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ESO Forward Plan 2019-20

Monthly Reporting - April

22 May 2019

Foreword

Welcome to our first monthly performance report for 2019.

Each month we report on a subset of metrics, which have data available at monthly granularity.

Our first quarterly report of this year will be published in July, and will detail our performance against our wider metric suite together with an update on our progress against the deliverables set out in our current Forward Plan[1].

As this is the first reporting month of the new performance year, we have included background information on the metrics which explain how to interpret the performance.

A summary of our monthly metrics is shown in Table 1 below

Contents

Metric	Performance	Status
Balancing cost management	£77.1m outturn against £94.5m benchmark	● (green)
Energy forecasting accuracy	Demand forecast error above target, Wind forecast error below target.	● (amber)
Month-ahead BSUoS forecast	8% forecasting error	● (green)
System access management	2.48/1000 cancellations	● (green)
Connections agreement management	100%	● (green)
Right first time connection offers	100%	● (green)

Table 1: Summary of monthly metrics

You can find out about our vision, plans, deliverables and full metric suite in the Forward Plan pages of our website[2].

We welcome feedback on our performance reporting to box.soincentives.electricity@nationalgrideso.com .

Louise Schmitz
ESO Regulation Senior Manager

[1] https://www.nationalgrideso.com/document/140736/download
[2] https://www.nationalgrideso.com/about-us/business-plans/forward-plans-2021

Role 1 Managing system balance and operability

Operate the system safely and securely, whilst driving overall efficiency and transparency in balancing strategies across time horizons	Support market participants to make informed decisions by providing user friendly, comprehensive and accurate information

Metric 1 – Balancing cost management

Consumer benefit

We will continue to use this metric to highlight our performance on controlling balancing cost spend and the size of the BSUoS charge. The continuing decarbonisation and decentralisation of generation combined with changes in how energy is being consumed would have, without intervention, caused a significant increase in balancing cost spend. We have and continue to be focused across the organisation on finding and delivering both step-change and incremental improvements in what we do to deliver savings for the consumer through controlling, reducing and optimising this cost.

Metric

The metric compares our current balancing spend against historic trend following adjustments for significant cost drivers. The benchmark only includes cost drivers that were identified at the beginning of the year; a benchmark for expected balancing costs is derived from a linear trend through five-year moving averages of historic balancing cost (excluding Black Start), beginning with the rolling mean for 2009-2013 to 2013-17.

The methodology is unchanged from that agreed with Ofgem for 2018-19, please refer to pages 10 – 12 of the Forward Plan Performance Metric Definition 2018-19 for the methodology[3].

In 2018-19, there were unforeseen step changes in costs that were not present in the historical rolling average, or the forward-looking cost adjusters. In recognition that there are foreseeable fundamental drivers that might impact balancing costs but which historical costs might not reflect, we will also include additional adjustments. The adjustments for these foreseeable fundamental drivers this year are:

1. HVDC availability

Availability of the Western HVDC Link will continue to have a downward impact on the rolling average, reducing the constraint spend we would anticipate for managing flows from Scotland into England. We forecast a reduction in balancing spend of £135m.

[3] https://www.nationalgrideso.com/sites/eso/files/documents/Performance%20Metrics%20Definition.pdf

2. South East reinforcement work

We anticipate higher costs in operating the system caused by the unavailability of transmission assets in the South East of the network. This will be for 12 weeks and is to deliver reinforcements recommended by the NOA process. These reinforcements are required to provide increased capability on the network and optimise costs across TNUoS and BSUoS for the anticipated increased power flows driven by more interconnection.

As a result of this reinforcement we see a reduction of constraint costs of between £1.4bn and £3.7b over the total lifetime of this project. Taking the middle of this range gives a saving of ~£60m a year for 40 years. It's challenging to say specifically when these savings will occur, however our initial thoughts suggest they would occur mainly between 2020 – 2030 as that is when Great Britain is a net importer.

We forecast an increased balancing spend of £60m-80m to manage transmission network flows during this work.

3. RoCoF and Vector Shift

A programme of work is planned to start in 2019-20 to change the settings of existing RoCoF relays and replace Vector Shift relays. A recent modification to the Distribution Code requires all generators to have completed this work by 2022 to be compliant. With balancing costs rising year on year with the increasing levels of asynchronous generation, there would have been a system risk driven by these relay settings. So, to mitigate this, we have been proactive in working with all the DNOs to agree an accelerated change programme to curtail these costs earlier.

4. Other drivers

During 2018-19 we incurred additional costs in maintaining a safe and secure system. We have identified that the following further cost risks may continue into next year which may form part of further adjustments as they become clearer

- Scottish security during 2018-19: we incurred significant unforeseeable additional cost due to generator outages in Scotland. We needed to arrange contracts with different generators and take significant actions in the balancing mechanism to maintain system security. We currently anticipate that these generators will return from outage in 2019-20.
- The Capacity Market was suspended during 2018-19. This could lead to generators increasing their prices in the balancing market during periods where margins are short, in turn leading to an increase in balancing costs in 2019-20.

Performance benchmarks

Five year rolling average	Savings from HVDC	South East reinforcement increase	RoCoF increase in cost	Benchmark 2019-20
£1019m	(£135m)	£60m-80m	£110m	£1054m-£1074m

April 2019 Performance

For monthly breakdown of costs, please refer to our balancing costs webpages[4].

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Benchmark cost (£m)	83.2	97.5	75.3	85.6	87.4	96.6	103.3	98.4	91.0	82.6	81.9	81.1	1064
Benchmark adjusted for WHVDC (£m)	94.5	108.7	75.3	85.6	87.4	96.6	103.3	98.4	91.0	82.6	81.9	81.1	1086.5
Outturn cost (£m)	77.1												77.1

Note that we are including an adjusted benchmark figure due to the unplanned unavailability of the Western HVDC link during April and May.

To calculate the monthly benchmark figures, we have apportioned the benchmark for the year across the 12 months in the same ratio as our year-ahead monthly BSUoS forecast[5].

Supporting information

As we approached Easter weekend (19th -22nd April), we identified that it could be an operationally challenging period due to the unseasonal warm and sunny weather combined with low demands. These conditions were likely to increase the issues around managing embedded generation affected by RoCoF and Vector Shift protection settings. There was also uncertainty around the level of accuracy of our demand forecasts due to the unusually late Easter and significantly different weather patterns compared with the previous Easter periods.

We brought our weekend strategy meeting forward one day to give us extra preparation time, including relevant teams from across the business to refine our strategy to identify the optimum approach to manage the risk of trip to embedded generation, and ensure a good voltage profile across GB.

The outcome of this increased focus on planning for the holiday period was that the average daily costs for the weekend were lower than the average daily cost for April as a whole, when we had anticipated the potential for significantly higher costs.

Following our debrief session to review our performance over that long weekend, we have now implemented the revised process as standard ahead of future public holiday / significant weekend periods.

[4] https://www.nationalgrideso.com/balancing-data
[5] https://www.nationalgrideso.com/document/141946/download

Metric 3 – Energy forecasting accuracy

Consumer benefit

We are working in strategic areas to improve our energy forecasting accuracy. This will support market participants to manage their generation and consumption ahead of real time and therefore reduce the number of actions that we need to take to balance the system. This will result in less consumer money spent to balance the system.

Metric

Day ahead demand forecast accuracy

The day ahead demand forecast accuracy is defined as the Mean Absolute Error (MAE; MW) calculated for each cardinal point and is based on:

- Operational national outturns in MW;
- National demand forecast in MW.

For more information on cardinal points, please see our website[6].

The target for each month is the average monthly mean absolute error (MW) over the past three financial years: 2016-17, 2017-18, 2018-19. At the time of writing not all the outturn data is available for the financial year 2018-19. So, those targets affected are marked as provisional in the table below and will be revised when the data is available. By following this methodology, the day ahead demand targets are set out in Table 2.

Table 2: day ahead demand forecast targets for financial year 2019-20

Month	Target (MW)	Month	Target (MW)
April	709.9	**October**	620.7
May	598.3	**November**	600.7
June	524.4	**December**	690.9
July	542.1	**January ***	645.5
August	569.7	**February ***	667.7
September	577.4	**March ***	719.4

[6] https://demandforecast.nationalgrid.com/efs_demand_forecast/faces/DataExplorer#!1

** Provisional target to be updated when final outturn data is available.*

Every month, the resulting MMAE is compared to the respective monthly target to identify whether we have achieved our target for the month. This will result in one of the following two outcomes:

- **Target missed:** MMAE (MW) > Average Monthly Mean Absolute Error (MW);
- **Target met:** MMAE (MW) <= Average Monthly Mean Absolute Error (MW).

April 2019 Performance

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

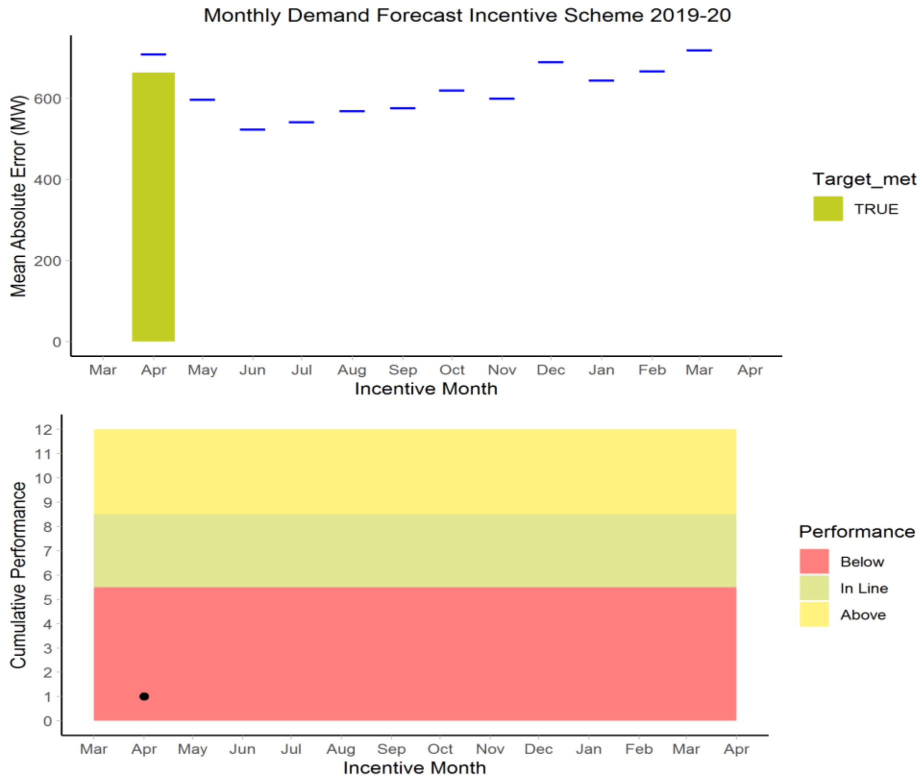


Figure 1: Demand Forecasting Performance

Supporting information

Unprecedented demand pattern on Sunday 21st April 2019:

Demands on Easter Sunday 21st May followed an unprecedented pattern. The afternoon minimum demand was significantly lower than the overnight minimum demand, by 1000MW, the equivalent of two conventional power stations. Although we have experienced the phenomenon of the afternoon trough being lower than the overnight before, it had previously been by a very small margin, and yet had still been costly to manage.

The issue was identified by demand forecasting five days ahead, and through excellent cross-team working between demand forecasting and other Commercial Operations teams, Network Access Planning teams and the Control Room, plans were put in place well ahead of time to manage the effects on the system. Consequently, with all mitigating measures in place, the cost of managing this unprecedented pattern of demand was comparable to an ordinary Sunday during the summer period.

Day ahead BMU wind generation forecast accuracy

The accuracy of the day ahead wind forecast is calculated using absolute percentage error (APE; %) calculated for each settlement period, and is based on:

- First run settlement metering data (in MW) excluding times where the wind farm received an instruction to reduce output from the ENCC: Bid Offer Acceptances (BOA)[7];
- Half hour BMU wind forecasts (in MW) excluding times where the wind farm received an instruction to reduce output from the ENCC: Bid Offer Acceptances (BOA);
- Total Wind BMU Operational Capacity. This is the total BMU wind capacity operating at national level.

  (The 2019-20 wind metric calculations will not include secondary BMU wind farms joining under Wider Access.**)**

The target is the average monthly mean absolute percentage error (%) calculated by considering the past three financial years: 2016-17, 2017-18, 2018-19. At the time of writing not all the outturn data is available for the financial year 2018-19. So, those targets affected are marked as provisional in the table below and will be revised when the data is available. By following this methodology, the day ahead demand targets are set out in Table 3:

Table 3: BMU wind generation forecast targets for financial year 2019-20

Month	Target (%)	Month	Target (%)
April	5.25	**October**	4.62
May	4.47	**November**	5.32
June	3.92	**December**	4.44
July	4.52	**January ***	5.39
August	4.21	**February ***	5.26
September	4.57	**March ***	6.06

** Provisional target to be updated when final outturn data is available.*

[7] Note that the exclusion of BOAs from this part of the calculation was incorrectly omitted in the Forward Plan text and has been corrected here.

Every month, the resulting MMAPE is compared to the predefined seasonal target to identify whether we have achieved our target for the month. This will result in one of the following two outcomes:

- **Target missed:** MMAPE (%) > average seasonal mean absolute percentage error (2018/19, 2018/17, 2017/16) (%);
- **Target met:** MMAPE (%) <= average seasonal mean absolute percentage error (2018/19, 2018/17, 2017/16) (%).

April 2019 Performance

Figure 2: Wind Forecasting Performance, shows our performance this month as the red histogram, against the blue monthly target.

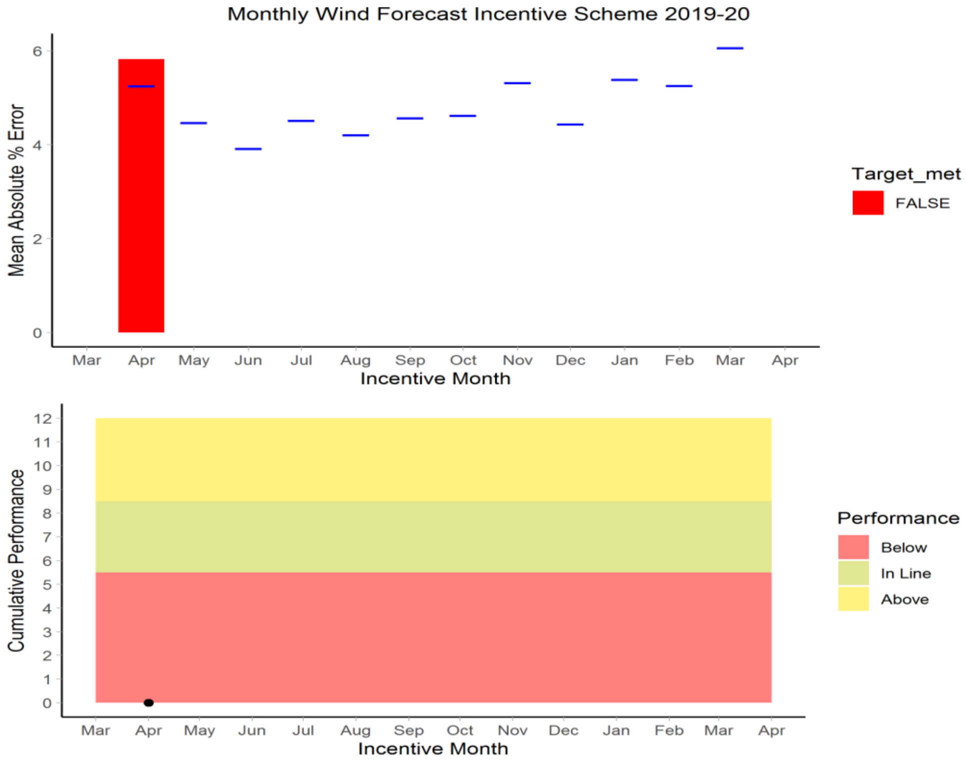


Figure 2: Wind Forecasting Performance

Performance benchmarks

At the end of the year, we will count how many months we have met our targets and apply the benchmarks:

- Below benchmark: 0-5 months;
- In line with benchmark: 6-8 months;
- Exceeds benchmark: 9-12 months.

Role 2
Facilitating Competitive Markets

Ensure the rules and processes for procuring balancing services, maximise competition where possible and are simple, fair and transparent	Promote competition in wholesale and capacity markets

Metric 9 – Month ahead forecast vs outturn monthly BSUoS

Consumer benefit

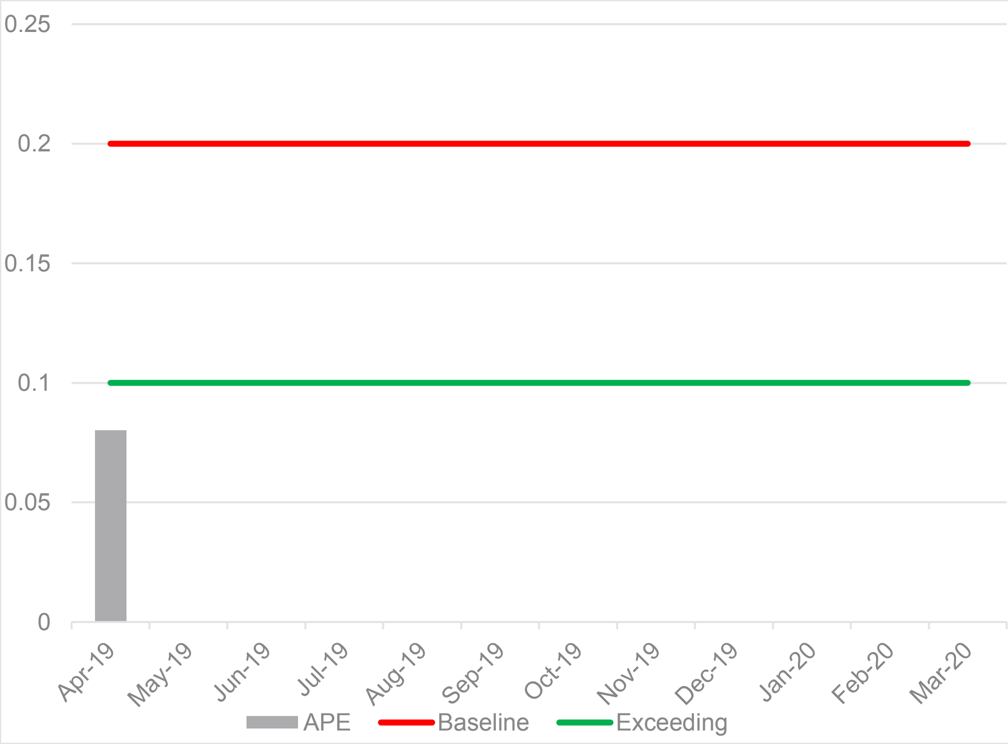
Some of our customers have told us they manage their price and balancing risks via month-ahead products. We also understand large consumers on pass-through contracts seek to understand their month-ahead BSUoS costs. For both of these reasons the quality of our month ahead BSUoS forecast can influence the risk premia that parties are having to manage with the ultimate benefit of reducing consumer cost.

Metric

The metric will count the occurrences of absolute percentage error (APE) for our monthly forecast with outturn data available at month end.

April 2019 Performance

Month	Actual	Month-ahead Forecast	APE	APE>20%	APE<10%
April-19	2.79	3.02	0.08	0	1



Supporting information

This month we achieved an error measure of 8%, which is exceeding our baseline expectation.

Outturn costs for April were close to forecast with BSUoS returning to close to its average level. The main driver behind this reduction was constraints with much lower levels of wind in April, network outages were still in place but were less impactful due to the lower wind.

Performance benchmarks

Historically, there has been significant volatility between our month ahead forecast and outturn. There can be large swings in accuracy of percentage variance. To ensure we are incentivised to improve our forecast this metric does not just look explicitly at the volatility but at the number of occurrences outside of a 10% and 20% band. This means we will be appropriately incentivised to avoid very high errors.

In 2017 we would not have met either threshold, we therefore consider these benchmarks to be a realistic performance target.

Exceeds benchmark: Exceeding is meeting baseline performance and five or more forecasts less than 10% APE.

In line with benchmark: Of the 12 forecasts over a financial year, baseline performance is less than five forecasts above 20% APE.

Below benchmark: five or more forecasts above 20% APE.

Notable achievements and events this month

- We published the Power Responsive Annual Report for 2018 on 8th April. The report builds upon previous versions, with the input of a dedicated industry group reviewing and improving the market metrics. This allowed for a greater comparison with 2017, painting an emerging picture of the direction in which demand side participation and prices are headed.
- In conjunction with Renewable UK and renewable generators, we held a Power Available industry workshop on 16th April, with 36 attendees, to seek views on data accuracy and monitoring policy. Following on from this workshop, we are conducting work to arrive at an appropriate accuracy standard for Power Available.
- We held the third Information Systems (IS) Change Forum on 30th April. This forum continues the dialogue with the industry on the IT changes and developments that are being progressed to support wider BM access and Project TERRE.
- Introducing competitive procurement for Restoration (Black Start) Services: we received 31 Expressions of Interest for the South West and Midlands competitive tender, 20 of which are eligible for the Invitation to Tender, and around half of which are from or include ‘non-traditional’ black start technologies or fuel types.

Roles 3 & 4
Facilitating whole system outcomes and supporting competition in networks

Coordinate across system boundaries to deliver efficient network planning and development	Coordinate effectively to ensure efficient whole system operation and optimal use of resources	Facilitate timely, efficient and competitive network investments

Metric 11 – System access management

Consumer benefit

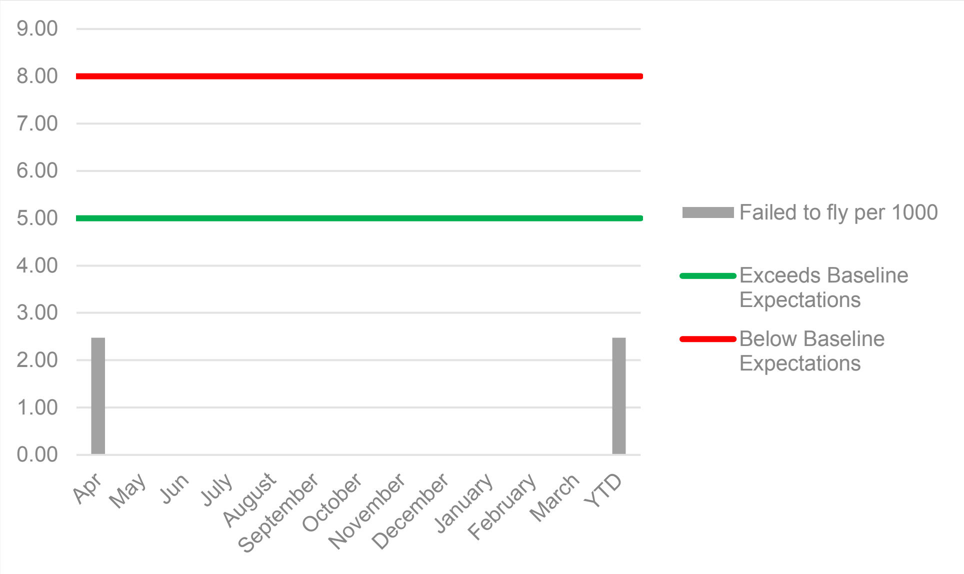
Reducing unnecessary network and balancing costs by improving the system access request planning process.

Metric

This metric focusses on driving down the number of planned outages that are delayed by more than an hour or cancelled by us in the control phase due to process failure, investigating the reason for cancellations and putting in place changes into the process where appropriate to prevent a repeat. Sometimes we should cancel system access requests that have been accepted into the plan because these are no longer securable or the costs are too high. We will continue to cancel system access requests where needed, but this number should be as low as practical to avoid costs for external stakeholders and our costs in re-planning these requests.

This measure is a count of the number of outages out of every 1,000 delayed by more than an hour or cancelled within day.

April 2019 Performance



Supporting information

The 'outage season' started on 1st April, meaning that this is when we allow more system access, due to lower peak system demands.

This year the peak system demand reduced gradually during April, and as a result there were fewer planned outages, consequently resulting in result fewer cancellations and delays.

Performance benchmarks

Current performance 2018-19: 4.47 delays more than an hour or cancellations within day per 1,000 outages accepted into the master outage plan.

(Note that in our Forward Plan we stated current performance as 5.25/1000. Since publication we reviewed the data and determined that the 2018-19 performance was 4.47/1000.)

We have set our 'exceeding benchmark' target at 5. As we enter our first year of legal separation from the NG TO, we will be implementing and refining new processes for planning and executing system access in England and Wales, and we believe this target will set us a challenge to ensure our new ways of working are efficient and effective.

Exceeds benchmark: Less than or equal to 5 per 1,000 outages

In line with benchmark: Between 4 and 8 per 1,000 outages

Below benchmark: More than 8 per 1,000 outages

Metric 13 – Connections agreement management

Consumer benefit

Reducing balancing costs by ensuring that we have access to appropriate commercial options following changes to the transmission network, to maintain its operation of the transmission system. Some agreements permit us to curtail generation under certain circumstances at no cost but if an agreement is not up to date and the generation requires curtailment, we may need to instruct this through a Bid Offer Acceptance (BOA). Ensuring that connections agreements are up to date to reflect changes to the transmission network gives us more options to ensure the system can be run safely and securely and potentially saves BSUoS cost when we would need to pay to curtail generation.

Metric

This metric will measure how long it takes from the point of notification for these agreements to be updated. This metric drives efficient and effective management of existing connections contracts by measuring the percentage of contracts up to date within nine months.

Updating connection agreements requires collaboration between us and the relevant TO and then a three-month period to get the updated agreement signed off by the customer. We cannot control all aspects of the performance as it requires interaction between us, the TO and the customer, so targets reflect this.

April 2019 Performance

Number of agreements that need updating	Number of agreements that need updating identified 9 months ago	Number of agreements updated within 9 months	Percentage of agreements updated within 9 months	Status
2	1	1	100%	●

Supporting information

Ensuring that connection agreements correctly reflect any changes to the transmission system benefits consumers by preventing unnecessary constraint costs.

This metric measures the number of connection agreements updated within 9 months of notification.

So far 2 agreements have been identified

- One was completed in April 2019, within the 9-month timeframe.
- The second is within 9 months and is due to be updated in the coming months.

Further agreements are being checked and will be added should a requirement to change the agreement be identified.

Performance benchmarks

2018-19 performance: = 86%.

Exceeds benchmark: >90% of agreements to be updated within nine months of notification.

In line with benchmark: 80-90% of agreements to be updated within nine months of notification.

Below benchmark: < 80% of agreements to be updated within nine months of notification.

Metric 14 – Right first time connection offers

Consumer benefit

Ensuring Connection offers sent to customers are 100% correct minimises re-work and facilitates timely and efficient connection to the network.

With the increase in renewable generation and smaller sized projects connecting to the networks, the customers we now work with have much less knowledge of the networks and the processes for connection. This provides us with an opportunity to provide excellent customer service and to use the skills and knowledge we have of the industry to help new entrants come into the market.

Metric

To measure the quality of a customer's connection offer we use a right first time measure. The right first time metric will report all connection offers signed within a calendar month and identify if a 'reoffer' has been made (i.e. the offer was not right first time and needed rework) and what the root cause for the rework was. Any reoffers directly attributable to the ESO will impact the performance of the metric. Any rework driven by a TO or driven by a customer change to requirements during the process will be excluded from the metric performance but reported for information only.

Performance benchmarks

Current performance: = 94%.

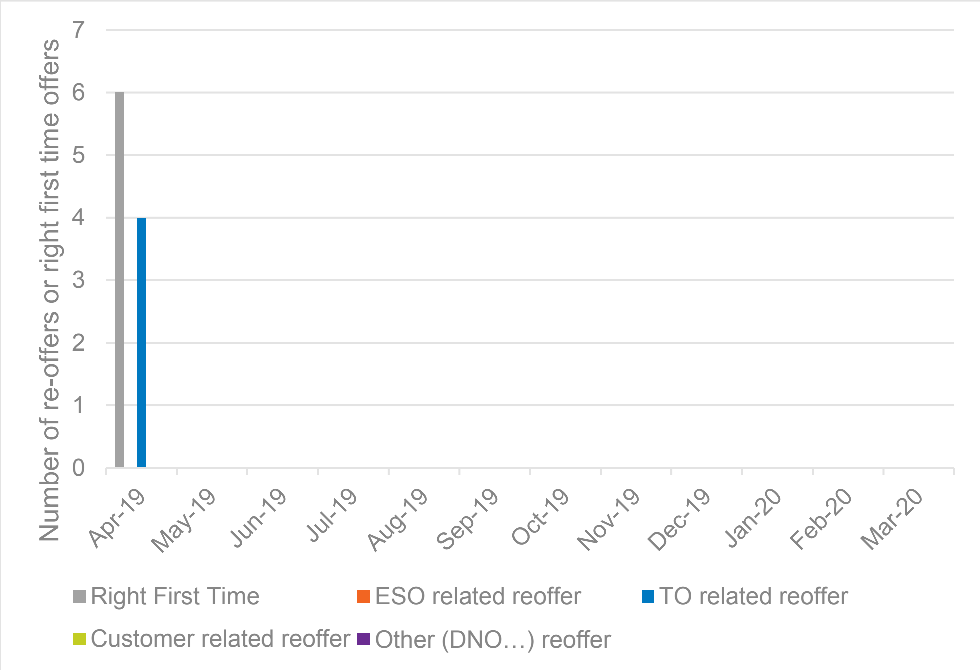
Exceeds benchmark: >95% of offers right first time.

In line with benchmark: 95% of offers right first time.

Below benchmark: < 95% of offers right first time.

April 2019 Performance

Connections Offers	Results
Year to date number of connections offers	9
Reoffer required due to ESO error	0
Year to date percentage of connections reoffers caused by ESO error	100%



Notable achievements and events this month

Network Development ran one webinar and one workshop in April. The NOA methodology webinar was on 11th April and was designed to raise people's awareness of the approaching consultation. It was the first time we have held such a webinar for the NOA methodology. Six people rang into the webinar and while none provided feedback on the webinar, two did ask questions about the NOA. The NOA for Interconnectors (NOA IC) workshop was held on 17th April, building on experience gained from holding one in May 2018. The workshop was attended by five stakeholders, and their feedback, coupled to feedback received via a one to one stakeholder meeting, provided valuable input into the development of the draft NOA IC methodology for NOA 2019/20.

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