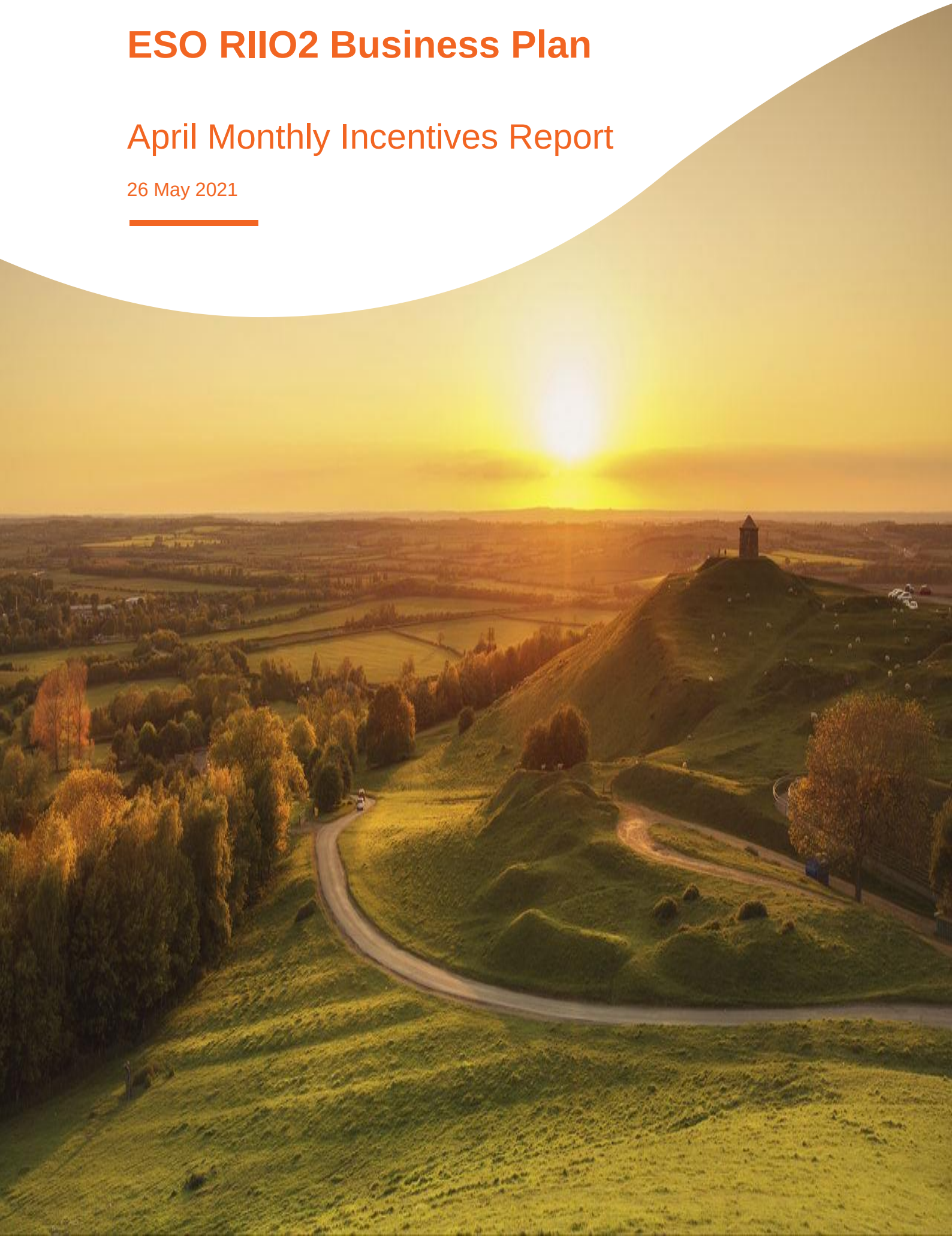
nationalgridESO

ESO RIIO2 Business Plan

April Monthly Incentives Report

26 May 2021



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 April we have successfully delivered the following notable events and publications:

- There was a record low carbon intensity for the GB electricity grid, it was the greenest it has ever been.
- National Grid ESO joined the Global Power System Transformation (G-PST) Consortium, this is a public-private partnership with other system operators from around the world to help accelerate the net zero transition.
- Eight Electricity System Restoration Service contracts were awarded for the Northern regions.
- We published a five-year forecast of Transmission Network Use of System (TNUoS) tariffs
- We published the 2021 Summer Outlook Report, which sets out our view of electricity supply and demand for the coming summer months and the operational tools we will use to manage any challenges
- We launched our Distribution System Operation (DSO) consultation, introducing our proposed approach to supporting the transition to DSO, which will help us achieve a smarter energy system.

In Role 2 we also highlight a significant issue with the under-recovery of £43m of Balancing Services Use of System (BSUoS) charges that were identified for Charging Year 20/21 at the end of March, due to a procedural error. Ofgem have now approved EDF Energy's modification CMP373 which means we will recover ~£33m trading costs through Charging Year 21/22 SF (Settlement Final) run for the period of between 1 October 2021 and 31 March 2022.

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

Table 1: Summary of Metrics and Regularly Reported Evidence

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£130m vs ex-post benchmark of £95m	●
Metric 1B	**Demand Forecasting**	Absolute Percentage Error of 2.9% vs benchmark of 2.4%	●
Metric 1C	**Wind Generation Forecasting**	Absolute Percentage Error of 3.5% vs benchmark of 5.1%	●
Metric 1D	**Short Notice Changes to Planned Outages**	0 delays or cancellations due to an ESO process failure (vs benchmark of 1 to 2.5)	●
RRE 1E	**Transparency of Operational Decision Making**	99.6% of actions have reason groups allocated	N/A
RRE 1G	**Carbon intensity of ESO actions**	2.1gCO2/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, 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	0 outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	17% forecasting error	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

April 2021 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, recognizing 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'.

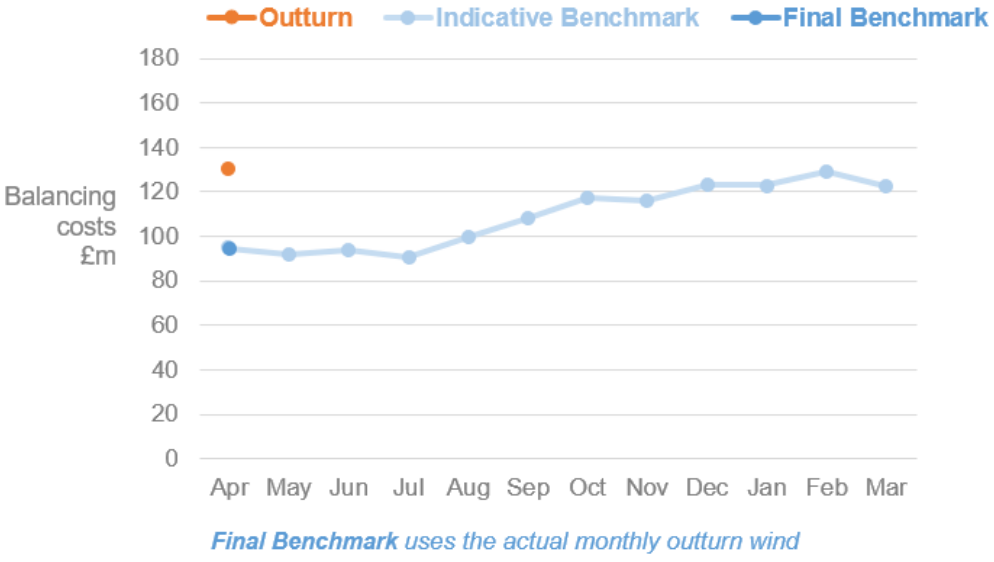
iii. An equation for the straight-line relationship between outturn wind and total balancing costs is then formed using the outputs of point (i.) and point (ii.).

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.

Figure 1: Monthly total balancing cost benchmark versus outturn.



***Final Benchmark** uses the actual monthly outturn wind*

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	41.3
Indicative benchmark: constraint costs (B)	59.9	50.6	52.2	49.1	58.3	66.8	59.9
Indicative benchmark: total costs (C=A+B)	101.2	91.9	93.6	90.5	99.7	108.2	101.2
Outturn wind (TWh)	2.8						2.8
Ex-post benchmark: constraint costs (D)	53.5						53.5
Ex-post benchmark (A+D)	94.8						94.8
Outturn balancing costs	130.4						130.4
Status	●						●

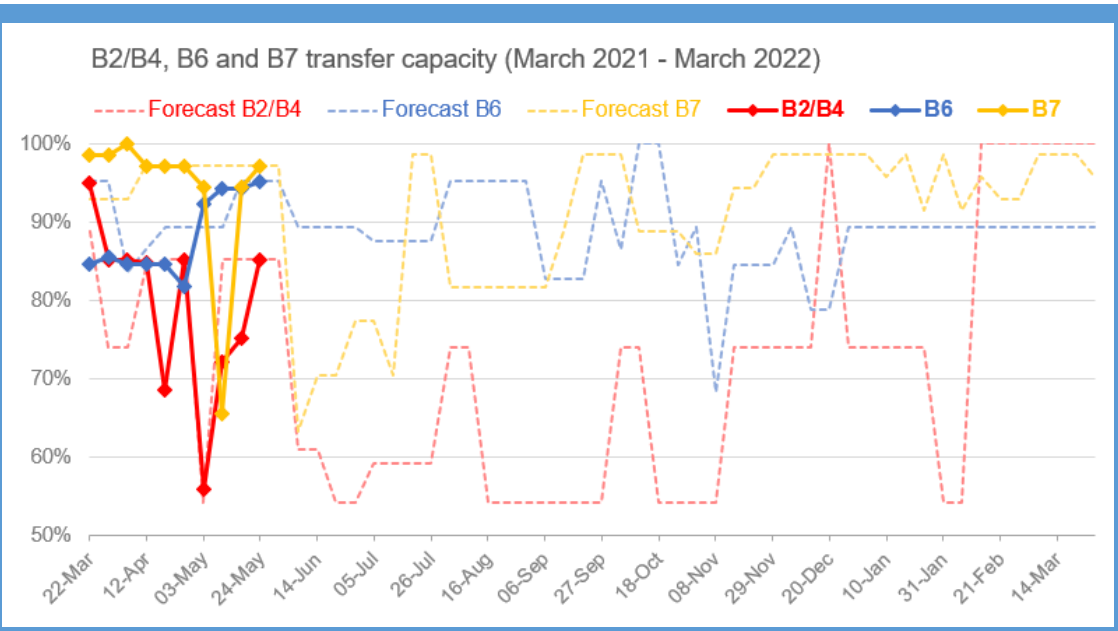
Performance benchmarks

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

Supporting information

The balancing costs for April were lower than the costs for March (£171.5m) but outturned above benchmark. Please note the 2020-21 incentivised balancing cost figures did not include costs for restoration but from April 21 these are included so we have included the restoration costs here for direct comparison.

Lower wind levels, coupled with the full availability of the Western Link resulted in lower constraint costs than March as boundary capacities were less depleted. As shown in the graph below, B7 (Upper North of England) was largely unaffected in April with B6 (SP Transmission to NGET) and internal Scotland constraints, such as B2 (North to South SHE Transmission) and B4 (SHE Transmission to SP Transmission boundary), lightly depleted due to outages.

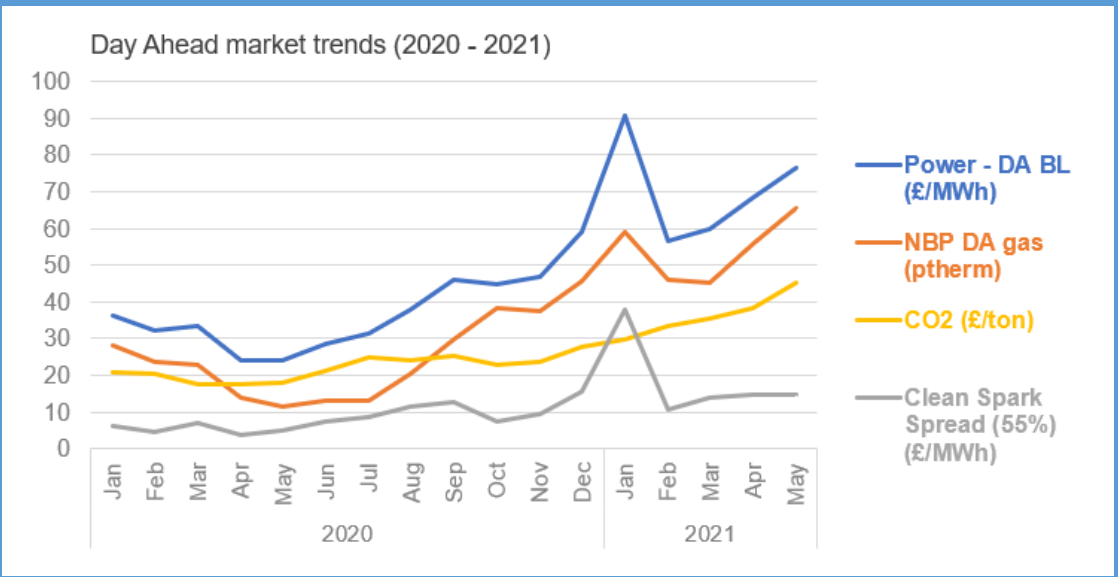


Operating costs were also lower than March as margins were less challenging with lower demand levels following the change to BST. However, on 12 April, significant demand uncertainty due to weather variability and COVID-19 restriction relaxations, coupled with tight margins, triggered high price Balancing Mechanism actions being required to ensure sufficient generation was available to meet the demand and reserve requirement.

Please note that we covered the detail surrounding the decisions made on this challenging day extensively during the subsequent Operational Transparency Forum (21 April). A recording of the session can be found here.

Fast reserve and Response costs remained high due to continuing uncertainty on the system.

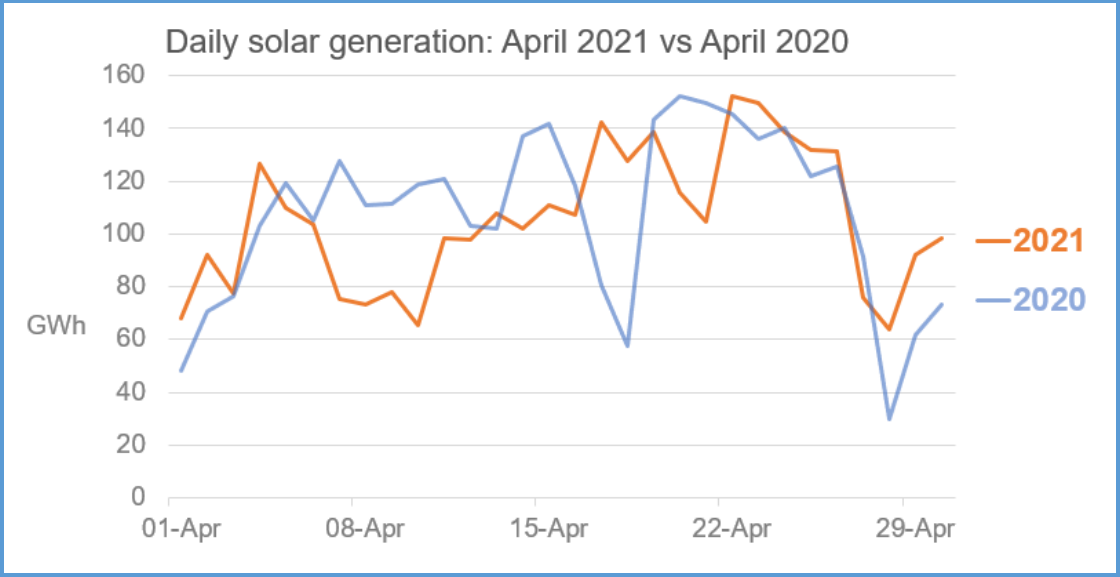
Changes in energy balancing costs



The monthly day ahead power price has risen significantly over the course of the last year from ~£33/MWh for Jan-Mar 2020 to ~£69/MWh for Jan-Mar 2021. This is driven by significant increases in gas prices and CO2 prices. Higher DA (Day Ahead) power prices can lead to a higher cost for the actions we take to balance the system due to the change in the market fundamentals particularly on the buy (offer) side. With the increasing penetration of renewable generation, the cost for

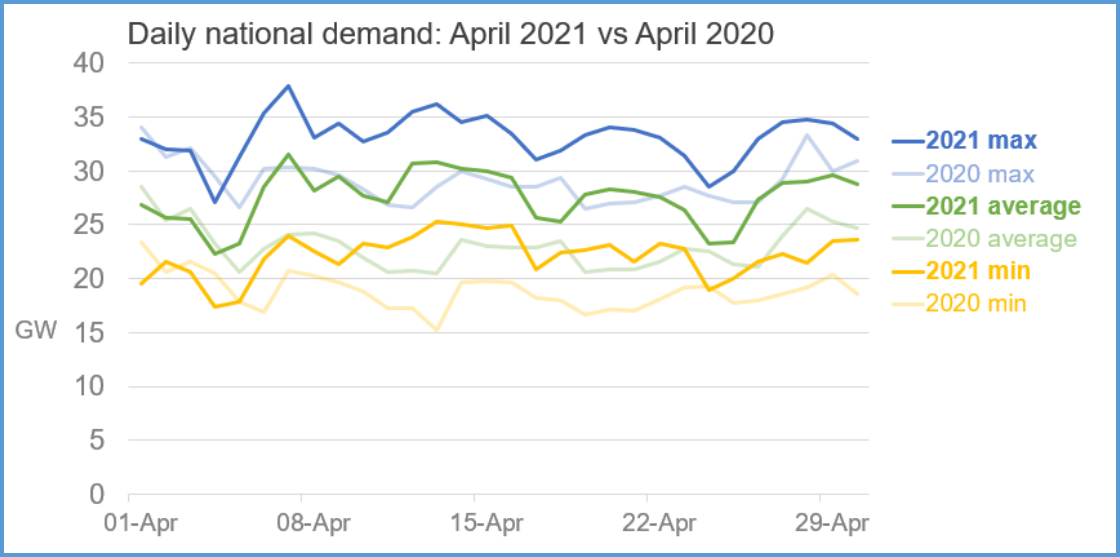
managing sell (bid) actions is also increased due to more bid actions taken to manage thermal constraints and RoCoF (Rate of Change of Frequency).

Comparison of solar generation against April 2020



Over the course of the month the total solar output was of a comparable level to the total output in April 2020 at ~3.2TWh.

Comparison of demand against April 2020



Demand levels have been significantly higher over the course of the month in comparison with April 2020 where strict lockdown measures saw large demand suppressions.

Metric 1B Demand forecasting accuracy

April 2021 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 the reporting in the Forward Plan, there are two differences in relation to the 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)

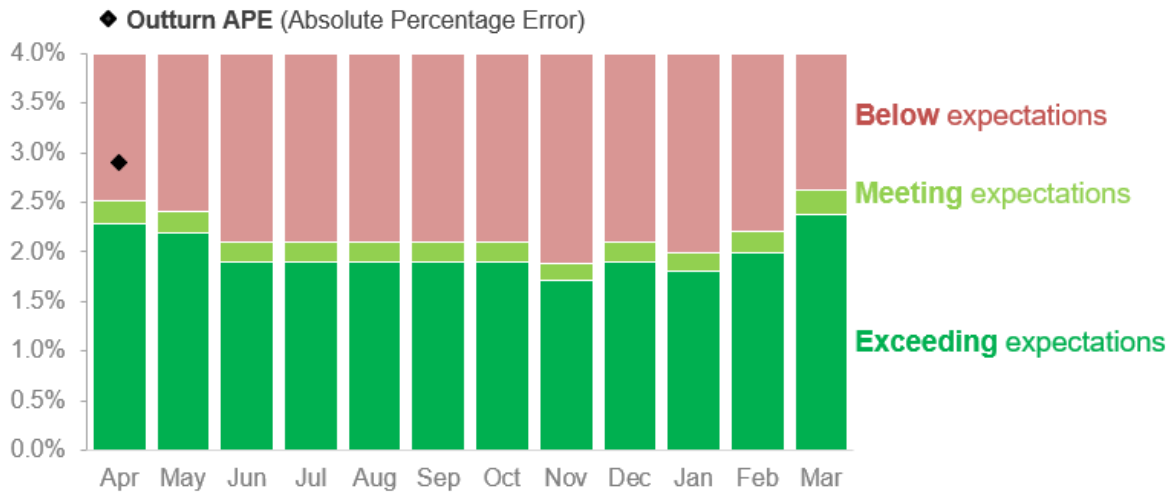


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
Indicative benchmark[1] (%)	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**												
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

[1] Monthly benchmark figures have been updated in this re-published version of the April report, to align with the revised figures in the Addendum published by Ofgem on 27 May 2021.

Supporting information

In April 2021, our day ahead demand forecast indicative performance was not within the benchmark of 2.4%. April's APE (Absolute Percentage Error) was 2.9%.

The biggest errors coincided with Easter, and the weekend at the end of the school holiday following the Easter break. Clock change (late March) and Easter are typically the times in the Spring when the demand forecasting uncertainty is increased and forecasting inaccuracies are at their highest.

It has been challenging to find a recent historical day to base the forecast. The dates from 2020 are not good, as they were affected by demand suppression related to the COVID-19 pandemic. Other limiting factors in finding a good recent historic date are the relative position to clock change and Easter. The first part of April is shortly after clock change. This significantly limits the number of recent spring time days that could be used as a basis for the forecast. Secondly, Easter and the Easter Bank Holidays fall on a different week in the year in relation to previous years, and school holidays change their position accordingly to the date of Easter.

An additional challenge related to the fact that temperatures in April were much lower than normal. April had the third lowest average UK minimum temperature for the month since records began in 1884. People could have over-responded to the low temperatures, leading to forecasting errors.

April was also one of the sunniest months on record. The demand forecast assessed by this metric factors in the behaviour of embedded solar generation, and is published between 09:00 and 09:30 on D-1. It is difficult to accurately forecast solar radiation more than 24 hours ahead: this has had a significant negative impact on this month's performance.

Summary of the biggest errors in April		
Error greater than	Number of SPs when this occurred	% of total April SPs
1000 MW	254	18%
1500 MW	130	9%
2000 MW	61	4%
2500 MW	40	3%
3000 MW	32	2%

The ESORI guidance obliges the ESO to provide narrative relating to the effect of Triad avoidance, and notification of any missed or late publication of forecast data.

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

During April, there was no instances of missed/late publication of forecast data.

Metric 1C Wind forecasting accuracy

April 2021 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[2] 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)

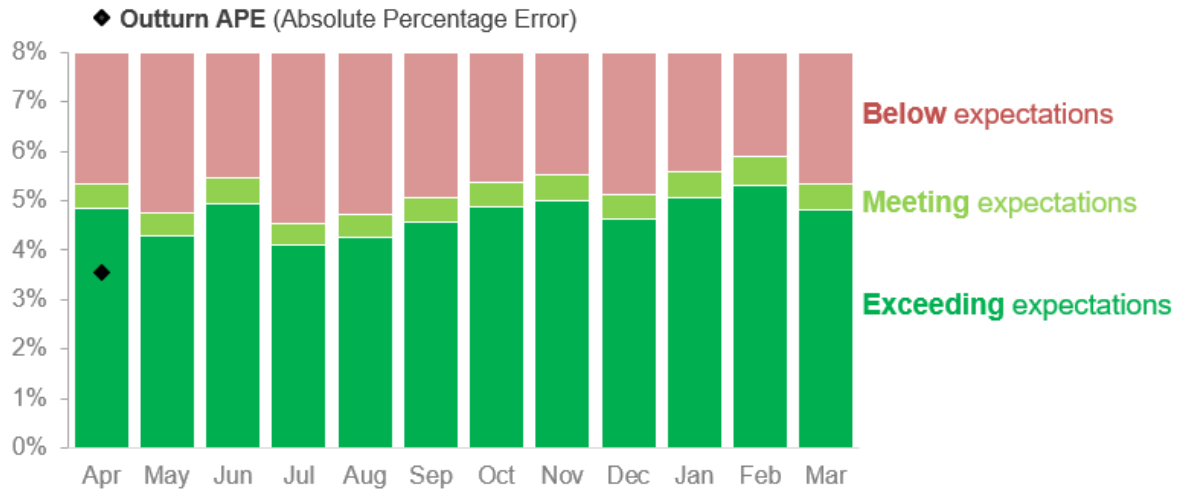


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
BMU Wind Generation Forecast Benchmark[3] (%)	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[4] (%)	**3.5**												
Status	●												

Performance benchmarks

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

[3] Monthly benchmark figures have been updated in this re-published version of the April report, to align with the revised figures in the Addendum published by Ofgem on 27 May 2021.

[4] 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.

Supporting information

In April 2021, our day ahead wind forecast indicative performance was within the benchmark of 5.1%. April's APE (Absolute Percentage Error) was 3.54%.

Significant weather events in April are detailed below. We normally expect greater wind power forecast error in these circumstances.

The weather in April was characterised by very cool dry weather with clear skies and overnight frosts. Temperatures were below average for the time of year for much of April because of the North and North East wind, and this brought sleet and snow on the few occasions that precipitation occurred. There were no significant storm systems in April 2021 and so the wind power forecast accuracy was better than April in previous years.

Significant lightning activity happened several days in the month. Lightning is a good indication of atmospheric instability and is commonly difficult to forecast. This can lead to greater wind power forecast errors on these days. Lightning was observed in East Anglia (6 April), North Wales (11 April), and the South Coast & English Channel (28 April).

Wind farms with CFD (Contracts for Difference) contractual arrangements switch off for commercial reasons while prices are negative for 6 hours or more. In April, there were no occasions when the electricity price went negative. The electricity price used for this analysis is the Intermittent Market Reference Price.

Market Price Data for April can be downloaded here.

During April there were no instances of missed or late publication of forecast data.

Metric 1D Short Notice Changes to Planned Outages

April 2021 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												845
Outages delayed/cancelled	0												0
Number of outages delayed or cancelled per 1000 outages	0												0

Performance benchmarks

- **Exceeding expectations:** Less than 1 outages 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 April, the ESO has successfully released 845 outages and there have been no delays or cancellations due to an ESO process failure. This is within the 'Exceeds expectations' target of less than one delay or cancellation per 1000 outages and is a better start to the 2021-22 year than in 2020-21 when there were 4.89 cancellations or delays per 1000 outages in April 2020.

The ESO is continuing to liaise with the TOs and DNOs to effectively facilitate system access and has released significantly more outages in April 2021 at 845 compared to the April 2020 figure of 409. The number of outages released in April 2020 was heavily suppressed by the COVID lockdown, whereas the 807 outages released in April 2019 is comparable with this year.

RRE 1E Transparency of operational decision making

April 2021 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.

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

	Apr[5]	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%											
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.6%											
Percentage of actions with no category applied or reason group identified	**0.4%** (173)											

[5] April figures were updated in this re-published version of the April report on 22 June 2021. The original figures were incorrect due to an error in the model calculations. The methodology and raw data have not changed.

Supporting information

This month, 81% of actions were either taken in merit order, or taken out of merit order due to an electrical parameter. For the remaining actions, where possible, we allocate them to reason groups for the purposes of our analysis. We were unable to allocate reason groups for 3% of the total actions this month.

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.

RRE 1G Carbon intensity of ESO actions

April 2021 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.

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.

For full details of the methodology please refer to the Carbon Intensity Balancing Actions Methodology document.

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											

Supporting information

April 2021 saw an average difference between the carbon intensity of FPNs and the equivalent profile with balancing actions applied of 2.06 gCO2/kWh. The maximum difference was 37.8 gCO2/kWh and the minimum was -12.2 gCO2/kWh.

The start of the month saw the largest divergence between FPNs and balancing actions. The 4th and 5th had a combined average difference of 18.6 gCO2/kWh, with ESO's actions resulting in increased carbon intensity compared to that which would have resulted from the FPNs, for the full two days.

The number of balancing actions taken over this period was higher than usual, with 2089 Bid Offer Acceptances (BOAs) on the 4th and 1642 on the 5th. There were 904 balancing actions tagged as "System" on the 4th, compared to only 158 "System" tagged actions the previous day. This indicates that a lot of actions were required to manage the system stability over the period, such as restricting power flow from Scotland down to England.

As is often the case when looking at the carbon intensity of balancing actions, when there is a major difference between the two figures it is due to the control room having to curtail wind to ensure system stability and security. At the start of 4 April, wind was generating 3.6 GW, whereas at the end of the day it was generating 14.1 GW. The energy that would have been supplied by wind had it not been curtailed was replaced by more conventional generation, leading to a higher carbon intensity as a result of these balancing actions.

The rest of April saw lower levels of wind generation than the start, so there was little difference between carbon intensity of FPNs and the equivalent profile with balancing actions applied for the remainder of the month.

RRE 1I Security of Supply

April 2021 Performance

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

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

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

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

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

Table 8: Frequency and voltage excursions

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz)	0											
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	0											
Voltage Excursions defined as per Transmission Performance Report[6]	0											

Supporting information

There have been no reportable frequency and voltage excursions for April 2021.

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

RRE 1J CNI Outages

April 2021 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)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0											
Integrated Energy Management System (IEMS)	0											

Table 10: Planned CNI System Outages (Number and length of each outage)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0											
Integrated Energy Management System (IEMS)	0											

Supporting information

There were no outages, either planned or unplanned, encountered during April 2021.

Notable events this month

Record low carbon intensity for GB electricity

Great Britain's electricity grid was the greenest it's ever been at 1pm on Monday 5 April. The carbon intensity of electricity dropped to 39 gCO2/kWh, the lowest figure in history. Sunny spells and blustery conditions, coupled with low demand driven by the Easter holiday, meant renewable sources of power dominated the energy mix over the holiday weekend. At 1pm wind power made up 39% of the electricity mix, solar power 21%, and nuclear 16% – meaning zero carbon power sources made up almost 80% of the nation's power.

National Grid ESO joins global system operator consortium

We announced the launch of the Global Power System Transformation (G-PST) Consortium on 21 April, this is a public-private partnership with other system operators from around the world to help accelerate the net zero transition. G-PST consists of the Australia Energy Market Operator, National Grid ESO, California Independent System Operator, Ireland's system operator (EirGrid), and Denmark's system operator (Energinet).

Electricity System Restoration Service contracts awarded

Our Electricity System Restoration Service strategy (formerly known as Black Start) gives us the ability to fire up Britain's electricity system after a total blackout. These services use auxiliary sources of generation to kick-start bigger ones creating 'islands' of power which connect together on the main transmission network to gradually restore the grid.

On 30 April we announced contracts with eight providers for Electricity System Restoration Services in the Northern Regions which covers Northwest, Northeast and Scotland. The eight contracts, two of which are new, total £53.8 million with each bid offering commercial benefits compared to other bidders and Electricity System Restoration Services options.

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

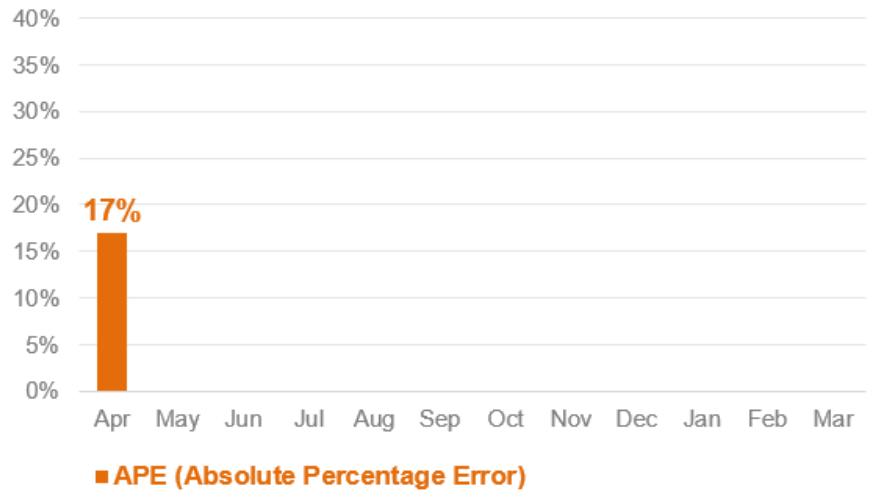
April 2021 Performance

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	3.88											
Month-ahead forecast	3.22											
APE (Absolute Percentage Error)	**17%**											

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



Supporting information

The outturn BSUoS for April was lower than March but higher than forecast. Constraint costs fell as a result of lower wind and the Western Link HVDC being available having returned in mid-March. The volume rose slightly due to implementation of CMP333 from 1 April which offset the seasonal demand reduction normally observed as we move to BST.

As part of our Constraint Management 5 Point Plan, we will be working to provide enhanced BSUoS forecasting. In 2021 we will focus on:

- Creating a new approach to forecast those items where we have the data, the information and the capability to provider clearer forecasts

- Providing transparency of the data we use to create the forecasts through our Data Portal
- Providing the methods and approaches we use to create different sections of the forecast
- Providing more sensitivities around our forecasts to provide clarity on where the uncertainty is.

Notable events this month

Five-Year View of TNUoS Tariffs published

On 30 April we published a five-year forecast of Transmission Network Use of System (TNUoS) tariffs[7]. Under the NGESO licence condition C4 and Connection and Use of System Code (CUSC), we publish a five-year view of future TNUoS tariffs regularly on our website. This report provides the forecast for the period of 2022-23 to 2026-27, and also includes the initial quarterly forecast of TNUoS tariffs for year 2022-23.

In this forecast, we have included the Transmission Demand Residual (TDR) banded charges methodology from 2023-24, according to Ofgem's minded-to decision. The total TNUoS revenue to be collected is forecast at £3,366m for 2022-23, rising to £3,550m in 2026-27. Offshore revenue is forecast to increase steadily in the next five years, offset by the downward trend in onshore TO revenues under their RIIO-2 business plans. The 2022-23 revenue forecast will be updated through the year and finalised by January 2022 Final Tariffs, based on onshore and offshore TOs' submissions.

Under-recovery of Balancing Services Use of System (BSUoS)

Through our end of year processes, we identified that £43m of Balancing Services Use of System (BSUoS) charges were under-recovered for Charging Year 20/21 at the end of March. This is made up of ~£33m of trading activities between 30 September 2020 and 9 March 2021 and ~£10m Accelerated Loss of Mains Change Programme (ALoMCP).

The under-recovery of £33m trading costs was caused by a procedural error in uploading the trading data into the billing system and we should have resumed the ALoMCP cost recovery from August 2020, following a temporary cease to offset over-recovery of the scheme in a previous year. We raised the issue immediately to the industry at the Transmission Charging Methodology Forum (TCMF) on 8 April.

We carefully considered the options of recovering the costs and the impact it may have on the industry, in particular under the current COVID-19 pandemic situation. Having engaged with the industry further on this matter via a dedicated webinar, we decided to defer the recovery of £10m ALoMCP costs to Charging Year 21/22; the trading costs would be recovered through the Reconciliation Final (RF) run for Charing Year 20/21. This was in line with the CUSC methodology to ensure that costs would be recovered from the correct parties over the settlement periods where the costs were incurred as well as provide a longer notice for parties to plan for this cost recovery.

Subsequently, EDF Energy raised CMP373 'Deferral of BSUoS Billing Error Adjustment' on 20 April, that in effect sought to recover the trading costs through Charging Year 21/22 SF (Settlement Final) run. This Proposal has been approved by the Authority. As a result, we will recover ~£33m trading costs through Charging Year 21/22 SF run for the period of between 1 October 2021 and 31 March 2022.

We took this incident very seriously and have commissioned PwC to help review and improve our BSUoS charging processes and enhance our control environment to ensure that we will not repeat such incident in the future. We will share the key findings with the industry at the future TCMF.

[7] https://www.nationalgrideso.com/document/191116/download

Role 3 System insight, planning and network development

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

Notable events this month

Summer Outlook Report

On 8 April we published the 2021 Summer Outlook Report[8] setting out our view of electricity supply and demand for the coming summer months and the operational tools we will use to manage any challenges. During the summer we typically face different operational challenges than those seen over winter. This is an annual publication to help the industry prepare for these challenges. Similar to last year's report, this year's Summer Outlook also takes account of the continued COVID-19 pandemic by providing industry with three forecast scenarios to help them prepare for any potential changes over the coming months.

Enabling the DSO Transition consultation

On Monday 19 April, we launched our Distribution System Operation (DSO) consultation, introducing our proposed approach to supporting the transition to DSO, which will help us achieve a smarter energy system.

As the electricity network evolves, the traditional roles and responsibilities in the industry, particularly of Distribution Network Operators (DNOs), will change. DNOs will have a significant role in managing the network at a local level and making sure regional service providers can support the delivery of an efficient and resilient system. The ESO already works closely with DNOs in many areas, but these relationships will need to extend and deepen to facilitate the DSO transition. Our consultation describes a proposed ESO approach to the DSO transition as well as a vision of how we will be working with DNOs in 2025.

Strong collaboration across industry will be pivotal to the success of the DSO transition and we received 15 responses to our request for feedback from stakeholders which we are currently reviewing. The DSO transition webinar was held on 6 May where we provided the opportunity for industry to hear from ESO colleagues and ask questions on the approach and vision.

We're aiming to build on the fantastic collaborative work already underway to support the DSO transition, for example through forums such as the ENA's Open Networks project and the Regional Development Programmes (RDPs).

[8] https://www.nationalgrideso.com/document/189741/download