nationalgridESO

ESO RIIO2 Business Plan

October Monthly Incentives Report

23 November 2021

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 October 2021 we have successfully delivered the following notable events and publications:

1. We collaborated with GE Digital and went live with an inertia measurement and forecasting service tool. This measures frequency and power flow changes between regions of Britain to give our control engineers a real-time view of system inertia.

2. Reactive Technologies announced the launch of its flagship grid stability measurement service that was developed with the support of the ESO.

3. North Sea Link (NSL) interconnector went live in October after extensive collaboration between the ESO, NSL and Statnett to complete the delivery of the IT systems needed to enable their commercial operations.

4. Grid Code modification GC0137, Minimum specification for equipment providing grid-forming capability, was approved to go to Ofgem for a decision. This modification proposes to add a non-mandatory technical specification to the Grid Code, relating to Virtual Synchronous Machine ("VSM") capability.

5. We held a webinar for the Future of Reactive Power project to update industry on the latest progress, project plan and design approach. We also provided an overview of system technical needs for reactive power.

6. Phase 1 of the Whole System Technical Code (WSTC) consultation was opened. This is an opportunity to support the Energy Codes Reform (ECR) outcome on code simplification and consolidation, and also to address some of the challenges of using the technical codes.

7. Work is continuing on our third Bridging the Gap to Net Zero report that will build on our 2021 peaks and troughs focal point. We have now concluded our external engagement.

8. The pre-tender consultation for Stability Phase 3 was closed and the team are now preparing for the launch of the one-stage tender.

9. Our annual Winter Outlook was published. We will be providing regular updates at the ESO Operational Transparency Forum.

10. We released our Autumn Offshore Coordination progress publication. This provides a consolidated view of the latest activities across the ESO offshore coordination project.

The table below summarises our Metrics and Regularly Reported Evidence (RRE) performance for October 2021:

Table 1: Summary of Metrics and Regularly Reported Evidence

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£315.6m vs benchmark of £128m	
Metric 1B	**Demand Forecasting**	Forecasting error of 1.9% (vs benchmark of 2.0%)	
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 5.2% (vs benchmark of 5.1%)	
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**	99.9% of actions have reason groups allocated	N/A

RRE 1G	**Carbon intensity of ESO actions**	4.8gCO2/kWh of actions taken by the ESO	N/A
RRE 1I	**Security of Supply**	0 instances 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 outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 35%	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

October 2021-22 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.

1. 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'.
2. 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'.
3. 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.).
4. 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 12.16 *(£m/TWh)*) + 19.75 *(£m)* + 41.32 *(£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.

Figure 1: Monthly balancing cost outturn versus benchmark

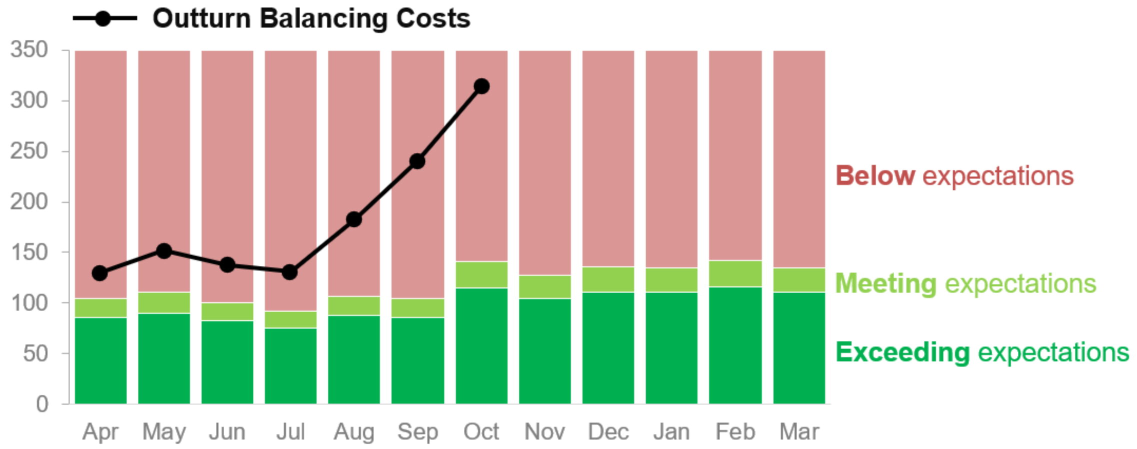


Table 2: Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	YTD
Benchmark: non-constraint costs (A)	41.3	41.3	41.3	41.3	41.3	41.3	41.3	289.2
Indicative benchmark: constraint costs (B)	59.9	50.6	52.3	49.2	58.4	66.9	76.3	413.4
Indicative benchmark: total costs (C=A+B)	101.2	91.9	93.6	90.5	99.7	108.2	117.6	702.7
Outturn wind (TWh)	2.8	3.2	2.5	1.9	3.0	2.8	5.5	21.6
Ex-post benchmark: constraint costs (D)	53.5	58.9	49.9	42.5	55.7	53.4	86.6	400.6
Ex-post benchmark (A+D)	**94.8**	**100.3**	**91.2**	**83.8**	**97.1**	**94.8**	**128**	**689.9**
Outturn balancing costs[1]	**130.0**	**151.7**	**137.8**	**130.9**	**182.4**	**240.3**	**315.6**[2]	**1288.6**
Status	●	●	●	●	●	●	●	●

Restoration is included from April 2021: Please note that the 2020-21 incentivised balancing cost figures did not include costs for restoration, but from April 2021 these are included.

Performance benchmarks

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

[1] Please note that previous months' outturn balancing costs have been updated with reconciled values
[2] Balancing cost figures were corrected in this re-published version of the October report on 17 December 2021. In the original report, some Constraints Sterilised Headroom costs were incorrectly allocated across other categories within Constraint Costs, due to an error in the reporting model. There are also minor changes to the overall figures for each month as the revised report uses slightly more up-to-date data.

Supporting information

The balancing costs for October were £315.6m, which is £75.3m higher than September, and in the ‘Below Expectations’ range.

Breakdown of costs vs previous month

		(a) Sep-21	(b) Oct-21	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	2.2	10.2	8.0	
	Operating Reserve	146.8	58.5	(88.3)	
	STOR	9.9	4.1	(5.9)	
	Negative Reserve	0.5	3.4	2.9	
	Fast Reserve	16.5	17.4	0.9	
	Response	32.1	41.1	8.9	
	Other Reserve	1.5	1.9	0.4	
	Reactive	12.4	13.4	1.0	
	Black Start	3.3	3.0	(0.3)	
	Minor Components	-23.0	9.0	32.0	
Constraint Costs	Constraints - E&W	3.9	30.1	26.3	
	Constraints - Cheviot	6.0	11.0	5.0	
	Constraints - Scotland	3.4	38.5	35.2	
	Constraints - Ancillary	10.3	6.5	(3.8)	
	ROCOF	5.6	19.3	13.7	
	Constraints Sterilised HR	8.9	48.2	39.2	
Totals	Non-Constraint Costs - TOTAL	202.2	161.9	(40.3)	
	Constraint Costs - TOTAL	38.0	153.7	115.7	
	Total Balancing Costs	**240.3**	**315.6**	**75.3**	

As shown in the total rows above, costs rose across most categories, the largest increase being in Constraint Costs, and a reduction in the cost for Operating Reserve from what was seen in September.

The main drivers of the changes this month were:

- **Operating Reserve:** £88.3m reduction. Operating Reserve costs remain high, although these are substantially reduced from the previous month given the lower cost of actions in the Balancing Mechanism (BM). Tuesday 12 October was the most expensive day in this category, with a daily spend of nearly £11m. This cost was incurred through the additional actions taken by ESO to meet the operational margin and reserve requirements. Available energy prices in the Balancing Mechanism on this day were high, hence the high cumulative spend.

- **Constraints Sterilised Headroom:** £39.2m increase. This correlates to the higher spend on constraints this month, restricting generation behind a constraint will sterilise any additional available energy on generators behind that constraint. October was a windy month, with active constraints requiring management (resulting in spend) and meaning that headroom held on those generators was replaced elsewhere outside the constraint. This forms part of the total figure allocated against the “constraint” category.

- **Response:** 8.9m 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 - E&W**: £26.3m increase. A combination of planned circuit outages and high wind levels led to an increase in actions taken to manage thermal and voltage constraints, leading to high costs.

- **Constraints – Scotland**: £35.2m increase. Windy weather during the month meant that managing thermal constraints required a high volume of BM actions to reduce the output of generation.

- **RoCoF**: £13.7m increase from the previous month due to high prices in the UK and Europe driving up the cost of securing the interconnectors

Constraint Costs vs Non-Constraint Costs

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

Overall October balancing costs are higher this year than for the same period last year. Constraint costs have risen sharply from the previous month due to planned outage volumes ahead of clock change, and high wind levels. YTD costs for 2021 Constraints remains lower than the YTD Constraint costs at the same time in 2020. Non-Constraint Costs are lower than the previous month but are still significantly higher than last year, as tight system margins and high gas prices have driven up prices for Operating Reserve, Fast Reserve and Response.

Constraint Costs

Compared with the same period last year:

Constraint costs have outturned higher than in 2020 this month due to:

- Increased thermal constraint costs to manage network congestion during high wind periods and facilitating network outages, particularly in Scotland.
- Increased spend on voltage support constraint requirements.

Compared with the previous month:

Constraint costs were higher than in September in all areas bar Ancillary costs

- As with the factors discussed above for the 2020 comparison, the increased spend was due to actions taken to manage thermal constraints and voltage management actions during high wind periods.
- RoCoF spend was higher than in September due to high prices in the UK and Europe driving up the cost of securing the interconnectors

Non-Constraint Costs

Compared with the same period last year:

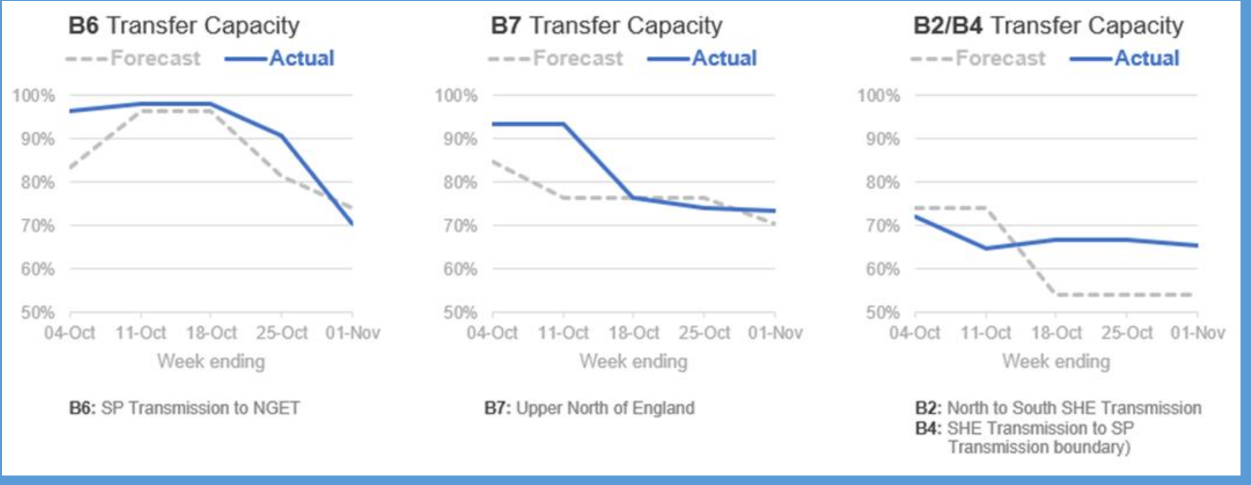
- Non-constraint costs remain significantly higher this year than last year. This is due to the continuing high prices available in the Balancing Mechanism and Day Ahead markets, driving the costs of actions taken.
- Response costs are also higher than this time last year due to the introduction of the Dynamic Containment service which has increased the requirements for response holding. This has

meant more response volume has been procured, and at a higher price than previously, given the increase in available energy costs.

Compared with the previous month:

- Non-constraint costs have decreased since the very high levels experienced in September. Whilst Operating Reserve costs remain high due to tight system margins and high gas prices in comparison to previous years, there has been a decrease of over £88m in spend for this area.

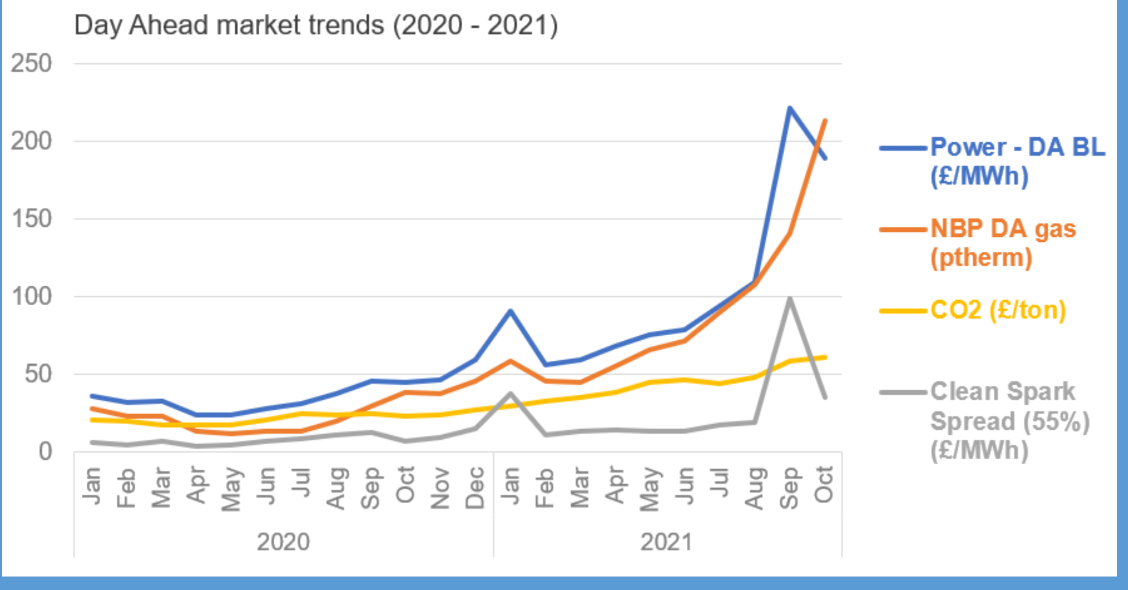
Network availability



Transfer capacity has been higher than forecast for the majority of the month. High wind levels have meant constraints have been activated, and actions taken to manage these contribute to the Constraints portion of the balancing costs.

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

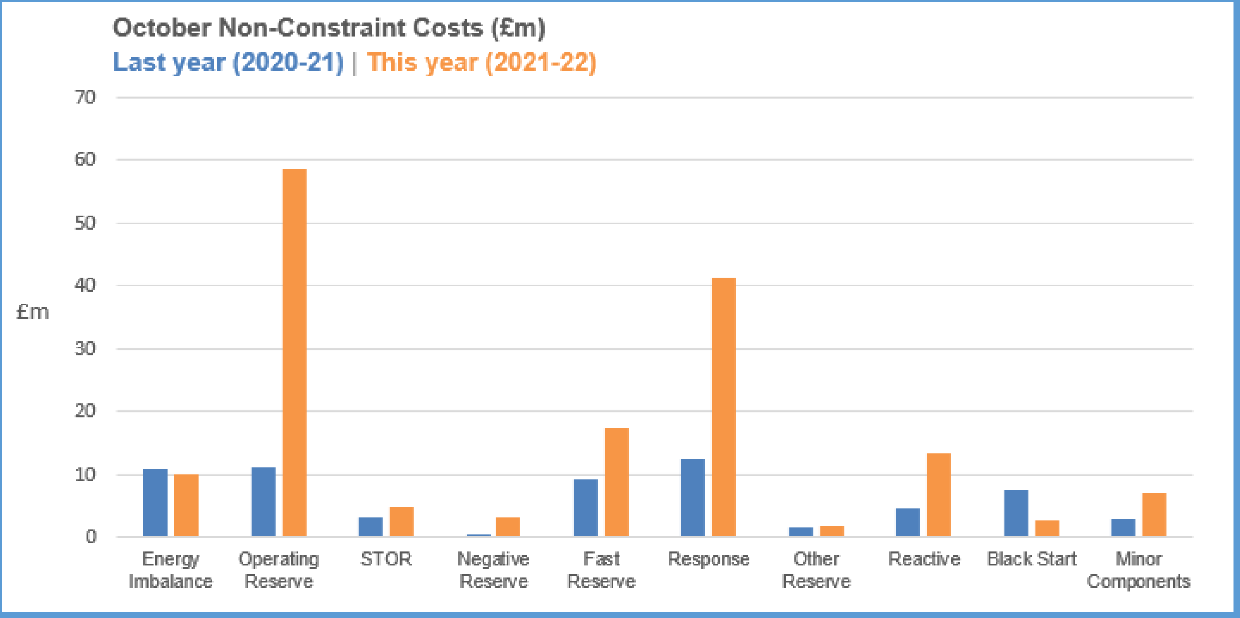


DA BL: Day Ahead Baseload **NBP DA: National Balancing Point Day Ahead**

Power day ahead prices fell slightly in October but remain high. Day ahead gas prices continue to rise this month which impact the cost of actions available to ESO to balance the system. This cost increase impacts the buy (offer) actions that we take, but also on the cost of sell (bid) actions that may be taken to manage thermal constraints – as was the case this month. The carbon price for this month has continued in the upward trend as seen for the majority of the year.

The combination of these factors demonstrates the increase in some of the underlying cost drivers of prices that are available for balancing actions, to ESO, and ultimately drive the total balancing cost total.

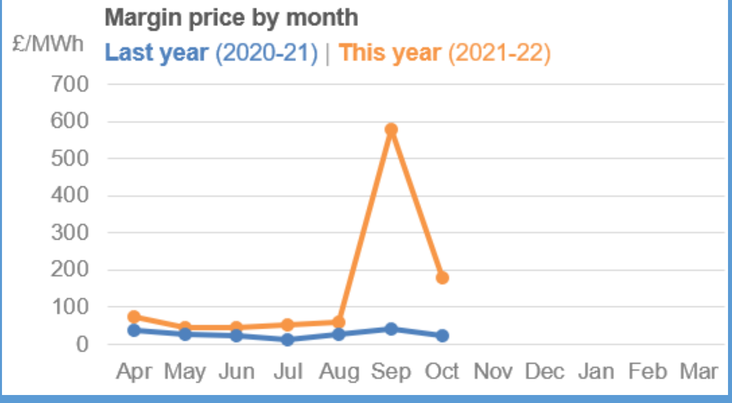
Cost trends vs seasonal norms



Comparing this year's October energy costs with those of October last year we can see that in the majority of categories prices have risen against last year.

- **Operating Reserve** costs have risen significantly in comparation to October 2020. This increase is driven by the higher cost of actions to maintain reserve available in the Balancing Mechanism, reflecting higher Day-Ahead power prices than last year.
- **Response** costs have increased from last year with the introduction of the Dynamic Containment service.
- **Fast Reserve** costs have also increased from last year. This is due to higher market prices and tighter margins driving the cost of Balancing Mechanism actions up, which in turn leads to higher costs for reserve

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for a single MWh) have fallen since the previous month but remain high when compared to the previous year.

Daily costs trends

There were several high cost days during October 2021 where actions were required to ensure all operability requirements were met. During periods of high wind and system outages, expensive actions were required to ensure system inertia remained above the minimum required level (including actions to increase inertia and provide voltage support).

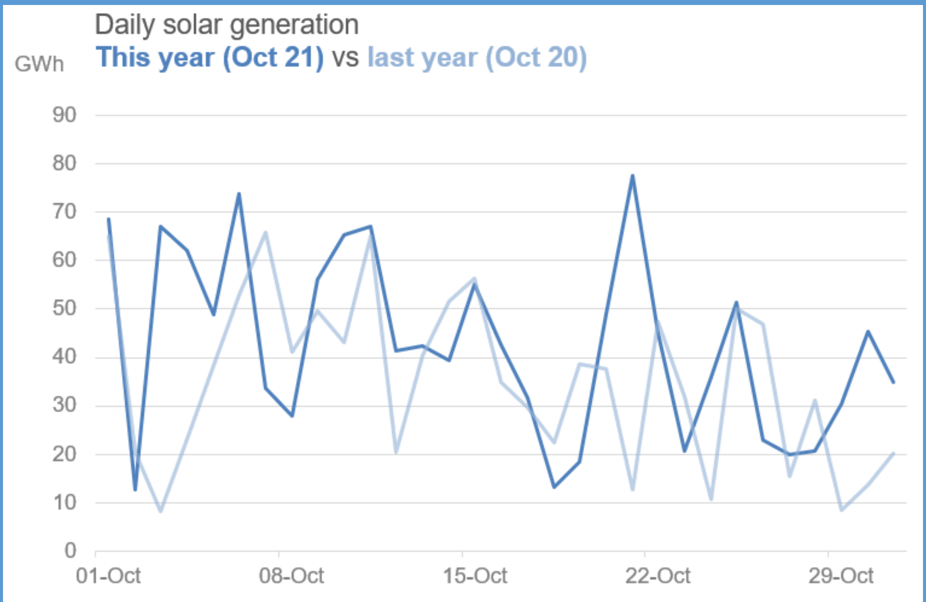
The highest cost day in October was Friday 1 October and both trading and BM actions were taken to manage an initially short market as well as to manage thermal constraints arising from windy conditions.

High cost days and balancing cost trends are discussed weekly at the Operational Transparency Forum to give ongoing visibility of the operability challenges and the ENCC associated actions.

Significant events

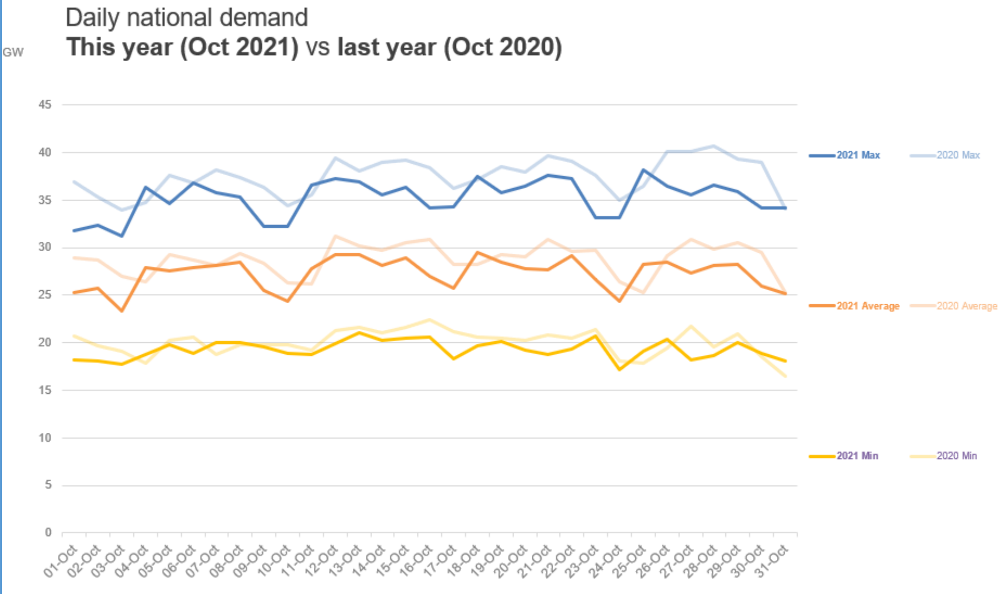
There were no significant events for this month that had an impact on balancing costs.

Solar generation - comparison against last year



Solar generation this year was comparable to last year but with higher output days.

Outturn Demand vs 2020-21



Demand for October this year has been lower than in comparison to last year. During both 2021 and 2020, no very low demands were observed in this month.

Metric 1B Demand forecasting accuracy

October 2021-22 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 last year'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.

Figure 2: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

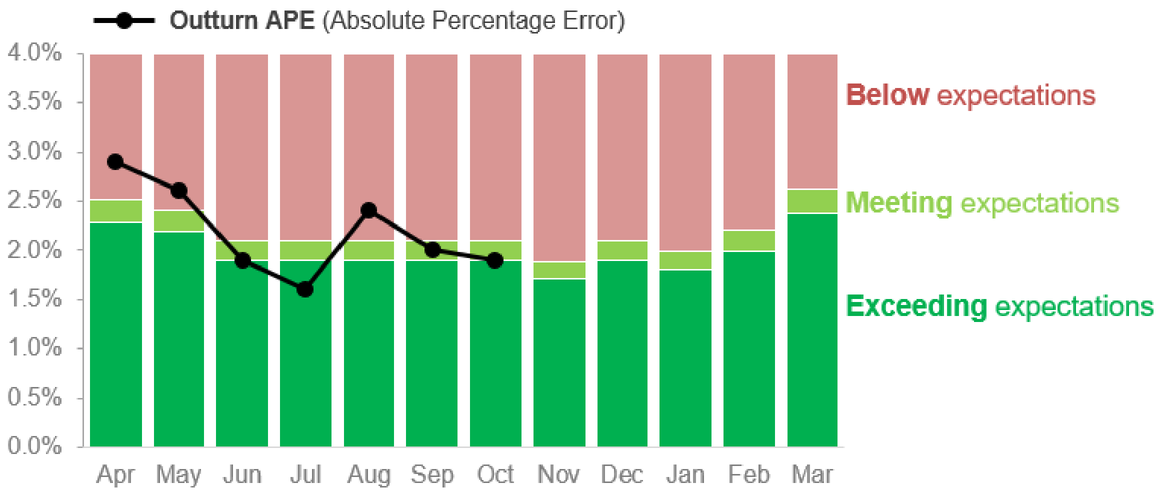


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
Indicative benchmark (%)	2.4	2.3	2.0	2.0	2.0	2.0	2.0	1.8	2.0	1.9	2.1	2.5	**2.1**
APE (%)	**2.9**	**2.6**	**1.9**	**1.6**	**2.4**	**2.0**	**1.9**[3]						
Status	●	●	●	●	●	●	●						

Performance benchmarks

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

[3] The October APE was corrected from 2.0% to 1.9% in this re-published version of the October report on 14 February 2022. The October status has changed from 'meeting expectations' to 'exceeding expectations'.

Supporting information[4]

In October 2021, our day ahead demand forecast indicative performance was “exceeding expectations” with a MAPE (mean absolute percentage error) of 1.9% compared to the benchmark of 2.0%.

Throughout the month 1B metric performance was comfortably within the benchmark. The clock change weekend significantly influenced the overall monthly performance. Nonetheless, ESO managed to exceed expectations.

The most challenging time period in October was the last weekend, the clock change weekend. Clock change weekend, both in autumn and spring, is a time when the forecasting uncertainty is heightened. It typically introduces the biggest performance challenges.

Performance in October 2021: big errors		
Error greater than	Number of SPs	% out of the SPs in the month (1490)
1000 MW	179	12%
1500 MW	65	4%
2000 MW	9	1%
2500 MW	0	0%
3000 MW	0	0%

In October there were no instances of missed or late publication of forecast data.

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

[4] This commentary was updated on 14 February 2022 following corrections in the October data, which changed the October APE from 2.0% to 1.9% and the status from ‘meeting’ to ‘exceeding expectations’.

Metric 1C Wind forecasting accuracy

October 2021-22 Performance

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

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

Figure 3: BMU Wind Generation Forecast APE vs Indicative Benchmark (2021-22)

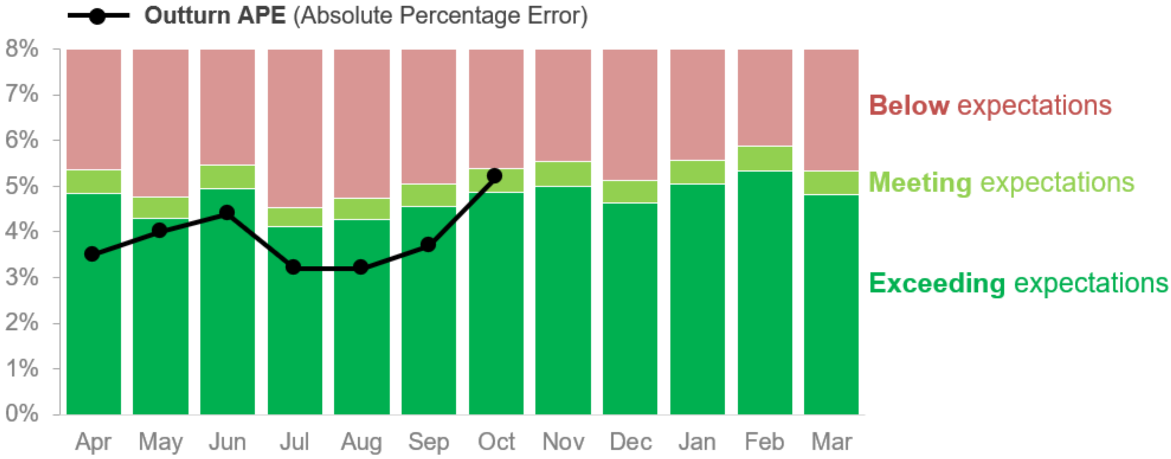


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
BMU Wind Generation Forecast Benchmark (%)	5.1	4.5	5.2	4.3	4.5	4.8	5.1	5.3	4.9	5.3	5.6	5.1	**5.0**
APE (%)	**3.5**	**4.0**	**4.4**	**3.2**	**3.2**	**3.9**	**5.2**						
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

In October 2021, our day ahead wind forecast indicative performance was meeting expectations with a benchmark of 5.1%. October's MAPE (mean absolute percentage error) was 5.2%.

October is traditionally the month when the weather transitions into the stormier Winter phase. This was certainly evident at the start of the month with very heavy rainfall on October 1st and 2nd.

Forecasting wind power output is much easier when wind conditions are low, and the scope of large errors is significantly reduced.

During October the jet stream alternated between passing to the North and passing to the South of the UK. In between times it was broken up into segments. This is a particularly difficult weather scenario to forecast accurately, since the jet stream controls the movement and formation of low pressure storm systems in the Atlantic and across the UK. When low pressure storm systems pass over the UK, small weather forecast errors in timing, track and intensity of the storm can have a large impact on the resultant wind power output. The most difficult weather scenario to forecast is when there are multiple low pressure centres active at the same time since this is more difficult for the supercomputers to calculate. This was the case on October 1st, 2nd, 3rd, 18th, 19th 20th, 30th and 31st.

The other factor that influences wind power forecast accuracy is metering error. For wind farms that have connected during the past 12 months, some issues with their metering data have been observed. These issues and other metering issues have been addressed with a weekly working group that is prioritizing and diagnosing metering issues. Improvement in metering data quality will lead to improved modelling of wind farm behaviour, which will result in more accurate forecasts going forward.

Wind farms with Contract for Difference (CfD) contractual arrangements switch off for commercial reasons while prices are negative for 6 hours or more. In October there were three occasions when the electricity price went negative but none of these occasions lasts for more than 6 hours. The electricity price used for this analysis is the Intermittent Market Reference Price. Market Price Data for October can be downloaded from the EMR settlement website[5].

In October there were no instances of missed or late publication of forecast data.

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

Metric 1D Short Notice Changes to Planned Outages

October 2021-22 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

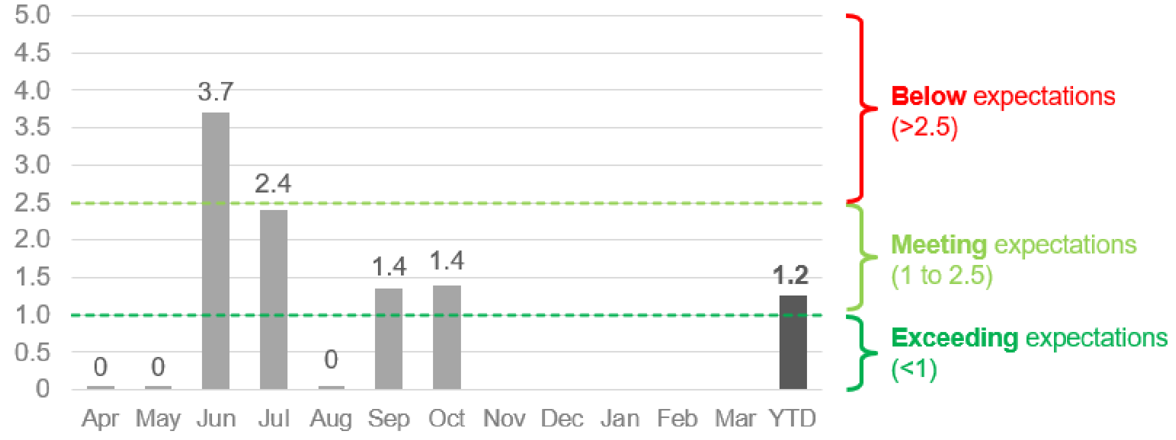


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	845	856	810	831	810	735	723						5610
Outages delayed/cancelled	0	0	3	2	0	1	1						7
Number of outages delayed or cancelled per 1000 outages	0	0	3.7	2.4	0	1.4	1.4						1.2

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

In October, the ESO successfully released 723 outages and there was a total of one delay or cancellation due to an ESO process failure. This gives a score of 1.38 per 1000 outages which is within the 'Meets Expectations' range of between 1 and 2.5 outages per 1000.

For April to October as a whole, the total delays or cancellations due to an ESO process failure is 7 out of 5610 outages. This gives a score of 1.25 per 1000 outages which is within the 'Meets Expectations' range. This is an improved performance compared to the same period last year (April to October 2020) when there were 2.74 cancellations or delays per 1000 outages (14 cancellations/delays out of 5118 outages).

The single event in October was a situation where one outage was delayed by the TO which impacted another planned outage, this resulted in two outages overlapping that could not take place simultaneously due to the impact it would have on a connected customer. The overlap of the two outages, that could not occur simultaneously, was missed by human error and was not identified in the outage planning database eNAMS. An Operational Learning Note (OLN) is to be written to identify the corrective actions for missing the knock-on impact initially

RRE 1E Transparency of operational decision making

October 2021-22 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.

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	90.4%	88.4%	89.3%	89.0%	88.4%	89.1%	92.6%					
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.6%	99.6%	99.7%	99.8%	99.8%	99.7%	99.9%					
Percentage of actions with no category applied or reason group identified	**0.4%** (173)	**0.4%** (147)	**0.3%** (56)	**0.2%** (87)	**0.2%** (81)	**0.3%** (109)	**0.1%** (61)					

Supporting information

For October, 92.6% of actions were either taken in merit or taken out of merit due to electrical parameters. For the remaining actions, where possible, we allocate actions to reason groups for the purpose of our analysis. We were unable to allocate reason groups for 0.1% of the total actions for this month. Although this remains a low percentage, we continue to look to understand any further trends or reasons for these actions being taken out of merit order.

RRE 1G Carbon intensity of ESO actions

October 2021-22 Performance

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

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

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

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	2.1	6.2	4.5	4.5	6.9	1.0	4.8					

Supporting information

The month of October 2021 saw an average difference between the carbon intensity of Final Physical Notifications (FPNs) and balancing actions of 4.75 gCO2/kWh.

37% of the time the actions taken by the control room lowered the carbon intensity from the market position as we secure and balance the system. The maximum difference was 40.7 gCO2/kWh and the minimum was -20.4 gCO2/kWh[6].

Renewable volatility continues to be predominantly solved through the use of gas (Combined Cycle Gas Turbines, CCGT), and there is a continuing sporadic use of coal, most likely linked to the relatively high gas prices.

[6] The minimum difference between the carbon intensity of FPNs and balancing actions was corrected from 20.4gCO2/kWh to -20.4gCO2/kWh in this re-published version of the October report on 14 February 2022.

RRE 1I Security of Supply

October 2021-22 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 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	0	0	0	0	0					
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	0	0	0	0	0	0	0					
Voltage Excursions defined as per Transmission Performance Report[7]	0	0	0	0	0	0	0					

Supporting information

There were no reportable voltage or frequency excursions in October.

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

RRE 1J CNI Outages

October 2021-22 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	0	0	0	0	0					
Integrated Energy Management System (IEMS)	0	0	0	0	0	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	0	1 outage 216 minutes	0	0	0					
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0					

Supporting information

There were no outages, either planned or unplanned, encountered during October 2021.

Notable events during October

Inertia measurement

As coal and gas power plants are phased out to meet Britain's net zero targets, we need to have better visibility of the inertia on the system to enable us to operate with more zero carbon generation. Our new tools will provide better measurement, contributing to ensuring we secure the system as economically as possible.

The combined approach of the stability pathfinder and our new inertia measurement capabilities will take us closer to our ambition of being able to operate a zero-carbon transmission system when this generation mix is provided by the market.

GE Digital's effective inertia measurement and forecasting service tool

In October we went live with an inertia measurement and forecasting service tool that we collaborated on with GE Digital. It measures frequency and power flow changes between regions of Britain 50 times a second to give our control engineers a real-time view of system inertia. It includes a machine learning model which also integrates with our control room system to give a 24-hour ahead forecast of system inertia – a vital view for our engineers in ensuring security of supply. As the first operational installation, the tool is currently in use by our business teams to understand the improved accuracy and develop the processes to integrate into our operational teams. Our intention is to launch this into the Control Room in Spring 2022.

Reactive Technologies grid stability measurement service

In October, Reactive Technologies announced the launch of its flagship grid stability measurement service, developed with the ESO, following the construction of the world's largest continuously operating grid-scale ultracapacitor in Teesside. This forms a critical part of the second innovative solution that will providing a real-time view of the system inertia once it goes live into the control room in Spring 2022.

With both inertia systems being "first-of-their-kind" operational installations, developed from innovation projects, there were delivery and innovation risks associated with both systems as well as dependencies on the Phasor Measurement Unit (PMU) roll out plans of the TOs. With the cost of managing low inertia increasing, the ESO decided to install both systems to minimise these risks and ensure that improved inertia monitoring would be available within the Control Room to improve transparency around decision making.

The GE Digital and Reactive Technologies systems complement each other in using different approaches, with potentially different levels of accuracy, enabling confidence to be built by comparing their outputs. In addition, the GE solution provides the ability to forecast inertia for the next 24 hours, based on operational data and machine learning.

North Sea Link interconnector

North Sea Link (NSL) went live on 01 October, ahead of which the ESO completed the delivery of the IT systems needed to enable their commercial operations. This required extensive collaboration between the ESO, NSL and Statnett to ensure the systems were robust, tested and fully integrated between all parties. There was also great teamwork during the commissioning tests with regular meetings that made sure the tests were a success. Since go-live we have continued to develop additional functionality in the IT systems which is due to be implemented this month. We have also established new processes in the control room to maximise the capacity available to exchange renewable energy between the two power systems.

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

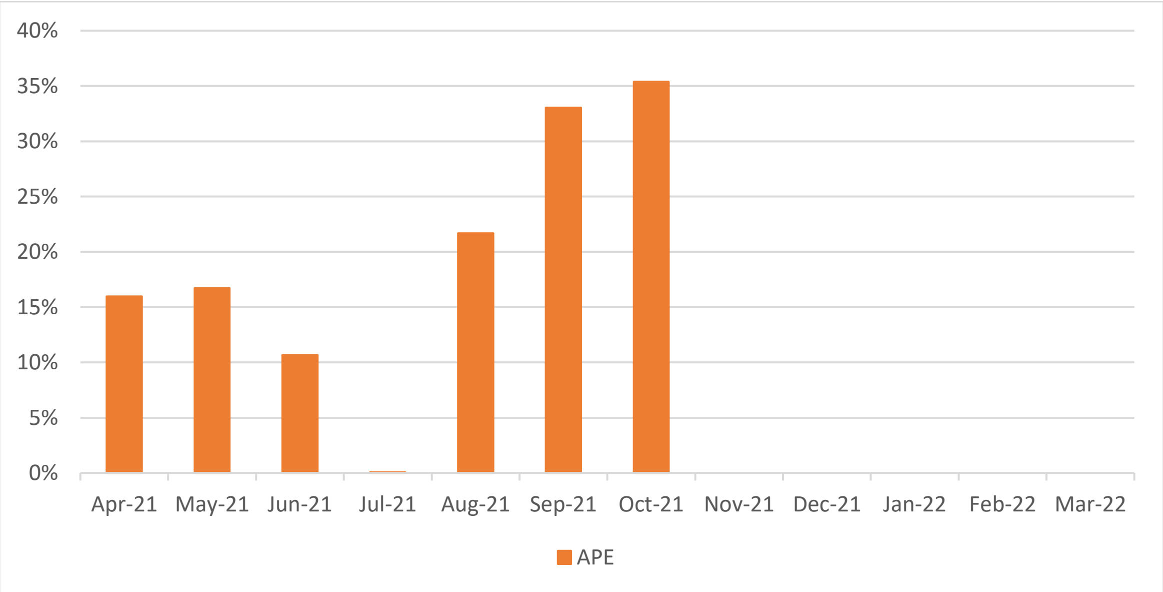
October 2021-22 Performance

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

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	3.8	4.5	4.6	4.2	5.8	7.1	8.4					
Month-ahead forecast	3.2	3.7	4.1	4.2	4.5	4.7	5.5					
APE (Absolute Percentage Error)[8]	**16%**	**17%**	**11%**	**0%**	**22%**	**33%**	**35%**					

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



Supporting information

The outturn BSUoS for October was significantly higher than September. Continued high Balancing Mechanism prices impacted significantly on the costs of actions taken to operate the system. Increased wind levels caused Constraint costs to rise due to increased congestion on the system and synchronising machines for voltage support and inertia. The total BSUoS volume increased as we move towards winter.

[8] 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 October

GC0137 Minimum specification for equipment providing grid-forming capability

This modification proposes to add a non-mandatory technical specification to the Grid Code, relating to what is referred to as Virtual Synchronous Machine ("VSM") capability. This specification will enable applicable parties (primarily those utilising power electronic converter technologies e.g. wind farms, HVDC interconnectors, and solar parks) to offer an additional grid stability service which will provide the opportunity to take part in a commercial market-based system.

At the end of an involved development process the final report for this modification was approved to go to Ofgem for a decision at the October 2021 Grid Code Panel meeting. The specification will allow participation in future pathfinders to provide stability products and is a key step to net zero. It is a world first as we are the first country to have set specifications for this and ENTSO-E are using it as an input for their work.

Future of Reactive Power webinar

Future of Reactive Power project held its third industry webinar[9] on Thursday 14 October 2021. The main purpose of this webinar was to update the industry on the latest progress, project plan and design approach, and also the overview of system technical needs for reactive power, together with the playback of recent market survey results. The ESO have been working with project partner Afry to deliver the analysis work in all three focused areas: technical analysis, market analysis, and commercial analysis. There were 27 providers on the call, including the traditional Reactive Power service providers as well as potential new providers. We received positive feedback on the webinar, with one provider scoring it 10 out 10 with the following comments 'Overall, the webinar was pretty comprehensive, clear, and concise. It helped the understanding of the market opportunity. Looking forward to next updates.'

Whole System Technical Code Consultation

We included a proposal for a digitalised whole system technical code during our RIIO-2 industry consultation process in 2019. This sought to digitalise and consolidate the Distribution Code (and its associated Engineering Recommendations (ERECs)), which relates to the distribution systems, and the Grid Code, which relates to the transmission system. We committed to ensure that there was engagement from industry on the direction of this work from the outset.

Phase 1 of this project is expected to conclude by 31 March 2022. There has been industry engagement at various forums since June 2021 which was focussed on building awareness of the project and informed our first consultation. The aim was to gather views on the scope, objectives, and approach, and guide the formation of an industry-led governance structure for the project. Between 27 September 2021 and 12 November 2021 when the first consultation was open, there were 18 attendees across the 6 webinars we held to discuss the consultation and enable industry participants to ask questions and provide feedback. For our first consultation, we have received a total number of 24 responses. We are currently reviewing the responses and shortly we will be contacting stakeholders interested in being part of the steering group that will be directing the project going forward. Since inception, we have engaged with over 500 industry stakeholders at different forum, bilateral and project specific meetings.

The second consultation will be designed and published by the steering group and project members, as informed by the first consultation, and will propose a more detailed single project scope.

[9] https://players.brightcove.net/867903724001/default_default/index.html?videoId=6277091190001

Role 3 System insight, planning and network development

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

Notable events during October

Bridging the Gap 2022 – Peaks and Troughs

We have started working on our third Bridging the Gap to Net Zero report that will build on our 2021 peaks and troughs focus. We are digging deeper into some of the dynamic peaks and troughs that present the greatest level of challenge to the ESO and wider energy system, and have begun working closely with our industry colleagues once again to challenge and review the critical actions needed to ready GB's energy system for high levels of renewables.

Stability Pathfinder Phase 3

The pre-tender consultation sought feedback on a number of documents ahead of the one-stage invitation to tender. The window to provide feedback closed on 22 October and the team are now preparing for the launch of the one-stage tender. In September we published the pre-tender consultation for Stability Phase 3 through the ESO website and facilitated two pre-tender webinars[10].

Winter Outlook publication

We published our annual Winter Outlook 2021-22[11] on Thursday 7 October and will be providing regular updates on operational surplus at the ESO Operational Transparency Forum. The report states that although the forecasts show there is sufficient capacity available for winter 2021-22, we will likely publish electricity margin notices in winter at a similar level to last year. Additionally, the report states that operability requirements remain complex but we have existing tools and services to manage anticipated operability challenges, that we expect sufficient operation surplus for each week of winter 2021-22, and that any tight margin days could see significant price spikes in the Balancing Mechanism. There is sufficient interconnector import and generation availability to meet demand throughout winter 2021-22, with a Loss of Load Expectation (LOLE) of 0.3 hours/ year – within the government set Reliability Standard of three hours LOLE – under the base case scenario. Additionally, under the base case scenario the de-rated margin at underlying demand level is stated as 3.9GW.

Autumn Offshore Coordination progress publication

On 18 October, we released our Autumn Offshore Coordination progress publication[12], providing a consolidated view of the latest activities across the ESO offshore coordination project, explaining how these activities align with the wider Offshore Transmission Network Review (OTNR), and signposting upcoming project milestones and opportunities to engage.

Following this, on 21 October, we hosted two industry webinars, one specifically for offshore developers, to provide an update on project progress and signpost next steps and opportunities to inform future work; and a project-wide progress webinar[13] where the Offshore Coordination project team discussed progress since the start of the year and provided an opportunity for stakeholders

10 https://www.nationalgrideso.com/future-energy/projects/pathfinders/stability/Phase-3
11 https://www.nationalgrideso.com/research-publications/winter-outlook
12 https://www.nationalgrideso.com/document/214981/download
13 https://www.nationalgrideso.com/future-energy/projects/offshore-coordination-project/latest-news

to ask questions[14]. Across both webinars we had in excess of 300 attendees and over 60 questions were raised and answered.

The ESO, under the Central Design Group (CDG) Terms of Reference (as part of the OTNR Pathway to 2030 workstream), established an Environmental subgroup to provide advice during the creation of the Holistic Network Design (HND). The ESO chaired the first meeting of the group in October 2021.

[14] https://www.nationalgrideso.com/document/220581/download