ESO RIIO2 Business Plan

July 2022-23 Incentives Report

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

- We have updated our Electricity National Control Centre (ENCC) Transparency Roadmap.
- The ESO have been awarded a second grant from Ofgem's Strategic Innovation Fund (SIF) as part of a wider project that looks to understand how domestic flexibility can be used to help manage the grid.
- On Tuesday 12 July we held a Reserve Reform Show & Listen session which detailed our latest proposals for Quick Reserve Service Design plus a recap of Slow Reserve Design.
- We held a Power Responsive Summer Event in London on Wednesday 13 July with over 250 attendees made up of small and large providers, energy managers, industry experts, consultants, energy associations and suppliers/aggregators.
- The EMR Delivery Body and Delivery Partners hosted the annual Capacity Market Launch Event on Tuesday 19 July. Key updates from all Delivery Partners were provided in the presentations including developments in the Capacity Market over the past 12 months.
- On Thursday 27 July we published our Winter Outlook 2022-23: Early view report. This year we are committed to providing an early view to help the electricity industry prepare for the Winter ahead.
- We launched our 2022 Future Energy Scenarios (FES) along with a summary document. We also recorded a briefing event to hear views from a panel of experts across industry and government discussing the future of energy security and addressing the challenges of our 2050 target.
- On Thursday 07 July, we published the Pathway to 2030 Holistic Network Design (HND) and more detailed supporting documents. We held a launch webinar on Tuesday 12 July and an HND Industry Code, Standard and License Recommendation Report Webinar on Tuesday 19 July.

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

Table 1: Summary of Metrics

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£382m vs benchmark of £103m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 2.3% vs benchmark of 1.9%	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 4.4% vs benchmark of 4.0%	●
Metric 1D	**Short Notice Changes to Planned Outages**	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**	88.6% of actions taken in merit order	N/A
RRE 1G	**Carbon intensity of ESO actions**	0.3gCO_2/kWh of actions taken by the ESO	N/A
RRE 1I	**Security of Supply**	1 instance where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	1 planned system outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 24%	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

July 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

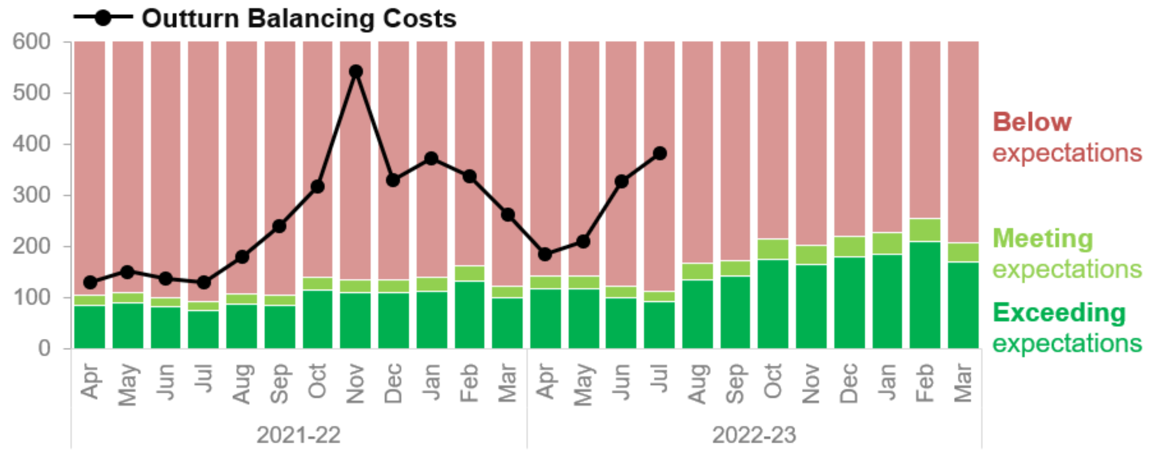


Table 3: 2022-23 Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	YTD
Benchmark: non-constraint costs (A)	50	50	50	50	50	50	151
Indicative benchmark: constraint costs (B)	97	89	90	81	101	107	276
Indicative benchmark: total costs (C=A+B)	147	139	140	132	152	158	427
Outturn wind (TWh)	3.8	3.8	3.1	2.7			13.4
Ex-post benchmark: constraint costs (D)	80	80	62	52			274
Ex-post benchmark (A+D)	130	130	113	103			476
Outturn balancing costs[1]	186	211	327	382			1106
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.

July performance

The balancing costs for July 2022 were around £382m, showing an increase from the previous month of nearly £55m.

Whilst constraint and non-constraint costs remain higher than last year, the constraint spend also increased from June, and the non-constraint costs decreased from the previous month.

Persistent high gas prices are the key factors responsible for continued high prices compared to last year for Operating Reserve, STOR, Response and Reactive. This resulted in significantly higher non-constraint costs 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.

Breakdown of costs vs previous month

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

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

		(a) Jun-22	(b) Jul-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	22.9	1.9	(21.0)	
	Operating Reserve	24.9	29.9	5.0	
	STOR	5.2	8.1	3.0	
	Negative Reserve	0.5	0.4	(0.1)	
	Fast Reserve	15.7	19.6	3.9	
	Response	42.8	43.4	0.6	
	Other Reserve	1.5	1.5	(0.0)	
	Reactive	17.1	19.7	2.6	
	Restoration	10.6	4.5	(6.1)	
	Minor Components	10.1	12.6	2.5	
Constraint Costs	Constraints - E&W	54.5	115.3	60.8	
	Constraints - Cheviot	30.6	0.5	(30.1)	
	Constraints - Scotland	45.8	47.2	1.5	
	Constraints - Ancillary	3.7	0.3	(3.4)	
	ROCOF	2.8	1.8	(1.1)	
	Constraints Sterilised HR	43.5	75.2	31.7	
Totals	Non-Constraint Costs - TOTAL	151.3	141.7	(9.6)	
	Constraint Costs - TOTAL	180.8	240.2	59.4	
	Total Balancing Costs	**332.1**	**381.9**	**49.8**	

As shown in the total rows above, this month's significant increase in costs came from the constraint spend which increased by nearly £60m, while the non-constraint spend showed a decreased of nearly £10m.

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

Within the Non-Constraint costs, a significant decrease was seen in the Energy Imbalance spend, whilst all the other categories either decreased or showed little variance from the previous month.

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

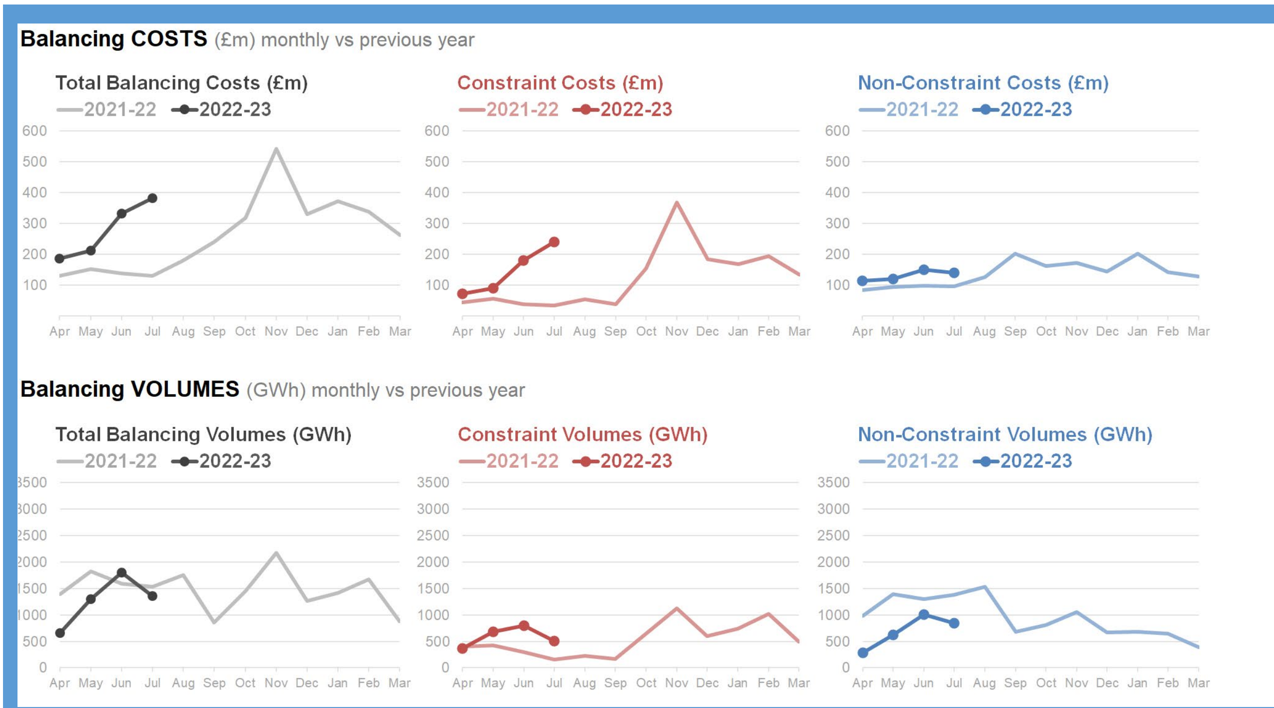
- **Constraint E&W: £60.8m increase.** The sharp cost increase was driven by the events of Wednesday 20 July that challenged the management of the system. This led to costly actions being taken to resolve a power flow import constraint in the South East of England. The result of this was a daily outturn cost of more than £61m for this category.
- **Constraints Sterilized Headroom: £31.7m 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-Cheviot: £30.1m 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 England-Scotland network boundary, leading to fewer costs being allocated to this category.

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

- **Energy Imbalance: £21m decrease.** The market was mostly long in July 2022, whilst in June 2022 the market was mostly short.

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.



Constraint Costs

Compared with the same month of the previous year:

Constraint costs were £206m higher than in July 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 £60m higher than in June 2022 due to:

- System operations being challenged by unforeseen events over some days that triggered daily outturns for this category in excess of £60m. This resulted in an increased monthly cost, despite a decreased volume of constraint actions and a lower wind generation level in comparison with previous month.

Non-Constraint Costs

Compared with the same month last year:

Non-Constraint costs were £45m higher than in July 2021 due to:

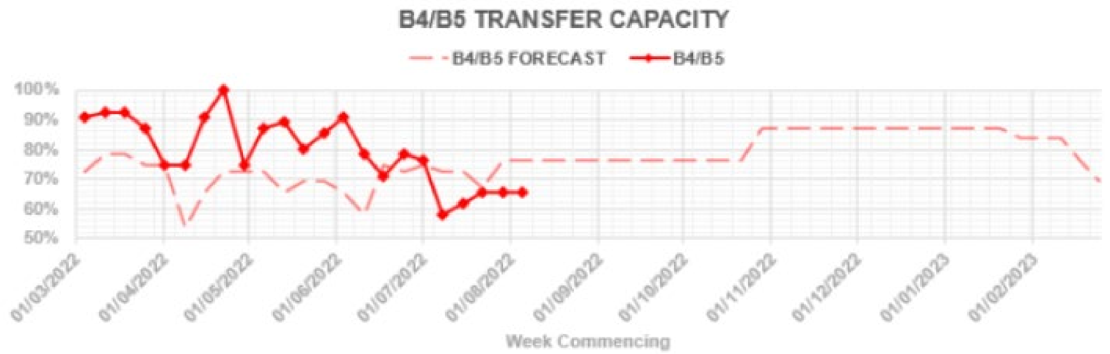
- The higher price of actions taken to manage the system. Particularly the price of offers in the BM which are higher due to increased wholesale costs. The volume of actions was lower than the previous year and this shows that it is the cost of the actions required rather than the volume which is driving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

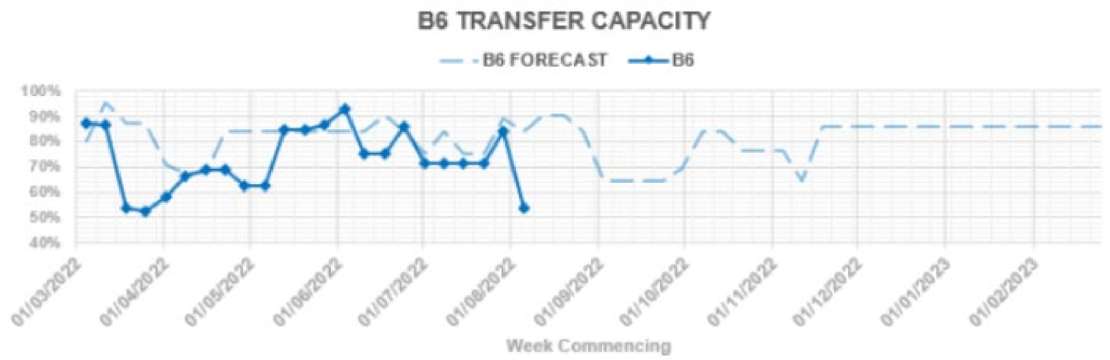
Compared with the previous month:

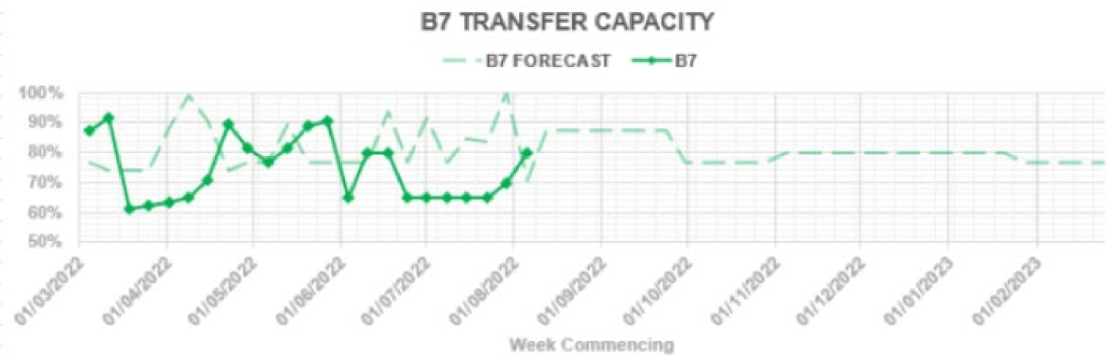
Non-Constraint costs were £10m lower than in June 2022 due to:

- Decreased costs in Energy Imbalance due to the mostly long market in July 2022, compared to a mostly short market in June 2022.

Network availability 2022-23

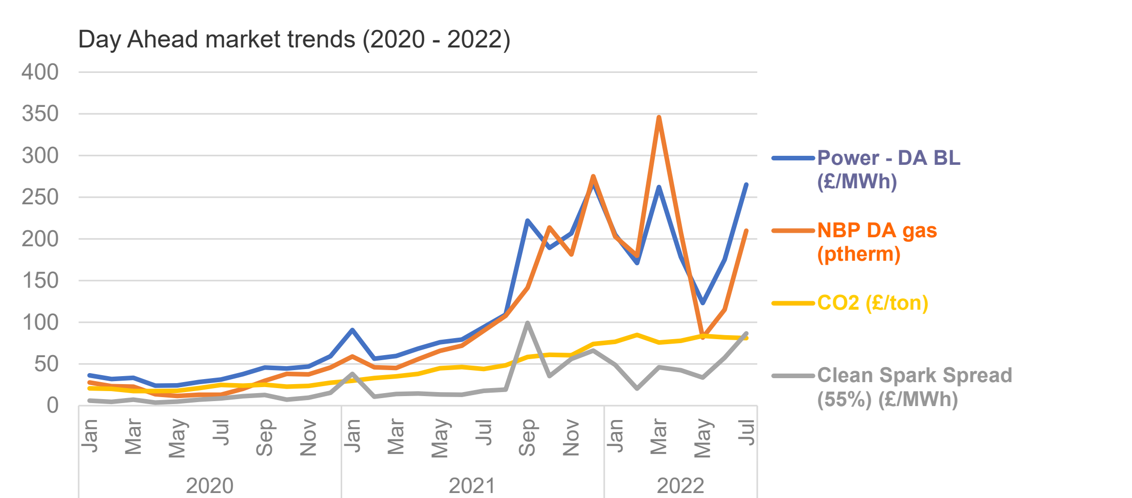






Please note that transfer capacity is discussed in more detail at each week's Operational Transparency Forum. Details of how to sign up, and recordings of previous meetings are available here.

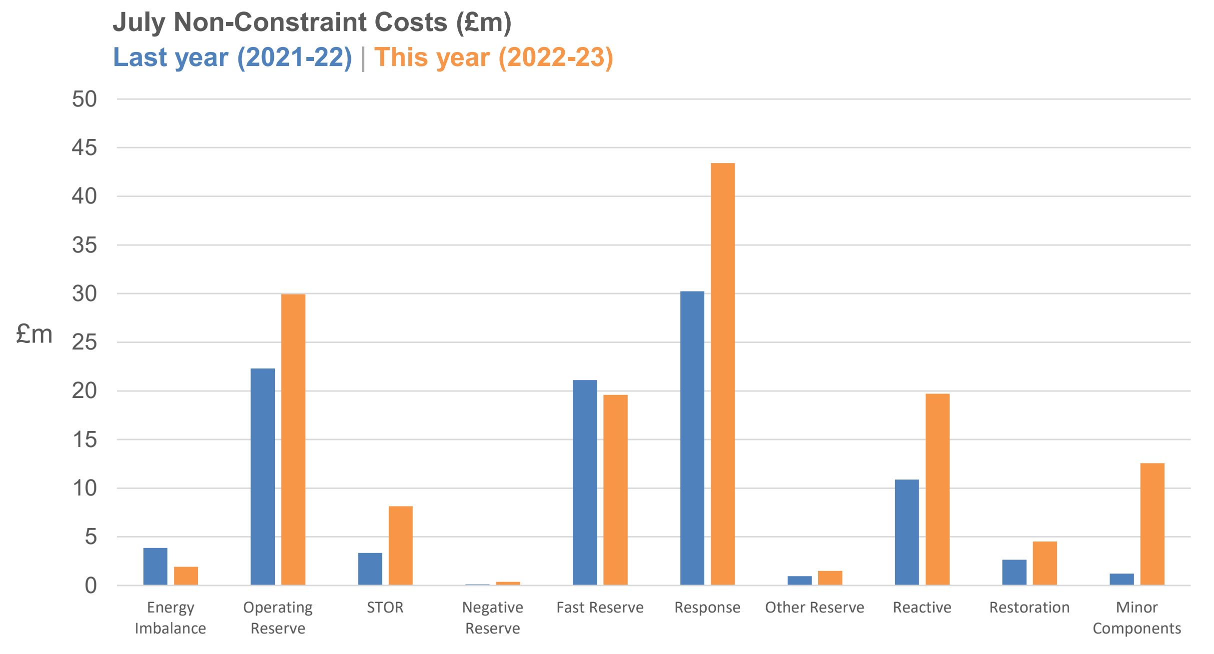
Changes in energy balancing costs



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

Power day ahead prices increased in March and remain significantly above previous year 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 the upward trend as well.

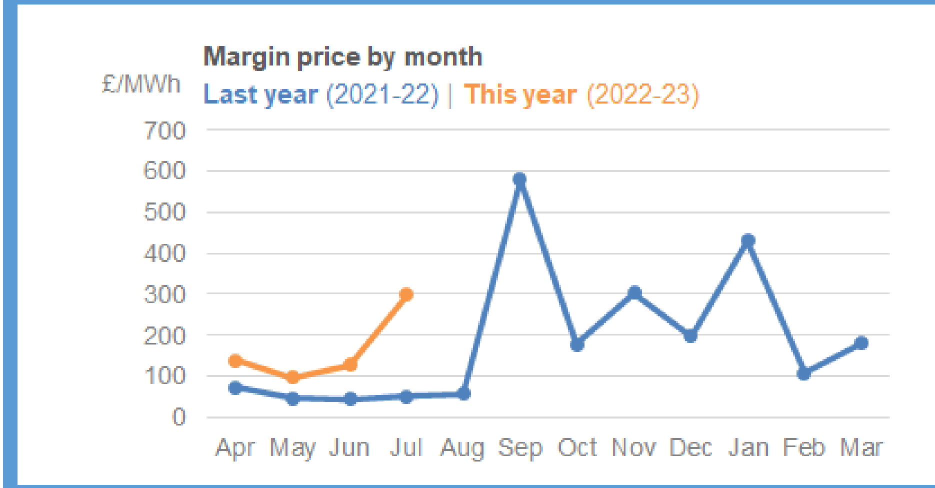
Cost trends vs seasonal norms



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

- **Response** costs are £13.2m higher. With the introduction of the Dynamic Containment service, this continues to be higher spend than the previous year, but offsets some costs in other categories.
- **Operating Reserve** costs are £7.6m higher. High wholesale market prices leading to high cost of BM actions is the main driver behind the cost increase.
- **Reactive** costs are £8.8m 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 sharply increased since June and remain high when compared to last year.

Daily costs trends

The monthly balancing costs in July outturned at £382m showing an increase from June of around £50m.

Wednesday 20 July was the most expensive day with a daily spend of around £64m. For further details please refer to the Significant events section at the bottom of the Metric 1A.

Wednesday 6 and Tuesday 12 July were other expensive days with a daily outturn of around £27m and £25m respectively. 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 were the main driver behind these expensive days. When a bid is taken to resolve a constraint, the energy on the system must then be replaced. When a large volume of BM bids are required to manage the flow on a boundary to below the constraint limit, that volume of energy needs to be procured in the BM to rebalance. The cost of the replacement energy is significantly higher than in previous years due to the ongoing high wholesale market prices.

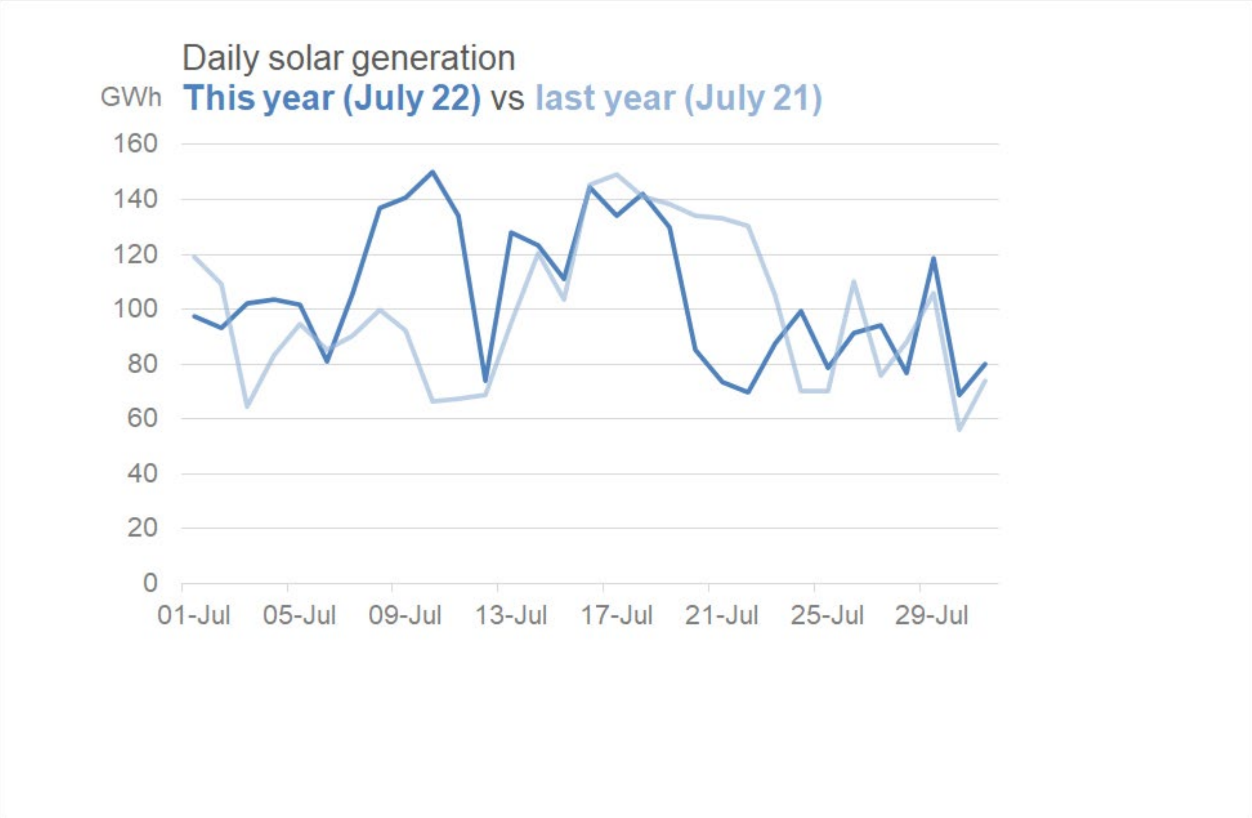
High-cost days and balancing cost trends are discussed every week at the Operational Transparency Forum to give ongoing visibility of the operability challenges and the associated ESO control room actions.

Significant events

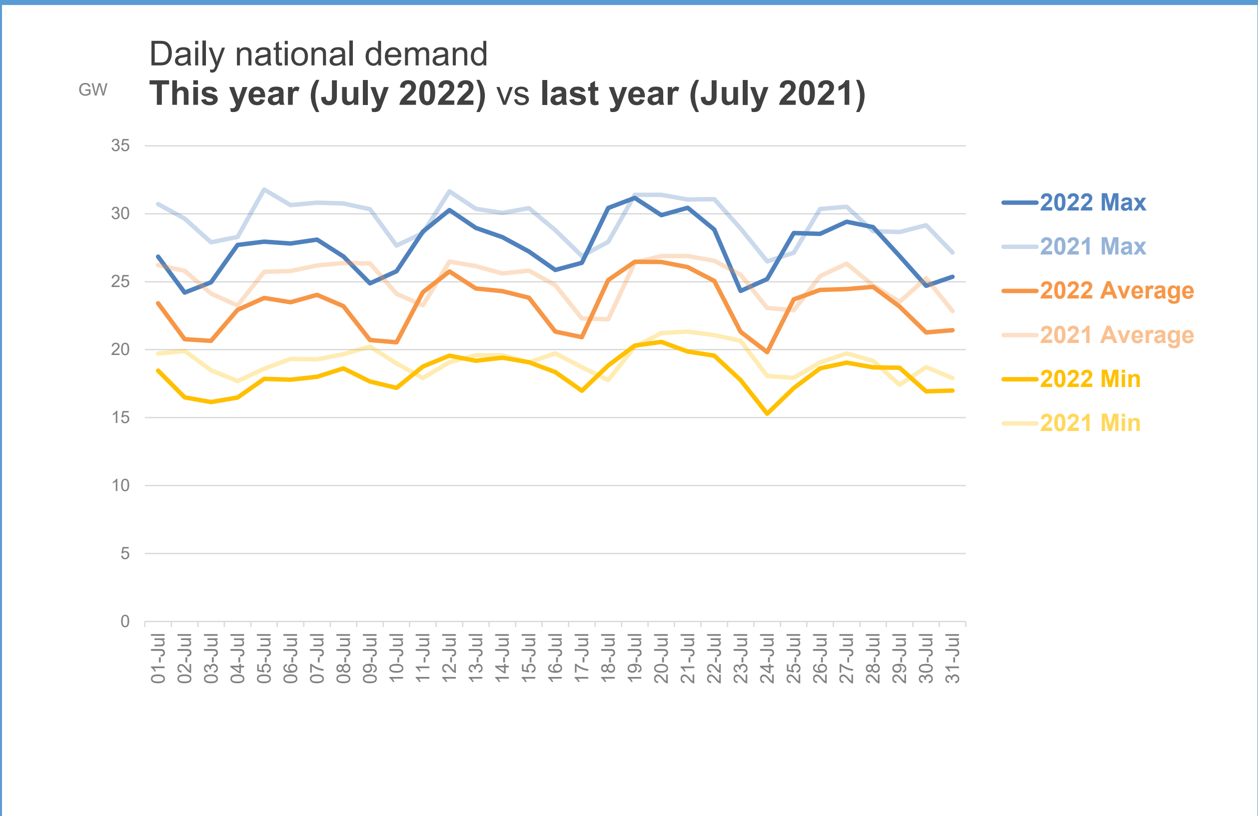
On 20th July 2022, high power prices from the continent drove all South East interconnectors to export power to the continent. This combined with London demand drove power flows across network boundaries that were weakened by unplanned outages.

NGESO carried out trades on the interconnectors to help manage the power flows across the network boundaries in the South East of England. Scarce supplies of power on the continent resulted in extreme prices leading to a total trading expenditure for the Constraints-E&W category in excess of £59m.

Solar generation - comparison of July this year vs July last year



July Outturn Demand vs July 2021-22



Metric 1B Demand forecasting accuracy

July 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.

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

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

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

Compared with 2020-21's reporting, there are two differences in relation to metric 1B. The first one is that the performance is reported as the mean absolute percentage error (APE) rather than mean average error expressed in MW. The second difference is that the accuracy is measured for each Settlement Period, rather than each Cardinal Point.

Updated benchmark for 2022-23: The benchmark for this metric has been updated 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

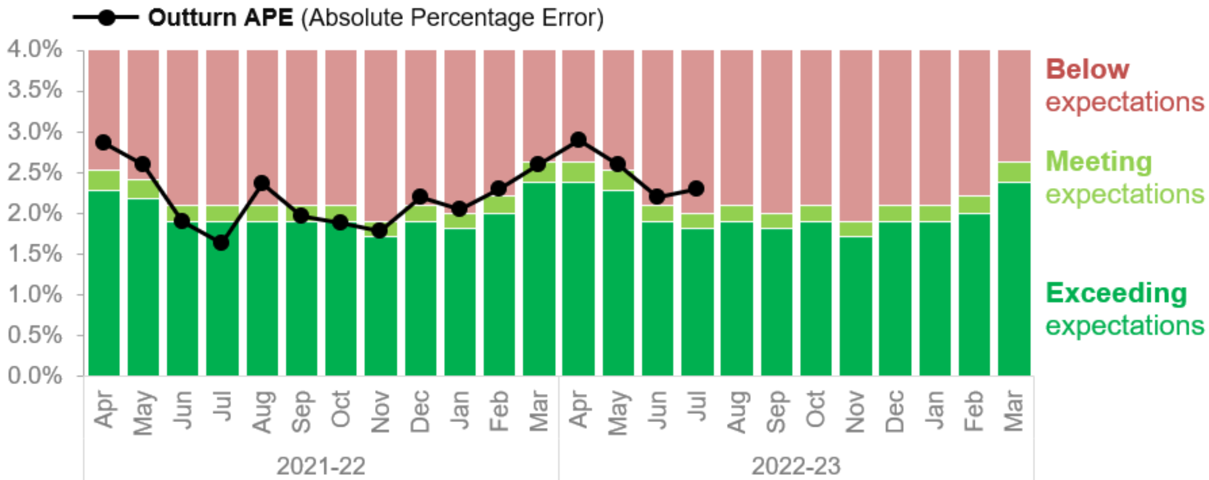


Table 4: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

	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**									
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 July 2022, the mean absolute percentage error (MAPE) of our day ahead demand forecast was 2.3% compared to the indicative performance target of 1.9%, and therefore below expectations.

The biggest challenges in July 2022 were weather related, with unusually high temperatures for many days and variable cloud cover strongly affecting some days.

The distribution of settlement periods 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	229	15%
1500 MW	72	5%
2000 MW	31	2%
2500 MW	6	0%
3000 MW	1	0%

The largest errors at the day ahead forecasting horizon were observed on 6, 13 and 22 July, and the settlement periods with the highest MAPE were between SP25 and SP30.

A large contributor to these errors was solar/PV generation, affected by unpredicted variable cloud cover. Finding suitable profile days for the unprecedented heat waves in July also posed an additional challenge.

In addition to the work being undertaken to build a new solar/PV model, we are in negotiations to expand the weather forecast data we receive and feed into our models. Once complete, sufficient time will be required to gather enough data (at least 1 full quarter) then retrain and thoroughly test new models.

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

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

Metric 1C Wind forecasting accuracy

July 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

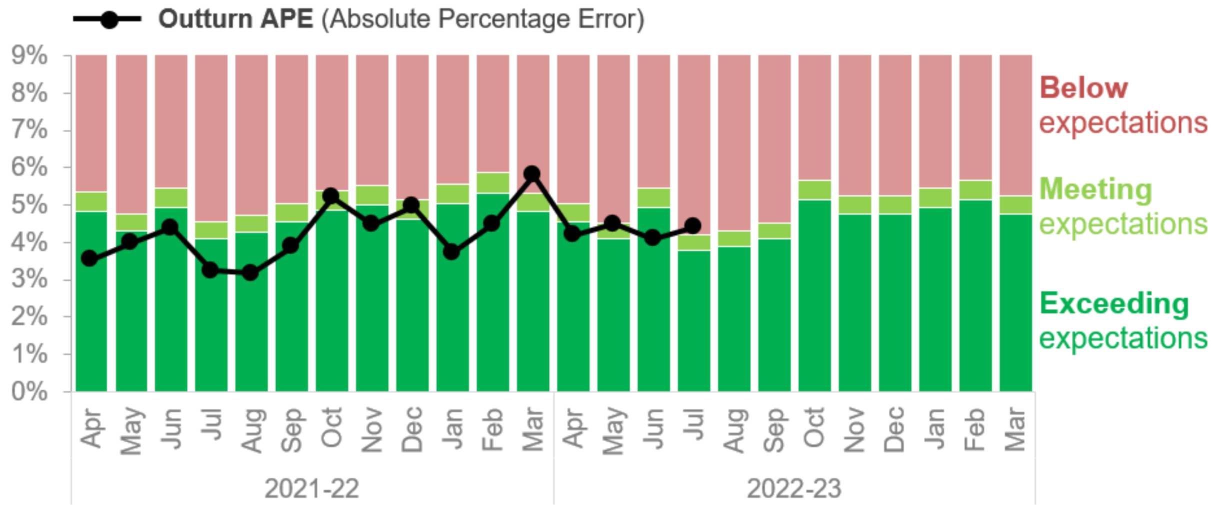


Table 5: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2022-23)

	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**									
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 **July 2022**, our MAPE (mean absolute percentage error) was 4.4% compared to the benchmark of 4.0% and therefore falls in the 'below expectations' category.

July was largely dominated by high pressure systems, which generally lead to light winds and settled weather conditions. The Met Office has confirmed July 2022 as the driest July since 1911, with only 24% of expected rainfall recorded. Wind levels were also consistently low throughout the month. These favourable conditions would usually help us achieve greater wind forecasting accuracy. However, during periods of calm weather, wind farm construction happens at high speed, increasing their capacity and thus our margin for error. 576MW of new wind farm capacity was connected in July.

Lightning is a good sign of atmospheric instability, which can be an indication of wind power forecast error. Although July was generally calmer than previous months, there was still some significant lightning activity which could account for forecasting inaccuracies. Lightning was a feature on 1 July in Sheffield and Nottingham, in Southampton and Portsmouth on 18 July, and in western Scotland on 23 July. There was also significant lightning activity on 19 July in southern England, central Wales, and northern Scotland. This was a direct result of the heatwave that swept over the UK, which saw temperatures reach record-breaking heights of 40.3 °C in Lincolnshire. Steep lapse rates in the mid-troposphere associated with the plume of hot air resulting from the heatwave led to the development of a line of thunderstorms that initiated a cold front, with several thousand lightning strikes consequently being detected.

Wind farms with CFD contractual arrangements switch off for commercial reasons while prices are negative for 6 hours or more. In July 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 July 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 0 occasions of missed or late publications in July.

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

Metric 1D Short Notice Changes to Planned Outages

July 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

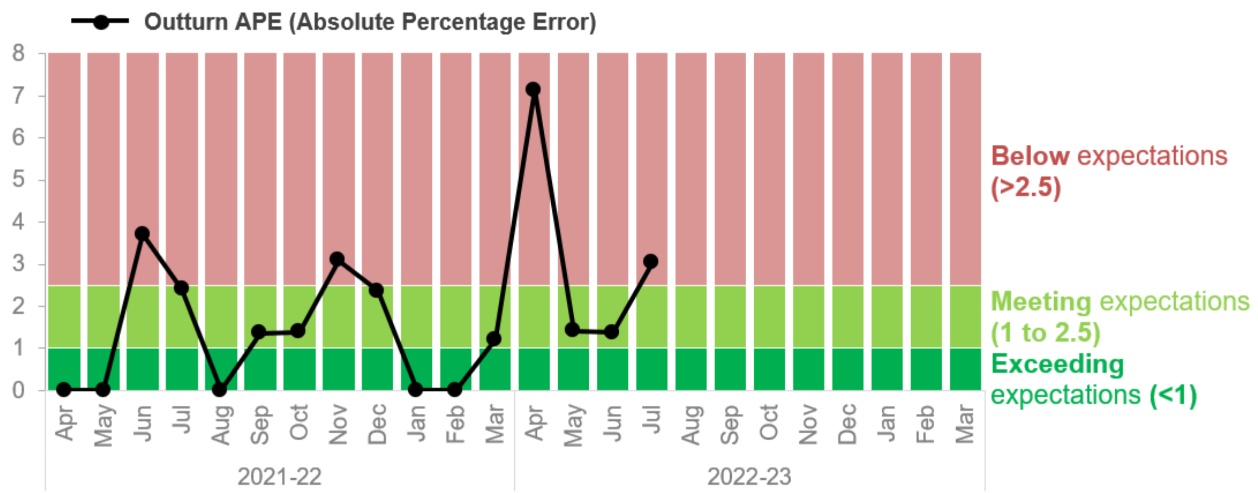


Table 6: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	700	709	730	660									2799
Outages delayed/cancelled	5	1	1	2									9
Number of outages delayed or cancelled per 1000 outages	7.1	1.4	1.4	3.0									3.2
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 July, the ESO has successfully released 660 outages and there has been two delays or cancellations due to an ESO process failure. The number of stoppages or delays per 1000 outages is 3.0, which is 'Below Expectations'. The two events can be summarised below:

A delay occurred on an outage where it was not identified in planning timescales that for a particular substation bar fault, there would be back energisation of a Super Grid Transformer

(SGT) and a 400kV circuit. These are unacceptable conditions. The Control Room spotted this issue and liaised with the Transmission Owner (TO) in order to get the protection settings modified and therefore to prevent this unacceptable condition from occurring. The TO did not have any resource allocated for this request as it was not identified within planning timescales. Consequently, the outage was delayed until the protection could be modified. An Operational Learning Note has been written highlighting the importance to read the intertrip capabilities section within the protection schedules when these system configurations could arise following a fault.

The second delay occurred when reselection of a cross-boundary circuit was required within a substation before proceeding. This re-selection required the circuit to be off-loaded for switching time and needed site attendance. There was some confusion on the date this would proceed and no outage booking (in eNAMS) was created to reflect this requirement. This resulted in one of the TO parties being unaware of the requirement. It could not be facilitated in control timescales as they did not have available field staff for the switching. The switching was agreed between all parties and took place the following day. An OLN has been written highlighting the importance of creating eNAMS booking for switching outages, this will ensure all parties are made aware of these requirements in advance and serves as a reminder. Corrective actions have been adopted to add relevant notes to substations in NGESO tools. These notes will act as a reminder to notify adjacent TOs of cross boundary resource requirements.

RRE 1E Transparency of operational decision making

Q1 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 7: Percentage of balancing actions taken outside of 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%							
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.7%	99.6%	99.4%							
Percentage of actions with no category applied or reason group identified	**0.3%**	**0.3%**	**0.4%**	**0.6%**							

Supporting information

This month 88.6% 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 July 2022, we sent 41,150 BOAs (Bid Offer Acceptances) and of these, only 263 remain with no category or reason group identified, which is 0.6% of the total.

RRE 1G Carbon intensity of ESO actions

Q1 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 10: 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								

Supporting information

In July, the average carbon intensity of balancing actions was 0.3 gCO2/kWh. This was the lowest monthly average in the year so far. For Q1 2022-23 the average carbon intensity was 3.2 gCO2/kWh. This reduction is because we are taking significantly few operational actions in July 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 reduces ESO interventions and mean that if we do take operational actions pulling back carbon generation (e.g., if the market was long), the monthly carbon RRE1G figures will also reduce significantly.

In July, the largest decrease in carbon intensity due to ESO's actions was at 14:00 on 31 July with a minimum intensity of ESO actions of -17.1 gCO2/kWh. The minimum for the year so far is -26.2 gCO2/kWh on 29 May.

RRE 1I Security of Supply

July 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 ≤ 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 12: 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								
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	1	1	1	1								
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0								

Supporting information

There have been no reportable voltage and one frequency excursions for July 2022.

Due to extreme hot weather, on 19 July 2022 at 22:11, IFA2 tripped while exporting 1029MW from GB to France. Frequency increased to 50.352Hz and returned to operational limits by 22:15.

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

RRE 1J CNI Outages

July 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 13: 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								
Integrated Energy Management System (IEMS)	0	0	0	0								

Table 14: 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								
Integrated Energy Management System (IEMS)	0	0	0	0								

Supporting information

In July 2022 there was one planned CNI system outage. The outage was part of regular planned maintenance activities on the BM production systems, and impacted the key BM Suite components used for scheduling and dispatch of generation.

Notable events during July

ENCC Transparency Roadmap

We have updated our Electricity National Control Centre (ENCC) Transparency Roadmap[4], which highlights the activities we will be delivering to increase the transparency of our data in the short to medium term.

Strategic Innovation Fund (SIF) projects

The ESO and consortium partners have been awarded a second grant from Ofgem's Strategic Innovation Fund (SIF) as part of a wider project that looks to understand how domestic flexibility can be used to help manage the grid.

The CrowdFlex project is exploring consumer behaviour in order to understand how domestic flexibility can support the coordination of energy consumption, generation and grid management and will now move into the second, Alpha, phase of delivery. A successful Discovery phase, completed in early 2022, established that the energy industry would like to see domestic flexibility resources play an active role in energy markets and services. Such resources have the potential to greatly reduce system operation costs, while minimising the need for additional capacity and network reinforcement, thereby reducing costs for the end consumer.

Following funding confirmation for the Alpha phase, the team will look to develop:

- an understanding of system needs and utilisation of domestic assets.
- plans for testing flexibility services in a real-world trial, including stacking multiple services
- greater clarity around data needs and statistical modelling approaches for forecasting flexibility
- better understanding of potential regulatory barriers.
- a plan to successfully engage with consumers, incentivise them to change their behaviour and ensure the trial can deliver the expected commercial and $CO2$ reduction benefits.

In addition to supporting the path to net zero emissions, CrowdFlex will be a critical vehicle for delivering economic impact through flexibility incentives, including time-of-use tariffs. These tariffs offer consumers cheaper electricity prices when demand is low, or generation is high. An earlier CrowdFlex study, the UK's largest ever domestic flexibility study, found that time-of-use tariffs can help customers reduce their evening peak demand by up to 23%.

The CrowdFlex project's flexibility modelling is also contributing to an ambitious industry-wide mission launched by ESO in 2021 to digitise the GB energy system. The Virtual Energy System will be a digital twin of the physical energy system, working in parallel to enable an open, unified, real-time view of every part of the GB energy system.

[4] https://www.nationalgrideso.com/document/222181/download

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

July 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 12: Monthly BSUoS forecasting performance (Absolute Percentage Error) – two-year view

Table 17: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[5] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	5.3	6.8	9.4	10.3								
Month-ahead forecast	11.0	9.0	7.7	7.82								
APE (Absolute Percentage Error)[6]	**106%**	**32%**	**17%**	**24%**								

Supporting information

Wholesale electricity prices were 52% higher in July than in June (day ahead July price was £245/MWh compared to £161/MWh in June), contributing to higher costs.

July outturn costs were above the 95th percentile of the forecast produced at the beginning of June. This is mainly due to the wholesale electricity price being higher (£245/MWh) than the value in the forward curve available at the time of forecast (£179/MWh).

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

Notable events during July

Quick Reserve Service Design, and Slow Reserve Design.

On Tuesday 12 July we held a Reserve Reform Show & Listen session which detail our latest proposals for Quick Reserve Service Design, such as Recovery Period and Performance Monitoring, plus a recap of Slow Reserve Design.

Quick Reserve, separated into Negative Quick Reserve (NQR) and Positive Quick Reserve (PQR), is aimed primarily for reacting to pre-fault disturbances to restore the energy imbalance quickly and return the frequency close to 50.0 Hz.

Slow Reserve, separated into Negative Slow Reserve (NSR) and Positive Slow Reserve (PSR), will be the first of our series of new Reserve products. It is designed to operate post-fault and aims to provide ESO with access to firm, bi-directional energy to displace large losses on the system and recover frequency to ± 0.2Hz within 15 minutes.

Power Responsive Summer Event

We held a Power Responsive Summer Event in London on Wednesday 13 July. Over 250 attendees made up of small and large Demand Side Response (DSR) providers, energy managers, industry experts, consultants, energy associations and suppliers/aggregators. There were 14 Exhibitors on the day made up of aggregators who fed back that it was one of the best events they have attended regarding attendee interaction and new leads. DNO's and the ESO had stands which were always busy with people asking questions to account managers and SME's face to face. The days topics were well received, with updates from Ofgem, BEIS and the ESO, and a session on creating a flexible network. DNOs held a session on market opportunities hosted by aggregators and suppliers alongside energy associations. All sessions had Q&A opportunities which were well utilised with lots of good questions that were answered by speakers. Another big highlight for attendees was the networking opportunity that the event offered.

Annual Capacity Market Launch Event

The EMR Delivery Body and Delivery Partners hosted the annual Capacity Market Launch Event on Tuesday 19 July. The Event was attended by c 270 participants ahead of the Prequalification Submission Window which opened on Wednesday 27 July 2022.

Key updates from all Delivery Partners were provided in the presentations including developments in the Capacity Market over the past 12 months.

The Event also included a Q&A session, it was good to see a range of questions raised by several of the participants which were answered by all Delivery Partners. The Event was generally well received and overall satisfaction score for the Event was 7.62

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 July

Winter Outlook 2022-23: Early view report

On Thursday 27 July we published our Winter Outlook 2022-23: Early view report[7]. This year we are committed to providing an early view to help the electricity industry prepare for the Winter ahead. It sets out our Base Case view for winter as well as the actions we are taking to build our resilience to the risks and uncertainties arising from European gas supplies. It does not include the full detailed analysis that is usually included in the Winter Outlook Report. This will be developed over the coming weeks and months for publication in the Autumn. We will continue to monitor the market outlook for winter, and it's likely that the information presented in the early view will change by the time we publish the Winter Outlook Report as we incorporate new market intelligence.

Margins are expected to be within the Reliability Standard under normal market conditions. There may be some tight periods that we expect to be able to manage using our standard operational tools. We are taking actions to build our resilience to potential risks and uncertainties due to a possible shortage of gas supply in Europe. This includes extending the life of coal units and exploring market-based demand side response.

Future Energy Scenarios (FES) 2022 published

On Monday 18 July we launched our 2022 Future Energy Scenarios (FES)[8] along with a summary document[9]. We also recorded a briefing event[10] to hear views from a panel of experts across industry and government discussing the future of energy security and addressing the challenges of our 2050 target. There are videos to watch on our website[11] which take a deeper look at each one of the FES 2022 Key Messages with presentations, Q&A, and a panel discussion.

FES outlines four different pathways for the future of energy and represents a range of different, credible ways to decarbonise our energy system as we strive towards achieving net zero by 2050. Based on extensive stakeholder engagement, research and modelling, each scenario considers how much energy we might need; where it could come from; and how we maintain a system that is reliable. We explore how different parts of the energy system can help lower emissions across the economy. By strategically investing in infrastructure to onboard clean energy, making the system smarter and more flexible, and reforming the wholesale electricity market, this would unlock benefits to the energy system and consumers. It could also reduce dependence on energy imports and help to insulate the economy from geopolitical shocks.

In 'Leading the Way', combining high consumer engagement with significant and innovative investment enables the Net Zero target to be met in 2047 with annual emissions net negative in 2050.

'Consumer Transformation' and 'System Transformation' both meet the target of Net Zero greenhouse gas emissions by 2050. As well as meeting all the interim carbon budgets. The ways they do this are very different and highlight the varying roles of supply and demand as well as different fuels like electricity and hydrogen.

Annual carbon emissions in 'Falling Short', previously called 'Steady Progression', in 2050 are still reduced by almost 80% of 1990 levels, which would have been close to meeting the previous carbon reduction target.

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[7] https://www.nationalgrideso.com/document/264521/download
[8] https://www.nationalgrideso.com/document/263951/download
[9] https://www.nationalgrideso.com/document/263861/download
[10] https://players.brightcove.net/867903724001/default_default/index.html?videoId=6309677901112
[11] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

Pathway to 2030 with Holistic Network Design (HND) published

On Thursday 07 July, we published the Pathway to 2030 Holistic Network Design (HND)[12] and more detailed supporting documents. We held a launch webinar on Tuesday 12 July and a HND Industry Code, Standard and License Recommendation Report Webinar on Tuesday 19 July.

The HND is an innovative, centralised, strategic network design that integrates connecting 23GW offshore wind with capacity to transport electricity it produces around GB to where it will be used. It also balances the objectives of cost to consumers, deliverability and operability, and minimising the impact on the environment and communities. Combined with offshore wind already operational and further advanced in its development, the HND supports the delivery of the Government's ambition for 50GW offshore wind by 2030. The recommended design should save consumers £5.5 billion from 2030. This includes £13 billion of reduced network constraint costs resulting from transporting more power from offshore wind to where it will be used. This is 32TWh over a 10 year period from 2030, equivalent to powering 10 million homes for a year; reducing cumulative CO_2 emissions from fossil fuel alternatives by two million tonnes just between 2030 and 2032 – equivalent to grounding all UK domestic flights for a year.

The HND will be followed by a Detailed Network Design (DND) and consenting process to determine transmission routes, technology choices, and the locations for substations and converter stations. The next steps involve an HND follow up exercise to include network recommendations for further offshore wind projects, including all ScotWind leaseholders by Q4 2022-23. We will also be working with developers in the first HND to update their connection contracts and with industry to progress the code and standard changes that we recommend are required to enable delivery of the HND.

Network Options Assessment (NOA)

We have also published a refreshed 2021-22 Network Options Assessment (NOA)[13] alongside the Pathway to 2030 Holistic Network Design. The NOA provides our recommendations for which reinforcement projects should receive investment and when.

The NOA 2021/22 Refresh was published on 7th July to update and refresh the recommendations within the NOA 2021/22 (published in January 2022) based on the recommended offshore design to connect 50GW of offshore wind as per the Pathway to 2030 publication. The additional offshore generation, the optimised connection points and the coordinated offshore network led to additional onshore transmission system needs that needed addressing.

In the NOA Refresh, 94 schemes were identified as required to meet the Government's ambition for 50GW of offshore wind by 2030 comprising of 56 scheme that were identified as HND essential options and 38 schemes identified as *"optimal"* for delivery of the HND leading to a total cost of £21.7bn. Furthermore, working closely with the TOs, 11 HND essential options were identified whose delivery is currently estimated beyond 2030 and require acceleration to facilitate the current Government targets.

Going forward, we will continue to work in partnership with stakeholders, to reform the network planning processes, to deliver a Centralised Strategic Network Plan as envisaged in Ofgem's consultation. We are currently developing the HND follow-up process with an expectation that this will commence following this publication of the HND in July 2022, and with an aim to provide in-scope developers with our HND follow-up process recommendations in Q1 2023. Our plans for further analysis – as part of a transition to a Centralised Strategic Network Plan – are being developed and we will share more information with Stakeholders this autumn. This will include changes and enhancements to the assessment of the onshore network considered by the NOA process.

Improvement on engagement with ESO Connection Customers

Since April 2022 we have successfully held two in person Customer Seminars. The first one in Glasgow in May 2022, which addressed more generic Connections, Networks and ESO related matters. The second seminar held in July 2022 oversaw the successful delivery of our new concept to the type of events we run for our Customers as it was focused on the Demand and DER Connections customers, enabling the focus on more specific issues, strategies and themes that are relevant to those in attendance. Both events were successful in the number of attendees, participation on the day, and post event feedback (scores of 4.5 for the first seminar and 4.3 for the second seminar, out of a score of 1-5).

[12] https://www.nationalgrideso.com/document/262676/download

[13] https://www.nationalgrideso.com/document/262981/download

We have also introduced new monthly webinars called Customer Connection Agoras, which give the opportunity to provide presentations to customers on subjects that have been requested and hold Q&A on any matters customers would like to raise with us. These have an average in attendance of approx. 60-65 customers. All webinars are recorded, uploaded to the website, and shared with customers via our Customer Newsletter.

We have expressed in our BP1 deliverables to have focused on enabling more engagement with customers on a regular basis and the events delivered so far have been well received. We will take on board the feedback to look how we can further improve on the frequency and type of engagement mediums.