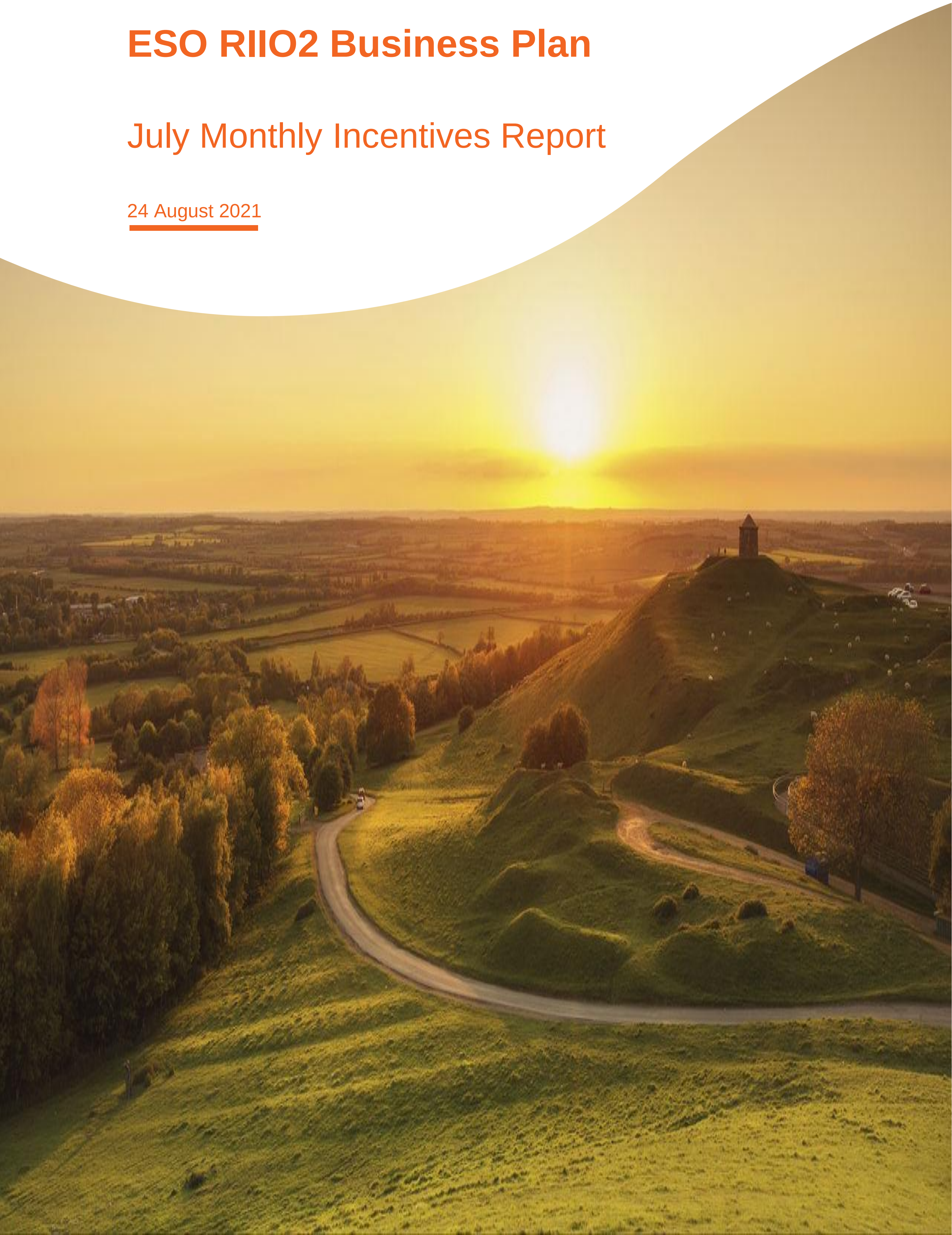
ESO RIIO2 Business Plan

July Monthly Incentives Report

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

- On 12 July we published our Future Energy Scenarios (FES) 2021. FES is based on extensive stakeholder engagement, research and modelling. It describes what the future of energy may look like between now and 2050.
- We held three Net Zero Market Reform workshops on the 'case for change', to gather evidence for the case for market reform through open discussions between stakeholders.
- The first monthly Central Design Group was held in July, which will be the vehicle through which the ESO delivers a Holistic Network Design (HND) to provide a coordinated National Electricity Transmission System (NETS), including onshore and offshore assets, primarily required to connect offshore wind up to 2030.
- On 27 July, we published our Network Innovation Allowance (NIA) annual summary for 2020-21, sharing the latest progress on our innovation portfolio.
- For the Regional Development Plan (RDP) projects we held two webinars for Distributed Energy Resource (DER) in July, one in conjunction with WPD and the other in conjunction with UKPN.
- We conducted a Technical Feasibility Assessment on how Energy Storage could help manage constraints on the Electricity Transmission Network between 2022-2030.
- Ofgem approved the ESO's proposed System Test Plan for GB, in accordance with the EU's Network Code on Emergency and Restoration (NCER). Ofgem also approved the ESO's amended proposals for the list of Significant Grid Users in relation to the NCER.
- There were updates on three CUSC modifications that were raised by the ESO:
    - CMP365 'Improvements to CUSC Governance Arrangements', was approved by the Authority and will be implemented on 30 July 2021.
    - CMP370 'Aligning the CUSC with the Interactivity Policy' has been recommended by the CUSC Panel for implementation and is now with Ofgem for a decision.
    - CMP377 'Clarification of Section 14 BSUoS Charging Methodology' was raised by the ESO.
- We hosted a webinar on 28 July to launch an upcoming mock tender event as part of the Procurement and Compliance Workstream in the Distributed ReStart project. The mock tender event will run from 2 August to 6 September for potential DER providers.

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

Table 1: Summary of Metrics and Regularly Reported Evidence

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£127m vs benchmark of £83.8m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 1.6% (vs benchmark of 2.0%)	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 3.2% (vs benchmark of 4.3%)	●
Metric 1D	**Short Notice Changes to Planned Outages**	2.4 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	●
RRE 1E	**Transparency of Operational Decision Making**	99.8% of actions have reason groups allocated	N/A
RRE 1G	**Carbon intensity of ESO actions**	4.5gCO2/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**	1 planned system outage	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 3%	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 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

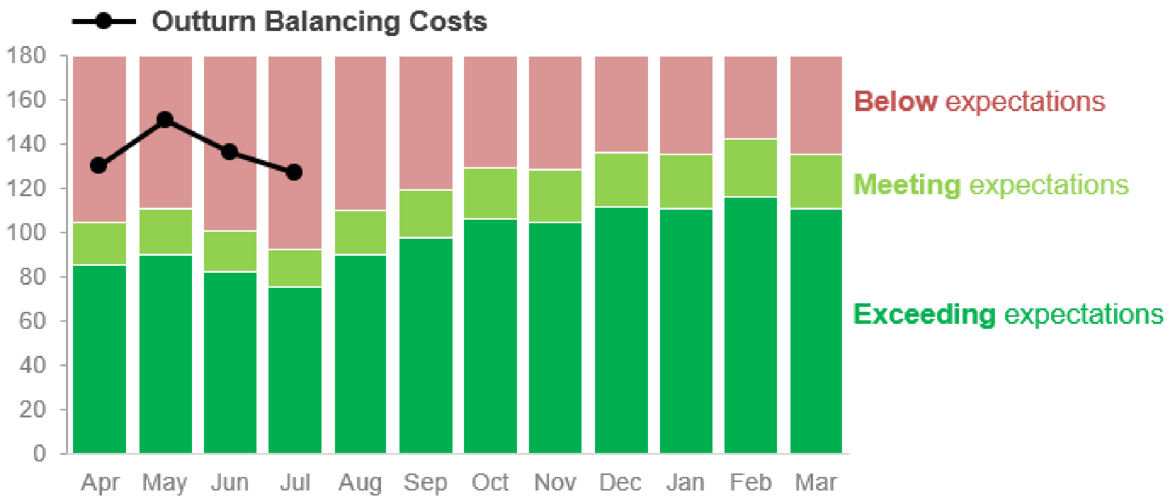

Table 2: Monthly balancing cost benchmark and outturn (Apr-Sep 2021)

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	165.2
Indicative benchmark: constraint costs (B)	59.9	50.6	52.2	49.2	58.3	66.8	211.8
Indicative benchmark: total costs (C=A+B)	101.2	91.9	93.6	90.5	99.7	108.2	377.2
Outturn wind (TWh) [1]	2.77	3.22	2.48	1.87			10.35
Ex-post benchmark: constraint costs (D)	53.5	58.9	49.91	42.49			204.8
Ex-post benchmark (A+D)	**94.8**	**100.3**	**91.2**	**83.8**			**370.1**
Outturn balancing costs[2]	**129.5**	**150.9**	**135.7**	**126.7**			**542.8**
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

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[1] Please note that the 'Outturn wind' figure was corrected in this re-published version of the July report on 14 September 2021. As a result, the 'Ex-post benchmark (D)' and 'Ex-post benchmark (A+D)' were also revised as they are calculated using the 'Outturn wind' figure. Figure 1 and some parts of the Supporting information were also revised to reflect the change.

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

Supporting information

The balancing costs for July were £126.7m, which is £9m lower than June, but still in the 'below expectations' range.

Breakdown of costs vs previous month[3]

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

		(a) Jun-21	(b) Jul-21	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	7.1	3.9	(3.2)	
	Operating Reserve	16.5	22.2	5.6	
	STOR	4.3	3.4	(0.9)	
	Negative Reserve	0.1	0.1	0.0	
	Fast Reserve	19.9	19.5	(0.4)	
	Response	30.0	29.1	(1.0)	
	Other Reserve	1.1	0.9	(0.2)	
	Reactive	7.2	9.4	2.1	
	Black Start	11.1	3.3	(7.9)	
	Minor Components	0.7	1.3	0.6	
Constraint Costs	Constraints - E&W	11.9	6.2	(5.8)	
	Constraints - Cheviot	2.3	0.9	(1.4)	
	Constraints - Scotland	0.9	1.7	0.8	
	Constraints - Ancillary	5.8	6.2	0.4	
	ROCOF	5.7	11.1	5.4	
	Constraints Sterilised HR	11.0	7.7	(3.3)	
Totals	Non-Constraint Costs - TOTAL	98.0	93.0	(5.1)	
	Constraint Costs - TOTAL	37.7	33.8	(3.9)	
	Total Balancing Costs	**135.7**	**126.7**	**(9.0)**	

As shown in the total rows above, this month's total reduction of £9m is split between constraint costs, which fell by £3.9m, and non-constraint costs which fell by £5.1m.

The main drivers of the changes this month were:

- **Black Start: £7.9m reduction.** Black Start costs for June were due to Capital Contributions agreed for new providers of Black Start services awarded as part of the tenders for South West, Midlands and the Northern regions. These pay for the equipment upgrades to enable existing plant to have Black Start capability and are assigned against the month in which they are receipted. This can lead to peaks (such as in June) and troughs (like experienced this month) in the Black Start costs.
- **Constraints – E&W: £5.8m reduction.** Wind levels across the country during July were lower than in June and those constraints that were active in July were not driven by wind levels. The majority of the wind was in England and Wales and was therefore largely unconstrained.
- Constraints on the South Coast were the key driver of constraint spend for July, affected by interconnector availability and flows rather than wind.
- **Operating Reserve: £5.6m increase.** Operating reserve costs increased largely due to regular instances of a short market through the month. 29 and 30 August were the most expensive days for this category of cost, with a daily spend of over £1m in both cases. On those days, wind generation

[3] Please note that the split of Constraint and Non-Constraint Costs was revised in this republished version of the July report on 14 September 2021: Black Start costs are now included in Non-Constraint Costs, in line with how the Benchmark was calculated. In the previous version of this report, Black Start costs were included in Constraint Costs.

was short-falling against forecast overnight and required late desynchronization of generators at a cost in order to meet demand.

- **RoCoF: £5.4m increase**. RoCoF costs remain significantly below the historical spend as a result of the changes implemented over recent months in the way we manage inertia. The increase in RoCoF costs from June is driven by the cost of trading to reduce the flow on the interconnectors to secure for RoCoF. The volume traded was lower than June, but the cost of trading was higher per MWh leading to a higher overall cost.

Constraint Costs vs Non-Constraint Costs

Overall July balancing costs are lower this year than for the same period last year. Constraint costs have remained lower as a result of changes to inertia management, lower wind, higher demand and good levels of network availability. Non-constraint costs have remained higher than last year with higher Balancing Mechanism (BM) prices driven by, firstly, the ongoing scarcity of generation to meet margin requirements and secondly, the procurement of new products to maintain operability and save costs overall.

Constraint Costs

Compared with the same period last year:

- Constraint costs for July 2021 are significantly lower than July 2020 due to a number of factors including those mentioned above.
- 'Constraints – Ancillary' cost has dropped by £15.5m as there has not been a need to enact ODFM (Optional Downward Flexibility Management) or negotiate any other contracts to manage downward regulation, due to higher outturn demand and lower wind levels.
- 'Constraints – E&W' cost has dropped by approximately £21m compared with the same period last year, largely driven by increased network availability in the North of England (last year, transmission network upgrades required an outage on a key boundary for the whole summer) and lower wind levels in the North this year but also due to higher minimum demand levels resulting in reduced generator intervention to meet voltage requirements.
- Significantly, RoCoF costs for July have remained at a much lower level than last year as a result of the changes in the way we manage inertia as described in the Frequency Risk and Control Report (FRCR). This is possible because of the reduction in RoCoF risk through the ALoMCP (Accelerated Loss of Mains Change Programme) and the introduction of Dynamic Containment. RoCoF costs for July this year were approximately £20m lower than July last year.

Compared with the previous month:

- Constraint costs in July were £3.9m lower than in June. This was mainly driven by the reduction in 'Constraints – E&W' costs as covered above.
- The suppression of constraint costs, particularly the RoCoF component which has been a key driver in recent years, is anticipated to continue due to the enduring application of Phase 1 of the FRCR and in the coming months the implementation of Phase 2 of the FRCR.

Non-Constraint Costs

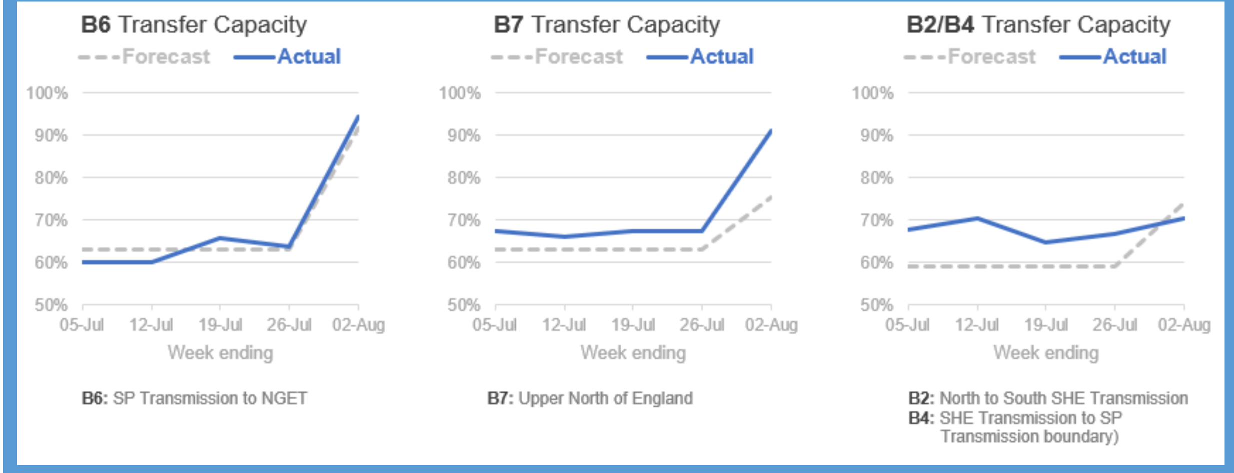
Compared with the same period last year:

- Operating Reserve, Fast Reserve and Response costs were higher in July this year, with overall non-constraint costs also making up a larger proportion of total spend. The average price of energy in the BM rose during the winter due to tight margins and although prices have fallen since then, the average price of energy has remained high. Q1 prices have been significantly above those for last year and this remains the case for July.

Compared with the previous month:

- July's £93m non-constraint costs are marginally lower than June (£98m). The drop in Black Start and Energy Imbalance costs are partly offset by increases in Operating Reserve and Reactive costs. This brings non-constraint costs largely in line with May of this year.

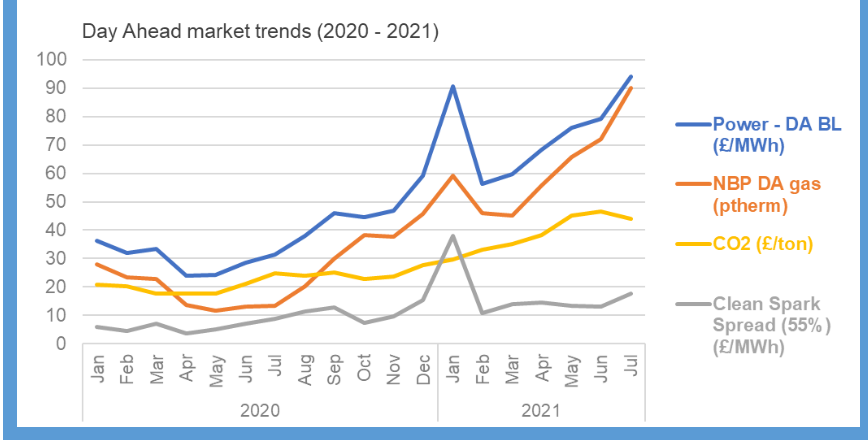
Network availability – July transfer capacity



There were significant boundary capacity reductions on B2/B4, B6 and B7 due to network availability in July. These could have led to significantly increased costs. However, relatively low levels of wind north of the boundaries (Scotland and North of England) for the majority of the month meant that the risk of increased costs did not materialise to any great extent.

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.

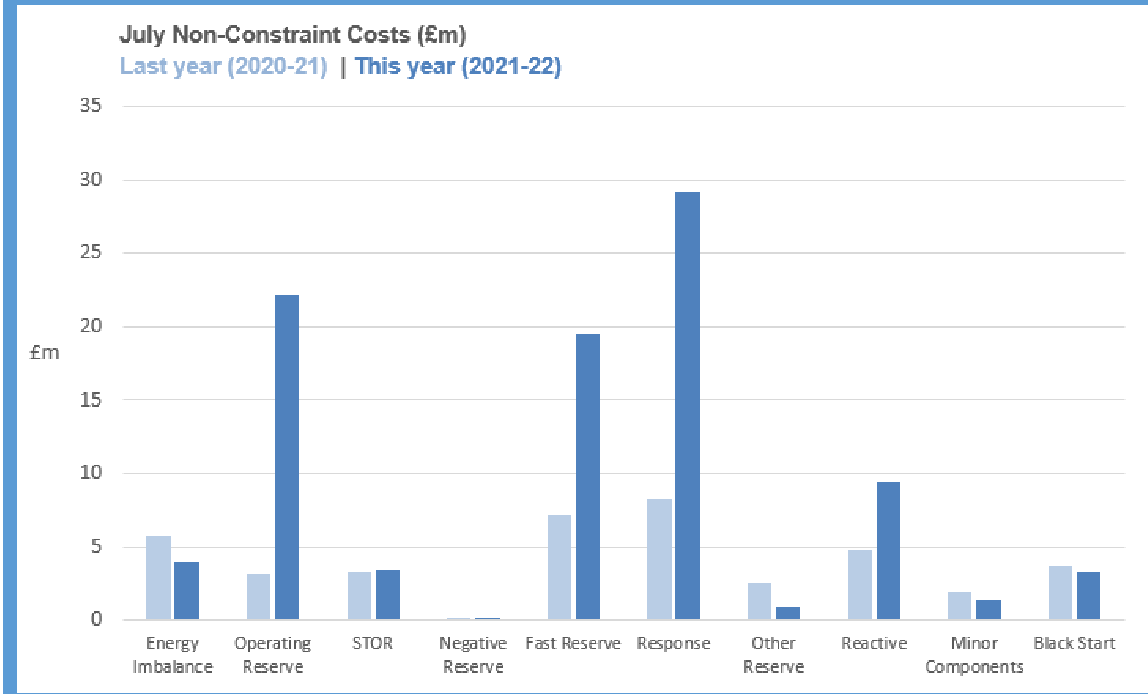
Changes in energy balancing costs



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

Power day ahead prices continued the upward trend in July driven predominantly by higher gas prices. Average day ahead power baseload averaged £94/MWh in July 2021 vs £31/MWh in July 2020. Gas prices have risen due to concerns over low European gas storage inventories and lower LNG (Liquified Natural Gas) availability in Europe due to high LNG Asian spot prices continuing to draw LNG cargoes across the summer. Supply constraints on pipeline deliveries from Norway and Russia have meant deliveries this summer are lower than expected. Day ahead gas prices averaged 90p/th in July 2021 vs 13p/th in July 2020. Carbon prices have remained near record highs.

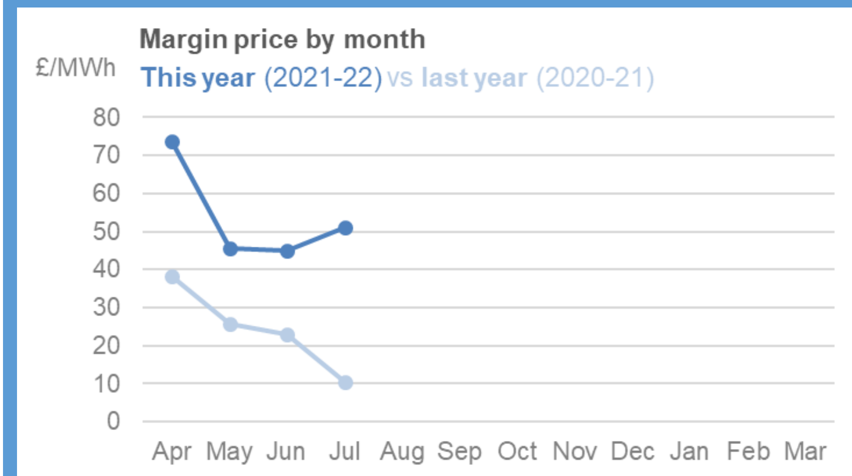
Cost trends vs seasonal norms



In a similar way to that experienced in Q1, comparing July energy costs with those of July last year, we can see:

- **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.
- **Operating Reserve** and **Fast Reserve** costs have also increased. This is as a result of tighter margins on the system driving BM prices up and making the procurement of Reserve more expensive.

Drivers for unexpected cost increases/decreases



As a result of tighter margins on the system, BM prices rose in July, impacting the cost of reserve.

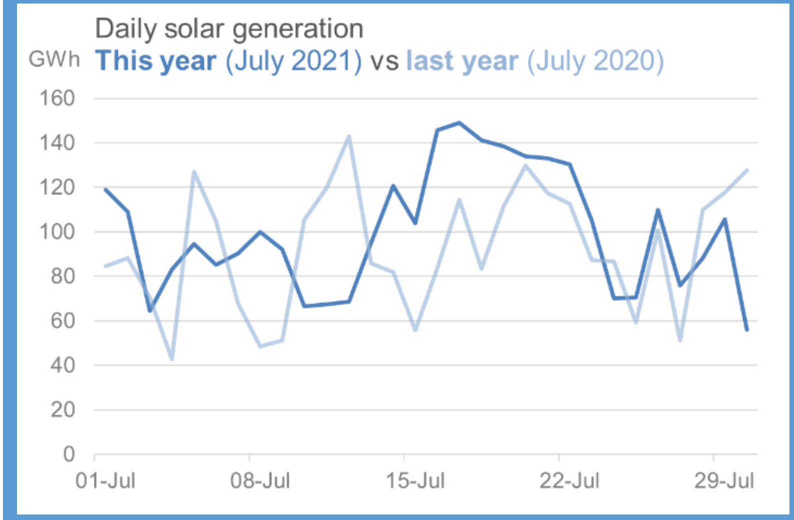
Daily costs trends

In July there were no significantly high cost days to note. The highest daily cost for Energy during the month was Sunday 18 July where demand uncertainty and a predominantly short market resulted in relatively large volumes of high prices offers accepted in the BM to meet demand.

Significant events

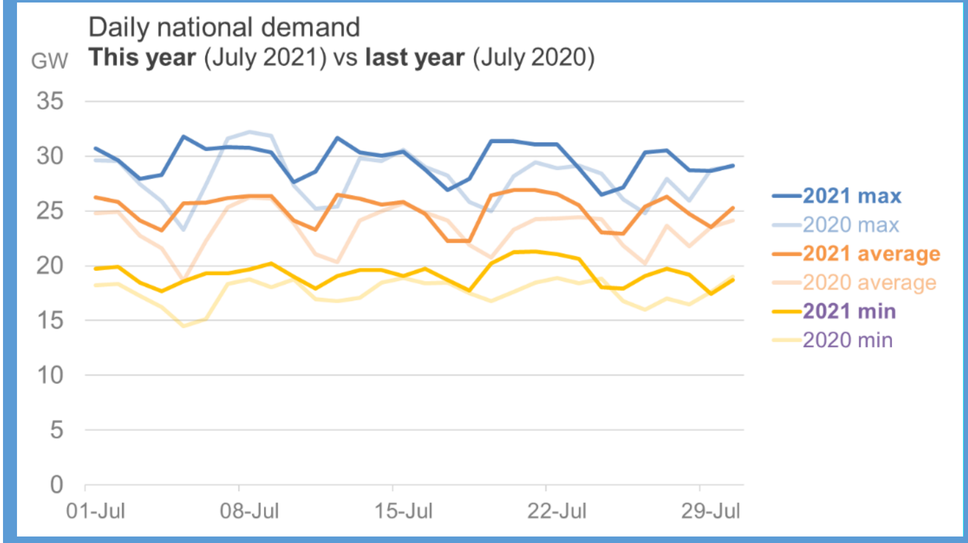
There were no major events in July that had a significant impact on balancing costs. A transmission fault which occurred on the B6/B7 boundary could have impacted balancing costs, but relatively low wind levels in the North of England and Scotland meant that this high cost was not incurred. The Euro 2020 final, on Sunday 11 July, required some additional response deployment to manage demand variability although this had little impact on balancing costs.

Solar generation - comparison against last year (July 2021)



Solar output was slightly higher in July 2021 compared with July 2020.

Outturn Demand vs 2020-21



Demand levels have been consistently higher during July 2021 compared with July 2020. This is as we would expect with the COVID-19 restrictions eased significantly this year. As in Q1 2020-21, during July 2020 we took specific steps to manage the record-breaking low demand conditions, such as the use of ODFM and the Sizewell de-load contract, which increased constraint costs. With higher demand in July this year, similar actions have not been required.

Metric 1B Demand forecasting accuracy

July 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)

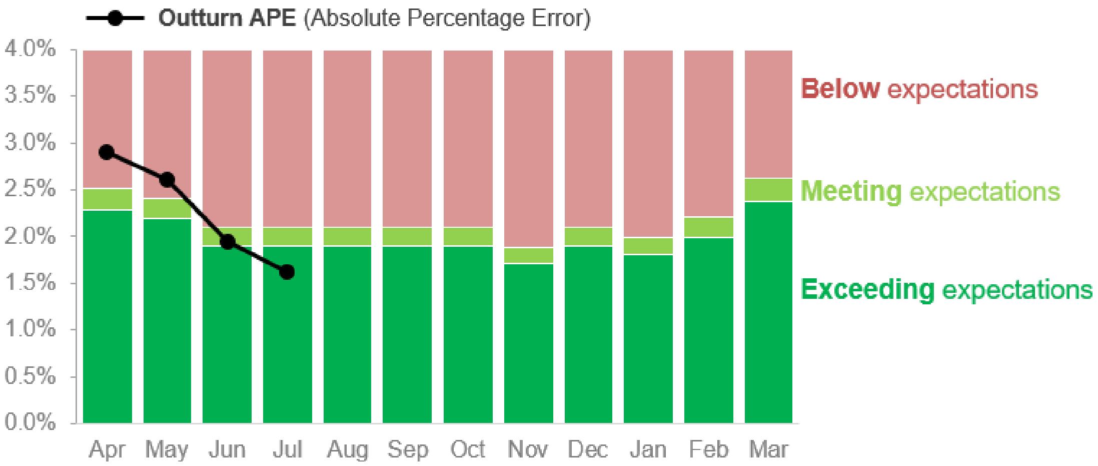


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

	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**									
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 July 2021, our day ahead demand forecast indicative performance was within the ‘exceeds expectations’ target for the first time this year, with a MAPE (Mean Absolute Percentage Error) of 1.6% against a benchmark of 2.0%.

Our new additional national demand forecasting model which uses machine learning techniques continued to help facilitate improved performance in July.

The most challenging days to forecast in July were Sunday 11 July, Sunday 18 July and Thursday 22 July. On those days the MAPE was above 3%. On all three days there were large solar PV forecast errors around midday and to a lesser extent in the afternoon, due to the weather being more overcast than forecast.

The biggest errors at the day ahead forecasting horizon were mostly observed between 06:00 and 08:00, SP13 (Settlement Period) to SP16.

A summary of the largest errors is shown in a table below.

Performance in July 2021: largest errors		
Error greater than	No of SPs	% out of the SPs in the month
1000MW	100	7%
1500MW	18	1%
2000MW	1	0%
2500MW	0	N/A
3000MW	0	N/A

Triad avoidance: Triads only take place between November and February, and therefore did not impact our forecasting performance during June.

Missed / late publications: There were 0 occasions of missed or late publications in July

Metric 1C Wind forecasting accuracy

July 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)

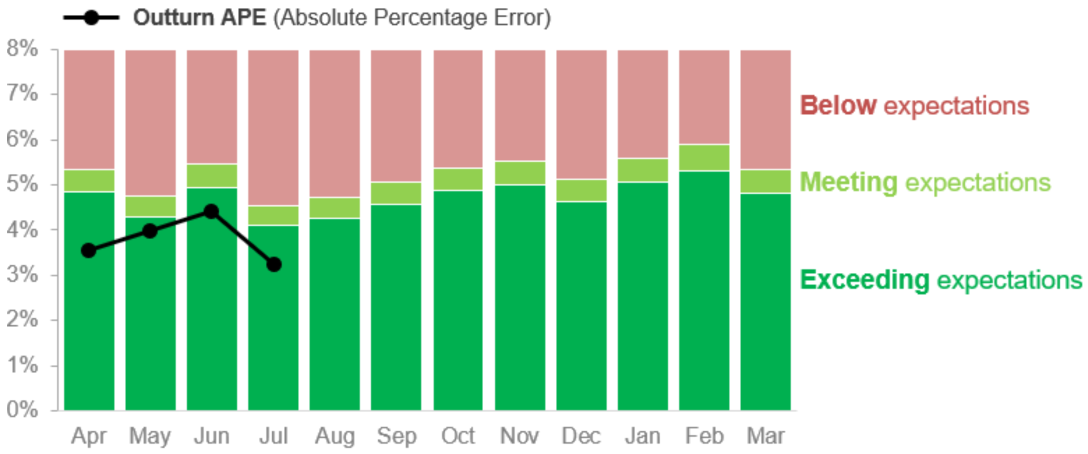


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)

	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**									
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 July 2021, our wind forecast indicative performance remained within the ‘exceeding expectations’ target, with a MAPE (Mean Absolute Percentage Error) of 3.2% against a benchmark of 4.3%.

July saw some of the lowest wind speeds and lowest wind generation outputs in the past 10 years. In particular, the GB Load Factor[4] of metered wind was below 5% for a higher percentage of the time in July 2021 than in any other July over the past decade.

Forecasting wind generation output is much easier when there is less wind: in those circumstances the likelihood of large errors is significantly reduced.

Looking forward, the consequences of climate change suggest that wind extremes, both extended high wind events and extended low wind events, will become more common in the future.

Significant weather events in July are listed below. We normally expect greater wind generation forecast error in these circumstances.

> 10 July – Low pressure system moving from Cornwall to East Anglia.
> 28 July – Low pressure system moving across Scotland
> 30 July – Storm Evert moving from Bristol to East Anglia bringing thunderstorms and heavy showers.

Apart from these three days, the weather in July was very calm and settled and as a result, good wind generation forecast accuracy was achieved.

Significant Lightning activity happened on the following days.

> 16 & 17 July – Kent and East Anglia
> 18 July – English Chanel and Thames Estuary
> 24 July – Newcastle & North East

Lightning is a good indication of atmospheric instability and is difficult to forecast. This can lead to greater wind power forecast errors on the days when lightning occurs.

Wind farms with CFD (Contracts for Difference) contractual arrangements switch off for commercial reasons when prices are negative for 6 hours or more. In July there were no occasions when electricity prices were negative. 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/.

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[4] GB Load Factor is the ratio of the total output of all GB wind farms compared to their maximum potential output, over a period of time.

Metric 1D Short Notice Changes to Planned Outages

July 2021-22 Performance

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

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

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	845	856	810	831									3342
Outages delayed/cancelled	0	0	3	2									5
Number of outages delayed or cancelled per 1000 outages	0	0	3.7	2.4									1.5

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 831 outages and there has been a total of two delays or cancellations due to an ESO process failure. This gives a score of 2.4 per 1000 outages which is within the ‘Meets Expectations’ range of between 1 and 2.5 outages per 1000.

For the year to date, the total delays or cancellations due to an ESO process failure is 5. This gives a score of 1.5 per 1000 outages which is also within the ‘Meets Expectations’ range. This is an improved performance compared to the same period last year (April to July 2020) when there were 1.83 delays or cancellations per 1000 outages (7 delays/cancellations out of 2654 outages).

Below are details of the two delays / cancellations due to an ESO process failure for July. The explanations are by their nature fairly technical:

1. The first event was caused by a modelling discrepancy between the software tools used by the planning department and those used by the control room. The studies undertaken within planning timescales did not identify any operability challenges associated with taking out of service the assets for which the outage was requested (a circuit and a Mesh Corner of a substation). However, when coming to release the outage within control room timescales, it was identified that there were unacceptable post-fault thermal overloads under certain contingencies. As this issue was driven by taking out one of the Mesh Corners in a substation, it was agreed with the relevant TO to release the circuit and leave the Mesh Corner in service until further analysis could be undertaken. The discrepancies between the planning and real-time software tools are part of an ongoing investigation.

2. The second occasion was an outage that was delayed due to confusion based on the suggested substation running arrangements for a specific circuit outage between the control room and planning department. As it was not clear how the substation was to be configured, the control room identified pre-fault thermal overloads prior to releasing the circuit. Therefore, a new running arrangement was identified that resolved the issues seen in real-time. However, the new running arrangement then had to be sent back to the planning department to check it against future weeks, as the outage had an Emergency Return to Service of On-completion (meaning that once released, it cannot be returned until completed). The analysis determined there were no operability concerns with the proposed substation configuration and the outage was eventually released. An Operational Learning Note is to be written to identify corrective measures.

RRE 1E Transparency of operational decision making

July 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%	89.1%								
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.6%	99.6%	99.7%	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)								

Supporting information

For July 89.1% of actions were either taken in merit, or taken out of merit order 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 very low percentage, we are still looking to understand any further trends or reasons for these actions being taken out of merit order.

RRE 1G Carbon intensity of ESO actions

July 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								

Supporting information

The month of July 2021 saw an average difference between the carbon intensity of FPNs (Final Physical Notifications) and balancing actions of 4.49 gCO2/kWh.

The maximum difference was 43 gCO2/kWh and the minimum was -17.6 gCO2/kWh. The average carbon intensity figure was 22% higher this month than it was last month.

Gas and coal units generally provided peak load but did not run during the night. There was a maximum of only 24 consecutive coal free hours for the full month.

RRE 1I Security of Supply

July 2021-22 Performance

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

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

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

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

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

Table 8: Frequency and voltage excursions

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

Supporting information

Whilst there were no instances in July where frequency was 0.3 – 0.5 Hz away from 50Hz for more than 60 seconds, there was a transmission event that resulted in the frequency falling below 49.7Hz for 30.4 seconds between 14:58:03 and 14:58:33 on 22 July 2021.

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

The transmission event occurred at Heysham 400kV substation and led to the unexpected disconnection of approximately 1550MW of generation in a short period of time. This event led to a frequency excursion, but not beyond the threshold for reporting against RRE 1I.

This event was discussed in detail at the ESO Operational Transparency Forum on 4 August 2021. You can watch a recording of the webinar here and access the slides here (slides 15-18).

RRE 1J CNI Outages

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

Supporting information

This month there was one planned CNI system outage. The outage, planned 6 months in advance, was a standard maintenance activity to ensure system resilience, which impacted the key BM Suite components used for scheduling and dispatch of generation.

The testing of this function is planned as an annual activity as it may be necessary to invoke the capability in the event of an incident.

As part of this outage, we were additionally able to plan and complete some maintenance and configuration tasks.

Notable events during July

System Test Plan approved in accordance with NCER regulation

On Tuesday 13 July, Ofgem issued its decision to approve the ESO's proposed System Test Plan for GB, in accordance with the EU's Network Code on Emergency and Restoration (NCER). The plan should set out how equipment and capabilities that are necessary to deliver the system defence plan and restoration plans should be tested. We sent the proposal on 21 December 2019, following a period of consultation. Having reviewed the proposed System Test Plan, Ofgem considers that it fulfils the relevant articles of the NCER. We must now ensure that any amendments to the test plan follow the change process outlined in the NCER Regulations.

NCER proposals for significant grid users list approved

Ofgem issued a decision on Tuesday 13 July to approve amended proposals from the ESO in relation to the NCER. The amended proposals for the list of Significant Grid Users (SGUs) responsible for implementing installation measures from other EU Network codes and the list of high priority SGUs were approved on the basis that the regulator considers that the amended proposals meet the requirements of the network code. Ofgem was also satisfied that the amended Terms and Conditions (T&Cs) for GB defence and restoration providers reflect the current obligations as set out within the Grid Code, the Balancing and Settlement Code and the ESO's black start strategy and procurement methodology. The regulator noted that the ESO will be expected to review the T&Cs once the modifications to its licence to introduce the GB Electricity Restoration Standard take effect.

Distributed ReStart – Procurement

The Procurement and Compliance Workstream in the Distributed ReStart project is running a mock tender event from 2 August to 6 September for potential DER providers. The purpose of this 'live' exercise is to gather feedback to test the functional requirements and assessment criteria for a distribution restoration zone. It is another opportunity for our stakeholders to input into the development of a fit for purpose procurement process, by providing as close to real tender data based on the information requested in our draft tender documents.

To kick start this five-week long test event, a launch webinar was hosted on 28 July where the purpose of the test procurement event and instructions to participate were shared with over 13 DER providers including battery storage, aggregators and telecommunications/supply chain. To support these potential participants, the project team are hosting a mid-point surgery on 18 August for Q&As and further support on the test process.

Initial feedback from stakeholders is that they appreciate seeing mock tender requirements to understand what can be requested in a procurement event, and the opportunity to feedback on how their plant capabilities might fare against these functional requirements. More feedback will be gathered at the end of the event and summarised in the workstream's final report, to be published in December.

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

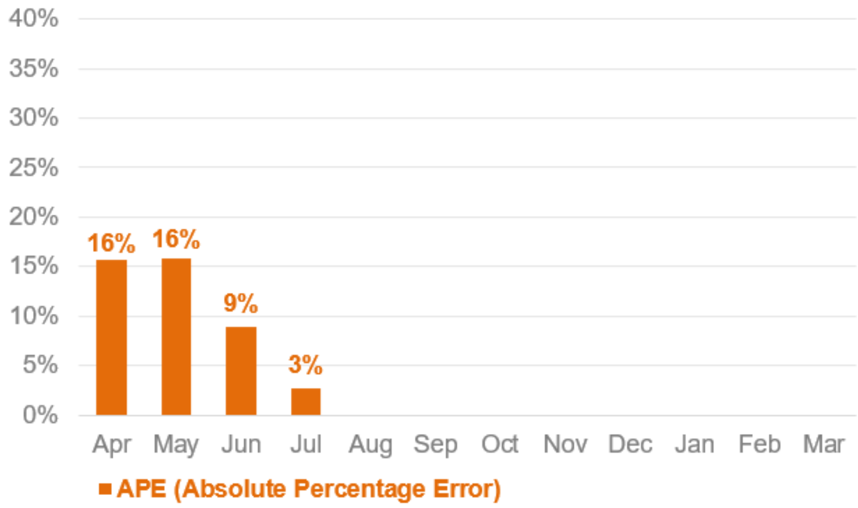
July 2021-22 Performance

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								
Month-ahead forecast	3.22	3.73	4.09	4.22								
APE (Absolute Percentage Error)[6]	**16%**	**16%**	**9%**	**3%**								

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



Supporting information

The outturn BSUoS for July was slightly lower than June due to marginally lower costs and higher volume. Constraint costs and Energy Imbalance costs fell whilst Operating Reserve costs increased. The total BSUoS volume was slightly higher than June due to being a longer month.

The key driver in the accuracy of the BSUoS forecast improving for the July forecast is the reduction in volatility of costs in recent months. Energy imbalance costs, reserve costs and constraint costs in particular are more stable with far less variability than seen during the last 12 months, enabling a more confident view of future costs.

[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

Net Zero Market Reform - Case for Change Workshops

We held three virtual workshops with breakout sessions from 27-29 July. These workshops were used to gather evidence for the case for market reform from an investment, flexibility and location perspective through open, co-creation-based discussions between stakeholders. In these sessions we discussed the following key questions:

Workshop 1 - Investment:

- "What, if any, are the key barriers in current market design for investment in assets needed for net zero?"
- ''Other than an ROI calculation, how would you evidence the case for change for market reform from an investment perspective?"

Workshop 2 - Flexibility:

- "What are the biggest market barriers/challenges to flexibility on the supply side?"
- "What are the biggest market barriers/challenges to flexibility on the demand side?"

Workshop 3 - Location:

- "What problems, if any, are there with current locational market signals?"
- "What principles and objectives should be considered when setting locational signals? What trade-offs are involved?"

We received 71 responses to "How would you rate the event?" both during the event and also as part of a post-workshop survey. The mean average score was 8.1 out of 10.

CMP365: Improvements to CUSC Governance Arrangements

CMP365[7] has been approved by the Authority, which directed that the original proposal of this modification be implemented on 30 July.

This modification is based upon the principles of Grid Code GC0131: 'Quick Wins' Improvements to Grid Code open governance arrangements. The aim is to incorporate a smoother and more efficient process for code modifications that will allow for the best use of industry time. This includes supporting better use of industry resources and the potential for workgroups and Panel members to respond quickly to drivers for change. The modification will make clarifications to the CUSC in the following areas:

- Initial assessment of proposals
- Quoracy
- Assessment of alternatives
- Titles and summaries of proposals
- Role of the Code Administrator Consultation
- Production of draft legal text

CMP370: Aligning the CUSC with the Interactivity Policy

On Friday 30 July, CUSC Panel unanimously recommended that CMP370 should be implemented. CMP370 was raised by the ESO to align the CUSC with the Interactivity Policy developed under the Energy Network Association (ENA) Open Networks Project. Interactivity can occur where two or more applications are received to connect to the same part of the transmission system but where not all applicants can be connected due to restrictions such as limited network capacity or fault levels. The Interactivity Policy is used by the ESO to determine which applicants can connect on the terms offered and which will need to be re-offered (if applicable), and provides transparency and consistency to applicants. CMP370 introduces a definition of Interactivity and a reference to the Interactivity Policy into the CUSC, and amends the CUSC offer acceptance period to be in line with the Interactivity Policy. The modification was sent to Ofgem on 13 August 2021 for their decision.

CMP377: Clarification of Section 14 BSUoS Charging Methodology

CMP377 Clarification of Section 14 Balancing Services Use of System (BSUoS) Charging Methodology was raised by the ESO and published[8] on Thursday 22 July and further clarified on 4 August. The modification seeks to amend how the BSUoS charging methodology is described in the CUSC in order to provide greater clarity. It addresses four areas: COVID-19 cost recovery calculations; the capitalisation of defined terms in the legal text relating to CMP373 Deferral of BSUoS Billing Error Adjustment; clarification of storage import terminology; and general housekeeping. CMP377 is not expected to change how BSUoS charges are calculated but only seeks to clarify existing rules. Consultation responses are requested by 2 September.

[7] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp365
[8] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp377

Role 3 System insight, planning and network development

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

Notable events during July

Future Energy Scenarios (FES) 2021 launched

On Monday 12 July we published our Future Energy Scenarios (FES) 2021[9]. In addition to the interactive document, the FES web pages were developed to be more user-friendly. FES is based on extensive stakeholder engagement, research and modelling and FES 2021 describes what the future of energy may look like between now and 2050.

The FES publication event week was run virtually following the success of the previous year. Following feedback that an attraction of the event is the networking between sessions, we incorporated networking sessions throughout the week. These were hosted by ESO colleagues and attended by 56 stakeholders.

Many of the stats we use to monitor our performance for the publication improved this year compared with FES 2020 which was itself a record year. The week attracted over 400 stakeholders and our watch back / on demand presentations were viewed more than 140 times. During the first few weeks the number of times the document was viewed was 6% higher than the previous year.

The report outlines four different, credible pathways for the future of energy between now and 2050. Each one considers how much energy we might need and where it could come from. The overall scenarios remain consistent with those in FES 2020 but some details within them are new for 2021 following extensive modelling, research and stakeholder engagement. 'Consumer Transformation' and 'System Transformation' represent two different ways to get to net zero by 2050 - either by changing the way we use energy or by changing the way in which we generate and supply it. In 'Leading the Way', a combination of high consumer engagement and world-leading technology and investment help to enable our fastest credible decarbonisation journey. In this scenario, the UK reaches net zero in 2047 and goes on to reduce emissions by 103% by 2050 (compared to 1990 levels) - in other words, it is net negative. Decarbonisation happens slowest in 'Steady Progression', where 2050 emissions are reduced by 73% of 1990 levels.

The key messages from this year's FES are as follows:

- Achieving net zero requires detailed policies and clear accountabilities, coupled with an immediate and sustained focus on delivery, to maintain the momentum provided by the Energy White Paper.
- Consumer behaviour is pivotal to decarbonisation – how we all react to market and policy changes, and embrace smart technology, will be vital to meeting net zero.
- Holistic energy market reform is needed to drive the investment and behaviour changes needed to deliver net zero and ensure security of supply at a fair and reasonable cost for all consumers.
- Significant investment in whole system infrastructure will be required over the coming decade. This should be optimised to ensure timely delivery and value for consumers.

As well as a specific chapter on net zero, FES 2021 has dedicated chapters on the consumer view (residential, transport and industrial & commercial), the system view (bioenergy, natural gas,

[9] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021

hydrogen and electricity supply) and flexibility to explore these in detail. As part of a move to more regional analysis, a new spatial heat model was used this year.

We hosted a range of virtual events[10] during the week of 12 July to share the key messages and insight from our 2021 analysis.

We also launched a new podcast series called The Future of Energy, where we talk to ESO experts about the big themes from FES 2021 including net zero, electric vehicles, renewables, heat and hydrogen.

RDP webinars hosted jointly with UKPN & WPD for DER providers

For the Regional Development Plan (RDP) projects we held two webinars for Distributed Energy Resource (DER) in July, one in conjunction with WPD and the other in conjunction with UKPN. 75 people attended the webinars, which provided background context on RDPs and explained some specific connection conditions that have been placed on many DER parties in the RDP regions (South West and South East of England). We also set out a new thermal transmission constraint management service that we are developing to provide an alternative means to the Balancing Mechanism (BM) and Wider Access for smaller parties to provide constraint management services. We have a set of questions on our website inviting views from DER on this new service which we will use to develop it further.

Energy Storage Technical Feasibility Assessment

We conducted a Technical Feasibility Assessment[11] on how Energy Storage could help manage constraints on the Electricity Transmission Network between 2022-2030. Following the conclusion of the tender process, DNV Services UK Ltd has been selected to perform the technical analysis. They will present a finalised report back to the ESO by December 2021 which will outline details from four related work-packages including recommendations based on the analysis undertaken.

First Central Design Group held through ESO offshore coordination project

On 22 July, through the ESO offshore coordination project, we held the first formal Central Design Group (CDG), attended by BEIS, Ofgem and the onshore TOs. The CDG will meet monthly on a formal basis – supported by a series of other meetings and subgroups between the ESO, onshore TOs and wider stakeholders – and will be the vehicle through which the ESO delivers a Holistic Network Design (HND) to provide a coordinated National Electricity Transmission System (NETS), including onshore and offshore assets, primarily required to connect offshore wind up to 2030. The meeting was attended by the necessary members to enable productive discussions on the delivery timeline, and commercial and environmental elements of the HND. Positive feedback on the coordination and delivery of the meeting was received from several stakeholders following the meeting. The formal CDG will meet again on 18 August.

The CDG and HND sit within the Pathway to 2030 workstream of BEIS' Offshore Network Review (OTNR). The workstream has the objective of 'Enabling achievement of 40 GW of offshore wind by 2030 by increasing central coordination and accelerating delivery of the required onshore and offshore grid infrastructure.' We have a key role in delivering high-level integrated and operable offshore

[10] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

[11] https://www.nationalgrideso.com/future-energy/projects/pathfinders/constraint-management/energy-storage-technical-feasibility-assessment

network designs. During the week commencing 12 July, we appointed and commenced work with Imperial College Consultants to support the ESO in delivering against this requirement.

Annual Innovation summary

On Tuesday 27 July, we published our Network Innovation Allowance (NIA) annual summary[12] for 2020-21. We highlighted the latest progress on our innovation portfolio ahead of our goal to be able to operate the system carbon free by 2025 – focussing on the 12 months from April 2020 to March 2021. A total £7.3mn spend on innovation has seen nine new projects begin, we have completed a further nine, and progressed 14 others. The summary shows that we are broadly following the project prioritisation set out at the beginning of 2020-21. We stated that projects that address system stability and the digital transition will receive the most attention this year with combined spending at over £4mn. However, the whole energy system projects saw less investment than previously anticipated, which we will aim to address in the next regulatory period.

[12] https://www.nationalgrideso.com/future-energy/projects/nia-annual-summary-report