nationalgridESO

ESO Forward Plan 2020-21

Monthly Reporting: July

21 August 2020

Foreword

Welcome to our monthly performance report for July 2020. Each month, we report on a subset of metrics and performance indicators. This report provides an update on our performance and metrics against our deliverables set out in the 2020-21 Forward Plan Addendum[1].

We report our progress against our deliverables on the Forward Plan tracker[2] which is updated monthly on our website. The Forward Plan tracker has been updated to take account of the revisions to deliverables set out in the Forward Plan addendum.

Contents

A summary of our monthly metrics and performance indicators covering July is shown in Table 1 below.

Metric/Performance Indicator	Performance	Frequency	Status
Balancing Cost Management	£136.2m outturn against £65.5m benchmark	Monthly	●
Energy Forecasting Accuracy	Both demand and wind forecast targets were not met	Monthly	●
Security of Supply	0 excursions for voltage and frequency	Monthly	●
System Access Management	2.64/1000 cancellations	Monthly	●
Month-ahead BSUoS Forecast	16% forecasting error	Monthly	●
Right First Time Connection Offers	95% first time connection offers	Monthly	●

Table 1: Summary of metrics and performance indicators

● **Exceeding expectations**

● **Meeting expectations**[3]

● **Below expectations**

You can find out about our vision, plans, deliverables and full metric suite in the Forward Plan pages of our website[4].We welcome feedback on our performance reporting to box.soincentives.electricity@nationalgrideso.com

Gareth Davies

ESO Regulation Senior Manager

[1] https://www.nationalgrideso.com/document/173131/download
[2] https://www.nationalgrideso.com/document/162046/download
[3] We have updated the colour scheme for our metrics to give increased transparency of our performance, noting that meeting expectations still represents good performance. This should give a clearer representation of the status of our activities.
[4] https://www.nationalgrideso.com/our-strategy/forward-plan

Role 1 Control Centre operations

1A Balancing cost management

July 2020 Performance

The approach we use for measuring our Balancing Costs performance is based on a linear trend in a five year rolling mean, based on annual Balancing Services Costs (excluding Black Start). In order to meaningfully employ a linear trend, the data points need to handle one-off permanent changes to the system network which would not be captured by the five-year trend. So far, the only change modelled in this way has been the Western Link. We also make adjustments for significant events which we expect to have an impact on balancing costs, whether this is an upwards or downwards adjustment. These are trends which we would not expect to be captured in the 5-year rolling average, because they relate to either new assets or new trends in market behaviour. Additional information regarding balancing costs calculation and benchmark adjustment can be found on our website[5].

Low demand periods are challenging to manage and the volume of actions required by the ESO to ensure the system remains secure lead to higher costs. During the period where demand is impacted by the COVID-19 pandemic, the ESO's balancing costs spend is expected to be significantly higher than the benchmarks stated here. During this period, we will continue to report our performance in comparison to the benchmark, but will focus on providing a detailed narrative which explains the costs we have incurred. We also welcome Ofgem's review of costs incurred over the summer period, and will be transparent with our stakeholders about the actions we have taken.

Please note that the benchmarks were re-calculated in July 2020 to remove the ElecLink adjustor since the interconnector go-live date has been delayed.

	Apr	May	Jun	Jul	Aug	Sep	Total
Benchmark cost (£m)	67.0	48.2	82.6	65.5	102.0	103.7	1199.3
Additional cost forecast due to WHVDC fault (£m)	0	0	0	0	0	0	0
Benchmark adjusted for WHVDC (£m)	67.0	48.2	82.6	65.5	102.0	103.7	1199.3
Outturn cost (£m)	121.5	158.8	135.1	136.2			
Status							

Table 2: Apr-Sep 2020 Monthly balancing cost benchmark and outturn.

	Oct	Nov	Dec	Jan	Feb	Mar	Total
Benchmark cost (£m)	126.9	82.8	126.6	133.2	142.5	118.3	1199.3
Additional cost forecast due to WHVDC fault (£m)	0	0	0	0	0	0	0
Benchmark adjusted for WHVDC (£m)	126.9	82.8	126.6	133.2	142.5	118.3	1199.3
Outturn cost (£m)							551.6 [YTD]
Status							

Table 3: Oct-Mar 2020-21 Monthly balancing cost benchmark and outturn.

[5] https://www.nationalgrideso.com/document/166231/download

Supporting information

Total balancing costs for July were similar to June and remain above the benchmark. COVID-19 continued to suppress demand by greater than 5% through the month which continued to drive higher costs. A large volume of Optional Downward Flexibility Management (ODFM) was used on 5 July and this, alongside the very low demand which was driving that requirement, and high winds led to high spend on this day. Another high spend day was 28 July when the system experienced large volumes of constraint actions being required to manage system outages and very high wind.

Performance benchmarks

- ● **Exceeding expectations:** at least 10% lower than the figure implied by the benchmark.
- ● **Meeting expectations:** within 10% of the figure implied by the benchmark.
- ● **Below expectations:** at least 10% higher than the figure implied by the benchmark.

1B Energy forecasting accuracy

July 2020 Demand Forecasting Performance

As outlined in the Forward Plan Role 1 Energy Forecasting Accuracy metric (Metric 1b), the ESO's forecasting performance will be assessed at the end of the performance year. Annual performance targets have been calculated with exceeding, in-line with and below expectations values set out. To allow transparency of our performance during the year, each month we will report an indicative performance for both metrics.

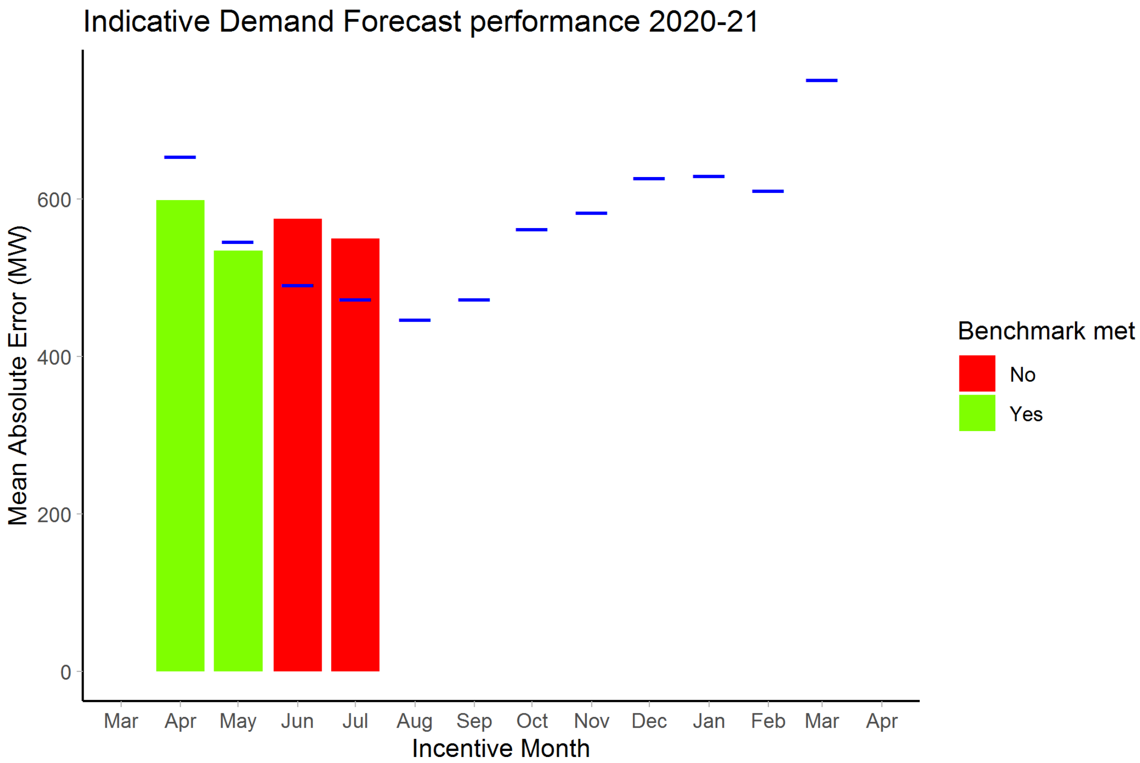

Figure 1: Demand Forecasting , shows our performance for April as the green histogram against the blue target line.

Day ahead demand forecast benchmarks for financial year 2020-21			
Month	**Benchmark (MW)**	**Month**	**Benchmark (MW)**
April	654	October	562
May	546	November	583
June	491	December	627
July	473	January	630
August	447	February	611
September	473	March	752

Table 4: Demand Forecasting Benchmarks

Supporting information

DA Demand Indicative Performance for July: 550MW

In July 2020, our day ahead demand forecast indicative performance was not within the benchmark of 473MW. July's MMAE (monthly mean average error) was 549.7MW (accounting for the ODFM service).

Further easing of the COVID-19 lockdown restrictions coupled with subsequent localised lockdowns have made demand less predictable in July. On the days when the biggest errors were observed, solar generation forecasting performance was the most common source of the error.

July 2020 Wind Generation Performance

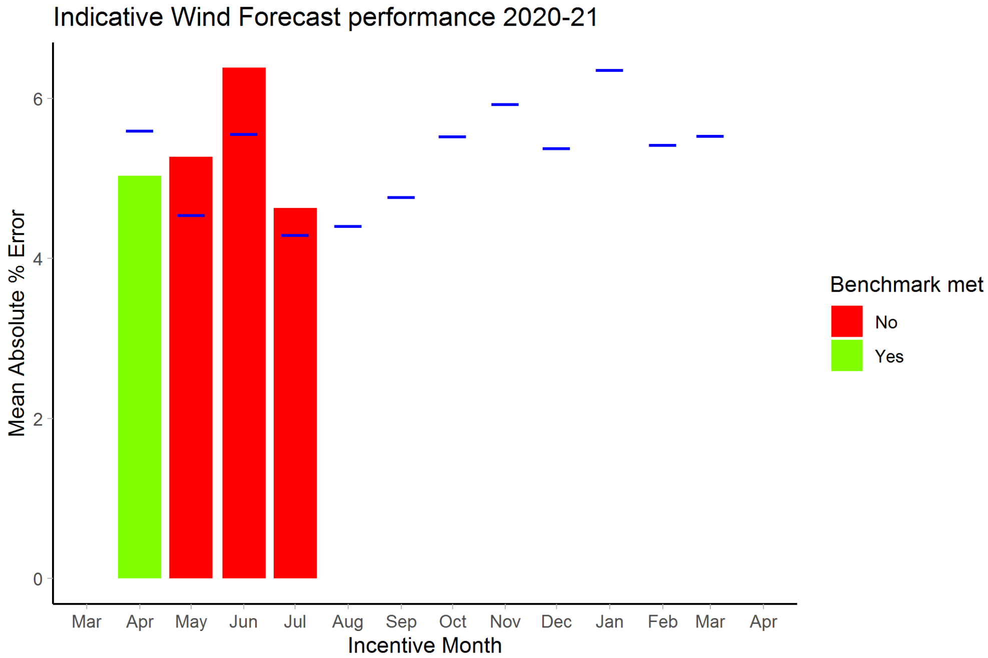

Figure 2 shows our performance this month as the green histogram, against the blue monthly target.[6]

BMU wind generation forecast benchmarks for financial year 2020-21

Month	Benchmark (%)	Month	Benchmark (%)
April	5.60	October	5.53
May	4.54	November	5.93
June	5.56	December	5.38
July	4.29	January	6.36
August	4.41	February	5.42
September	4.77	March	5.54

Table 5: Wind Forecasting Benchmarks

[6] Corrected on 28 January 2021

Supporting information

DA Wind Indicative Performance for July: 4.83%[7]

In July 2020, our day ahead wind forecast indicative performance was not within the target of 4.29%. July's MMAPE (monthly mean absolute percentage error) was 4.83%[7].

There were three main events that caused large forecast errors in July.

Firstly, negative prices on the day-ahead markets were seen on 5 July for 9 hours. Wind farms that have Contract for Difference (CfD) arrangements normally respond to this by reducing output down to zero independently of any instructions from the Electricity National Control Centre. This effect will have contributed to the wind power forecast error on that day. As we have previously discussed with Ofgem, this is a factor that needs to be taken into consideration if a true picture of wind power forecast error is to be seen.

Secondly, the remnants of tropical storm Eduard brought heavy rain and unpredictable weather to the Thames Estuary area where there is a high concentration of wind farms. It has been seen that on previous occasions the remnants of a tropical storm bring increased weather forecast errors. The complex processes associated with decomposing storm systems are very difficult to model accurately, as the Numerical Weather Prediction model used does not have sufficient precision and resolution. We understand that this is a limitation of today's weather forecasting technology, which we hope to see improve in the future.

On Tuesday 27th a low pressure system passed directly over Scotland. When low pressure systems pass directly over, this can lead to timing errors. This can be seen in the greater than 10% (with a peak of 26%) forecast error for the 27th and 28th as the low pressure system moved over Scotland at a different rate to that implied by the weather forecast. Identifying these ramping events and correcting for them has been the subject of many scientific papers. It is hoped improvements in the near future will enable these ramping events to be forecasted more accurately.

Performance benchmarks

- **Exceeding expectations:** Error which is at least 5% lower than the benchmark
- **Meeting expectations:** Error which is within 5% of the benchmark
- **Below expectations:** Error which is at least 5% higher than the benchmark

[7] Corrected on 28 January 2021

1C Security of Supply

July 2020 Performance

Quality of service delivered in running the electricity network by providing the number of reportable voltage and frequency excursions that occurred during the previous month, and a total for the year to date.

	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar
Voltage excursions	0	0	0	0								
Frequency excursions	0	0	0	0								

Table 6: voltage and frequency excursions over 2020-21

Supporting information

There were no excursions on both voltage and frequency. Our performance was therefore exceeding expectations in July.

Performance benchmarks

- **Exceeding expectations:** 0 excursions for both voltage and frequency over 2020-21
- **Meeting expectations:** 1 excursion for either voltage or frequency over 2020-21
- **Below expectations:** More than 2 excursions in total over 2020-21

1D System Access Management

Publishing this metric encourages the ESO to investigate the causes of outage cancellations and amend processes where appropriate to prevent a repeat. We will ensure that we seek to minimise costs across the whole system and all timescales when making a decision to recall or delay an outage on the transmission system.

July 2020 Performance

Figure 3: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Number of outages	Outages delayed/cancelled	Number of outages delayed or cancelled per 1000 outages
Apr	409	2	4.89
May	629	0	0
Jun	847	2	2.36
July	769	3	3.90
Aug			
Sep			
Oct			
Nov			
Dec			
Jan			
Feb			
YTD	2654	7	2.64

Table 7: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

Supporting information

For July, the number of delays or stoppages per 1000 outages has risen to 2.64, which is no longer within our 'Meets Expectations' target of 2.50 per 1000 outage. This has been, caused by three events.

The first delay was down to an incorrect assessment of an outage request caused by a data discrepancy within our outage planning database - Transmission Outages Generator Availability (TOGA). A full circuit outage was identified in TOGA and assessed by the outage planner until it was identified that only part of the circuit was required. The actual requested outage resulted in unacceptably high voltage under fault conditions overnight. The proposed resolution could not be implemented as it would have been necessary to put demand at single circuit risk. We discussed the implications with the Transmission Owner (TO) and Distribution Network Operator (DNO) for the outage and it was agreed it could be taken daily to ensure system security and was successfully released later in the week.

There were several lessons learnt due to the TOGA data error, the first being a creation of new circuit codes which allows the TO to select the full circuit or a section of the circuit within the vicinity of where the issue appeared. This should resolve the problem that was experienced as the full circuit was assessed out of service, rather than only a section of it. By creating the new codes, it has been validated to correctly reflect in the model that is used to assess outages within planning timescales. It has also been raised the importance of checking all outages have been correctly applied to the model before assessing any outages on the network.

The final two events occurred later in July and are still under investigation to identify the root causes and learnings. Further details will be provided in our August report.

Performance benchmarks

- **Exceeding expectations:** < 1 outage cancellations per 1,000 outages
- **Meeting expectations:** 1 - 2.5 outage cancellations per 1,000 outages
- **Below expectations:** > 2.5 outage cancellations per 1,000 outages

Notable events this month

Automated Constraint Optimisation

We have started a trial service with a software company that automatically identifies grid reconfigurations to improve the transfer capacity of congested boundaries. The first case was assessed in July and the process identified a substation running arrangement that improved the constraint limit in the south east of England by 1GW in the first week, and 800MW in the second week. The strategy was adopted in real time, but outturn power flows were not high enough to make use of the higher transfer limits. We will continue to test the service on different parts of the network and monitor the balancing cost benefits.

New change and outage process agreed with TOs

A new process has been agreed with the onshore TOs to help minimise short-term change and prioritise outage requests within current year. This process should ensure that only essential changes to existing outages, or work having no impact to constraint costs, are added into the outage plan with less than four weeks' notice.

Role 2 Market development and transactions

2E Month ahead forecast vs outturn monthly BSUoS

BSUoS forecasts are important to our stakeholders, although we note that our ability to forecast BSUoS is impacted by factors outside of our control. BSUoS costs are factored into the wholesale price of energy charged by generators, and therefore a forecast is vital for those parties when working out where to price their generation.

Due to the volatility in the comparison of our month ahead forecast with the outturn, we report the percentage variance so there can be large swings in accuracy. This metric does not just look explicitly at the volatility, but at the number of occurrences outside of a 10% and 20% band.

July 2020 Performance

Month	Actual	Month-ahead Forecast	APE	APE>20%	APE<10%
April-20	4.74	3.69	0.22	1	0
May-20	6.24	3.87	0.38	1	0
June-20	5.28	7.18	0.36	1	0
July-20	4.79	5.56	0.16	0	0
Aug-20					
Sept-20					
Oct-20					
Nov-20					
Dec-20					
Jan-21					
Feb-21					
Mar-21					

Table 8: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance

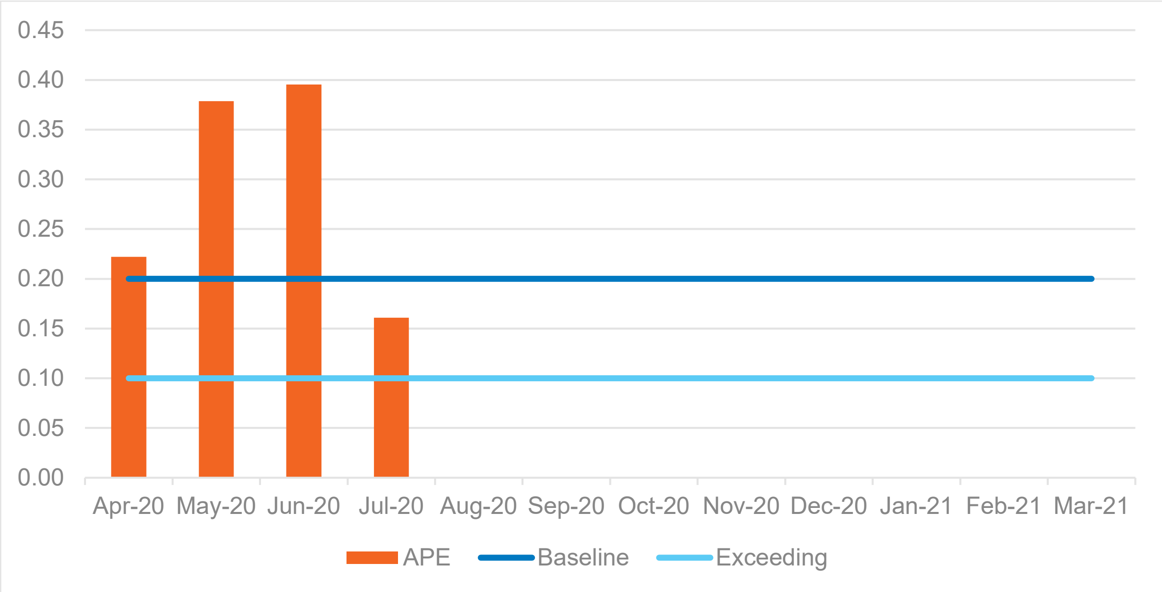

Figure 4: Monthly BSUoS forecasting performance

Supporting information

In June, in an effort to provide greater transparency to the market we produced three BSUoS forecasts for July based on incurring additional costs due to low demands caused by the COVID-19 pandemic. We produced forecasts with additional costs based on 5%, 10% and 15% reductions in demand, with 10% reduction being our best view at the time based on current conditions.

The BSUoS charge for July outturned at £4.79 against a forecast of £5.56 (for the predicted 10% reduction in demand) giving an APE of 16%. However, due to the easing of lockdown restrictions, demand outturned closer to normal demand and a demand reduction of around 5% was observed over the month. Our forecast BSUoS charge for a 5% reduction in demand was £4.93, which was closer to the actual BSUoS charge.

Performance benchmarks

● **Exceeding expectations:** Less than 5 out of 12 monthly forecasts are above 20% Absolute Percentage Error, and 5 or more forecasts less than 10% Absolute Percentage Error

● **Meeting expectations:** Less than 5 out of 12 monthly forecasts are above 20% Absolute Percentage Error

● **Below expectations:** 5 or more out of 12 monthly forecasts above 20% Absolute Percentage Error

Notable events this month

Modification GC0147 'Last resort disconnection of embedded generation – enduring solution' Raised

The unprecedented reduction in consumer demand during the COVID-19 pandemic, combined with the highly changeable recent weather has resulted in new challenges for the ESO in maintaining the grid frequency.

In April 2020, an urgent Grid Code modification (GC0143: "Last resort disconnection of Embedded Generation") was raised by the ESO with support from Ofgem, to address an expected period of particularly low demand ahead of the May Bank Holiday. The modification sought to minimise the risk of disruption to security of supply.

Where necessary, the ESO can issue emergency instructions to Distribution Network Operators to disconnect demand during significant events. By clarifying the nature of these instructions, the modification enabled the ESO to ensure security of supply and to meet customer expectations should any of our range of commercial tools not suffice.

Due to its urgency meaning the usual governance processes were expedited, GC0143 included a time-out date of October 2020. GC0147 seeks to establish a permanent solution of equivalent value while facilitating greater input to the solution from wider industry.

Consumers and most commercial and industrial customers / stakeholders may benefit directly from this modification, as it ultimately serves to avoid widespread black-system events.

Power Responsive Summer Insights series

As a result of the COVID-19 pandemic, we have been unable to host our usual Summer Reception to celebrate the progress made in demand side flexibility. However, in order to keep stakeholders up to date on the latest flexibility developments we launched our Summer Insights series that forms a collection of podcasts[8] from industry experts, including BEIS, DNOs, demand side providers, and the ESO. We published podcasts daily from 26 June to 10 July 2020.

BSUoS taskforce issues interim report for consultation

On Wednesday 22 July, the second Balancing Services Use of System (BSUoS) taskforce issued its interim report[9] for consultation. The taskforce was created upon direction from Ofgem, following its decision on the Targeted Charging Review, to decide which parties should be liable for Balancing Services Charges, and how these charges should be recovered. The taskforce's initial conclusions are that "Final Demand" should pay all BSUoS charges, subject to sufficient notice to industry prior to implementation, and that BSUoS should be recovered through a charge which is fixed ex ante. The Task Force is yet to recommend whether the charge should be volumetric (£/MWh) or per site (£/site). The consultation will run for 5 weeks, responses are expected by 26 August 2020.

Update on reserve procurement

We announced we do not intend to procure any further firm fast reserve in its current form. In the Thursday 16 July update[10], we stated that we do not believe it to be suitable for procuring at day ahead, and instead we intend to focus our efforts on reserve reform and the design and implementation of standardised fast acting reserve products (both upwards and downwards). We intend to continue to use the optional fast reserve service to meet our total fast reserve volume whilst we also develop and implement the new standardised reserve products and the platform in which these products can be procured via a day ahead mechanism.

Additionally, we announced we don't currently foresee any further firm Short Term Operating Reserve (STOR) procurement in 2020. Should we need to procure any firm STOR during early 2021, as it transitions to day-ahead procurement, we will announce this in good time.

[8] http://powerresponsive.com/summer-insights-2020-industry-podcasts/
[9] http://www.chargingfutures.com/media/1456/second-balancing-services-charges-task-force-interim-report-and-consultation.pdf
[10] https://www.nationalgrideso.com/document/173101/download

Role 3 System insight, planning and network development

3A Right First Time connection offers

July 2020 Performance

This metric measures whether the ESO aspects of connection offers were correct the first time they were sent out to customers.

Connections Offers	Results
Year to date number of connections offers	100
Year to date ESO related reoffers	5
Year to date percentage of Right First Time connections offers determined from ESO related reoffers	95%

Table 9: Connections re-offers data

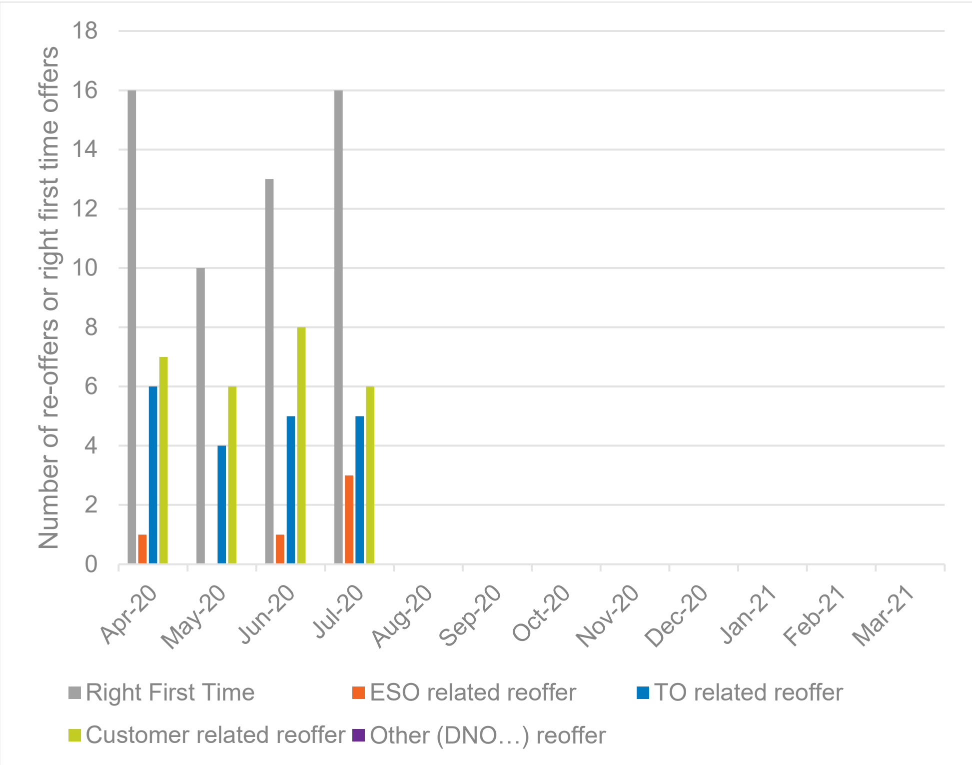

Figure 5: Connections offers monthly performance

Supporting information

We saw 28 offers returned in July, 12 of which were subject to a re-offer. There were 3 recorded ESO related re-offers on contracts signed in this period which means that we are still meeting our target at 95% Right First Time. The issues that led to an ESO related re-offer were listed as follows:

- Driven by both the customer and the ESO, amendments were made to company name and number, and to extend the acceptance date. The customer has several projects of similar names which are being developed in different similar named project companies. The initial offer was made out in the name of one of the customer's other project companies.
- The reoffer updated the Appendix F. We negotiated and created a standard Appendix F which included ESO requirements around 'Chapter 11 Voltage Regulation at the Grid Supply Point' and 'Chapter 12 Emergency Instructions for the generators on Appendix G'.
- There were several re-offers for various reasons triggered by the customer, ESO and TO. The ESO related element were some contract provisions relating to restrictions on availability and a related agreement that were missed in the customer's original offer.

Performance benchmarks

● **Exceeding expectations:** 100% of connection offers Right First Time (excluding those where the error was not due to the ESO)

● **Meeting expectations:** 95-99.9% of connection offers Right First Time (excluding those where the error was not due to the ESO)

● **Below expectations:** Less than 95% of connection offers Right First Time (excluding those where the error was not due to the ESO)

Notable events this month

Future Energy Scenarios (FES) publication and virtual events

The Future Energy Scenarios (FES) document[11] was published in July and is the result of in-depth analysis by our own team of experts, combined with stakeholder insight and input from industry specialists. This collaborative approach gives us the breadth and depth of knowledge we need to develop realistic scenarios for the future of energy in the UK.

During the week of 27 July, we held a series of virtual events[12] to share the key insight from our FES 2020 analysis. This included a launch on Monday 27 July to present the FES 2020 key messages and the significant findings from the analysis. On Wednesday 29 July and Thursday 30 July, we hosted a series of deep dive sessions to look at specific topics in more detail.

Early Competition Phase 2 consultation

We launched this consultation in early July, it sets out a proposed end to end model for Early Competition. This brings together the building blocks we discussed with stakeholders through a series of workshops in May. The consultation closed on the 14 August. We had 7 responses. We will publish a summary of the feedback in early September on our Early Competition website[13]. Supporting this consultation, we have run two webinars. The first aimed to provide a high-level overview of the content of the consultation and an opportunity for stakeholders to ask clarification questions. The second was a Q&A session held on 23 July. This session was to ask questions about the content of the consultation and to provide verbal / survey feedback on the content.

Both sessions were well received by stakeholders with them keen for us to repeat similar sessions linked to our next consultation.

Cruachan Power Station providing stability services

On 15 July Drax Group's Cruachan Power Station, a hydroelectric pumped storage plant in Scotland, started to provide National Grid ESO with vital system support services as part of a six-year contract. One of the power station's generating units will provide support services such as inertia, to keep power supplies secure without generating any electricity, and enable more wind and solar power to come online. Drax is the first of five providers to supply system support services to the grid in a move expected to save consumers more than £120m over the course of the contracts.

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[11] https://www.nationalgrideso.com/document/173821/download
[12] https://www.nationalgrideso.com/future-energy/future-energy-scenarios-fes/fes-2020-virtual-conference
[13] https://www.nationalgrideso.com/future-energy/projects/early-competition-plan

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