ESO RIIO2 Business Plan

August Monthly Incentives Report

23 September 2021

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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

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

- The ESO has begun working with Open Climate Fix (OCF) on solar generation forecasting. The new innovation project will see the ESO and OCF develop a first-of-its-kind solar 'nowcasting' service for the ESO's control room.

- The ESO is collaborating with the Smith Institute on a new Network Innovation Allowance (NIA) funded project to develop an approach to forecasting day-ahead reserve requirements.

- The ESO requested to allow the procurement of a non-frequency balancing service – Net Transfer Capacity (NTC) – following non-market-based procedures. Ofgem granted the ESO a temporary derogation from Standard Licence Condition (SLC) 28. Ofgem also approved the ESO's proposal to update the Procurement Guidelines Statement (PGS) to include the Net Transfer Capacity (NTC) service.

- The ESO proposed to amend the national terms and conditions (T&C) required by Article 18 of the EU electricity balancing guidelines (EBGL). This proposal seeks to improve the procurement of Dynamic Containment services by using an automated auction platform and was approved by Ofgem.

- The CUSC modification CMP326: Introducing a 'Turbine Availability Factor' for use in Frequency Response Capacity Calculation for Power Park Modules (PPMs) has been approved by Ofgem

- The ESO published the Transmission Network Use of System (TNUoS) draft tariffs for 2022-23. The total TNUoS revenue to be collected is forecast at £3,434m, an increase of £68m from the April forecast.

- Ofgem published a consultation on its views on the development of early competition in onshore electricity transmission networks outlined in the ESO's Early Competition Plan (ECP). The regulator considers that the process proposed by the ESO for identifying network needs, that are suitable for early competition, appears logical.

- The Energy Networks Association (ENA) published the ESO led consultation on a standard agreement for ESO and DSO flexibility services.

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

Table 1: Summary of Metrics and Regularly Reported Evidence

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£184.2 vs benchmark of £97.1m	
Metric 1B	**Demand Forecasting**	Forecasting error of 2.4% (vs benchmark of 2.0%)	
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 3.2% (vs benchmark of 4.5%)	
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**	99.8% of actions have reason groups allocated	N/A
RRE 1G	**Carbon intensity of ESO actions**	6.9gCO2/kWh of actions taken by the ESO	N/A

RRE 1I	**Security of Supply**	0 instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds, 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	0 outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 23%	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 2021-22 Performance

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

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

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

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

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

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

Total Balancing Costs *(£m)* = (Outturn Wind *(TWh)* x 12.16 *(£m/TWh)*) + 19.75 *(£m)* + 41.32 *(£m)*

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

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

Figure 1: Monthly balancing cost outturn versus benchmark

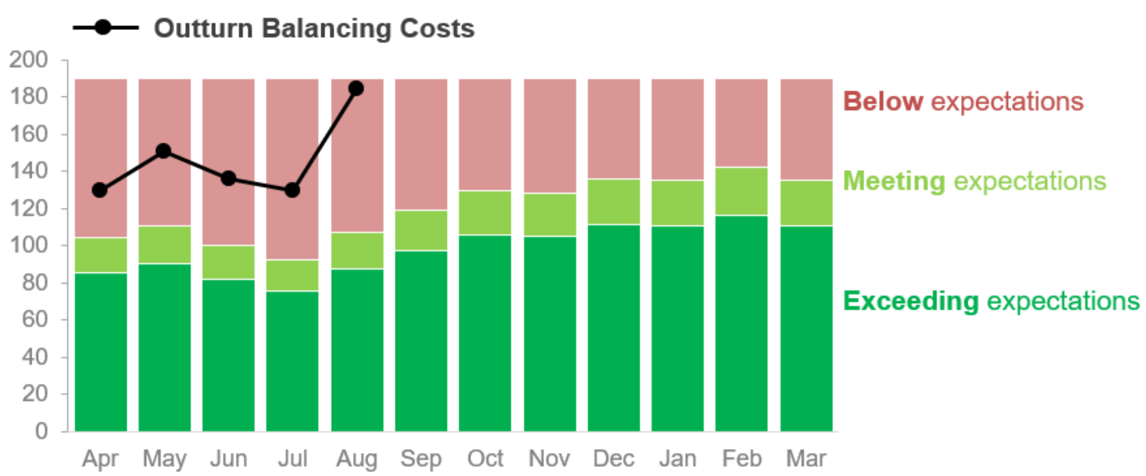


Table 2: Monthly balancing cost benchmark and outturn (Apr-Sep 2021)

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	YTD
Benchmark: non-constraint costs (A)	41.3	41.3	41.3	41.3	41.3	41.3	206.5
Indicative benchmark: constraint costs (B)	59.9	50.6	52.2	49.2	58.3	66.8	270.2
Indicative benchmark: total costs (C=A+B)	101.2	91.9	93.6	90.5	99.7	108.2	476.9
Outturn wind (TWh)	2.77	3.22	2.48	1.87	2.96		13.3
Ex-post benchmark: constraint costs (D)	53.5	58.9	49.91	42.49	55.74		260.5
Ex-post benchmark (A+D)	**94.8**	**100.3**	**91.2**	**83.8**	**97.1**		**467.2**
Outturn balancing costs[1]	**129.5**	**150.9**	**137.0**	**129.6**	**184.2**		**731.2**
Status	●	●	●	●	●		●

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

Performance benchmarks

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

Supporting information

The balancing costs for August were £184.2m, which is £54.6m higher than July, and in the 'Below Expectations' range**.**

Breakdown of costs vs previous month

[1] Please note that previous months' outturn balancing costs have been updated with reconciled values

Balancing Costs variance (£m): August 2021 vs July 2021

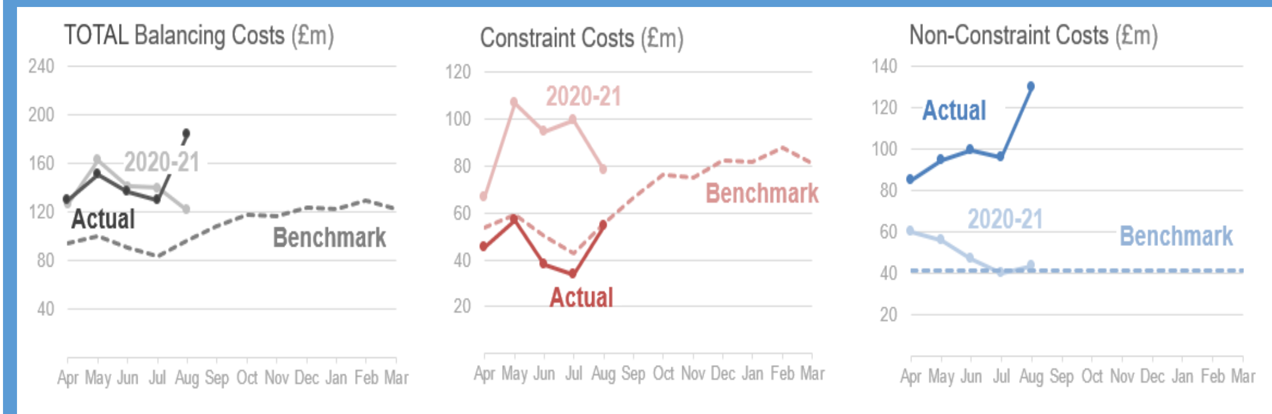
		(a) Jul-21	(b) Aug-21	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	3.9	16.5	12.6	
	Operating Reserve	22.2	28.6	6.5	
	STOR	3.3	3.4	0.1	
	Negative Reserve	0.1	0.9	0.8	
	Fast Reserve	21.0	20.4	(0.6)	
	Response	29.7	37.9	8.2	
	Other Reserve	0.9	1.3	0.4	
	Reactive	10.2	11.7	1.5	
	Black Start	2.9	5.6	2.7	
	Minor Components	1.6	3.4	1.8	
Constraint Costs	Constraints - E&W	6.2	7.4	1.3	
	Constraints - Cheviot	0.9	0.6	(0.4)	
	Constraints - Scotland	1.7	0.3	(1.4)	
	Constraints - Ancillary	6.3	11.1	4.9	
	ROCOF	11.1	27.2	16.1	
	Constraints Sterilised HR	7.7	7.9	0.2	
Totals	Non-Constraint Costs - TOTAL	95.8	129.7	33.9	
	Constraint Costs - TOTAL	33.8	54.5	20.7	
	Total Balancing Costs	**129.6**	**184.2**	**54.6**	

As shown in the total rows above, costs rose across all categories due to increases in the price of energy with Energy Imbalance, Response and RoCoF being the biggest changes.

The main drivers of the changes this month were:

- **Energy Imbalance: £12.6m increase.** The system was generally shorter in August then it was in July and the increase in Balancing Mechanism prices led to an increase in cost.
- **Response: £8.2m increase.** Higher prices in the Balancing Mechanism led to an increase in the cost of re-positioning units to provide Response.
- **RoCoF: £16.1m increase.** Despite relatively low wind levels the wind outturn was still 1TWh higher than July. This combined with lower demand led to lower inertia levels and therefore higher volumes of trades to secure the system against the RoCoF risk.

Constraint Costs vs Non-Constraint Costs



Overall August balancing costs are higher this year than for the same period last year. Constraint costs continue to outturn lower than last year as a result of low levels of wind and changes made as a result of recommendations in the Frequency Risk and Control Report. Non-constraint costs have risen sharply as tight system margins and high gas prices have driven up prices in the Balancing Mechanism.

Constraint Costs

Compared with the same period last year:

Constraint costs continue to be lower this year than last year due to:

- Lower RoCoF costs as a result of changes in the way we manage inertia (Frequency Risk and Control Report implementation) coupled with relatively benign weather conditions
- Thermal Constraints constraint costs are also lower due to good network availability, particularly in the North of England and Scotland, and low wind this year
- Ancillary Service constraints costs are lower as we have not needed to enact the Optional Downwards Flexibility Management (ODFM) service or put in place any other security contracts as we did last year during lockdown

Compared with the previous month:

Constraint costs were higher than July in a number of areas

- RoCoF spend was higher than July due to high prices in the UK and Europe driving up the cost of securing the interconnectors
- Ancillary service costs were higher than July due to contracts put in place to secure specific transmission constraints.

Non-Constraint Costs

Compared with the same period last year:

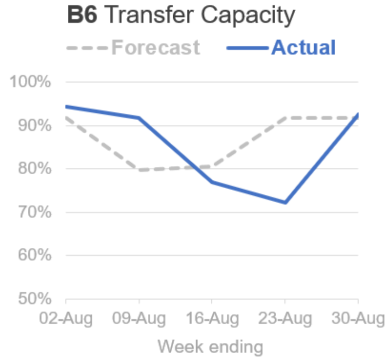
The non-constraint costs were significantly higher this year than last year. This was predominantly due to a sharp increase in energy prices in the Balancing Mechanism and Day Ahead markets, meaning the costs of the actions we took were much higher than in previous years and therefore driving up balancing costs.

In addition, in August this year we are procuring a new service, Dynamic Containment Low. In August last year this service was not being procured and the requirements for response holding were in total lower due to the wider system conditions.

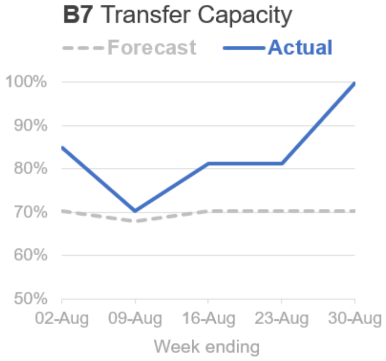
Compared with the previous month:

The non-constraint costs increased from July. This increase was predominantly driven by increased price of actions as the trend observed when comparing against last year has continued. This has driven up costs in nearly all non-constraint cost categories despite volumes of actions taken being relatively stable. Low wind levels has also been a factor as this has led to a higher volume of actions being taken to manage Operating Reserve in particular.

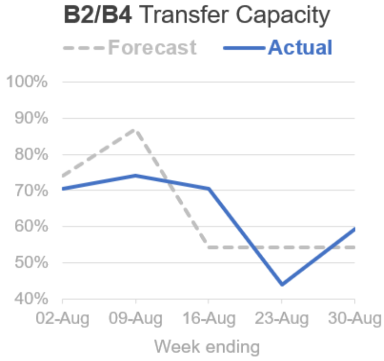
Network availability



B6: SP Transmission to NGET



B7: Upper North of England

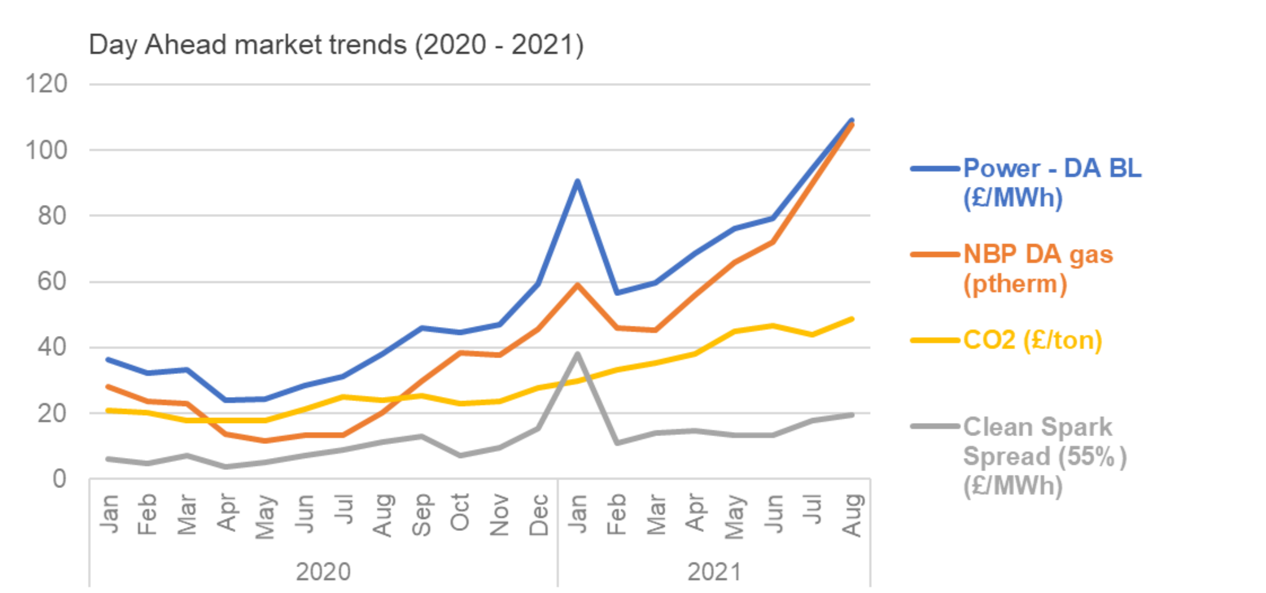


B2: North to South SHE Transmission
B4: SHE Transmission to SP Transmission boundary)

Availability was generally high on the boundaries in the north of England and Scotland. Low wind levels mean that the constraints in the area were largely inactive and weren't significantly driving costs.

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

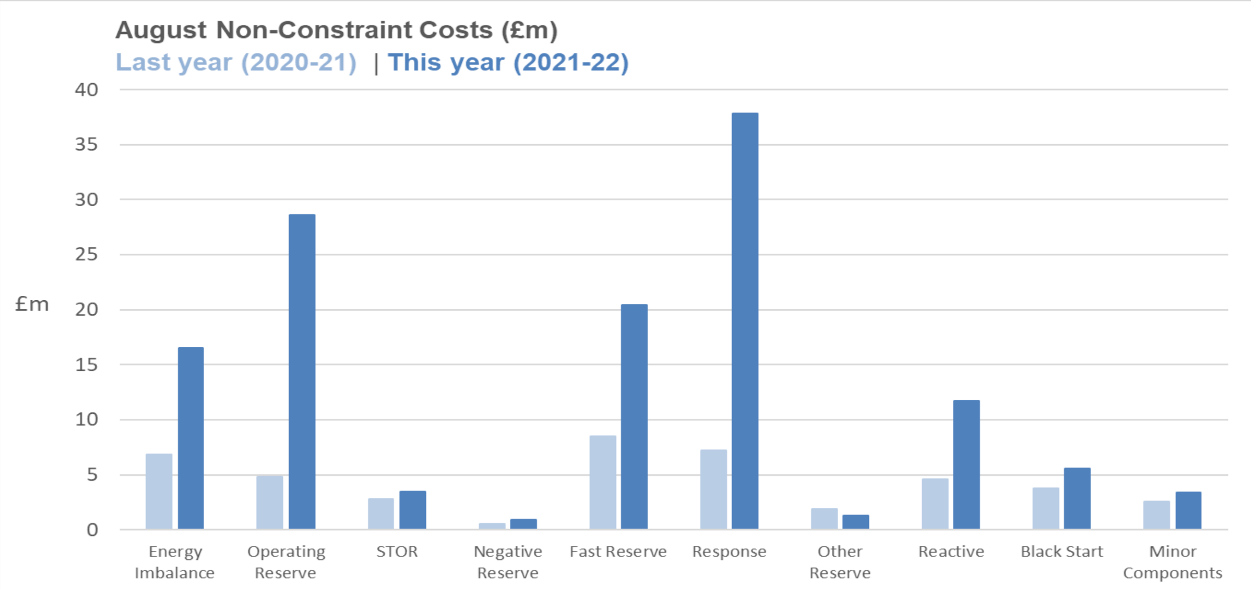
Changes in energy balancing costs



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

Power day ahead prices continued the upward trend as seen throughout 2021 to date driven predominantly by higher gas prices. Average day ahead power baseload averaged £109/MWh in August 2021 vs £38/MWh in August 2020 and £94/MWh in July 2021, which is a £17/MWh increase in just one month. Gas prices have risen due to concerns over low European gas storage inventories and potential scarcity of supply for the winter. Supply constraints on pipeline deliveries from Norway and Russia have meant deliveries this summer are lower than expected. Day ahead gas prices averaged 108p/th in August 2021 vs 20p/th in August 2020 and lifting from 90p/th in July 2021, a 18p/th increase in just one month. Carbon prices have also remained near record highs.

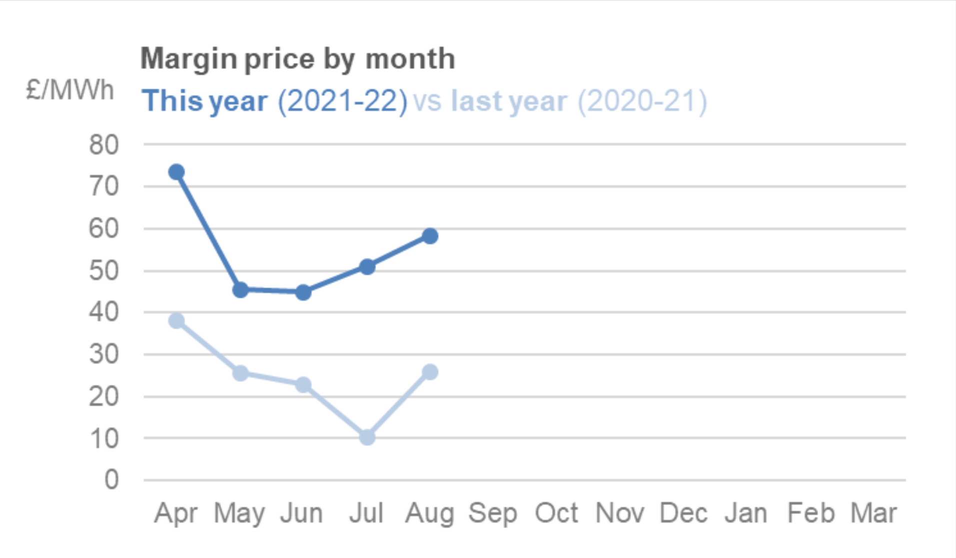
Cost trends vs seasonal norms



Comparing August energy costs with those of August last year, we can see prices have risen across almost all categories driven by the higher Balancing Mechanism prices:

- **Response** costs have increased with the introduction of the Dynamic Containment service as part of changes made to manage inertia. The changes here have enabled a risk-based approach to managing RoCoF resulting in lower constraint costs.
- **Energy Imbalance, Operating Reserve** and **Fast Reserve** costs have also increased. Tighter margins and higher market prices have driven Balancing Mechanism prices up, leading to higher costs for the procurement of reserve and balancing energy.

Drivers for unexpected cost increases/decreases

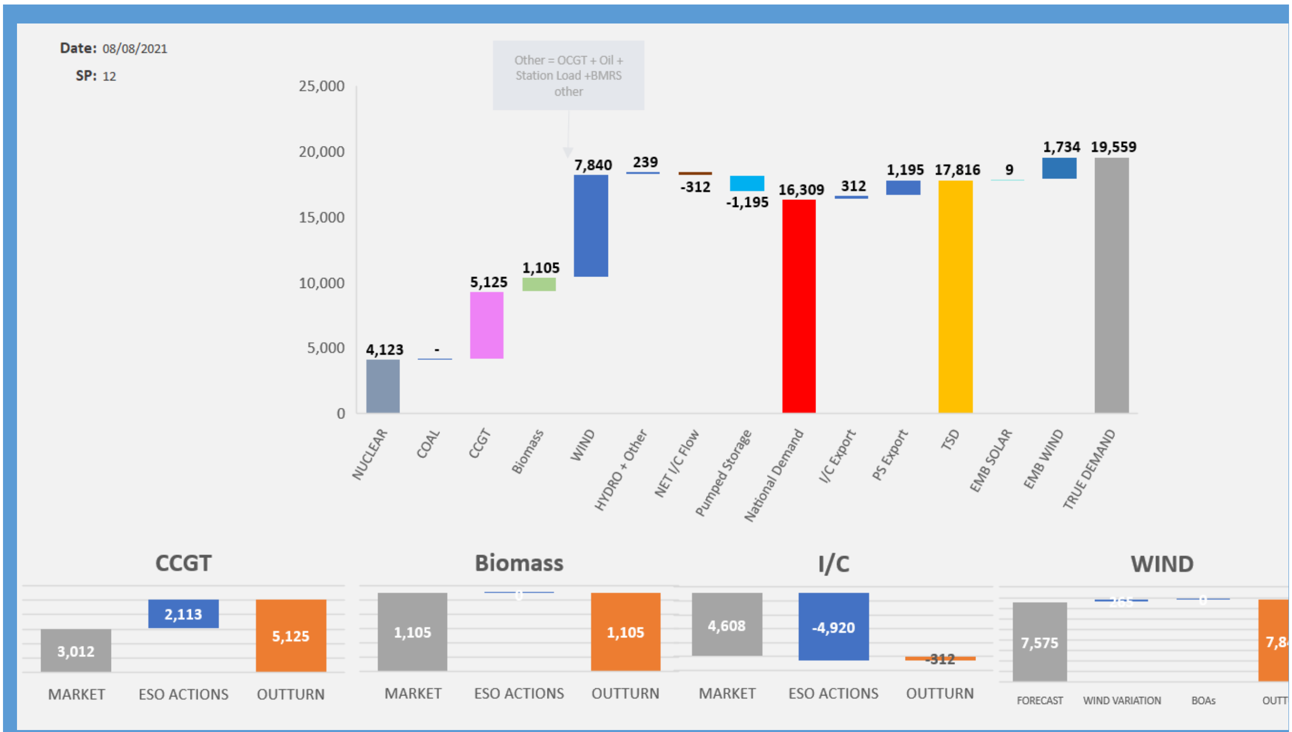


Margin prices continued their upward trend and remain significantly higher than last year; however costs did increase in August last year as restrictions eased and demand increased.

Daily costs trends

High costs were incurred on 6 August to 8 August as a period of high winds displaced conventional generation, resulting in low inertia levels below the minimum inertia level of 140GVA.s. This required expensive actions to reduce largest losses, increase inertia and provide voltage support.

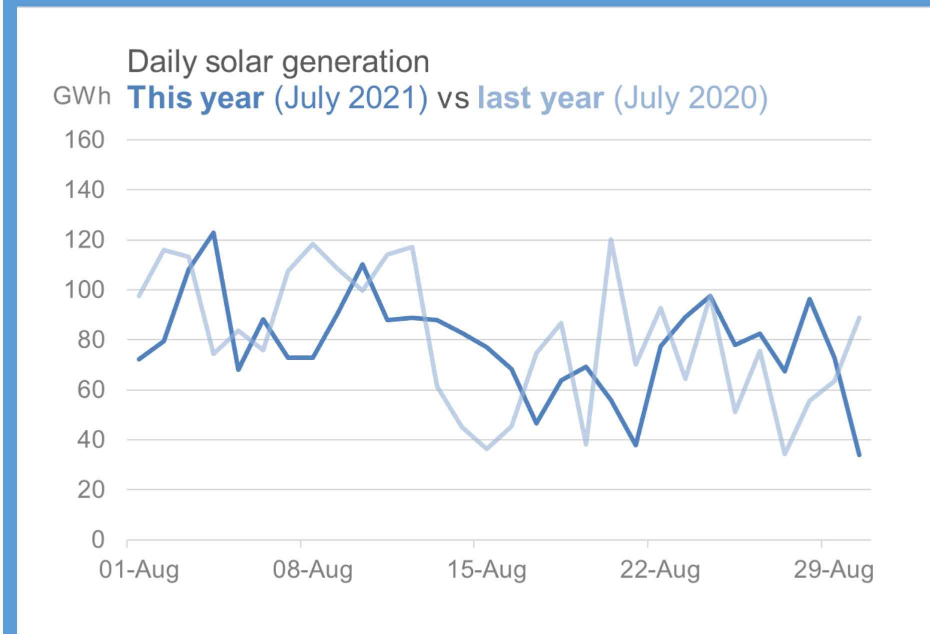
The minimum demand period occurred on 8 August settlement period 12, which is the half hour ending at 0600. This waterfall chart, as discussed at the Operational Transparency Forum, gives a view as to the volume of actions required to manage all the operability challenges. Conventional units were synchronised to meet voltage requirements while trades on the interconnectors were required to ensure there was enough downward regulation. On other days during this period of high wind, additional units were also required to be synchronised to increase inertia.



Significant events

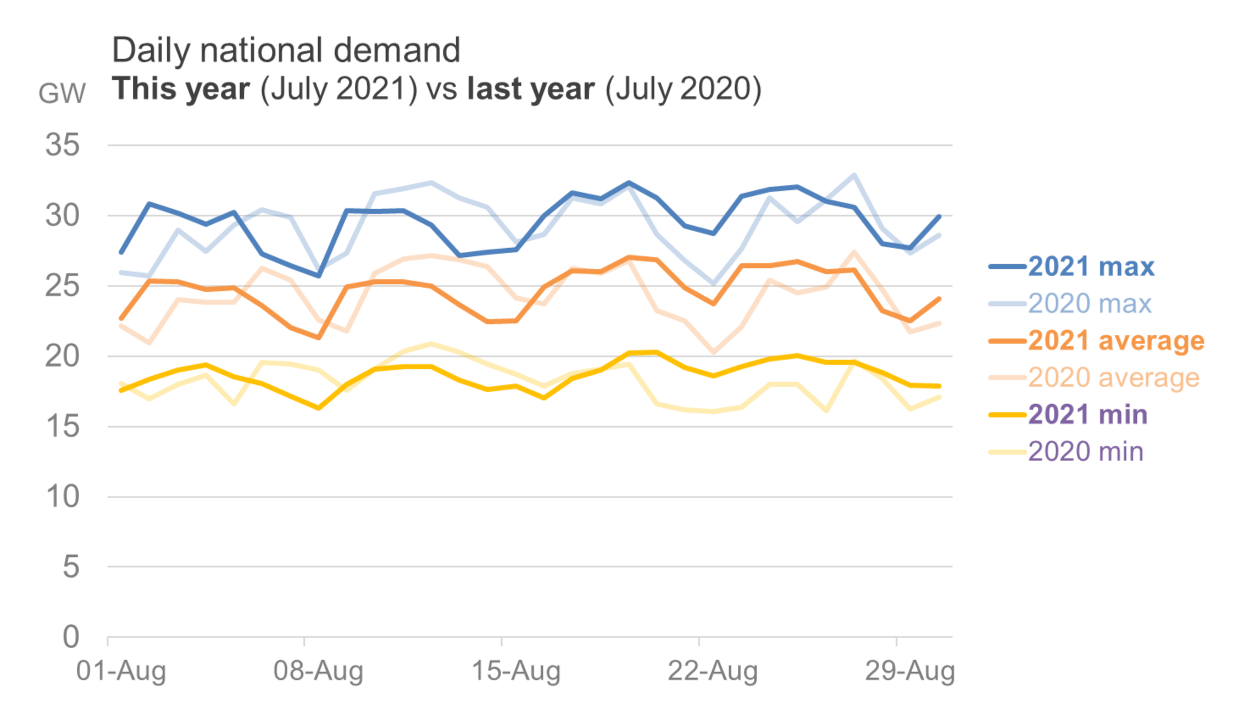
There were no events in August that had a significant impact on balancing costs.

Solar generation - comparison against last year



Solar generation this year was slightly lower than last year with fewer high output days.

Outturn Demand vs 2020-21



Demand for August this year was closer to last year as restrictions eased last year and demand increased. There were no very low demands observed in August this year or last year.

Metric 1B Demand forecasting accuracy

August 2021-22 Performance

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

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

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

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

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

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

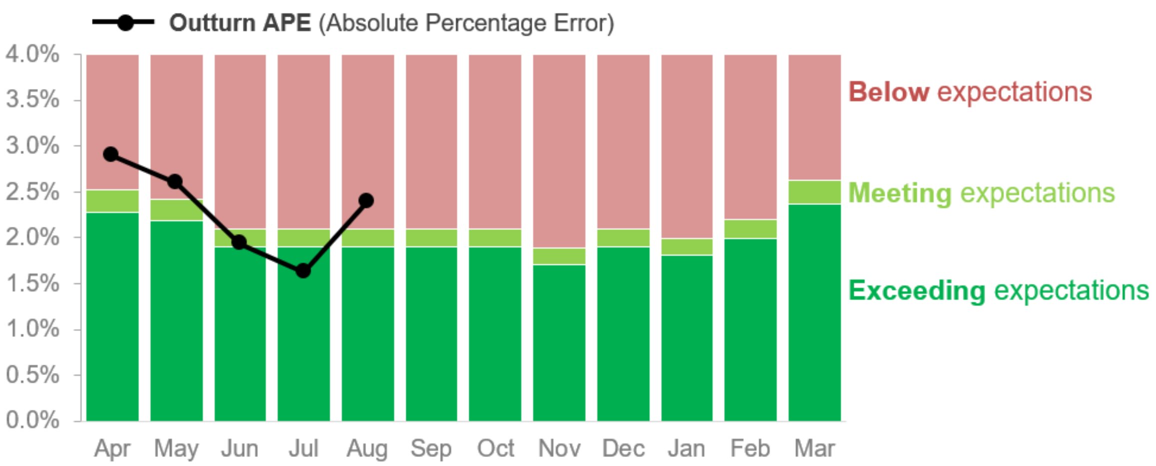


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

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

Performance benchmarks

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

Supporting information

In August 2021, our day ahead demand forecast indicative performance was not within the benchmark of 2.0%. August's MAPE (mean absolute percentage error) was 2.4% therefore we are Below Expectations.

Forecasting performance in August was affected by the uncertainty related to the effect of "staycations". The usual Summer holiday pattern was distorted by changing travel restrictions regulations put in place to control the spread of COVID-19. This resulted in unexpected behaviour as people responded quickly to changes in restrictions, which translated into more challenging forecasting conditions.

The biggest errors at the day ahead forecasting horizon, when the absolute percentage error was above 10%, were observed on 30 August which was a Bank Holiday.

Performance in August 2021: big errors		
Error greater than	**No of SPs**	**% out of the SPs in the month**
1000MW	247	17%
1500MW	89	6%
2000MW	28	2%
2500MW	9	1%
3000MW	2	0%

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

Metric 1C Wind forecasting accuracy

August 2021-22 Performance

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

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

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

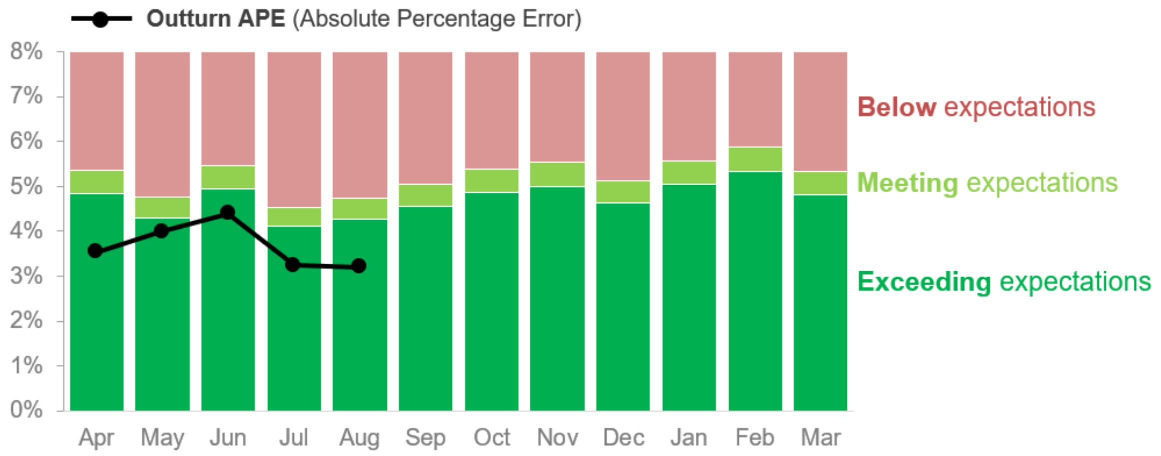


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)

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

Performance benchmarks

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

Supporting information

In August 2021, our day ahead wind forecast indicative performance was within the benchmark of 4.5%. August's MAPE (mean absolute percentage error) was 3.2% therefore we are Exceeding Expectations.

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

August 2021 was in line with the typical average weather for August in previous years, with relatively calm weather conditions interspersed with thundery showers. There were no named storms that passed over the UK during August and the weather forecasting at other times was accurate.

The only weather events of note occurred on the following days.

- 6, 7, 8 and 9 August – Heavy and thundery showers across Wales and the South of England.
- 11 August – Weather front moving across Scotland
- 20 and 21 August – Weather front moving in from the West bringing thundery showers.

Metric 1D Short Notice Changes to Planned Outages

Q1 2021-22 Performance

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

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

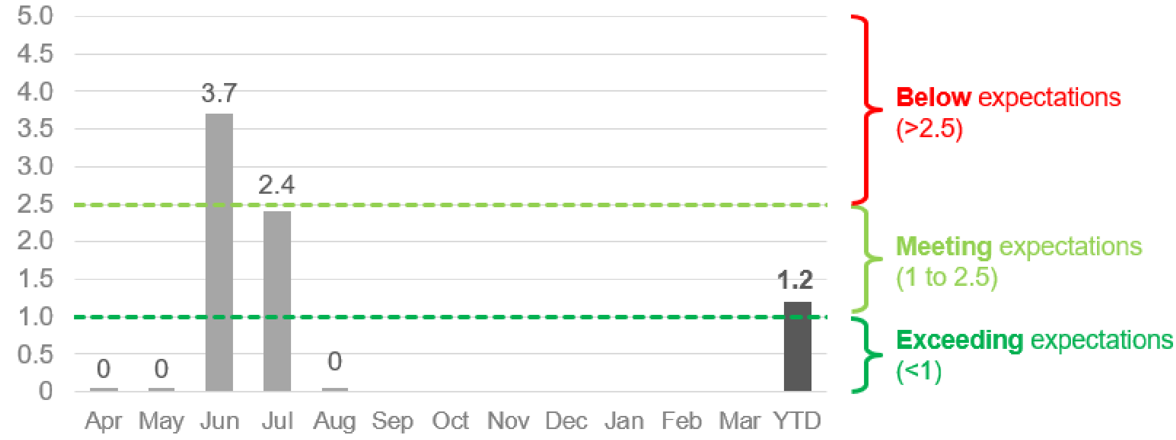


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD[2]
Number of outages	845	856	810	831	810								4152
Outages delayed/cancelled	0	0	3	2	0								5
Number of outages delayed or cancelled per 1000 outages	0	0	3.7	2.4	0								1.2

Performance benchmarks

- **Exceeding expectations:** Fewer than 1 outage delayed or cancelled per 1000 outages
- **Meeting expectations:** 1-2.5 outages delayed or cancelled per 1000 outages
- **Below expectations:** More than 2.5 outages delayed or cancelled per 1000 outages

Supporting information

During August, the ESO successfully released 810 outages and there has been a total of zero delays or cancellations due to an ESO process failure. This gives a score of 0 per 1000 outages which is within the 'Exceeds Expectations' range of less than one delay or cancellations per 1000.

[2] Year To Date figures updated

RRE 1E Transparency of operational decision making

August 2021-22 Performance

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

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

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

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

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

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

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

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

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

Supporting information

For August, 88.4% of actions were either taken in merit or taken out of merit due to electrical parameters. For the remaining actions, where possible, we allocate actions to reason groups for the purpose of our analysis. We were unable to allocate reason groups for 0.2% of the total actions for this month. Although this remains a low percentage, we continue to look to understand any further trends or reasons for these actions being taken out of merit order.

RRE 1G Carbon intensity of ESO actions

August 2021-22 Performance

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

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

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

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

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

Supporting information

The month of August 2021 saw an average difference between the carbon intensity of FPNs (Final Physical Notifications) and balancing actions of 6.89 gCO2/kWh, up from 4.49 gCO2/kWh the previous month.

The maximum difference was 73.75 gCO2/kWh and the minimum was -16.24 gCO2/kWh[3]. The average carbon intensity figure was 23% lower this month than it was in July.

For about one third of settlement periods, the ESO's balancing actions secured the system whilst reducing the carbon intensity supplied by the market.

[3] The minimum difference between the carbon intensity of FPNs and balancing actions was corrected from 16.24 gCO2/kWh to -16.24 gCO2/kWh in this re-published version of the August report on 14 February 2022.

RRE 1I Security of Supply

August 2021-22 Performance

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

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

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

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

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

Table 8: Frequency and voltage excursions

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

Supporting information

There were no reportable voltage or frequency excursions in August.

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

RRE 1J CNI Outages

August 2021-22 Performance

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

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

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

Unplanned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	0							
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 216 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 2021.

Notable events during August

ESO working with Open Climate Fix (OCF) on solar generation forecasting

The ESO has teamed up with OCF – a non-profit start-up co-founded by former DeepMind researcher Jack Kelly – to use AI to improve the way the grid forecasts solar generation. The new innovation project will see the ESO and OCF develop a first-of-its-kind solar 'nowcasting' service for the ESO's national control room. Nowcasting involves a machine learning model forecasting the near future – in minutes and hours rather than days – and has historically found use in predicting rainfall. OCF's pioneering work applies a similar approach to predicting where sunlight will fall. The increased certainty in solar forecasts that OCF's nowcasting service could bring to the ESO's control room could mean fewer carbon-emitting generators held in reserve, and more efficient balancing actions – meaning better value for consumers. It would mark a significant step forward in the ESO's ambition to be able to operate a zero carbon electricity system by 2025.

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

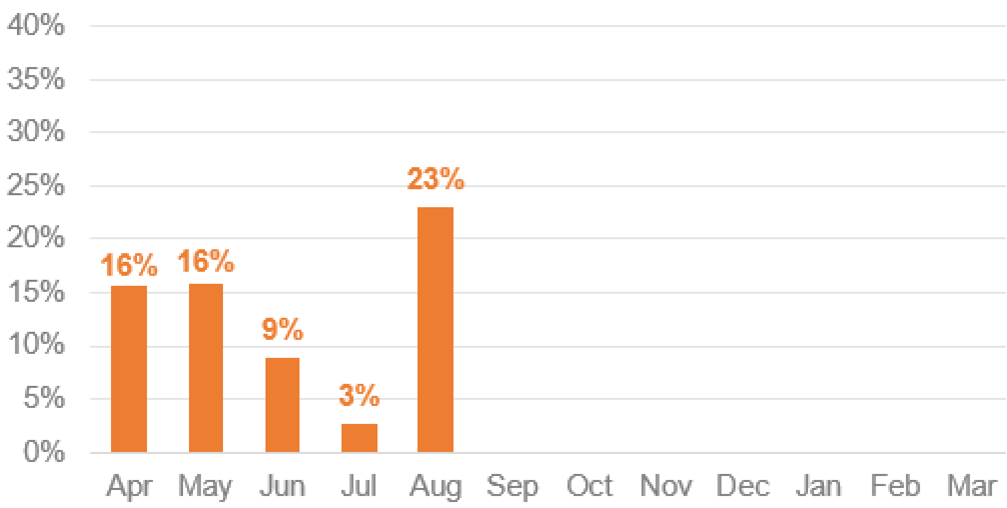
August 2021-22 Performance

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.

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	3.82	4.43	4.49	4.11	5.84							
Month-ahead forecast	3.22	3.73	4.09	4.22	4.52							
APE (Absolute Percentage Error)[5]	**16%**	**16%**	**9%**	**3%**	**23%**							

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



Supporting information

The outturn BSUoS for August was significantly higher than July and higher than forecast. Balancing costs rose higher than anticipated across all categories as a result of higher prices in the balancing mechanism and the Over the Counter (OTC) market. This was driven by tight margins and high gas prices in GB and across Europe. The total BSUoS volume was slightly lower than July.

[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

New day-ahead reserve requirements forecasting project

The ESO is collaborating with the Smith Institute on a new Network Innovation Allowance (NIA)-funded project to develop an approach to forecasting day-ahead reserve requirements. Announced on Tuesday 10 August, the Dynamic Reserve Setting (DRS) project sees the ESO aiming to test a new, fully dynamic day-ahead approach to scheduling reserve with the potential to "boost the efficiency of balancing actions and improve value for consumers". The project is set to last for approximately twelve months, with the initial proof-of-concept expected in November 2021.

Regulator grants the ESO a derogation for balancing service procurement[6]

Ofgem issued its decision on Monday 23 August to grant the ESO a temporary derogation from Standard Licence Condition (SLC) 28 which requires the procurement of non-frequency balancing services to follow market-based procedures. This follows a request from the ESO on 18 June 2021 to allow the procurement of a non-frequency balancing service – Net Transfer Capacity (NTC) – following non-market-based procedures. The ESO, in agreement with interconnector owners, has established that NTC cannot be procured using market-based procedures and that it therefore will not be able to comply with its licence arrangements. Having reviewed the information submitted and the supporting economic analysis, the regulator has made its decision on the basis that it considers that NTC will be critical in ensuring operational security, noting that the locational nature of the service limits the suitability of market-based procurement. This will take effect immediately and is valid until the earliest date of a methodology for capacity calculations as part of the TCA being established, or 1 May 2023. Ofgem also approved the ESO's proposal to update the Procurement Guidelines Statement (PGS) to include the Net Transfer Capacity (NTC) service which will take affect from 30 August 2021.

Dynamic Containment to move to pay-as-clear auction

On Tuesday 31 August, Ofgem issued its decision to approve the ESO's proposal to amend the national terms and conditions (T&C) required by Article 18 of the EU electricity balancing guidelines (EBGL). The ESO's proposal seeks to improve the procurement of Dynamic Containment (DC) services by using an automated auction platform as well as moving from a pay-as-bid assessment to a pay-as-clear (PAC) auction. On 1 September 2021, Dynamic Containment Low Frequency launched on the EPEX SPOT platform, EPEX SPOT also currently provide the auction platform for the Weekly Frequency Response Auction Trial.

Following the success of the Weekly Auction Trial, the EPEX SPOT platform for day-ahead procurement of response services offers process automation which provides:

- An online user interface that enables market participants to submit offers and for the ESO to configure their requirements
- An automated assessment algorithm to calculate the accepted and rejected offers and the total volume of DCL procured
- A more granular procurement by EFA periods allowing for potentially different prices and volumes in each period depending on the system needs
- A move to pay-as-clear payment mechanism

The changes will introduce additional functionality which will give market participants greater flexibility in how they provide the service, potentially leading to an increase in supply of DC.

CMP326: Introducing a 'Turbine Availability Factor' for use in Frequency Response Capacity Calculation for Power Park Modules (PPMs)

On Tuesday 10 August Ofgem approved CUSC modification CMP326. The ESO raised this modification in October 2019 to introduce a cap on the MW element in the Holding Payment calculation for Frequency Response provided by sites with PPMs. ESO believe that this will provide more accurate response capability data and allow the Control Room to make more efficient decisions in terms of which sites to instruct for Mandatory Frequency Response when balancing the system. ESO proposed to calculate the MW value cap by using the Maximum Export Limit (MEL) divided by Registered Capacity which is then applied to the response capability value. This change would then allow a 'Turbine Availability Factor' to be used in the CUSC to ensure that Holding Payments made by the ESO in respect of Frequency Response for PPMs is accurately settled and will reflect the number of turbines available.

Forecast of 2022-23 Transmission Network Use of System (TNUoS) tariffs

In August, the ESO published the Transmission Network Use of System (TNUoS) draft tariffs[7] for 2022-23. TNUoS is designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. It is applicable to transmission connected generators and suppliers for use of the transmission networks. The total TNUoS revenue to be collected is forecast at £3,434m, an increase of £68m from the April forecast. This is due to inclusion of the K factor adjustment (+£41m) and a revision of the OFTO and TO Maximum Allowed Revenue (+£27m). The 2022-23 revenue forecast will be updated later this year and finalised by January 2022.

[6] Updated to reflect correct NTC derogation timings

[7] https://www.nationalgrideso.com/document/207346/download

Role 3 System insight, planning and network development

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

Notable events during August

Ofgem issues consultation on early onshore network competition

On Tuesday 3 August, Ofgem published a consultation on its views on the development of early competition in onshore electricity transmission networks outlined in the ESO's Early Competition Plan (ECP). It is Ofgem's view that the continued development of arrangements allowing early competition in electricity transmission represents good value for money for consumers while the potential savings and other benefits over the longer-term may be significant. The regulator also considers that the process proposed by the ESO for identifying network needs, that are suitable for early competition, appears logical. However, Ofgem would like the ESO to expand on its thinking around how the benefits of competition and innovation can be incorporated into the design process at an earlier stage. Having considered responses, Ofgem will confirm whether early competition will be implemented within the RIIO-2 arrangements and will confirm who should carry out each key role. Responses are requested until 14 September.

Energy Networks Association (ENA) publishes ESO led consultation on a standard agreement for ESO and DSO flexibility services

On 27 August 2021, the ENA Open Networks project launched a consultation on the next version of its standard agreement for flexibility services, which seeks to further drive standardisation, consistency and transparency.

This work, led by the ESO, will result in common arrangements for both DSO and ESO services. The ESO is actively involved in consultation events including the ENA webinar planned on 22 September. The consultation is open until Friday 22 October 2021.