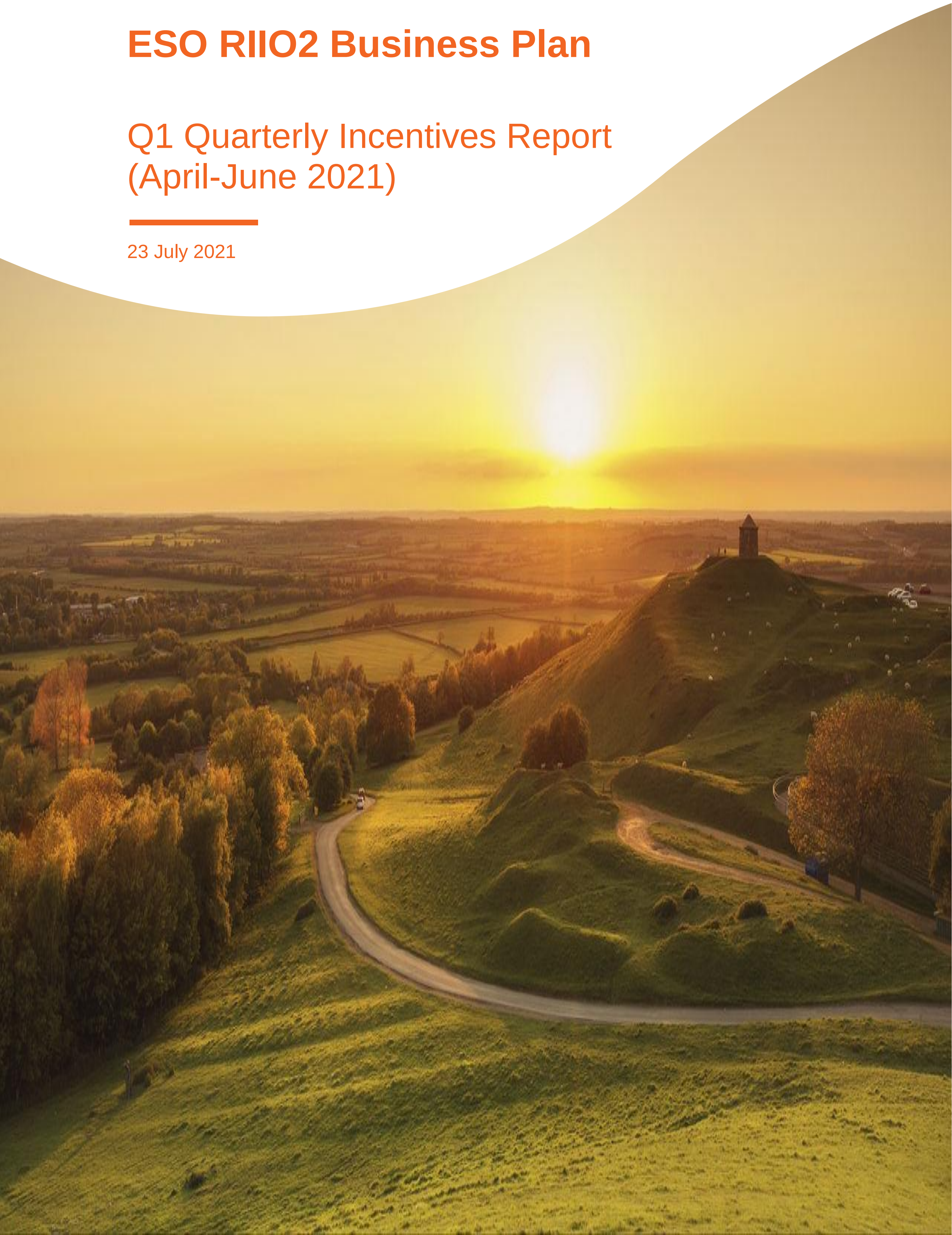
ESO RIIO2 Business Plan

Q1 Quarterly Incentives Report (April-June 2021)

23 July 2021



Contents

Introduction

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

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

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

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

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

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

Please see our website for more information.

Summary

In Q1 we have successfully delivered the following notable events and publications:

- Eight Electricity System Restoration Service contracts were awarded for the Northern regions in April.
- On 20 May we hosted a webinar and began focused engagement on Distributed ReStart procurement and compliance. From May to July we have held three desktop exercises to road test the organisational structures designed to deliver restoration from Distributed Energy Resources (DER).
- We held Reserve Reform co-creation workshops on two days in May, to help us come to a better proposal for the new reserve product suite.
- In May we published a report on our conclusions and key findings from the Power Potential commercial market trials that ran in January to March this year.
- We held our second Markets Forum on 22 June. We shared the latest updates from ESO Markets and feedback was sought on which topics to discuss with industry in future.
- In early June we hosted two technical workshops on the Dynamic Moderation and Dynamic Regulation services. We discussed the design of the services and sought feedback.
- The Code Administrator Annual report, which is a summary of last year's activity, was published in May. This was followed by a publication that provided details on the team deliverables for 2021-22.

- In April we launched our Distribution System Operation (DSO) consultation, introducing our proposed approach to supporting the transition to DSO, which will help us achieve a smarter energy system. We held a webinar on 6 May to allow stakeholders to hear from ESO colleagues around the ten coordinating functions we proposed in our consultation.
- We submitted our Early Competition Plan to Ofgem at the end of April and in May we held a webinar providing an overview.
- In Q1 we have been working closely with developers of in-flight offshore projects to understand costs, benefits, opportunities and blockers for greater coordination.
- In June we published our Winter Review and Consultation. This is an annual document which compares what we forecast in our Winter Outlook 2020-21 publication with what actually happened.
- We also published a report in June on increasing constraint costs and what we are doing to address this.
- In June we informed participants of the Stability Pathfinder Phase 2 that there has been an extension to the timeline. We have completed the Expression of Interest review and are now carrying out Feasibility Studies and Connection reviews.
- Our second annual GB voltage screening report was published in June. This provides an analysis on the transmission network and identifies potential regions with increasing voltage requirements.

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

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) performance for Q1 2021-22.

Table 1: Summary of Metrics

Monthly (M) and Quarterly (Q) Metrics

Metric		**Performance** (June figure for monthly Metrics & RREs, Q1 figure for quarterly Metrics & RREs)	**M / Q**	**Status** Apr	May	Jun	**Q1**
Metric 1A	**Balancing Costs**	In June, £132m vs benchmark of £91m	M	●	●	●	●
Metric 1B	**Demand Forecasting**	June forecasting error of 1.9% (vs benchmark of 2.0%)	M	●	●	●	●
Metric 1C	**Wind Generation Forecasting**	June forecasting error of 4.4% (vs benchmark of 5.2%)	M	●	●	●	●
Metric 1D	**Short Notice Changes to Planned Outages**	In June, 3.7 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	M	●	●	●	●
Metric 2A	**Competitive procurement**	In Q1, 57% of services procured by competitive means (vs Year 1 benchmark of 50-60%)	Q	n/a	n/a	n/a	●

Below expectations ● **Meeting expectations** ● **Exceeding expectations** ●

Table 2: Summary of RREs

RRE		Performance (June figure for monthly Metrics & RREs, Q1 figure for quarterly Metrics & RREs)	M / Q
RRE 1E	**Transparency of Operational Decision Making**	In June, 99.7% of actions have reason groups allocated	M
RRE 1F	**Zero Carbon Operability indicator**	In Q1, the system could accommodate a maximum 85% zero carbon transmission connected generation	Q
RRE 1G	**Carbon intensity of ESO actions**	In June, 4.5gCO2/kWh of actions taken by the ESO	M
RRE 1H	**Constraints cost savings from collaboration with TOs**	In Q1, £335m avoided costs	Q
RRE 1I	**Security of Supply**	In June, 0 instances where frequency was more than ±0.3Hz away from 50Hz, and 0 voltage excursions	M
RRE 1J	**CNI Outages**	0 outages in June	M
RRE 2B	**Diversity of service providers**	Varying diversity of providers across the different markets	Q
RRE 2E	**Accuracy of Forecasts for Charge Setting**	4% forecasting error in June	M

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

Q1 2021-22 Performance

This metric measures our balancing costs based on a benchmark that has been calculated using the previous three years' costs and outturn wind generation. It assumes that the historical relationship between wind generation and constraint costs continues, recognising that there is a strong correlation between the two factors. Secondly, it assumes that non-constraint costs remain at a calculated historical baseline level. A more detailed explanation follows:

At the beginning of the year the non-adjusted balancing cost benchmark is calculated using the methodology outlined below. The final benchmark for each month is based on actual outturn wind, but an indicative view is provided in advance based on historic outturn wind.

i. Using a plot of the historic monthly constraints costs (£m) against historic monthly outturn wind (TWh) from the 36 months immediately preceding the assessment year, a best fit straight-line continuous relationship is set to determine the monthly 'calculated benchmark constraints costs'.

ii. Using a plot of historic monthly total balancing costs (£m) against historic monthly constraint costs from the 36 months immediately preceding the assessment year, a best fit straight-line continuous relationship is set, with the intercept value of that straight line used to determine the monthly 'calculated benchmark non-constraints costs'.

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

iv. The historic 3-year average outturn wind for each calendar month is used as the input to the equation in point (iii). The output is 12 ex-ante, monthly non-adjusted balancing cost benchmark values. The sum of these monthly values is the initial 'non-adjusted annual balancing cost benchmark'. The purpose of this initial benchmark is illustrative as it will be adjusted each month throughout the year.

Total Balancing Costs *(£m)* = (Outturn Wind *(TWh)* x 12.16 *(£m/TWh)*) + 19.75 *(£m)* + 41.32 *(£m)*

A monthly ex-post adjustment of the balancing cost benchmark is made to account for the actual monthly outturn wind. This is done by following the process described in point (iv.) above but using the actual monthly outturn wind instead of the historic 3-year average outturn wind of the relevant calendar month. The annual balancing cost benchmark is then updated by replacing the historic value for the relevant month with this actual value.

ESO Operational Transparency Forum: The ESO hosts a weekly forum that provides additional transparency on operational actions taken in previous weeks. It also gives industry the opportunity to ask questions to our National Control panel. Details of how to sign up and recordings of previous meetings are available here.

Figure 1: Monthly balancing cost outturn versus benchmark

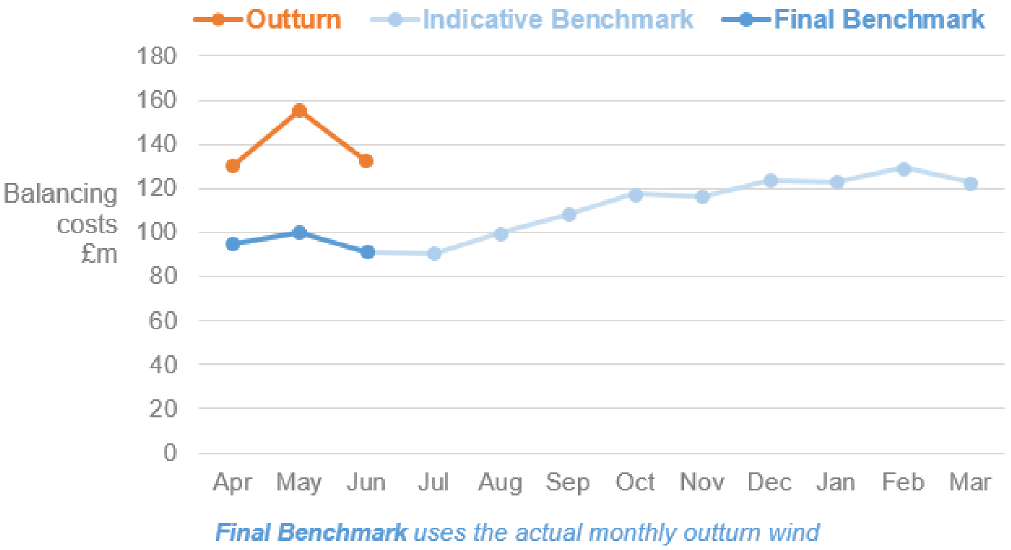


Table 3: Monthly balancing cost benchmark and outturn (Apr-Sep 2021)

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	YTD
Benchmark: non-constraint costs (A)	41.3	41.3	41.3	41.3	41.3	41.3	124.0
Indicative benchmark: constraint costs (B)	59.9	50.6	52.2	49.1	58.3	66.8	162.8
Indicative benchmark: total costs (C=A+B)	101.2	91.9	93.6	90.5	99.7	108.2	286.7
Outturn wind (TWh)	2.8	3.2	2.5				8.5
Ex-post benchmark: constraint costs (D)	53.5	58.9	49.91				162.3
Ex-post benchmark (A+D)	**94.8**	**100.3**	**91.2**				**286.3**
Outturn balancing costs	**130.4**	**155.0**	**132.5**				**417.9**
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

June performance

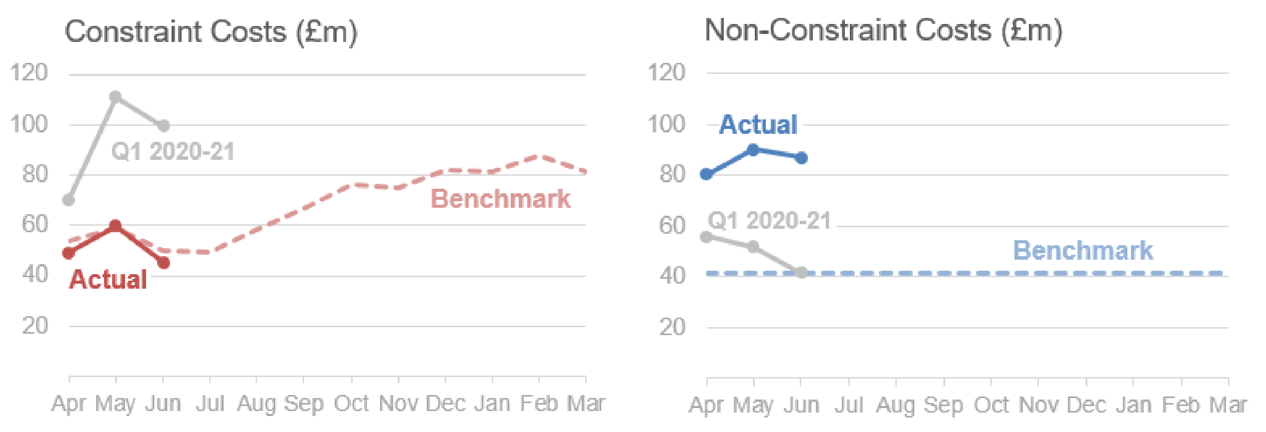
The balancing costs for June were lower than May, but outturned above the benchmark.

Most of this month's reduction is in constraint costs, which fell from £60m in May to £45m in June, due to significantly lower RoCoF costs, as outlined in detail below under 'Constraint Costs'. The reduction in RoCoF costs was partly offset by increases in both thermal constraint costs (as a result of network unavailability) and voltage costs (as a result of lower demands).

Q1 performance

Overall, Q1 balancing costs are lower this year than Q1 last year. Constraint costs have fallen as a result of several factors including changes to inertia management, lower wind, higher demand and good levels of network availability. However, energy costs have risen with higher BM (Balancing Mechanism) prices as a result of tighter margins and the procurement of new products to maintain operability and save costs overall.

Please note that the 2020-21 incentivised balancing cost figures did not include costs for restoration but from April 2021 these are included, so we have included the restoration costs here to facilitate a direct comparison.



Constraint Costs

Q1 constraint costs have fallen significantly compared to the same period last year due to a number of factors as mentioned above. Most significantly, RoCoF costs have fallen considerably as a result of changes in the way we manage inertia as described in the Frequency Risk and Control Report (FRCR). This is possible because of the reduction in RoCoF risk through the ALoMCP (Accelerated Loss of Mains Change Program) and the introduction of the Dynamic Containment service. The RoCoF costs for Q1 this year were approximately £48m lower than Q1 last year.

Similarly, June's constraint costs were significantly lower than May's, driven mainly by RoCoF costs falling by almost £33m (from ~£39m to ~£6m), again driven by the changes outlined above.

Non-Constraint Costs

Compared with the same period last year, Operating Reserve costs, Fast Reserve and Response costs were higher in Q1 this year, with overall non-constraint costs also making up a much larger proportion of overall spend. The average price of energy in the BM rose in the winter due to tighter margins and although prices have fallen, they are still significantly higher than last year.

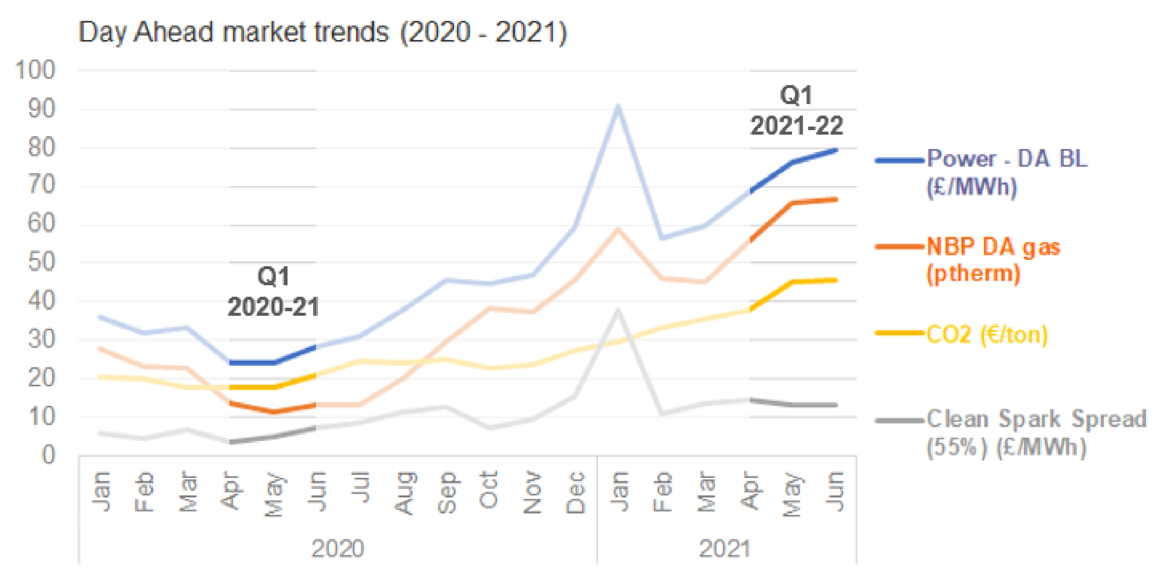
The other major change from last year is the introduction of Dynamic Containment which has contributed to rising Response costs but has led to savings elsewhere as the recommendations from the FRCR take effect.

Comparing to last month, June's £87m non-constraint costs are marginally lower than May (£90m). Falls in Energy Imbalance costs are broadly offset by increases in Response and Operating Reserve costs.

Network availability

Low wind levels coupled with good network availability through Q1 (see below) has resulted in lower thermal constraint costs than last year. However lower network availability in June this year did result in an increase in thermal costs from May, but low wind levels limited the potential impact on balancing costs.

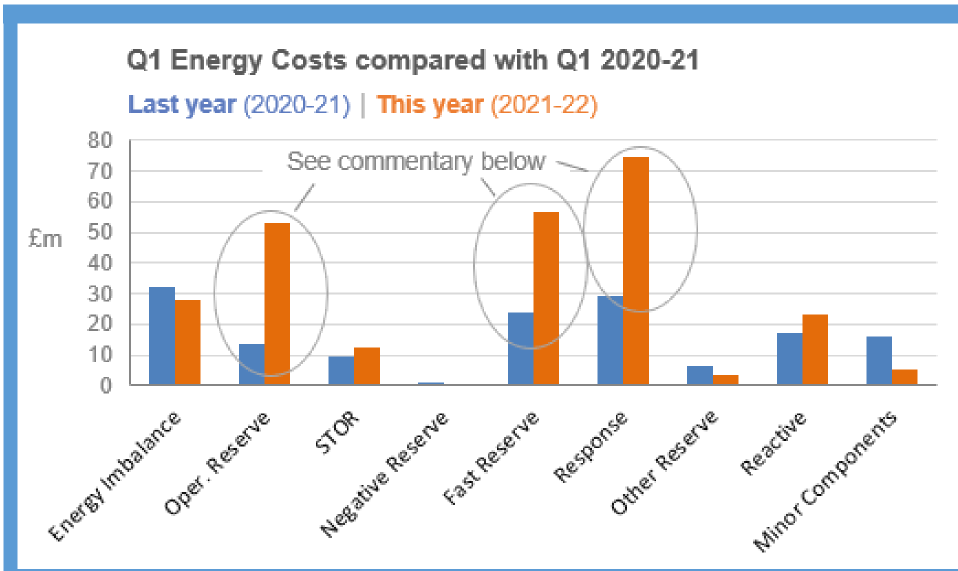
Changes in energy balancing costs



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

Power, Gas and Carbon prices continued to rise but at a slower rate than in previous months. Q1 prices were significantly higher than Q1 last year with Baseload Power roughly £50/MWh higher. Higher DA (Day Ahead) power prices can lead to a higher cost for the actions we take to balance the system due to the change in the market fundamentals particularly on the buy (offer) side.

Cost trends vs seasonal norms



Looking at this year's Q1 energy costs compared to Q1 last year:

- **Response** costs have increased with the introduction of Dynamic Containment as part of the changes in managing inertia. The changes here have allowed us to change how we manage RoCoF resulting in the changes to constraint costs.
- **Operating Reserve** and **Fast Reserve** have also increased as a result of tighter margins on the system driving Balancing Mechanism prices up, making the procurement of Reserve more expensive.

Drivers for unexpected cost increases/decreases

As a result of tighter margins on the system, BM prices have risen impacting on the cost of reserve.

Daily costs trends

The highest cost day in Q1 as a whole was 12 April. On that day significant demand uncertainty due to weather variability and relaxation of the government's COVID-19 restrictions, coupled with tight margins, triggered high price Balancing Mechanism actions being required to ensure sufficient generation was available to meet the demand and reserve requirement.

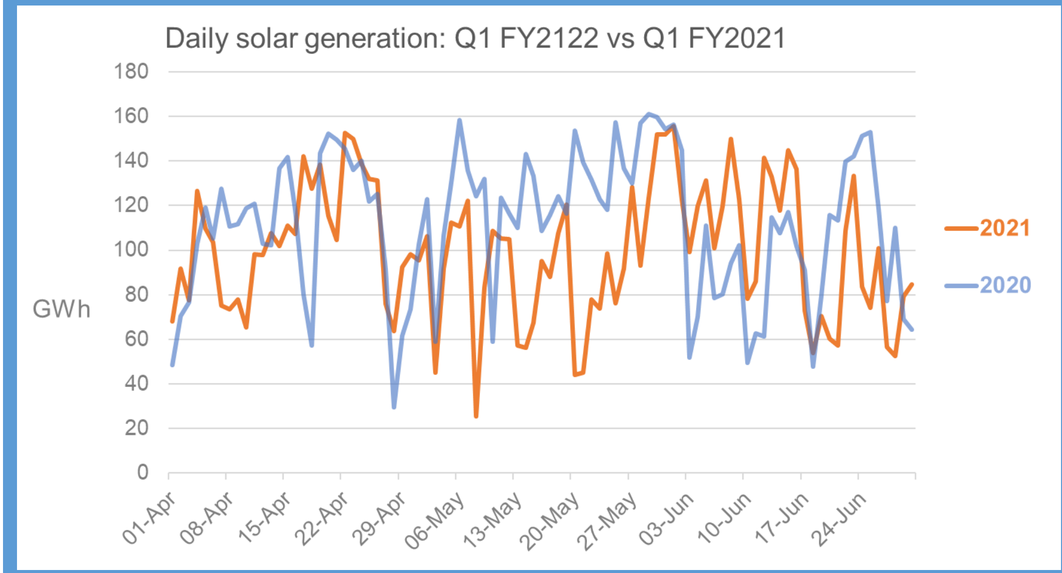
We covered the detail surrounding the decisions made on this challenging day extensively during the subsequent Operational Transparency Forum (21 April). A recording of the session can be found here.

In June, there were no significantly high cost days to note.

Significant events

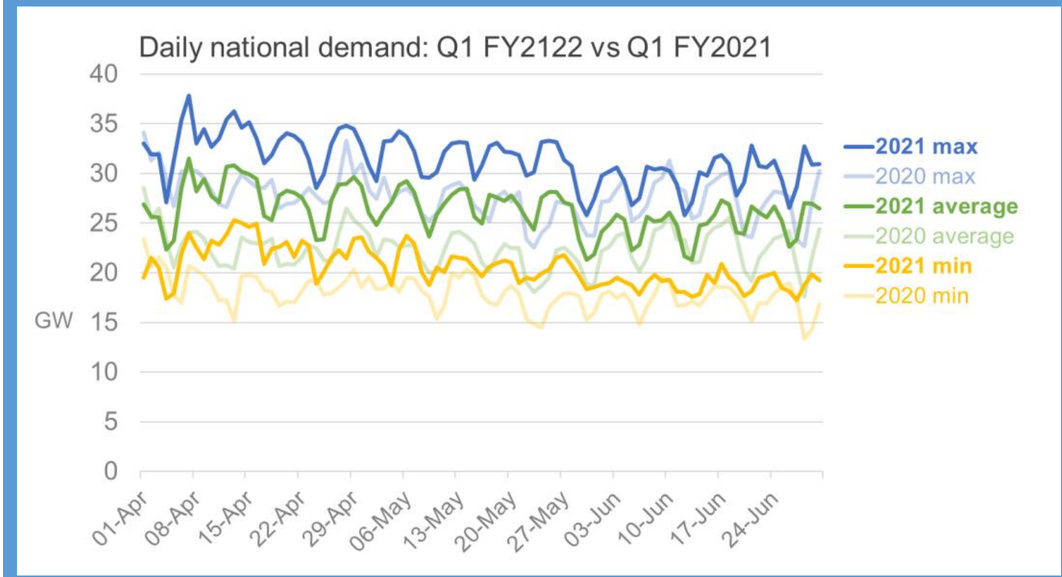
There were no major events in Q1 that had a significant impact on balancing costs.

Solar generation - comparison against last year (June 2021)



Overall, solar output has been slightly lower for Q1 this year compared to last year. But through the first half of June this year it was consistently higher, having been lower for almost all of May.

Outturn Demand vs 2020-21



Demand levels have been significantly higher over the course of Q1 this year with the easing of COVID-19 restrictions. The average daily demand this year has been around the level of the maximum daily demand last year. In Q1 last year we took steps to manage record breaking low demand conditions, which increased constraint costs. With higher demand in Q1 this year, similar actions were not required:

- ODFM: In Q1 last year we instructed Optional Downward Flexibility Management (ODFM) several times, resulting in an increase in constraint costs. The service has been re-introduced for 2021 in case of very low demands, but hasn't been required yet.
- Sizewell contract: In Q1 last year we negotiated a bilateral de-load contract with Sizewell power station. This increased constraint costs but led to savings in energy costs and was effective in keeping total costs lower than they otherwise would have been.

Metric 1B Demand forecasting accuracy

Q1 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)

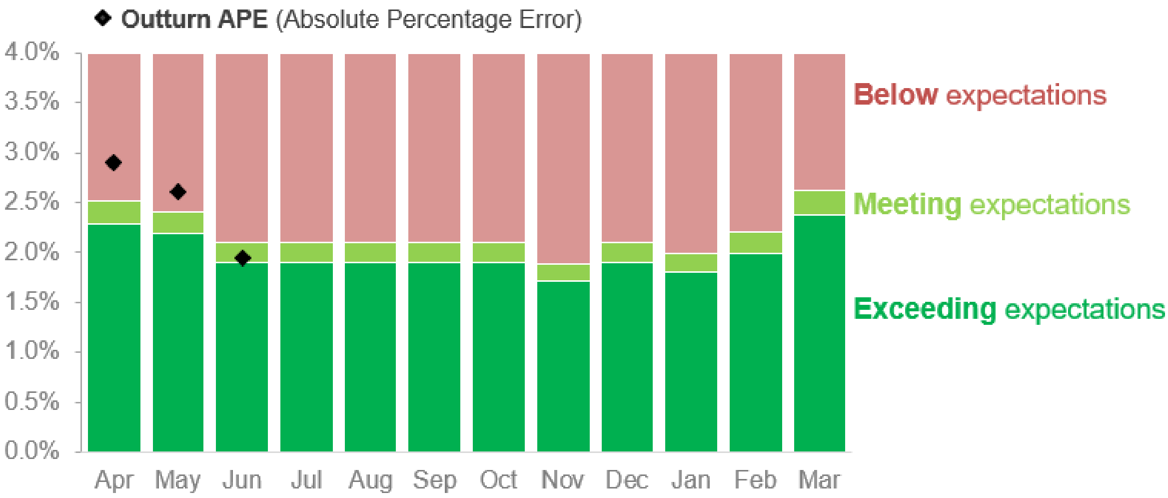


Table 4: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
Indicative benchmark (%)	2.4	2.3	2.0	2.0	2.0	2.0	2.0	1.8	2.0	1.9	2.1	2.5	**2.1**
APE (%)	**2.9**	**2.6**	**1.9**										
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 **June 2021**, our day ahead demand forecast indicative performance is within the 'meeting expectations' target with a MAPE (Mean Absolute Percentage Error) of 1.9%.

For **Q1 (April – June)** our overall performance did not meet the indicative benchmark, with April and May performance being below expectations.

Our new additional national demand forecasting (machine learning) model was released in Q1 and after being available to the forecasting team and control room users from the middle of May, we incorporated it into our processes from June. This has helped facilitate improved performance in June as detailed below:

- The model was developed between October 2020 and April 2021 and uses machine learning techniques. It has been in an operational mode on a development system since early May 2021 and has been showing encouraging results when compared with actual demand. What makes the model extremely valuable, especially during the pandemic is the ability to assess the relationship between demand and weather every 30 minutes with new data. The purpose of this feature is to allow flexibility to adjust for changes in 'regimes' of demand, for example in the event that the Prime Minister calls for a national lockdown. We've seen in the last year the difference in demand patterns during the pandemic, and the aim is for the model to help adjust for that.
- Going forward, with more data feeding into the forecast the model should improve. The numbers don't directly feed into the ESO's systems, but are used as advisory numbers which are taken into consideration by our energy forecasting team and control room. Once we become more familiar with the model's best features, that information can also inform a judgement of where to look at the machine learning forecast, and where to rely on other advice and expertise.

The most challenging days in June, when the daily MAPE was above 3%, were Tuesday 1 June, Saturday 19 June and Sunday 20 June. 1 June was the day after the Spring Bank Holiday and it's common that errors are higher on days either side of Bank Holidays as these days are less typical and therefore it's more difficult to find a similar historic day to use as a basis for forecasting. Over the weekend of 19-20 June, temperatures were cool for the time of year. There was a number of heavy outbursts of rain and demand was higher than forecasted. It can be difficult to forecast the exact timing of outbursts of rain even when they are expected on a certain day.

Performance in Q1 2021/22						
	April 2021: big errors		May 2021: big errors		June 2021: big errors	
Error greater than	No of SPs	% out of the SPs in the month	No of SPs	% out of the SPs in the month	No of SPs	% out of the SPs in the month
1000MW	254	18%	391	26%	192	13%
1500MW	130	9%	162	11%	59	4%
2000MW	61	4%	53	4%	8	1%
2500MW	40	3%	13	1%	2	0%
3000MW	32	2%	0	N/A	0	0

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

There were 0 occasions of missed or late publications.

Metric 1C Wind forecasting accuracy

Q1 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)

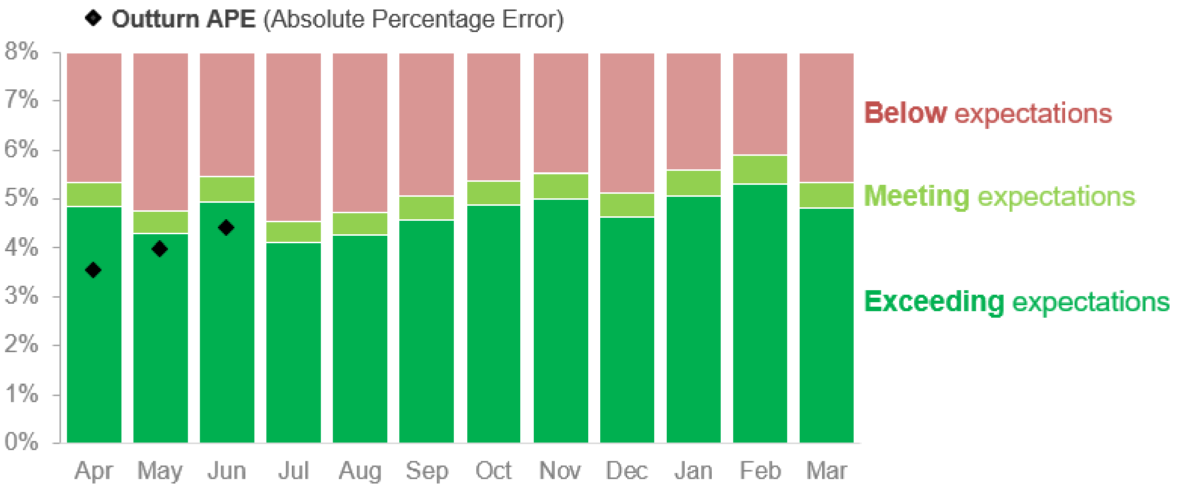


Table 5: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)

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

Performance benchmarks

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

Supporting information

In June 2021, our wind forecast indicative performance was within the ‘exceeding expectations’ target, with a MAPE (Mean Absolute Percentage Error) of 4.4% against a benchmark of 5.2%.

For Q1 (April – June) our overall performance is also within the ‘exceeding expectations’ target.

This performance is supported by the improvements delivered during 2020-21 as part of the Platform for Energy Forecasting (PEF) project. These changes mean that we can now produce forecasts, more frequently and at a higher level of detail. More detail of these developments can be found in the 2020-21 End of Year Report Evidence Chapters.

In Q1 we were also helped by the very stable weather conditions that we have seen during this period. Stable weather is more predictable and so our weather service provider has been able to provide us with very accurate weather forecasts during this time. This has allowed us to translate them into very accurate wind power forecasts.

The other factor to consider is the impact of COVID-19. Due to social distancing and other requirements to manage the pandemic, the rate of construction of new wind farms has been less than it otherwise would have been. New wind farms are a source of forecasting error, since the models have not been refined in light of metered data. With a greater proportion of mature wind farms a higher level of accuracy can be achieved.

Metric 1D Short Notice Changes to Planned Outages

Q1 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

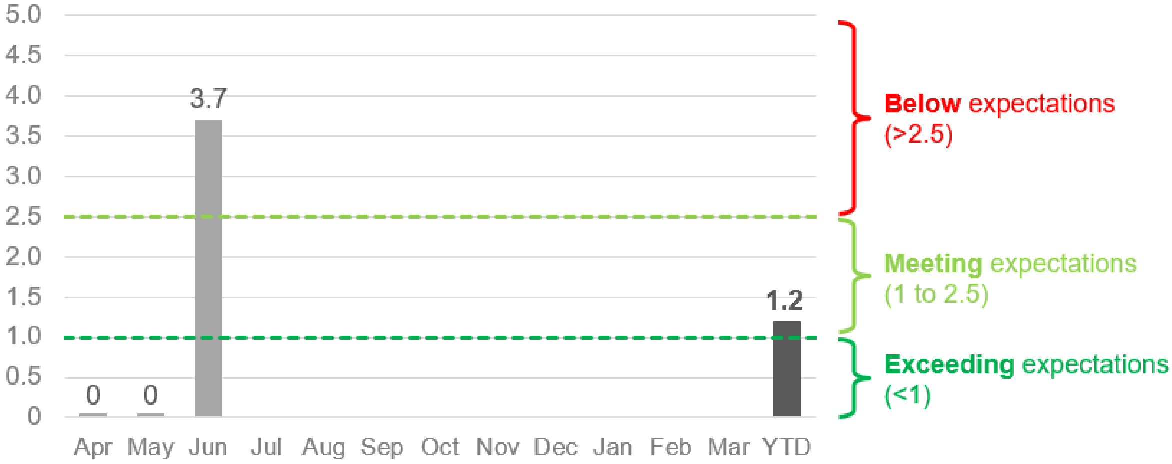


Table 6: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	845	856	810										2511
Outages delayed/cancelled	0	0	3										3
Number of outages delayed or cancelled per 1000 outages	0	0	3.7										1.2

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

June: Below expectations

For June, the ESO has successfully released 810 outages and there has been a total of 3 delays or cancellations due to an ESO process failure. This gives a score of 3.7 per 1000 outages which is within the ‘below expectations’ range of >2.5 per 1000 outages.

Q1 overall: Meets expectations

For Q1 (April to June) as a whole, the total delays or cancellations due to an ESO process failure is also 3 as there were 0 in both April and May. This gives a Q1 score of 1.2 per 1000 outages which is within the ‘Meets Expectations’ range of between 1 and 2.5 outages per 1000.

This is an improved performance compared to the same period last year (April to June 2020) when there were 2.12 cancellations or delays per 1000 outages (4 cancellations/delays out of 1885 outages).

Details of the 3 delays / cancellations due to an ESO process failure for June:

1. The first event was caused by a generator that was unaware of an outage which was going to impact them. We notified the generator within planning timescales but as no response was obtained, the outage was signed into plan rather than following up to seek agreement. An Operational Learning Note has been shared to ensure customer agreement is obtained before outages are agreed into the plan.

2. The second event was a planning error regarding a specific fault that would split a substation leading to an abnormal network configuration feeding DNO demand. We did not identify that the fault would split the substation nor the impact on DNO demand within planning timescales. Therefore, the DNO was notified of the outage but not the fact that it would be fed from an abnormal network configuration. The ESO control room contacted the DNO the night before the outage was due to start, who requested additional time to study the impact on their demand. As a result, the outage was delayed. An Operational Learning Note is being written to identify corrective measures for this outage.

3. The final event involved a large generation group being put at a single circuit risk due to the nature of the requirements of a TO substation upgrade project. Shortly before the outage was due to start, we identified that the automatic protection scheme would not operate as expected and the generation group could not be secured without special action that could not be obtained in control timescales. This was due to the TO’s automatic protection scheme not being designed to cater for two out of three circuits being on outage simultaneously during the final project stage. This meant the control room was unable to release the outage. The outage has now been re-planned to avoid this issue.

RRE 1E Transparency of operational decision making

Q1 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 7: Percentage of balancing actions taken outside of merit order in the BM

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	90.4%	88.4%	89.3%									
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.6%	99.6%	99.7%									
Percentage of actions with no category applied or reason group identified	**0.4%** (173)	**0.4%** (147)	**0.3%** (56)									

Supporting information

This month 89.3% 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. We were unable to allocate reason groups for 0.3% of the total actions this month.

During Q1 (April to June) as a whole, we sent more than 95,000 BOAs (Bid Offer Acceptances), of these only 376 remain with no category or reason group identified, an average of 0.4%

Throughout Q1, following the Dispatch Transparency data going live on our Data Portal, we have used our weekly Operational Operational Transparency Forum to discuss instances where actions have been taken out of pure economic order, and we have covered the methodology applied through the Dispatch Transparency tool in detail.

In Q2 we expect to be able to move from weekly to daily (D+1) publication of this dataset to provide additional insight and transparency at shorter timescales. We'll publicise the change in the Operational Transparency Forum, which takes place every Wednesday at 11am.

RRE 1F Zero Carbon Operability Indicator

Q1 2021-22 Performance

This Regularly Reported Evidence (RRE) provides transparency on progress against our zero-carbon operability ambition by measuring the proportion of zero carbon transmission connected generation that the system can accommodate.

For this RRE, each generation type is defined as whether it is zero carbon or not. Zero carbon generation includes hydropower, nuclear, solar, wind and pumped storage technologies. As this RRE relates to the ESO's ambition to be able to operate a zero carbon transmission system by 2025, only transmission connected generation is included and interconnectors are excluded (as EU generation is out of scope of our zero carbon operability ambition). Note that the generation mix measured by RRE 1F and RRE 1G differs.

The Zero Carbon Operability (ZCO) indicator is defined as:

$$ZCO(\%) = \frac{(Zero\ carbon\ transmission\ connected\ generation)}{(Total\ transmission\ connected\ generation)} \times 100$$

Part 1 – Defining the maximum ZCO limit for BP1

The ESO will define the approximate maximum ZCO limit (using a reasonable approximation of likely operating conditions), the system can accommodate at the start and end of BP1, explaining which deliverables are critical to increasing the limit.

Table 8: Forecast maximum ZCO% after our operational actions

BP1 2021-23	Maximum ZCO limit	Calculation and rationale
Start of BP1 (Q1 2021-22)	**80% - 85%**	The calculation of the maximum ZCO limit for the start of BP1 is based on the generation plant mix. We assume that the zero-carbon generation output is high, i.e. it is windy with significant contributions from nuclear, pumped storage and hydro, and then overlay system constraints. This overlay reduces the final ZCO as we remove zero carbon generation and add on carbon-producing generation such as CCGT or biomass to meet our response, inertia and voltage requirements. This range is compared with real-world system data to ensure consistency. For example, we are forecasting a maximum ZCO limit of between 80% to 85% and the April maximum ZCO figure is 84.6%.
End of BP1 (Q4 2022-23)	**85% - 90%**	The forecast of the maximum ZCO limit that the system can accommodate at the end of BP1 uses a very similar methodology. However, we factor in our forecast changes to the generation mix and significant operational developments. These developments are in line with our operational strategy and more detail is set out in our Operability Strategy Report. The most significant developments that impact ZCO will be improvements to our new response products, the stability pathfinders, stability market, the accelerated loss of mains change programme, the implementation of the Frequency Risk and Control methodology, the voltage pathfinders and reactive reform. All of these developments are increasing our ability to operate a zero carbon system by either increasing the operability envelope where secure system operation is possible, or by enabling new zero carbon providers of ancillary services.

Part 2 – Regular reporting on actual ZCO

Every quarter, the ESO will report the data on the ZCO provided by the market versus the ZCO following ESO actions. This is presented at a monthly granularity.

The table below is calculated according to the formula for ZCO for each settlement period for every day over the reporting period. ZCO is a percentage of the zero carbon transmission generation (hydropower, nuclear, solar, wind and pumped storage technologies) divided by the total transmission generation. Two figures are calculated: one represents the system conditions before ESO interventions are enacted, the other is after. This indicator measures progress against our zero carbon operability ambition by showing the proportion of zero carbon transmission generation that the system can accommodate. For each month, the settlement period that has the highest ZCO figure after our operational actions were enacted is displayed. The corresponding market ZCO figure is also included. It is worth noting that this market ZCO figure might not necessarily be the maximum ZCO that the market provided over the month. For example, the maximum ZCO provided by the market over Q1 was on the 20 May settlement period 46 and was 93.2%. The ZCO dropped to 79.2% after our operational actions were taken into account.

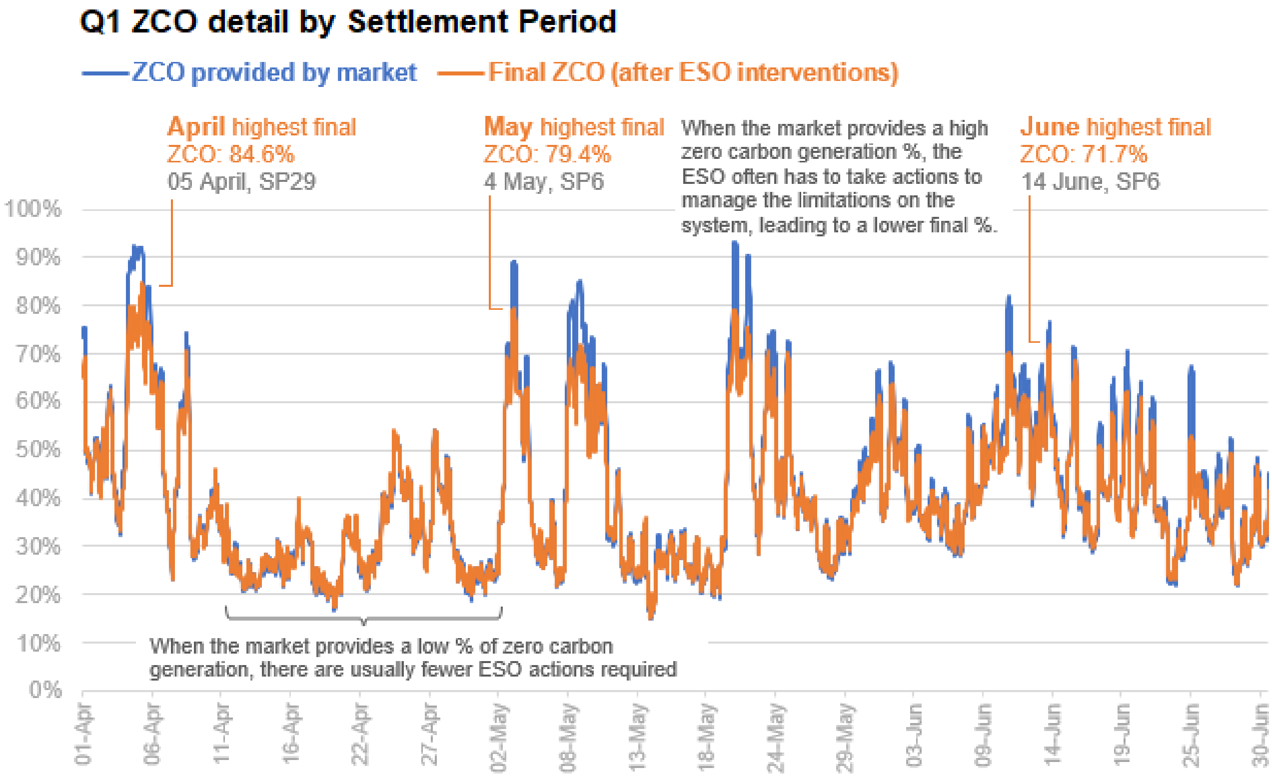
Figure 6 further below shows the underlying data by settlement period and highlights when the maximum monthly values occurred.

Table 9: Q1 maximum zero carbon generation percentage by month

Month	**Highest ZCO% in the month** (after ESO operational actions)	**ZCO% provided by the market** (during the same day & settlement period)	Date / Settlement Period
April	84.6%	91.5%	05 Apr / SP29
May	79.4%	89.2%	04 May / SP6
June	71.7%	75.1%	14 June / SP6

Figure 5: Maximum monthly ZCO% after ESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred)

Figure 6: Q1 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

The highest zero carbon percentage outturn in Q1, following ESO actions was 84.6%, which occurred on 05 April, Settlement Period (SP) 29. During that SP the market provided 91.5% ZCO, with actions taken by the ESO to manage the system reducing the final figure to 84.6%. This is broadly in line with our estimated maximum ZCO for Q1 of 80%-85%.

The start of April was cold but with high renewable output, which is why the ZCO figures post ESO actions were at their highest for the quarter. The maximum figures for May and June were lower than the maximum in April, because the demand (not shown on the graph above) was lower due to warmer weather. At times like those, when the demand is lower but the renewable output remains high, the ZCO after ESO actions is often lower. This is because we still have to take similar sets of actions (to manage operability constraints such as voltage) which represents a larger proportion of the overall amount of generation. The other point to note is how closely linked the ZCO figure is with wind output - the low wind spells during most of April and the start of May are clearly visible on the graph above where the ZCO% drops below 30%.

The maximum ZCO figures align with settlement periods of high renewable output, for example when it is windy. Usually (but not exclusively), these figures occur at times of low solar output. This is because the majority of solar generation is embedded and hence excluded from ZCO. Therefore, at times of high solar output operational actions will be still needed, even though the ZCO figure provided by the market will appear relatively low as it will not include the solar.

Going forward, the recent go live of the Deeside stability contract (see Role 3) and other upcoming Stability Pathfinder Phase 1 contracts are expected to facilitate a higher ZCO percentage in the future.

RRE 1G Carbon intensity of ESO actions

Q1 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 10: 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									

Supporting information

The month of June 2021 had an average difference of 4.54 gCO2/kWh between the carbon intensity of FPNs and BOAs. The maximum difference was 74.4 gCO2/kWh, the minimum difference of -12.3 gCO2/kWh. The average difference this month was 1.63 gCO2/kWh lower than last month, but the peak was 24 gCO2/kWh higher.

For most of the month, there wasn't much divergence between the carbon intensity plots of BOAs and FPNs. The peak difference occurred at 2:30 am on 25 June, but by 7:30 am on the same day the delta had returned to normal levels. For the past two months, the peak difference has occurred during a sustained period of separation between the two traces. The peak in June was driven by wind, not in MWh but instead in % share of the generation mix, picking up overnight but settling back down before the morning.

Managing wind pickup during low demand through the night can be difficult. Wind units have different characteristics from conventional plant, and they tend to be clustered in groups. To guarantee system stability and security, it could be a risk to have too much wind generating in certain areas at certain times, such as through the night. There were ten times more System tagged instructions on the 25th than there was on the 24th of June, many of those instructions will be the cause of the peak difference.

RRE 1H Constraints Cost Savings from Collaboration with TOs

Q1 2021-22 Performance

The Transmission Operators (TOs) need access to their assets to upgrade, fix and maintain the equipment. TOs request this access from the ESO, and we then plan and coordinate this access. We look for ways to minimise the impact of outages on energy flow and reduce the length of time generation is unable to export power onto the network.

This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

There are two ways the ESO can work with the TOs to minimise constraint costs. We will report on both for RRE 1H:

1. ODI-F savings: Actions taken through the System Operator: Transmission Owner (SO:TO) Optimisation ODI-F
    - Output Delivery Incentives (ODIs) are incentives that form part of the TOs' RIIO-2 framework. They are designed to encourage licensees to deliver outputs and service quality that consumers and wider stakeholders want to see. These ODIs may be financial (ODI-F) or reputational (ODI-R).
    - One of these ODIs, the SO:TO Optimisation ODI-F, is a new two-year trial incentive to encourage the Electricity Transmission Owners (TOs) to provide solutions to the ESO to help reduce constraint costs according to the STCP 11-4[1] procedures. The ESO must assess the eligibility of the solutions that the TOs put forward in line with STCP 11-4, and must deliver the solutions in order for them to be included as part of the SO:TO Optimisation ODI-F and this RRE 1H.
    - For RRE 1H, where constraint savings are delivered through the SO:TO Optimisation ODI-F, the savings are calculated in line with the methodology for that incentive.
2. Other savings: Actions taken separate from the SO-TO Optimisation ODI-F
    - The ESO also carries out other activities to optimise outages. In these cases, the assumptions used for estimating savings will be stated in the supporting information.

Figure 7: Estimated £m savings in avoided constraints costs (ODI-F)

(Estimated savings in GWh are also shown for context)

[1] The STCP 11-4 'Enhanced Service Provision' procedure describes the processes associated with the ESO buying a service from a TO where this service will have been identified as having a positive impact in assisting the ESO in minimising costs on the GB Transmission network.

Figure 8: Estimated £m savings in avoided constraints costs (Other)

(Estimated savings in GWh are also shown for context)

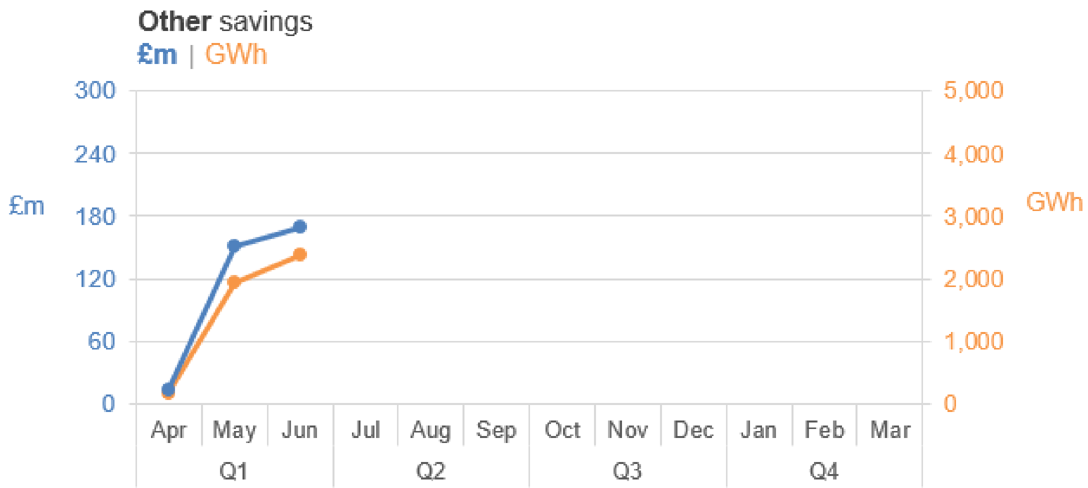


Table 11: Estimated £m savings in avoided constraints costs

		Apr	May	Jun	Q1 Total
ODI-F savings	£m	0	0	0	**0**
Other savings	£m	15	151	170	**335**
ODI-F savings	GWh	0	0	0	**0**
Other savings	GWh	189	1935	2383	**4,507**

Supporting information

ODI-F (STCP 11-4) Constraint Cost Savings

The Network Access Planning (NAP) team has proposed and worked with the relevant TOs to deliver three active STCP 11-4 opportunities that have the potential to provide cost savings. These opportunities are:

- Changing the overload protection setting on a circuit which is due to provide continuous improvement to the GALLEX constraint costs.
- Increasing the rating on a circuit into the South East of England which allows an increase in the SEIMPPR2 constraint limit.
- Increasing the rating on circuits to allow the final high-priority decommissioning of circuits in central London.

No constraint cost savings of this type were realised in Q1 2021-22. This is due to these constraints not being active during this period, and therefore no enhancement to the summer rating of the circuits mentioned above was needed.

However, as it was likely that work on site would be needed to facilitate the opportunities for cost savings, identifying these opportunities early has meant that the cost saving actions will be available over the Autumn and Winter months when they are most valuable.

In most cases, these opportunities for enhancement can only be delivered during outages to the relevant equipment. We are working with the TOs to ensure that this work can be delivered at minimum cost to the consumer by accommodating the work during existing planned outages or by agreeing additional outages into the plan at optimal times.

STCP 11-4 opportunities, also proposed by NGESO, that are in progress with the relevant TOs and will most likely be active in Q2 2020-21 include:

- The temporary uprating on a circuit in Central Scotland to allow an increase in North-South flows in Scotland.
- The installation of an overload protection scheme which will allow increased flow across the SSE-SP boundary
- Improved ratings on a Scotland – England boundary circuit which will increase the B6/SCOTEX boundary thermal limit.
- There are initial discussions regarding uprating of a cable in SW Scotland which have proved promising. The NAP team are currently carrying out a cost-benefit analysis for this.

Other Savings (Customer Value Opportunities):

Following Network Access Planning's success with the Customer Value Opportunities metric in 2020-21, all teams in NAP have continued to improve and find better ways of planning system access to deliver savings and benefits to the end consumer.

The Network Access Planning team has made excellent progress this quarter. In collaboration with our stakeholders (TOs and DNOs), the team has identified and recorded about **50 instances** where its actions directly resulted in adding value to the end consumers and its innovative ways of working facilitated increased generation capacity to connected customers.

Some of these instances include:

- Requests for rating enhancements from TOs
- Re-evaluating system capacity
- Identifying and facilitating opportunity outages
- Outage duration reduction for customers
- Aligning outages with customer maintenance and generator shutdowns
- Proposing and facilitating alternative solutions for long outages that impact customers
- Splitting of outages to minimize constraint costs.

Together these represent a total of **4,506,800 MWh (approximately £335m)** of extra generation capacity in Q1 2020-21, which would have otherwise been constrained at a cost to the consumer.

** We used average values of £78/MWh for wind and £55/MWh for other generation to estimate the cost.*

RRE 1I Security of Supply

Q1 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 12: 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									
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	0	0	0									
Voltage Excursions defined as per Transmission Performance Report[2]	0	0	0									

Supporting information

There have been no reportable voltage and frequency excursions in June, or in Q1 as a whole.

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

RRE 1J CNI Outages

Q1 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 13: Unplanned CNI System Outages (Number and length of each outage)

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

Table 14: Planned CNI System Outages (Number and length of each outage)

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

Supporting information

There were no outages, either planned or unplanned, encountered during June 2021 or during Q1 as a whole.

Notable events during Q1

Electricity System Restoration Service contracts awarded

Our Electricity System Restoration Service strategy (formerly known as Black Start) gives us the ability to fire up Britain's electricity system after a total blackout. These services use auxiliary sources of generation to kick-start bigger ones creating 'islands' of power which connect together on the main transmission network to gradually restore the grid. On 30 April we announced contracts with eight providers for Electricity System Restoration Services in the Northern Regions which covers Northwest, Northeast and Scotland. The eight contracts, two of which are new, total £53.8 million with each bid offering commercial benefits compared to other bidders and Electricity System Restoration Services options.

Distributed ReStart update

On 20 May we held a webinar[3] which provided an overview of our developments in procurement and compliance, as a commencement of our focussed engagement as we develop our process and thinking. We then invited Distributed Energy Resource (DER) participants for further 1-2-1 meetings to fully understand their requirements and seek feedback on our proposals. The first meeting was held on 27 May and further meetings were held in June.

Distributed ReStart completed its desktop exercises to road test the organisational structures designed to deliver restoration from Distributed Energy Resources (DER). These designs had been co-created with our stakeholders. We held three exercises in May, June and July with industry stakeholders participating (DNOs, TOs, ESO & DERs). The project team has built a simulator and each exercise saw stakeholders enacting their control roles whilst using the simulator. During each exercise there were plenty of opportunities for stakeholders to provide feedback, so much so that we were able to build on the feedback to improve the designs as we moved through tom the next exercise. We will be sharing the results in September.

[3] https://players.brightcove.net/867903724001/default_default/index.html?videoId=6255943776001

Role 2 Market development and transactions

Metric 2A Competitive Procurement

Q1 2021-22 Performance

This metric measures the overall % of services procured through competitive means (auctions and tenders) calculated by £ expenditure.

Please note the following points when interpreting the data for this metric:

- For **Restoration**, there may be a significant lag time between when a contract is agreed and when it comes into effect. Therefore, in some cases actions we take in the current quarter may not impact Metric 2A until months or years later.
- For **Frequency Response** (FR), a lower '% of services procured through competitive means (auctions and tenders)' may appear to indicate that the market has become less competitive, but can actually be a sign of the opposite. When the market becomes more competitive, the market price drops. This can lead to a reduction in overall competitively procured spend and therefore a lower percentage of total services that are competitively procured.

Figure 9: Percentage of £m spend by procurement method

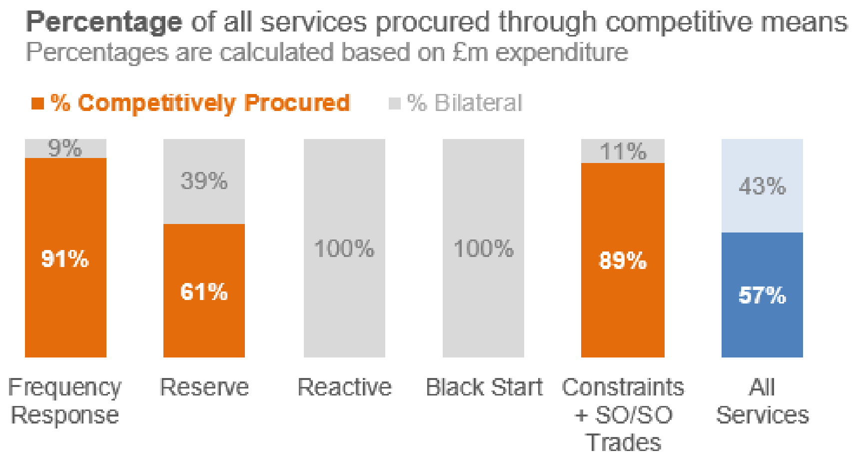


Figure 10: Absolute £m spend by procurement method

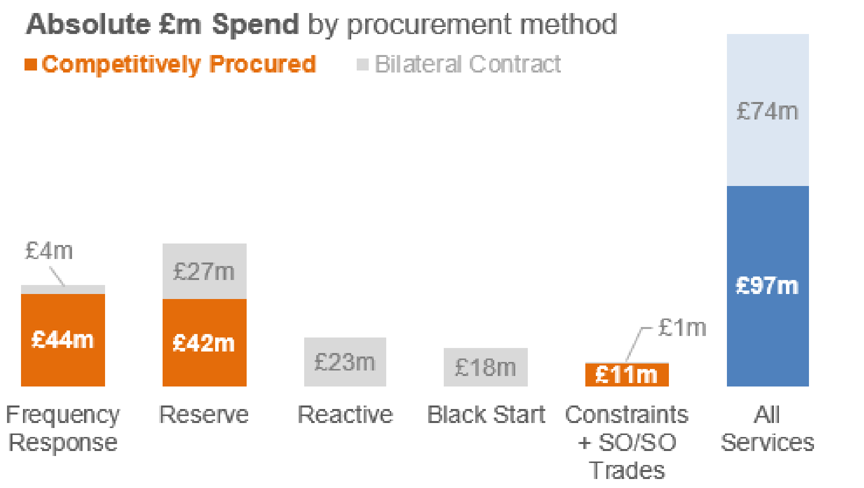


Table 15: Percentage of services procured through competitive means by Quarter

Services	Q1	Q2	Q3	Q4	YTD
Frequency Response	91%				91%
Reserve	61%				61%
Reactive	0%				0%
Black Start	0%				0%
Constraints & SO/SO Trades	89%				89%
All services	**57%**				**57%**
Status (All services)	●				●

Performance benchmarks (Year 1)

- ● **Exceeding expectations:** >60%
- ● **Meeting expectations:** 50-60%
- ● **Below expectations:** <50%

Supporting information

Average Market Prices

	Q1	Q2	Q3	Q4
Dynamic Containment (£/MW)	17			
FFR Weekly Auction - DLH (£/MW)	8.1			
FFR Weekly Auction - LFS (£/MW)	4.0			
Optional Fast Reserve (£/MWh)	102			
STOR DA (£/MW)	3.3			

Frequency Response

The Dynamic Containment market continues to clear at the price cap of £17/MW as we have not yet reached our volume requirement. This is drawing providers away from the FFR markets, resulting in higher costs in those markets as well. Whilst DC costs are high, they are resulting in lower costs elsewhere in managing low inertia conditions. As more battery assets are commissioned and more providers enter the market we expect competition to increase and prices to start going down. This quarter we have also not been securing as much through FFR and are therefore spending more to access mandatory frequency response through the BM. As bilaterally contracted frequency response volumes and prices are reasonably static, this increase in the amount we are spending on response is resulting in a higher percentage of services procured through competitive means at 91% compared to 85% for 2020-21 overall.

Reserve

The day ahead market for STOR went live on 1 April 2021, which has increased the amount of reserve that we are able to buy through competitive markets, as there was limited opportunity for reserve providers through 2020 since the suspension of the original STOR tender events. The Q1 figure of 61% is therefore higher than the overall 2020-21 figure of 39%.

Reactive

We continue to develop our thinking around market-based procurement of reactive power, and have just concluded an RFI process to identify potential partner companies to run an innovation project around this.

Black Start

Despite awarding contracts through open and competitive tenders for the South West and Midlands in 2020, the spend associated with them will not appear until 2022 and therefore does not appear in this metric. We plan to launch a further competitive event in Q2 2021-22 for services in the South-East region, however spend for this tender will also not flow through into this metric this financial year.

Constraints & SO/SO Trades

Two units who were successful in Phase 1 of the Stability pathfinder went live in April, which has increased the amount of spend through competitive markets, with a Q1 figure of 89% compared to an overall figure for 2020-21 of 15%. We anticipate further increases in October when further units will start delivering.

RRE 2B Diversity of Service Providers

Q1 2021-22 Performance

This Regularly Reported Evidence (RRE) measures the diversity of technologies that provide services to the ESO in each of the markets covered by performance metric 2A (Competitive procurement). We report on total contracted volumes (mandatory and tendered) in MWs or MVARs.

There are four services we report on below: Frequency Response (MFR, EFR, FFR, Dynamic Containment), Reserve (STOR, Fast Reserve), Reactive, Constraints. Data on Restoration services is not included in this report due to the sensitive nature of the information, which will be provided to Ofgem separately.

Figure 11: Q1 total contracted volumes by service type

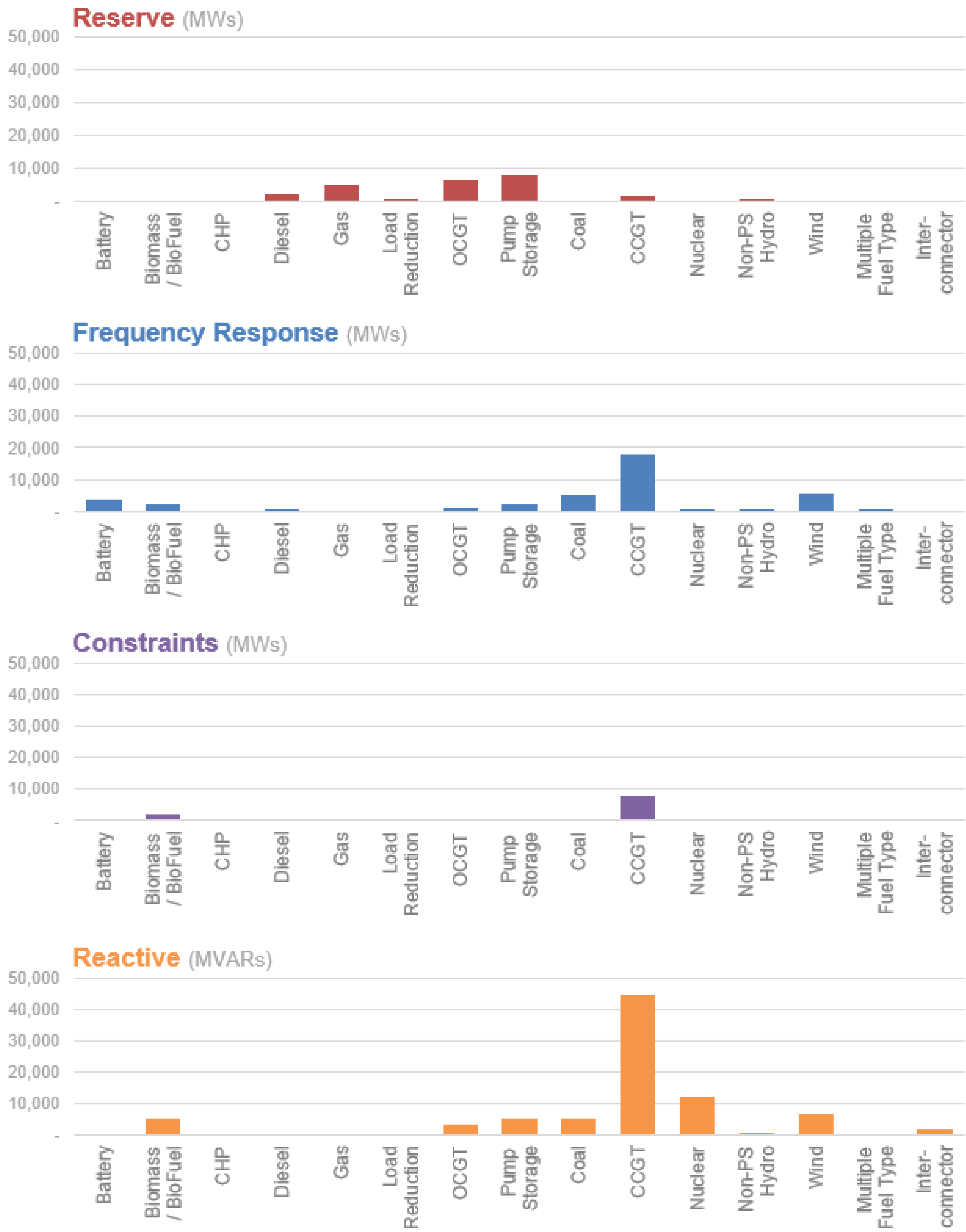


Table 16: Q1 monthly contracted volumes provided to the ESO by service type

Reserve

MWs	Apr-21	May-21	Jun-21	Q1
Total	7,788	7,786	7,786	**23,360**
Battery	-	-	-	-
Biomass/BioFuel	-	-	-	-
CHP	-	-	-	-
Diesel	689	687	687	**2,063**
Gas	1,695	1,695	1,695	**5,085**
Load Reduction	72	72	72	**216**
OCGT	2,061	2,061	2,061	**6,183**
Pump Storage	2,600	2,600	2,600	**7,800**
Coal	-	-	-	-
CCGT	479	479	479	**1,437**
Nuclear	-	-	-	-
Non-PS Hydro	192	192	192	**576**
Wind	-	-	-	-
Multiple Fuel Type	-	-	-	-
Interconnector	-	-	-	-

Constraints

MWs	Apr-21	May-21	Jun-21	Q1
Total	3,123	3,123	3,253	**9,499**
Battery	-	-	-	-
Biomass/BioFuel	595	595	595	**1,785**
CHP	-	-	-	-
Diesel	-	-	-	-
Gas	-	-	-	-
Load Reduction	-	-	-	-
OCGT	-	-	-	-
Pump Storage	-	-	-	-
Coal	-	-	-	-
CCGT	2,505	2,505	2,635	**7,645**
Nuclear	-	-	-	-
Non-PS Hydro	-	-	-	-
Wind	23	23	23	**69**
Multiple Fuel Type	-	-	-	-
Interconnector	-	-	-	-

Frequency Response

MWs	Apr-21	May-21	Jun-21	Q1
Total	13,146	12,808	13,047	**39,001**
Battery	1,360	1,038	1,246	**3,644**
Biomass/BioFuel	785	785	805	**2,375**
CHP	-	-	-	-
Diesel	44	44	42	**130**
Gas	-	-	-	-
Load Reduction	-	-	-	-
OCGT	373	373	373	**1,119**
Pump Storage	728	728	728	**2,184**
Coal	1,782	1,782	1,782	**5,346**
CCGT	5,999	5,999	5,999	**17,997**
Nuclear	92	92	92	**276**
Non-PS Hydro	70	70	70	**210**
Wind	1,881	1,881	1,881	**5,643**
Multiple Fuel Type	32	16	29	**77**
Interconnector	-	-	-	-

Reactive

MVARs	Apr-21	May-21	Jun-21	Q1
Total	27,889	27,889	27,889	**83,667**
Battery	-	-	-	-
Biomass / BioFuel	1,734	1,734	1,734	**5,202**
CHP	-	-	-	-
Diesel	-	-	-	-
Gas	-	-	-	-
Load Reduction	-	-	-	-
OCGT	967	967	967	**2,901**
Pump Storage	1,630	1,630	1,630	**4,890**
Coal	1,731	1,731	1,731	**5,193**
CCGT	14,832	14,832	14,832	**44,496**
Nuclear	4,095	4,095	4,095	**12,285**
Non-PS Hydro	189	189	189	**567**
Wind	2,192	2,192	2,192	**6,576**
Multiple Fuel Type	-	-	-	-
Interconnector	519	519	519	**1,557**

Supporting information

Reserve

From 1 April 2021 we commenced procurement of the firm Short-Term Operating Reserve (STOR) product via daily auctions with ~ 1300MW procured each day. This is a very liquid market with over 220 individual units prequalified. Prior to 1 April 2021 the firm STOR service was delivered by contracts procured in October 2019 or earlier. Due to the technical requirements (response time/delivery duration) the service is typically delivered by more traditional Diesel, Gas and Coal fuels.

With the forthcoming reserve products coming online through 2022, we would expect to see new technologies entering the market for the proposed fast acting product, with the existing players more geared to the proposed slower acting product. For Fast Reserve, we are only procuring the Optional service where units are contracted on the day to be available, having taken the decision not to procure the firm service in line with the Clean Energy Package (as is the case for the STOR daily auctions). The move away from a firm service and certainty of guaranteed availability payments, has seen the number of units offering their services to Fast Reserve reduce with the service delivered predominantly from Gas Reciprocating Engines. Hydro stations provide us with further optional reserve via bilateral contracts.

Frequency Response[4]

From October 2020 we launched Dynamic Containment (DC) which was the 1st of our new frequency product suite via daily auctions. This market is still growing with over 800MW procured daily. Over the past few years tendered frequency products have seen a significant change in the generation type delivering these services. Dynamic frequency has seen a move away from the more traditional generation from Diesel, Gas and Hydro to more Demand Side Response (DSR) and Storage assets and are expecting this growth to continue, as the technical and delivery requirements of the new services (1 second delivery) is more suited to these types of technology.

During 2021-22 we will continue to progress the transition from the existing legacy products Dynamic FFR (DFFR) and Static FFR procured through monthly tender and the Dynamic Low High (DLH) and Low Frequency Static procured through the weekly auctions to the new suite of response products of Dynamic Containment, Dynamic Moderation and Dynamic Regulation.

The introduction of DC has seen a reduction of units participating in the Monthly and weekly frequency tenders as providers have moved their portfolios to provide this service, this can be seen in the gradual drop in accepted MW in DFFR and DLH auctions since October 2020.

Constraints

Constraint costs are when the ESO pays generators to constrain their output due to network capacity limitations and typically for them to increase or decrease MWs on the system. This service is generally limited to the providers that are connected to the Transmission system and generally localised, therefore there are limited options to provide the service. This would typically either be provided by Transmission Connected CCGT or Wind providers depending on where the constraint exists. When the Constraint Management Pathfinder goes live, there could be a spread across more technology types depending on the interest of the party and the tender outcome.

Reactive

The reactive power service is delivered primarily by providers who have Mandatory Service Agreements and are typically connected to the Transmission Network. These providers would also be in the Balancing Mechanism (BM), meaning the ESO has a means to instruct and settle Reactive Power services. Additionally, we sometimes have specific locational needs that cannot be accessed in the BM. These needs would also be met by Transmission connected providers only, due to their short-term nature and effectiveness. We have however recently launched Voltage Pathfinders, which have attracted more diverse technologies to provide reactive services and has proven that distribution network providers can also be effective to meet a transmission need.

[4] Frequency Response figures were corrected in this re-published version of the Q1 report on 9 August 2021. Some of the original figures were incorrect due to an error in the data model. Figures for the other services have not changed.

RRE 2E Accuracy of Forecasts for Charge Setting

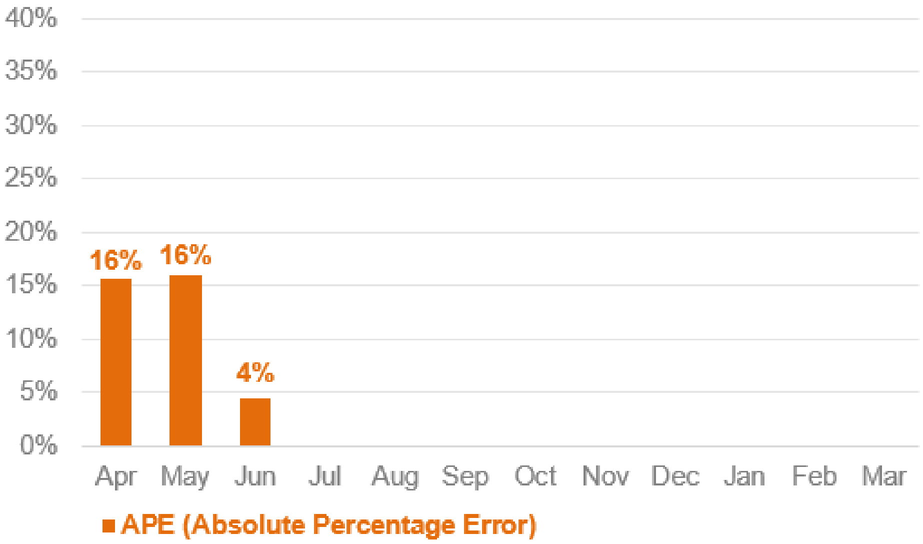
Q1 2021-22 Performance

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 17: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	3.82	4.44	4.28									
Month-ahead forecast	3.22	3.73	4.09									
APE (Absolute Percentage Error)[5]	**16%**	**16%**	**4%**									

Figure 12: Monthly BSUoS forecasting performance (Absolute Percentage Error)



Supporting information

Forecast accuracy improved significantly this month at 4% APE compared with 16% APE in April and May. This improvement was driven by the fact that the weather in June was largely as expected. For Q1 as a whole the APE is significantly lower than Q1 last year (33% average APE) as the initial lockdown caused increases in costs and reductions in demand making BSUoS very difficult to forecast.

The outturn BSUoS for June was down from £4.44 /MWh in May to £4.28 /MWh for June. Constraint costs fell as a result of changes in the RoCoF costs following the implementation of the recommendations of the FRCR (Frequency Risk and Control Report). Operating Reserve costs rose slightly along with Response and these were offset by a fall in Energy Imbalance as the system was less short in June. The total BSUoS volume was lower than May as we move into the summer months.

[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.

Notable events during Q1

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

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

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

We carefully considered the options of recovering the costs and the impact it may have on the industry, in particular under the current COVID-19 pandemic situation. Having engaged with the industry further on this matter via a dedicated webinar[6], we decided to defer the recovery of £10m ALoMCP costs to Charging Year 21/22; the trading costs would be recovered through the Reconciliation Final (RF) run for Charing Year 20/21. This was in line with the CUSC methodology to ensure that costs would be recovered from the correct parties over the settlement periods where the costs were incurred as well as provide a longer notice for parties to plan for this cost recovery.

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

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

Reserve Reform Workshop

On 26 and 27 May we held successful Reserve Reform co-creation workshops. This related to the new reserve products which will go through the various elements of product and service design we consulted on earlier this year. These smaller workshops will allow us to come to a better proposal for the new reserve product suite. The output of the workshops will form the basis of a final consultation on product and service design in the summer.

Power Potential trials

The Power Potential commercial market trials ran from 6 January to 28 March 2021. By working in partnership with UK Power Networks (UKPN) and with the industry in a trial environment, we were able to identify a number of learning points. We were aware of the flexibility market DNOs are working on and are ensuring there is no conflict with the reactive power market. On 4 May 2021 we submitted our report[7] on the conclusions and key findings from Power Potential. A Power Potential Final showcase was held on Thursday 24 June.

The ESO and UKPN confirmed plans in June to assess how wind and solar farms can dynamically feed in power to provide voltage control services to balance the system and help the grid run more efficiently in a new joint project. With the live trials now complete, we will use the insights to inform our Future of Reactive project.

The road to net zero carbon electricity markets

On 22 June we held our second Markets Forum[8], the session opened with a discussion on what the Single Markets Platform (SMP) is, why it is needed and our approach to the programme. We shared the latest updates from ESO Markets on the Net Zero Market Design project and the Pathfinders. An updated draft of the 2025 codes roadmap was also shared, with further detail provided on several of the areas and views sought on which topics to discuss with industry in future. There were 196 attendees and 58 of the attendees gave a rating (out of 10) for "How satisfied are you with this session?". The mean average rating was 7.8 with 66% scoring an 8 or more.

Dynamic Moderation and Dynamic Regulation

Following provider feedback, we hosted two technical workshops on the services, Dynamic Moderation and Dynamic Regulation, with industry in early June. We explored key topics from the service design that industry wanted us to cover as well as topics we were looking to gather feedback on. We shared a video[9] summary of the feedback we received in the workshops and also published a survey to ensure all providers had the chance to submit comments on these topics. The output from the workshops and survey will feed into the review of the service design.

We have also published a survey[10] to gather any further comments as we appreciate not everyone could join the workshops. The survey includes questions we covered in each session.

Code Administrator deliverables 2021

In May we published two documents. The first was the Code Administrator Annual report[11] which is a summary of last year's activity. This was followed by a publication[12] that provides details on the team deliverables that we'll be working towards this year. This is to provide clarity on what we're working on over the next 12 months, continuing to build on the improvements we made last year, and to reassure stakeholders that we're continuing to take their feedback onboard.

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[6] https://www.nationalgrideso.com/document/190426/download
[7] https://www.nationalgrideso.com/document/191146/download
[8] https://www.nationalgrideso.com/industry-information/balancing-services/road-to-net-zero-electricity-markets/events
[9] https://players.brightcove.net/867903724001/default_default/index.html?videoId=6262025138001
[10] https://forms.office.com/pages/responsepage.aspx?id=U2qK-fMlEkKQHMd4f800leceXXJm2hZMihRFMe_vO_pUREFWTExHOUhJVExLME5UTEoyM0ZCWDlLWi4u
[11] https://www.nationalgrideso.com/document/191571/download
[12] https://www.nationalgrideso.com/document/191576/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 Q1

Enabling the DSO Transition consultation

On Monday 19 April, we launched our Distribution System Operation (DSO) consultation[13], introducing our proposed approach to supporting the transition to DSO, which will help us achieve a smarter energy system. As the electricity network evolves, the traditional roles and responsibilities in the industry, particularly of Distribution Network Operators (DNOs), will change. DNOs will have a significant role in managing the network at a local level and making sure regional service providers can support the delivery of an efficient and resilient system. The ESO already works closely with DNOs in many areas, but these relationships will need to extend and deepen to facilitate the DSO transition. Our consultation describes a proposed ESO approach to the DSO transition as well as a vision of how we will be working with DNOs in 2025. Strong collaboration across industry will be pivotal to the success of the DSO transition and we received 15 responses to our request for feedback from stakeholders which we are currently reviewing. The DSO transition webinar[14] was held on 6 May where we provided the opportunity for industry to hear from ESO colleagues and ask questions[15] on the approach and vision. The Association for Decentralised Energy (ADE) and Energy Networks Association (ENA) also presented their views on the importance of, and priorities for the DSO transition. Over 100 stakeholders attended the webinar.

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

Early Competition

We submitted our Early Competition Plan to Ofgem at the end of April. This has been well received by Ofgem and we had really positive feedback on our stakeholder engagement from our ESO Networks Stakeholder Group. In May we held a webinar[16] providing an overview of the Early Competition Plan submitted to Ofgem. Ofgem have also published a letter[17] which sets out the low-regret activities we will be progressing through to the end of the year whilst Ofgem consult on Early Competition and make their decision.

Offshore Coordination engagement

Within the Early Opportunities workstream of the offshore coordination project we have been working closely with developers of in-flight offshore projects to understand costs, benefits, opportunities and blockers for greater coordination. Through regular meetings with developers and the TOs, we have undertaken detailed analysis and consolidated this information into a project proposal pack for all projects that have been put forward for coordination. This was presented to Ofgem and BEIS on 27 May. These draft high level models for ways to deliver early coordination have informed the models proposed by Ofgem in their early summer consultation.

Within our Pathway to 2030 workstream, we have been asked by BEIS and Ofgem to deliver a Holistic Network Design (HND), to provide a coordinated National Electricity Transmission System (NETS), including onshore and offshore assets, primarily required to connect offshore wind. We will

[13] https://www.nationalgrideso.com/document/190271/download
[14] https://players.brightcove.net/867903724001/default_default/index.html?videoId=6252928262001
[15] https://www.nationalgrideso.com/document/192106/download
[16] https://players.brightcove.net/867903724001/default_default/index.html?videoId=6255747447001
[17] https://www.ofgem.gov.uk/sites/default/files/docs/2021/05/early_competition_update_2021_0.pdf

achieve this via a newly formed Central Design Group (CDG), which the ESO will lead, in collaboration with the TOs. Throughout April to July, we have collaborated closely with the TOs to agree and establish the Terms of Reference and broader foundations that will be critical in underpinning this group, which will in turn enable us to progress with a brand new approach to network design. During this period, we have also engaged with offshore project developers to keep them informed of progress.

Winter Review and Consultation

On 24 June we published our Winter Review and Consultation[18]. This is an annual document which compares what we forecast in our Winter Outlook 2020-21[19] publication with what actually happened. It also provides an opportunity for stakeholders to share their views on the winter ahead and how we can approach any opportunities and challenges.

As anticipated in our Winter Outlook, this winter saw a little more tightness in the system than in recent years – though well within the security of supply standard. Our control room managed some occasionally challenging conditions to ensure that security of supply was maintained.

Addressing increasing constraint costs

On Thursday 17 June we published a report[20] on increasing constraint costs and what we are doing to address this. Constraint costs are when the ESO pays generators to constrain their output due to network capacity limitations. The paper includes analysis which shows modelled constraint costs increasing significantly this decade – from c. £0.5bn/year today to between £1bn and £2.5bn/year at a maximum before they reduce again at the end of the decade when new major transmission investments come online. Recognising the potential step-up later this decade, the ESO has a medium/long term plan in place to mitigate these projected increases through a range of initiatives on which we are working closely with industry. Please see the ESO's five point plan[21] to manage constraints on the system for further information.

Stability Pathfinder Phase 1 - Deeside Power

Through the Stability Pathfinder Phase 1, Deeside Power Station, a combined cycle gas turbine (CCGT) power plant operated by Triton Power in Flintshire, has entered an agreement to provide the ESO with vital system support services as part of a six year contract. Announced on Wednesday 23 June, the station's two gas turbines will provide the grid with support services including inertia and reactive power. The project is said to be the first conversion of a gas turbine rotor to provide standalone inertia and stability services anywhere in the world. The operator has procured the equivalent amount of inertia as would have been provided by around five coal-fired power stations – saving consumers an expected £128mn over the contract's duration.

Stability Pathfinder Phase 2

On 1 June we informed participants of the Stability Pathfinder Phase 2 that there has been an extension to the timeline[22]. We have completed the Expression of Interest review of over 1500+ solutions and are now carrying out Feasibility Studies and Connection reviews ahead of running the tender in Q4 2021-22. We have consulted with the market on several key documents such as the contract terms[23], technical specification and assessment methodology[24] and the final versions of

[18] https://www.nationalgrideso.com/document/195776/download
[19] https://www.nationalgrideso.com/document/178126/download
[20] https://www.nationalgrideso.com/document/194436/download
[21] https://www.nationalgrideso.com/news/our-5-point-plan-manage-constraints-system
[22] https://www.nationalgrideso.com/document/192731/download
[23] https://www.nationalgrideso.com/document/191696/download
[24] https://www.nationalgrideso.com/document/197046/download

these have now been published. We have also engaged with them on changes to the contract length[25] and have updated them on the revisions.

We continue to liaise with Ofgem and Industry around some broader questions such as licensing of 0MW units and residual value.

Voltage Screening Report

Our annual GB voltage screening report[26] was published in June, we have analysed the GB transmission network and identified potential regions that with increasing voltage requirements we are going to be seeing over the next 10 years. This is the second report of this type and we are seeking feedback from stakeholders.

[25] https://www.nationalgrideso.com/document/197051/download

[26] https://www.nationalgrideso.com/document/196326/download