ESO RIIO2 Business Plan

February 2022 Incentives Report

23 March 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 February we have successfully delivered the following notable events and publications:

- Began work on the Domestic Flexibility Trial with Octopus Energy.
- We issued the Frequency Risk and Control Report for 2022-23 consultation on 21 February.
- We published the T-1 and T-4 Capacity Auction results on 15 February and 23 February respectively.
- The foundational release of the Single Markets Platform (SMP) went live into production.
- We are preparing IT system changes for the Balancing Mechanism (BM) and the Ancillary Services Dispatch Platform (ASDP), scheduled for deployment on 22-23 March.
- On 8 February, we hosted a second workshop on Stability Market Design NIA project with the wider industry.
- On 17 February we issued the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS) consultation
- For the Pennine Voltage Pathfinder, we ran a competitive process to manage voltage for a 10 year period. On 07 February, we announced that Dogger Bank C and National Grid Electricity Transmission had been selected to deliver 700MVAr of reactive power capability between 2024 and 2034.
- The B6 Constraint Management Pathfinder (CMP) launched its consultation on 07 February for its draft service specification, draft framework agreement, and draft standard contract terms.
- We are developing a Holistic Network Design (HND) as part of the BEIS-led Offshore Transmission Network Review (OTNR).

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

Table 1: Summary of Metrics

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£337.9 m vs benchmark of £147.2m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 2.3% (vs benchmark of 2.1%)	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 4.5 % (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**	98.3% of actions have reason groups allocated	N/A
RRE 1G	**Carbon intensity of ESO actions**	10.6 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 12%	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

February 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)

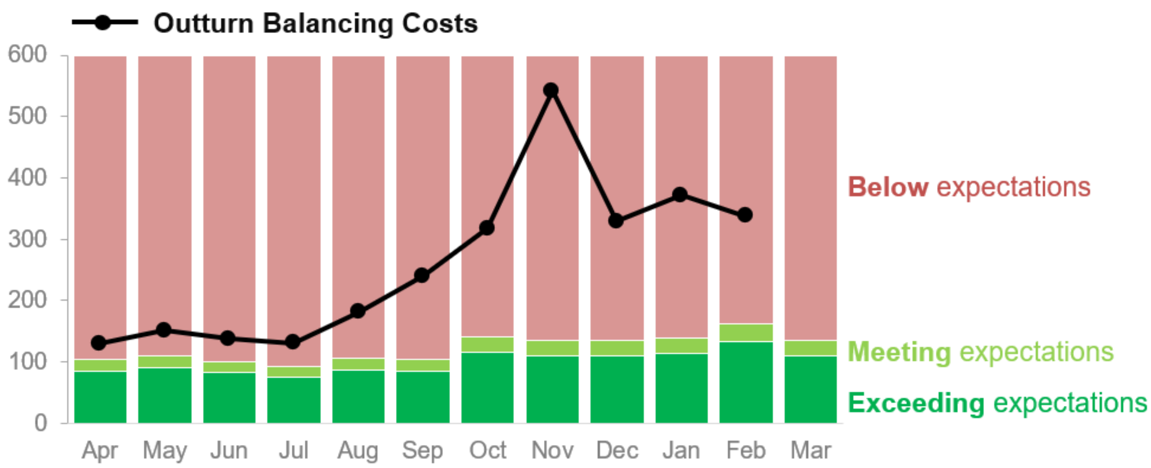


Table 2: Monthly balancing cost benchmark and outturn (Apr 2021-Feb 2022)

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	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	41.3	454.3
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	87.8	740.2
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	129.1	1194.5
Outturn wind (TWh)	2.8	3.2	2.5	1.9	3.0	2.8	5.5	5.1	5.1	5.4	7.1	44.4
Ex-post benchmark: constraint costs (D)	53.5	58.9	49.9	42.5	55.7	53.4	86.6	81.8	81.4	85.7	105.8	755.2
Ex-post benchmark (A+D)	**94.8**	**100.3**	**91.2**	**83.8**	**97.1**	**94.8**	**128.0**	**123.1**	**122.7**	**127.1**	**147.2**	**1210.1**
Outturn balancing costs[1]	**129.9**	**151.6**	**137.9**	**130.5**	**181.0**	**240.0**	**317.3**	**541.5**	**329.5**	**371.6**	**337.9**	**2868.7**
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

February performance

The balancing costs for February were around £338m, which is a decrease of nearly £34m from the previous month and remains in the 'below the expectations' range.

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

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

Tight system margins leading to scarcity pricing, combined with high gas prices were the key factors responsible for continued high prices compared to last year for Operating Reserve, Fast Reserve, Response and Reactive, resulting in significantly higher non-constraint costs.

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): February 2022 vs January 2022

		(a) Jan-22	(b) Feb-22	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Non-Constraint Costs	Energy Imbalance	13.0	16.3	3.3	
	Operating Reserve	90.4	36.1	(54.3)	
	STOR	11.1	3.7	(7.4)	
	Negative Reserve	0.6	0.2	(0.3)	
	Fast Reserve	18.9	18.0	(0.8)	
	Response	23.5	29.7	6.2	
	Other Reserve	2.2	1.9	(0.3)	
	Reactive	28.3	22.6	(5.8)	
	Restoration	8.3	2.6	(5.7)	
	Minor Components	6.7	11.5	4.8	
Constraint Costs	Constraints - E&W	17.4	21.9	4.5	
	Constraints - Cheviot	13.1	21.1	8.0	
	Constraints - Scotland	77.7	88.5	10.8	
	Constraints - Ancillary	1.2	1.1	(0.1)	
	ROCOF	6.6	17.9	11.3	
	Constraints Sterilised HR	52.7	44.9	(7.8)	
Totals	Non-Constraint Costs - TOTAL	203.0	142.6	(60.4)	
	Constraint Costs - TOTAL	168.7	195.2	26.6	
	Total Balancing Costs	**371.6**	**337.9**	**(33.8)**	

As shown in the Total rows above, Non-Constraint costs are the key contributor to the costs decrease from the previous month, showing a decrease of over £60m, whilst Constraint Costs increased by nearly £27m.

Against the Constraint category, the breakdown shows that Constraint-Scotland, Constraint-Cheviot and RoCoF were the categories with the largest increase from January, whilst a decrease was recorded in the Constraint Sterilized HR spend.

Within the Non-Constraint costs, a significant decrease from the previous month was seen in the Operating Reserve category. A cost reduction was also seen across the following categories: STOR, Reactive, Restoration, and Reserve. Response was the only category that increased from January.

- **Constraint – Scotland: £10.8m increase.** Throughout the month constraint actions were needed due to the prevailing windy weather. Particularly over the last part of the month, when a series of significantly windy days required large volume of BM actions to reduce generation to manage thermal constraints. Between Sunday 20th and the month end, there were five days when the daily spend for this category was around or above £7m, with Wednesday 23rd showing the highest outturn with a spend of nearly £8m.

- **Constraint – Cheviot: £8m increase.** The cost increase was driven by an increase in the volume of BM actions to manage power flow restrictions on the Scotland-England network boundary to solve thermal constraints. The most expensive day for this category in February was Sunday 20th with a daily spend of nearly £6m.

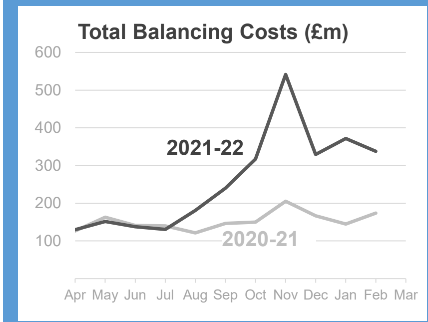
- **RoCoF: £11.3m increase.** February weather has been significantly windy, with a metered wind output of over 7TWh, which is over 1.6TWh higher than January. This led to lower inertia levels and therefore higher volumes of BM actions required to secure the system against the RoCoF risk. The spend has been mitigated through the application of the Frequency Risk and Control Report.

- **Response: £6.2m increase.** On a more volatile system with high wind, more response actions were required at a higher cost.

- **Operating Reserve: £54.3m decrease.** The February spend for this category wasn't exposed to the same type of volatile price structure we saw in January, when some of the highest daily costs on record were incurred. This was driven by healthy margins requiring less intervention to maintain reserve requirements.

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.



Overall, balancing costs were lower in February than January, primarily driven by reduced non-constraint costs associated with Operating reserve, with this somewhat offset by higher constraint costs, However, they are still significantly higher this year than for the same period last year.

Constraint Costs

Compared with the same month of the previous year:

Constraint costs were £94m higher than in February 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 £26.6m higher than January due to:

- Lower boundary availability which required a higher volume of BM actions to constrain off generation and replace energy and headroom elsewhere

Non-Constraint Costs

Compared with the same month last year:

Non-constraint costs were £70m higher this year than in February 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 February 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).

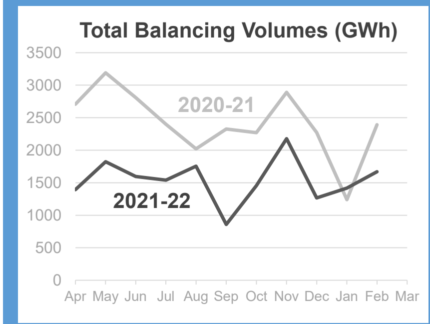
Compared with the previous month:

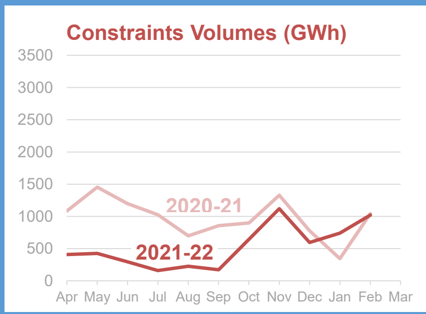
Non-Constraint costs were £60.4m lower than January 2021 due to:

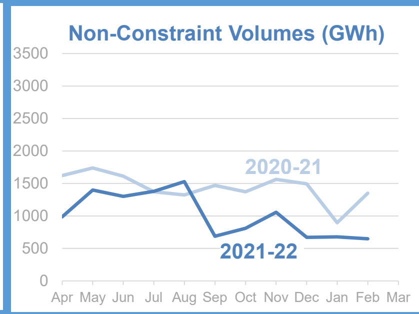
- Operating Reserve decrease in cost of over £54m from January when some of the highest daily costs on record were incurred for this category due to high BM prices being submitted by units which were required to maintain reserve levels.

- STOR, Reactive and Restoration decrease in cost is mainly due to a lower volume of Non-Constraint actions required which will be partly driven by February being a shorter month by 3 days.

Volumes







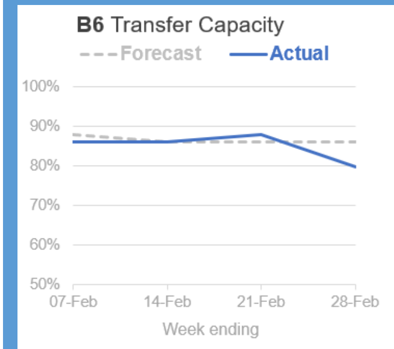
February 2022 constraint volume was in line with the volume recorded over the same period last year and slightly increased from January due to high wind levels.

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

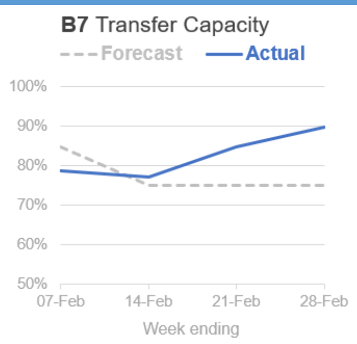
Compared with FY 2020-21, this year has been a year of consistently lower volume of action for non-constraints, with July and August the only outliers.

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.

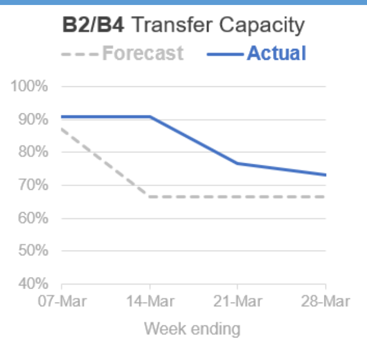
Network availability



B6: SP Transmission to NGET



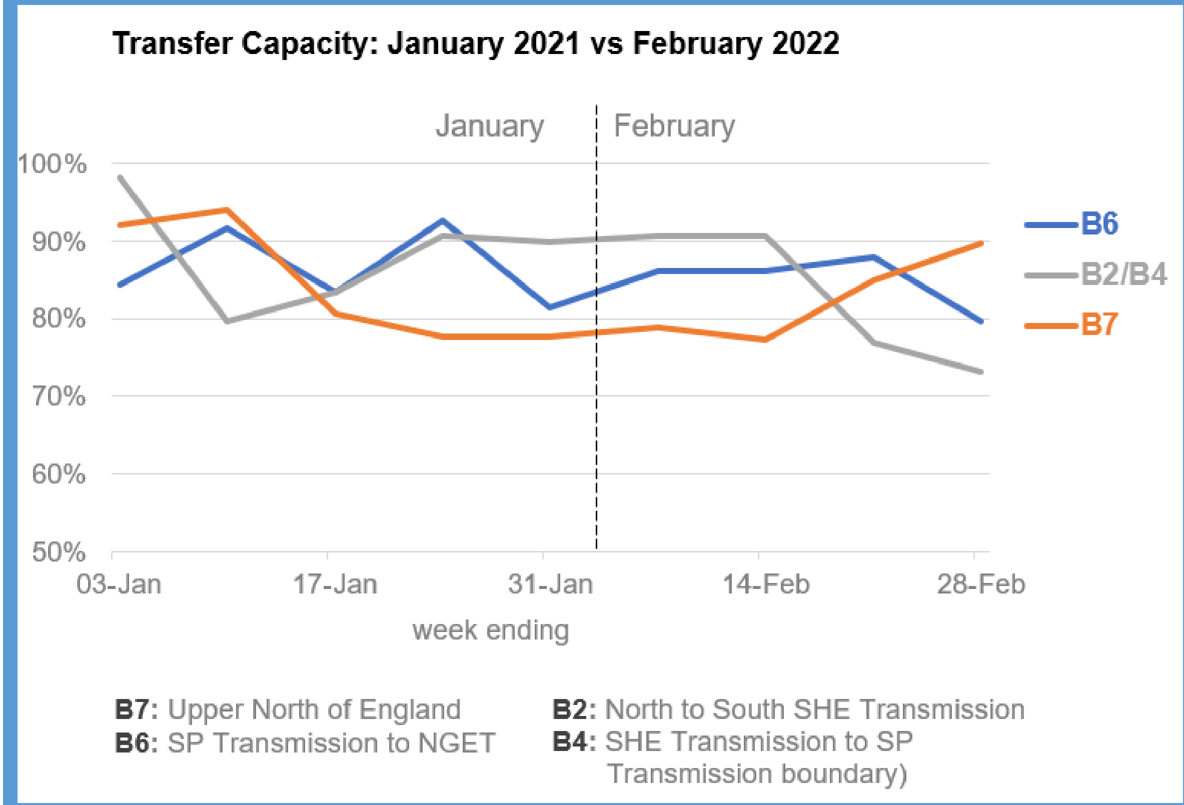
B7: Upper North of England



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

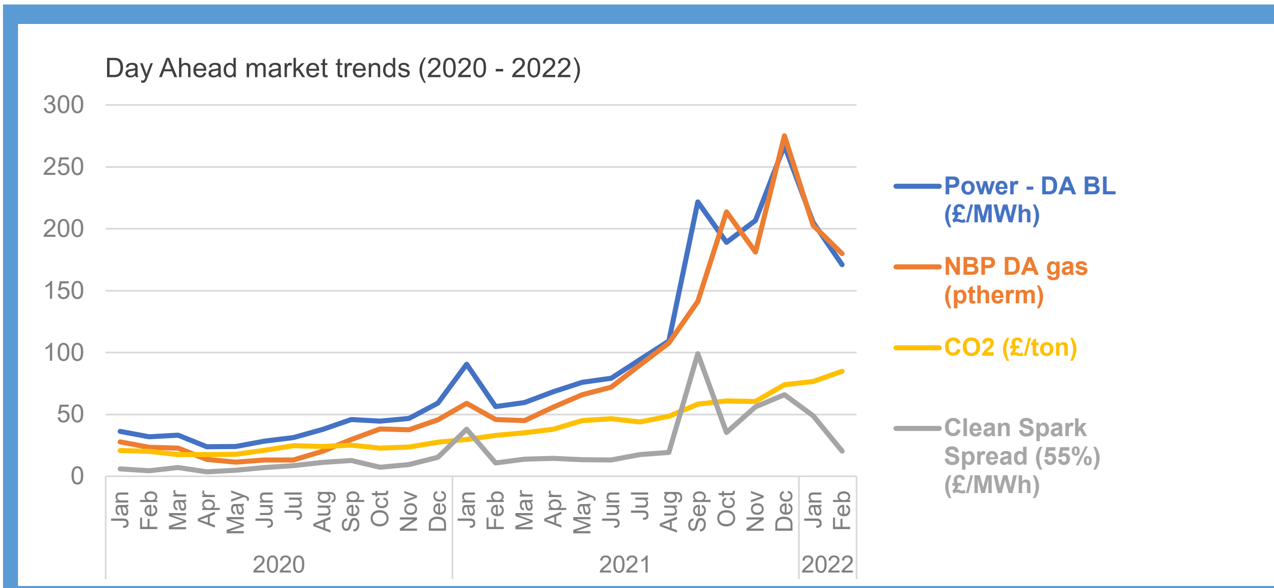
Boundary capacity has been above forecast for the majority of the month. The reduced boundary capacity from 100% combined with windy conditions led to the need for a large volume of BM actions to manage constraints.

The B7 boundary was significantly above forecast towards the latter part of the month due to outage optimisation, network reconfiguration and within control room optimisations. This mitigated the cost risk for this congested and often high spend boundary.



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

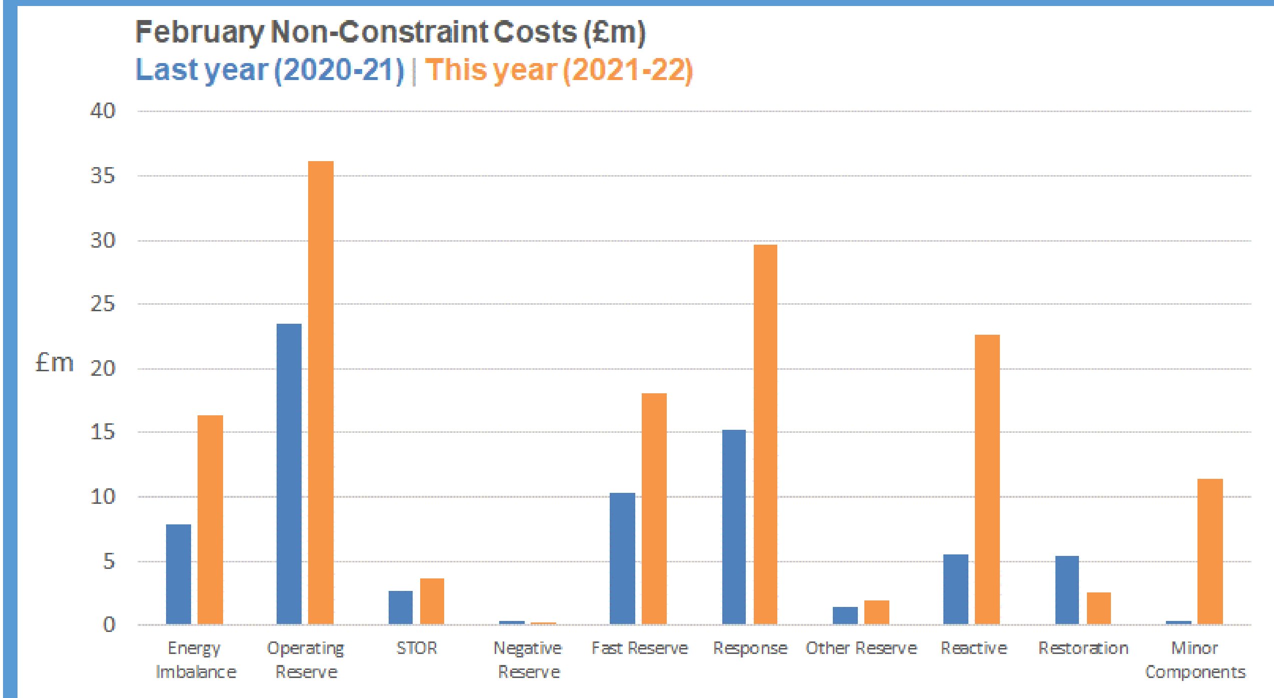


DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Power day ahead prices have fallen again in February but still remain significantly above previous year levels. The day ahead gas prices have followed a similar trend and also remain very high in comparison with the earlier parts of the year and the previous year. Carbon prices continue the upward trend seen throughout 2021 and 2022 so far.

These continued higher prices impact on both the buy (offer) and sell (id) actions available to the ESO to manage our operability requirements. This demonstrate some of the external drivers of the underlying high prices available to ESO for balancing actions.

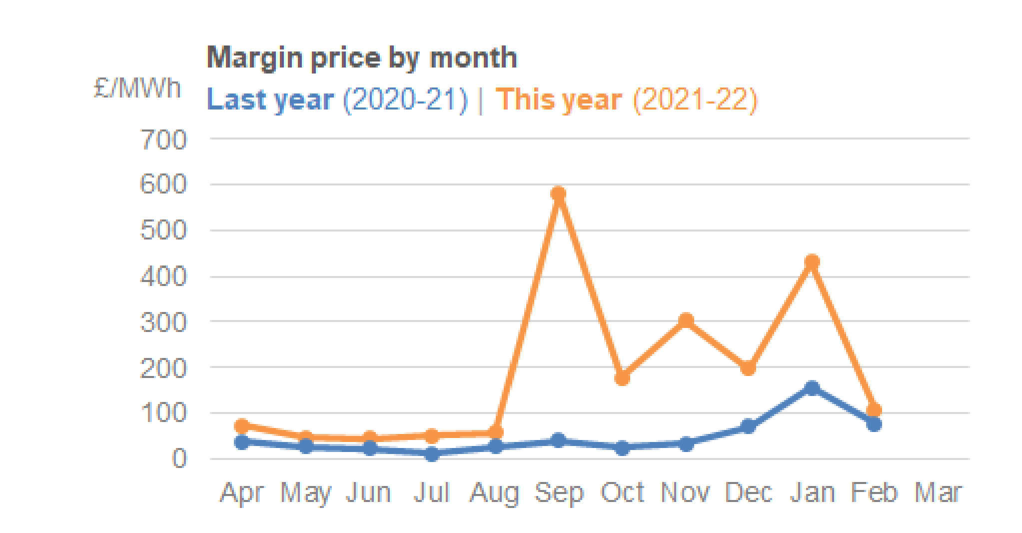
Cost trends vs seasonal norms



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

- **Operating Reserve** costs are £12.7m higher. This is mainly due to the high cost of BM actions. 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.
- **Reactive** costs are £17m higher. 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 are £14.4m higher. 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.
- **Fast Reserve** costs are £7.8m higher than the previous year which is due to the increased cost of actions taken and therefore related to the continued high wholesale market prices.

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for a single MWh) have decreased since January 2022 and are more in line with the price recorded in February last year. This is reflective of the reduction in Operating Reserve costs and indicates that the overall cost of actions taken has decreased. This is driven by overall healthier margins relieving the effect of scarcity pricing that was more pronounced in previous months.

Daily costs trends

There were several high cost days during February 2021 where expensive actions were needed to ensure all operability requirements were met. The monthly balancing cost outturned at £338m which is a decrease of £34m from the previous month.

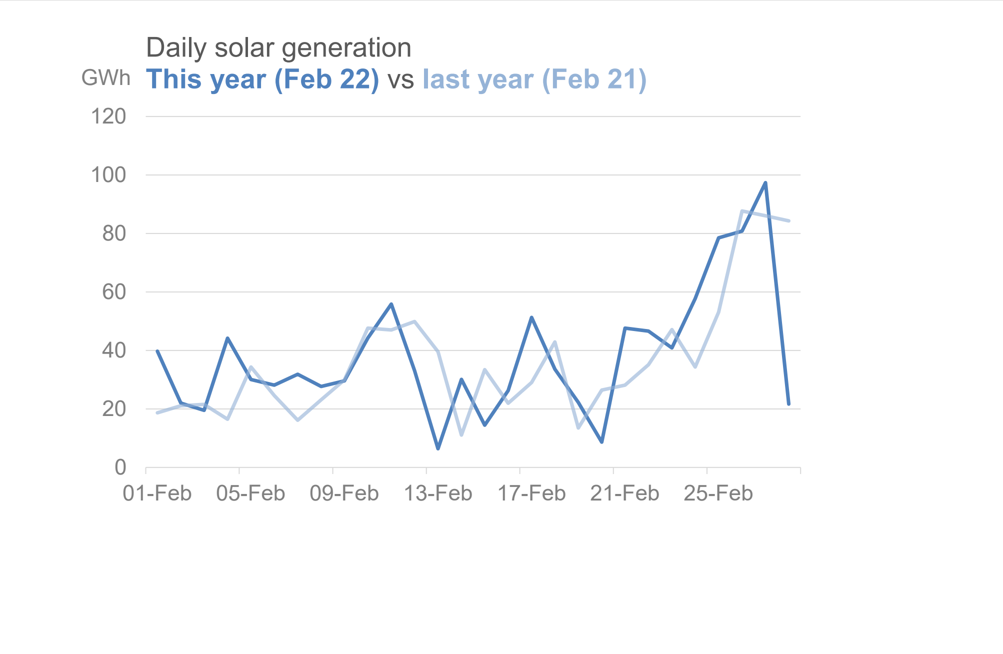
In February there were 16 days on which the daily spend passed £10m, of which eight days recorded a daily outturn around or above £15m. Among these days Sunday 20th, Wednesday 23rd and Thursday 24th recorded a daily spend of £25.5m, £22.7m and £20m respectively. Windy weather requiring a large volume of BM actions to reduce generation to manage thermal constraints was the main driver behind these expensive days. When a bid is taken to resolve a constraint, the energy on the system must then be replaced. When a large volume of BM bids are required to manage the flow on a boundary to below the constraint limit, that volume of energy needs to be procured in the BM to rebalance. The cost of the replacement energy is significantly higher than in previous years due to the ongoing high wholesale market prices.

High cost days and balancing cost trends are discussed every week at the Operational Transparency Forum to give ongoing visibility of the operability challenges and the associated Electricity National Control Centre (ENCC) actions.

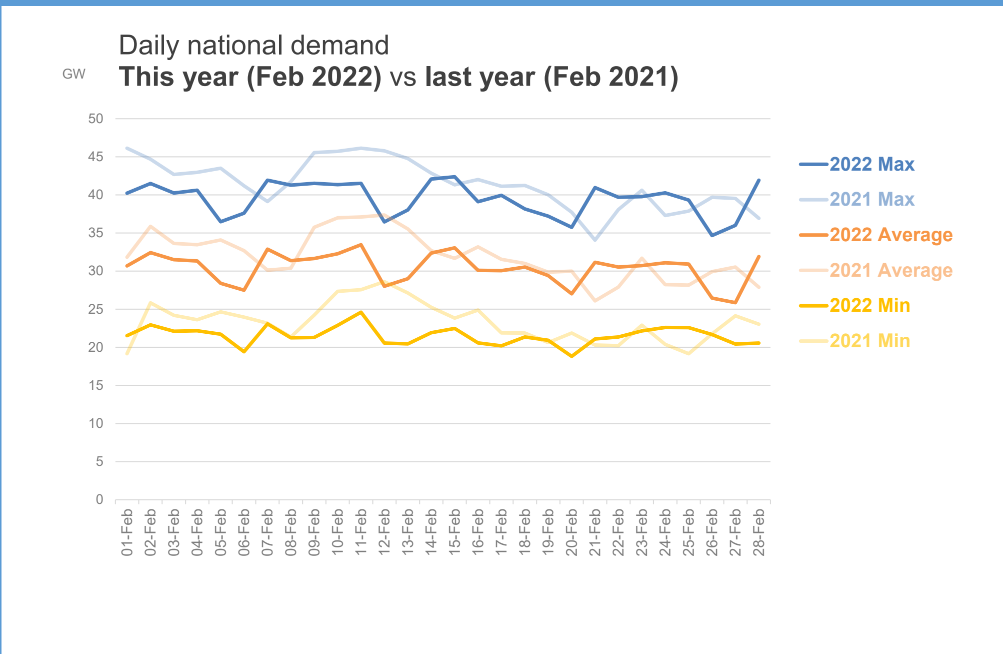
Significant events

There were no significant events during February.

Solar generation - comparison against last year



Outturn Demand vs 2020-21



Metric 1B Demand forecasting accuracy

February 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)

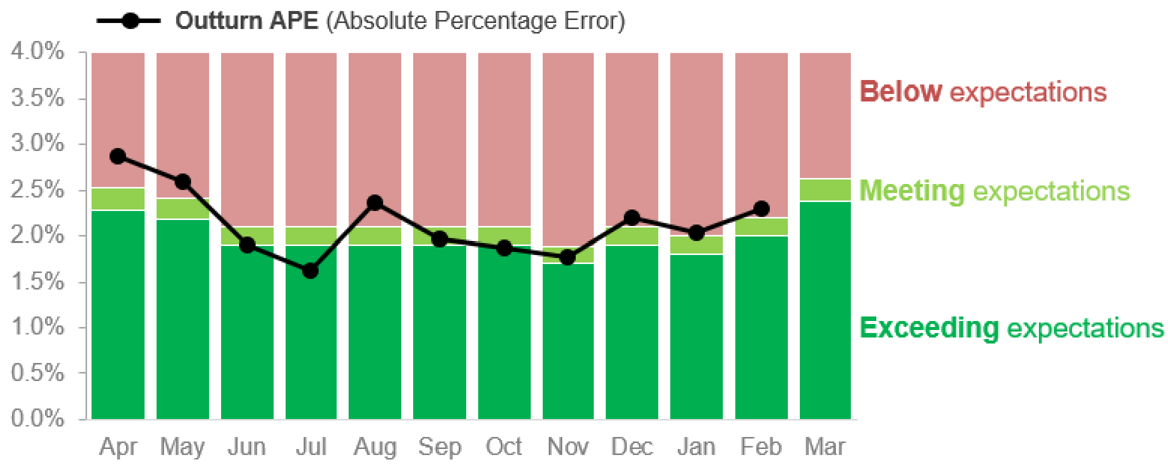


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

	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**	**1.8**	**2.2**	**2.0**	**2.3**		
Status	●	●	●	●	●	●	●	●	●	●	●		

Performance benchmarks

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

Supporting information

For **February 2022**, our MAPE (mean absolute percentage error) was 2.3% compared to the benchmark of 2.1%, and therefore below expectations.

The bigger errors mostly occurred in the second half of February which coincided with the school holiday period. This year, contrary to recent years, the spring half term was not centred in one week, i.e. the school holiday week off was not common across local authorities. Some had half term in the third week of February while others had it in the fourth week of the month. School holidays impact behaviour of people which then translates itself into electricity demand shape and level. The fact that the school holiday was stretched over two weeks rather than one resulted in a limited pool of historical dates with the same half term pattern in February to draw from. This challenged the demand forecast accuracy.

Additionally, we experienced sizable solar power forecast errors. The national demand forecast for this metric is published daily before 10 am for all the settlement periods on the following day. Solar generation is inherently difficult to forecast accurately even at this lead time. It is even harder to get it right during months when prevailing weather conditions are highly changeable and volatile.

Storm Dudley and storm Eunice further increased the uncertainty on demand forecasting performance on 16 and 18 February respectively.

To identify the settlement periods that ESO performed the best in February, monthly average performance errors by settlement periods were calculated. Within this frame, there were 17 settlement periods for which the day ahead MAPE was better than the target of 2.1%.

The table below focusses on the data from the big error perspective and has been presented on a monthly basis.

Error greater than	Number of SPs	% out of the SPs in the month (1344)
1000 MW	300	22%
1500 MW	138	10%
2000 MW	62	5%
2500 MW	19	1%
3000 MW	4	0.3%

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

In February 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 has 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

February 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)

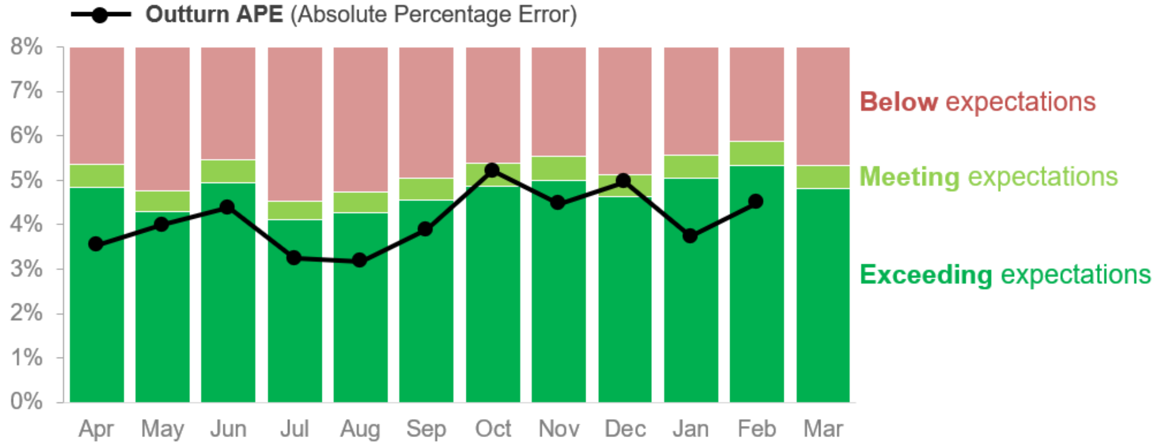


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)

	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**	**4.5**		
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

Supporting information

For **February 2022**, our MAPE (mean absolute percentage error) was 4.5% compared to the benchmark of 5.6% and therefore exceeded expectations.

The beginning of February was dominated by the UK being on the boundary between high pressure systems to the south and low pressure systems to the north. This led to consistently high wind speeds which are easier to forecast.
In the evening on 9 February, an area of low pressure moved across the north of Scotland, the timing and trajectory of which can be difficult to forecast and led to increased errors. This was followed by an area of high pressure which slowly moved to cover the UK which brings calmer weather making it easier to forecast. Once again this is followed by another area of low pressure across the North Atlantic on 11 February bringing windier conditions as it pushes against the high pressure system to the south.
Throughout the month the jet stream was mostly pointed in the direction of the UK, meaning that many storms were pushed in our direction and were significantly stronger. There were three major storms in February, storm Dudley on 16 February, storm Eunice on 18 February and storm Franklin on 20- 21 February. These storms caused some issues with forecasting as both timing of the storms, as well as cut out when wind speeds are very high (>55mph), can result in significant wind forecasting errors. Storm Dudley also brought in some significant lightning which can be indicative of atmospheric turbulence which can make forecasting wind speeds and by extension wind power harder.
Another low pressure system crossed the north of Scotland on 24 February bringing more difficult to forecast conditions once again. This was followed by another area of high pressure to the south which stabilised the high winds as it pushed up against the lower pressure systems to the north. Towards the end of the month, we had another area of low pressure in the North Atlantic which as it moved away, was replaced by an area of higher pressure which often is difficult to forecast the timing of.

Wind farms with CFD contractual arrangements switch off for commercial reasons while prices are negative for 6 hours or more. In February there were no occasions when the electricity price went negative for 6 hours or more. The electricity price used for this analysis is the Intermittent Market Reference Price. Market Price Data for February can be downloaded from here.
https://www.emrsettlement.co.uk/settlement-data/settlement-data-roles/

In February 2022 there were no instances of missed or late publication of 1C metric data.

Metric 1D Short Notice Changes to Planned Outages

February 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

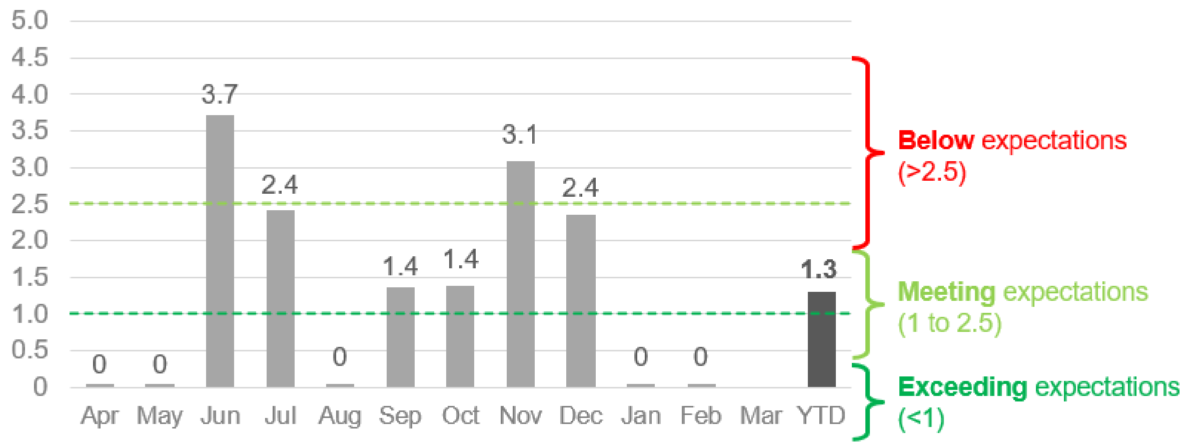


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	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	543		7655
Outages delayed/cancelled	0	0	3	2	0	1	1	2	1	0	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	0		1.3

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 February, the ESO has successfully released 543 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 February 2021 was 625 and has decreased in February 2022 to 543, 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 7655 compared with 7649 the previous year. Overall, the ESO is continuing to liaise with the TOs and DNOs to effectively facilitate system access through weekly or monthly liaison meetings to maximize system access.

RRE 1E Transparency of operational decision making

February 2021-22 Performance

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

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

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

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

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

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

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

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
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%	98.3%
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%	100%
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)	**0.0%** (27)

Supporting information

This month 98.3% of actions were taken in merit order or taken out of merit order due to an electrical parameter. For the remaining actions, where possible, we allocate actions to reason groups for the purposes of our analysis. During February 2022, we sent 55,417 BOAs (Bid Offer Acceptances) and of these, only 27 remain with no category or reason group identified, 0.05%.

RRE 1G Carbon intensity of ESO actions

February 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	10.6	

Supporting information

In February 2022, the average carbon intensity of balancing actions was 10.6 gCO2/kWh, for comparison, January 2022 had an average carbon intensity of 6.4 gCO2/kWh. The time with the largest decrease in carbon intensity due to the ESO's actions was 00:00 am on 14 February 2022 with a minimum of –53.3 gCO2/kWh. This was lower than January 2022's minimum value of -36 gCO2/kWh. In February, the time with the highest carbon intensity was 04:30am on 23 February 2022 with a value of 81.4 gCO2/kWh. February 2022 average is the highest so far this incentive year.

RRE 1I Security of Supply

February 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	0	
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	0	0	0	0	0	0	0	0	0	0	0	
Voltage Excursions defined as per Transmission Performance Report[2]	0	0	0	0	0	0	0	0	0	0	0	

Supporting information

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

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

RRE 1J CNI Outages

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

Supporting information

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

Notable events during February

Domestic Flexibility Trial

We're working with Octopus Energy to launch a pioneering real-time project to determine if flexibility in household electricity can help better match supply and demand on the electricity grid this winter.

Announced on Tuesday 8 February, the domestic flexibility trial will be running from 11 February to 31 March. This trial will assess the roles households can play during period of low margins and has been made available to Octopus Energy's 1.4mn smart meter customers. The ESO will nominate events at the day ahead stage and Octopus Energy have incentivised their customers who take part to get paid if they decrease their power consumption below their usual levels for pre-defined two-hour windows across several key periods during this winter.

We have had one event on 24 February with demand reduction volumes of up to 30MWs with 35,000 customers participating.

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

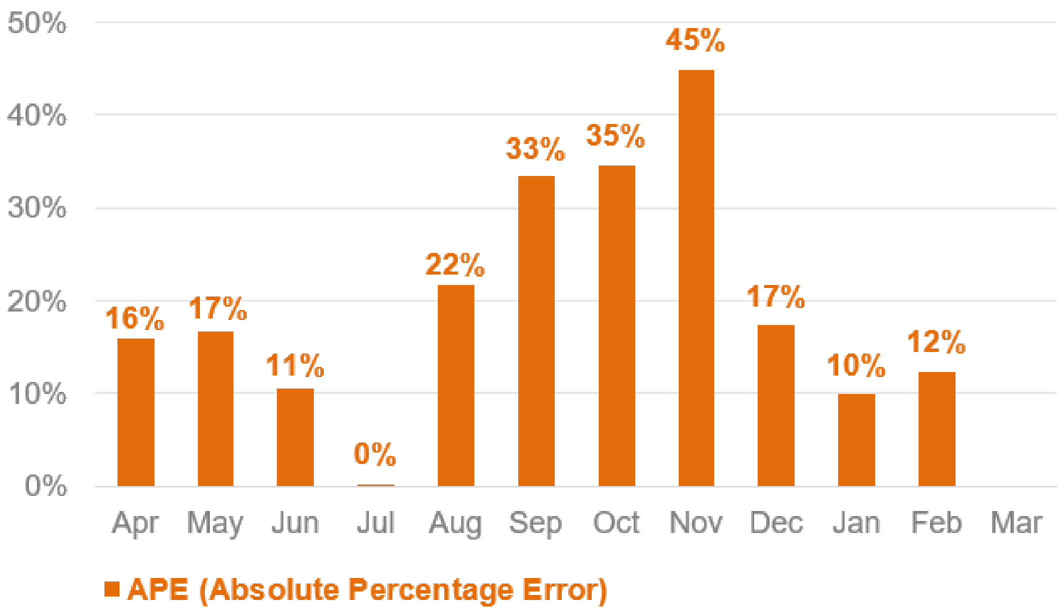
February 2021-22 Performance

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[3]

	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	9.0[4]	
Month-ahead forecast	3.2	3.7	4.1	4.2	4.5	4.7	5.5	6.9	6.2	7.3	7.9	
APE (Absolute Percentage Error)[5]	**16%**	**17%**	**11%**	**0%**	**22%**	**33%**	**35%**	**45%**	**17%**	**10%**	**12%**	

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



Supporting information

Outturn BSUoS remained high for February 2022, similar in level to October 2021, December 2021 and January 2022 but lower than November 2021. Continued high Balancing Mechanism

[4] Figure updated due to process error on 25 March 2022

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

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 February 2022 was significantly better than previous months.

Notable events during February

Frequency Risk and Control Report for 2022-23 consultation

On Monday 21 February we issued a consultation on the Frequency Risk and Control Report (FRCR) for 2022. The FRCR process was introduced in 2021 and is aimed at engaging widely with industry on the right balance between operational spending and risk mitigation to allow the targeting of spend to mitigate 'good' (or more likely) risks in a more flexible way than would be possible with rigid rules. The 2021 version of the report introduced these mechanisms and made significant changes to the ESO's risk appraisal processes. We have noted that since its introduction, the volumes of interventions that have been required to take through trades, or Balancing Mechanism actions to curtail Rate of Change of Frequency risks, has decreased significantly compared with previous years. The 2022 version builds on this to consider simultaneous events. An assessment is made of the value of securing these and their likelihood. The conclusions as consulted on are that while significant numbers of events are covered incidentally due to other factors, it is poor value to spend further money solely to secure further simultaneous events. Views are invited as previously on whether the FRCR represents appropriate development in determining the way that we will balance cost and risk in maintaining security of supply while operating the system. Responses were requested by 04 March, and following a recommendation from the SQSS Panel, the FRCR will be submitted to Ofgem by 1 April for approval. We also hosted a webinar on 28 February to answer any questions relating to the FRCR and our consultation.

T-1 Capacity Auction publication

On Tuesday 15 February, National Grid ESO published the results of its T-1 Capacity Auction for delivery in 2022/23. A total 4,996MW was procured across 226 Capacity Market Units (CMUs) at a record high clearing price of £75/kW, meaning the total cost of the Capacity Auction of nearly £375 Million Existing Generating CMUs and Proven Demand Side Response (DSR) CMUs made up 65.17% of the Capacity entering the Auction, while New Build Generation made up the remainder. Gas units accounted for the majority of MW awarded at 3,385.25MW, with DSR second at 515.89MW, and coal third at 411.13MW.

T-4 Capacity Auction publication

On Wednesday 23 February, we published the results of the T-4 Capacity Auction for delivery in 2025-26. A total 42,364MW was procured across 574 Capacity Market Units (CMUs) at a clearing price of £30.59/kW, meaning the total cost of the Capacity Auction is nearly £1.3 Billion. Existing Generating CMUs and Proven Demand Side Response (DSR) CMUs made up 77% of the capacity entering the auction, of which 86.6% were awarded a Capacity Agreement, while New Build Generation CMUs, Refurbishing CMUs and Unproven DSR CMUs made up the remainder, of which 13.4% were awarded a Capacity Agreement.

Single Markets Platform go-live

The foundational release of the Single Markets Platform (SMP) went live into production on 10 February. This is a key milestone for a project that is a vital deliverable through RIIO-2 to support the ESO in becoming a better buyer of balancing services and part of a wider strategy to utilise digital ways of working to make it easier to do business with the ESO.

This first release supports the onboarding process for new and enduring frequency response products (Dynamic Moderation, Dynamic Regulation and Dynamic Containment) and represents the first step in the development of the platform that ultimately will ensure a seamless and consistent user experience to access ESO markets for a diverse range of current and future participants. From 10 February, new users can set up an account on SMP and start to commit their asset information to the system and create units for pre-qualification in these services. For existing Dynamic Containment users, we have also pro-actively moved the asset and unit data across to SMP as well as directly set up their accounts.

This is the first of many releases that will progressively deliver enhanced functionality, improved look and feel as well as application across more balancing services and ultimately interaction across the DSO / Flexibility markets.

Ancillary Services Reform - Response services

We are preparing IT system changes for the Balancing Mechanism (BM) and the Ancillary Services Dispatch Platform (ASDP), scheduled for deployment on 22-23 March. These are being delivered as part of Ancillary Services Reform (ASR), completing the suite alongside Dynamic Containment (DC):

- Dynamic Regulation (DR)
- Dynamic Moderation (DM)

Delivering these frequency response products forms part of our RIIO-2 commitments of enabling competition as well as helping us to react to a low inertia electricity system.

Service providers will be onboarded onto the EPEX platform and able to submit their data in readiness for the first DR auction. This is planned for 08 April. DM Go-live is from 21 April and the first DM auction is planned for 6 May.

Stability Market Design NIA project

The ESO Electricity Market Development Team hosted a second workshop on Stability Market Design NIA project with the wider industry on 08 February. It was a very engaging session and received positive feedback. The Stability Market Design innovation project will consider current GB stability arrangements and investigate an optimal and enduring market design for stability products. This could allow the ESO to start to develop a potential stability market and best optimise long- and short-term stability procurements.

Traditionally synchronous generation has provided stability requirements (inertia, short circuit level & dynamic voltage support) as a by-product. As more non-synchronous generation enters the system, the ESO needs alternative sources of stability. Stability pathfinders allow us to test procurement approaches for long-term stability requirements, but the ESO still relies on the dispatch of synchronous generation in the Balancing Mechanism to ensure stability. The development of a stability market could offer the ESO a route to access stability services through an open, transparent, and competitive market.

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 February

National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS) consultation

On Wednesday 17 February, we published a consultation on the proposed areas of evaluation for the review of the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS). The SQSS sets out the criteria and methodology for planning and operating the NETS, and the review is intended to consider how the standard should adapt to facilitate the net zero operation of the system. It proposes to cover topics relating to sections of the standard on the main interconnected transmission system, the offshore transmission system, generation and demand connection requirements, and operational standards. Additionally, the review proposes to consider governance procedures and the introduction of competitively appointed transmission owners. We intend to assess and implement quick wins between April 2022 and April 2023, while reviewing the remaining topics between April 2023 and March 2026. The consultation closed on 09 March.

Pennines Voltage Pathfinder

We ran a competitive pathfinder process to manage voltage for a 10 year period. As part of introducing greater competition onto the network, our second voltage pathfinder compared market-based solutions against transmission owner solutions.

On 07 February, we announced that Dogger Bank C and National Grid Electricity Transmission have been selected to deliver 700MVAr of reactive power capability between 2024 and 2034. This is necessary for keeping voltage stable and is the first time such reactive power capability will be provided by an Offshore generator. The competition process was introduced to ensure that the most cost-effective services were selected, while maintaining our commitment to manage voltage within strict guidelines.

B6 Constraint Management Pathfinder (CMP)

The B6 Constraint Management Pathfinder (CMP) launched its consultation on 07 February for its draft service specification, draft framework agreement, and draft standard contract terms. The Pathfinder aims to reduce network constraint costs on the Anglo-Scottish (B6) boundary. The consultation feedback deadline was 5pm on 25 February. The consultation precedes the CMP B6 tender process, for service delivery in 2024-25, currently being planned for later in the year.

Offshore Coordination

The ESO is developing a Holistic Network Design (HND) as part of the BEIS-led Offshore Transmission Network Review (OTNR) that is supporting delivery of the Government's 2030 offshore wind targets. The announcement of the ScotWind leasing round results on 17 January 2022 is a significant milestone on the UK's pathway to net zero. With OTNR project partners and key stakeholders, we have reviewed the outcome to understand how we should approach it in the HND. An update statement has been published on our website[6].

The Holistic Network Design (HND) methodology document was also published[7]. This document aims to provide an overview of our approach to how we will deliver the HND. The executive summary

[6] https://www.nationalgrideso.com/document/239686/download
[7] https://www.nationalgrideso.com/document/239466/download

provides an overview of the building blocks to deliver the HND; the full methodology document provides more detail on each of those blocks.

The first Developer Forum was held to communicate consistent messages to developers in scope for the Pathway to 2030 workstream.

On 10 February 2022 we published our commitments to improving our stakeholders' experience on the ESO website[8].

[8] https://www.nationalgrideso.com/document/239471/download