ESO RIIO2 Business Plan 1 (2021-23)

October 2022-23 Incentives Report

23 November 2022

ESO

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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 of Notable Events

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

- We published our Winter Outlook 2022-23 on 6 October 2022, building on the Winter Outlook - Early View we published in July 2022. It presents our view of the electricity system between October 2022 and March 2023 and is published to inform the energy industry and support its preparations for the winter ahead.
- We submitted the final proposals for our new Demand Flexibility Service, and held a communications workshop with industry in October. The service has since gone live, on 4 November, so will be covered in next month's report.
- Modifications to the TNUoS and BSUoS revenue recovery conditions in the Electricity System Operator licence were approved by Ofgem.
- Ofgem also approved modifications to the RIIO-2 Price Control Financial Instruments and Licence conditions to implement the closeout of RIIO-1.
- We successfully completed a software upgrade which allows us to share data more effectively with DNOs. This supports our Regional Development Programmes, where we're working with partner DNOs to deliver whole system solutions to facilitate the connection of Distributed Embedded Resources.
- On 20 October 2022, the EMR Delivery Body, alongside Delivery partners, EMR Settlement (EMRS) and the Electricity Settlements Company (ESC), conducted a Stress Event Customer Webinar. The purpose of this session was to aid Capacity Providers to further understand their obligations if a Stress Event were to occur, as a part of winter preparation and readiness.
- We held two Offshore Coordination webinars in October, as part of the 'Holistic Network Design Follow Up Exercise' which considers additional offshore wind farms in Scotland and in the Celtic Sea.
- We also launched our restoration service tender for the Northern region, which covers the North East, North West and Scotland areas

Table 1: Summary of Metrics and RREs for Role 1

This table summarises our Metrics and Regularly Reported Evidence (RRE) performance for August 2022.

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£493m vs benchmark of £176m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 2.5% vs benchmark of 2.0%	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 4.8% vs benchmark of 5.4%	●
Metric 1D	**Short Notice Changes to Planned Outages**	0 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**	92.6% of actions taken in merit order	N/A
RRE 1G	**Carbon intensity of ESO actions**	7.4gCO_2/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 planned and 0 unplanned system outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 4%	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 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[1] ***(£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.

[1] This is the benchmark formula for 2022-23. The benchmark for 2021-22 was calculated as: (Outturn Wind (TWh) x 12.16 (£m/TWh)) + 19.75 (£m) + 41.32 (£m)

Figure 1: Monthly balancing cost outturn versus benchmark – two-year view

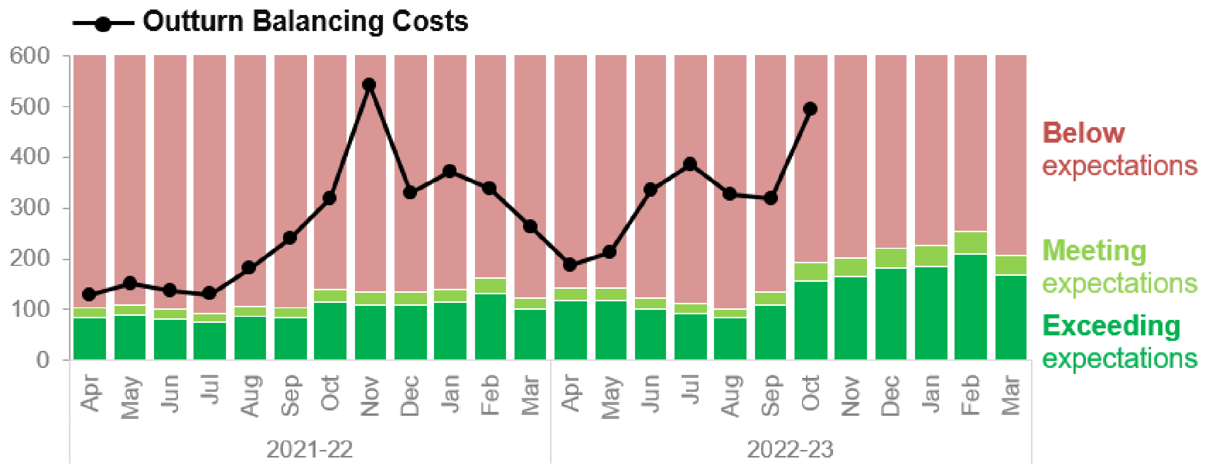

Table 2: Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Benchmark: non-constraint costs (A)	50	50	50	50	50	50	50						353
Indicative benchmark: constraint costs (B)	97	89	90	81	101	107	146						**711**
Indicative benchmark: total costs (C=A+B)	147	139	140	132	152	158	196						**1064**
Outturn wind (TWh)	3.8	3.8	3.1	2.8	2.3	3.5	5.6						**24.8**
Ex-post benchmark: constraint costs (D)	80	80	62	52	42	73	125						**515**
Ex-post benchmark (A+D)	130	130	113	130	93	123	176						868
Outturn balancing costs[2]	**188**	**213**	**335**	**385**	**327**	**318**	493						2259
Status	●	●	●	●	●	●	●						●

Rounding: monthly figures are rounded to the nearest whole number, with the exception of outturn wind which is rounded to one decimal place.

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

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

Supporting information

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

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

The Balancing costs for October 2022 were £493m, which is an increase of £175 m from September 2022.

Both, non-constraint and constraint costs increased this month, and both remain higher than last year.

A new cost category, Winter Contingency, has been added to the non-constraint costs this month. In response to the disruption of gas supplies to Europe, the Secretary of State approached ESO to secure additional non-gas capacity over winter 2022/23. The ESO has contracted five generation units across three coal fired power stations to stay available across this winter to provide extra generation should it be needed to ensure electricity security of supply. These contracts began in October 2022 and are the main driver of the increase in non-constraint costs this month.

The overall increase in constraint costs this month is the result of high wind and low demand. This in turn increases the cost of the Balancing Mechanism (BM) actions that we are required to take in order to reduce generation behind constraints and replace it with alternative generation.

Breakdown of costs vs previous month

Balancing Costs variance (£m): October 2022 vs September 2022

		(a) Sep-22	(b) Oct-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-2.5	-9.2	(6.7)	
	Operating Reserve	53.4	64.1	10.8	
	STOR	11.2	5.6	(5.6)	
	Negative Reserve	0.4	0.4	(0.1)	
	Fast Reserve	22.9	17.1	(5.8)	
	Response	33.8	27.4	(6.5)	
	Other Reserve	1.5	2.5	0.9	
	Reactive	36.8	41.4	4.6	
	Restoration	3.0	3.5	0.5	
	NEW CATEGORY Winter Contingency	0.0	62.0	62.0	
	Minor Components	41.5	21.5	(20.0)	
Constraint Costs	Constraints - E&W	8.6	53.9	45.4	
	Constraints - Cheviot	3.1	5.7	2.6	
	Constraints - Scotland	48.5	36.0	(12.5)	
	Constraints - Ancillary	0.7	1.3	0.7	
	ROCOF	8.0	23.8	15.8	
	Constraints Sterilised HR	46.9	136.1	89.2	
Totals	Non-Constraint Costs - TOTAL	202.1	236.2	34.1	
	Constraint Costs - TOTAL	115.7	256.8	141.2	
	Total Balancing Costs	**317.7**	**493.0**	**175.3**	

As shown in the total rows above, this month's significant increase in costs came from the constraint spend which increased by £141.2m. The non-constraint spends also showed an increase of £34.1m.

In the constraint category, the breakdown shows that Constraints E&W, RoCof and Constraints Sterilized Headroom were the key categories behind this increase, as all the other categories showed a decrease or minor variance.

In the non-constraint category, a significant increase was seen in Winter Contingency and Operating Reserve whilst all the other categories either decreased or showed little variance from the previous month.

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

- **Constraints Sterilized Headroom[3]: £89.2m increase**. As more generation was restricted behind constraints, the higher spend was to replace the additional energy available on constrained generators elsewhere outside the constraint.
- **Constraint E&W: £45.4m 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. The most expensive day for this category was Saturday 1 October with a daily spend of over £27m.
- **RoCoF: £15.8m increase.** Lower inertia levels during times of high wind required a higher volume of BM actions to secure the system against the RoCoF risk.
- **Constraint-Scotland: £12.5m decrease.** A change in the outage pattern and generation pattern resulted in fewer BM actions being required to reduce generation in order to manage thermal constraint over the Scotland, leading to reduction in the costs being allocated to this category.

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

- **Winter Contingency: £62m increase.** Due to the winter contingency contracts than began this month. See introduction to this section for more detail.
- **Energy Imbalance: £6.7m decrease**. The market was mostly long in October 2022.
- **Operating reserve: £10.8m increase**. Due to high BM prices being submitted by units which were required to maintain reserve levels.

Constraint vs non-constraint costs and volumes

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 2020-21 and 2021-22.

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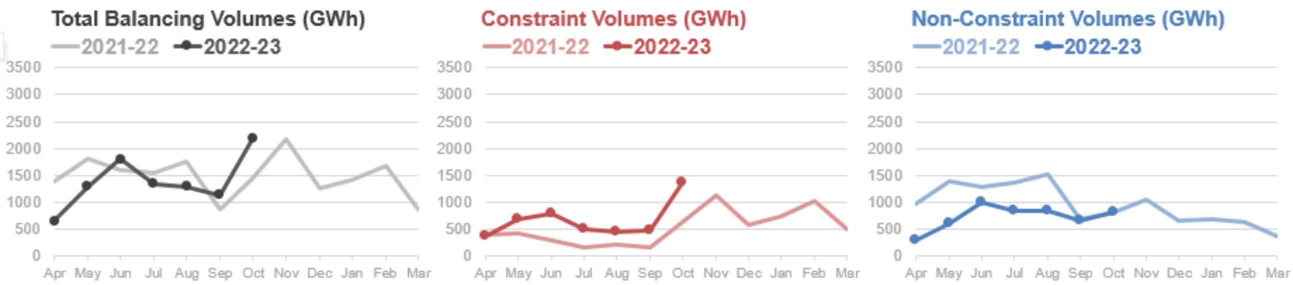
[3] Explanation of Constraints Sterilised Headroom:
When the ESO takes balancing actions (bids and offers) to redispatch generation to resolve a system constraint (e.g. a thermal or voltage constraint), the total cost of the bids and offers which are taken to resolve the constraint are normally categorised as constraint costs, and contribute to the line items within the constraint costs section of the table above (such as E&W).
However, in a situation where margins are tight, the cost of the offer (replacement energy) would be higher than usual. In this situation, some costs (associated with the offer) would be categorised as Constraint Sterilised Headroom, rather than one of the other Constraint categories. Constraints Sterilised Headroom is the result of post-event categorisation of balancing actions, rather than an action consciously taken by the Control Room.

Balancing COSTS (£m) monthly vs previous year

Balancing VOLUMES (GWh) monthly vs previous year



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 be revised once the data issue is resolved.

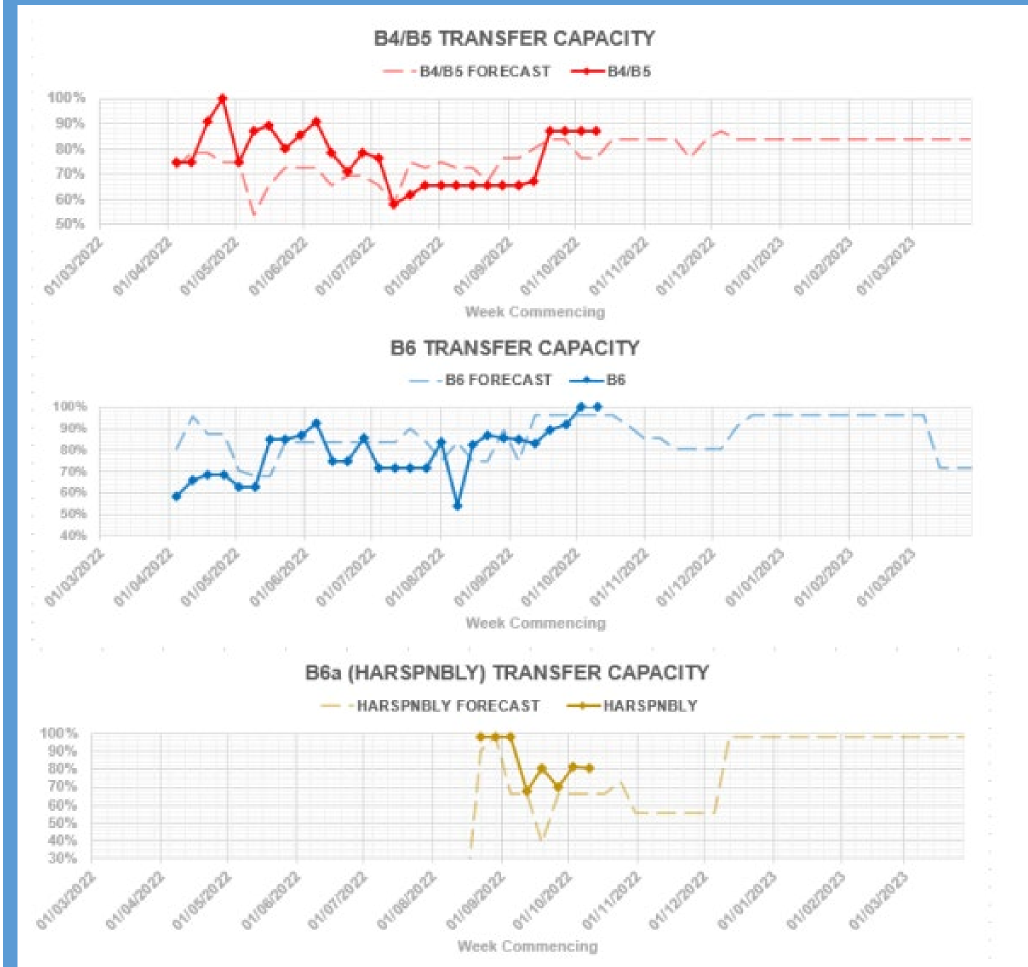
Constraint costs

Compared with the same month of the previous year:	Constraint costs were £103m higher than in October 2021 due to: The increased cost of actions to manage thermal constraints and network congestion during high wind periods. • The higher volume of actions which is in line with a higher wind generation level.
Compared with last month:	Constraint costs were £140m higher than in September 2022 due to: • Lower boundary availability which required a higher volume of BM actions to constrain generation and replace energy and headroom elsewhere.

Non-constraint costs

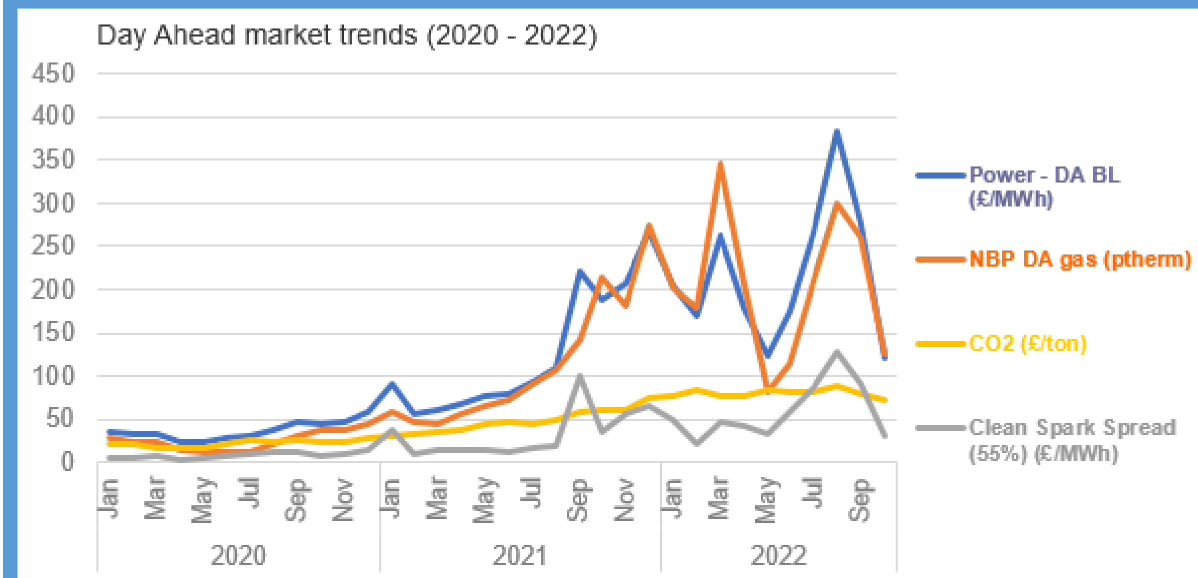
Compared with the same month of the previous year:	Non-constraint costs were £72m higher than in October 2021 due to: • The winter contingency contracts • The volume of actions was higher than previous year.
Compared with last month:	Non-constraint costs were £34m higher than in September 2022 due to: • The winter contingency contracts which began in October 2022. See introduction to this section for more detail.

Network availability 2022-33



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.

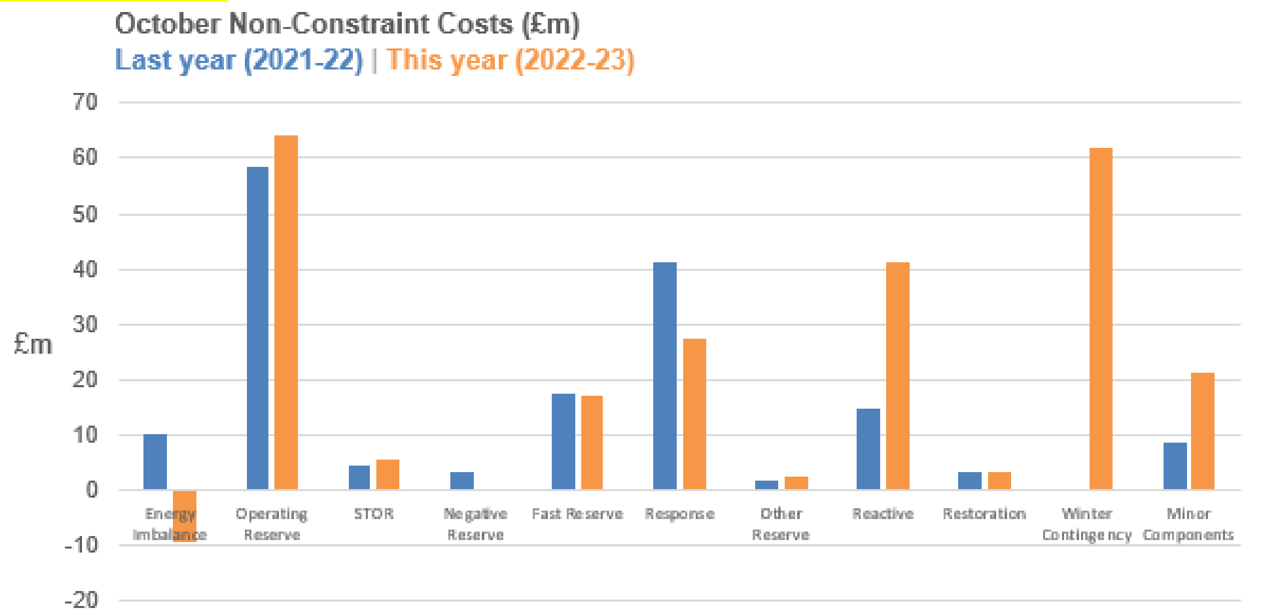
Changes in energy balancing costs



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

Power day ahead prices have fallen again in October. The day ahead gas prices have followed a similar trend. Carbon prices are slightly lower than the previous month, but higher than the same period of 2020 and 2021.

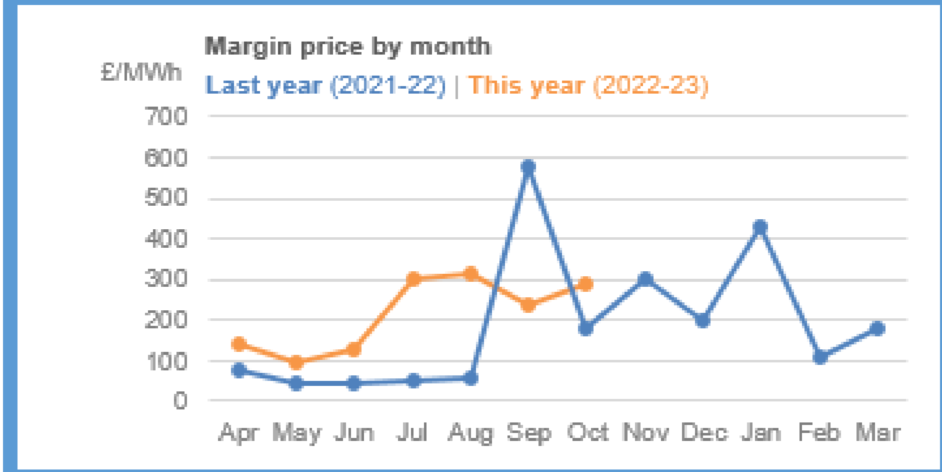
Cost trends vs seasonal norms



Comparing October 2022 non-constraint costs with those of October 2021, we can see that there has been a rise in Operating Reserve, Reactive, Minor components and the new cost of the Winter contingency contracts. The STOR, Fast Reserve, Restoration and Other Reserve categories showed little variance. We do not cover the variation in Minor Components here as it is driven by the data issue referenced earlier.

- **Operating Reserve costs are £5.6m higher. This** is mainly due to the high cost of BM actions driven by the high wholesale market prices
- **Reactive costs are £26.7m higher**. As the volume of actions taken is in line with seasonal norms, the increase in spend is driven by the increased cost of the actions taken and is therefore related to the continued high wholesale market prices.
- **Winter Contingency is £62m higher** due to the winter contingency contracts which began in October this year

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for a single MWh) have increased slightly since September and are higher than the same month last year

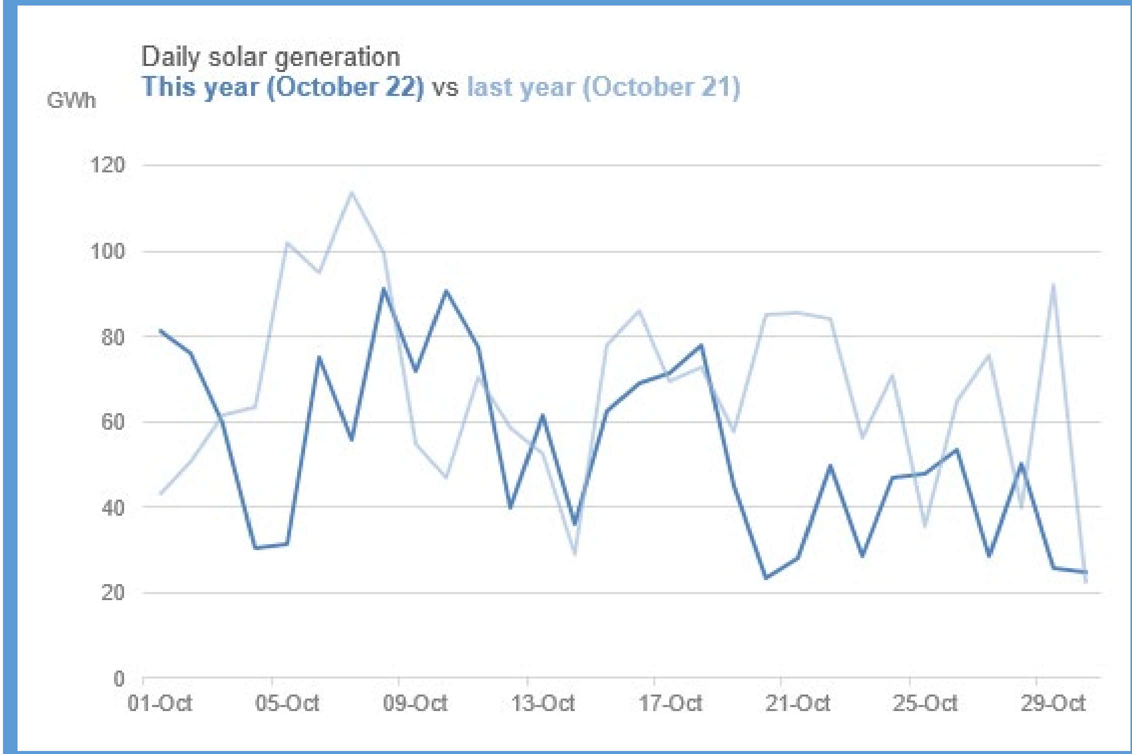
Daily costs trends

Thursday 06 October was the most expensive day in the month with a daily spend of slightly over £35m. Saturday 1st and Sunday 09 October were other expensive days with a daily outturn spend above £27m in each case. The main drivers were periods of windy weather and a significant number of new outages requiring a larger volume of BM actions to reduce generation to manage thermal constraints.

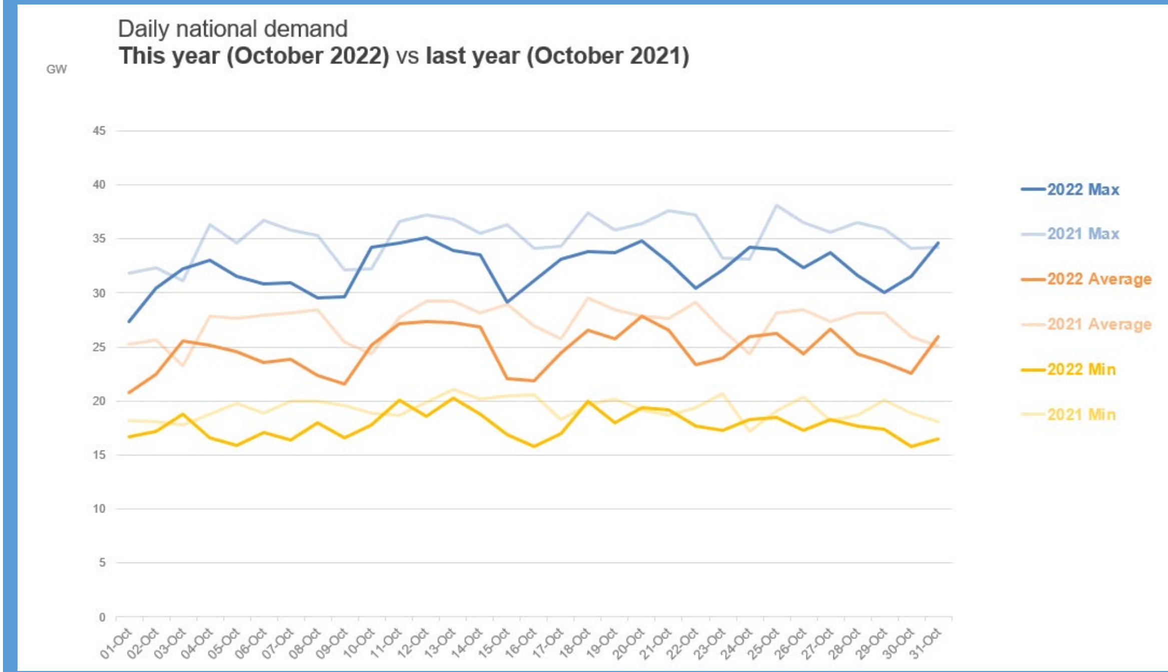
When a bid is taken to resolve a constraint, the energy on the system must then be replaced. When a large volume of BM bids is required to manage the flow on a boundary to below the constraint limit, that volume of energy needs to be procured in the BM to rebalance. The cost of the replacement energy 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.

Solar generation - October 2022 vs October 2021



Outturn Demand – October 2022 vs October 2021-21



Metric 1B Demand forecasting accuracy

October 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 will 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.

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

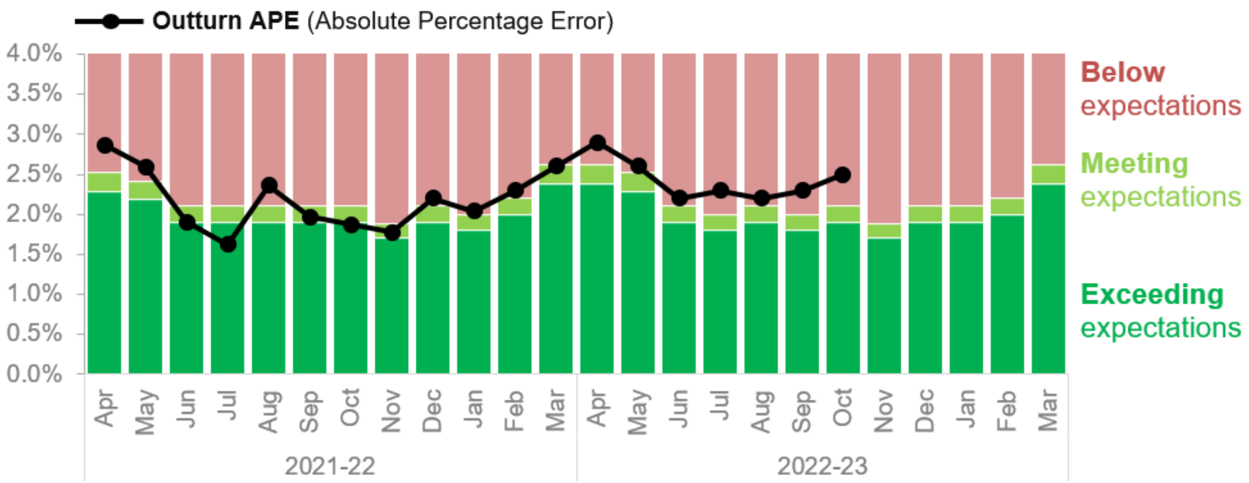


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
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 (%)	2.9	2.6	2.2	2.3	2.2	2.3	2.5						
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 October 2022, the mean absolute percentage error (MAPE) of our day ahead demand forecast was 2.51% compared to the indicative performance target of 1.96%, and therefore below expectations.

The biggest challenges in October 2022 continue to be weather related.

Solar generation is decreasing as the days grow shorter, but the variability in cloud cover within the day meant that solar errors contributed to many of the largest error days. Similarly, wind remained high but variable, and the timing of these large swings can cause big percentage errors even if off by only a few SPs.

National demand has continued to fall year on year, and this was especially noticeable in October 2022. Part of this drop can be explained by milder than normal weather as we head into the colder months. This greatly reduced national demand has the effect of increasing the percentage errors.

Additionally, clock change day (BST>GMT) posed extra challenges with altered behaviour, timings, and number of SPs.

The distribution of Settlement Periods (SP) by error size is summarised in the table below:

Error greater than	Number of SPs	% out of the SPs in the month (1488)
1000 MW	287	19%
1500 MW	112	8%
2000 MW	41	3%
2500 MW	16	1%
3000 MW	4	0%

The days with the largest MAPE were 30/10, 15/10, 20/10 and 5/10.

The SPs with the largest MAPE were SP23-33

From November, we will be increasing the amount of weather data we receive and feed into our models. This will enable model improvements to be developed over the winter period. Given the normal day-to-day variability in forecast error, it will take time to collect enough data to robustly measure the impact of these forecast improvements (at least one full quarter), so accuracy improvements won't be seen immediately.

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

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

Metric 1C Wind forecasting accuracy

October 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.

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

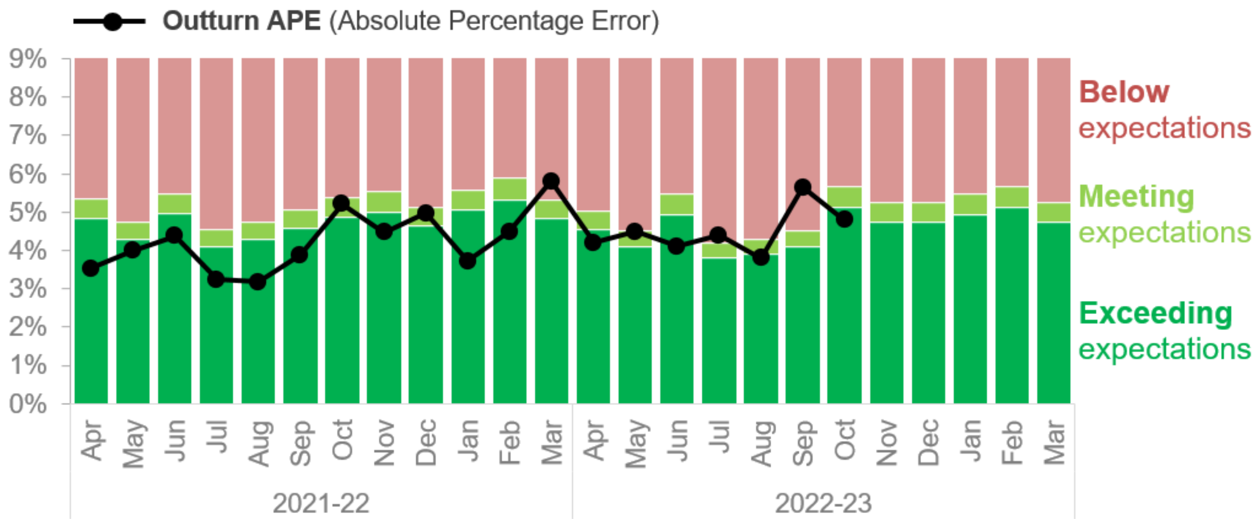


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2022-23)

	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	4.1	4.4	3.8	5.7	4.8						
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 October 2022, our MAPE (mean absolute percentage error) was 4.8% compared to the indicative benchmark target of 5.4% and therefore ‘exceeding expectations’.

October tends to be one of the trickiest months for wind forecasting owing to the wildly variable weather conditions as we transition into the stormier winter season. Higher winds often correlate with higher errors, including those due to the exact timing of weather fronts – the forecast being off by 1 hour can cause very large percentage errors. The difficulty in accurate forecasting in October is evident in the MAPE benchmark of 5.4% - the equal highest of the year.

There were 10 days with an average MAPE above 5.4% including one day (5 Oct) where the MAPE was 16.7%. This particular day was an outlier with unstable weather conditions where the promise of high winds didn’t eventuate. Other than this outlier, October was generally more predictable and less stormy than in previous years. Even so, it was a particularly windy month and GB wind generation records were broken.

Lightning was a regular feature in October with approximately half the days affected. Lightning is often a good indication of atmospheric instability 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 October 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 for this month can be downloaded here: https://www.emrsettlement.co.uk/settlement-data/settlement-data-roles/

From November, we will be increasing the amount of weather data we receive and feed into our models. This will enable model improvements to be developed over the winter period. Given the normal day-to-day variability in forecast error, it will take time to collect enough data to robustly measure the impact of these forecast improvements (at least one full quarter), so accuracy improvements won’t be seen immediately.

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

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

Metric 1D Short Notice Changes to Planned Outages

October 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 – two-year view

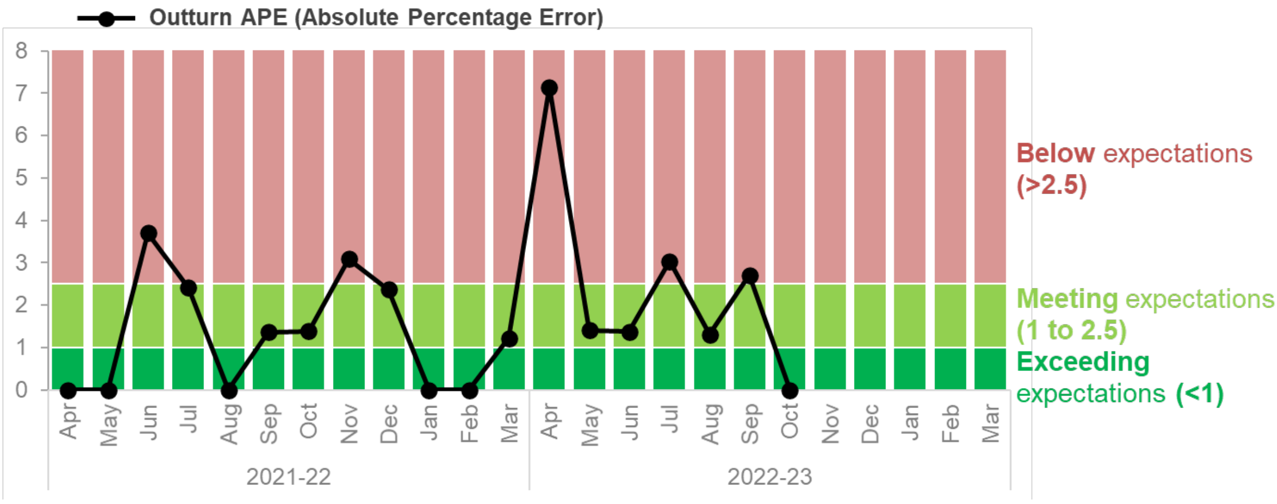


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	700	709	730	660	766	739	684						4988
Outages delayed/cancelled	5	1	1	2	1	2	0						12
Number of outages delayed or cancelled per 1000 outages	7.1	1.4	1.4	3.0	1.3	2.7	0						2.4
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 October, the ESO has successfully released 684 outages and there have been no delays or cancellations due to an ESO process failure. This is within the ‘Exceeds Expectation’ target of less than one delay or cancellation per 1000 outages.

The number of outages released in October 2021 was 723 and has decreased in October 2022 to 643, this is due to the reduced number of outage requests received from the TOs/DNOs for this period. This brings the cumulative number of short-notice changes per 1000 outages in 2022-23 back into the ‘Within Expectation’ target of less than 2.5 per 1000 outages.

Overall, the ESO is continuing to liaise with the TOs and DNOs to effectively facilitate system access through weekly or month liaison meetings to maximize system access.

RRE 1E Transparency of operational decision making

October 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.

Figure 5: Percentage of balancing actions taken in merit order in the BM – two-year view

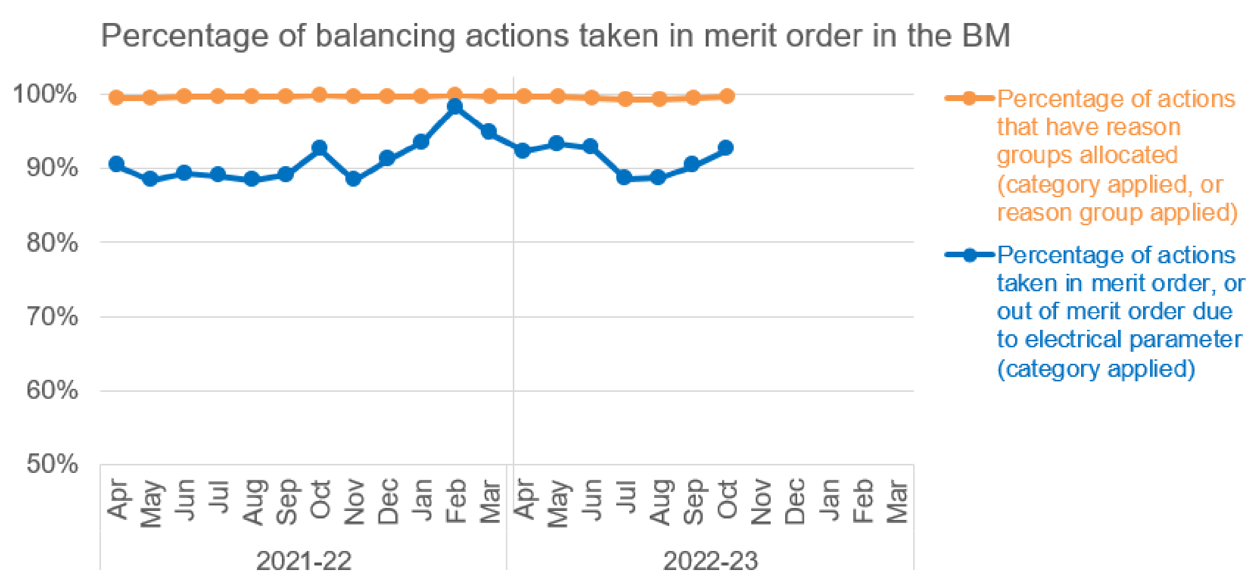


Table 6: Percentage of balancing actions taken outside of merit order in the BM

	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)	92.3%	93.3%	92.8%	88.6%	88.7%	90.4%	92.6%					
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.7%	99.6%	99.4%	99.4%	99.6%	99.7%					
Percentage of actions with no category applied or reason group identified	0.3%	0.3%	0.4%	0.6%	0.6%	0.4%	0.3%					

Supporting information

This month 92.6% 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 October 2022, we sent 64,312 BOAs (Bid Offer Acceptances) and of these, only 191 remain with no category or reason group identified, which is 0.3% of the total.

Data issue: Please note that we have recently identified an issue with the data used to support this metric. The impact of this issue is minor and is very unlikely to affect the reported figures.

- Over the 19-month period from April 2021, 11 days were not captured by the dataset.
- We have identified the cause in the data which is provided by an ESO legacy tool and we have implemented countermeasures to ensure any future missing days are flagged promptly and included into the dataset.
- We are unable to recreate the previous missing days due to the time elapsed.

RRE 1G Carbon intensity of ESO actions

October 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 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.

Figure 6: Average monthly gCO2/kWh of actions taken by the ESO - two-year view

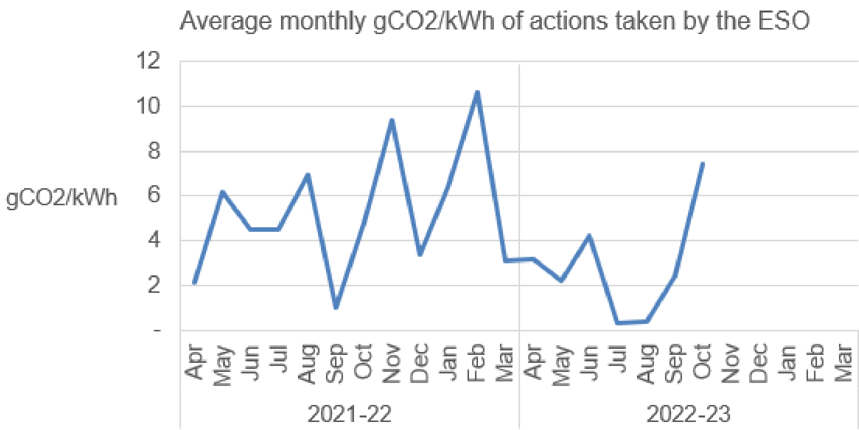


Table 7: Average monthly gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	3.2	2.2	4.2	0.3	0.4	2.4[4]	7.4					

Supporting information

In October, the average carbon intensity of balancing actions was 7.4 gCO2/kWh. This was an increase from September, but an expected increase as temperatures drop and the demand rises. In addition wind levels have picked up which has meant that we have had to constrain off wind generation due to thermal export constraints and replace the missing energy with carbon generation. This has added to the carbon intensity increase for the month.

Please note that the average Carbon Intensity figure for September has been revised as a data processing error has been corrected.

For Q1 2022-23, the average carbon intensity was 3.2 gCO2/kWh, whereas the figures have been lower throughout Q2. Q2 saw a reduction in the carbon intensity as we were taking significantly fewer operational actions compared with previous months. In addition, carbon generation has been supporting the increased exports from GB and they also provide the needed network ancillary services. This

[4] The average Carbon Intensity figure for September has been revised from -0.4gCO2/kWh to 2. 4gCO2/kWh as a data processing error has been corrected.

reduces ESO interventions and means that if we do take operational actions pulling back carbon generation, the market carbon figures for this RRE will also reduce significantly.

In October, the largest decrease in carbon intensity due to ESO’s actions was at 08:00 on 2 October with a minimum intensity of ESO actions at –16.3 gCO_2/kWh. The minimum for the year so far is –26.2 gCO_2/kWh on 29 May.

RRE 1I Security of Supply

October 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. On a monthly basis we 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 (2022-23)

	2022-23											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz for over 60 seconds)	0	0	0	0	0	0	0					
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	1	1	1	1	0	0	0					
Voltage Excursions defined as per Transmission Performance Report[5]	0	0	0	0	0	0	0					

Supporting information

There were no reportable voltage or frequency excursions in October.

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

RRE 1J CNI Outages

October 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) – two-year view

Unplanned	2021-22	2022-23											
	TOTAL	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	0	0	0	0					
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0					

Table 10: Planned CNI System Outages (Number and length of each outage) – two-year view

Unplanned	2021-22	2022-23											
	TOTAL	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	3[6] outages	0	0	0	1 outage 186 minutes	0	0	0					
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0					

Supporting information

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

[6] July 2021: 1 outage, 216 minutes.
November 2021, 1 outage, 215 minutes.
March 2022, 1 outage, 196 minutes.

Notable events during October 2022

Restoration service tender launched for Northern region

This year, as part of the Electricity System Restoration (ESR) strategy, the ESO has launched back-to-back competitive tenders to encourage more market liquidity and improve the diverse makeup of providers for restoration services.

Launched earlier in June, the South East region tender incorporated outputs from the Distributed ReStart innovation project for the first time. Additionally, by lowering some of our minimum technical requirements, newer technologies such as wind and battery storage dominated the distribution-led categories for restoration service provision. In the South East expressions of interest, there was three-fold the number of providers compared to previous years.

To continue in this trend, we launched the Northern region restoration service tender on 17 October which covers the North East, North West and Scotland areas. There was a lot of provider interest in the run up to this tender, and the expression of interest closed on 11 November. We are also working closely with the relevant DNOs across the regions as they have a more enhanced role to play for the distribution-led projects.

In between these two tenders, the ESO also launched a wind-specific restoration services in August, which was mainly aimed at supplementing ESR provisions nation-wide to help meet our restoration and resilience standards by tapping into the potential of 50GW of offshore wind generation forecasted for 2030. The outcome ESO hopes to achieve through this wide participation is more competition, better technical/economic solutions and the ability to achieve the ESO’s Electricity System Restoration Standard (coming into effect in December 2026) target to restore 60% of regional demand within 24 hours and 100% within 5 days.

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

October 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 7: Monthly BSUoS forecasting performance (Absolute Percentage Error) – two-year view

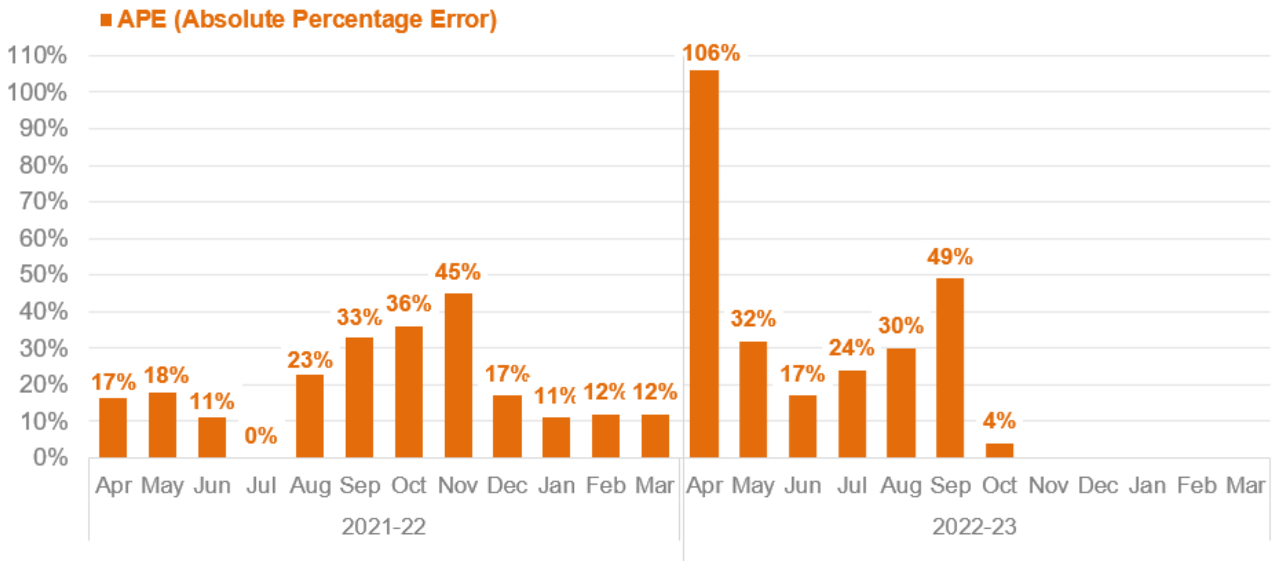


Table 11: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[7] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	5.3	6.0	9.4	10.3	9.2	8.5	12.5					
Month-ahead forecast	11.0	9.0	7.7	7.8	11.9	12.7	12.1					
APE (Absolute Percentage Error)[8]	**106%**	**49%**	**17%**	**24%**	**30%**	**49%**	**4%**					

Supporting information

The BSUoS charge (£/MWh) depends on the total BSUoS cost and the total volume.

The BSUoS cost forecast is probabilistic and therefore produces percentile values. The published forecast for each month is based on the central value of the BSUoS cost forecast (50th percentile). If the outturn BSUoS costs is below the 50th percentile of the cost forecast,

[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.

this means we expect the actual BSUoS charge to be lower than the forecast, if the actual volume is at or above the estimate, and vice-versa.

October performance

This month's Absolute Percentage Error of 4% is the lowest of 2022-23 so far. This is due to the better estimation of BSUoS volumes.

Costs: The October forecast was based on an average of the forward price curves derived between 1 and 7 September 2022. October outturn costs were around the 95th percentile of the forecast produced at the beginning of September, because the proportion of demand from renewable generation was higher in October (35%) than September (26%). The biggest difference between BSUoS costs in September and October was for constraint costs, which were £141 million higher for October. This was because October was a warm and windy month with low demand and high renewable generation.

Volumes: October actual BSUoS volume was only 5.5% higher than the estimate. (42.5 TWh instead of the estimate 40.3 TWh).

Notable events during October 2022

Demand Flexibility Service update

In October, progress continued on our new Demand Flexibility Service. The service went live on 4 November, so will be covered in our November report. The consultation launched in September closed on 3rd October. We submitted our final proposals to Ofgem on 14 Oct, and provider responses were issued on 18 Oct. We also held a communications workshop on 20 Oct with industry participants as result of their feedback.

Modifications to the TNUoS and BSUoS revenue recovery conditions in the Electricity System Operator licence approved

In August 2022, Ofgem consulted on proposed modifications to the conditions in the ESO licence which set out how much TNUOS and BSUoS revenue we are allowed to collect. The purpose of the modification was to ensure that the ESO licence conditions enable the accurate treatment of forecast risk and of the treatment of any over-collection so that the ESO recovers the correct amounts. The changes revised the calculation of the TNUOS Allowed Revenue calculation by introducing a new variable (DISC) to ensure that forecast risk associated with the calculation is not borne by the ESO. (Definition to DISC variable can be found here)

The modification also revised the definition of the TNR variable so as to allow the ESO to agree with Ofgem an alternate value for recovered revenue. (Definition to TNR variable can be found here).

This introduced a mechanism for the ESO to recover any revenue resulting from a restatement of RIIO-1 recovered revenue. There was also a change to the formula for calculating the Legacy Electricity Market Reform (EMR) incentives variable to provide a mechanism whereby the over-forecasting of EMR incentive revenue by the ESO can be returned to consumers via a reduction in Allowed Revenue.

Following internal review of the proposed modifications we submitted a response noting our agreement with the proposal. In our response, we also suggested some changes to the draft text of the licence modifications to better achieve the stated aims. We were the only respondent to the consultation and Ofgem agreed with our suggested amendments to the licence text. The decision to implement the modifications was published by Ofgem on 19th October. It comes into effect on 14 December 2022.

The Regulatory Policy team will make the necessary amendments to the conformed copy of the licence held on Grid:Home by the effective date in December.

Ofgem's decision letter can be found on their website at Decision on modifications to the Electricity System Operator licence conditions | Ofgem

Ofgem approve modifications to the RIIO-2 Price Control Financial Instruments and Licence conditions to implement the closeout of RIIO-1

The RIIO-1 price control period ran from 1 April 2013 until 31 March 2022. Within this framework there were several cost areas, which due to their uncertain nature, could only be finalised once all costs were known. As a result, at the end of the RIIO-1 price control, some elements needed to be settled, or subjected to 'close-out'. Ofgem issued a consultation in February 2022 which proposed the methodologies to be used to enable close-out of the ESO RIIO-1 price control. This included EMR IT Funding, Offshore Coordination Project, Early Competition Plan Project, Code Modification proposal 345 sunk IT costs, Covid-19 adjustments and withdrawal from Project TERRE (the Trans-European Replacement Reserves Exchange).

In September 2022, Ofgem then published the statutory consultation to amend the ESO's licence to enable the implementation of the close-out methodologies which had been decided on previously.

Along with changes to the licence there are also changes to be implemented in the ESO RIIO-2 Price Control Financial Model and Price Control Financial Handbook.

Having reviewed both the consultation on the proposed methodologies we confirmed that we agreed with Ofgem's proposals and then later confirmed that we agreed with the proposed modifications to the licence to implement close-out. The changes to the licence will go-live on 26 December 2022. An updated conformed copy of the licence will be available on Grid:Home.

Ofgem's decision can be found on their website at Decision on modifications to the RIIO-2 Price Control Financial Instruments and Licence conditions to implement the closeout of RIIO-1 | Ofgem

Stress event customer webinar held to aid capacity market providers' winter preparation

The Capacity Market (CM) regime is designed to deliver Security of Supply to the UK. The applicants of the CM are awarded Capacity Agreements if they are successful within the auction process and obliged to deliver during a System Stress Event.

On the 20th of October, the EMR Delivery Body, alongside Delivery partners, EMR Settlement (EMRS) and the Electricity Settlements Company (ESC), conducted a Stress Event Customer Webinar to aid Capacity Providers to further understand their obligations, as defined in their Capacity Agreements, if a Stress Event were to occur as a part of winter preparation and readiness.

The webinar detailed the relevant roles and responsibilities of the industry parties pre and post a Stress Event, as well as outlining the requirements for Capacity Providers. The event was well attended by 160+ parties and scored an 8/10 customer scores. The slides and the Q&A are published on the EMR Delivery Body website (Slides and Q&A). The recording of the Stress Event webinar is accessible here.

Role 3 System insight, planning and network development

Please note there are no metrics for Role 3

Notable events during October 2022

Winter Outlook 2022/23 published

We published our annual Winter Outlook 2022-23 on Thursday 6 October and will be providing regular updates on operational surplus at the ESO Operational Transparency Forum. This Winter Outlook is developed in the context of unprecedented turmoil and volatility in energy markets in Europe and beyond and shortfalls of gas in continental Europe could have a range of knock-on impacts in Britain. Therefore, in this Winter Outlook in addition to our Base Case, we also set out scenarios to illustrate the implications should some of those risks to security of energy supplies materialise.

Our central view remains, as set out in the Base Case, that there will be adequate margins (3.7GW / 6.3%) through the winter to ensure Great Britain remains within the reliability standard[9], although we expect there to be days where we will need to utilise many of the tools in our operational toolkit, including use of system notices such as Electricity Margin Notices and Capacity Market Notices. Given the scale of uncertainty and risks associated with the current geopolitical situation we have developed a range of new tools, including:

- **Winter Contingency Contracts** – On instruction from BEIS, the ESO has contracted 5 generation units across 3 three coal fired power stations to stay available across this winter to provide extra generation should it be required.
- **Demand Flexibility Service** – an innovative service building on a successful trial run earlier in the year which will recompense consumers for agreeing to reduce their electricity consumption across set periods of time.

While our Base Case assumes that capacity across all providers (generation, storage, interconnection etc.) is available in line with commitments secured under the Capacity Market, we have also modelled a scenario whereby the energy crisis in Europe results in electricity not being available to import into Great Britain from continental Europe. This could be due to a combination of factors, including a shortage of gas in Europe (which in turn limits power generation in Europe) and / or generation unavailability (e.g., due to a high level of outages across the French nuclear fleet). We have also considered the scenario where there is a shortfall of gas available in Great Britain.

Our first illustrative scenario examines what would happen if there were no electricity imports from continental Europe[10]. In this scenario we would deploy our mitigation strategies – dispatching the retained coal units and our Demand Flexibility Service. By securing 4GW[11] through these actions, we would maintain adequate margins and mitigate impacts on customers.

A second, more extreme scenario, looks at a hypothetical escalation of the energy crisis in Europe such that there is insufficient gas supply available in Great Britain (in addition to no electricity available to import from continental Europe as per above scenario). In the unlikely event that escalation of the situation in Europe means that insufficient gas supply were to be available in Great

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[9] The reliability standard is 3 hours Loss of Load Expectation (LOLE). Modelling shows the Base Case LOLE to be 0.2 hrs, well within the standard

[10] The scenario assumes no electricity imports available from France, Netherlands and Belgium; 1.2 GW imports from Norway; 0.4 GW exports to Northern Ireland & Ireland.

[11] We expect the additional coal units to provide 2 GW and therefore the Demand Flexibility Service would need to provide 2 GW.

Britain this would further erode electricity supply margins[12] potentially leading to interruptions to customers for periods. All possible mitigating strategies, including our new measures, would be deployed to minimise the disruption.

Software upgrade to enhance data sharing for RDPs

As part of our Regional Development Programmes, the ESO is working with partner DNOs to deliver whole system solutions to facilitate the connection of Distributed Embedded Resources (DER). A core part of this work relies on the increased sharing of operational information and data to enable the delivery of our N-3 intertripping project (a co-ordinated transmission-to-distribution intertripping scheme) and our MW Dispatch project (which will deliver a new coordinated transmission constraint management service across specific DNO regions).

The SCADA system (Supervisory Control and Data Acquisition) is the tool that provides operational awareness and control functionality to the ESO, within which the TASE software allows integration of external data links so that the system is able to receive and understand common data forms. To facilitate increased data sharing, we have recently successfully completed a software upgrade to our TASE application which allows us to share SCADA data more effectively with DNOs across our Inter-Control Centre Communications Protocols (ICCP) links. This upgrade means that our DNO stakeholders and partners will be able to utilise both older and newer versions of TASE when exchanging data with the ESO across these links.

This work is also an enabler for our two new ICCP link deliveries with both NGED and SSEN, both of which are nearing final commissioning and expected to be available to support the deployment of our N-3 intertripping project and new MW Dispatch capabilities with partner DNOs.

Offshore Coordination webinars

The Holistic Network Design Follow Up Exercise (HNDFUE) is the follow up to the initial Holistic Network Design (HND) that was delivered in July 2022 and forms part of the Offshore Transmission Network Review (OTNR). The HNDFUE considers additional offshore wind farms in Scotland and in the Celtic Sea and will facilitate an economic, efficient, operable, and coordinated design that minimises environmental and community impact in accordance with the four objectives outlined in the methodology. This will further support the Government's previously stated government targets for offshore wind and net zero and aims to provide recommended designs by the end of Q1 2023.

On 25 October, a ScotWind webinar was held, which focused on the scope of the HNDFUE, engagement opportunities and interface points being considered, which attracted over seventy attendees, ahead of workshops being held in Glasgow in November.

On 27 October we held a Celtic Sea webinar, again attracting over seventy attendees. This webinar focused on how the ESO are working with The Crown Estate, how we will engage with stakeholders as we develop the design recommendations and how this all interacts with the leasing round.

[12] Due to the curtailment of gas supplies to gas fired power stations in GB for example CCGTs etc.