-	-	-
Wind	23	23	23	69	8	45	45	69	167	69
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-

Reactive

MVARs	Apr-22	May-22	Jun-22	Q1	Q2	Q3	Q4	Q1	2021-22	2022-23
Total	31,895	31,895	31,895	89,467	91,602	92,938	95,661	95,685	369,668	95,685
Battery	-	-	-	-	-	-	-	-	-	-
Biomass / BioFuel	1,734	1,734	1,734	5,202	5,202	5,202	5,202	5,202	20,808	5,202
CHP	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-
OCGT	967	967	967	2,901	2,901	2,901	2,901	2,901	11,604	2,901
Pump Storage	1,630	1,630	1,630	4,890	4,890	4,890	4,890	4,890	19,560	4,890
Coal	1,731	1,731	1,731	5,193	5,193	5,193	5,193	5,193	20,772	5,193
CCGT	16,164	16,164	16,164	44,496	44,496	45,820	48,468	48,492	183,280	48,492
Nuclear	4,095	4,095	4,095	12,285	12,285	12,285	12,285	12,285	49,140	12,285
Non-PS Hydro	189	189	189	567	567	567	567	567	2,268	567
Wind	2,466	2,466	2,466	6,576	7,311	7,323	7,398	7,398	28,608	7,398
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-
Interconnector	2,919	2,919	2,919	7,357	8,757	8,757	8,757	8,757	33,628	8,757

Supporting information

Reserve

The STOR service continues to attract the more traditional technologies with 230+ individual STOR units (BM/NBM) with over 6.5GW of capacity registered for the service and 129 separate units bidding in during Q1 2022-23. There has been more interest in recent months for new technologies (battery storage and aggregated demand management) looking at the STOR service, ahead of the forthcoming new reserve products when we would expect to see new technologies and smaller plant entering the market. For Fast Reserve, we still procure an optional service where a small number of (prequalified) more traditional technologies contract on the day to make their capacity available should it be required.

Frequency Response

Balancing frequency services are delivered by providers who are awarded contracts through competitive tendering that take place on a daily basis. The unit base is a mix of BM and Non-BM primarily DNO connected, however we are starting to see an increase in TO connected units that are providing frequency services. The increase of batteries providing tendered frequency services continues with this asset type now making up the majority of the MW providing frequency services.

Constraints & SO/SO Trades

Constraint costs are when the ESO pays generators to constrain their output due to network capacity limitations and typically for them to increase or decrease MWs on the system. Historically, this service has been limited to the providers that are connected to the transmission network. Once the Constraint Management Pathfinder goes live, this will potentially increase the number of technology types providing this service in 2022 and reduce constraint costs.

Reactive

The reactive power service is delivered primarily by providers who have Mandatory Service Agreements and are typically connected to the Transmission Network. These providers would also be in the BM. The launch of the Voltage Pathfinders has proven that distribution network providers can also be effective to meet a transmission need. The Peak Gen shunt reactor service went live in Q1 2022-23, and we expect the Zenobe Battery to start delivering in Q2 2022-23 to meet a need in the Mersey region. We also recently awarded contracts to meet reactive needs in the Pennines region that are due to commence in 2024-25.

RRE 2E Accuracy of Forecasts for Charge Setting

Q1 2022-22 Performance

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

Figure 12: Monthly BSUoS forecasting performance (Absolute Percentage Error) – two-year view

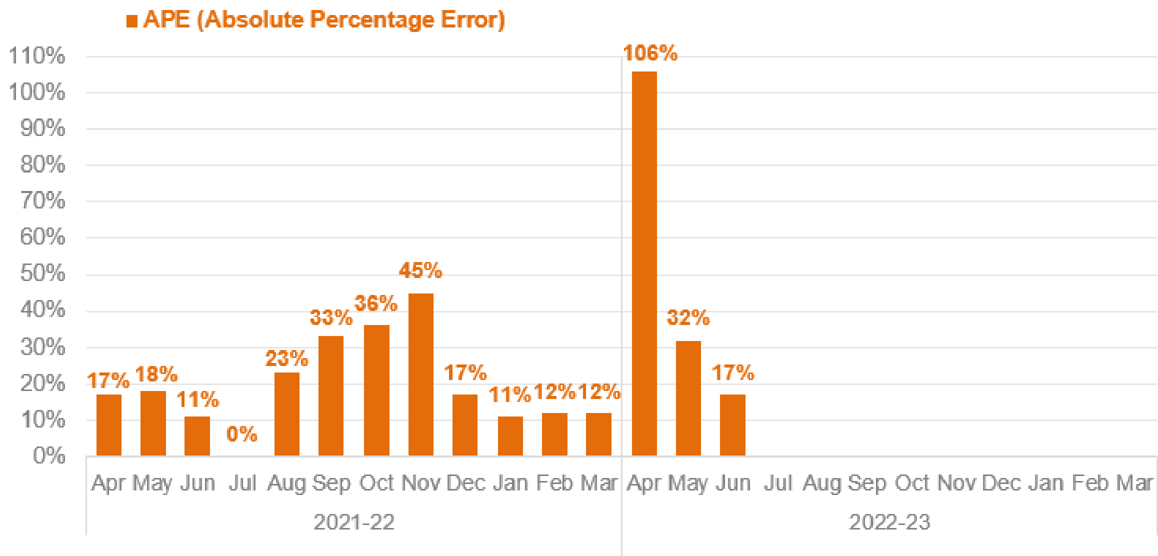


Table 17: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[9] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	5.3	6.8	9.4									
Month-ahead forecast	11.0	9.0	7.7									
APE (Absolute Percentage Error)[10]	**106%**	**32%**	**17%**									

Supporting information

The biggest difference between BSUoS costs in May and June was for constraint costs, which were about £90 million higher for June. This was driven by the costs associated with managing constrained network in the South East of England.

The wholesale electricity prices were also 27% higher in June than in May (day ahead June price was £161/MWh compared to £126/MWh in May), contributing to higher costs.

The primary driver of the 17% variance is constraint costs, which were forecast to be £100 million but outturned at £180 million. The wholesale electricity prices available at the time of forecast (£152/MWh) was also lower than outturn.

[10] 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.

Notable events during Q1

Reserve products

In April 2022 we shared a summary[11] of our proposed product and service design for two new Reserve products. The Reserve Reform project is developing a suite of new products to ensure safe and secure operation of the network in a zero-carbon world. Our aim is to introduce standardised products which are transparent, fair, and competitive for all technology types, ultimately promoting market depth and reducing costs to the end consumer. This document seeks views on key elements of product and service design for the first two new products: Negative Slow Reserve (NSR) and Positive Slow Reserve (PSR). In parallel, we are working on the design for other Reserve products and will publish a similar summary of proposed service design as soon as possible to seek feedback from industry in the same way that we are doing for Slow Reserve. Through this latest engagement, we want to showcase our thinking behind the Slow Reserve products and seek input on some elements still being defined. We will be engaging with industry participants via a series of events where we are discussing our proposals in more detail.

First auction held for Dynamic Moderation

In May 2022, our new frequency response service Dynamic Moderation held its first auction, completing the full suite of the new frequency response services, alongside Dynamic Containment and Dynamic Regulation.

These three new dynamic services will deliver a faster response to frequency events, allowing the ESO to manage everyday frequency fluctuations more effectively, both small and large.

By enabling access for a more diverse range of technologies, including variable generation, storage, and demand-side participants, these services allow greater competition, which alongside a move from month-ahead tenders to day-ahead auctions, will contribute to both improved security and cost efficiency for consumers.

These services also mark the first time that the ESO has used the Single Market Platform to onboard service participants and is part of our commitment to improve the ease with which different technologies can participate in the markets we operate.

Net Zero Market Reform, Phase 3 Assessment

Britain's electricity market needs to be substantially reformed if it is to deliver a net zero electricity system by 2035 at least cost to households and industry. In May 2022 we presented our Assessment and Conclusions[12] from Phase 3 of Net Zero Market Reform. We found that the current market design, based on a blanket national wholesale price for electricity, is no longer fit for purpose for a rapidly decarbonising system.

Our study makes clear that the existing wholesale market design is contributing to a dramatic rise in constraint costs and inefficiencies in balancing the network, while undermining the capability to deliver demand-side flexibility. And if left unchanged, the current national pricing model will impose excessive and unnecessary costs on consumers.

The favoured reform option outlined in the report from the ESO, which analysed over 1,500 individual stakeholder interactions, is a nodal location-based wholesale market with central dispatch.

This option could create opportunities for low-cost, low-carbon electricity to be harnessed when and where it is abundant, contributing to lower household electricity prices and reduced network operating costs, while helping to decarbonise the system.

It could also facilitate the efficient management of the system and help to incentivise flexible assets to locate and operate in the optimal way for the electricity system.

'Nodal pricing' divides the national network into different nodes, each with their own wholesale electricity price which reflects the cost of supplying electricity at that location.

[11] https://www.nationalgrideso.com/document/249031/download
[12] https://www.nationalgrideso.com/document/247306/download

When coordinated by a system known as ‘central dispatch’ it could also help unlock efficiency savings and provide an easier route to market for small, flexible assets.

The scale of these benefits is currently being assessed by Ofgem, with the ESO’s report feeding into that process. Moving to a locational pricing system would require legislative and regulatory changes and any final decisions on fundamental reform will be made by the Government.

The next phase of analysis by the ESO will assess the implementation and implications of nodal pricing and central dispatch, as well as assessment of other market design elements to complement these proposed reforms to the wholesale market.

Read the full Net Zero Market Reform assessment and options study here

The TNUoS Task Force launches

Applications for the Transmission Network Use of System (TNUoS) Task Force closed on 21 June 2022, with a total of 26 individual applications. Following this, a collaborative assessment process between the ESO and Ofgem took place to review applications. The final list of members has now been confirmed, with the first Task Force meeting held on 13 July 2022. The Task Force has been set up to consider improvements to the current charging arrangements, and members represent a broad range of industry parties and include generators, storage operators, suppliers, non-domestic energy users, and consumer representatives, as well as the ESO and Ofgem. Members will be expected to represent the views of their sector, work to develop, and evaluate solutions, actively communicate progress and gather feedback, and attend meetings, with participation expected to require four to six working days of effort per month over an initial six-month period.

ESO supports improvements to STC workgroup quoracy arrangements and governance rules

On Thursday 30 June, NGET raised STC code modification CM083 ‘Workgroup Quoracy Improvements’. The current quoracy rules for modifications to the System Operator/Transmission Owner Code can slow progress and result in an inefficient use of industry time. CM083 therefore proposes to make changes to the governance rules to limit the participation required while introducing certain safeguards. This enables workgroups to be convened swiftly, but with effective participation, maximises the efficient use of industry resources, and facilitates proportionate engagement in on-going code change by STC parties, rather than forcing arbitrary attendance in order to meet with quoracy rules. The ESO worked with NGET to develop this proposal and wrote the solution leading to the STC panel approving it as needing no further development and to go straight to consultation.

NGET also developed proposals with the ESO for other reforms leading to their raising CM084 ‘Clarify STCP Modification Approach for Cross-Code Changes’. This modification proposes to clarify the governance arrangements where Panel decisions to approve/reject STC Procedure (STCP) modifications may need to be unwound following an Ofgem determination for a corresponding cross-code modification. CM084 offers two potential governance process routes to help provide transparency to the Panel, Ofgem and industry on the rules around the assessment and determination of STCP modifications resulting from cross-code modifications which may have material impact on the STC, as well as ensuring that STC governance rules are future-proofed. These ideas will now be further refined in an industry workgroup.

Role 3 System insight, planning and network development

Please note there are no monthly or quarterly metrics or RREs for Role 3.

Notable events during Q1

Innovation strategy

In April we announced our innovation strategy[13], which has been developed in consultation with industry and informed by the results of our Bridging the Gap work. It sets out how we need to innovate in 2022/2023, our strategic priorities, the role innovation is playing at the heart of GB's transition to zero carbon, and where to focus our efforts to set us on the right path for 2025 and beyond.

Summer Outlook Report

In April, we published our latest Summer Outlook report[14] which provides a view into the season ahead. This year, we've undertaken extra analysis to address the global energy crisis. We continue to monitor its impact on GB energy prices and system operability and will provide further updates through our Operational Transparency Forum as required. We have taken a number of measures to reduce costs to consumers, these measures include the development of pathfinder projects, new pre-fault frequency services and the delivery and implementation of this year's Frequency Risk and Control Report. Upward margins are traditionally less of a concern during summer due to lower peak demands than in winter. However, due to the events in Ukraine, we have carried out additional analysis assessing a range of possible interconnector scenarios. We continue to have the right tools and services available to manage system operability during the summer, such as our stability services and Dynamic Containment.

ESO and PeakGen voltage management project goes live in Merseyside

In May, the first of our voltage management projects went live, with the Mersey Reactive Power solution installed in Frodsham, Cheshire. It consists of a shunt reactor that absorbs reactive power, increasing the efficiency of the network and managing high voltage levels. PeakGen was awarded a contract for the solution and has now installed its 200MVAr reactor at a substation in the region, where it will now provide reactive power for the next decade.

A temporary military-style 'Bailey bridge' had to be built across an active river to move the 200 tonne reactor into place. We awarded the contract as part of our Mersey Pathfinder, in an effort to manage high overnight voltage in the Merseyside region of England.

Winter Review and Consultation 2022

In June, we published our Winter Review and Consultation 2022[15], providing a review of our 2021/22 Winter Outlook Report[16] analysis compared to what happened. The review highlights that conditions over winter 2021/22 were close to average with no prolonged cold spells that occurred during times with low wind output. In addition, interconnectors were observed to import when needed, and availability of thermal generation was in line with forecasts. The report states that although the Winter Outlook Report indicated a potential need for Electricity Margin Notices (EMNs), none were issued as margins were less tight than the previous winter. The review details that high wholesale electricity prices meant that the cost of individual ESO actions was higher than in previous years although, overall volumes of actions were lower, largely due to the rise in gas prices.

[13] https://reports.nationalgrideso.com/innovationstrategy/
[14] https://www.nationalgrideso.com/document/248821/download
[15] https://www.nationalgrideso.com/document/261721/download
[16] https://www.nationalgrideso.com/document/212691/download

Bridging the Gap flexibility tracker

The first tracker[17] was published on 30 June with input from Ofgem and BEIS. This tracker has been developed to monitor progress against the key actions for the 2025 flexibility milestones, which we identified with stakeholders as part of the 2022 Bridging the Gap project. The tracker creates an overview of the progress towards flexibility being made by the entire industry, as the actions have been collated from a wide range of industry plans and strategies. In this first tracker, all the actions are in the green with no areas for concern. The tracker will be published every six months.

New RDP concept of Forward Power Flow Limit

We have been working with NGET and UK Power Networks on a Regional Development Programme covering the East Anglia region. In June, we reached a conclusion for Burwell Grid Supply Point (GSP) and re-offered a connection agreement to UKPN to capture that solution. In our exploration of the issues at Burwell GSP it was determined that the site was subject to both export constraints (when generation on the DNO network is greater than demand) and import constraints (when a growing volume of battery storage and demand on the DNO network is importing more than generation is exporting). Working collaboratively with NGET and UKPN we have introduced a new RDP concept, called an SGT Flexible Forward Power Limit, at the GSP to enable the DNO to manage the import constraint using its Active Network Management (ANM) system. As a result, we have enabled circa 360MW of DER to connect earlier than the connection date of 2028, when transmission reinforcement works complete, at Burwell GSP. This ultimately provides an additional tool for managing system issues at GSPs and may enable us to connect further volumes of DER where applicable.

[17] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/bridging-the-gap-to-net-zero/flexibility-timeline-tracker