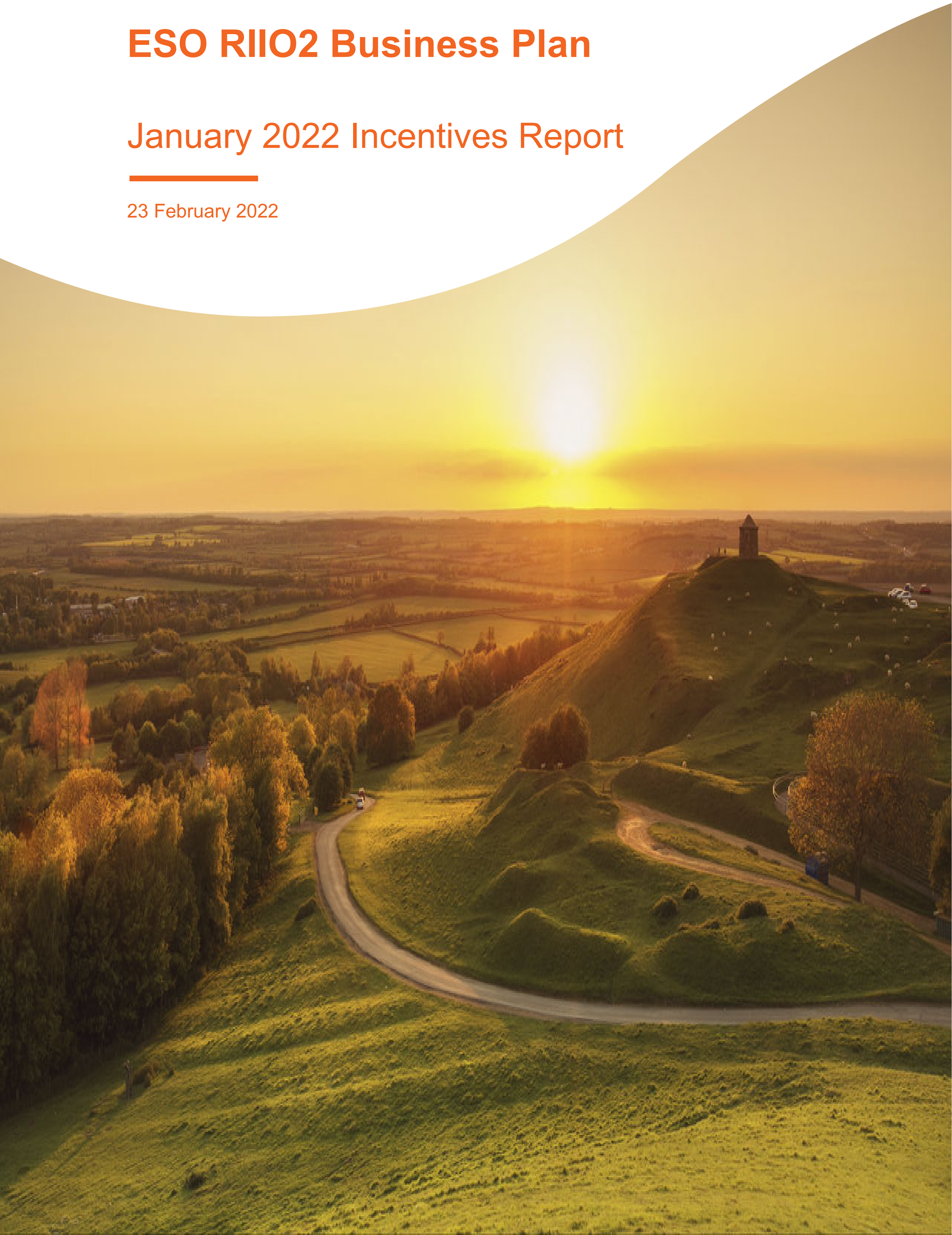
nationalgridESO

ESO RIIO2 Business Plan

January 2022 Incentives Report

23 February 2022



Contents

Introduction

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

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

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

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

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

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

Please see our website for more information.

Summary

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

- On Saturday 29 January we saw the most wind ever on GB's electricity system with a record of 19.6GW of wind power.
- On 11 January we provided an update on CrowdFlex, the UK's largest domestic flexibility study, which has found that active households could significantly reduce peak electricity demand by using time-of-use tariffs.
- GC0137 Minimum specification for equipment providing grid-forming capability was approved by the Authority for implementation into the Grid Code.
- On 17 and 18 January 2022 we hosted the first events of Phase 3 of our Net Zero Market Reform project.
- In January we published the BSUoS forecast for February 2022 on the ESO Data Portal.
- Final Transmission Network Use of System (TNUoS) tariffs for 2022-23 were published on Monday 31 January.
- We announced our latest Operability Strategy Report on Tuesday 18 January.
- On 31 January 2022 we published our annual Networks Options Assessment (NOA) 2021/22.

The table below summarises our Metrics and Regularly Reported Evidence (RRE) performance for January 2021-22.

Table 1: Summary of Metrics

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£369.8m vs benchmark of £126.7m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 2.0 % (vs benchmark of 1.9%)	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 3.7 % (vs benchmark of 5.3%)	●
Metric 1D	**Short Notice Changes to Planned Outages**	0 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	●
RRE 1E	**Transparency of Operational Decision Making**	93.5% of actions have reason groups allocated	N/A
RRE 1G	**Carbon intensity of ESO actions**	6.4 gCO2/kWh of actions taken by the ESO	N/A
RRE 1I	**Security of Supply**	0 instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds, 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	0 planned system outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 10%	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

January 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 (£m)

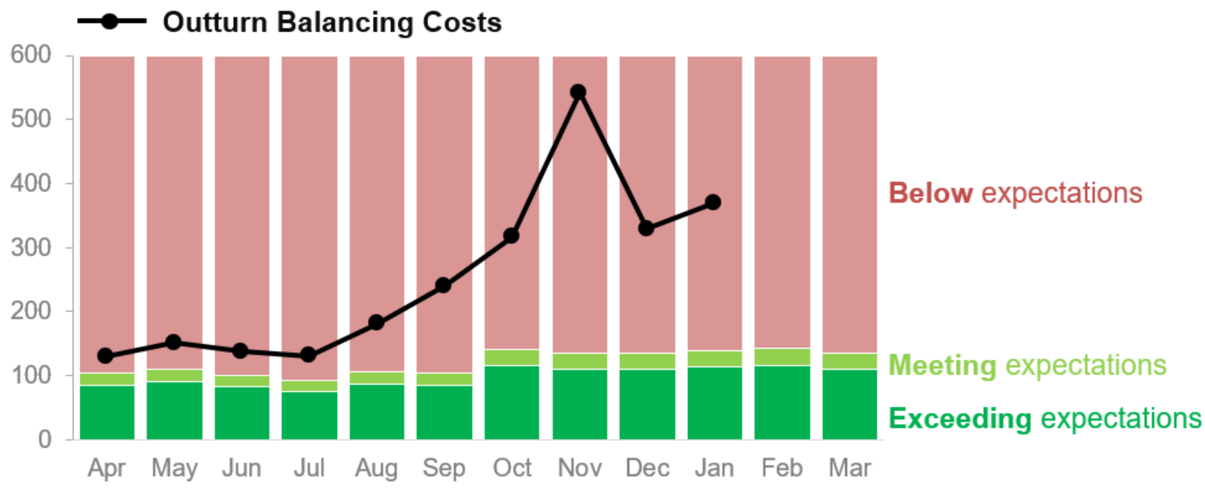


Table 2: Monthly balancing cost benchmark and outturn (Apr 2021-Jan 2022)

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	YTD
Benchmark: non-constraint costs (A)	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	413
Indicative benchmark: constraint costs (B)	59.9	50.6	52.3	49.2	58.4	66.9	76.3	75.0	82.2	81.6	652.4
Indicative benchmark: total costs (C=A+B)	101.2	91.9	93.6	90.5	99.7	108.2	117.6	116.3	123.5	122.9	1071.6
Outturn wind (TWh)	2.8	3.2	2.5	1.9	3.0	2.8	5.5	5.1	5.1	5.4	37.3
Ex-post benchmark: constraint costs (D)	53.5	58.9	49.9	42.5	55.7	53.4	86.6	81.8	81.4	85.4	649.4
Ex-post benchmark (A+D)	**94.8**	**100.3**	**91.2**	**83.8**	**97.1**	**94.8**	**128.0**	**123.1**	**122.7**	**126.7**	**1062.9**
Outturn balancing costs[1]	**129.9**	**151.6**	**137.8**	**130.4**	**180.9**	**239.9**	**316.9**	**541.5**	**329.6**	**369.8**	**2528.2**
Status	●	●	●	●	●	●	●	●	●	●	●

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

Performance benchmarks

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

Supporting information

January performance

The balancing costs for January were nearly £370m, which is £40m higher than the December figure of around £330m and remains in the 'below expectations' range.

Both constraint and non-constraint costs remain higher than last year, with the non-constraint spend also showing an increase from December, whilst the constraint costs decreased from the previous month.

The significant increase in non-constraint costs compared to last year and to the previous month was the result of continued high wholesale prices combined with periods of tight system margins leading to scarcity

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

pricing. This further drove up prices for Operating Reserve this month, whether procured through the Balancing Mechanism as scheduled reserve, or through our ancillary services markets.

The significant constraint cost increase from last year, was the result of continued very high wholesale prices, combined with high wind and reduced boundary capability due to system outages. This required us to take a large volume of Balancing Mechanism (BM) actions to reduce generation behind constraints and replace it with alternative generation.

Breakdown of costs vs previous month

Balancing Costs variance (£m): January 2022 vs December 2021

		(a) Dec-21	(b) Jan-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	7.0	13.0	6.0	
	Operating Reserve	44.7	90.4	45.7	
	STOR	4.5	10.8	6.3	
	Negative Reserve	0.8	0.6	(0.3)	
	Fast Reserve	21.6	19.1	(2.6)	
	Response	24.1	23.7	(0.4)	
	Other Reserve	1.8	2.1	0.3	
	Reactive	23.6	26.7	3.1	
	Restoration	6.8	8.3	1.5	
	Minor Components	9.4	6.5	(2.9)	
Constraint Costs	Constraints - E&W	18.1	17.4	(0.7)	
	Constraints - Cheviot	20.9	13.1	(7.8)	
	Constraints - Scotland	60.4	77.7	17.3	
	Constraints - Ancillary	0.6	1.2	0.6	
	ROCOF	3.4	6.6	3.2	
	Constraints Sterilised HR	81.9	52.7	(29.2)	
Totals	Non-Constraint Costs - TOTAL	144.3	201.1	56.8	
	Constraint Costs - TOTAL	185.3	168.7	(16.6)	
	Total Balancing Costs	**329.6**	**369.8**	**40.2**	

As shown in the total rows above, the majority of this month's increase in costs came in Non-Constraint costs which increased by £57m, whilst Constraints costs decreased by £17m.

Against the Non-Constraint category, the breakdown shows that Operating Reserve, STOR, Energy Imbalance and Reactive were the categories with the largest increase from the previous month, with Operating Reserve showing a substantial increase of £46m. A decrease in monthly costs was seen in Fast Reserve and Minor Components.

Within the Constraint category, the breakdown shows that Constraint-Scotland and RoCoF were the two categories with the largest increase from December 2021.

Overall, Constraints Sterilized Headroom and Constraints-Cheviot were the categories with the largest decrease from the past month.

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

- **Operating Reserve: £45.7m increase.** Around 70% of the monthly spend for this category was incurred on Friday 14 January and Monday 24 January, when offers up to £4,000/MWh were accepted to meet the operational margin requirements, generating a daily spend of around £23m and £49m respectively. Rapid price changing on some units led to a very volatile price structure on all units, particularly on 24 January. See 'daily costs trends' section further below for more detail.

- **Constraint Sterilized Headroom: £29.2m decrease.** The cost associated to the replacement of Headroom that was available on constrained generation was lower than the previous month, however it still retains a significant impact on the Balancing Costs accounting for over 30% of the monthly Constraint Costs. This decrease partially offsets the increase in Operating Reserve and shows that although less cost was incurred due to headroom sterilised behind a constraint, the requirement to increase reserve levels to meet our operational margin requirement remained.

- **Constraints-Scotland: £17.3m increase.** Throughout the month constraint actions were needed due to the prevailing windy weather. A large volume of BM actions was required to reduce generation to manage thermal constraints. The most expensive day for this category was Wednesday 12 January with a daily spend of nearly £8m. There were also six other days in January when the spend recorded was around or above £5m.

Constraint Costs vs Non-Constraint Costs

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

Balancing costs for January 2022 increased from the previous month and overall remain significantly higher than the previous year. The cost increase in January is mainly driven by the Non-Constraint costs that showed an increase from December 2021, as well as being consistently higher than the previous year. Although January Constraint Costs were lower than December, they are higher than the same period last year.

Constraint Costs

Compared with the same month of the previous year:

Constraint costs were £128m higher than in January 2021 due to:

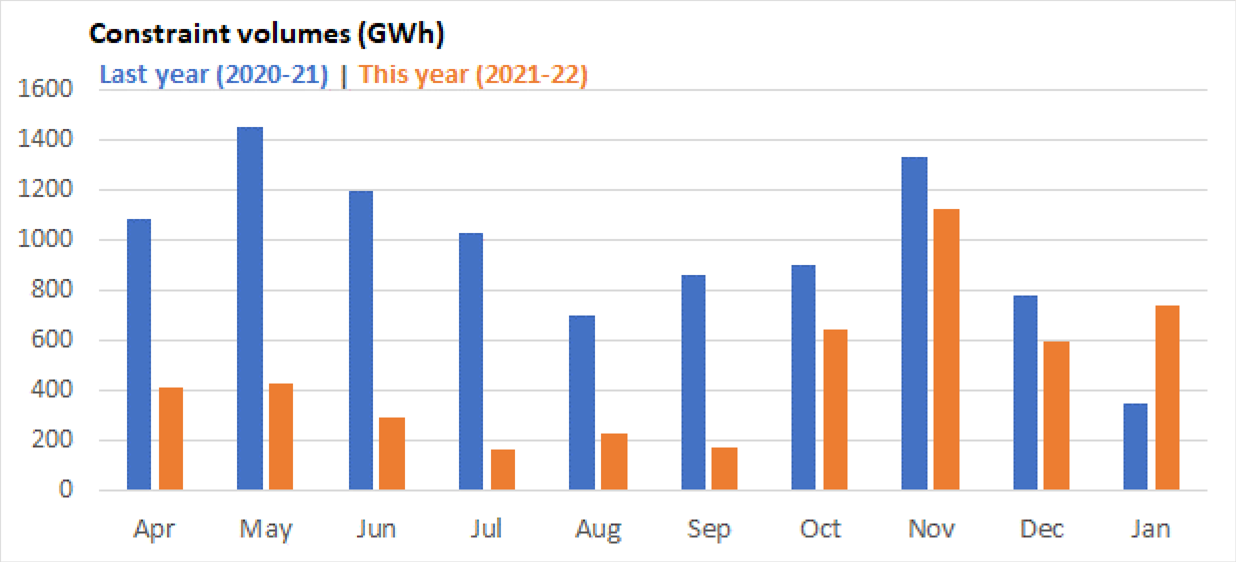
- An increased cost of actions to manage thermal constraints and network congestion during high wind periods.
- Increased spend for replacement energy and headroom associated with wind driven constraints in Scotland.

Compared with the previous month:

Constraint costs were £16.6m lower than December 2021 due to:

- Improved boundary availability which required fewer BM actions to constrain off generation and replace energy & headroom elsewhere.

Constraint volumes



Compared to January 2021, January 2022 had a higher volume of constraint actions due to the high winds experienced and large volume of BM actions required to manage thermal constraints. January was the first month of 2021-22 where the volume of actions exceeded the volume of actions of the corresponding month in the previous year.

Non-Constraint Costs

Compared with the same month last year:

Non-constraint costs were £97.4m higher than January 2021 due to:

- Continued high prices submitted or resubmitted in the BM and at the Day Ahead market stage. This means the actions which the ESO needs to take are only available at high costs. This impacts on the costs of Operating Reserve and Reactive. These high prices are market driven, partly due to an increase in wholesale costs and party due to scarcity pricing in times of tight margins or perceived tight margins.

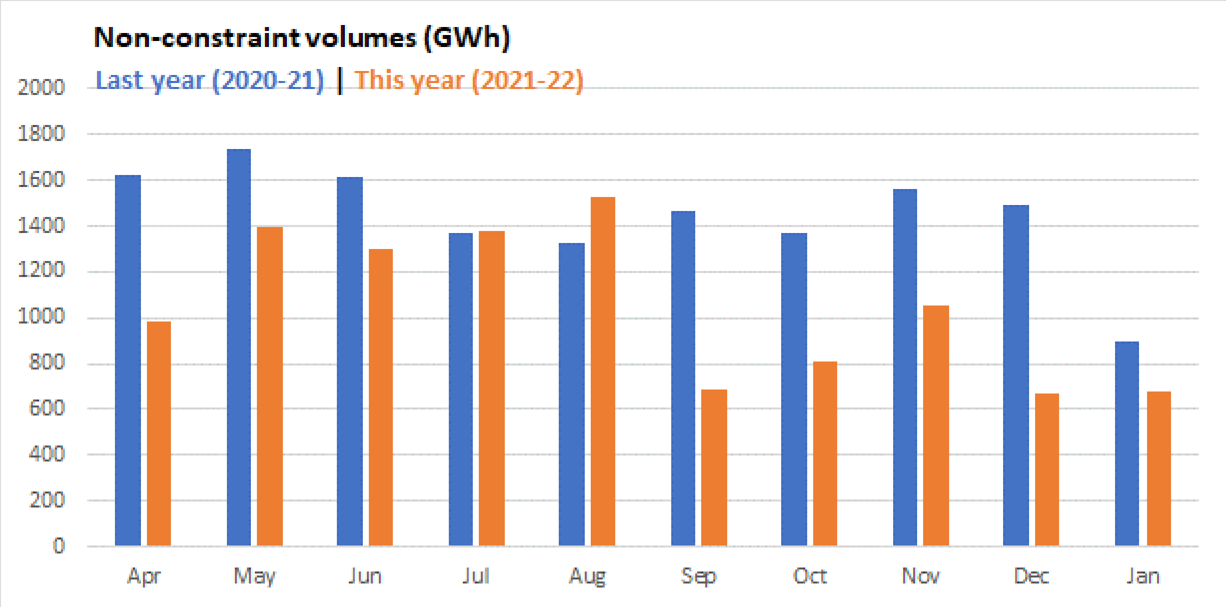
- Response costs remain higher than in January 2021 due to the introduction of the Dynamic Containment service, and the amended requirement for response holding. This has meant a higher volume of response has been procured, and at a higher price than for the same period in 2021. The addition of the Dynamic Containment service has resulted in large savings in the Constraints – RoCoF category due to the implementation of the Frequency Risk and Control Report (FRCR).

Compared with the previous month:

Non-constraint costs were £56.8m higher than December 2021 due to:

- Increased costs in Operating Reserve due to high BM prices being submitted by units which are required for system operation. These high prices are market driven due to scarcity pricing in times of tight margins or perceived tight margins.

Non-constraint volumes

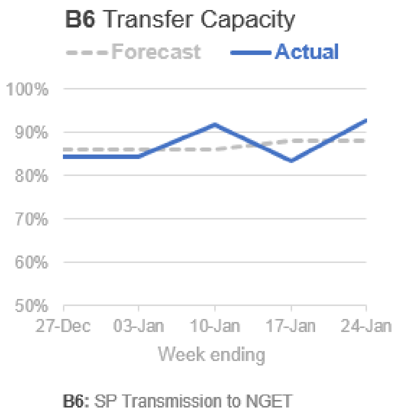


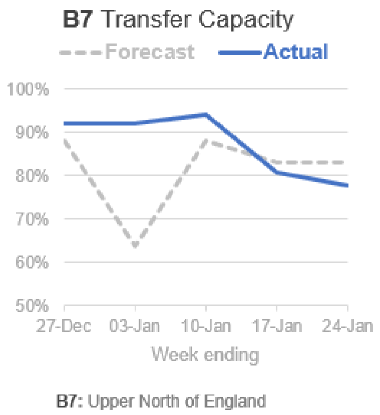
Compared with January 2021, January 2022 showed a lower volume of actions taken for Non-Constraint reasons despite the cost outturning higher.

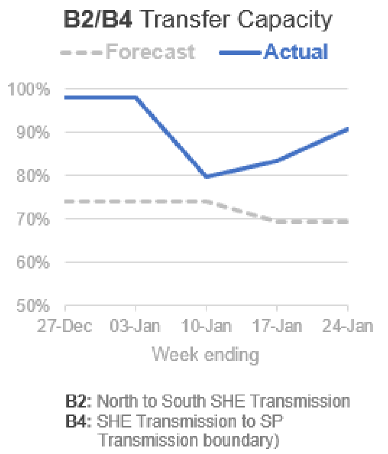
Compared with 2020-21, this year has been a year of consistently lower volume of action for non-constraints, with July and August the only outliers.

Both of these comparisons show that it is the cost of the actions required rather than the volume which is driving the overall non-constraint cost.

Network availability

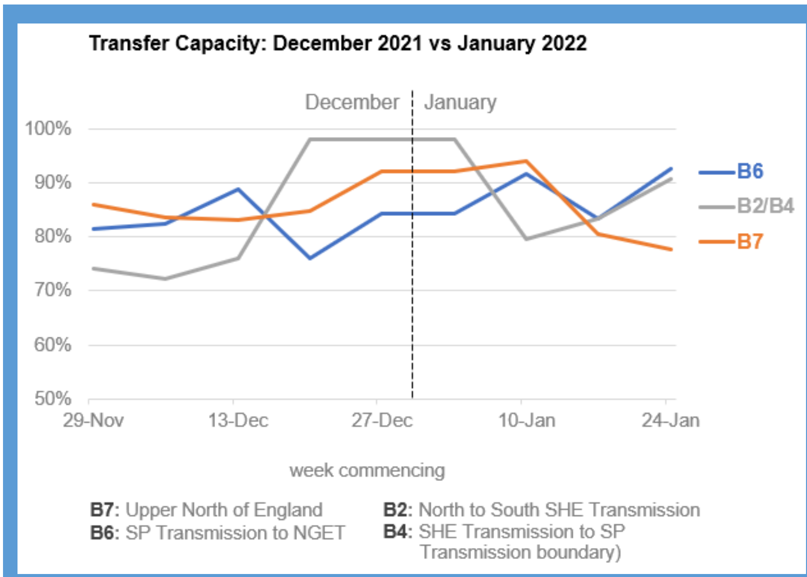






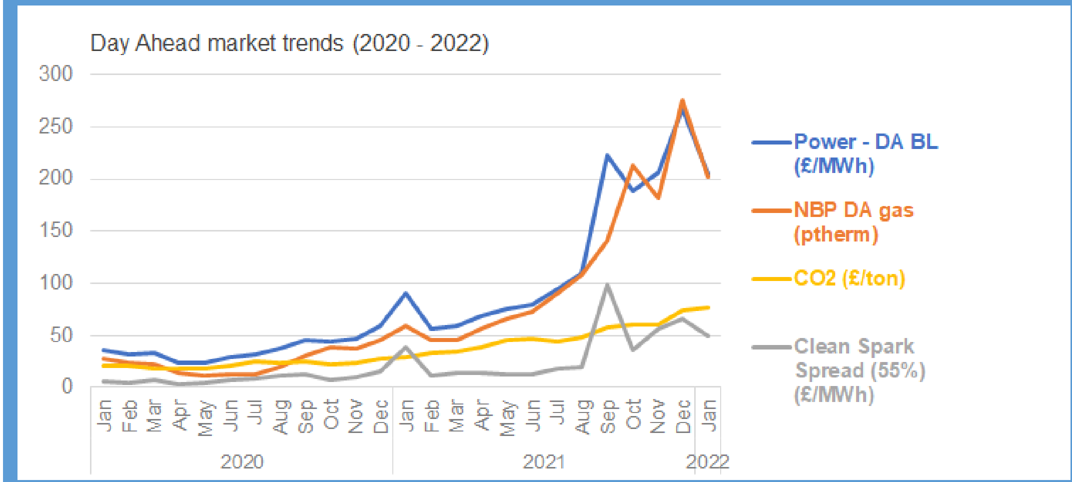
Boundary capacity has been in line with or above forecast for the majority of the month. The reduced transfer capacity combined with windy conditions led to the need for a large volume of BM actions to manage constraints.

The B7 and B2/B4 transfer capacities were significantly above forecast at certain points due to outage optimisation, network configuration and outage plan changes which meant that costs were mitigated beyond where they could have been.



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.

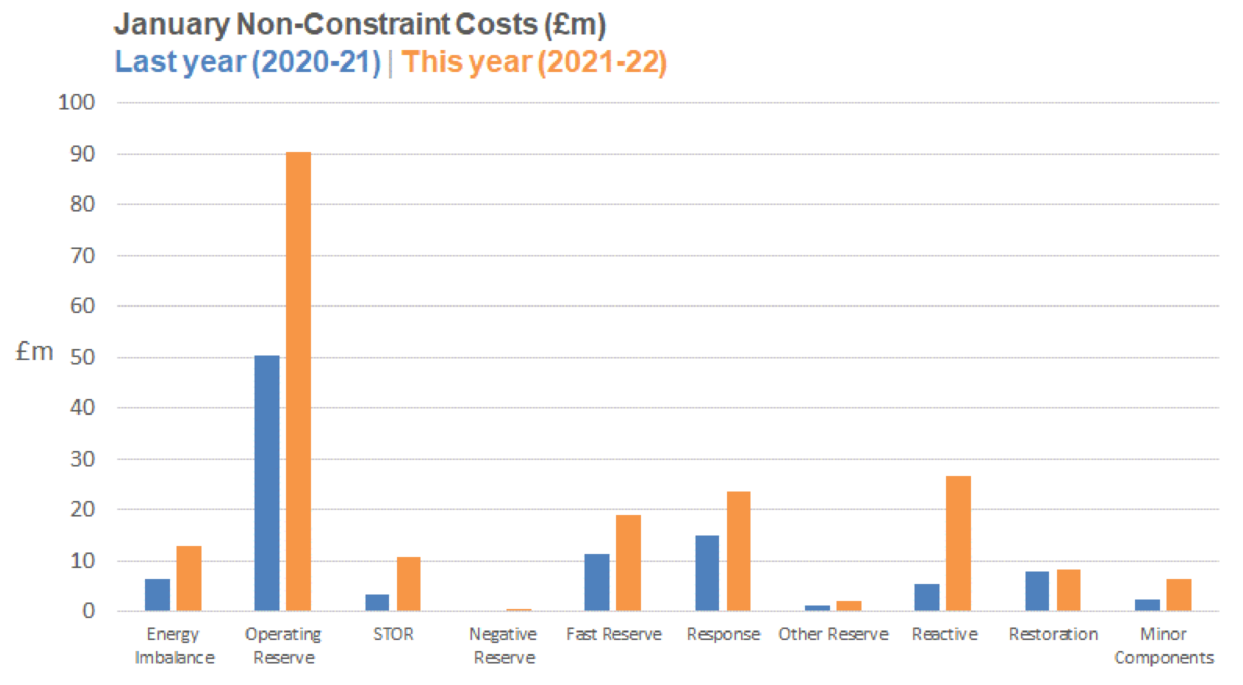
Changes in energy balancing costs



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

Power day ahead prices have fallen in January but remain very high compared to the previous year. The day ahead gas prices have also fallen since December but remain very high in comparison with early 2021. Carbon prices continue the upward trend seen throughout 2021. These continued higher prices impact on both the buy (offer) and sell (bid) actions available to the ESO to manage our operability requirements. This demonstrates some of the external drivers of the underlying high prices available to ESO for balancing actions.

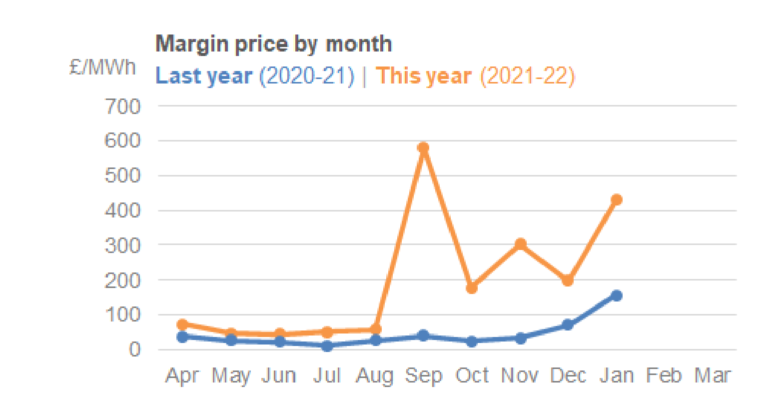
Cost trends vs seasonal norms



Comparing January 2022 non-constraint costs with those of January 2021 we can see that there has been a rise in all categories.

- **Operating Reserve** costs have increased by around £40m, driven by the high cost of BM actions. This is driven significantly by the continued high wholesale market prices along with scarcity pricing in periods of tight margin resulting in high offer prices submitted and taken for actions in the BM.
- **STOR** costs have increased by around £7m. We have included a STOR case study later in this section to provide more detailed information about the drivers of this increased spend.
- **Reactive** costs have increased by over £21m. As the volume of actions taken is in line with seasonal norms, this is driven by the increased cost of the actions taken and is therefore related to the continued high wholesale market prices.
- **Response** costs have increased by nearly £9m. With the introduction of the Dynamic Containment service this continues to be higher spend than the previous year but offsets some cost in other categories as covered earlier.

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for a single MWh) have increased since December 2021 and remain high when compared to last year. This is due to the increased cost of actions taken to make more generation available to meet our operational margin requirements.

Daily costs trends

There were several high cost days during January 2021 where expensive actions were needed to ensure all operability requirements were met. The monthly balancing costs outturned at £370m, which is an increase from the previous month of over £40m.

Friday 14 January and Monday 24 January were the most expensive days with a daily spend of £27.2m and £44.2m respectively. In both cases, the main driver behind the high costs were the expensive operational actions taken to meet the margin requirements. Tight margins were experienced on both days with a Capacity Market Notice issued on Monday 24 January and subsequently withdrawn. Although margins were adequate with actions taken by the ESO control room, the price of these actions were inflated due to scarcity pricing within the market.

Other expensive days were Saturday 1 January and Tuesday 25 January with a daily outturn of £19.1m and £20.1m respectively, and Tuesday 4 January and Wednesday 12 January with a spend of £17.8m and £16.2m respectively. Windy weather requiring a large volume of BM actions to reduce generation to manage thermal constraints was the main driver behind these expensive days.

Significant events

A Capacity Market Notice was issued at 13:34 on Monday 24 January and withdrawn at 14:06. This was covered in more details in the Operational Transparency Forum on Wednesday 26 January, the recording is available to watch on the data portal.

Case study – Short Term Operating Reserve (STOR) market

Changes to the price methodology for the day ahead procurement of STOR, implemented by the ESO in early January, led to a saving of approximately £26m in January 2022. Here we outline the changes we have made and the impact these have had on costs.

Background:

The long-term tender round process for procuring Short Term Operating Reserve (STOR) was replaced by day-ahead auctions from 1 April 2021. The MW volume requirement is derived as the volume required to offset for the largest loss on the system – minus any volume already secured via long-run reserve contracts. Any shortfall in STOR volumes secured via the day-ahead auctions is procured in real time via the BM.

Changes to the buy order methodology

The total availability cost of Short Term Operating Reserve (STOR) increased in January 2022 to £7.45m from £2.00m in December 2021 (the STOR figures in the balancing costs variance table, shown between January 2022 and December 2021, differ due to the exclusion of long-run STOR contracts).

STOR day-ahead auction costs: December 2021 and January 2022

	Average Buy Order Price (£/MWh)	Average MW Contracted	Total Spend (excl. Shortfall Cost)	AVG Daily Spend (excl. Shortfall Cost)	Avg £/MWh (excl. Shortfall cost)
Dec-21	19.61	1087	£2,004,566	£64,663	£5.48
Jan-22	34.57	1362	£7,465,970	£240,838	£16.74

The increase in the total cost of the service resulted from a revision of the buy order methodology for day-ahead procurement. This was done to address shortfalls in Operating Reserve volumes contracted via the day-ahead auction process, by better reflecting our 'alternative cost'. The 'alternative cost' is the cost if we were to secure the total requirement via the BM, rather than through day ahead auctions.

In the event of a Short Term Operating Reserve shortfall, the ENCC must take actions to secure the full reserve requirement, which is required to cover the largest system loss throughout specified STOR windows. The service must cover the largest loss in accordance with the ESO's Frequency Risk and Control Report (FRCR)/ Security and Quality of Supply Standards (SQSS) obligations. In recent months, the ESO have observed a marked increase in the number of auctions failing to secure the full STOR requirement. These occasions tend to coincide with forecasts for tight system margin.

Due to factors such as reduced competition and reduced optionality in the Balancing Mechanism (BM), relative to a Day-Ahead auction, it has often been more expensive to secure reserve volume within day compared to securing the equivalent volume ahead of time. This was particularly the case for days on which system margin was tight and, consequently, wholesale electricity prices and prices in the Balancing Mechanism were highest.

Wider wholesale market and system conditions affect the procurement of STOR due to the associated effect on STOR providers' opportunity cost. Specifically, higher prices in real time, which are most prevalent on tight margin days, equate to a higher opportunity cost in contracting for STOR.

As such, the buy order methodology was amended in early January 2022 to account for the change in market dynamics and to best reflect our alternative costs on tight margin days.

Three days in January (14th, 17th & 24th) were characterised by particularly tight margins and mandated an unprecedented buy order price, as derived by the revised alternative cost assessment methodology.

The total expenditure on STOR availability for the MW secured via the Day-Ahead auctions amounted to £6.3m – 85% of the total STOR expenditure for the month of January.

While this cost is substantial, when the cost of the STOR shortfalls, which were secured via the BM, are factored into the calculations, the total cost of the service fell in January relative to December.

Total STOR costs (including auction cost and shortfall cost): December 2021 and January 2022.

	Average Buy Order Price (£/MWh)	Total Requirement	Total Spend (incl. Shortfall Cost)	AVG Daily Spend (incl. Shortfall Cost)	Avg £/MWh (incl. Shortfall cost)
Dec-21	19.61	1340	£12,593,505	£406,242	£27.93
Jan-22	34.57	1340	£12,366,589	£398,922	£27.98

The alternative cost of the STOR service on two of the three dates in question was significantly higher than the actual expenditure as determined by the auction cost plus the shortfall cost.

Impact of new buy order methodology: cost savings for three tight margin days in January 2022

	Requirement (excl. LR Contracts) (MW)	Auction Shortfall (MW)	Auction Cost	Shortfall Cost	Total STOR Cost	Alternative Cost	Cost Avoidance
14/01/2022	1340	167	£2,023,425	£1,034,709	£3,058,134	£8,302,452	£5,244,319
17/01/2022	1340	246	£2,388,619	£401,670	£2,790,289	£2,187,960	-£602,329
24/01/2022	1340	311	£1,912,911	£3,449,718	£5,362,629	£14,863,737	£9,501,108

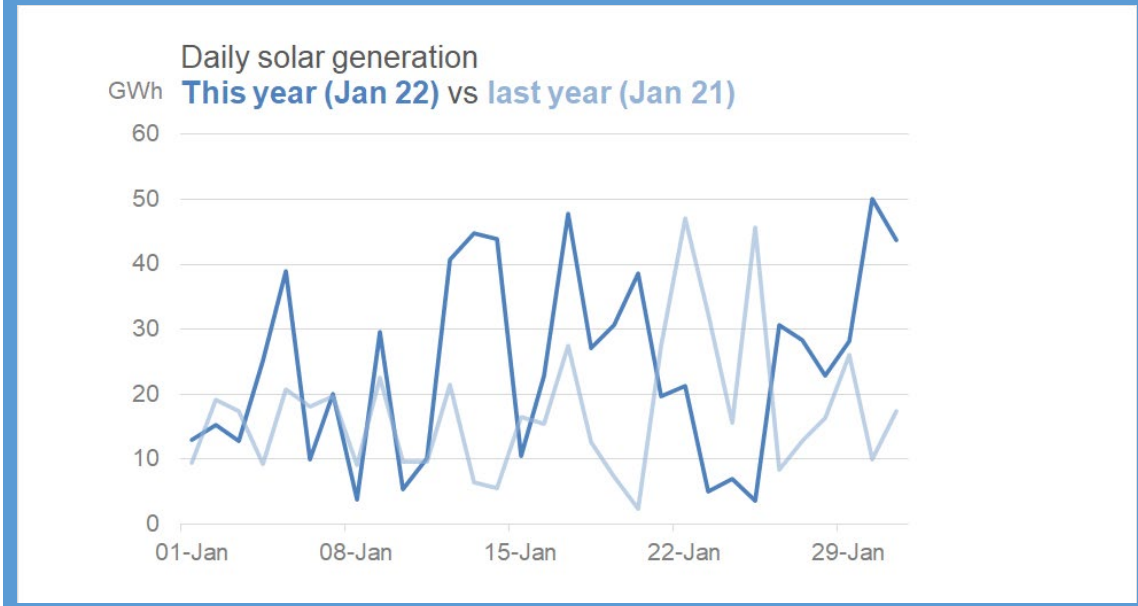
The equivalent analysis for the month of January shows an average cost saving resulting from the STOR procurement strategy of £986k per day – equivalent to a total saving throughout the month of around £26m.

Average daily cost savings for January 2022

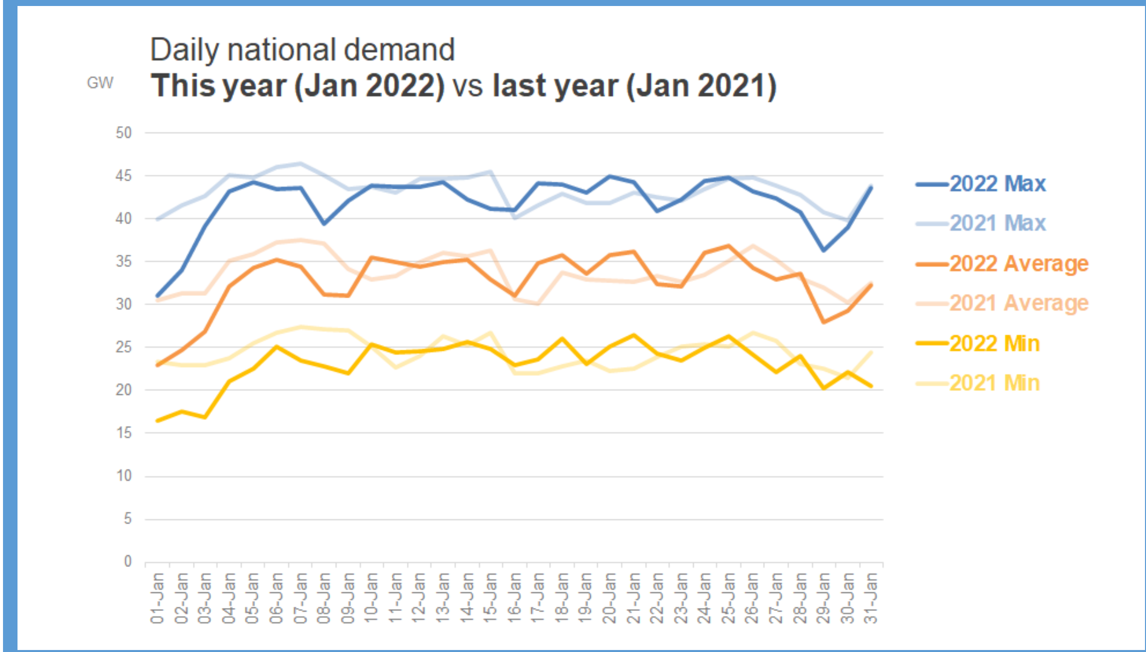
	Daily Requirement (excl. LR Contracts) (MW)	Avg Auction Shortfall (MW)	Avg Auction Cost	Avg Shortfall Cost	Avg Total STOR Cost	Avg Alternative Cost	Avg Cost Avoidance
Jan-22	1340	28.25806452	£240,838	£158,084	£398,922	£1,384,509	£985,586

We'll continue to adapt the buy order methodology to reflect the changing market dynamics and optimise for lowest cost.

Solar generation - comparison against last year



Outturn Demand vs 2020-21



Metric 1B Demand forecasting accuracy

January 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)

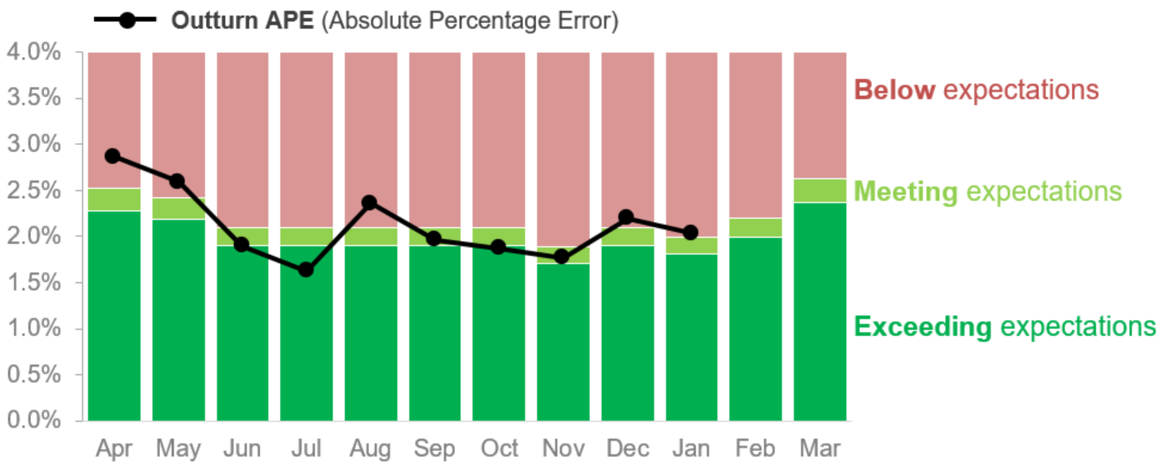


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Indicative benchmark (%)	2.4	2.3	2.0	2.0	2.0	2.0	2.0	1.8	2.0	1.9	2.1	2.5	**2.1**
APE (%)	**2.9**	**2.6**	**1.9**	**1.6**	**2.4**	**2.0**	**1.9**[2]	**1.8**	**2.2**	**2.0**			
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

[2] It has been identified that the figure of 2.0% (rounded from 1.95%) reported for October 2021 was incorrect, and has been updated to the correct figure of 1.9% (rounded from 1.87%). As a result, the October status has changed from 'meeting expectations' to 'exceeding expectations'.

Supporting information

For **January 2022**, our MAPE (mean absolute percentage error) was 2.0% compared to the benchmark of 1.9%, and therefore below expectations.

The biggest challenge in January 2022 was finding historical profile dates to use as an input into the forecast calculation, particularly in the first half of the month. The beginning of January is typically difficult from this perspective, as it is heavily dependent on the Bank Holiday position and festive holiday pattern. The last time when Monday 3 January was the substitute Bank Holiday for New Year's Day was 11 years ago.

Another challenge when selecting the best historical profile day was that the most recent January was not comparable. Last year, starting from 6 January 2021, a national lockdown was introduced which included the closure of schools. Last year's lockdown led to a significantly different demand curve.

Furthermore, Triad Avoidance during the darkness peak (DP) in January led to additional uncertainty of demand. ESO engaged in discussions with companies which participate in triad avoidance, which allowed us to further verify our forecasting and post event estimation of this activity.

The biggest errors were observed on 02, 04, 21 and 24 January. The first two days can be explained by the challenge of finding a profile day and uncertainty of behavioural effects related to the end of the festive season. On Friday 21 January, there was a weather forecast error, leading to a less accurate forecast of solar generation output which exacerbated the under-forecast. On Monday 24 January, market prices were very high and ESO observed significantly lower demand on the transmission network, especially between SP 30-46. This might be an indication of the generation connected to the distribution networks (which appears as negative demand at the transmission system) responding to price signals.

To identify the settlement periods that ESO performed the best in January, monthly average performance errors by settlement periods were calculated. Within this time frame, there were 22 settlement periods for which the day ahead MAPE was better than the target of 1.9%.

Error greater than	Number of SPs	% out of the SPs in the month (1488)
1000 MW	321	22%
1500 MW	158	11%
2000 MW	62	4%
2500 MW	25	2%
3000 MW	5	0%

ESO continues to use two forecasting models which run in parallel. The models' outputs are reviewed by experienced forecasters and used to deliver improved forecasts.

In January 2022 there were no instances of missed or late publication of national demand forecast data.

As part of our continuous drive to increase data transparency, the Energy Forecasting team introduced a new dataset on the ESO Data Portal, Day Ahead Half Hourly Demand Forecast Performance. Estimates of triad avoidance are included in this dataset.

Metric 1C Wind forecasting accuracy

January 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)

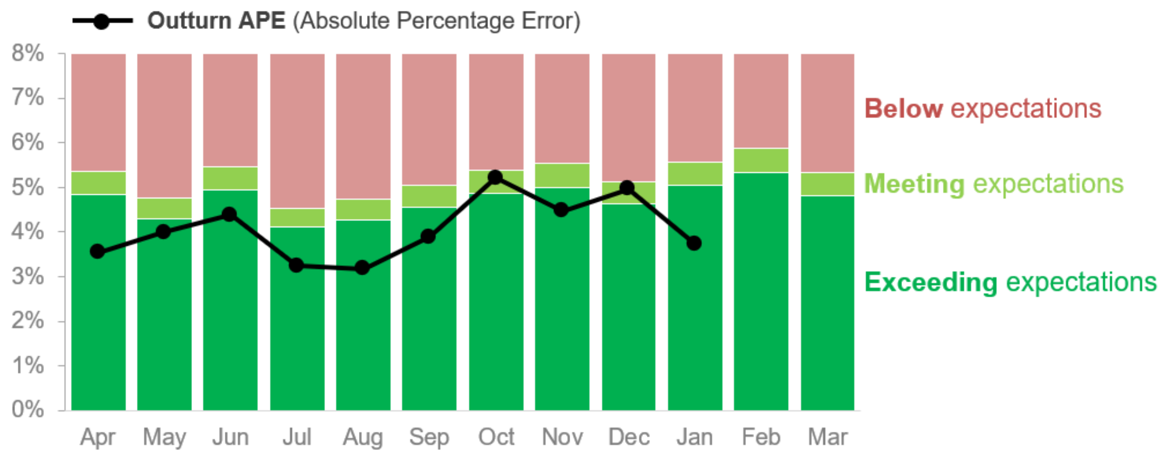


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
BMU Wind Generation Forecast Benchmark (%)	5.1	4.5	5.2	4.3	4.5	4.8	5.1	5.3	4.9	5.3	5.6	5.1	**5.0**
APE (%)	**3.5**	**4.0**	**4.4**	**3.2**	**3.2**	**3.9**	**5.2**	**4.5**	**5.0**	**3.7**			
Status	●	●	●	●	●	●	●	●	●	●			

Performance benchmarks

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

Supporting information

For **January 2022**, our MAPE (mean absolute percentage error) was 3.7% compared to the benchmark of 5.3% and therefore exceeding expectations. This is despite a set of challenging weather conditions which made wind generation output more difficult to forecast. Days where the wind level changes significantly during the day are more difficult to forecast, as the timing of the change is difficult to predict exactly. This was the case on several days in the first week of January, and is often the result of the movement of areas of low pressure.

There was also significant lightning activity in the first part of the month in many regions of the country. Lightning can be indicative of atmospheric turbulence which can make forecasting wind speeds and by extension wind power harder.

On 10 and 11 January, a high-pressure front entered the UK which can cause some issues with timings as the wind begins to ramp down. This high pressure remained over the UK, slowly drifting southwards until 18 January when the high pressure began to move south-east towards the North Sea. A second area of high pressure entered the UK from the west on 22 January, which began to fade on 26 January especially in the north. These areas of high pressure brought stable and calm periods. This helped our forecasting accuracy, as long periods of high or low wind speed are easier to forecast as they cause less variation in generation output than medium or rapidly varying wind speeds.

29 January saw storm Malik hit North and Eastern Scotland as well as the North-East of England. This low-pressure system brought with it strong winds which can cause cut off in some windfarms (leading to over forecasting) as well as the difficulty in forecasting the timing and path of the storm. Overnight on 30 and 31 January, storm Corrie entered the UK from the Atlantic causing similar issues.

Wind farms with Contract for Difference (CfD) contractual arrangements switch off for commercial reasons while prices are negative for 6 hours or more. In January there was one occasion when the electricity price went negative for 6 hours or more which was between 02/01/22 23:00 and 03/01/22 05:00. The negative prices heavily affected our accuracy as during this period our MAPE was 10.5% whereas in the previous 6 hours it had been 2.2% and in the 6 hours after the MAPE was 1.1%

The electricity price used for this analysis is the Intermittent Market Reference Price. Market Price Data for January can be downloaded from here.
https://www.emrsettlement.co.uk/settlement-data/settlement-data-roles/

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

Metric 1D Short Notice Changes to Planned Outages

January 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

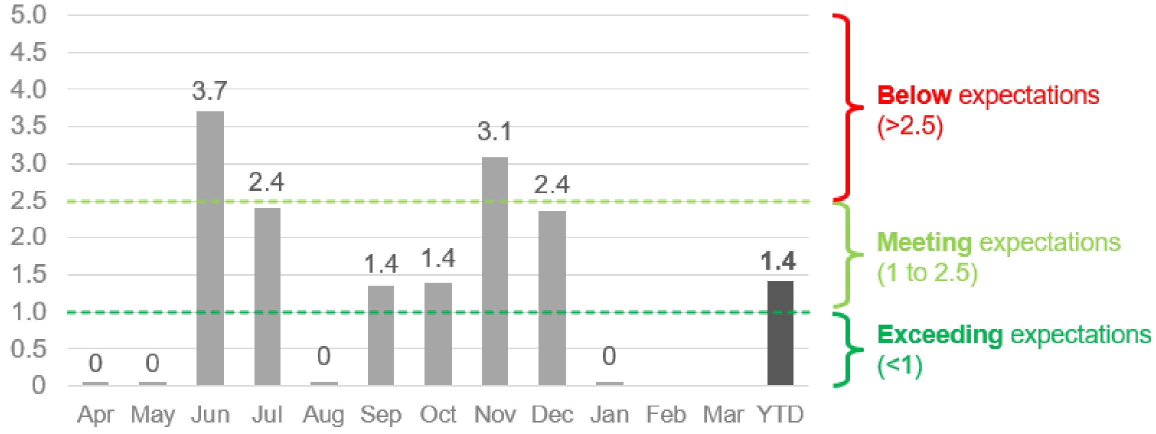


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	845	856	810	831	810	735	723	648	423	431			7112
Outages delayed/cancelled	0	0	3	2	0	1	1	2	1	0			10
Number of outages delayed or cancelled per 1000 outages	0	0	3.7	2.4	0	1.4	1.4	3.1	2.4	0			1.4

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 January, the ESO has successfully released 431 outages and there have been no delays or cancellations due to an ESO process failure. This is within the 'Exceeds Expectation' target of less than one delay or cancellation per 1000 outages. The number of outages released in January 2021 was 540 and has decreased in January 2022 to 431, this is due to the reduced number of outage requests received from the TOs/DNOs for this period. However, the overall number of outages released to date has increased to 7112 compared with 7024 the previous year. Overall, the ESO is continuing to liaise with the TOs and DNOs to effectively facilitate system access through weekly or month liaison meetings to maximize system access.

RRE 1E Transparency of operational decision making

January 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
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	90.4%	88.4%	89.3%	89.0%	88.4%	89.1%	92.6%	88.4%	91.2%	93.5%
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.6%	99.6%	99.7%	99.8%	99.8%	99.7%	99.9%	99.7%	99.8%	99.8%
Percentage of actions with no category applied or reason group identified	**0.4%** (173)	**0.4%** (147)	**0.3%** (56)	**0.2%** (87)	**0.2%** (81)	**0.3%** (109)	**0.1%** (61)	**0.3%** (232)	**0.2%** (93)	**0.2%** (95)

Supporting information

This month 93.5% of actions were taken in merit order, or taken out of merit order due to an electrical parameter. For the remaining actions, where possible, we allocation actions to reason groups for the purposes of our analysis. We were unable to allocate reason groups for 0.2% of the total actions this month.

During January 2022, we sent 52,787 BOAs (Bid Offer Acceptances) and of these, only 95 remain with no category or reason group identified, 0.2%.

RRE 1G Carbon intensity of ESO actions

January 2021-22 Performance

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

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

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

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	2.1	6.2	4.5	4.5	6.9	1.0	4.8	9.4	3.4	6.4		

Supporting information

In January 2022, the average carbon intensity of balancing actions was 6.4 gCO_2/kWh, for comparison, December 2021 had an average carbon intensity of 3.4 gCO_2/kWh. The time with the largest decrease in carbon intensity due to the ESO's actions was 00:00 am on 30 January 2022 with a minimum of –36 gCO_2/kWh. This was lower than December 2021's minimum value of -20.2 gCO_2/kWh. In January, the time with the highest carbon intensity was 01:00am on 27 January 2022 with a value of 51.6 gCO_2/kWh.

RRE 1I Security of Supply

January 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	0	0	0	0	0	0		
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	0	0	0	0	0	0	0	0	0	0		
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0	0	0	0	0	0	0		

Supporting information

There have been no reportable voltage and frequency excursions in January 2022.

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

RRE 1J CNI Outages

January 2021-22 Performance

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

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

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

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

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

Planned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	1 outage 216 minutes	0	0	0	1 outage 215 minutes	0	0		
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0		

Supporting information

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

Notable events during January

GB electricity system sees record levels of wind power

On Saturday 29 January we saw the most wind ever on GB's electricity system with a record of 19.6GW of wind power. Through the day, it was stated that wind generated 51.8% of British electricity, with nuclear accounting for 15.1%, gas 15.0%, imports 9.3%, biomass 4.6%, hydro 1.6%, solar 1.4%, and coal 1.2%.

Reducing demand with time-of-use tariffs

On 11 January we provided an update on CrowdFlex, the UK's largest domestic flexibility study, which has found that active households could significantly reduce peak electricity demand by using time-of-use tariffs. This study was undertaken by the ESO, Scottish and Southern Electricity Networks Distribution, Octopus Energy and Ohme, which investigated how 25,000 households responded to price signals by reducing or increasing electricity demand. Domestic flexibility could reduce peak electricity demand by up to 23%, according to the study.

The UK's largest domestic flexibility study has found that active households could significantly reduce peak electricity demand by using time-of-use tariffs. A Phase 1 report[4] was published in November 2021.

The study analysed the impact of two types of signalling to customers:

- Enduring signals, created by customers who chose to move from a flat tariff to a time-of-use (ToU) tariff
- One-off signals, which asked customers to sign up to a "Big Turn Up" or "Big Turn Down" event and rewarded those who changed their demand over a specified two-hour period

Customers on ToU tariffs significantly reduced their demand during the evening peak by 15-17% and maintained that reduction over six months. Households that owned an electric vehicle (EV) showed a greater ability to flex their demand, achieving reductions of up to 23% in the proportion of a household's daily demand consumed during the evening peak.

Responses to one-off signals were similarly significant and strongly affected by EV ownership. The "Big Turn Up" saw an increase in the magnitude of average electricity demand expected during a household's evening peak by 617% for EV owning households, or 131% in non-EV owning households. The "Big Turn Down" request saw a very significant reduction in demand compared to the average evening peak power demand; a reduction of 59% and 41% in in demand over the period for EV households and non-EV households, respectively.

With electricity demand predicted to approximately double according to Future Energy Scenarios (FES)[5], the opportunities offered by time-of-use tariffs can help manage demand and help balance the grid which will be crucial in delivering a net zero future cost effectively.

Operability Strategy Report 2022

We announced our latest Operability Strategy Report[6] on Tuesday 18 January. The 2022 Operability Strategy Report reviews system operability across the five key areas of Frequency, Stability, Voltage, Thermal and Restoration. We highlighted a 300MW maximum requirement for Dynamic Regulation & Dynamic Moderation by 2025, the need for 1,600MVAr of additional reactive power absorption by 2025, and that some boundaries will see peak power flows 400% greater than existing capability by 2030. Additionally, that system inertia must remain above 96GVA.s for secure zero carbon operation by 2025, and that the requirements of the Electricity System Restoration Standard (ESRS) need to be implemented by 2026. We are delivering frequency services that are fit for operating a zero carbon network where system frequency will, at times, be more variable. Our stability pathfinders and voltage pathfinders reduce our reliance on fossil fuelled generation for critical transmission system services. We can already maintain our system restoration capability without warming or running fossil fuelled plant.

[4] https://www.nationalgrideso.com/document/230236/download
[5] https://www.nationalgrideso.com/future-energy/future-energy-scenarios
[6] https://www.nationalgrideso.com/document/227081/download

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

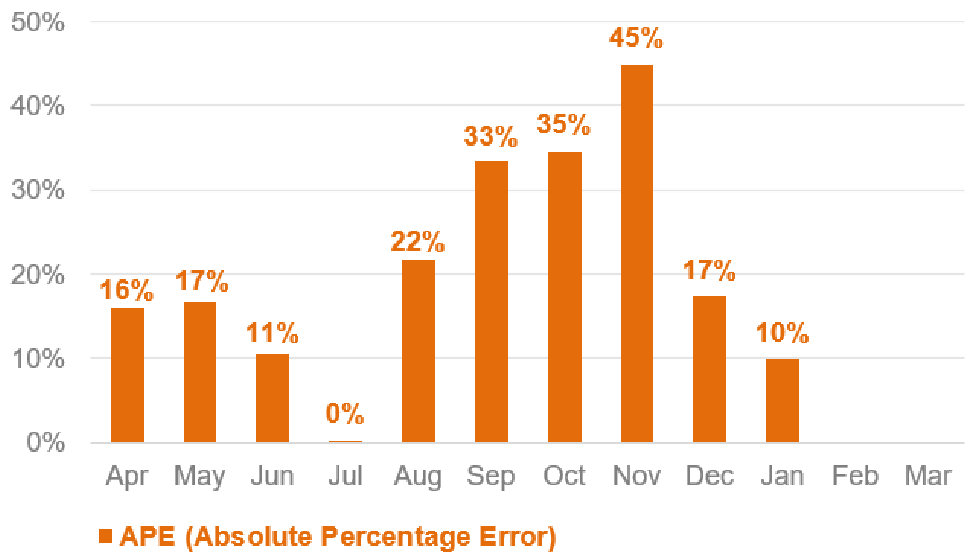
January 2021-22 Performance

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	3.8	4.5	4.6	4.2	5.8	7.1	8.4	12.5	7.5	8.1		
Month-ahead forecast	3.2	3.7	4.1	4.2	4.5	4.7	5.5	6.9	6.2	7.3		
APE (Absolute Percentage Error)[7]	**16%**	**17%**	**11%**	**0%**	**22%**	**33%**	**35%**	**45%**	**17%**	**10%**		

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



Supporting information

Outturn BSUoS remained high for January 2022, similar in level to October 2021 and December 2021 but lower than November 2021. Continued high Balancing Mechanism prices are driven by the overall increase in wholesale and carbon costs and further impacted by scarcity pricing during periods of tight margin meant that the cost of actions taken to operate the system were significantly increased.

Accuracy of the forecast for January 2022 was better than previous months.

[7] 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.

Work on revising the BSUoS forecasting methodology is in flight with a forecast for February 2022 produced using the updated methodology. Further updates, including incorporating a revised view of the constraint costs, are ongoing and will be included in forecasts in the future. This will provide more accurate forecasting for BSUoS cost scenarios. We are managing the communication of these updates through our Operational Transparency Forum.

Notable events during January

GC0137 Minimum specification for equipment providing grid-forming capability

This modification proposes to add a non-mandatory technical specification to the Grid Code, relating to what is referred to as Virtual Synchronous Machine ("VSM") or Grid Forming capability. This specification will enable applicable parties (primarily those utilising power electronic converter technologies (wind farms, HVDC interconnectors, and solar parks) to offer an additional grid stability service which will enable their participation in a commercial market based system to provide this support. At the end of an involved development process the final report for this modification was submitted to Ofgem for a decision following approval at the October 2021 meeting of the Grid Code Panel. This has now been approved by the Authority for implementation into the Grid Code. The Code Administrator will implement this into the Grid Code on 15 February 2022.

Net Zero Market Reform events

On 17 and 18 January 2022 we hosted the first events of Phase 3 of our Net Zero Market Reform project. The objective of these sessions was to share the refined market design options for each of the key market design elements identified in Phase 2. On 17 January we focused on the market design elements that fall under the Operation category and on 18 January we focused on the market design elements that fall under the Investment category.

Each session was 3 hours long including a 1 hour Q&A session, and around 125 attendees from the industry attended each one. Menti was used to gather live feedback from the attendees. Attendees rated the event 8/10 on average when asked "How would you rate today's session?" We also launched an online survey for stakeholders to provide feedback and this was open for around 2 weeks. Slides and recordings from the events can be found on our dedicated webpage[8] for the project.

Balancing Forecasts

In January we published the BSUoS forecast for February 2022 on the ESO Data Portal[9].

Following our previous communication on the changes to the forecasting process, we can now provide a further related update, with a forward view of further improvement to be implemented. This was presented at the Operational Transparency Forum (OTF) on 26 January 2022.

- We are committed to continually improving our forecasting and providing greater insight to the market around changing BSUoS costs.
  - We have been publishing more detailed BSUoS forecasts in recent years but we recognise that recently these have not been providing sufficient insight into costs and ultimately the charges system users will face.
  - In our 5 point plan to manage constraints on the system we committed to improve transparency and insight into our forecasts of the costs incurred managing flows on the network.

- To address these challenges, we have now published a forecast based on a new improved methodology.
  - This model moves away from the previous BSUoS forecasting linear model to a more comprehensive probabilistic model.
  - It takes advantage of improved data inputs and we believe it will provide better insight into BSUoS costs over both short and longer timescales.
  - We plan on making incremental improvements to the modelling and datasets included, including the 24 month ahead Constraint Limit dataset. This will provide increased accuracy in our modelling forecast inputs. We want to provide clarity of the changes for our customers and other users of the forecast.

We continue to look for feedback on stakeholders' expectations in relation to the forecasts, this helps us to improve our communications.

CMP381: Defer exceptionally high Winter 2021/22 BSUoS costs to 2022/2023

On 14 January the Authority approved the WACM4 option of CMP381, which puts a cap on the BSUoS price at £20/MWh and will be applied to all settlement periods between 17 January and 31 March 2022, subject to a £200m cap. We are now reporting daily on the settlement periods and the BSUoS costs which have exceeded £20/MWh. Amounts deferred will be collected in 2022-23.

Final 2022-23 TNUoS tariffs published

Final Transmission Network Use of System (TNUoS) tariffs[10] for 2022-23 were published by the ESO on Monday 31 January 2022. The total revenue to be recovered is ~£3.594bn, decreasing by ~£10mn from the November draft forecast. The total revenue to be recovered from generators is forecast at £842.0m for 2022/23, an increase of £25.4m from the Draft tariffs. The change is mainly driven by the increase in revenue from offshore local tariffs. Revenue to be collected through demand is forecast at £2,752m for 2022/23. This value has reduced by £35m compared to the Draft tariffs. The main driver is the reduction in revenue to be collected in total through TNUoS. The impact on the end consumer is forecast to be £38.14 per household in 2022/23, a decrease of £0.95 from Draft tariffs. This is due to the decrease in the total demand revenue. Charges will be effective from 1 April 2022.

[8] https://www.nationalgrideso.com/future-energy/projects/net-zero-market-reform
[9] https://data.nationalgrideso.com/balancing/monthly-balancing-services-use-of-system-bsuos-forecast-reports
[10] https://www.nationalgrideso.com/document/235056/download

Role 3 System insight, planning and network development

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

Notable events during January

Network Options Assessment 2021/22 published

On 31 January 2022 we published our annual Network Options Assessment (NOA) 2021/22[11]. The NOA assesses the reinforcements required for the electricity transmission networks owned by the three onshore Transmission Owners (TOs) and recommends which reinforcement projects should receive investment. This NOA aims to enable progress for the next six months, rather than a full year. It provides recommendations for TOs to make progress with projects.

NOA for 2021/22 is different in format and content than in previous years. This is because the ESO needs to factor in outputs from the ongoing Offshore Transmission Network Review (OTNR), a project led by the Department for Business, Energy and Industrial Strategy. As part of the OTNR, the ESO will produce a Holistic Network Design (HND), later this year, recommending how offshore wind farm projects within its scope could be connected to the transmission network. While the NOA already factors in the system impact of 40 GW of offshore wind by 2030, the HND may lead to changes to allow for coordination.

Offshore Coordination

On 31 January, we presented at the Offshore Transmission Network Review (OTNR) quarterly webinar, hosted by BEIS. During this, we presented a progress update on the Holistic Network Design (HND), an overview of our methodology for this process, and signposted other recent and upcoming stakeholder activities. We also participated in the question and answer session from a range of industry and public stakeholders.

We published the Open Letter on the Pathway to 2030 Connection Contract Update Programme (CCUP) on 14 January 2022. This letter provided an update to relevant offshore project developers and other interested stakeholders on our plans for a connection contract programme, as a result of ongoing developments within the Pathway to 2030 workstream of the OTNR.

[11] https://www.nationalgrideso.com/document/233081/download