ESO RIIO2 Business Plan

August 2022-23 Incentives Report

23 September 2022

Contents

Introduction

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

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

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

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

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

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

Please see our website for more information.

Summary

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

- We launched a consultation on our proposal to launch a new Winter demand flexibility service, that will utilise and reward household and business energy flexibility.
- We have put in place contracts with EDF and Drax to secure up to approximately 1500 GWh of energy from four coal fired generation units that would otherwise have closed before Winter 2022/23.
- Octopus Energy published the results from the Domestic Scarcity Reserve Trial that we collaborated on in February and March this year.
- The ESO and Octopus Energy Group have announced the first successful integration of vehicle-to-grid (V2G) technology, using a test environment of the Balancing Mechanism
- As part of the ESO's Restoration and Resilience services strategy, a one-off wind specific tender was launched on 8 August, alongside the usual region-specific tenders.
- At the August Transmission Charging Methodology Forum and CUSC Issues Steering Group there was agreement for industry to look to develop ideas and solutions, on how to deal with winter and increasing costs. CMP395 has since been raised which seeks to cap BSUoS costs and defer payment to the 2023/24 charging year to help protect GB energy consumers during the energy cost crisis.
- The tender for B6 Constraint Management Pathfinder 2024–2025 was launched on 08 August and will close on 16 September, with contracts award in October. The parties that have already started providing the service ahead of the 2023 start date have saved the consumer £30m to date.
- ESO and Energy Exemplar announced an agreement to use the energy market simulation platform PLEXOS to identify cost-efficient grid expansion priorities.

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

Table 1: Summary of Metrics

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£326m vs benchmark of £93m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 2.2% vs benchmark of 2.0%	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 3.8% vs benchmark of 4.1%	●
Metric 1D	**Short Notice Changes to Planned Outages**	1.3 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**	88.7%% of actions taken in merit order	N/A
RRE 1G	**Carbon intensity of ESO actions**	0.4 gCO_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 30%	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

August 2022-23 Performance

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

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

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

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

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

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

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

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

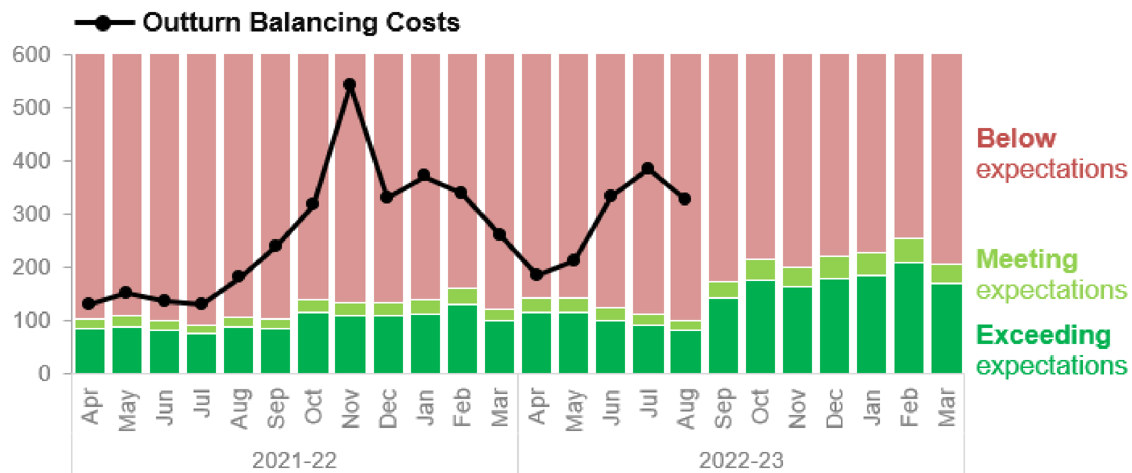


Table 2: 2022-23 Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	YTD
Benchmark: non-constraint costs (A)	50	50	50	50	50	50	252
Indicative benchmark: constraint costs (B)	97	89	90	81	101	107	458
Indicative benchmark: total costs (C=A+B)	147	139	140	132	152	158	710
Outturn wind (TWh)	3.8	3.8	3.1	2.7	2.3		15.7
Ex-post benchmark: constraint costs (D)	80	80	62	52	42		317
Ex-post benchmark (A+D)	130	130	113	103	93		569
Outturn balancing costs[1]	187	213	335	385	327		1445
Status	●	●	●	●	●		●

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

Performance benchmarks[2]

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

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. This data issue is under investigation and although the categorisation of costs is not correct, we are confident that the total costs are correct in all months.

August performance

The balancing costs for August 2022 were £327m, showing a decrease of £58m from July.

Whilst both constraint and non-constraint costs remain higher than last year, the constraint spend decreased from July. Due to the ongoing data issue stated above, the non-constraint cost element is reported as showing an increase this month.

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

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

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

Breakdown of costs vs previous month

Balancing Costs variance (£m): August 2022 vs July 2022

		(a) Jul-22	(b) Aug-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	1.9	-8.7	(10.6)	
	Operating Reserve	29.9	53.3	23.3	
	STOR	7.8	11.3	3.4	
	Negative Reserve	0.4	-0.3	(0.7)	
	Fast Reserve	19.6	25.5	5.9	
	Response	40.4	31.9	(8.5)	
	Other Reserve	1.5	1.4	(0.2)	
	Reactive	19.8	24.5	4.7	
	Restoration	4.6	2.8	(1.8)	
	Minor Components	18.3	48.0	29.7	
Constraint Costs	Constraints - E&W	115.3	18.9	(96.4)	
	Constraints - Cheviot	0.5	0.2	(0.3)	
	Constraints - Scotland	47.2	34.5	(12.7)	
	Constraints - Ancillary	0.3	0.4	0.1	
	ROCOF	1.8	2.6	0.8	
	Constraints Sterilised HR	75.2	80.5	5.3	
Totals	Non-Constraint Costs - TOTAL	144.3	189.6	45.2	
	Constraint Costs - TOTAL	240.2	136.9	(103.3)	
	Total Balancing Costs	**384.6**	**326.5**	**(58.1)**	

As shown in the total rows above, this month's significant cost reduction came from the constraint spend which fell by £103m, while the non-constraint spends increased by £45m. We will only be able to provide the complete, confirmed breakdown of costs across the different categories once the data issue has been resolved.

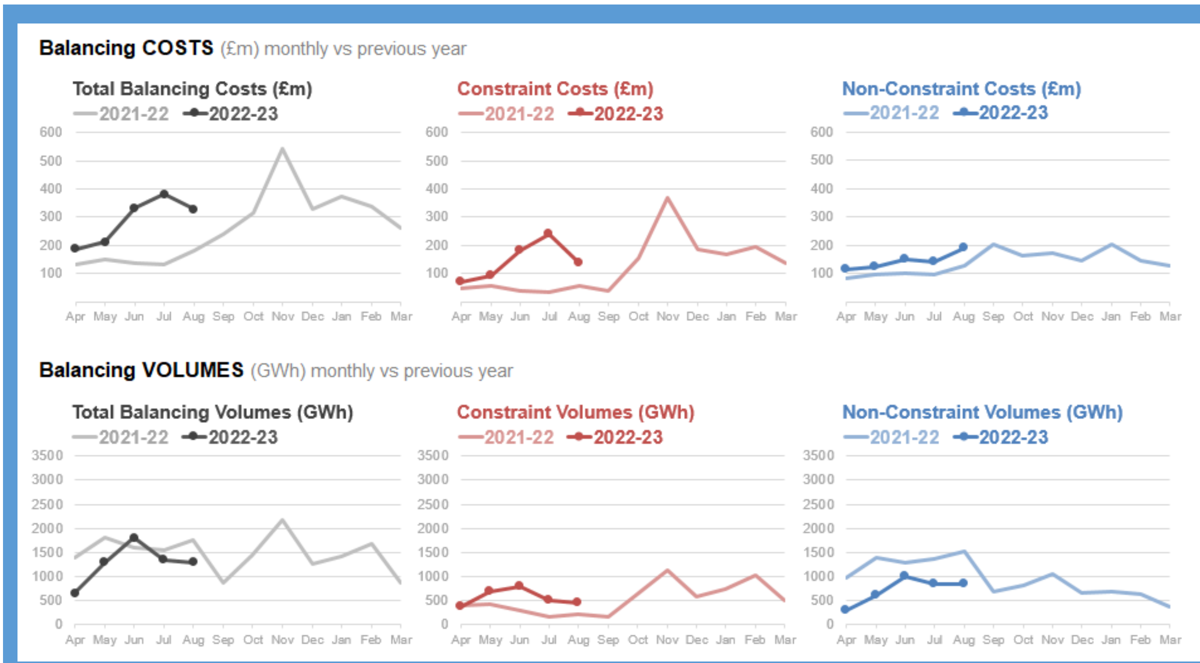
Within the constraint category, the breakdown shows that Constraints E&W was the key factor behind the decrease from July, as all the other categories showed only a small variance.

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

- **Operating reserve: ~£23m increase** due to high BM prices being submitted by units which were required to maintain reserve levels.
- **Minor Components: ~£30m increase** as mentioned above, we know that currently some costs are being allocated incorrectly as Minor Components, and this month the figure is bigger than in recent months

Constraint Costs vs Non-Constraint Costs

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



As discussed above, within Constraints, we know that currently some costs are being allocated incorrectly as Minor Components within Non-Constraint Costs. The narrative below discusses the broad themes of spend, but please note that the categorisation of costs between the constraint and non-constraint categories will be corrected once the data issue is resolved. The total balancing cost figures will not change.

Constraint Costs

Compared with the same month of the previous year:

Constraint costs were around £82m higher than in August 2021 due to

- The ongoing higher wholesale prices compared with last year. 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 the previous month:

Constraint costs were ~£103m lower than in July 2022 due to:

- Improved boundary availability which required fewer BM actions to constrain off generation and replace energy and headroom elsewhere, and a reduced volume of constraint actions and a lower level of wind generation compared to the previous month.

Non-Constraint Costs

Compared with the same month last year:

Non-Constraint costs were £64m higher than in August 2021 due to:

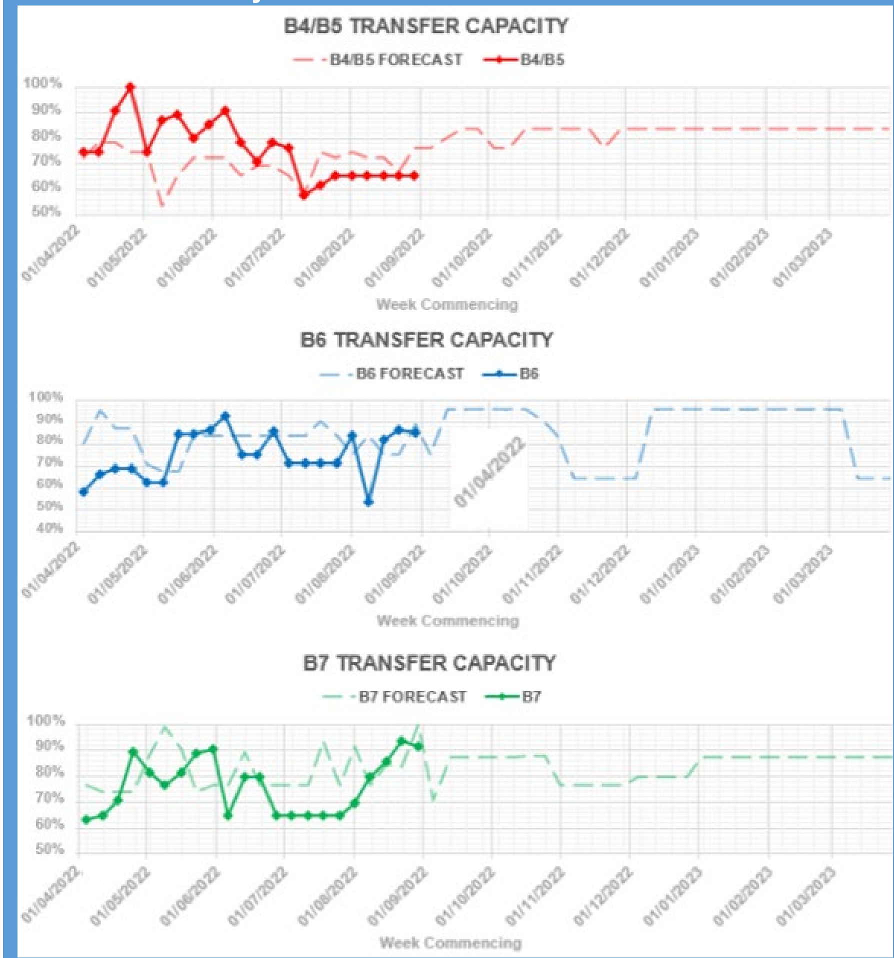
- The higher price of actions taken to manage the system. Particularly the price of offers in the BM which are higher due to increased wholesale costs. The volume of actions was lower than the previous year and this shows that it is the cost of the actions rather than the volume which is driving the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

Compared with the previous month:

Non-Constraint costs were ~£45m higher than in July 2022 due to:

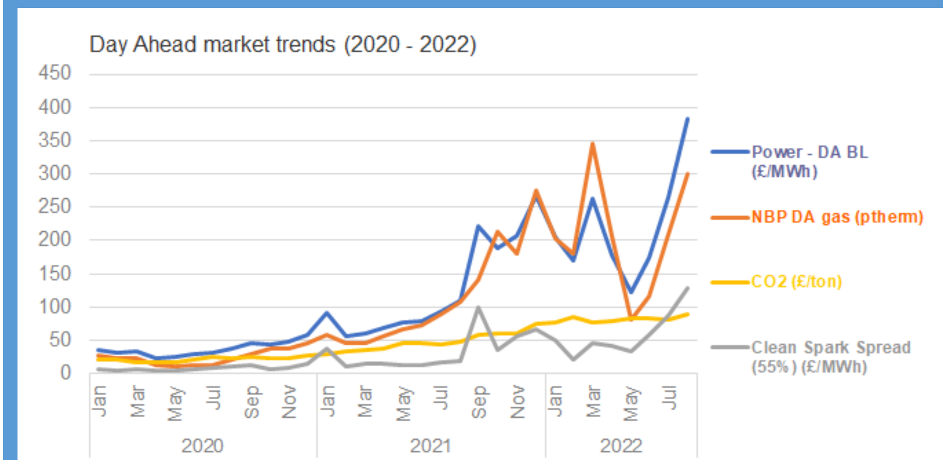
- Operating reserve increase in cost of over £23m due to high BM prices being submitted by units which were required to maintain reserve levels.
- Minor Components increase in cost of over £30m due to improper cost allocation.

Network availability 2022-23



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

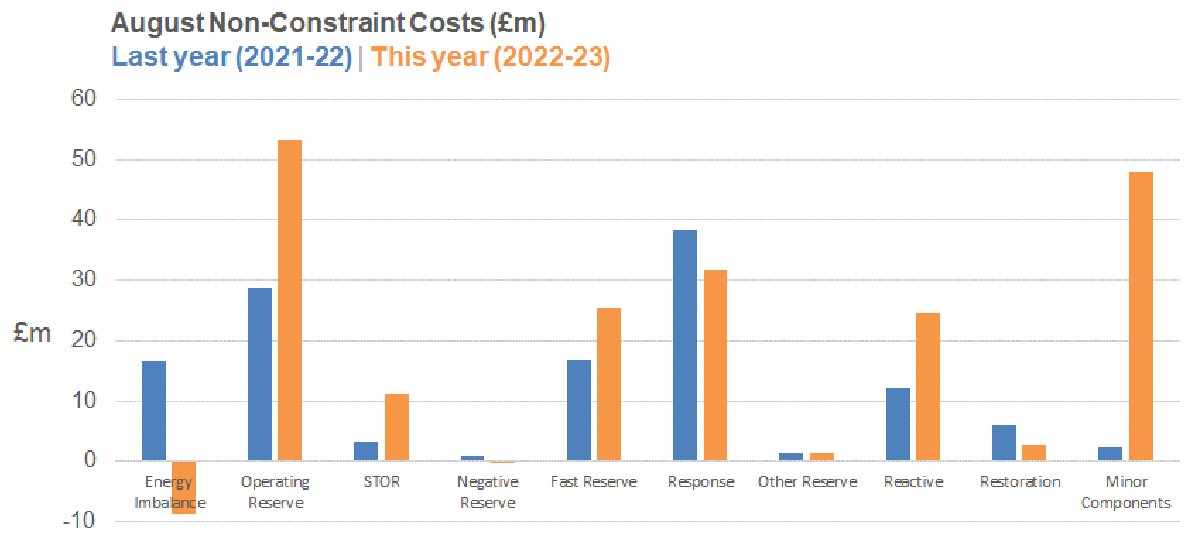
Changes in energy balancing costs



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

Power day ahead prices increased in August and remain significantly above the last year's prices levels. The day ahead gas prices have followed a similar trend and also remain very high in comparison with the previous year. Carbon prices continue their gradual upward trend as well.

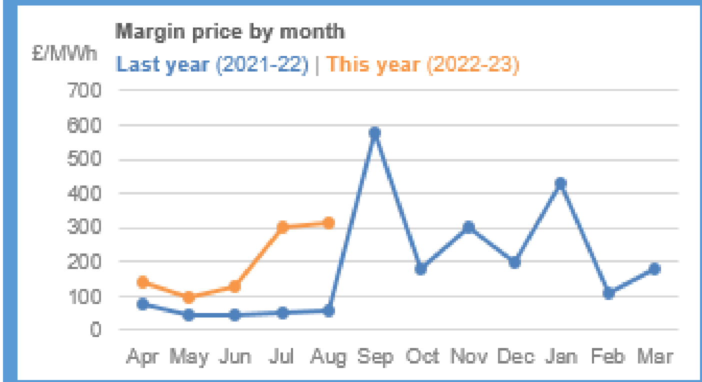
Cost trends vs seasonal norms



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

- **Operating Reserve** costs are £24.5m higher, **Fast reserve** costs are £8.6m higher, and **STOR** costs are £8.1m higher. The main driver for these increases is high wholesale market prices leading to high cost of BM actions.
- **Reactive costs** are £12.5m 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.

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for a single MWh) have increased slightly since July and remain significantly higher than the same month last year.

Daily costs trends

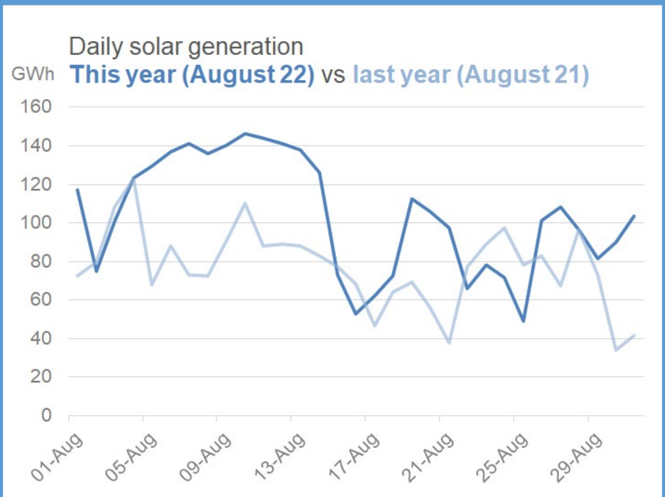
Thursday 11 August was the most expensive day in the month with a daily spend of slightly over £20m.

Wednesday 3 August, Wednesday 10 August and Tuesday 16 August were other expensive days with a daily outturn of around £19m 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.

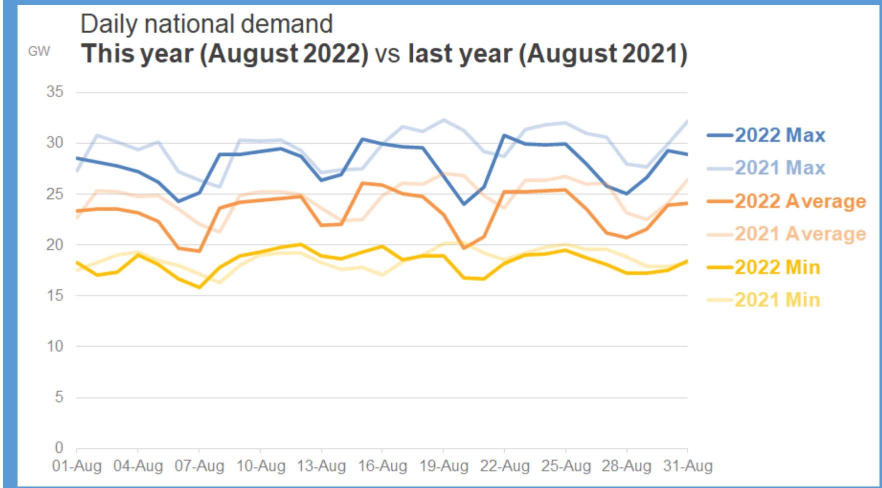
When a bid is taken to resolve a constraint, the energy on the system must then be replaced. When a large volume of BM bids is required to manage the flow on a boundary to below the constraint limit, that volume of energy needs to be procured in the BM to rebalance. The cost of the replacement energy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



August Outturn Demand vs August 2021-22



Metric 1B Demand forecasting accuracy

August 2022-23 Performance

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

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.

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

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

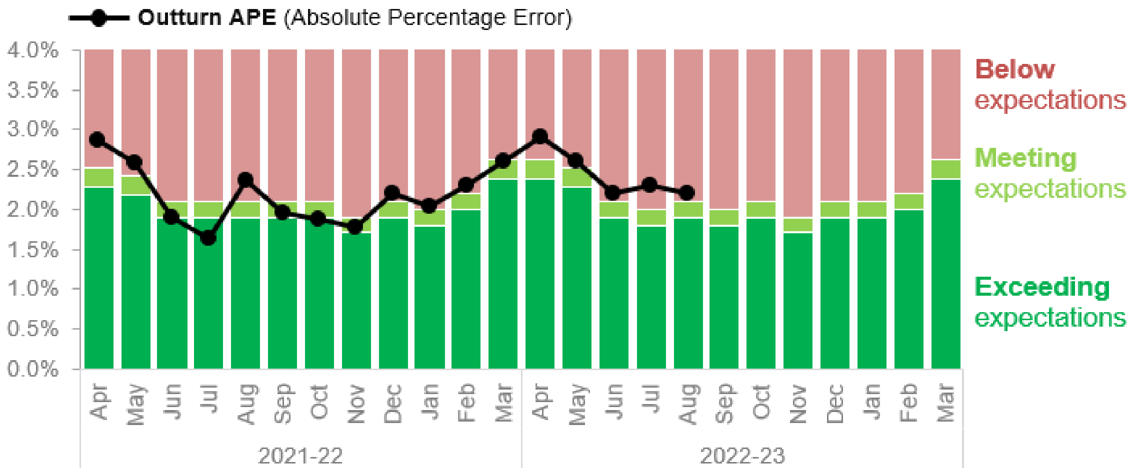


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Indicative benchmark (%)	2.5	2.4	2.0	1.9	2.0	1.9	2.0	1.8	2.0	2.0	2.1	2.5	**2.1**
APE (%)	**2.8**	**2.6**	**2.2**	**2.3**	**2.2**								
Status	●	●	●	●	●								

Performance benchmarks

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

Supporting information

For August 2022, the mean absolute percentage error (MAPE) of our day ahead demand forecast was 2.2% compared to the indicative benchmark target of 2.0%, and therefore 'below expectations'.

The distribution of settlement periods by error size is summarised below:

Summary of the biggest errors in August		
Error greater than	Number of SPs	% of the SPs in the month (1488)
1000 MW	213	14%
1500 MW	61	4%
2000 MW	11	1%

The largest absolute percentage errors at the day-ahead forecasting horizon were observed on 4 August (2.94%), 7 August (3.44%) and 26 August (5.24%). The settlement periods with the highest MAPE were between SP23 (11:00) and SP28 (14:00).

One of the largest contributors to these errors was solar/PV generation forecast errors. We are continuing to work on potentially expanding the weather forecast data that we receive and feed into our models.

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

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

Metric 1C Wind forecasting accuracy

August 2022-23 Performance

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

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

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

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

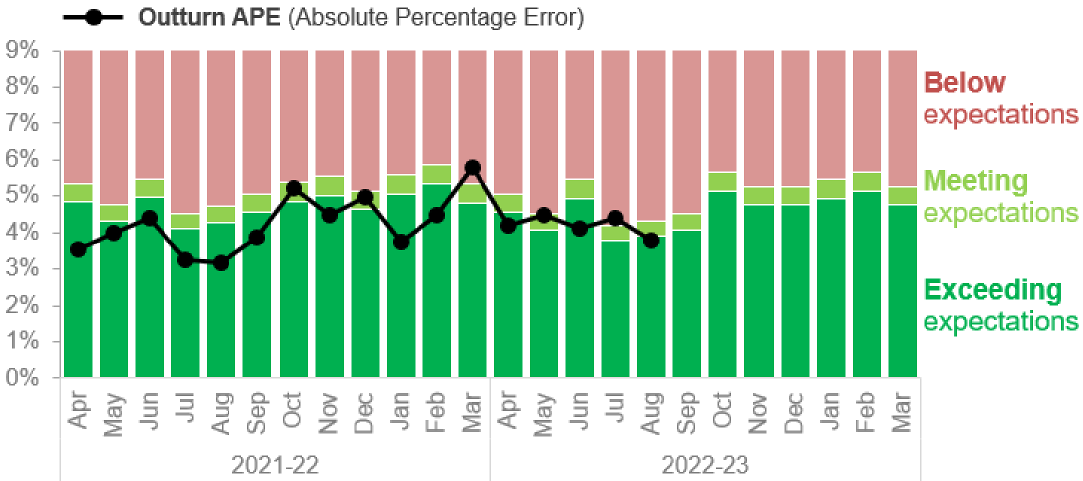


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2022-23)

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

August experienced the stable weather conditions that have become typical for the month in recent years. There was no named tropical storm reported for August 2022. Low pressure systems did see the development of inland thunderstorms over the western areas of the British Isles on 14 August, southern and central areas on 16 August, and the southeast on 17 August. Heavy and thundery showers were also reported across the UK on 2 August, southeast Scotland on 15 August, and across western Scotland on 22 August – signalling atmospheric turbulence. However, the rest of August was dominated by high pressure systems, which tend to induce settled weather conditions that make forecasting easier. Forecasting wind power output is also much easier when wind conditions are low, with the scope for large errors significantly reduced – which was the case for the vast majority of the month.

Lightning is a good indication of atmospheric instability and is commonly difficult to forecast, which can lead to wind power forecast inaccuracies. Six of the 31 days in August experienced significant lightning activity.

Thunderstorms and significant lightning activity would usually lead us to expect greater wind power forecast inaccuracies. However, the stable weather that we experienced over most of August meant that our weather service provider was able to provide us with very accurate weather forecasts during this time. This, in addition to the continued effective use of our models, saw wind forecasting accuracy for August exceed expectations.

Wind farms with CFD contractual arrangements switch off for commercial reasons while prices are negative for 6 hours or more. In August there were no occasions when the electricity price went negative for 6 hours or more. The electricity price used for this analysis is the Intermittent Market Reference Price. Market Price Data for August can be downloaded from here: https://www.emrsettlement.co.uk/settlement-data/settlement-data-roles/

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

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

Metric 1D Short Notice Changes to Planned Outages

August 2022-23 Performance

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

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

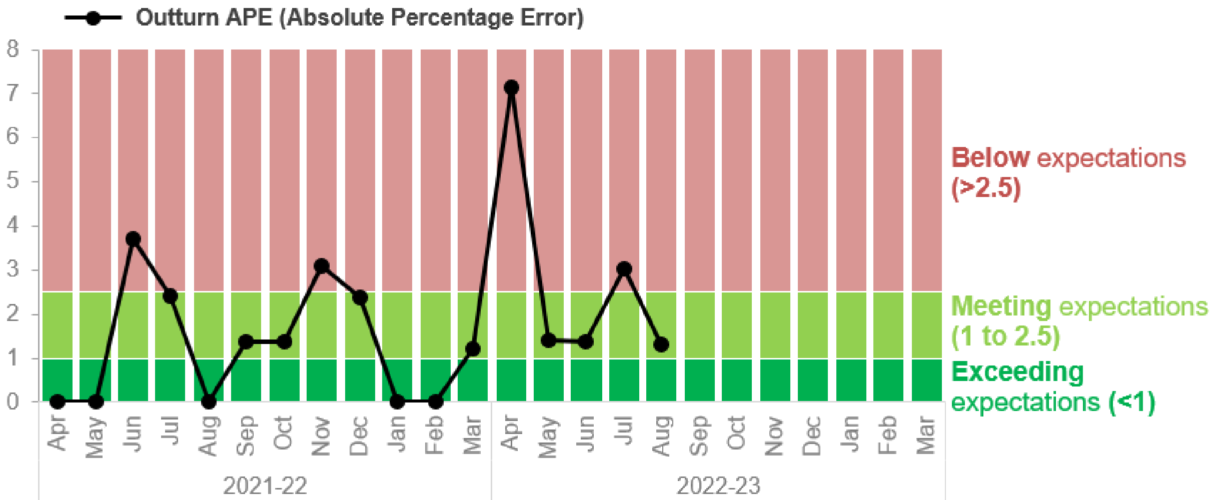


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	700	709	730	660	766								3565
Outages delayed/cancelled	5	1	1	2	1								10
Number of outages delayed or cancelled per 1000 outages	7.1	1.4	1.4	3.0	1.3								2.8
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 August, the ESO has successfully released 766 outages and there has been one delay or cancellation due to an ESO process failure.

The number of stoppages or delays per 1000 outages is 1.31, which is within the 'Meets Expectations' target of between 1 and 2.5 per 1000 outages.

The single event can be summarised below:

A delay occurred due to a discrepancy between the Off-line Transmission Analysis (OLTA) software (the planning tool used to simulate outages and contingencies on the network), and the real-time software used by the Control Room. Within planning timescales OLTA did not flag any problems for the pre-fault network and contingencies simulated. However, in advance of switching out a particular circuit, the control room real-time simulation identified that system volts pre-fault would exceed 420kV. This could not be secured if a fault occurred. The control room liaised with the TO and DNO to delay part of the works. They were able to release a Super Grid Transformer (SGT) but not the substation Mesh Corner to allow part of the TOs work to proceed. The particular outage combination that was requested on this occasion has since been reviewed by the planning department to work out different options for managing the network if the combination was to be requested again.

RRE 1E Transparency of operational decision making

August 2022-23 Performance

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

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

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

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

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

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

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

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

Table 6: Percentage of balancing actions taken in merit order in the BM (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	92.3%	93.3%	92.8%	88.6%	88.7%						
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.7%	99.6%	99.4%	99.4%						
Percentage of actions with no category applied or reason group identified	**0.3%**	**0.3%**	**0.4%**	**0.6%**	**0.6%**						

Supporting information

This month 88.7% 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 August 2022, we sent 40,479 BOAs (Bid Offer Acceptances) and of these, only 247 remain with no category or reason group identified, which is 0.6% of the total.

RRE 1G Carbon intensity of ESO actions

August 2022-23 Performance

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

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO_2/kWh associated with it. For full details of the methodology please refer to the Carbon Intensity Balancing Actions Methodology document. The monthly data can also be accessed on the Data Portal here. Note that the generation mix measured by RRE 1F and RRE 1G differs.

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

Table 7: Monthly gCO_2/kWh of actions taken by the ESO (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO_2/kWh)	3.2	2.2	4.2	0.3	0.4							

Supporting information

In August, the average carbon intensity of balancing actions was 0.4 gCO2/kWh. This was the second lowest monthly average in the year so far. For comparison, in Q1 2022-23 the average carbon intensity was 3.2 gCO2/kWh. The reduction in July and August is because we are taking significantly fewer operational actions compared with April to June. In addition, carbon generation has been supporting the increased exports from GB and they also provide the needed network ancillary services. This reduces ESO interventions and means that if we do take operational actions by pulling back carbon generation (for example if the market was long), the carbon intensity will also reduce significantly.

In August, the largest decrease in carbon intensity due to ESO's actions was at 22:30 on 31 August with a minimum intensity of ESO actions of -11.8 gCO2/kWh. The minimum for the year so far is -26.2 gCO2/kWh on 29 May.

RRE 1I Security of Supply

August 2022-23 Performance

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

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

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

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

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

Table 8: Frequency and voltage excursions (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz)	0	0	0	0	0							
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	1	1	1	1	0							
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0	0							

Supporting information

There were no reportable voltage or frequency excursions in August.

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

RRE 1J CNI Outages

August 2022-23 Performance

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

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

Table 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							
Integrated Energy Management System (IEMS)	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 186 minutes	0							
Integrated Energy Management System (IEMS)	0	0	0	0	0							

Supporting information

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

Notable events during August

ESO confirms contingency contracts with coal units this winter

As a consequence of the continued Russian Invasion of Ukraine, there are ongoing concerns that gas supplies from Russia to Europe are likely to be disrupted over the Winter 2022/23 period. In May the BEIS Secretary of State wrote to the ESO requesting us to engage with Industry to explore ways to enhance security of supply in light of this increased risk. We have put in place contracts with EDF Energy at their West Burton site and Drax to secure up to approximately 1500 GWh of energy from four coal fired generation units that would otherwise have closed before Winter 2022/23. These contracts ensure generation will be available at the request of the ENCC between 1 October 2022 and 31 March 2023.

Domestic Scarcity Reserve Trial

Between February and March this year, ESO collaborated with Octopus energy on the Domestic Scarcity Reserve Trial, investigating domestic households reducing their demand during a 2-hour window in response to a day ahead signal, when offered a financial incentive. The results from the trial were published on Octopus Energy's blog, with high level results presented to the OTF on Wednesday 27 July. Over 100,000 households agreed to take part in the trial, showing high engagement and large, repeatable demand response to grid needs, turning down by a total of 197 MWh over the trial. Customers also showed sustained engagement, with the majority of customers opting-in to multiple events. From a post-trial survey that was sent to all trial participants, 90% of respondents said they would participate in 2 or more events per week. We held a joint webinar with Octopus Energy to do a deep dive into the results and hold a Q&A session for any interested industry participants, this took place on Friday 05 August.

Octopus Energy and the ESO demonstrate future role for EVs in first for GB

Octopus Energy Group and National Grid ESO have announced the first successful integration of vehicle-to-grid (V2G) technology, using a test environment of the Balancing Mechanism, the primary tool used by National Grid ESO to balance Great Britain's electricity system in real-time.

This is the first time that V2G technology has been demonstrated in Great Britain to show that electric vehicles can receive a direct signal from the ESO to support system balancing. It marks a major turning point in electricity supply and means that in the future, consumers could play a direct role in balancing the national transmission system through their electric vehicles.

In a series of initial tests, Octopus charged and discharged the batteries of up to 20 electric cars from participating customers at times of grid imbalance. These tests have demonstrated the potential benefit of vehicle to grid charging – an hour of a million EVs exporting to the grid could generate the same amount of power as 5,500 onshore wind turbines.

It doesn't just benefit the system either. There is also the potential for savings to be passed on to consumers, even if they didn't actively participate

When a service is up and running, consumers could save cash off their energy bills as the BM incentivises the use of their car battery as a balancing device, contributing to reduced balancing costs across the network, which will help to reduce bills for all energy consumers.

Electricity System Restoration (ESR) Wind only tender launched

As part of the ESO's Restoration and Resilience services strategy, this year alongside the usual region-specific tenders (South East in June and North in September), a one-off wind specific tender was launched on 8 August. The primary driver behind this initiative is to prove that wind is capable of providing restoration services and by launching this tender nation-wide, the successful contracts will bolster existing and new restoration service provisions across different regions. Another key factor to do this right now, is to be in a good position to tap into the 50GW of offshore wind generation forecast for 2030. The wind tender process is planned to award contracts by December 2026 for a five year period. For this tender, ESO are procuring full service technical requirements and some of the minimum levels, have been reduced following stakeholder feedback from wind generators, to better suit entry into this restoration service market.

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

August 2022-22 Performance

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

Figure 5: Monthly BSUoS forecasting performance (Absolute Percentage Error) – two-year view

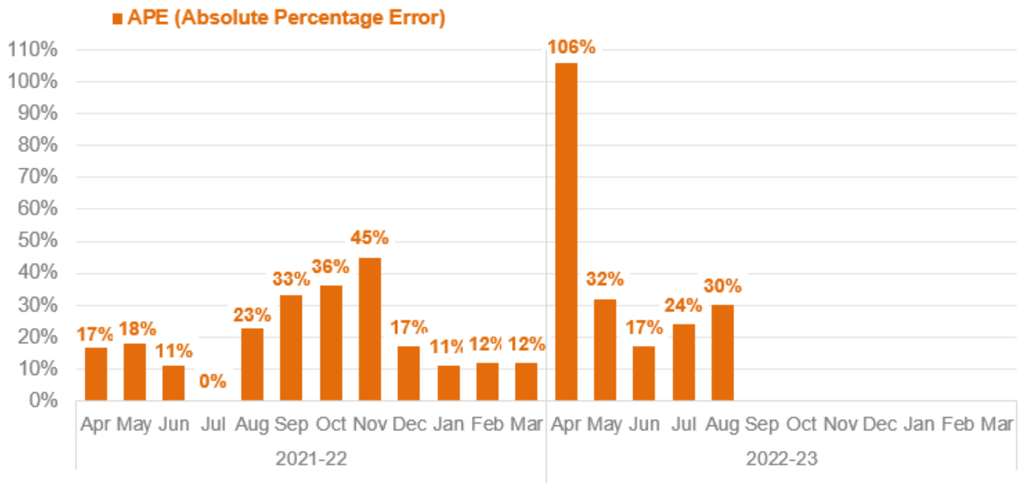


Table 11: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[4] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	5.3	6.8	9.4	10.3	9.18							
Month-ahead forecast	11.0	9.0	7.7	7.82	11.9							
APE (Absolute Percentage Error)[5]	**106%**	**32%**	**17%**	**24%**	**30%**							

Supporting information

The August outturn BSUoS cost was around the 35th percentile of the forecast produced at the beginning of July, and the volume was higher than the estimate.

This is mainly due to the constraints (£137 million) being lower than the value forecast at the beginning of July (£166 million), due to lower wind outturn than forecast.

[5] 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 August

Winter Demand Flexibility service

We're planning to launch a new service that will utilise and reward household and business energy flexibility. Building on the Domestic Scarcity Reserve trial we carried out with Octopus Energy, we have worked rapidly with a range of stakeholders, including energy suppliers and aggregators, to understand the challenges ahead of launching the service in time for this winter. While we don't expect to offer this as an enduring service, it is action we can take now against the backdrop of energy bills and the cost-of-living crisis.

Through their energy supplier or aggregator (providers), we'll be able to ask millions of consumers to reduce electricity consumption at certain times of the day when there's a system need. Consumers will be notified by their provider the day before and can choose not to take part. During the event window consumers will need to try and reduce electricity consumption – and if they do reduce electricity consumption, they will be rewarded.

On 1 September we launched a consultation which closes a on 3 October. Details can be found on our website here. We have also held a number of webinars and industry workshops.

Transmission Charging Methodology Forum and CUSC Issues Steering Group

The latest Transmission Charging Methodologies Forum and CUSC Issues Steering Group was held on Thursday 4 August. A key topic raised by industry was around that of the approach to winter, and the potential risk of increasing costs to consumers in the context of interconnectors (actions) and Balancing Services Use of System (BSUoS) charges. There was general agreement amongst participants that there may be benefit for industry to look to develop ideas and solutions on how to deal with winter and increasing costs. CMP395 has since been raised which seeks to cap BSUoS costs and defer payment to the 2023/24 charging year to help protect GB energy consumers during the energy cost crisis. We received positive feedback from workgroup members at the amount of work undertaken by the ESO to facilitate this urgent process, with the original proposal plus six alternates. We involved legal, finance and revenue expertise in the process to ensure issues within ESO's control were resolved quickly and were fully transparent.

Role 3 System insight, planning and network development

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

Notable events during August

B6 Constraint Management Pathfinder

The B6 (English/Scottish boundary) Constraint Management Pathfinder (CMP) launched in 2021 with contracts being awarded to 15 generators in September 2021, for service delivery starting in October 2023 – September 2024. The launch of this service was part of the ESO's 5 Point Plan to manage constraints on the system. This service connects parties to an intertrip scheme, where generators are armed pre-fault and will be disconnected from the system in 150ms in the event of a fault on the system. The service enables generation to stay on the system for longer, rather than being pre-emptively curtailed. Instead of paying constraint costs to turn off generation when there is the risk of a fault, this technology provides an option of allowing generation to continue for longer, by increasing the constraint limit. Resulting in reduced constraint costs which would ultimately be paid for by consumers.

Four of the parties awarded contracts were already connected to the intertrip scheme so have been able to commence providing the service ahead of the October 2023 contract start date. This has saved the consumer £30m in its first four months of operation from April 2022 and continues to deliver savings under high wind conditions.

The tender for B6 CMP 2024 – 2025 was launched on 08 August and will close on 16 September, with contracts award in October.

ESO to employ PLEXOS data modelling for grid expansion

On Wednesday 17 August, ESO and Energy Exemplar announced an agreement to use energy market simulation platform PLEXOS to identify cost-efficient grid expansion priorities. The data modelling tool facilitates nodal modelling for more granular future planning, co-optimisation of power and gas, as well as scalable cloud computation infrastructure. It will support offshore network modelling for proposed wind turbine farms, while also providing a higher level of integration and automation of current processes. The contract contains a three-year fixed period with two one-year optional extensions.