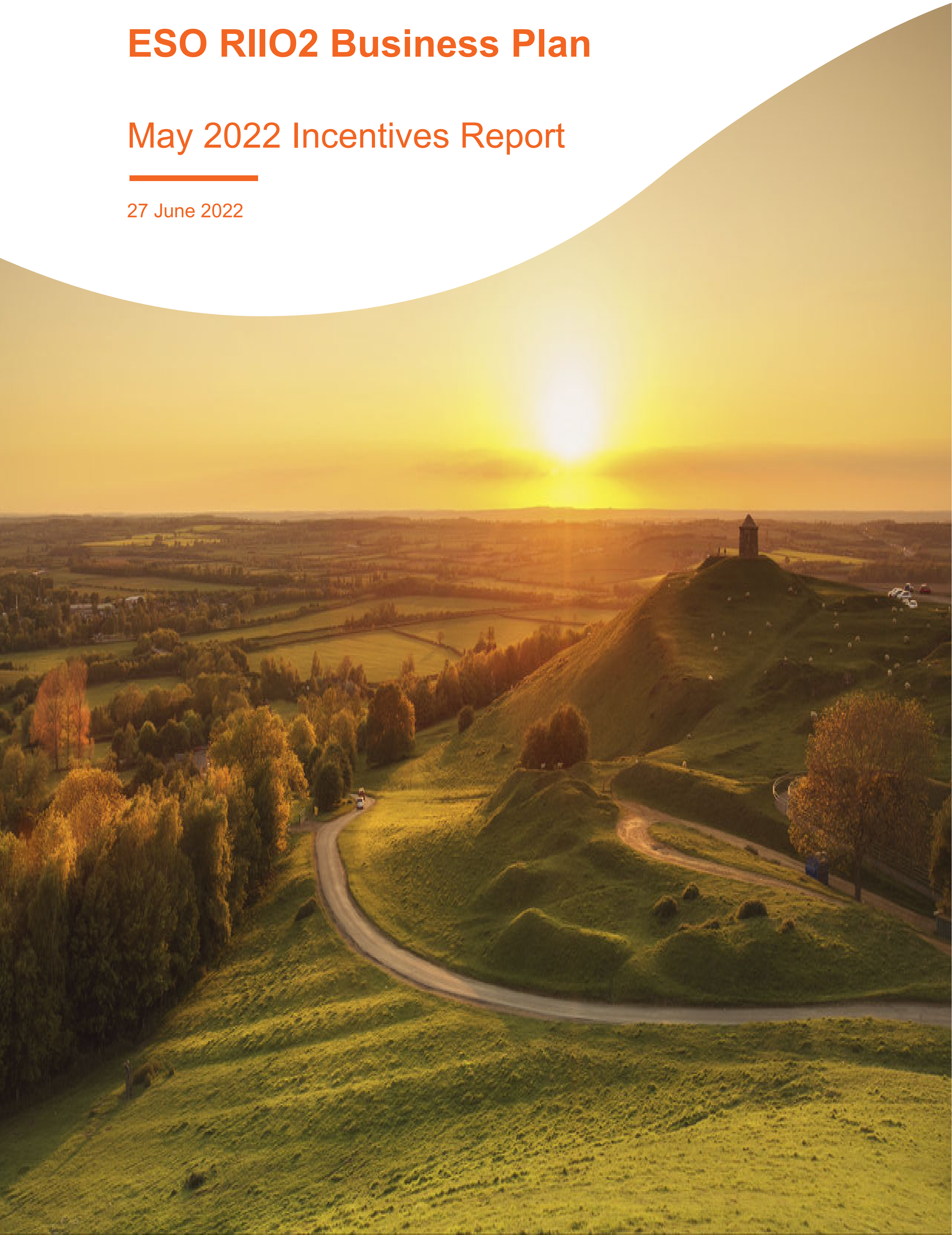
ESO RIIO2 Business Plan

May 2022 Incentives Report

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

- 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.
- Our new frequency response service Dynamic Moderation has held its first auction, completing the full suite of the new frequency response services, alongside Dynamic Containment and Dynamic Regulation.
- Ofgem approved our proposal for a GB Pricing Methodology for settlement of balancing energy for specific balancing products. This was submitted in accordance with Article 6(4) of the Electricity Regulation.
- Our Net Zero Market Reform Phase 3 Assessment and Conclusions, finds 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.
- ESO issued a request for information (RFI) to look at accessing additional reactive capability across England and Wales between 2023 and 2026.
- We published a paper on operational visibility of Distributed Energy Resource (DER).
- The first of our voltage management projects has gone live, with the Mersey Reactive Power solution installed in Frodsham, Cheshire.

The table below summarises our Metrics and Regularly Reported Evidence (RRE) performance for May 2022.

Table 1: Summary of Metrics

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£210.6m vs benchmark of £163.1m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 2.6% vs benchmark of 2.4%	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 4.5% vs benchmark of 4.3%	●
Metric 1D	**Short Notice Changes to Planned Outages**	1.4 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	●
RRE 1E	**Transparency of Operational Decision Making**	93.3% of actions taken in merit order	N/A
RRE 1G	**Carbon intensity of ESO actions**	2.2gCO_2/kWh of actions taken by the ESO	N/A
RRE 1I	**Security of Supply**	1 instance where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	0 planned system outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 32%	N/A

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

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

Gareth Davies
ESO Regulation Senior Manager

Role 1 Control Centre operations

Metric 1A Balancing cost management

May 2022 Performance

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

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

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

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

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

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

Total Balancing Costs *(£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 period: The benchmark for this metric has been updated provisionally for the period April 2022 to March 2023 in line with ESORI guidelines. These figures will be confirmed by Ofgem in due course.

Figure 1: Monthly balancing cost outturn versus benchmark (£m)

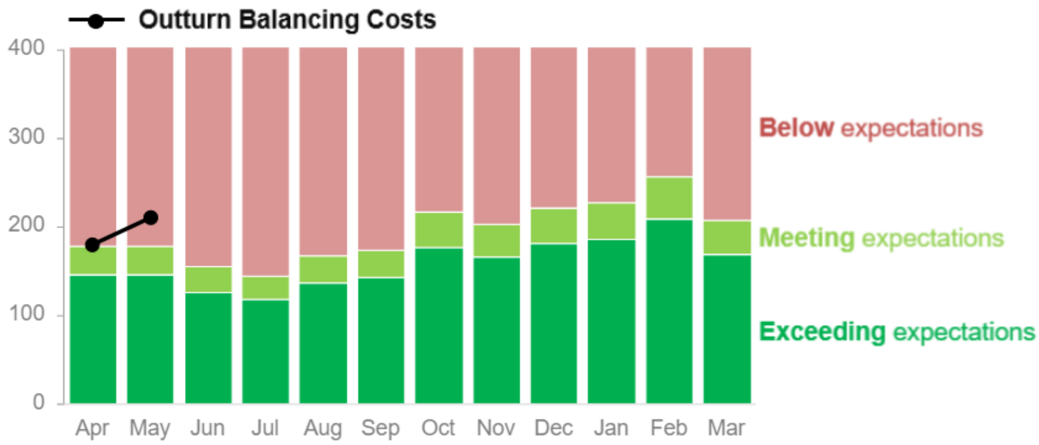


Table 2: Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	YTD
Benchmark: non-constraint costs (A)	50.4	50.4	50.4	50.4	50.4	50.4	**100.8**
Indicative benchmark: constraint costs (B)	97.0	88.6	90.1	81.1	101.3	107.2	**185.6**
Indicative benchmark: total costs (C=A+B)	147.4	139.0	140.5	131.5	151.7	157.6	**286.4**
Outturn wind (TWh)	3.8	3.8					**7.6**
Ex-post benchmark: constraint costs (D)	112.3	112.7					**224.9**
Ex-post benchmark (A+D)	162.3	163.1					**325.4**
Outturn balancing costs[1]	186.1	210.6					**396.7**
Status	●	●					●

Please note, any differences in figures for the ex-post benchmark are driven by the use of decimal numbers in the calculation.

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

Supporting information

May performance

Please note that due to a data issue on one date, the Minor Components line in Non-Constraint Costs is capturing some costs 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.

The Balancing costs for May 2022 were close to £211m, showing an increase from the previous month of nearly £25m. The outturn costs are closer to being in the 'meeting expectations' zone than in any month last year but were further from the benchmark than in April 2022. This is because the benchmark for FY23 includes the elevated costs experienced in FY21 and also FY22.

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

Persisting high gas prices were the key factors responsible for continued high prices compared to last year for Operating Reserve, STOR, Response and Reactive, resulting in significantly higher non-constraint costs despite a substantial decrease in 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.

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

Breakdown of costs vs previous month

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

		(a) Apr-22	(b) May-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	2.6	8.1	5.5	
	Operating Reserve	30.4	14.4	(16.0)	
	STOR	3.2	6.3	3.0	
	Negative Reserve	0.2	0.4	0.2	
	Fast Reserve	17.5	17.8	0.3	
	Response	25.4	31.5	6.2	
	Other Reserve	2.0	1.8	(0.2)	
	Reactive	21.5	23.7	2.2	
	Restoration	5.5	2.9	(2.6)	
	Minor Components	6.7	18.0	11.3	
Constraint Costs	Constraints - E&W	9.7	16.0	6.2	
	Constraints - Cheviot	8.7	8.8	0.1	
	Constraints - Scotland	23.3	33.7	10.5	
	Constraints - Ancillary	1.8	3.5	1.7	
	ROCOF	10.5	1.6	(8.9)	
	Constraints Sterilised HR	17.1	22.1	5.0	
Totals	Non-Constraint Costs - TOTAL	115.0	124.9	9.9	
	Constraint Costs - TOTAL	71.2	85.7	14.6	
	Total Balancing Costs	**186.1**	**210.6**	**24.5**	

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 £14.6m and £9.9m respectively.

Against the constraint category, the breakdown shows that Constraint-Scotland, Constraint-E&W and Constraint Sterilized Headroom were the key categories behind the cost increase from April. A decrease in Monthly cost was seen in the RoCoF category.

Within the Non-Constraint costs, a significant decrease from the previous month was seen in the Operating Reserve category. Response, STOR, Reactive and Energy Imbalance increased from April.

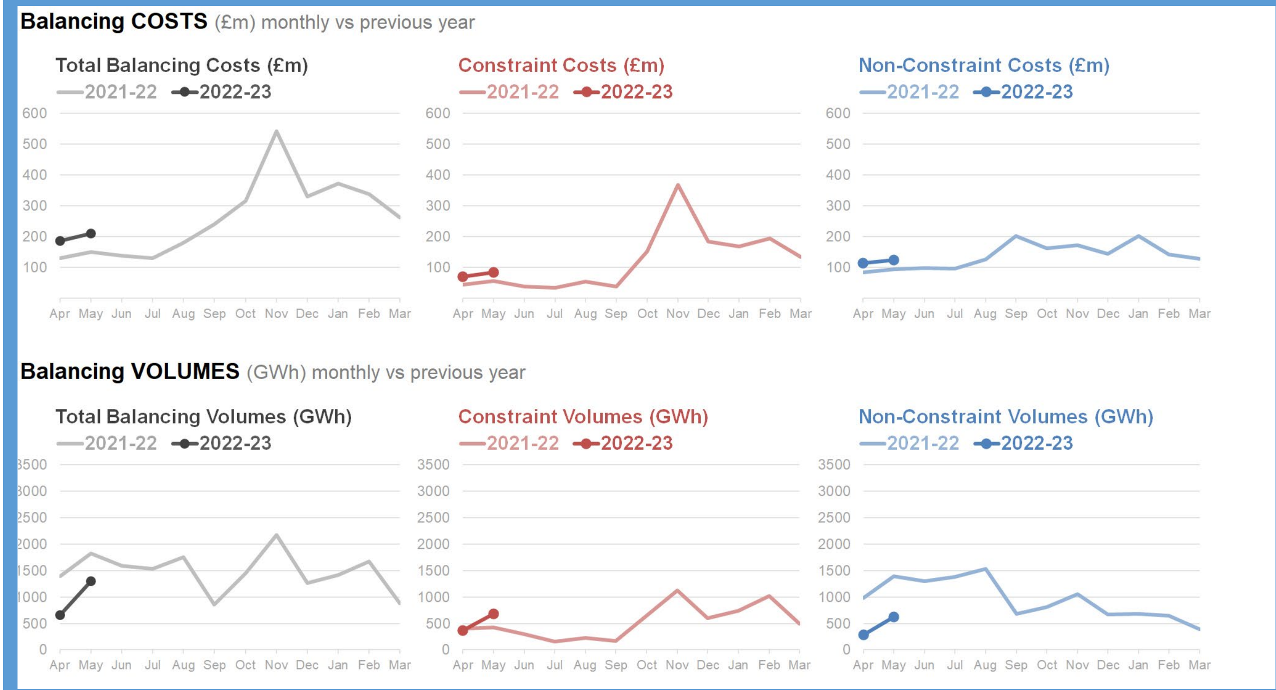
The main drivers of the biggest cost variances this month are detailed below:

- **Operating Reserve: £16m decrease.** Healthier margins requiring less intervention to maintain reserve requirements were the key driver of the cost decrease for this category.
- **Constraint-Scotland: £10.5m increase.** The cost increase was in line with higher wind generation level in Scotland compared to April requiring a higher volume of BM actions to manage power flow restrictions in Scotland. The most expensive days for this category were between Monday 9th and Thursday 12th when daily spend recorded remained between £5m and £6m per day throughout those days.
- **RoCoF: £8.9 decrease.** Decrease driven by the inertia requirements being met by synchronised generation, whether self-dispatched or instructed for voltage or another requirement.
- **Constraint-E&W: £6.2m increase.** A change in the outage pattern and generation pattern resulted in more BM actions required to reduce generation in order to manage thermal constraint in England and Wales, leading to more costs being allocated within those regions. The most expensive day for this category in May was Friday 27th with a daily spend of over £2m.
- **Response: £6.2m increase.** This is due to both increased volume and price of response procured this month. Providing response requires units to be repositioned to meet this requirement and the high BM prices mean the cost for this service has increased for the month.

- **Constraints Sterilized Headroom: £5m increase.** As more generation was restricted behind constraints, the higher was the spend to replace the additional energy available on constrained generators elsewhere outside the constraint.

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 £29.5m higher than in May 2021 due to

- The 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 £14.6m higher than in April due to:

- Overall increased wind levels, resulting in an increase in the volume of Balancing Mechanism actions to reduce generation required to manage thermal constraints.

Non-Constraint Costs

Compared with the same month last year:

Non-Constraint costs were £29.4m higher than in May 2021 due to:

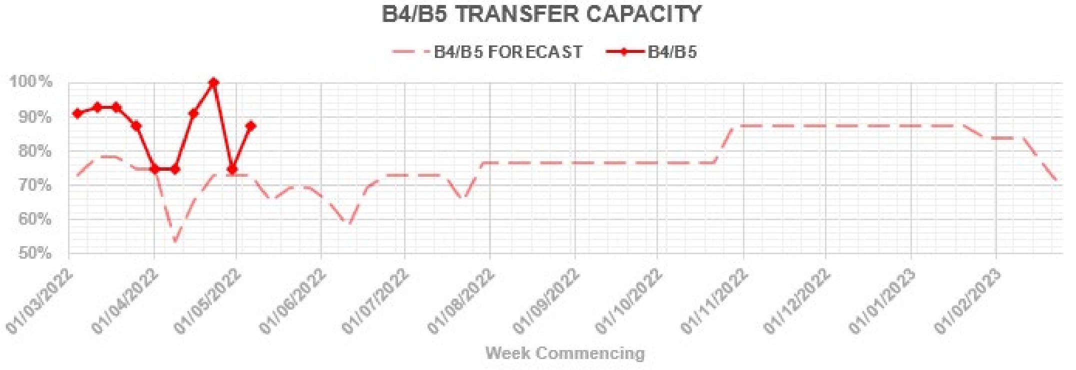
- The higher price of actions taken to manage the system. Particularly the price of offers in the BM which are higher due to increased wholesale costs. The volume of actions was lower than the

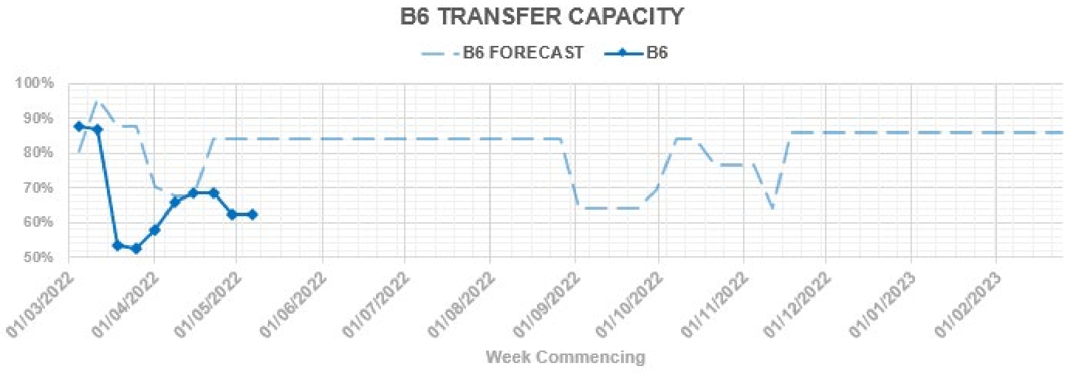
- previous year and this shows that it is the cost of the actions required rather than the volume which is driving the overall non-constraint cost.
- An element of this increase against last month will also be driven by the Minor Components spend.

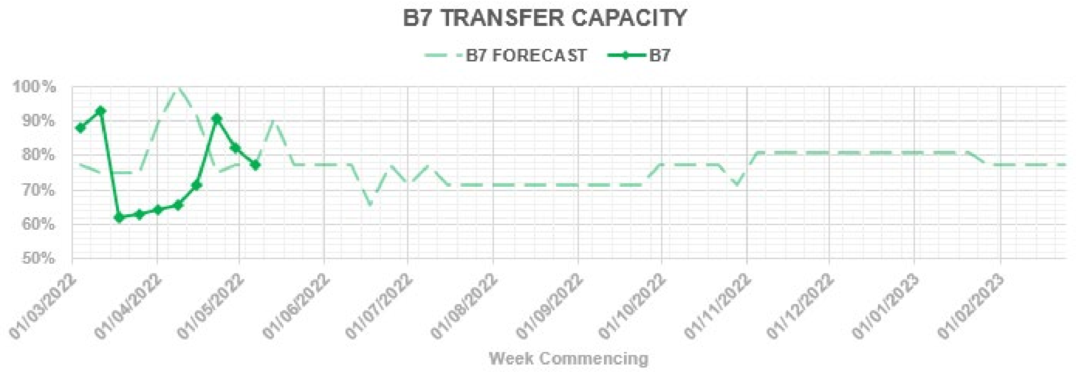
Compared with the previous month:

Non-Constraint costs were £10m higher than in April due to the misclassification of some actions into Minor Components. In reality, the Non-Constraint Costs are anticipated to be in line with the previous month.

Network availability 2022-23





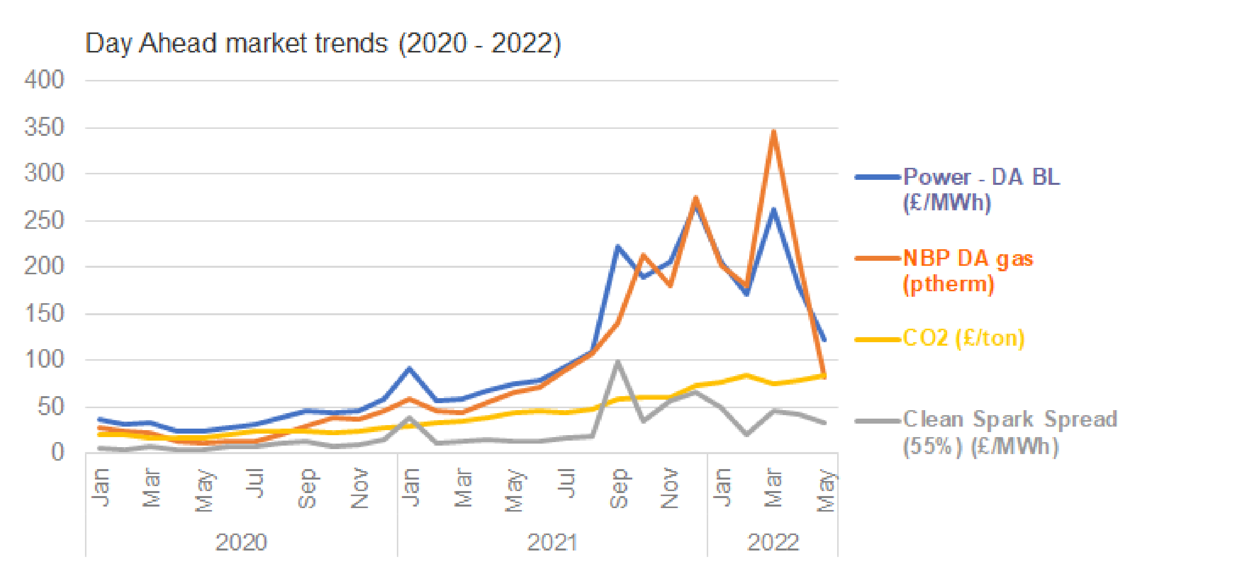


Boundary capacity has been at or above forecast for the B4/B5, internal Scotland boundaries for the majority of the month and at relatively high levels for most weeks.

The B6 and B7 boundary capacities were below the forecast and relatively constrained when compared to the 100% capacity. The tighter constraint volume contributed to the increased Constraints costs for this month.

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

Changes in energy balancing costs

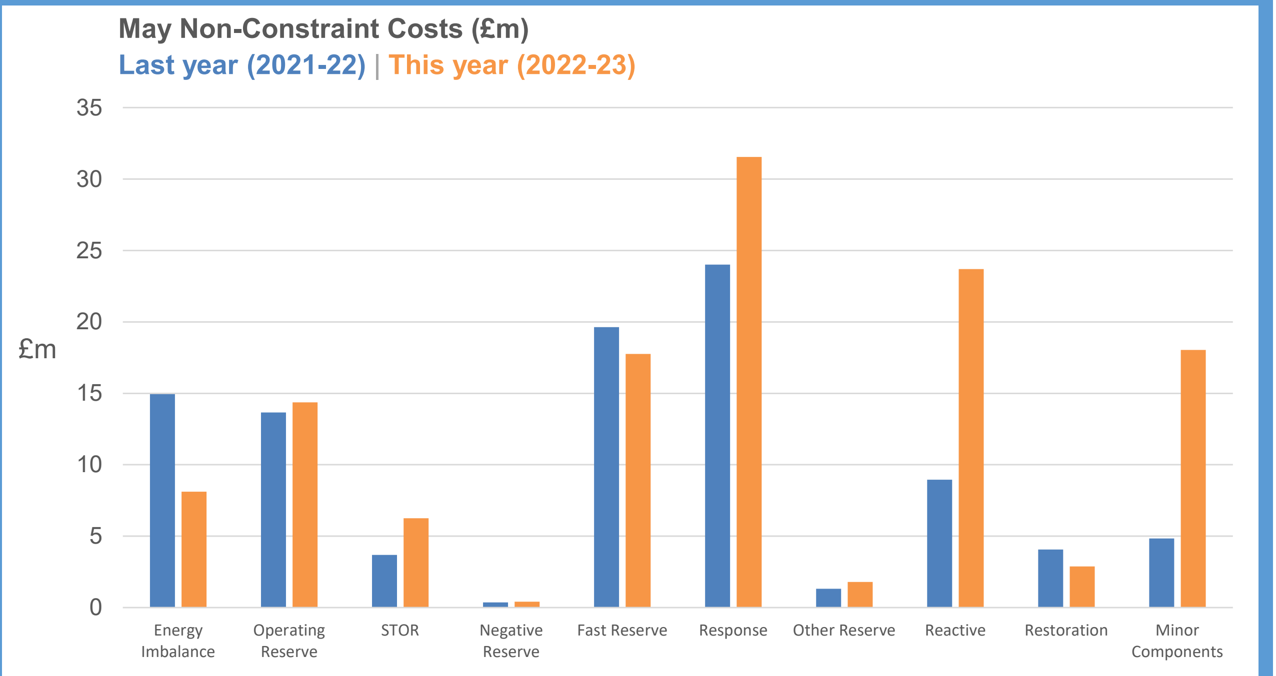


DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Power day ahead prices have fallen further in May but still remain above the level of previous years. The day ahead gas prices have followed a similar trend and is getting more in line with the previous year value. Carbon prices continue the upward trend seen throughout 2021 and 2022 so far.

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.

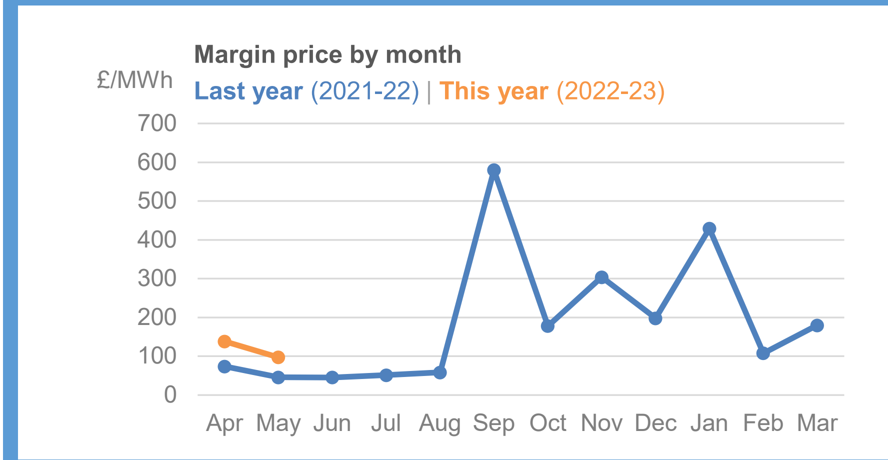
Cost trends vs seasonal norms



Comparing May 2022 non-constraint costs with those of May 2021 we can see that there has been a rise in Response, Reactive and STOR, whilst the other categories either decreases or showed little variance. We have not discussed the variance in Minor Components here as it is driven by the data issue referenced earlier.

- **Reactive** costs are £14.7m higher. As the volume of actions taken is in line with seasonal norms, this is driven by the increased cost of the actions taken and is therefore related to the continued high wholesale market prices.
- **Response** costs are £7.5m 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.

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for a single MWh) have decreased since the previous month, due to overall healthier margins relieving the effect of scarcity.

However, the May margin price remains higher than the price recorded in May last year which reflects the increased cost of actions taken to make more generation available to meet our operational margin requirements.

Daily costs trends

In May the monthly balancing costs outturned at £210.6m showing an increase from April of over £25m.

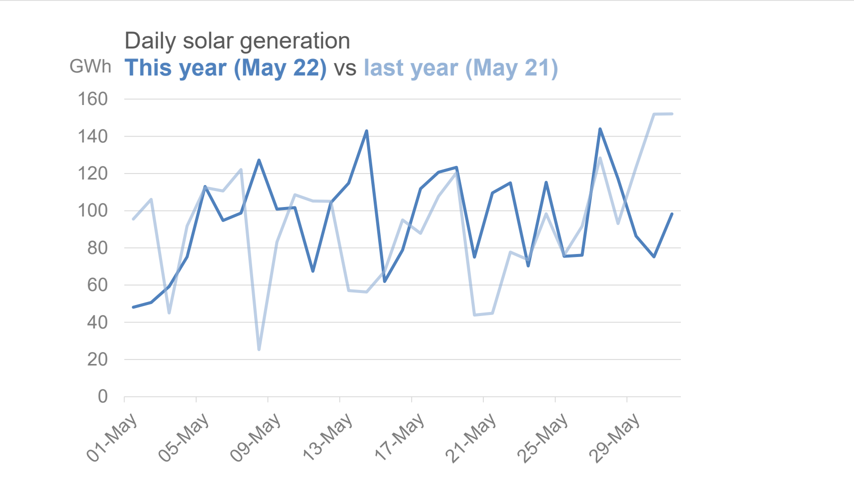
Throughout the mount we counted 7 days when the daily spend was around or above £10m, of which Friday 13th and Thursday 26th were the most expensive day of the month with a daily spend just below £12m in both cases. Windy weather requiring a large volume of BM actions to reduce generation to manage thermal constraints was 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.

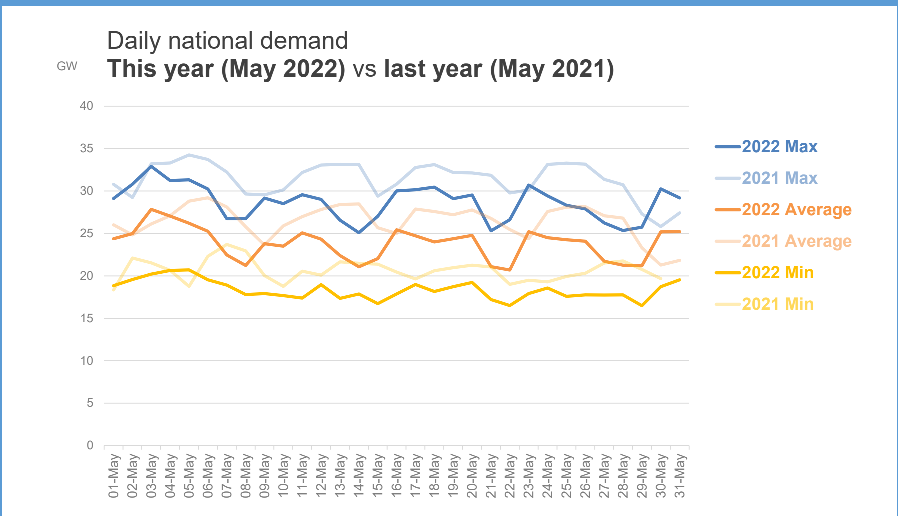
Significant events

There were no significant events during May.

Solar generation - comparison against last year



Outturn Demand vs 2020-21



Metric 1B Demand forecasting accuracy

May 2022 Performance

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

If the Optional Downward Flexibility Management (ODFM) service is used, it will be accounted for in the data used to calculate performance. The ESO 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 provisionally for the period April 2022 to March 23 in line with ESORI guidelines. These figures will be confirmed by Ofgem in due course.

Figure 2: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

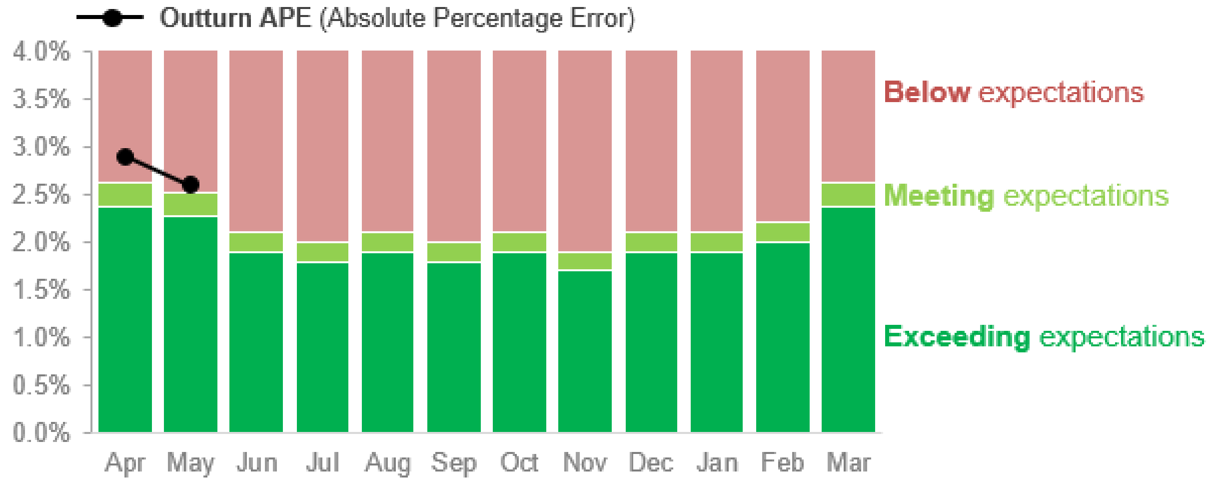


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

	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**											
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 **May 2022**, our MAPE (mean absolute percentage error) was 2.6% compared to the benchmark of 2.4%, and therefore below expectations.

The biggest errors on the day ahead forecasting horizon occurred on the 11,15,16 and 19 May and were mostly observed for the settlement periods between SP20 and SP35. This was mostly down to solar forecasting errors.

We are treating solar forecasting performance with high priority and investigating possible improvement. There is inherent, irreducible forecasting error with weather driven generation, which is outside of our control, i.e., weather data (radiation) data however there is a controllable element of the solar forecast, i.e., "model error" which we are going to work on in the next quarter.

To identify the settlement periods where ESO performed the best in May, monthly average performance errors by settlement periods were calculated.

Error greater than	Number of SPs	% out of the SPs in the month (1488)
1000 MW	311	21%
1500 MW	111	7%
2000 MW	35	2%
2500 MW	11	1%
3000 MW	2	0%

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

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

Metric 1C Wind forecasting accuracy

May 2022 Performance

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

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

Updated benchmark for 2022-23: The benchmark for this metric has been updated provisionally for the period April 2022 to March 23 in line with ESORI guidelines. These figures will be confirmed by Ofgem in due course.

Figure 3: BMU Wind Generation Forecast APE vs Indicative Benchmark (2022-23)

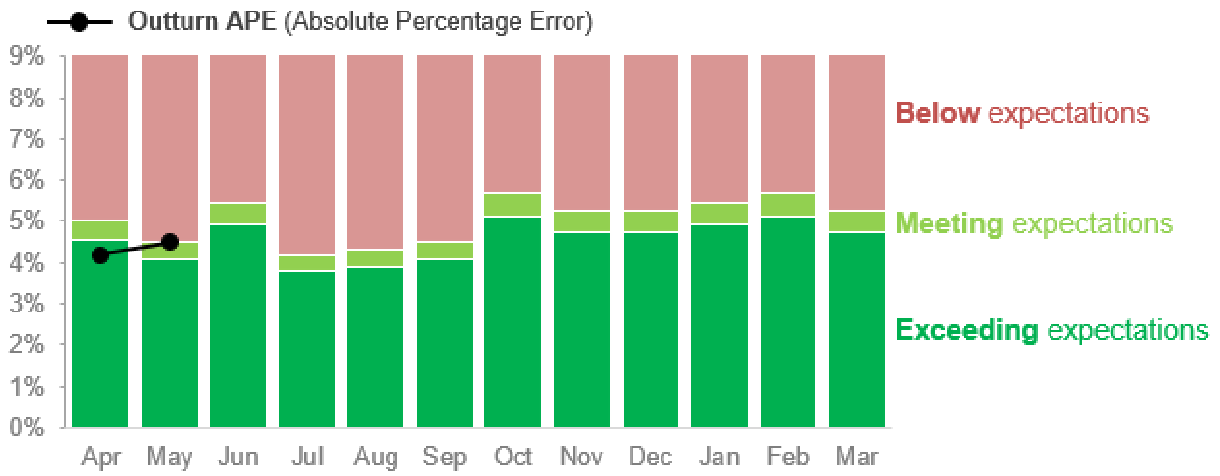


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
BMU Wind Generation Forecast Benchmark (%)	4.8	4.3	5.2	4.0	4.1	4.3	5.4	5.0	5.0	5.2	5.4	5.0	**4.8**
APE (%)	**4.2**	**4.5**											
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 **May 2022**, our MAPE (mean absolute percentage error) was 4.5% compared to the benchmark of 4.3% and therefore meets expectations.

May and June tend to be very stable months for good weather across the UK. The frontal system across northern areas brought rain and turbulent weather conditions on 05 and 06 May. A similar frontal system crossed Western and Central areas on 11 May. Stormy thunder showers moved up from the South on 15 and 16 May, and on 18 May the weather showed a very active multicell structure across Southern England moving North East with strong winds and frequent lightning and heavy rain. There were scattered thundery showers on 31 May.

Lightning was a feature on 05 May down the East coast and Kent, 14 and 15 May on the South coast, 16 May in Liverpool, Manchester and Leeds, 18 and 19 May in the South East and East Anglia, 23 May in East Anglia, and 29 May in Cornwall and South Wales. Lightning is a good indication of atmospheric stability which can be an indication of wind power forecast error.

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

https://www.emrsettlement.co.uk/settlement-data/settlement-data-roles/

Weather information was utilised 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

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

Metric 1D Short Notice Changes to Planned Outages

May 2022 Performance

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

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

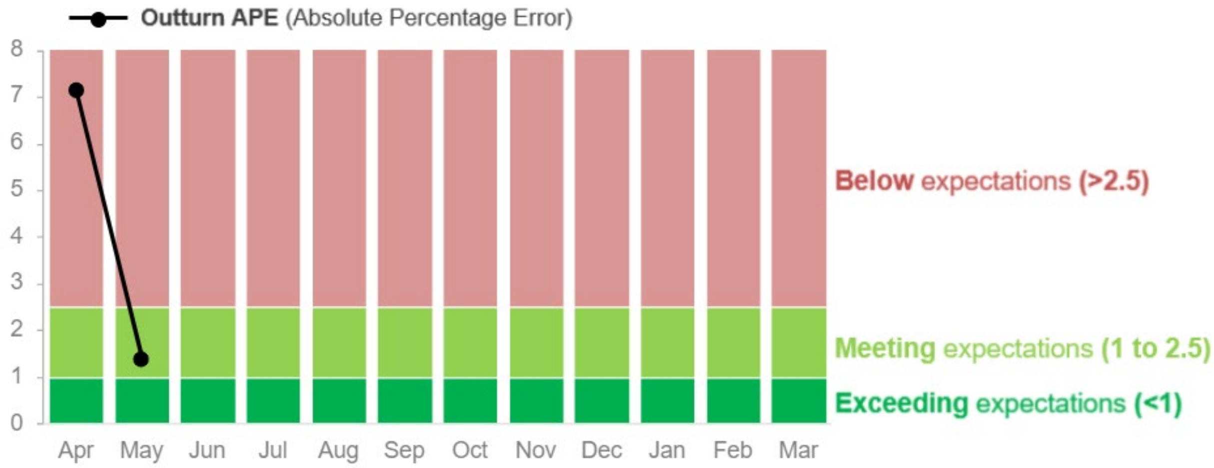


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	700	709											1409
Outages delayed/cancelled	5	1											6
Number of outages delayed or cancelled per 1000 outages	7.1	1.4											4.3
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 May, the ESO has successfully released 709 outages and there has been one delay or cancellation that occurred due to an ESO process failure. The number of stoppages or delays per 1000 outages is 1.41, which is within the 'Meets Expectations' target of less than 2.5 delays or cancellations per 1000 outages. The event can be summarized below:

A delay occurred due to outage that was unable to be released by the control room as it was identified for a certain fault on a Circuit Breaker which would lead to unacceptable power flows, resulting in a connected generator becoming unstable. The requested outage by the TO to switch out a section of 275kV busbar could not be accommodated due to a technical limitation that prevented a circuit from being reselected to the opposite busbar. Therefore, the planning department assessed switching out this circuit with the busbar following the usual planning process. However, a certain fault on a Circuit Breaker was missed by human error and was not identified until the outage had been agreed, and passed to the control room. As the outage could not be secured, the outage was sent back to planning to find alternative dates. An Operational Learning Note is being written to identify corrective measures.

RRE 1E Transparency of operational decision making

May 2022 Performance

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

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

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

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

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

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

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

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

	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%									
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.7%									
Percentage of actions with no category applied or reason group identified	**0.3%**	**0.3%**									

Supporting information

This month 93.3% 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 May 2022, we sent 41,341 BOAs (Bid Offer Acceptances) and of these, only 109 remain with no category or reason group identified, 0.3%.

RRE 1G Carbon intensity of ESO actions

May 2022 Performance

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

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in 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 7: gCO_2/kWh of actions taken by the ESO

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

Supporting information

In May 2022, the average carbon intensity of balancing actions was 2.2 gCO_2/kWh. The time with the largest decrease in carbon intensity due to the ESO's actions was 08:00am on 29th May 2022 with a minimum of –26.2 gCO_2/kWh. This was lower than April 2022's minimum value of -18.4 gCO_2/kWh. In May, the time with the highest carbon intensity increase was 02:00pm on 26 May 2022 with a value of 29.5 gCO_2/kWh. In comparison April 2022 had a maximum carbon intensity increase of 39.7 gCO_2/kWh.

RRE 1I Security of Supply

May 2022 Performance

This Regularly Reported Evidence (RRE) shows when the frequency of the electricity transmission system deviates more than ± 0.3Hz away from 50 Hz for more than 60 seconds, and where voltages are outside statutory limits. 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 ≤ f < 49.5	up to 60 seconds	2 times per year
48.8 < f < 49.2	Any	1-in-22 years
47.75 < f ≤ 48.8	Any	1-in-270 years

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

Table 8: Frequency and voltage excursions

	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										
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	1	1										
Voltage Excursions defined as per Transmission Performance Report[3]	0	0										

Supporting information

There have been no reportable voltage and one reportable frequency excursion for May 2022

On 4th 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.

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

RRE 1J CNI Outages

May 2022 Performance

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

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

Table 9: Unplanned CNI System Outages (Number and length of each outage)

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

Table 10: 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										
Integrated Energy Management System (IEMS)	0	0										

Supporting information

There were no outages, either planned or unplanned, encountered during May 2022.

Notable events during May

Balancing Strategy Capability Review

During April and May 2022 we have completed a series of 8 engagements (6 webinars, 2 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[4].

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).

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

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

May 2022 Performance

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

Figure 5: Monthly BSUoS forecasting performance (Absolute Percentage Error)

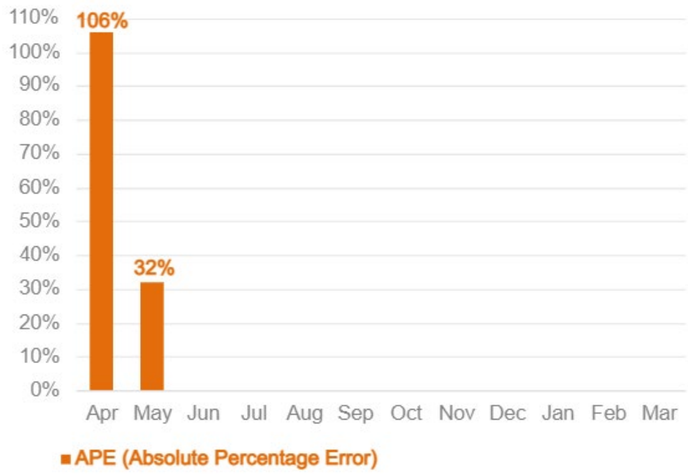


Table 11: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[5]

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	5.3	6.8										
Month-ahead forecast	11.0	9.0										
APE (Absolute Percentage Error)[6]	**106%**	**32%**										

Supporting information

Wind load factors for April and May were very similar (approximately 28%) but renewables contributed a higher proportion of the generation in May due to the lower national demand.

The wholesale electricity prices were lower in May than in April (day ahead May price was £126/MWh compared to £173/MWh in April).

May outturn costs were equivalent to approximately the 15th percentile of the forecast produced at the beginning of April. This is due to the elevated prices in the wholesale electricity forward curve available at the time. When the forecast was produced on 11 April, the month ahead wholesale price was approximately £195/MWh. During May we published our June 2022 BSUoS forecast and included a revised view of May. This was significantly lower at £6.58/MWh due to the reduction in wholesale electricity prices at the time of forecast production.

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

Notable events during May

First auction held for Dynamic Moderation

Our new frequency response service Dynamic Moderation has 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.

GB Pricing methodology approved

On 20 May 2022, Ofgem approved our proposal for a GB Pricing Methodology for settlement of balancing energy for specific balancing products submitted in accordance with Article 6(4) of the Electricity Regulation. This will allow the ESO to complete economic assessments on new balancing products to ensure that the most economically efficient payment mechanism is utilised, leading to best value for industry as a whole. This replaced the previous European Pricing Methodology set out ACER.

During the development of this piece of work, the ESO actively engaged various stakeholders through the mediums of webinar and bilateral conversations in order to build a GB Pricing Methodology which was robust, efficient and fit for purpose. The ESOs engagement activity received excellent feedback from members of the Joint European Stakeholder Group (JESG).

The GB Pricing Methodology has now gone live, and all new balancing products will undergo assessment moving forwards. All legacy products will remain on their current payment mechanisms.

New ESO report finds electricity market reform critical for delivery of future system that is affordable, secure and clean

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. Net Zero Market Reform, Phase 3 Assessment and Conclusions finds 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.

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

We issued an RFI on reactive capability in England and Wales

On 16 May the ESO issued a request for information (RFI) to look at accessing additional reactive capability across England and Wales between 2023 and 2026. We are at a very exciting time in the electricity industry as we move to a decarbonised electricity system and as we transition, we need to think differently about how the network is operated. One of the key technical challenges is in voltage management. This RFI sets out the challenge that we see in the short to medium term and is asking for existing and new providers that are capable of providing additional voltage services to come forward and express an interest in participating in a potential voltage contract. Within the RFI we set out the technical need in multiple zones across England and Wales and explain what information we need in order to make an assessment and determine the next stage which if appropriate would be to run a commercial tender process.

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 May

We published a paper on operational visibility of DER

In May we published a paper on operational visibility of Distributed Energy Resource (DER)[7]. It states increasing volumes of DER could provide Distribution System Operators (DSOs) and ESO with flexibility services, decreasing costs for consumers. The paper also notes the need to understand more about the volumes and behaviour of connected DER to better operate and plan networks, and the importance of continued system resilience including greater co-ordination between DSOs and ESO. The ESO has identified consumer benefits of up to potentially £150mn annually arising from greater operational visibility of DER.

The paper also discusses the need to remove of barriers to entry in markets that facilitate DER participation. This includes the need for operational metering at a standard that works for all parties and introduces the work being taken forward in Power Responsive this summer.

Feedback was invited on the paper by 10 June. 12 responses have been received which we are currently reviewing.

ESO and PeakGen voltage management project goes live in Merseyside

The first of our voltage management projects has gone 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.

[7] https://www.nationalgrideso.com/document/250251/download