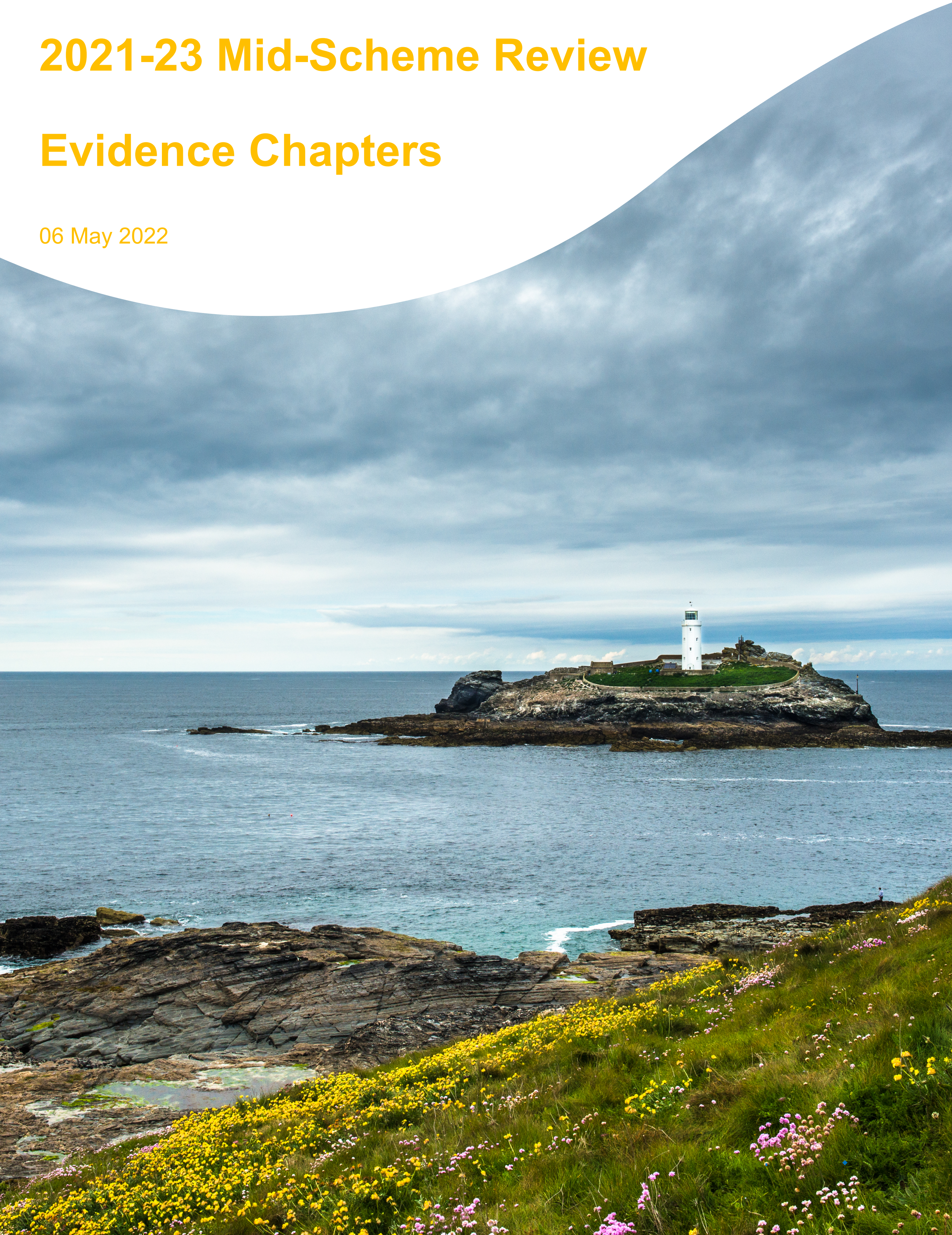
2021-23 Mid-Scheme Review

Evidence Chapters

06 May 2022



Contents

Role 1

Control Centre operations

Role 1: Control Centre Operations

Plan Delivery

- We have completed 66 out of the 92 milestones planned for this 12-month period. Of the 26 milestones which are not complete, 5 are ESO-related delays, and 21 are outside of ESO control. We have:
- Successfully operated the system under very challenging conditions.
- Launched a review of the Balancing Market and produced a balancing cost strategy.
- Continued with high levels of transparency and communication through the OTF.
- Developed new power system modelling tools and innovative inertia monitoring tools.
- Conducted a successful black start test and made good progress on the electricity restoration standard.
- Signed memorandum of understanding with ENTSO-E.

Metric performance

Over the 6-month period:

- 1A Balancing costs: £3,132m vs benchmark of £1,321m (below expectations)
- 1B Demand forecasting: 2.2% vs benchmark of 2.1% (meeting expectations)
- 1C Wind generation forecasting: 4.2% vs benchmark of 5.0% (exceeding expectations)
- 1D Short notice changes to planned outages: 1.3 per 1000 outages vs benchmark of 1 to 2.5 per 1000 (meeting expectations)

Stakeholder evidence

Role 1 survey:

- 9% exceeding expectations
- 84% meeting expectations
- 6% below expectations

Highlights:

- Our Operational Transparency Forum remains highly valuable weekly event for the ESO and industry
- Acted on feedback to ensure planned outages proceed without delay, minimising system disturbances and taking action to secure sensitive demand following unplanned faults
- Acted on feedback following our quarterly Technology Advisory Council
- Engage extensively with industry on Restoration Standard

Demonstration of plan benefits

- Control centre architecture and systems (A1) on track to deliver £305m consumer benefit over RIIO-2
- Control centre training and simulation (A2) on track to deliver £35m consumer benefit over RIIO-2
- Restoration (A3) on track to deliver £115m of net benefit from 2025 to 2050
- Implementation of Frequency Risk & Control Report (FRCR) has driven savings of approximately £435m in one calendar year

RREs:

- 1E Transparency of Operational Decision Making: 99.8% of actions have reason groups allocated
- 1F Zero Carbon Operability (ZCO) indicator: ESO has accommodated up to 87% zero carbon generation
- 1G Carbon intensity of ESO actions: Monthly average of 5.2 gCO2/kWh of actions taken by the ESO
- 1H Constraints cost savings from collaboration with TOs: £1,938m
- 1I Security of Supply reporting: 0 incidents
- 1J CNI outages: 3 planned BM outages

Value for Money

- Our forecast total expenditure for role 1 in BP1 is £246m, which is 18% higher than the benchmark of £208m
- The main driver of the deviation is increased expenditure on the Balancing Programme.
- Since our six-month report, we have re-assessed our delivery roadmap for the Balancing Programme given escalating costs
- We are engaging with industry to seek feedback on our next steps to ensure we deliver the right outcomes whilst managing our costs.

A.1 Plan Delivery for Role 1

Deliverable progress

For role 1, the RIIO-2 Delivery Schedule received an ambition grading of 5/5, providing the ESO with an ex-ante expectation of Ofgem's assessment of plan delivery if these deliverables are met. The ESORI guidance states that the Performance Panel should consider that the ESO has outperformed the Plan Delivery criterion if the ESO has successfully delivered the key components of a 4- or 5-graded delivery schedule.

During the first year of the Business Plan 1 period, a few highlights of role 1 performance are:

North Sea Link (NSL) go live

The ESO and NSL teams worked together to ensure that all the operational systems, processes and procedures were in place for the successful go live of the 1400MW NSL interconnector in October. Regular liaison took place during the commissioning phase between affected teams including the real time teams in the Electricity National Control Centre to ensure that system security and operability costs were managed during this critical phase.

We have adopted the same process with the Eleclink interconnector commissioning, and this is due to go live soon. We have also been working successfully with our interconnector stakeholders to improve communication and routes of escalation to ensure any issues are quickly resolved.

Electricity System Restoration (ESR) Standard

We established seven technical working groups in November 2021, meeting biweekly to collaborate with industry stakeholders on the framework changes needed to meet the new restoration timescales set out in the ESR Standard. These discussions with industry have been critical in helping to develop the technical requirements to deliver resilience and restoration capability. This will be essential to comply with the new ESR Standard by the end of December 2026. As planned, this work will now be moving under joint Grid Code and Distribution Code governance (code modification GC0156) to progress the code changes that are needed to implement these industry obligations.

Black Start test carried out successfully in March 2022

An Electricity System Restoration test between two power stations went ahead on 12 March 2022. A network corridor was switched out between two substations involving two Transmission Owners (TOs), ESO and TO control rooms, and TO field staff. This was geographically around 320 miles. One generator was used to energise a route progressively across Great Britain, involving nine substations in total, to create one power island. A second generator was used to energise another route to create a second power island. The two power islands were then successfully synchronised and remained stable.

This was massive success story for Electricity System Restoration within Great Britain, proving that a power island could be established across this distance. It was also a demonstration of linking power islands on the live high voltage transmission system. These tests are regularly practised on our training simulator but have not been done on the actual system for some time.

Changes to the Balancing Mechanism successfully implemented under Release R0

With the Balancing Mechanism R0 release, we have removed 8,000 hours of workarounds for our control room engineers by installing automated functionality to automatically extend existing instructions (automated instruction repeat) and additional automated data input functionality. This will help our engineers focus on important, value-add activities in an increasingly complex operating environment, and ensure their wellbeing.

To maintain continued safe and secure system operation, we've made priority asset health updates and implemented changes recommended by internal best practice process reviews. In addition, we can now make better use of wind power, building on the Power Available Phase 2 go-live in March 2021, through changes that will improve the economic advice presented to the control room.

This is a stepping stone towards achieving our zero carbon operation ambition. This is the first of a series of releases using our new release-based approach to delivery, in line with our move to a TechOps, Agile-focused way of working to deliver our transformational plan. Release R0 is part of deliverable D1.1.5 and is important to maintaining safe, secure and economic system operation while we develop and transition to our new tools.

Energy forecasting improvements through the Platform for Energy Forecasting (PEF)

Over the last 12 months, the PEF has enabled the continuous realisation of the estimated overall year-on-year benefit in balancing and reserve costs savings (~£175m) from improved forecasting models developed & delivered through PEF by maintaining the current level and improving, where possible, on forecasting performance.

We deployed the operational version of PEF into the Control Room, delivering benefits which included: features to improve security (single sign-on); enhanced monitoring of system and forecasting accuracy; reduction of manual workarounds; and new functionalities in National Control. This reduces approximately 500 hours of manual workarounds for National Control.

In addition, we agreed a reviewed roadmap for PEF deliveries in the years ahead, aiming to adopt new ways of working and a product model which will enable at least two major releases in 2022-23. This roadmap will be subject to changes as per customer prioritisation, regulatory requirements, outcome of the balancing capability review and BP2 final submission, and determination for forecasting budget.

Data and Analytics Platform (DAP)

Progress has continued on the Data and Analytics Platform. The first set of foundational platform design patterns have been built and verified by proof-of-concept in the cloud environment. Although significant churn of contracted resources in the project team has impacted progress, recruitment is under way to backfill a number of key roles. We are still on track to deliver this project within BP1. A strategic partner has been recruited to aid with a design and build, expected to start in Q1 FY22/23.

The implementation of the DAP platform is based on modern cloud-based design patterns, leveraging architectural best practice for ‘big data’ / ‘big compute’ platforms. The platform comprises various products and services that will enable the ESO to capture, curate and consume data of any variety and source, and deliver trusted, analytics ready data to the point of use, reliably and securely. To facilitate interoperability with the energy data ecosystem, data under management will be discoverable through an Open Data Catalogue, and accessible through a number of channels including API’s. The catalogue will include data dictionaries to aid understanding. All processing of data will be implemented through code, which may also be made open. Furthermore, as DAP will serve as the vehicle for all analytics development in the target state, as models and algorithms are brought under management on the platform, these too will be treated as presumed open. The platform will accommodate the creation of ring-fenced ‘collaboration zones’ whereby third parties such as academia, start-ups and other industry participants can collaborate with the ESO on specific data initiatives to support innovation and the creation of consumer value.

Artificial Intelligence (AI) and open data developments

Our ‘ESO Lab’ team uses machine learning to support different processes across the ESO, from solar forecasting to demand forecasting. We have progressed the following this year:

Our national demand AI model, introduced in May 2021, uses a transformer architecture recently developed by Google which applies ‘self-attention’. This deep neural network learns to attend to different parts of the inputs (weather, bank holidays etc.) on a case-by-case basis. Transformers have been at the heart of several recent breakthroughs in machine learning.

As part of our new Platform for Energy Forecasting (PEF), ESO Labs explored many different transformer architectures for forecasting national electricity demand. We conducted over 500 machine learning experiments over of several months. This research is still ongoing but is already being used by the Control Room, and so far the results are very promising: The accuracy of our new forecasting algorithm, based on the

Temporal Fusion Transformer architecture, showed a 58% reduction in mean absolute error 1-hour ahead. For 24-hours ahead, the mean absolute error was reduced by 14%. This algorithm informs the forecasts reported under Metric 1B Demand Forecasting.

Our carbon intensity Application Planning Interface (API), the open data system that predicts and monitors how clean electricity is, has now grown to 1.5 million hits per day and is used in industries across GB.

Operational metering requirements for aggregation

Operational metering requirements, as set out in the Grid Code, have been developed for large transmission connected generators. Aggregators seeking to enter the Balancing Mechanism (BM) with domestic flexibility are therefore struggling to meet the operational metering standards with respect to meter accuracy, latency and read frequency.

This year we have worked with aggregators and suppliers to understand their issues and find a way forward that will allow domestic flexibility to enter the BM. In March 2022 we announced a revised approach to interpreting operational metering standards that we believe works for domestic flexibility.

This approach has now gone live and through its initial trial phase in 2022 will be supported by the first dedicated industry workgroup formed under Power Responsive.

Key challenges

Balancing programme

The Balancing Programme was established to develop the balancing capabilities that the Electricity National Control Centre (ENCC) needs to deliver reliable and secure system operation, facilitate competition everywhere and meet our ambition for net-zero carbon operability.

To date, the programme has done extensive work to modify our existing capabilities to meet changing market conditions and customer requirements, however in their current form, our existing capabilities will not be able to meet all future challenges. Additional investment is required to develop new capabilities that can meet changing requirements to ensure that we have the vital flexibility to facilitate future changes, both expected and emerging, across the industry.

We have assessed the scale of change and complexity associated with ongoing transformation of our systems whilst maintaining our existing systems and enabling market changes and now have a better understanding of the complexity of change required and the large number of dependencies involved in transitioning from old to new systems.

The changes to the scope of the Balancing Programme have resulted in forecast costs that are £42m higher than the cost benchmark for within BP1. This is mainly due to now having a better understanding of scope, requirements and required solutions for future balancing services, which has resulted in higher than estimated costs. For existing balancing solutions, in BP1 we did not account for the level of change required to improve asset health while Balancing Transformation is being delivered.

Due to these increasing costs, we have stepped back and undertaken a review of our strategy, roadmaps and delivery plans. We have also initiated a process of engagement with industry to ensure that we are making the right choices to meet our goals, the needs of the market, and that we do so in a cost-efficient, transparent and effective way.

Balancing costs

The cost of operating the electricity system this year has been very high and well above the benchmark set and reported against in Metric 1A each month. Unprecedent increases in wholesale prices of electricity, coupled with extreme peaks in prices submitted in the Balancing Mechanism (BM) during periods of tight system margins due to market scarcity have been the key challenge throughout the year, and particularly over the winter period. The ESO is a price taker in the BM which has resulted in periods where we had to accept high priced offers in order to maintain system security.

Balancing actions taken to manage constraints on the system have been lower in volume than last year with the exception of January and February where high wind levels and planned network outages resulted in a higher volume of actions required. The high cost of constraints during the second half of the year is driven by the high offer prices available to the ESO when replacing the energy taken off the system to manage constraints, rather than simply the high bid prices on constrained generation.

The cost of balancing actions to manage non-constraint issues on the system has been higher than last year for the entire year despite the volume of actions taken being lower on the whole. This points to the key driver of cost being the increased prices submitted by market participants, particularly in the BM, but present throughout all of our markets.

CUSC modification CMP381 sought to defer exceptionally high winter 2021/22 BSUoS costs to 2022/23. The ESO worked closely in the workgroups and with Ofgem to facilitate this code modification which introduced a cap on BSUoS charges, protecting market participants over the winter period. These costs will be recovered across 2022/23.

We look at this year's balancing costs in detail below in Metric 1A Balancing Cost Management.

We have taken a number of steps to address the unprecedented balancing costs we have seen over the last year. Work under way on our strategy for managing Balancing Costs is detailed below. Our Market Monitoring team has also carried out a review of the Balancing Market, which is outlined in the 'New initiatives and changes' section.

Our strategy for managing balancing costs

The ESO understands the impact of balancing costs on its customers and their businesses and ultimately to all consumers, particularly given the overall increase in other energy costs and general cost of living crisis. This created a need to take additional action and move beyond the ESO's regular, continuous improvement activities and ensure that the ESO is doing as much as possible to effectively manage the elements that are under its control.

A team was established to carry out this enhancement work, focussed on three main areas:

- Tactical improvement activities that, once implemented, will have an immediate, positive and enduring impact on balancing costs. Three initial proposals are currently being analysed for piloting during April to June, in the following areas: maximising trading and market impact on margins; real-time constraint optimisation; and maximising accuracy of demand forecast at national and GSP level in operational timescales. The next step is a pilot of actions in each area to ensure that adequate benefit will be realised. If successfully implemented, these ideas are expected to realise reductions in the range £10m - £50m in balancing costs per year based on current electricity prices. Longer term strategic improvement ideas and other wins will be pursued during the next performance year.
- An end-to-end process review to fully understand our processes from a balancing cost perspective and to develop improvements in activities that span multiple teams. Relevant tactical improvement ideas from Role 1 will be included as well as collecting Role 2 and Role 3 improvements.
- Improved monitoring and measurement of our balancing cost activities and actions including these tactical improvements and actions identified as part of the process review

Managing the system through the winter

Initial analysis of winter 2021-22 shows that we experienced a warm winter without any severe cold periods. Wind was slightly stronger than the long-term average, but with no prolonged low wind periods. The consequence is that electricity demands were in the lower end of the expected range. Generation outages were close to normal levels, but interconnector outages were higher than average.

Progress of our deliverables

Our RIIO-2 Deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables. The first column shows how our deliverables meet the requirements of the Roles Guidance set out by Ofgem.

For Role 1 (Control Centre Operations), the Delivery Schedule lists 44 deliverables in total, which is made up of 198 milestones.

- 92 of these milestones were due to be completed in 2021-22, of which 66 are now complete.
- Of the 26 milestones which are not complete, 5 are ESO-related delays and 21 are outside of ESO control.

We provide detail below about those activities where milestones are not on track:

ESO-related delays:

D1.4.1 Creation of a data and analytics platform (3 delayed milestones)

- Significant churn of contracted resources in the project team has hampered progress on the data platform, with recruitment under way to backfill a number of key roles. A strategic partner has been recruited to aid with a design and build, expected to start in Q1 FY22/23.
- The scope of work and deliverables is currently being reviewed with the Operability Intelligence team and is scheduled to complete by end of Apr 2022, within BP1. The master data management strategy is also scheduled to complete by April 2022.

D1.1.7 Produce and publish detailed forecasts and analysis (1 delayed milestone)

- The milestone has been delayed due to issues related to hosting infrastructure availability in the production environment. These issues have been resolved, and a plan is in place to implement delayed forecasting products incrementally to deliver in FY23.
- PEF is a continuous improvement project to develop and implement ESO's new forecasting capability. We are adopting a new way of working and have started delivering forecasting as a product. We are exploring options to further enhance and implement newly developed forecasting products into operational use and share it with the market (where possible).

D1.2.2 Develop inertia monitoring capabilities (1 delayed milestone)

- Delayed activity due to priority focus on other activities across the delivery milestones. Activity had started to pull together the requirements both from internal and external stakeholders. Impact assessment to be completed in 2022-23.

Delayed due to issues which are outside of ESO's control in the short term:

D1.2.2 Develop inertia monitoring capabilities (5 delayed milestones)

- The second supplier's inertia monitoring solution is continuing to experience technical issues during testing and is now expected to be completed in April 2022.
- Stability Phase 2 development work was delayed due to high number of applications received and associated impact of TO assessment timeframes.
- Visibility milestone delayed due to priority focus on other activities across the delivery milestones.
- Constraints Management Pathfinder - Services now expected to go live in October 2023 based on TO intertrip implementation. IT services will be in place by that time and will not impact on go live date.

D3.3.1 Trial case studies based on different technology types (2 delayed milestones)

- The project end date has been extended to 31st December 2022 to allow completion of the Redhouse case study trial (proof of concept from new technology - grid-forming battery) and provide sufficient time for inclusion of the Distributed Restart project final proposals and functional designs report. This trial has been pushed back to Autumn 2022 due to discovery of network technical risks requiring additional equipment to be installed on the network. The team is working to deliver this in September 2022.

D2.2.2 Enhanced training and simulation with DNOs and wider industry (2 delayed milestones)

- Initial scoping and idea proposals were delayed due to authorised resource availability and the impact of COVID-19 (due to time to recruit, train and authorise there is no quick fix). This has now started. The framework is now being created to approach a variety of industry members to consider what secondments could be offered, and to understand the benefits these could bring. Initial list of DNO contacts is being created to explore the use of joint simulation training.

D1.3.1 Develop and deliver new real-time situational awareness tool (2 delayed milestones)

- A number of projects have been delivered such as SSD hard drive proof of concept and existing energy management system penetration testing. However, some projects such as Fault Level Enhancements have been delayed due to other projects blocking build deployment paths. The procurement process is at the final vendor selection stage. Negotiations on scope with the vendors has pushed back the award process by a few weeks.

D1.1.4 Liaise with ENTSO-E (1 delayed milestone)

- The ESO has withdrawn its membership of ENTSO-E from the end of 2021 as requested by the Trade and Co-operation Agreement (TCA). A Memorandum of Understanding (MoU) has been agreed between ENTSO-E and NGESO to define the future cooperation. The original milestone date was proposed in the TCA and it has become clear that defining the future arrangements for cooperation with all European TSOs will take longer than originally anticipated and will require an agreed co-ordinated approach by both the UK and the EU.

D2.3.1 Upgrades to current simulators (1 delayed milestone)

- We have arranged to meet with other industry partners to explore their use of simulator training and share best practice amongst ourselves, to better inform future simulator development. Visits are planned throughout 2022. These were planned earlier however due to COVID restrictions in place at the time it was not practical.

D2.4.1 Personalised updates and automated shift logins (4 delayed milestones)

- The project has stalled due to a number of complex issues including the buyout of the previous company to a larger company that is rescoping the system and its deliverables

D3.2.1 Facilitate and compile the annual assurance process for GB Black Start (1 delayed milestone)

- This milestone is no longer applicable as NGESO have been given until Dec 2026 to implement all changes needed to meet the standard.

D3.2.2 Validate restoration timelines for GB (1 delayed milestone) and D3.2.3 Maintain obligations and requirements against the new standard for Black Start capability provision (1 delayed milestone):

- This milestone is no longer applicable as NGESO have been given until Dec 2026 to implement all changes needed to meet the standard.

D3.2.4 Restoration decision making support tool designed and developed (1 delayed milestone)

- This was delayed to allow for stakeholder engagement in development of scope and requirements.

New initiatives and changes

Market monitoring and review of the Balancing Market

In April 2021, Ofgem introduced a new licence obligation for the ESO to proactively monitor activity in balancing services markets. This obligation results from the EU Regulation on Wholesale Energy Market Integrity and Transparency (REMIT), under which the ESO is a Person Professionally Arranging Transactions (PPAT). The ESO have had a small team of experienced staff in place to fulfil this obligation since November 2021. Consistent with KPMG's risk assessment recommendations, we have prioritised monitoring the BM by designing a tool which will extract data and query it against participants' submitted dynamic parameters in line with the open letter from Ofgem in September 2020, and REMIT and other market rules. The team's processes for monitoring and for submitting Suspicious Transaction Reports (STRs) to Ofgem is in place and working well, and we continue to work closely with Ofgem in submitting these reports. In our most recent progress review meeting with the Ofgem REMIT team, it was confirmed that the Market Monitoring team are meeting Ofgem's expectations as a PPAT.

In the latter part of this year our focus has turned to expanding our monitoring capability beyond the BM, to cover other ESO product groups such as Restoration, Trading and Ancillary Services. An in-depth risk assessment has been conducted into each of these areas and processes are now being implemented to mitigate any risks of manipulation.

On top of establishing our monitoring processes, the Market Monitoring team have also been driving a review of the Balancing Market, which is seeking to understand the reasons behind the exceptionally high cost of balancing on certain days in the latter half of 2021. Initial findings from the data analysis phase of the work were shared with stakeholders via a webinar on 29th March. In summary, the review has found that high costs have been driven by system tightness combined with accepted offers of up to £4,000/MWh across a large amount of coal and CCGT capacity. The size and inflexibility of the relevant units (embodied by declared dynamic parameters) has meant that the ESO had to accept offers up to £4,000/MWh across multiple hours just to cover the peak.

The stakeholder engagement phase is underway, for which we have held four multi-party roundtables, one single-party call and a questionnaire. We are now following some additional lines of investigation as a result of our engagement, and we hope to have a finalised report to share with Ofgem during May.

Improved power system modelling

We are acquiring new PSCAD software licenses and developing our internal capability to be able to run more advanced simulations in PSCAD. This will help us to detect issues related to the system disturbances observed in Scotland in the first half of the year. We have delivered this earlier in response to need. We have been establishing the necessary models in the new PSCAD software since our investigation into system disturbances started last Autumn. We have made good progress so far with positive engagement with system users. Before we build a full model of the GB system in PSCAD, the joint ESO/TO working group carried out studies in PSCAD to investigate the oscillation we saw last year.

Frequency Risk and Control Policy

Changes to the ESO's frequency policy as a result of implementing the recommendations of the first ever Frequency Risk and Control Report in 2021, combined with ongoing delivery of the Accelerated Loss of Mains Change Programme (ALoMCP) and growth of volumes participating in the Dynamic Containment (DC) service, have resulted in significant savings to how frequency risks are managed on the system. As a direct result of these changes, the ESO has reduced the volume of constraint actions on the system from 8TWh in 2020 to 1TWh in 2021 (calendar years). We estimate that this reduction represents a saving of £435m when compared with the actions we would have been required to take without the FRCR policy.

For full details, see our Consumer benefit case study for Role 1: FRCR.

Domestic flexibility trials

Across the ESO there are several innovative projects exploring the capability of new technology and asset types providing flexibility to the GB energy system. The ongoing trials detailed below all explore how aggregating different domestic assets can provide benefit to the future energy system, with the consistent aim of trying to create a pathway into balancing markets to maximise participation and value from the technology type.

At present there are several elements of market design that make it difficult for domestic assets to offer their flexible services. There are also many unknowns around the capability and reliability of these technology types when aggregated and applied to market conditions. Through our innovation projects we aim to bridge the gap between the current barriers in market design and the capability of domestic flexibility, to help shape a pathway for participation for new technologies in balancing activities.

1. Octopus Energy flexibility trials:

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

The trial ran from 11 February 2022 to 31 March 2022, and assessed the roles households can play during period of low margins. It was made available to Octopus Energy's 1.4 million smart meter customers. We have had eight separate events across three different time windows.

We informed Octopus Energy of each event at the day-ahead stage. This was determined using a methodology which was shared at our Operational Transparency Forum before the trial started. Octopus Energy have incentivised customers taking part to get paid if they decrease their power consumption below their usual levels for the above events. The first event on 24 February had demand reduction volumes of up to 30MWs, with 35,000 customers participating.

We will now be taking the data and learnings from the trial and reporting back our findings to the industry in Q1 2022/23. This will include the next steps which feed into other ESO initiatives and will be aligned with our RIIO-2 deliverables.

2. Powerloop Vehicle-to-Grid trials

Octopus Energy have also partnered with the ESO for an innovation project funded by Innovate UK to look at the viability of Vehicle to Grid (V2G) enabled Electric Vehicles (EVs) joining the Balancing Mechanism (BM). They will be making a fleet of 135 Nissan Leaf EVs with a combined capacity of 918kW spanning across 3 GSP groups available to us to test the viability of these class of assets.

The BM is currently the largest flexibility marketplace, and the primary tool for the ESO to solve multiple grid issues in real time. As the industry works towards its net zero goals, the actions taken within the BM will have an increasing focus on minimising carbon output, meaning alternative, greener flexibility options will need to be explored and utilised. By aggregating a portfolio of V2G EVs together, a 'battery-like' response can be provided to the ESO. This could compete alongside grid-scale storage assets to help provide flexibility ahead of fossil fuelled powered generation and contribute towards the transition to net-zero. Through providing this flexibility, EVs will also create a revenue stream for market participants, which will ultimately be fed back to the end consumer.

We will publish our findings following completion of the trial in June 2022.

Development of new Inertia Monitoring tools

During the year we have continued to develop our new inertia monitoring tools. These tools have emerged out of innovation projects with industry and been developed in partnership with two suppliers: GE Digital and Reactive Technologies. These 'first-of-their-kind' operational installations will enable us to have a clearer view of the total inertia on the GB system.

Historically inertia was provided by conventional coal or gas plant, however the reduction in fossil fuel generators has reduced the volume of inertia. The new tools will enable the ESO to have a clearer view of the inertia on the system, to be able to manage it and safely connect more zero carbon power.

The first tool, GE Digital's Effective Inertia tool, builds on the phasor measurement units (PMUs) that are being rolled out across RIIO-2 by Transmission Owners (TOs) to monitor the transmission network. The use of operational data from a number of our existing tools enables an inertia forecast to be calculated for each settlement period up to 24 hours ahead. GE Digital's effective inertia tool has been operating since October 2021 proving live inertia monitoring and 24-hour ahead forecast of the inertia contribution for Scotland. As an innovative solution, we are validating the results, including working with the National Physical Laboratory (NPL), ahead of introducing the tool into our Control Room in early summer 2022. As the TOs continue to install PMUs at the required locations within their networks, we will increase the coverage of this tool to include England & Wales, also enabling a GB inertia value to be calculated.

The second new tool is being developed in partnership with Reactive Technologies. This uses a different approach to the GE Effective Inertia system, requiring the world's largest continuously operating grid-scale ultracapacitor to send a pulse of power through the grid, enabling an inertia value to be measured. The ultracapacitor is completing commissioning ahead of the system going live in late April 2022. Following a period of assessment, it is anticipated that this second tool will also go live in our Control Room in summer 2022.

Memorandum of understanding signed between the ESO and ENSTO-E

Following the UK withdrawal from the EU, in accordance with the UK-EU Trade and Cooperation Agreement (TCA), ENTSO-E and the ESO discussed the need and the possibility of the ESO remaining a Party to several ENTSO-E Association level contracts. The aim of this was to ensure continued and unfettered access to the systems and processes required to ensure future cooperation with that outlined in the TCA.

The technical and legal high-level principles of future cooperation, and the associated access to the required systems and processes were reviewed, agreed, and documented in a Memorandum of Understanding (MoU) between the ESO and ENTSO-E. The MoU covers the continued access to the European Awareness System (EAS), the Operational Planning and Data Environment (OPDE) and the Physical Communications Network between the ESO, the European TSOs and the Regional Security Coordination Centres (RSCs) in Europe. In addition, the MoU covers the partial access to the RSC tools, namely Short Term Adequacy (STA), and the withdrawal from the Verification Platform Agreement as it is no longer required following the UK withdrawal from the EU.

The MoU was signed in December 2021 by the ESO and ENTSO-E. The first two contracts covering the European Awareness System and the Physical Communication Network were amended in line with the principles agreed in the MoU and signed in Q1 2022. The remaining affected contracts will be amended and signed by June 2022.

These amendments ensure unfettered access to the tools and processes which support security of supply between GB and Europe. They also enable future cooperation whilst awaiting a decision on the new methodology of Capacity Calculation resulting from the TCA.

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 1. Some of these projects are funded as part of the RIIO-2 price control, and are therefore eligible for consideration as part of the RIIO-2 incentive scheme. Other projects were funded as part of the ESO's RIIO-1 innovation funding, but are included for completeness as they support some of the ESO's RIIO-2 deliverables. The references in the table below provide links to additional information about each project.

Innovation Project Name	Description	Progress update	Deliverables supported	Status	Funding
Solar Nowcasting[1]	Research and Develop the use of machine learning & satellite images to nowcast PV at GSP-level.	Work package 1 deliverables have been published and the results we have achieved so far are very promising. Solar Nowcasting's best forecast is already 2.8 times more accurate than the existing PV forecast, with a mean absolute error (MAE) of 230 MW vs 650 MW. Work is underway to deliver a graphical user interface (GUI) displaying the forecast into the control room.	D1.2.3	Delivery	RIIO-2
Control REACT[2]	Provide information about forecast uncertainty, presented in real-time to Control Room engineers, to provide opportunities for them to make more economic and secure balancing decisions.	This project has successfully completed. We are currently planning to use the deliverables from this project to build a probabilistic forecasting platform on an ESO managed cloud environment. The platform will support the delivery of probabilistic forecasts of demand and generation and will facilitate their use for forecasting reserves and margins as demonstrated in the project.	D1.2.3	Completed	RIIO-1
Distributed Restart (NIC)[3]	Process and market for procuring restoration capability from distributed resources.	The procurement & compliance workstream delivered a new contractual and funding framework, now under review with the Electricity System Restoration Standard (ESRS) Project. A series of desktop exercises proved the concept of a Central Organisational Restoration model. These deliverables were supported by an innovative communications plan, using podcasts and industry expertise to share new knowledge. Demonstration of a bottom-up restoration via Distributed Generation is	D3.3.1, D3.3.2	Delivery	RIIO-1

[1] https://smarter.energynetworks.org/projects/nia2_ngeso002

[2] https://www.smarternetworks.org/project/nia_ngso0032

[3] https://www.smarternetworks.org/project/nic_esoen01

		ongoing until we close the project at the end of this year.			
Short-term System Inertia Forecast[4]	Proof of concept for an accurate day-ahead and intra-day system inertia forecast with multi-time resolution, that can be potentially used to support the day-ahead frequency response procurement and the real-time system operation.	This project has now successfully completed. Next steps planned include validating and benchmarking the inertia forecasting model under GB context when inertia measurement is available, and investigating the impacts of decreasing short circuit level and system strength in high power electronics penetrated systems.	D1.2.2	Completed	RIIO-1
Dynamic Reserve Calculation[5]	Use AI and machine learning to set reserve levels dynamically, at the day ahead stage.	Dynamic Reserve Setting is on track to deliver all outputs on time at the end April 2022. We are currently planning to use the deliverables from the project to build a day-ahead forecasting system for operational reserves to support control room operations.	D1.2.3	Delivery	RIIO-2

Note that the Control REACT and Dynamic Reserve Calculation projects also feed into role 2.

[4] http://www.smarternetworks.org/project/nia_ngso0020

[5] https://smarter.energynetworks.org/projects/nia2_ngeso003/

A.2 Metric Performance for Role 1

Table 1: Summary of metrics for Role 1

Metric		Measure	Unit	Full year 2021-22 Benchmark	Actual	Mid-scheme status
1A	**Balancing Costs**	*Total balancing costs*	£m	**1,321**	**3,132**	**Below expectations**
1B	**Demand Forecasting**	*APE (Absolute Percentage Error)*	%	**2.1%**	**2.2%**	**Meeting expectations**
1C	**Wind Generation Forecasting**	*APE (Absolute Percentage Error)*	%	**5.0%**	**4.2%**	**Exceeding expectations**
1D	**Short Notice Changes to Planned Outages**	*Number of short notice outages delayed by >1 hour or cancelled, per 1000 outages, due to ESO process failure*	#	**1-2.5**	**1.3**	**Meeting expectations**
2A	**Competitive procurement**	*% of services procured through competitive means (auctions and tenders) calculated by £ expenditure*	%	**50-60%**	**51%**	**Meeting expectations**

Metric 1A Balancing cost management

April – March 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 (2018-19, 2019-20 and 2020-21). 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

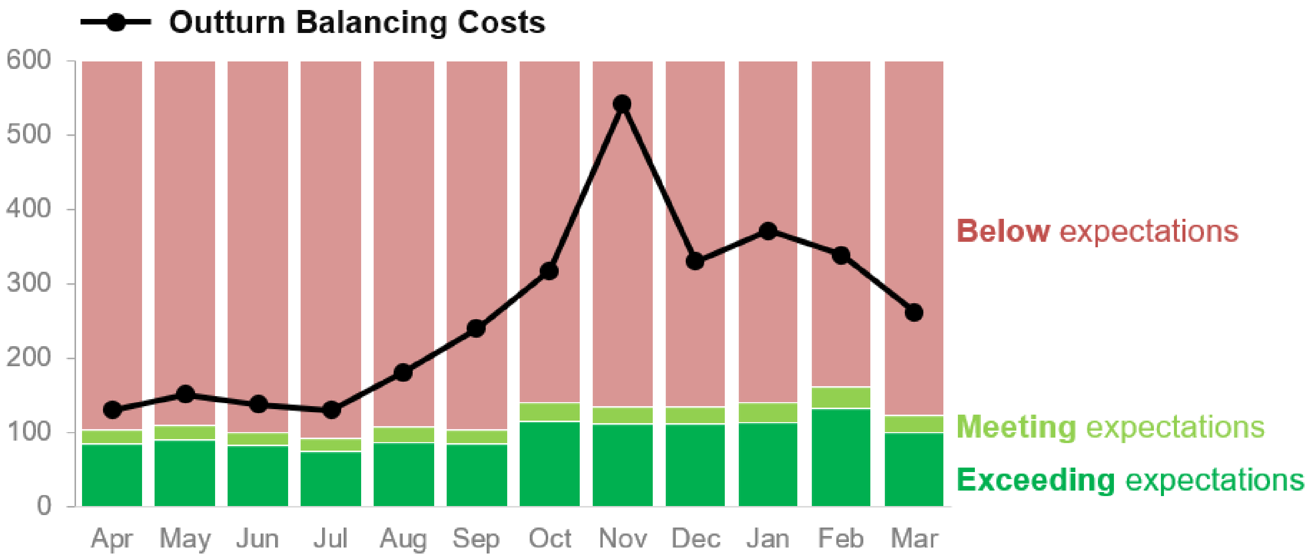


Table 2: Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
Benchmark: non-constraint costs (A)	41	41	41	41	41	41	41	41	41	41	41	41	**495.8**
Indicative benchmark: constraint costs (B)	60	51	52	49	58	67	76	75	82	82	88	81	**821.3**
Indicative benchmark: total costs (C=A+B)	101	92	94	90	100	108	118	116	124	123	129	123	**1317.1**
Outturn wind (TWh)	2.8	3.2	2.5	1.9	3.0	2.8	5.5	5.1	5.1	5.4	7.1	4.1	**48.4**
Ex-post benchmark: constraint costs (D)	53	59	50	42	56	53	87	82	81	85	106	70	**825.3**
Ex-post benchmark (A+D)	95	100	91	84	97	95	128	123	123	127	147	111	1321.2
Outturn balancing costs[6]	130	152	138	131	181	240	317	542	330	372	339	262	3132.6
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

Rounding: monthly figures are rounded to the nearest whole number, with the exception of outturn wind.

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

Due to the complexity and importance of this metric, and in response to stakeholder feedback, below we provide a significant amount of detailed analysis and context which is set out as follows:

1. **Mid-scheme performance summary**
2. **Actions taken by the ESO to reduce balancing costs**
3. **Drivers of balancing costs**
4. **Explanation of the ESORI benchmark**
5. **Year-to-date performance** – detail
6. **March 2022 performance** – detail

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

1. Mid-scheme performance summary

Balancing costs across the past 12 months have been significantly higher than the previous year (2020-21) and significantly higher than the benchmark.

Throughout the year, day ahead prices have been higher than they were at their peak last year, and in the second half of the year they have increased to the highest they have ever been. In addition, very high Balancing Mechanism (BM) offer prices submitted during periods of tight system margins were required to be taken by ESO to maintain system security. The ESO's real time actions, trading activities and newly introduced changes for this year, such as FRCR, have had demonstrable impacts on costs and volumes of energy procured. The volumes procured this year were lower than the previous year in 11 out of 12 months, but the cost per MWh was higher, leading to higher overall balancing costs.

The following activities are also under way:

Review of the Balancing Market

- The ESO Market Monitoring team are leading a review of the Balancing Market, which is seeking to understand the reasons behind the exceptionally high cost of balancing on certain days in the latter half of 2021. See 'new initiatives and changes' under Plan Delivery for more detail.

Our strategy for Balancing Costs

- As outlined above in the Plan Delivery section on challenges we've faced in 2021-22, we have a team in place that is developing our approach to managing balancing costs on an ongoing basis. This includes tactical improvements, a review of the end-to-end process, and improved monitoring of balancing cost activities.

Engagement with Ofgem and the ESO Performance Panel

- We have been in regular communication with Ofgem on the subject of balancing costs throughout the year. In March 2022 we held a session with the Panel to go talk specifically about balancing costs, the challenges we face, and steps we are taking to address them. We plan to hold further sessions as long as the Panel finds these useful.

Review of Balancing Costs benchmark

- We do not believe that the current benchmark for this metric is suitable for tracking performance against. We discussed with Ofgem the possibility of revising the benchmark. The idea of linking the non-constraint costs benchmark to wholesale costs was considered a possible solution. We concluded that the balancing market review and strategy work outlined above should be completed first, as this will give us a more complete understanding of the drivers of costs. We will continue to engage with Ofgem and consider a future change to the benchmark. We talk about the current benchmark in more detail later in this section.

Below we summarise the main factors impacting this year's balancing costs performance.

Unprecedented rises in wholesale costs, and periods of scarcity pricing	This year's high balancing costs have been predominately driven by high prices in the BM and throughout the market. As the cost of gas and emissions has gone up, we have seen significant increases in the day ahead power prices, impacting the cost of the actions we need to take to balance the system. This is most relevant when we are seeking to increase the output of generation (buy/offer). It is less relevant when we are seeking to decrease the output of generation (sell/bid), as these actions often involve renewable generation, which is not impacted by gas prices. However, when an action is taken to resolve a constraint, for example a bid at a wind farm to resolve a wind-driven constraint, there will be a corresponding offer action taken elsewhere to rebalance the energy on the system. When the price of this action is inflated, the cost of managing constraints will creep up. Whilst power prices have continued to rise throughout the year, from August 2021 balancing costs escalated significantly. Throughout the winter months we saw a number of periods of tight margins where scarcity pricing,

	particularly in the BM, meant that actions were taken at prices up to £4,000/MWh to meet Operating Reserve levels and maintain system security.
Lower volume of balancing actions taken, but at higher cost	Compared with 2020-21, in the majority of months, the volume of actions taken for both constraints and non-constraints has been lower. This reduction is due to several factors including the changes to frequency risk management and the removal of COVID-19 mitigating measures which had impacted on constraint costs the previous year. Non-constraint costs are directly impacted by wholesale prices and scarcity pricing. We cover this in more detail in the year-to-date performance section below. For constraint costs, in the first half of 2021-22 we spent around £270m less than the same period in the previous year. In the second half of the year, constraint costs were significantly higher than last year, and the volume of actions increased significantly. During periods of high wind and reduced boundary capability (due to system outages) we had to take action to reduce generation to manage thermal constraints. Although the volume of actions did increase through the second half of the year, the increase in constraint costs is more driven by the cost of replacement energy being high. When an action is taken to manage a constraint in the BM, a corresponding action will be required to bring the system back to balance. As an example, if a bid is taken to manage a constraint, then replacement energy will need to be bought. In a situation where offer prices are inflated due to increased wholesale power price and/or scarcity pricing, the cost of this replacement energy can be significantly higher.
Large variations in renewable generation output	Over the 12-month period we have seen significant variation in the proportion of generation provided by wind power. This ranged from September 2021 when wind power was at less than 10% of overall generation for sustained periods, to a new record of 19.5GW of wind generation in January 2022. Low wind generation output, combined with reduced levels of power imported from Europe due to interconnector outages and power prices, contributed to tight margins and high system prices at times. At the other extreme, in February 2022 when wind generation was higher than at any point last year, large volumes of actions had to be taken to manage thermal constraints and voltage.
Frequency Risk & Control Report (FRCR) implementation has led to a significant savings in RoCoF constraint costs	Changes to the ESO's frequency policy as a result of FRCR implementation in 2021, combined with delivery of the Accelerated Loss of Mains Change Programme (ALoMCP) and growth of the Dynamic Containment (DC) pipeline, have resulted in significant savings to how frequency risks are managed on the system. For full details, see our Consumer benefit case study for Role 1: FRCR. The 2022 FRCR Report was submitted to Ofgem for approval on 1 April 2022 and can be downloaded here.
Introduction of Dynamic Containment	The introduction of the Dynamic Containment (low and high) service, as part of our changes to evolve frequency control as described above, has increased the volume of response we hold. Market participants who previously participated in the Firm Frequency Response market have moved over to the Dynamic Containment market. This has reduced competition in the Firm Frequency Response market and resulted in lower volumes procured through this avenue. At times, this has left more requirement to be filled in the BM via mandatory Frequency Response to secure the system while these markets are developing and competition increases. The response procured in the BM is particularly affected by the increase in energy costs, i.e. where the cost of the action needed is increased.

	This has offset some of the savings achieved by the implementation of FRCR. These changes combined have enabled a risk-based approach to managing frequency risks, resulting in lower constraint costs. Overall, the FRCR, along with Dynamic Containment and continued delivery of the Accelerated Loss of Mains Change Programme (ALoMCP) is delivering a net reduction in frequency control spend by formalising the balance between the cost of securing the system and which risks are required to be secured operationally. The additional control of a fast acting response product has enabled a step change in frequency management by no longer having to constrain large loss risks to avoid a consequential RoCoF (Rate of Change of Frequency) event that may result in unacceptable frequency conditions. These actions have a direct balancing cost saving as well as reducing the volume of market re-positioning the ESO needs to undertake to secure the system. For full details, see our Consumer benefit case study for Role 1: FRCR.
Historic decisions such as 'Connect and Manage' continue to impact balancing costs	The actions which have the greatest impact on balancing costs are made in the longer-term timescales, outside of the Role 1 activities. Historic decisions have had a significant impact, for example the Connect and Manage regime has been successful in delivering the fastest decarbonising grid in the world. The impact of this regime is that the costs previously incurred in TNUoS are now realised in BSUoS, in the form of constraint costs and in more actions needing to be taken to manage inertia.
ODFM in place in 2021 but not required	Although we put the ODFM (Operational Downward Flexibility Management) product in place again for 2021, there has been no need to enact this, or negotiate any other contracts to manage downward regulation to date. This further contributed to lower reserve costs in the first half of the year.
North Sea Link (NSL) Interconnector went live on 01 October 2021	The go live of NSL impacts balancing costs in the following ways: **Frequency**: Although initially a minimal impact on our frequency response costs (connected was at 700MW), this impact is expected to increase as the flow can now reach 1400MW and become the largest loss on the system. The Dynamic Containment High service allows us to secure the risk of trip during exporting operation. **Constraints**: NSL connects into a constrained area of the network with high levels of wind generation. When it is windy, we need to pull generation (wind) back to make space for the NSL interconnector flow. This is a significant cost estimated at up to £15m a month while flow is at 700MW, and up to £30m when flow reaches 1400MW. **Margins**: Over Winter, NSL has helped increase margin which is helpful especially if there is little wind blowing at the time.

2. Actions taken by the ESO to reduce balancing costs

Below we set out some of the significant changes that have been implemented and how these have impacted balancing costs over the 2021-22 period and/or will impact them in the future.

Action taken	Date	Forward Plan/Delivery Schedule reference	Impact on balancing costs
Changes to Loss of Mains protection	Changes began in August 2019 and have continued through the year	RIIO-2 D15.3.2	The Loss of Mains changes have resulted in lower spending on inertia (falling from £20m per year to zero), and lower spending on constraining the largest loss.

Stability Pathfinder Phase 1	Stability Pathfinder Phase 1 awarded contracts to successful tenderers in January 2020.	Forward Plan Role 3	This project delivers a lower cost alternative for increasing inertia on the network until 2026 versus paying thermal generators. 12 contracts were awarded to a combination of new build and retrofitted synchronous compensators. 3 contracts are now operational with the remainder to go live over the following months. The consumer benefit of the Stability Pathfinder is discussed in RRE 3A.
Introduction of Dynamic Containment	DC Low launched in October 2020 with further product amendments over this year. DC high launched on 1 November 2021	Forward Plan Role 2	Increase in procured response to meet the total response requirement through our new fast-acting Dynamic Containment service. The additional control of a fast response product has enabled a step change in frequency management by no longer having to constrain large loss risks to avoid a consequential RoCoF (Rate of Change of Frequency) event that may result in unacceptable frequency conditions. These actions have a direct balancing cost saving (through reducing RoCoF constraint costs) as well as reducing the volume of market re-positioning the ESO is having to undertake to secure the system.
STOR Day Ahead procurement	April 2021	n/a	Day ahead markets for ancillary services lead to more volatile prices in those markets. This activity was carried out to allow STOR capacity to be secured in the Day-Ahead market, compliant with the clean energy package. Without this service the actions needed to access this reserve in the BM would have been more expensive.
Implementation of FRCR Phase 1 & Phase 2	Phase 1 from May 2021 Phase 2 from October 2021	n/a	The implementation of FRCR Phase 1 included relaxing the normal infeed loss constraint (always securing a <=1000MW loss to 49.5Hz, and always securing infeed losses to the wider 49.2Hz limit) and recategorizing some loss risks that meant no additional actions are taken to secure these risks. This has resulted in a decreased spend in managing RoCoF risks as well as a reduction in the cost of procuring response to manage the normal infeed loss. See Role 1 Consumer Benefits Case Study for more detail on the impact of FRCR.
Contracts to secure against specific transmission constraints	July 2021	RIIO-2 D1.1.3	Contracts to secure against transmission constraints result in an increase in ancillary service costs.

Optimising balancing actions	Throughout the year	RIIO-2 D1.1.3	Day to day actions in real time to ensure the most cost effective options are selected to meet all operability requirements and to optimise the balancing actions required.
Trading actions taken ahead of real time to drive competition in costs, and manage voltage requirements	Throughout the year	RIIO-2 D1.1.8	Over the 12 months, trading has delivered a saving of £198m when compared to the estimated cost for managing the same requirements in the Control Room. One particular example of trading delivering significant additional savings is the recent solving of a voltage constraint in the South East. The approach undertaken was a combination of multi-day trades, optimising interconnector flows to meet voltage requirements, and a contract tender for a medium term solution. This combined approach resulted in an estimated saving of £11.3m compared to the cost of similar actions required in the BM.
Changes to the buy order methodology for the day ahead procurement of STOR	From January 2022 onwards	n/a	Estimated total cost saving of our buy order methodology between January 2022 and March 2022 of £48m. This is calculated as the difference between the actual costs (auction costs plus shortfall costs) and the equivalent cost if the total volume had been procured in real-time through the BM. We estimate that £11m of those savings are a direct result of the change in approach that we implemented in January 2022.
Working with a TO to manage operability	September / October 2021	n/a	Due to planned system access and a fault condition, a voltage level just above the SQSS requirements would have occurred, in the event of a double circuit fault. In order to solve this potential overvoltage situation, we had sought an agreement with a local generator which would mitigate the overvoltage and return the system to the SQSS requirements. The cost of this contract (due to very high electricity prices and the risk to the generator) would have been approximately £50m. In parallel to this contract negotiation, we worked with the (TO) to fully understand what the risk was of operating over the SQSS limit (3-5kV) and any potential mitigations they could do, following a double circuit fault, to manage the resulting high volts. We came to an agreement with the TO which put in place pre-agreed reactive measures should the double circuit fault occur. As a result, the £50m contract was not required. In this way we were able to work across the industry to find an acceptable, cost saving option, with pragmatic challenge to the SQSS.

3. Drivers of balancing costs

There are numerous factors that impact the level of balancing costs at any one time. The extent to which the ESO can control or influence these factors varies greatly and depends on the timescales in which the factors occur. Below we set out a high-level summary of the main drivers, within Role 1 timescales, and the extent to which the ESO can influence each one.

Factor	Level of ESO influence	Explanation
Balancing actions taken	● High	The ESO is required to secure the system in line with the SQSS and therefore takes actions in a defined order to ensure operability. There may be limited options (and sometimes only one) to secure certain requirements, but the ESO will choose the actions to secure the system at the least cost to the consumer.
Operating margin	● High	The ESO determines the level of operating margin required to cover demand changes or generation breakdowns. However, when margins are tight, options are limited. During periods of tight margins, offer prices in the BM increase in response to the scarcity of electricity for those particular periods. This means the cost of the actions taken increases. This is out of ESO control.
Available products and services	● High	For example, the introduction of Dynamic Containment increases response costs in the short term but, combined with the FRCR policy change, has reduced frequency control costs, As competition increases in this area, Dynamic Containment costs are expected to reduce over time. As the number of larger loss risks connected to the system increases, we will hold more reserve and response to meet the requirements in order to avoid unacceptable frequency conditions.
Boundary availability *(including Transmission System Constraints)*	● Medium	We work closely with the Transmission Operators (TOs) to manage outages in order to maximise system availability. However, outages are necessary to maintain system operability, and these have an impact on network capacity.
Wholesale prices	● Low	Wholesale prices are set well in advance of the ESO role in operating the system and are based on supply, demand, the generation cost stack, and individual market participants' risk appetites. The ESO has some influence on prices by driving the availability of other markets for parties to participate in (e.g. Dynamic Containment)
Balancing Mechanism (BM) submitted prices	● Low	BM prices are driven mainly by supply and demand, and generation fuel costs (gas/carbon) when supply is plentiful. Higher levels of competition lead to lower prices but when options are limited, for example during periods of tight margin, scarcity pricing comes to play where increased prices are submitted due to the momentary increase in value of the commodity.
Renewable generation output	● Low	High levels of renewable generation can increase thermal constraint costs, as we are more likely to have to bid off some renewable generation that is located behind constraints and replace it with alternative generation at a cost. A high percentage of renewable generation can also lead to lower inertia and less availability of response and reserve from synchronous generation, driving up costs.

Provider and Generation Outages	🔴 Low	Providers and generation (BM Units) determine when they will take outages in line with their own maintenance cycles and requirements. It may be possible for ESO to establish contracts with specific providers to move or delay outages if system operability is impacted.
Demand level	🔴 Low	Level of demand can have a significant impact on the actions we need to take, e.g. in May 2020 when demand was low due to the national lockdown and wind output was high. High demand can also lead to high prices due to the effect on system margins and the related scarcity pricing behaviour.

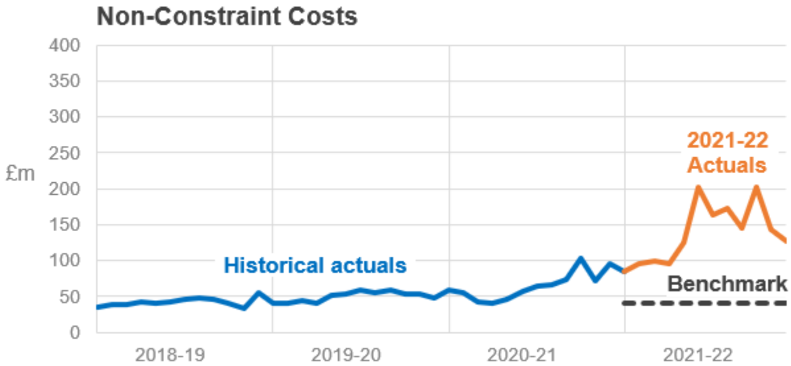
4. Explanation of the ESORI benchmark for balancing costs

The benchmark for this metric was derived using three years of historical balancing costs and wind generation output data, as follows:

- **Constraint costs:** The historical linear relationship between wind generation output and constraint costs is calculated, and applied to 2021-22. The benchmark is updated with the actual outturn wind every month, i.e., constraint costs are expected to be higher when wind generation output is higher.
- **Non-constraint costs:** The historical relationship between constraint costs and total balancing costs is used to determine that, if constraint costs were zero, total balancing costs would be £41m. That figure of £41m is used as the benchmark figure for every month.

The benchmark for constraint costs is based on the historical (3-year) relationship between constraint costs and wind output.

Our performance tracks the benchmark reasonably well at the start of 2021-22, but the benchmark does not take account of wholesale costs and BM offer prices, which were the main drivers of the record high costs in the second half of 2021-22.



The benchmark estimates what value non-constraint costs would be if constraint costs were zero, based on the historical (3-year) relationship between the two. This resulting figure of £41m is used as the non-constraint cost benchmark for every month.

This gives a benchmark figure that's 20% lower than the average costs across the previous three years. As with constraint costs, this part of the benchmark does not take account of the wholesale costs or BM offer prices.

In using three years of historic cost data, the current benchmark assumes that the conditions we are operating in now are the same as those in 2018-19 to 2020-21. However, the electricity system has evolved significantly over this period. There has been a dramatic increase in the amount of solar generation installed and at least a 30% increase in wind generation installed on the system during this time. This was largely driven by the Connect and Manage policy where wind generation was connected ahead of required network upgrades, and planned to be managed through constraint actions where required. The increased renewable penetration has impacted inertia levels which have continued their decline over the last three years, as well as impacting traditional constraints.

Therefore, we do not believe that the benchmark is a suitable measure to track performance against. Throughout our reporting we are comparing against last year and last month to look for trends and outliers and to drive performance.

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5. Year-to-date performance – Detail

Breakdown of total costs vs previous year

Total balancing costs for 2021-22 vs 2020-21

Balancing Costs variance (£m): FY 21-22 vs FY 20-21

		(a) FY 20-21	(b) FY 21-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	103	110	7	
	Operating Reserve	183	593	410	
	STOR	39	65	26	
	Negative Reserve	4	9	5	
	Fast Reserve	116	232	116	
	Response	146	341	195	
	Other Reserve	22	20	(2)	
	Reactive	65	190	125	
	Restoration	69	63	(7)	
	Minor Components	32	36	3	
Constraint Costs	Constraints - E&W	188	172	(16)	
	Constraints - Cheviot	99	93	(5)	
	Constraints - Scotland	93	446	353	
	Constraints - Ancillary	102	52	(50)	
	ROCOF	345	174	(171)	
	Constraints Sterilised HR	244	536	292	
Totals	Non-Constraint Costs - TOTAL	780	1659	879	
	Constraint Costs - TOTAL	1071	1474	403	
	Total Balancing Costs	**1850**	**3133**	**1282**	

Balancing costs for 2021-22 have been significantly higher than during 2020-21. The overall driver for the increased spend has been the increased pricing of the actions available in the BM, through trading and in our markets.

Constraint costs have exceeded the levels experienced last year. The cost of the actions taken was the driver of the spend, with volumes being equal or lower than last year in all months except January and February.

The key categories of Constraint costs which have increased are the 'Constraints – Scotland' and the 'Constraints Sterilised Headroom' categories. In both instances this is driven by the increased prices available to be taken to increase generation (through an offer) to either replace energy removed from the system (through a bid), to manage an active constraint, or to take action to replace headroom sterilised behind a constraint. The decrease in the RoCoF category is a result of the implementation of the Frequency Risk and Control Report (FRCR) which changes how we manage loss risks on the system (see Role 1 Consumer Benefits Case Study - FRCR) along with the launch of Dynamic Containment and continued delivery of the ALoMCP.

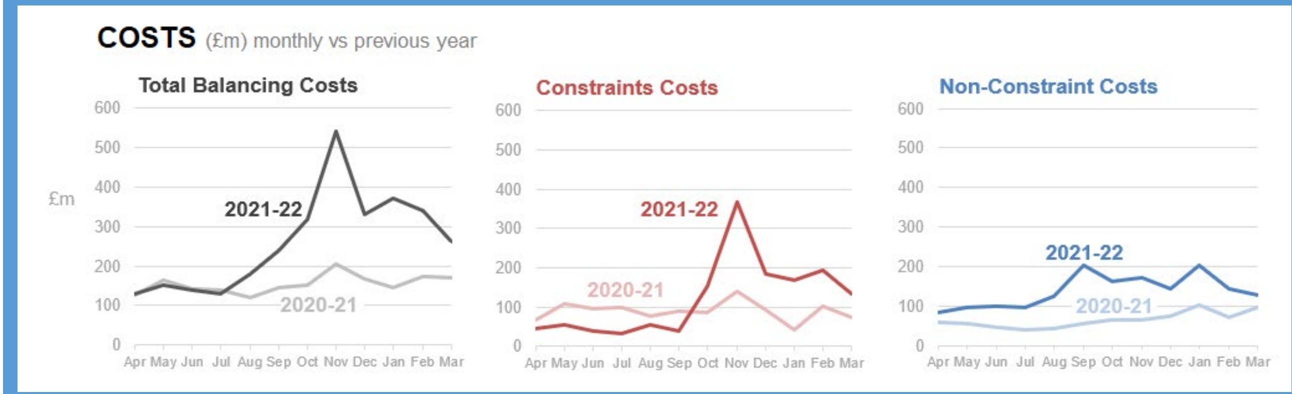
Non-constraint costs were the larger driver of the increase in total spend, as the table above shows. Increasing wholesale prices throughout the year, and particularly in the latter 6-8 months of the year, drove the price of actions available to be taken higher. This was further impacted by very high prices submitted during periods of tight margins or perceived tight margins, as a result of scarcity pricing. The volume of non-constraint actions taken has been significantly lower than last year throughout the year except for the months of July & August.

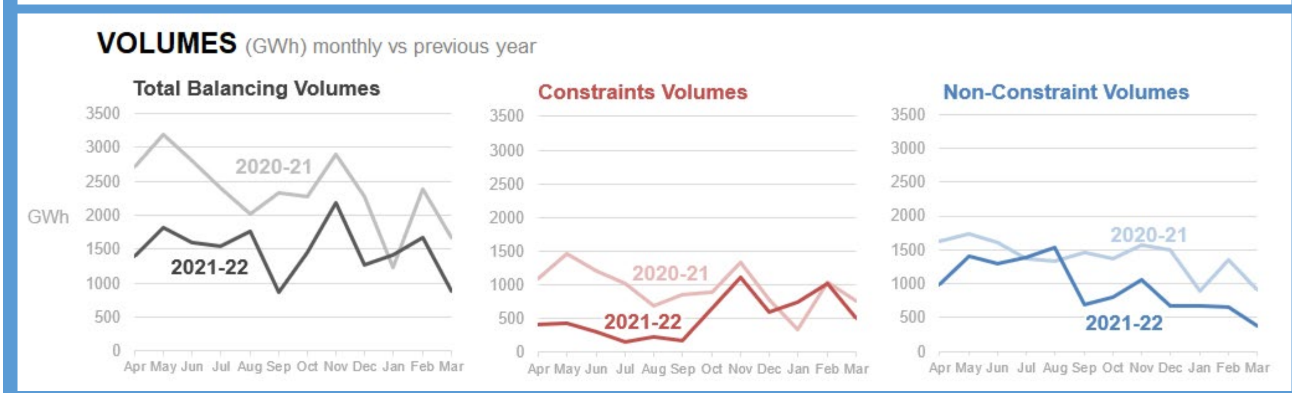
The greatest non-constraint cost category increase compared to last year was Operating Reserve. This was driven by the increased price at which reserve was procured in the Balancing Mechanism rather than an increase in volume. This was clearly driven by the increased prices submitted in the Balancing Mechanism, particularly during periods of tight margins or perceived tight margins.

Response costs are higher than last year due to the increased response requirements as a result of having access to fast acting response product Dynamic Containment to manage the change in approach to managing loss risks on the system, due to the implementation of the FRCR. Holding additional response reduces alternative actions e,g, RoCoF constraint actions to ensure system security.

Balancing costs and volumes – this year vs last year

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





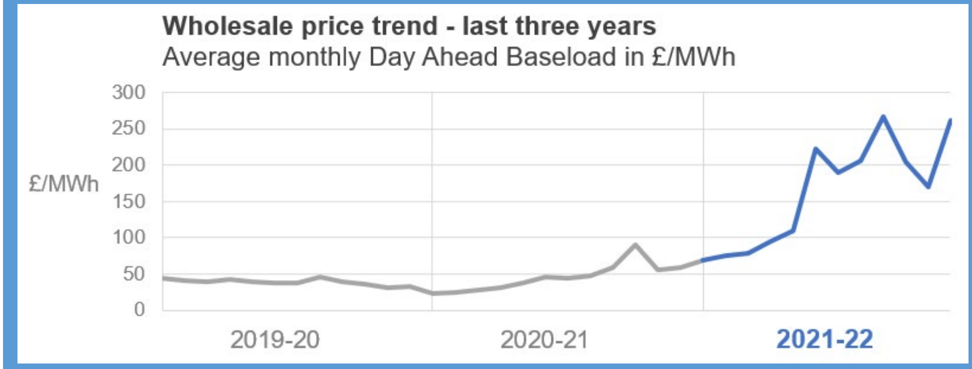
As shown above, the total volume of actions taken has been lower than the previous year in almost every month, but costs have been significantly higher.

In the first half of the year, constraint costs were lower than 2020-21, but from October they were much higher. This was driven by high cost offers accepted to replace the energy removed from the system to manage active constraints (due to wholesale prices reaching new highs and combined with regular periods of scarcity pricing). This was also affected by the volume of actions being higher in the second half of the year and more in line with the volumes of last year.

Non-constraint costs have remained above the level of last year in every month, with the volume of action significantly lower through the majority of the year.

How have wholesale prices and scarcity pricing impacted balancing costs?

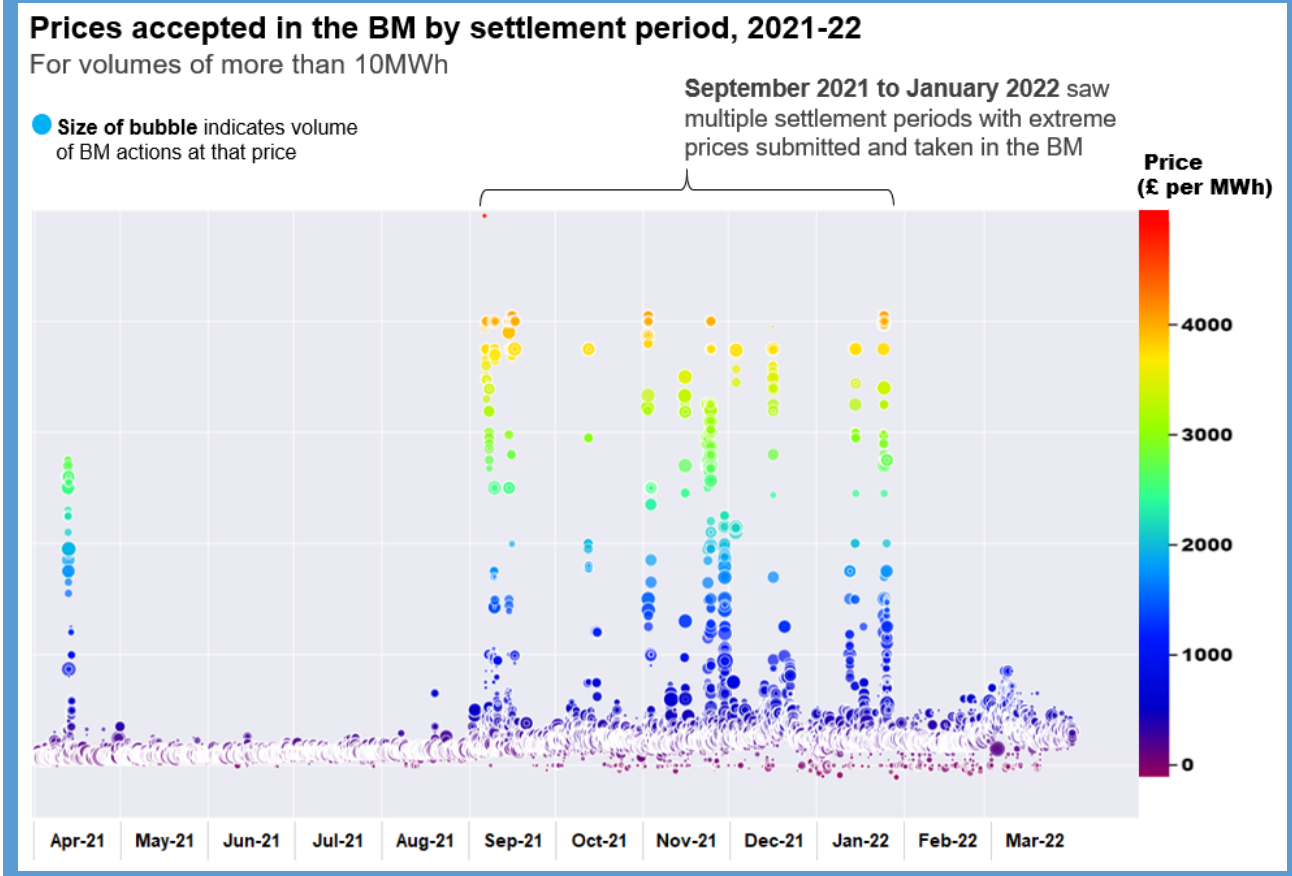
Wholesale prices



As shown in the chart, wholesale prices have rapidly increased through the year, particularly during the latter 6-8 months. This has driven the price of actions taken in the Balancing Mechanism and in our Ancillary Service markets higher and contributed to the increase in balancing costs.

Scarcity pricing

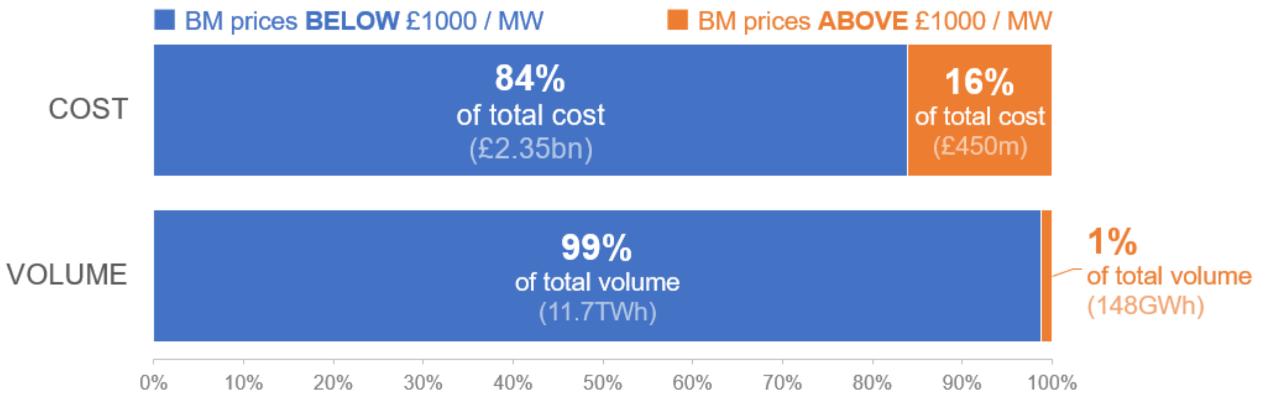
Below we show the prices submitted in the BM throughout the year, to highlight the periods where prices were in the £1000s per MWh during periods of tight system margins due to market scarcity.



And below we show the disproportionate effect that brief periods of extreme prices in the BM had on the overall balancing costs for the year.

16% of the year's balancing costs were spent on the 1% of actions that were taken when the BM price was above £1000 per MW

The graph below shows the total 2021-22 balancing costs and volumes, split by actions taken when BM prices were **below** or **above** £1000 / MW



Based on the figures above, we estimate that approximately three quarters of the total variance this year is driven by high wholesale prices, and the remaining one quarter is driven by periods of scarcity pricing. This is based on total variance of £1.8bn (actual balancing costs of £3.1bn vs benchmark £1.3bn), compared to approximately £450m (one quarter of £1.8bn) driven by scarcity pricing as shown above.

Network availability

B6: SP Transmission to NGET

B7: Upper North of England

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

The network availability is changeable through the year dependent on the outage pattern and system conditions. The actual transfer capacity, particularly for the B6 and B7 boundaries, was often higher than forecast due to additional optimisations possible in short timescales which are part of the regular activities within ESO control rooms and planning teams. This includes short term rating enhancements, network configuration changes and changes to the outage plan to deliver the same volume of work in the most efficient way.

6. March 2022 performance - Detail

The balancing costs for March were £262.1m, which is £77m lower than February, and in the 'below expectations' range**.**

Both constraint and non-constraint costs remain higher than last year but showed a significant decrease from the previous month.

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

Very high wholesale prices were the main driver behind the constraint costs in March due to the price of replacing the energy (through an offer) removed from the system (through a bid) due to an active constraint. Although the volume of actions for constraints was lower than last year, the spend showed a substantial increase from March 2021.

Breakdown of costs vs previous month

Balancing Costs variance (£m): March 2022 vs February 2022

		(a) Feb-22	(b) Mar-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	16.3	-9.6	(25.9)	
	Operating Reserve	36.1	40.2	4.1	
	STOR	3.7	5.6	1.8	
	Negative Reserve	0.2	0.6	0.3	
	Fast Reserve	18.2	21.5	3.4	
	Response	29.7	25.2	(4.5)	
	Other Reserve	1.9	1.6	(0.3)	
	Reactive	22.7	20.0	(2.7)	
	Restoration	2.6	7.9	5.3	
	Minor Components	11.9	14.3	2.4	
Constraint Costs	Constraints - E&W	21.9	18.7	(3.2)	
	Constraints - Cheviot	21.1	4.2	(16.9)	
	Constraints - Scotland	88.5	54.4	(34.0)	
	Constraints - Ancillary	1.1	0.9	(0.2)	
	ROCOF	17.9	8.0	(9.9)	
	Constraints Sterilised HR	44.9	48.8	3.9	
Totals	Non-Constraint Costs - TOTAL	143.3	127.2	(16.2)	
	Constraint Costs - TOTAL	195.3	135.0	(60.3)	
	Total Balancing Costs	**338.6**	**262.1**	**(76.5)**	

As shown in the total rows above, the majority of this month's decrease in costs came in constraint costs which reduced by £60.3m, whilst non-constraints costs fell by £16.2m.

Overall, 'Constraints – Scotland', Energy Imbalance, 'Constraints – Cheviot' and RoCoF were the categories with the largest decrease from February.

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

1. **Constraint Scotland: £34.0m decrease & Constraint Cheviot: £16.9m decrease.** The cost decrease was in line with a much lower wind generation level, resulting in an overall reduction in the volume of BM actions to reduce generation required to manage thermal constraints compared to February.
2. **Energy Imbalance: £25.9m decrease.** The system was generally longer in March then it was in February.
3. **RoCoF: £9.9m decrease.** As the wind outturn was 3TWh lower than previous month, less actions were required to secure the system against RoCoF risk.

Non-Constraint costs

Compared with the same month of the previous year:

Non-constraint costs were £31m higher than in March 2020 due to:

- The higher price of actions taken to manage the system. Particularly the price of offers in the BM which are higher due to increased wholesale costs. The volume of actions was lower than the previous year.

Compared with last month (February 2021):

Non-constraint costs were £16.2m lower than in February due to:

- The Energy Imbalance being much lower, in fact negative. This is due to the system being generally longer than in February.

Constraint Costs

Compared with the same month of the previous year:

Constraint costs were £60m higher than in March 2021 due to:

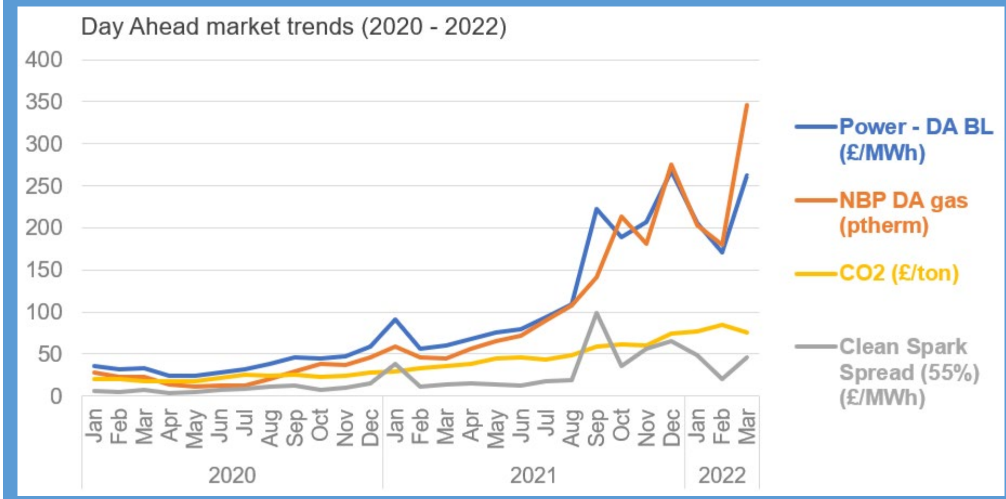
- The higher price of actions available to be taken to increase generation (through an offer) to either replace energy removed from the system (through a bid) to manage an active constraint.

Compared with last month (February 2021):

Constraint costs were £60.3m higher than in February due to:

- Reduced wind levels, resulting in an overall reduction in the volume of Balancing Mechanism actions to reduce generation required to manage thermal constraints compared to February.

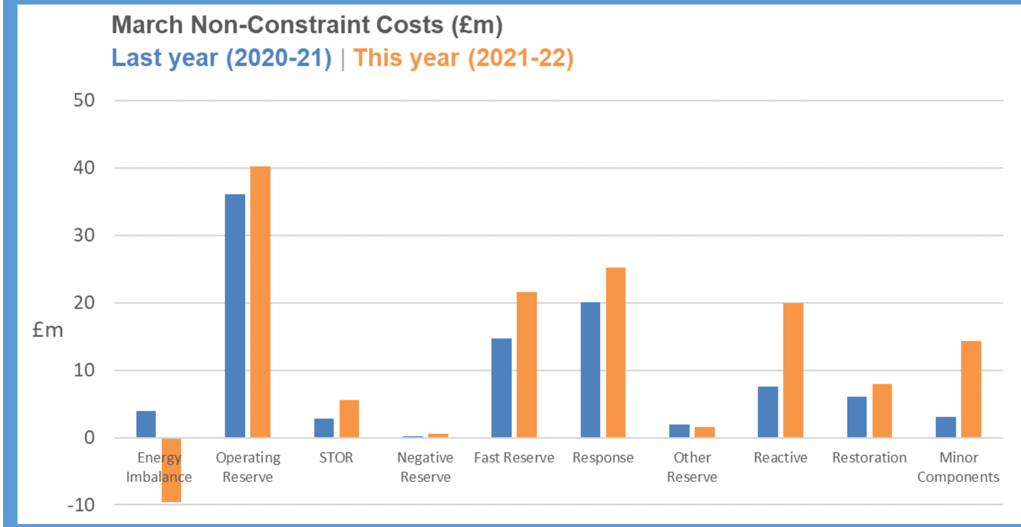
Changes in energy balancing costs



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

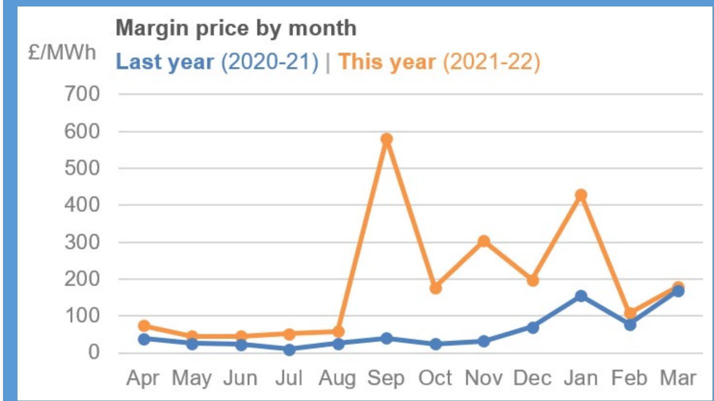
Power day ahead prices have risen in March and remain significantly above previous year levels. The day ahead gas prices have followed a similar trend and also remain very high in comparison with the earlier parts of the year and the previous year. Carbon prices continue fell slightly but remain significantly higher than the prices seen this year. These continued higher prices impact on both the buy (offer) and sell (bid) actions available to the ESO to manage our operability requirements. This demonstrates some of the external drivers of the underlying high prices available to ESO for balancing actions.

Cost trends vs seasonal norms



Comparing March 2022 non-constraint costs with those of March 2021 we can see that there has been a rise in most categories. The largest changes are Reactive (£12.4m higher), Minor Components (£11.3m higher) and Fast Reserve (£6.8m higher) and these are all driven by the increased prices submitted in the BM and our other markets.

Drivers for unexpected cost increases/decreases



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

Daily costs trends

The March 2022 balancing costs outturned at £262.1m which is a decrease of £76.5 from the previous month. There were several high costs days over the first twenty days of March, where expensive actions were needed to ensure all operability requirements were met.

In March, there were ten days on which the daily spend passed £10m, of which six days recorded a daily spend around or above £15m. Among these days, Tuesday 8 March, Wednesday 9 March and Sunday 13 March recorded a daily spend of £25.7m, £21.8m and £22.8m respectively. We also counted 19 days when the daily spend remained around or below £5m, with Saturday 5 March and Sunday 6 March the least expensive days with an outturn of £2m and £1.1m respectively.

Windy weather experienced on a few days and requiring a large volume of BM actions to reduce generation to manage thermal constraints was the main driver behind the expensive days in March. The high costs associated with replacing the constrained energy was the real driver due to the increased prices of actions available. When a bid is taken to resolve a constraint, the energy on the system must then be replaced. When a large volume of BM bids is required to manage the flow on a boundary to below the constraint limit, that volume of energy needs to be procured in the BM to rebalance. The cost of the replacement energy is significantly higher than in previous years due to the ongoing high wholesale market prices.

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

Significant events

There were no significant events during March.

Metric 1B Demand forecasting accuracy

April – March 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 (2020-21), there are two differences in relation to metric 1B. The first one is that the performance is reported as the mean absolute percentage error (APE) rather than mean average error expressed in MW. The second difference is that the accuracy is measured for each Settlement Period, rather than each Cardinal Point.

Figure 2: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

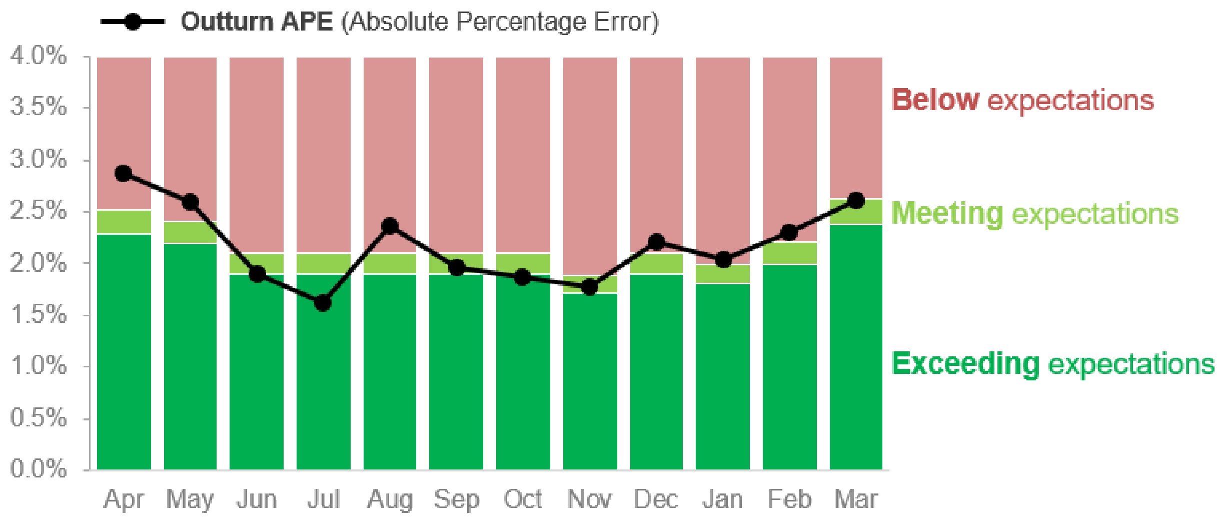


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	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**	**1.6**	**2.4**	**2.0**	**1.9**	**1.8**	**2.2**	**2.0**	**2.3**	**2.6**	**2.2**[7]
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

Performance benchmarks

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

[7] Full year figure to 3 decimal places is 2.177%

Supporting information

Year-to-date performance:

Day ahead national demand forecasting accuracy for the 2021-22 performance year was overall in line with expectations. We exceeded expectations in three months, met expectations in three others, and fell below expectations in the remaining six. Although to a lesser extent than the 2020-21 performance year, the COVID-19 pandemic still led to considerable levels of uncertainty, causing fluctuations in demand that made forecasting accuracy more difficult to achieve than pre-pandemic times.

This uncertainty was often offset by benefits brought in by the new additional national demand forecasting (machine learning) model, which was made available to the forecasting team and control room users from the middle of May 2021. It has proven effective in allowing flexibility to adjust for changes in 'regimes' of demand, for example if a national lockdown is imposed.

Our ambition to continuously improve our forecasting accuracy was evident in our transition away from using linear regression models in favour of a technique called Generalized Additive Model (GAM) at the end of August. This adoption of new, better techniques resulted in models displaying smaller levels of residual error. It also allowed us to meet absolute percentage error expectations in months with relatively smaller margin for error, such as September and November. This is despite November also being the first month of the 'triad avoidance' season, which typically introduces higher uncertainty over the demand during the Darkness Peak (DP).**Measures taken to improve forecasting performance**

During 2021-22, we have taken a number of actions to improve our forecasting accuracy and capability. The changes and their impacts are outlined below

New machine learning model introduced	In June we introduced a new, additional model into our processes. The model uses machine learning techniques and gives us the ability to assess the relationship between demand and weather every 30 minutes with new data. This gives us the flexibility to adjust for changes in 'regimes' of demand, for example in the event that a national lockdown is announced. During the pandemic we've seen many differences in demand patterns and the new model helps us 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.
New national demand forecasting models introduced	At the end of August, we introduced new national demand forecasting models. We moved away from using a linear regression model and now use a technique called Generalized Additive Model (GAM). This was a major change as the previous forecasting method had been in place for a number of years. The new models are more accurate, and better reflect the varying pattern of demand caused by measures introduced to control the pandemic. The GAM models run in parallel with the machine learning model. Both run in parallel and are visible to the Energy Forecasting team and the ENCC. The GAM models are used operationally, whereas the machine learning model is used as an additional source of advice/ challenge.
Continued benefits of the Platform for Energy Forecasting (PEF) project	Performance this year was also supported by improvements delivered as part of the PEF project during 2020-21, allowing us to

	produce more forecasts, more frequently and at a higher level of detail.
New dataset published to increase transparency	As part of our continuous drive to increase data transparency, the Energy Forecasting team introduced a new dataset on the ESO Data Portal in January, Day Ahead Half Hourly Demand Forecast Performance

Commentary for April 2021 to March 2022

April	🔴	Clock change and Easter are typically times when forecasting uncertainty increases. Comparisons to 2020 were also more difficult as COVID-19 measures had impacted demand for much of the year.
May	🔴	May 2021 was unusually cold and wet, driving atypical demand behaviour, which is more difficult to forecast accurately.
June	🟢	We incorporated our new additional national demand forecasting (machine learning) model into our processes from June.
July	🟢	The most challenging days to forecast in July were those with large solar PV forecast errors due to the weather being more overcast than forecast.
August	🔴	Forecasting accuracy was affected by uncertainty around the effect of unusual Summer holiday patterns driven by changing travel restrictions relating to COVID-19. The biggest errors were observed on the Bank Holiday.
September	🟢	New national demand forecasting models were deployed at the end of August. We moved away from using a linear regression model and now use a technique called Generalized Additive Model (GAM).
October	🟢	Performance was comfortably within the benchmark throughout the month, despite the clock change weekend when forecasting uncertainty is increased.
November	🟢	We met expectations in November's, the month with the most challenging benchmark. The most difficult days to forecast were those during Storm Arwen.
December	🔴	The fast spread of the Omicron variant of COVID-19 caused renewed uncertainty, with restrictions reintroduced. It was also the first time in over 10 years that 25 and 26 December fell on the weekend, adding more complexity. Lastly there was more uncertainty over demand levels during the Darkness Peak, due to Triad avoidance, as explained in the Triads section below.
January	🔴	Similar to December, it was difficult to find suitable historical dates to use for comparison due to the unusual timing of the bank holidays over this year's holiday period. The previous January was also impacted by a national lockdown. As in December, Triad avoidance led to more uncertainty over the Darkness Peak.
February	🔴	There were several challenges this month, with the spring half-term holiday unusually stretched over two weeks, large solar power forecast errors, and storms Dudley and Eunice adding further uncertainty.
March	🟢	Clock change and the days immediately around it always present more uncertainty. 28 March, the Monday after clock change, was the day in the month with the poorest performance. Settlement periods between 23 & 32 proved to be the least accurate. On some occasions, it was caused by weather forecast data error, which is outside ESO control. On other instances, it was due to solar forecast accuracy. The Solar Nowcasting innovation project, currently at the Research and Development stage, shows very promising results but mostly at the short-term lead time which is not what 1B metric is structured on.

Triads increase uncertainty over demand during the Darkness Peak (November to February only)

Triads are the three half-hour settlement periods of highest demand on the GB electricity transmission system between November and February (inclusive) each year. They are separated by at least ten clear days to avoid all three triads potentially falling in consecutive hours on the same day, for example during a particularly cold spell of weather. The ESO uses the triads to determine TNUoS demand charges for customers with half-hourly meters. The triads are designed to encourage demand customers to avoid taking energy from the system during peak times if possible. This can lead to some uncertainty in forecasting peak demands over the winter months.

The 'triad avoidance' season introduces higher uncertainty over the demand during the Darkness Peak (DP) which is between settlement periods 34 and 39. At the time of the 1B forecast publication, i.e. by 09:15 on D-1, the forecast shows the national demand without any triad avoidance expectation. Each evening during the triad season, the ESO runs an automatic assessment of triad activity, to establish if it occurred and how much avoidance there was over the settlement periods during the Darkness Peak. For the purpose of the 1B metric reporting, national demand outturn is adjusted by the estimated triad avoidance. All data is submitted as part of the reporting and also shared on the newly created ESO Data Portal in the following dataset: Day Ahead Half Hourly Demand Forecast Performance.

In January, the ESO engaged in discussions with companies which participate in triad avoidance, which allowed us to further verify our forecasting and post event estimation of this activity.

For further detail on triads, please see our website.

Missed / late publications

During the reporting year 2021-22 there were zero instances of missed or late publication of forecast data.

Metric 1C Wind forecasting accuracy

April – March 2021-22 Performance

This metric measures the average absolute percentage error (APE) between day-ahead forecast and outturn wind generation for each half hour period as a percentage of capacity for BM wind units only. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

A 5% improvement in historical 5-year average performance is required to exceed expectations, whilst coming within ±5% of that value is required to meet expectations.

Figure 3: BMU Wind Generation Forecast APE vs Indicative Benchmark (2021-22)

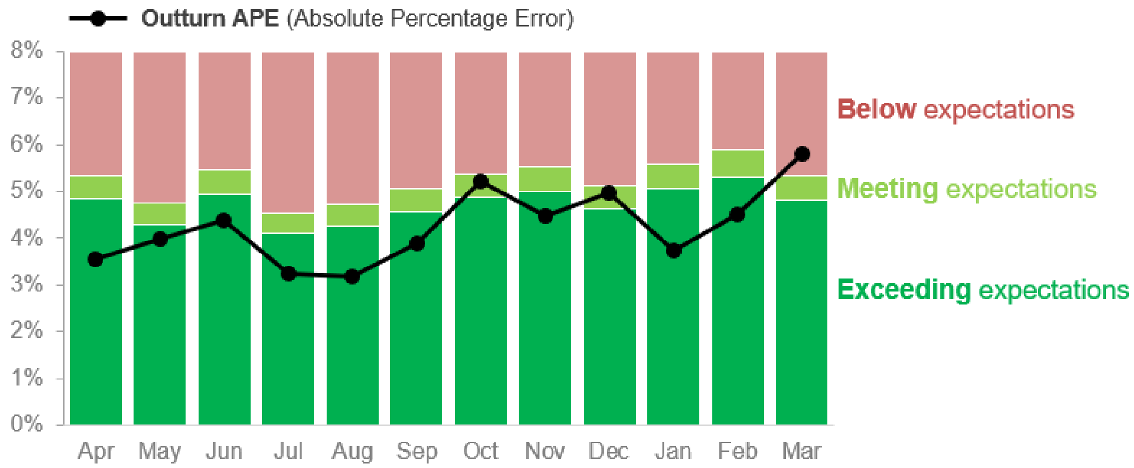


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	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	**4.7**
APE (%)	**3.5**	**4.0**	**4.4**	**3.2**	**3.2**	**3.9**	**5.2**	**4.5**	**5.0**	**3.7**	**4.5**	**5.8**	**4.2%**[8]
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

[8] Full year figure to 3 decimal places is 4.238%

Supporting information

Year-to-date performance:

Annual performance for the day ahead wind forecasting accuracy exceeded expectations. The indicative monthly target met or exceeded expectation on all but one month.

In the first six months of the reporting period, April to September, we exceeded the benchmark every month. Based on the analysis conducted by the World Climate Service, April to September 2021 was the least windy such period for most of the UK in the last 60 years. This contributed to the "exceeding expectations" scores for the first half of the year.

The impact of the Covid-19 pandemic on forecasting has been for the most part negative. However, social distancing and other pandemic-related restrictions led to the slowing of the rate of wind farm construction. There are typically metering errors in recently installed wind farms, which are consequently a source of forecasting error. Thus, with a greater proportion of mature wind farms, higher levels of accuracy were achieved. We know this factor should only be a temporary one and are working to monitor the quality of metering data that is provided by wind farms so that future performance analysis and improvement can be maintained.

Though the results for the 2021/22 performance year are successful, we still face many challenges when forecasting wind generation. Weather conditions are out of our control and we cannot expect to always experience the relatively stable weather that we experienced in this past performance year. In months where we 'met expectations' rather than exceeding them, such as October and December, this was largely due to uncertainty caused by lightning, jet stream movement, and the decomposition of ex-tropical storms. With the easing of Covid-19-related restrictions, wind farm construction will certainly begin to accelerate again, with targets of reaching 40GW offshore wind by 2030. This will provide new metering issue challenges as well as the vast geographical areas that these wind farms cover potentially making single wind forecasts insufficient for predicting the output of an entire wind farm.

Resolution of issues with metering for new wind farms

As stated above, metering error can influence wind forecast accuracy. For wind farms that have connected during the past 12 months, some issues with their metering data have been observed. These issues and other metering issues have been addressed with a weekly working group that is prioritizing and diagnosing metering issues. Improvement in metering data quality will lead to improved modelling of wind farm behaviour, which should result in more accurate forecasts going forward.

Commentary for April 2021 to March 2022

April	●	April saw very cool dry weather with clear skies and overnight frosts, with below average temperatures. Significant lightning activity happened several days in the month, indicating atmospheric instability which is commonly difficult to forecast.
May	●	May was one of the wettest on record, with significant lightning activity, leading to larger than usual wind power forecasting errors. But the national weather forecasting data combined with our forecasting models was relatively accurate.
June	●	Our weather service provider provided accurate weather forecasts for June, helped by very stable weather conditions.
July	●	July saw some of the lowest wind speeds and wind generation outputs in the past 10 years, which makes forecasting much easier, helping us exceed the benchmark.
August	●	In line with August weather in recent years, August was relatively calm overall, interspersed with thundery showers, helping us provide accurate forecasts.
September	●	September was typical of a transition month with calmer weather at the start of the month developing into more stormy conditions towards the end.
October	●	October is usually the month when the weather transitions into the stormier Winter phase and we faced forecasting challenges with multiple low pressure centres active at the same time.

November	●	November's weather can be the most difficult to predict due to ramping events with wind power transitioning from low to high or vice versa. This month we also saw storm Arwen and the remnants of ex-tropical storm Wanda pass over the UK.
December	●	December is usually a turbulent month where the number and intensity of storms arriving in the UK is governed by the position and intensity of the jet stream, which brought stormy conditions on a number of days this month.
January	●	January saw some challenging conditions to forecast, with days where the wind level changed significantly during the day, as well as significant lightning activity early in the month.
February	●	We benefitted from consistently high wind speeds at the start of the month, which are easier to forecast. Later in the month three storms, Dudley, Eunice and Franklin brought some challenges.
March	●	The weather in March was very typical for the time of year with blustery days interspersed with periods of calm but cold weather. Nothing notable from a wind power point of view.

Negative electricity prices

Wind farms with Contracts for Difference (CfDs) contractual arrangements switch off for commercial reasons while prices are negative for 6 hours or more. Below are details of occurrences over the last 12 months.

Month	Number of occasions when the electricity price went negative
April 2021 to September 2021	None
October 2021	Three occasions, but none of these lasted for more than 6 hours
November 2021	One occasion, but only for three consecutive hours.
December 2021	None
January 2022	One occasion when the electricity price went negative for 6 hours or more
February 2022	None
March 2022	None

The electricity price used for this analysis is the Intermittent Market Reference Price. Market price data between April 2021 and September 2021 can be downloaded here.

No missed / late publications in 2021-22

During the reporting year 2021-22 there were zero instances of missed or late publication of forecast data.

Metric 1D Short Notice Changes to Planned Outages

April – March 2021-22 Performance

This metric measures the number of short notice outages delayed by > 1 hour or cancelled, per 1000 outages, due to ESO process failure.

Figure 4: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

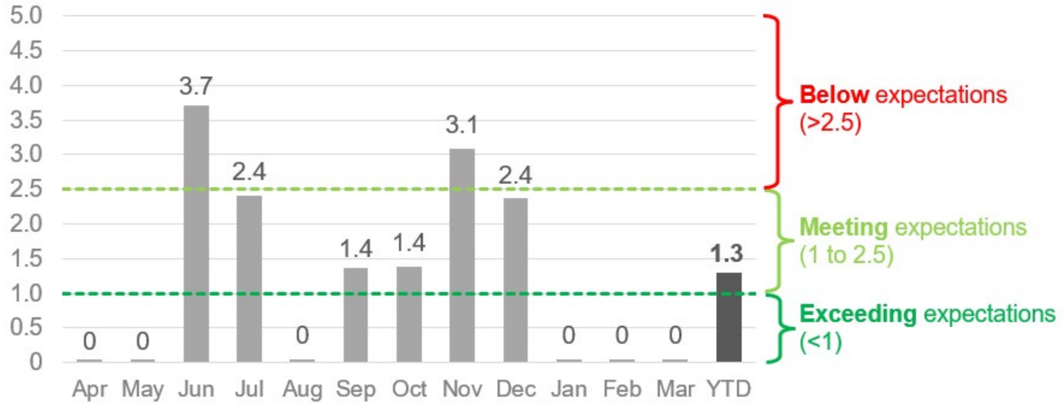


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
Number of outages	845	856	810	831	810	735	723	648	423	431	543	821	8476
Outages delayed/cancelled	0	0	3	2	0	1	1	2	1	0	0	1	11
Number of outages delayed or cancelled per 1000 outages	0	0	3.7	2.4	0	1.4	1.4	3.1	2.4	0	0	1.2	1.3
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

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

March performance: **Meeting expectations**

In March, the ESO has successfully released 821 outages and there has been a total of one delay and no cancellations due to an ESO process failure. This gives a score of 1.2 per 1000 outages which is within the 'meeting expectations' range of 1-2.5 per 1000 outages.

2021-22 Full Year performance: **Meeting expectations**

For 2021-22 as a whole, the total delays or cancellations due to an ESO process failure is 11. This gives a full year score of 1.3 per 1000 outages which is within the 'meeting expectations' range of 1- 2.5 per 1000.

Details of the five delays / cancellations due to an ESO process failure in the second half of the year (October 2021 to March 2022).

Full details of the 6 instances in the first half of the year can be found in the mid-year report[9].

October 2021	1.	The single event in October was a situation where one outage was delayed by the TO which impacted another planned outage, this resulted in two outages overlapping that could not take place simultaneously due to the impact it would have on a connected customer. The overlap of the two outages, that could not occur simultaneously, was missed by human error and was not identified in the outage planning database eNAMS. An Operational Learning Note (OLN) was written to identify the corrective actions for missing the knock-on impact initially.
November 2021	2.	The first event in November was a Transmission Operator (TO) outage where a non-standard outage combination was required leaving a Super Grid Transformer (SGT) and generator on one section of the substation. The ESO agreed with the Distribution Network Operator (DNO) to off-load the SGT in advance of the outage, and it was assumed that the generator would disconnect itself automatically in the event of a busbar fault. The risks were not fully discussed with the generator until the ESO control room contacted them over the weekend ahead of the Monday on which the outage started. The generator requested a circuit breaker protection modification at the substation which the TO was unable to deliver. Therefore, the TO decided not to proceed with this outage. An Operational Learning Note (OLN) was written that identifies corrective measures of highlighting non-standard outage combinations with the power station to facilitate discussions on substation running arrangements and options for modifying protection settings.
	3.	The second event was a delay caused by concerns within control room timescales that voltage limits would be exceeded in the event of a fault. Studies carried out by the Network Access Planning team ahead of real time had not highlighted this issue, but the real-time model used by the Control Room showed different results. Our investigation into the discrepancy between the two models concluded that the forecast demand was different to the real-time demands seen driving the voltage inconsistency. There are on-going projects which aim to improve demand modelling with a short-term and long-term solution.
December 2021	4.	The final event for Q3 was in December where the TO had requested a busbar outage within a substation. Prior to this outage, one of the three Super Grid Transformers (SGT) supplying the DNO demand was faulted and following repair was unable to be returned to service without disrupting another customer's supply. Within the outage planning database eNAMS, it showed that the SGT was available as the repair had been fixed by the TO. However, it was missed by the planning department that the SGT, whilst available, was off-load. When the outage was requested within control timescales, the DNO demand was not securable following the next credible fault and the DNO was not agreeable to the risk. As a result, the outage was delayed by one day until agreement from another customer was obtained to return the SGT before taking the busbar outage. An

[9] https://www.nationalgrideso.com/document/247411/download

		Operational Learning Note (OLN) was written which identified best practice during the outage planning process and was shared across the department.
January 2022		There were zero delays or cancellations due to an ESO process failure.
February 2022		There were zero delays or cancellations due to an ESO process failure.
March 2022	5.	The single event for Q4 was in March where the control room over a weekend raised concern over two outages starting on the Monday. Both outages had a very high Emergency Return to Service (ERTS) duration and would significantly reduce the constraint limit between Scotland and Northern England (B6 constraint) for several weeks. As this outage combination carried a risk of weather-related high constraint costs, a review of the risk was carried out against wind forecasts and re-confirmation of the outage sanction. The planning department were able to confirm that the cost sanction was still valid, and also managed to agree a profiled ERTS for one of the outages to provide an option to recall the outage, which helped to reduce the forecasted exposure cost of the constraint. Overall, one of the outages was delayed by several hours, whilst the other was released on time due to the importance of the work.

A.3 Stakeholder evidence for Role 1

- The ESO Operational Transparency Forum remains a hugely valuable weekly event for the ESO and industry, and continues to be shaped and developed based on stakeholder feedback. It draws audiences of over 100 every week and has achieved an average feedback score of 9 out of 10 across the year.
- Independent stakeholder survey results showed 94% of responses were either meeting or exceeding expectations.
- We have acted on feedback across Role 1, including ensuring planned outages proceed without delay, minimising system disturbances, taking action to secure sensitive demand following unplanned faults, and improving how we communicate with stakeholders.
- We have also acted on specific feedback across a number of areas following our quarterly meetings with the Technology Advisory Council.
- We have engaged extensively with the industry on the Electricity System Restoration Standard, and improved our stakeholder engagement on the Distributed ReStart Procurement and Compliance process.

The ESO incentive scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of the ESO's plan delivery. To demonstrate performance against this criterion, we report on our stakeholder satisfaction survey results, as well as describing how we have worked with stakeholders during the year.

Stakeholder surveys

The ESO has commissioned surveys from market research company BMG. These surveys measure satisfaction for each ESO role, and are carried out on a six-monthly basis. The survey is targeted at senior managers, decision makers and experts, and includes a wide selection of relevant stakeholders who have had material interactions with the ESO's services.

For role 1, the following question was asked:

> "One of the ESO Roles is focused on Control Centre Operations, which includes key activities such as real-time system operation, system restoration and provision of data and forecasting. The ESO's recent activity in this area includes; facilitating the go live of our stability pathfinder products into real time operations, continuing to work with industry stakeholders on the transparency of our actions via the Operational Transparency Forum and our data portal, workshops focusing on the implementation of the Electricity Restoration Standard, setting up the Balancing Market review, finalising reports for the Distributed ReStart project and implementing the go-live of a new interconnector and facilitating commissioning of future interconnectors, whilst improving our communications in this area."

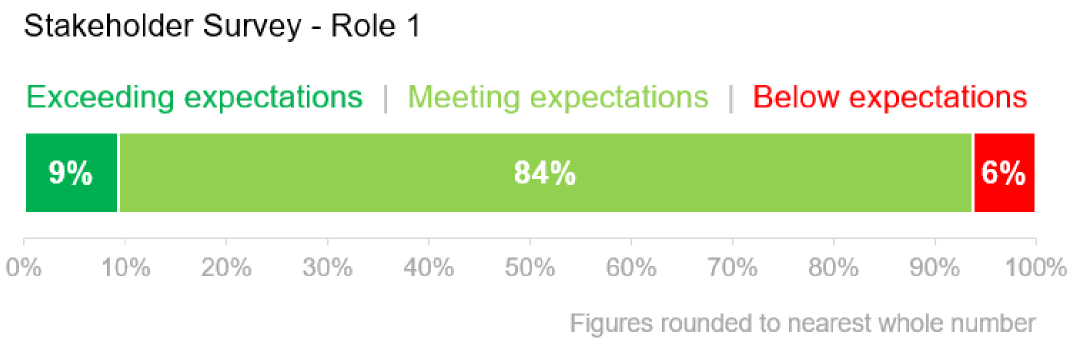
Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

- If they rated the ESO as below expectations, they were asked what the ESO needed to do to meet their expectations.
- If they rated the ESO as meeting expectations, they were asked what the ESO needed to do to exceed their expectations.
- If they rated the ESO as exceeding expectations, they were asked what the ESO did that exceeded their expectations.

For Role 1, we contacted 104 stakeholders, and received 32 responses to this question, which were distributed as follows:

- **9%** exceeding expectations
- **84%** meeting expectations
- **6%** below expectations

  (Percentages rounded to the nearest whole number)



"Exceeding Expectations" feedback

Stakeholders who scored us as 'exceeding expectations' were asked what the ESO did that exceeded their expectations. They raised the following points:

- The Operational Transparency Forum exceeded expectations
- Day to day communication with the control room was always responsive and solution oriented, and exceeded expectations

"Meeting Expectations" feedback

We asked all stakeholders who scored us as 'meeting expectations' what would it take for the ESO to be 'exceeding expectations' for them, here is a summary of that feedback for Role 1.

- Some stakeholders felt that there had been some sub-optimal balancing decisions made by the ESO, contributing to high balancing costs.
- Some felt that the ESO would exceed expectations if communications were improved. More notice should be given when organising meetings and sharing information, and the ESO should consult more widely with industry partners and stakeholders. Information on significant events could also be more detailed.
- Although feedback on the OTF from these stakeholders was overwhelmingly positive, there were some suggestions for how it could be improved. Some felt that the ESO could improve how it deals with questions, for example by having experts online to respond to questions live. It was also suggested that the ESO should avoid inadvertently being asked to give guidance on these calls.
- Other stakeholders suggested that the ESO should fully explain and discuss outages in real time and forward planning scenarios, and the ESO should jointly and proactively align on timing and scope changes.

"Below Expectations" feedback

Two stakeholders scored us as "below expectations". In response to being asked what the ESO needed to do to meet their expectations, these two points were raised:

- One stakeholder felt that the Control Centre activities (as listed in the survey question) were too tactical. These activities should be more transformational and focussed on changing the operation to make it leaner, more customer focused and agile.
- One stakeholder noted instances where NAP (Network Access Planning) had studied and approved an outage, but that outage had then been rejected when it was due to be released by the ENCC, despite there having been no change to the system.

Acting on stakeholder feedback

The Stakeholder Evidence criterion also takes account of the ESO's consultations and ad-hoc surveys throughout the year, whether the ESO has actively sought and considered the feedback of stakeholders throughout the business plan cycle, and the ESO's explanations for feedback received.

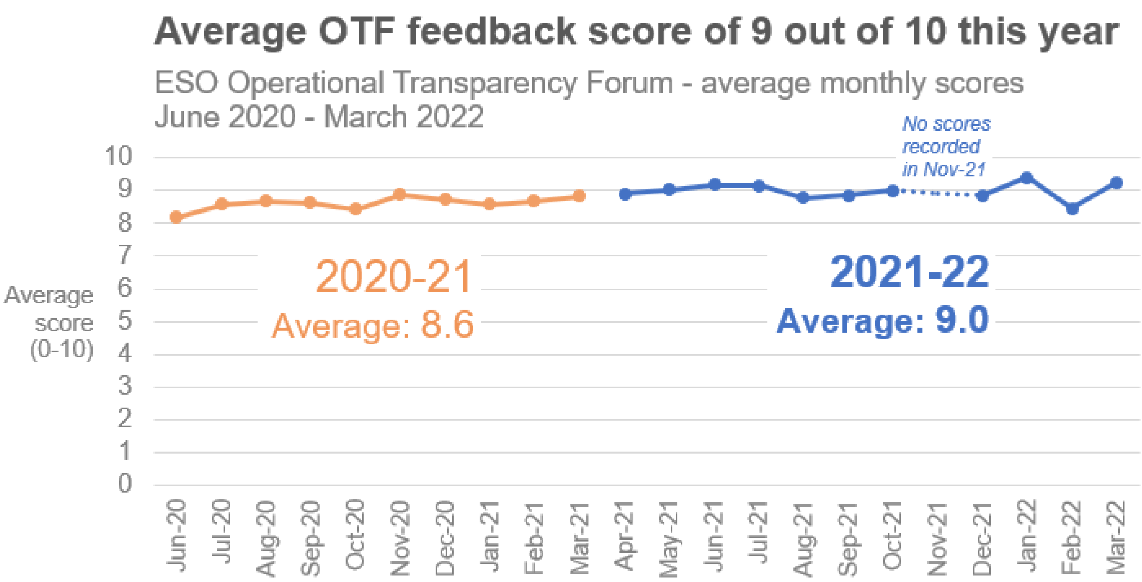
Operational Transparency Forum (OTF)

The operational transparency forum is a key weekly webinar designed to engage with people who have an interest in the operational decision-making processes which occur within the ESO. This provides an opportunity for the wider market to understand actions taken, be provided with a forward look for the week ahead and ask questions in an open and transparent public forum. This event has a continued weekly attendance of over 100 people from a diverse group of stakeholders and is completely driven by the audience, with regular content and specific topics scheduled in direct response to the questions asked or specific requests made. The forum is open to all and is a key platform for interacting with industry wide stakeholders. Nearly 1400 questions have been asked and responded to this year and more than 1300 people have registered to receive updates.

A copy of all slide decks and webinar recordings from the 50 events hosted this year can be found on the event's data portal page, alongside links to subscribe for updates or download an invitation:

https://data.nationalgrideso.com/plans-reports-analysis/covid-19-preparedness-materials

Feedback received



In the past year, feedback has been critical to shaping how the webinar is delivered and we have made significant changes to the format as a result. Most data has been collected through a weekly post-event poll with an average score between April 2021 and March 2022 of 9.0 out of 10 across 184 unique contributions which is an improvement on 2020-2021 where the average score was 8.6 out of 10. This post-event survey tracks overall quality of the event, quality of the responses to questions and relevance of topics discussed in order to ensure that the format continues to remain relevant and enable a cycle of continuous improvement.

End of year survey

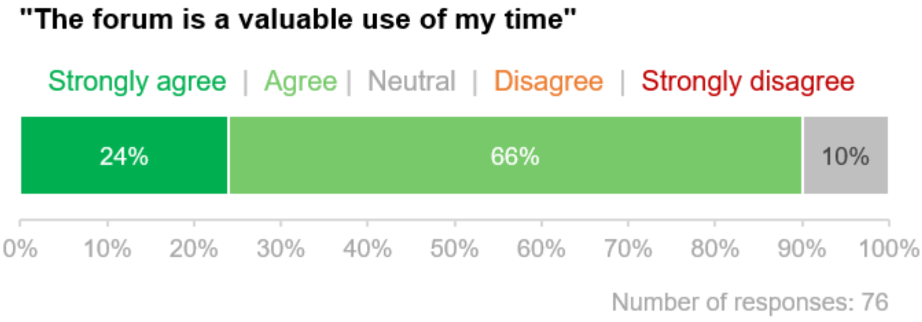
An end of year survey was also conducted on 30 March 2022 to monitor overall performance for the forum and support the continued process of acting on feedback. Below we talk through the results and changes we have made in each area in response to feedback.

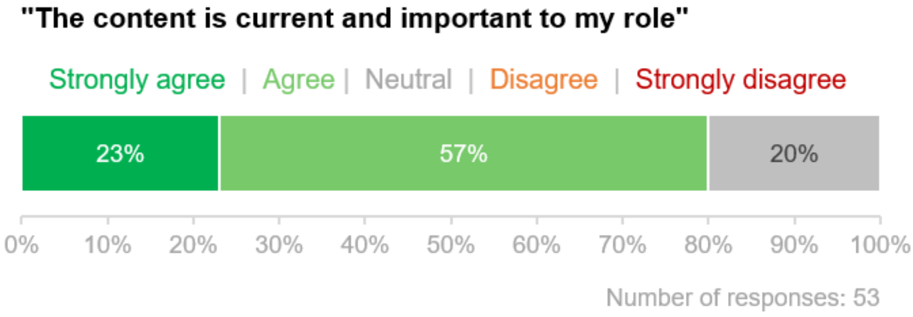
Content & Event Quality

In the end of year survey 90% of attendees agreed or strongly agreed that the forum is a valuable use of their time, whilst 80% viewed the content presented as current and important to their role. This demonstrates that the format continues to be appropriate and that there is desire for the forums to continue into 2022-23. Across the year, improvements in this area have included:

- an additional weekly topic of operational margin across the winter period
- changes in the way in which we present constraint limits and forecasts
- operational actions displayed for high cost periods
- further breakdown of the constraint portions of balancing mechanism costs.

All of these changes stem from direct requests of forum attendees and have been established as part of the regular format.





In addition, focus areas have continued to be scheduled weekly with content tailored to specific requests or general question themes. The word frequency diagram below shows general interest areas for the audience across the year.

***Word frequency diagram**: the more frequently the word occurs in stakeholder questions the larger the size on the diagram*

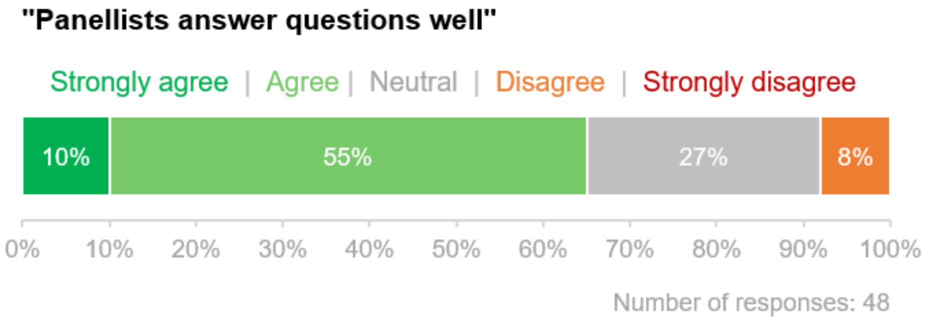
Responding to Questions

Between April 2021 and March 2022, a total of 1378 questions have been responded to through this forum. We are aware that the live, transparent question and answer format is a key element of this event and across the year significant changes have been made to ensure the extremely broad and varied focus areas are responded to appropriately. A major change is the greater numbers of experts contributing answers to the live event through greater use of crowd sourced responses from across the business. This is in response to the feedback that we may avoid difficult questions in preference for those we can provide quick responses to. Acting on this same feedback, we have also adapted processes to follow upvote order more directly when responding to questions to remove this perception of bias.

The content of the webinars has been significantly streamlined to provide a target minimum of 20 minutes for Q&A. This results in fewer questions to be taken away for response at a later time by reducing time constraints and places greater emphasis on an attendee led format. This is a result of direct feedback that too many questions were being taken away due to time constraints.

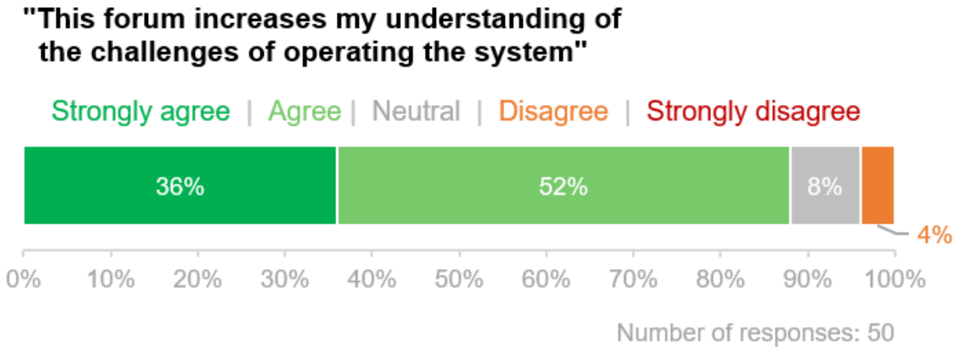
The variability and volumes of questions asked means that despite improvements made to the process we do not always have the appropriate expertise immediately available to provide live answers. We have received feedback that we were not transparent with questions we had not yet responded to. Whilst the vast majority of questions are resolved by the following week or answered live, some are complex enough to require more detailed review. Questions we have not yet answered are now published weekly as part of the slide pack presented.

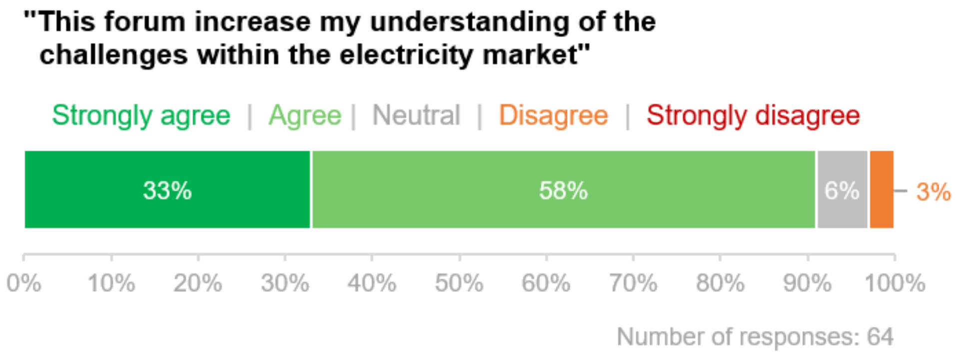
We are aware from ongoing feedback that this is a continued area of focus. 65% of people agreed or strongly agreed that questions were answered well, but 8% of the audience disagreed. This is consistent with the weekly post event polls and across 2022 we will continue to increase the breadth of contributing experts from across the business to attend the events and contribute towards answering questions.



Improving transparency of decision making

The key purpose of the weekly transparency forum is to provide the audience with a view of immediate operational decision-making processes and challenges. For this reason, in the end of year survey we asked if the forum enhanced the audience's understanding of the challenges operating the system and 88% agreed or strongly agreed whilst only 4% disagreed. Similarly, we asked if the forum increased the audience's understanding of the challenges within the electricity market and 91% agreed or strongly agreed whilst only 3% disagreed.





Overall, feedback indicates that the platform is continuing to deliver value for stakeholders. We are aware this can continue to be improved and we will be inviting attendees to a workshop to share views on their expectations for 2022-23.

Stakeholder engagement during the year

The Stakeholder Evidence criterion also takes account of the ESO's consultations and ad-hoc surveys throughout the year, whether the ESO has actively sought and considered the feedback of stakeholders throughout the business plan cycle, and the ESO's explanations for feedback received.

Control Centre architecture and systems

Area	Stakeholder feedback	Action taken by the ESO
Transparency / communication / forward thinking	In 'exceeding expectations' feedback from our mid-year report, overall, stakeholders who felt the ESO had exceeded expectations provided positive feedback primarily around transparency and forward thinking	Following a transformer fault at a substation with a transformer already on outage (and unable to be recalled within timescales necessary to avoid potential demand insecurity), the ESO liaised promptly with all three parties to articulate the potential demand insecurity at the following day's demand peak to seek a resolution. The TO expedited oil samples to enable RTS (Return to Service) more quickly than would normally be expected. One DNO ('DNO 1') considered moving demand but could not access required resource overnight due to COVID reasons. DNO2 eventually managed to transfer demand out of the group to reduce anticipated peak demand to an amount which was secure (to the next transformer fault). This secured sensitive demand, including London underground. TO "appreciate the regular communications and final resolution we will endeavour to RTS (return to service our transformer) as soon as possible" DNO1 "thanks, sorry we couldn't help on this occasion but relieved a positive outcome was possible"

		DNO2 “although it’s been a difficult night, we appreciate the overall resolution is probably the best solution to ensuring sensitive demand security given the nature of the unplanned fault compounded by an existing outage”
Network operations	In ‘meeting expectations’ feedback in our mid-year stakeholder survey, while it was recognised that the ESO achieves its activities as expected and meets the agreed processes described in the System Operator Transmission Owner Code Procedures (STCPs), stakeholders felt the ESO could exceed expectations if a variety of areas relating to our network operations were improved, from reducing the increasing number of system disturbance events to making fewer changes to agreed planned outages.	We realise the importance of minimising system disturbances, Grid Code Modification GC0151 ‘Compliance Processes and Modelling amendments following 9th August Power Disruption’[10] was introduced in November 2021. This aims to improve the processes around system Users demonstrating compliance with the Grid Code and the provision of modelling information. There are a number of elements to this modification one of which is around compliance with fault ride through during and after a fault. Since introduction of the Grid Code Modification, we have seen an improvement of engagement and response by Connectees to ensure compliance under fault conditions. If non-compliance is observed, then Connectees work with Compliance Teams to enable quick identification and resolution on the non-compliance. On 6 May 2021, we also wrote an open letter[11] to all transmission connected generation and network operators to remind all parties of the requirements for compliance with Grid Code and STC. We realise that short term changes to our outage plans are challenging for our customers. We will continue to work with TOs and Users to minimise the amount of short term changes to our operational plans. There are times where short term changes to plans are required to allow a Transmission Owner to carry out essential unforeseen work on equipment or for constraint management purposes to minimise costs to the end consumer. Where we do make changes we will endeavour to ensure that impacted customers and stakeholders are made aware of the reasoning for the changes.
Control room communication	In ‘meeting expectations’ feedback in our mid-year survey, many stakeholders felt the ESO would exceed expectations if communications with the ESO were improved, whether this was on providing greater clarity on outage planning/notifications or providing flexibility on the scheduling of phone calls with stakeholders. Stakeholders would like to ensure their needs as customers are met, with	We continue to work with industry stakeholders on transparency of our actions via the Operational Transparency Forum (OTF) and via our data portal as well as answering many bilateral queries. See section above on the OTF. Key Control Room employees also attend OTF to answer customer and stakeholder questions. In November 2021 we also expanded the winter operability liaison meeting to cover a broader range of topics as requested to do so via customers and stakeholder. Future topics are always welcome.

[10] https://www.nationalgrideso.com/industry-information/codes/grid-code-old/modifications/gc0151-grid-code-compliance-fault-ride

[11] https://www.nationalgrideso.com/news/open-letter-transmission-connected-generation

	improved engagement with the control room.	
Fortnightly forums to facilitate data sharing between the ESO and DNOs	In the mid-year Call for Evidence, stakeholders said that they find these sessions helpful, notably the sharing of technical detail on some recent system incidents. However, they do still find it challenging to get meaningful, real-time information when system events happen. They felt that while there may be certain commercial confidentiality issues it is important that there is a process whereby DNOs can receive early notification of system events.	Regular sessions with DNOs have continued with bi-annual operability liaison meetings to focus on Winter and Summer Outlook. Grid Code modification GC0109 has been agreed and implemented by the ESO to provide additional information on the BMRS in addition to existing system warnings.
Communication with TOs and interconnectors	In 'meeting expectations' feedback in our mid-year survey, stakeholders commented on how we could exceed expectations focused on the ESO-TO interaction, and how the process between the ESO and TOs/interconnectors could be streamlined in terms of communication, documentation, and flexibility. Stakeholders also want the control room to engage more quickly with the TOs when system events occur.	Communication with TOs: ESO control & planning teams (ENCC & NAP) have been working with a TO to agree enhanced transmission services through the STCP11-4 process. This has allowed additional post fault actions to be pre agreed, allowing generator outages in critical system security areas to proceed as designated resulting in large system cost savings. We are now looking to use the same approach with other TOs. ENCC is maintaining regular liaison meetings with TOs. Following customer feedback from them a TO we have added items in the meeting agenda to address the concerns raised and actioned appropriately. Following feedback from a TO regarding the business separation of TO and DNO control desks, ENCC has modified its process for instructing demand control in the north of Scotland. ENCC has created and issued an Operational Communications document to all network operators. This was requested by network operators through the E3C Electricity Task Group and highlights all the ENCC instructions relating to demand control/restoration. ENCC has agreed with network operators to test & refresh annually. The Summer & Winter Operability Liaison meetings between ESO and network operators have been tailored to include agenda items & presentations raised by network operator representatives. Communication with interconnectors: We have established new governance around escalations involving interconnector queries. This has proved successful as it gives a clear escalation route, so issues are raised in the right place, first time. We also implement a daily control room call during interconnector commissioning to ensure robust

		communication. This allows all parties to quickly discuss the following day's testing, and means issues can be discussed and resolved directly. We are now looking to use the same approach with other interconnectors.
Accuracy, transparency, and timeliness of data	In 'meeting expectations' feedback in our mid-year survey, stakeholders wanted to see information provided remaining accurate and transparent, and data to be reported quicker.	We endeavour to report as soon as possible against any key communications with broader customers and stakeholders. We also react and respond to any feedback provided through the OTF regarding accuracy and transparency of information (please continue to use this forum to raise any concerns in the future).
KPI related to ensuring planned outages proceed	In 'meeting expectations' feedback in our mid-year survey, stakeholders said that while it was recognised ESO achieves its activities as expected and meets the agreed processes described in the STCPs, stakeholders felt the ESO could exceed expectations if … areas relating to our network operations were improved, by making fewer changes to agreed planned outages.	Building on our 'fail to fly' ESO internal KPI, we have introduced a new KPI named made to fly. This captures instances where intervention within control room timescales has prevented outages from being cancelled. We also capture other instances such as outages which would not normally have proceeded due to a fault, and outages which may have been recalled due to a fault, but intervention has enabled them to proceed.
Example of ensuring planned outages proceed	'Meeting expectations' feedback in our mid-year survey highlighted making fewer changes to planned outages	During Storm Arwen a major B6 boundary circuit tripped following physical damage. The resultant fault outage would previously have prevented the following day's planned outage of an AC circuit also on the B6 boundary. By considering the HVDC circuit, performing relevant commutation assessments, system impact assessments and collaborating with the TO (Transmission Owner) to reduce the ERTS (Emergency Return To Service) of the outage, we could secure the system with this outage taken as planned without delay despite the accentuating circumstances. The TO showed gratitude that the planned outage could proceed without delay especially given the extreme weather and the major fault that had occurred. A delay to this outage would have caused considerable costs as resource was already committed.
Focussing on issues experienced by generators	In 'below expectations' feedback in our mid-year survey, some stakeholders voiced concerns that there was a greater focus on commercial operations in contrast to the issues experienced by generators such as ageing transmission assets, vital to system operations.	We endeavour to always operate the system in an economic and efficient manner. We have always used the OTF to deep-dive certain scenarios and to answer any immediate queries customers and stakeholders have. Any ideas for what we can address in the future are always welcome.

Constraint management	In 'below expectations' feedback in our mid-year survey, stakeholders highlighted the need for greater transparency and management of constraints.	A five-point plan to address constraints was produced 18 months ago, and we continue to make progress against this. See examples below. Early April 2022 we announced the award of contracts for the B6 Constraint Management Pathfinder for delivery from October 2023 to September 2024. The contracts aim to reduce constraint costs over the Anglo-Scottish border and help to achieve zero-carbon operation of the system. This is one of many Pathfinders being run by the ESO to help constraint management. We have recently taken a novel approach to inter-trip solutions by adapting a pre-existing scheme associated with decommissioned generation to include renewable generation and so increase the capacity of the B6 boundary during windy conditions thus lowering constraint costs via an agile solution. We have implemented an independent Market Monitoring Team with capability to monitor and report any relevant market behaviours to the regulator. Specific to transparency of constraints we have also introduced a "Managing constraints in real time" regular section to the Operability Transparency Forum (OTF) to articulate the issues associated with constraints and provide topical examples from control room. To date Thermal constraints and Voltage constraints have been covered in the sessions and we plan to include Inertia and ROCOF (rate of change of frequency) constraints as soon as the timetable permits. Subsequent feedback via SLIDO at the OTF – "Welcome the new section and very useful explanation and demonstration of managing thermal constraints in real time – any chance other constraints can be presented in subsequent OTFs?"
Outage arrangements coordination	In the mid-year Call for Evidence, a stakeholder found that continuing to meet with the ESO planning teams on a regular basis is an effective way of managing outage requirements. However, there is now an additional communication channel which has occasionally led to last minute changes or requests.	We realise that short term changes to our outage plans are challenging for our customers. We work with TOs and Users to minimise the amount of short term changes to our operational plans. We work to ensure that only essential outages such as those involving urgent unforeseen repairs enter the planning processes at short notice in the 3 week period ahead of real time. There are occasions where we have to optimise our operational plans to minimise the cost to consumers linked to constraint management. For instance, during periods of high wind it may be beneficial to delay the start of a planned outage to prevent a restriction of energy on the system and activities such as this leads to consumer cost savings of many hundreds of million pounds per year. We will continue to work with TOs and Users to minimise short term changes to our operational plans.

Technology Advisory Council (TAC)

The Technology Advisory Council meets once per quarter to guide the ESO's digital, data and technological transformation. Below is a summary of how we have used their feedback.

In the mid-year report, we published a detailed account of how we had used the feedback from the March, June and September 2021 meetings. Below we share details of how we've used the feedback from the December 2021 and March 2022 meetings.

December 2021 – Enhanced Frequency Control project

We presented on our Enhanced Frequency Control project (deliverables D12.1 D15.7.1, D15.9.1)

TAC feedback	How we have used it or how we will use it
We should review communication and latency requirements to ensure they are appropriate	• We carried out checks on latency of the current PMU measurement data that received by NGESO and identified the way to improve the latency by forward streaming data against aggregated streaming data • We engaged with a TO for changing PDC streaming to forward and establish the latency in the actual system as early as possible which was not in the original plan • We also engaged with different technology provider(s) and looking at different options available
The EFC projects needs to follow the latest security standards.	• Following the TAC group feedback, the project team engaged with experts to develop the cyber security requirements (including C37.118) for the future system.
We need to be clear how the EFC projects sits alongside, and delivers benefits over and above, other projects such as Dynamic Containment and the Pathfinder projects	• We are currently engaging with NGESO market team to define the future market requirements and ensure that all projects are appropriate.
The ESO should look to international comparators to learn lessons about enhanced frequency control in a heavily renewable and/or distributed system	• Similar systems are used in Iceland and South Australia. We are exploring these. • We engaged with CIGRE working group and the Electric Power Research Institute (EPRI) in the United States to consider similar research work • We will continue our research work looking at the approach and findings of other countries.

March 2022 – Balancing and Network Control programmes

We presented an update on the Balancing and Network Control programmes, having last presented on these topics in March 2021 (see above).

TAC feedback	How we have used it or how we will use it
Break down the Balancing services into smaller module-based models, removing dependencies where possible, reducing complexity and making change easier	• This is the approach we will take to developing the Open Balancing Platform, in line with the TAC's comments and learning lessons from past delivery. • New services will then be developed and delivered incrementally, based on business and/or consumer value. • It is difficult to do with our current systems (BM and EBS) due to their legacy monolithic and complex structure.
Market reform (for example locational marginal pricing) will take time to	• We are pleased that the TAC agree that there is a need for our Balancing Transformation work to continue.

assess and implement – we should not assume it is a forgone conclusion. There will still be a need for the ESO to carry out a residual balancer role. Lots of markets will not be factored into a locational marginal price.	• We will ensure that our systems are not just flexible to, but also help enable, any future market reform. • Given the uncertainty, we must continue engaging with industry to ensure our systems remain aligned with the direction of travel.
It is not a surprise that Balancing Programme costs have gone up. The required investment should be framed in terms of the size of the market. But the ESO must be as transparent as possible on costs and delivery.	• We have implemented a strategic review of our Balancing capability. We will outline to industry our current challenges, cost and benefit forecasts and delivery options to agree a roadmap. • We will then update industry through the TAC, our external engagement plan and regular updates to ensure transparency.
There are good options for assurance, both internally and externally that we should consider. External assurance of costs and risks should be considered.	• We have engaged a consultancy firm to carry out an audit of the process the Balancing Programme has for planning, cost forecasting and tracking, risk management and governance. • We are developing a long term assurance strategy to run alongside the Balancing Programme. • We would be happy to share the output of this at future TAC meetings and will look to implement recommended changes, where it is possible and proportionate to do so.

Restoration

Area	Stakeholder feedback	Action taken by the ESO
Electricity System Restoration Standard (ESRS)	'Meeting expectations' feedback from the mid-year survey: Be more aware of the interaction between planned generation outages and system stability in real time. the importance of the new restoration standard being mandated to the industry by BEIS SOS there has been no engagement led by ESO to date on how the restoration capability presently virtually non-existent in our region is going to be established on the ground at the level being mandated."	The ESO has engaged extensively with the industry on the ESRS as follows: • We issued a 5 week consultation on ESRS in November 2021 to get wider views on how best to implement the standard. • We initiated seven working groups since Nov 2021 that meet every fortnight to address the consultation responses and further explore areas of development required to achieve the new standard.
Planned outages and system stability	'Below expectations' feedback from the mid-year survey: Greater awareness of the interaction between planned outages and system stability in real time is needed to ensure there is sufficient restoration capability for all regions.	The ESO closely monitors and seeks to ensure sufficient restoration capability is available across GB at all times. Nonetheless, through implementing stability pathfinders (phase 1 completed, phase 2 planned) this has and will continue to improve stability services and further assist existent and future restoration capability. We continually liaise with key stakeholders on these issues and any specific information will be presented at the OTF.

Distributed ReStart - Procurement and Compliance stakeholder engagement	The following feedback was provided at a stakeholder webinar in May 2021:	
	On the proposed procurement process for Distribution Restoration: "Timescales for expression of interest, feasibility studies and implementing new assets does not feel sufficient."	We have extended the planned timeframes between the key procurement stages as part of the tender rollout in 2022. For more consistency, the procurement process for Top-up services has been better aligned with that of the anchor generator.
	On the commercial questions as part of the Test Procurement event: "More information and clarity required around the breakdown of costs for requirements relating to both anchor generators and top-up services – it is not clear how some of these costs could be calculated without a detailed feasibility study?"	We have incorporated this feedback into the business-as-usual process for procuring restoration services. The Test Procurement Event was deliberately designed to merge the main stages and therefore in reality, the commercial costs will only be submitted following a successful detailed feasibility study which will be funded by the ESO for the DER providers.
	On the proposed code changes: "In G99, need a fourth category that sets restoration investments separate from BAU as there are knock-on effects to how generators are assessed in terms of compliance. Mentioned issues with 'long term parallel plant'."	The code change proposals are explained within Section 12 and 13 of G99. G99 has been updated to relax some requirements when in a Black Start situation.
Distributed Restart - Organisation systems and telecoms stakeholder engagements	The following feedback was provided during desktop exercises / Engineering advisory Council session:	
	"A key learning point for me is that I hadn't fully appreciated that the cascade communication process in the current Local Joint Restoration Plans (LJRPs) can mean that the executor may not have communicated directly with the instructor, which is not normal in our industry and understandably raised concerns with the participants"	Communication of status information will be critical to a successful restoration process. Although each party may be using different tools to manage their own assets, there will have to be appropriate exchange of information between systems and people to support the process. The Project's functional specifications for Voice & Data Cyber Secure and power-resilient comms have been updated. This was published in our final Workstream report in September 2021. We are further refining these specifications as we finalise our testing of the Distributed Restoration Zone (DRZ) Controller at the HVDC Centre in late Spring this year.
	"I believe once you are finished with the technology for Distributed Restart it should be built into the NGESO ESR testing regime as a regular thing such that all stakeholders who would be involved get the periodic chance to attend. I am sure the simulator could be adapted to a conventional LJRP but even without the principles are the same and the discussions equally valid."	The Distributed Restart project has made final recommendations for training, shared learnings from our simulation experience and proposed options for adaptation of the method we used. Real training post-implementation needs to be individualised to the distribution network operators (DNOs) based on their own systems and specific restoration strategies. Desktop exercises will help to tease out the training requirements. This process will be starting in the second half of 2022.

A.4 Demonstration of Plan Benefits for Role 1

The fourth evaluation criterion for the ESO incentive scheme is Demonstration of Plan Benefits, where the Performance Panel will consider the actual benefits the ESO has realised from delivering its Business Plan, or any outputs additional to the Business Plan.

At the time of publishing our original RIIO-2 Business Plan in December 2019, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the RIIO-2 Business Plan. The relevant CBAs for Role 1 are:

- Control centre architecture and systems (A1)
- Control centre training and simulation (A2)
- Restoration (A3)

In this section, we provide a progress update for each of the activities for which we originally provided a Cost-Benefit Analysis, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence, and describing any sensitivity factors which would impact on the delivery of the stated benefit. Deliverable activity statuses reflect the delivery of RIIO-2 milestones and do not recognise either work completed prior to April 2021 nor progress made towards yet to be completed milestones.

We also provide a specific case study on the **Frequency Risk and Control Report (FRCR)**, which was not covered by the original Cost-Benefit Analysis document.

The Panel will also consider the ESO’s Regularly Reported Evidence (RRE) as part of the Demonstration of Plan Benefits criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the ESORI guidance. For Role 1, the items of RRE reported at the end of the year are:

- 1E. Transparency of operational decision making
- 1F. Zero Carbon Operability (ZCO) indicator
- 1G. Carbon intensity of ESO actions
- 1H. Constraints cost savings from collaboration with TOs
- 1I. Security of Supply reporting
- 1J. CNI outages

CBA: Control centre architecture and systems (A1)

Benefit described in RIIO-2 business plan	"We estimate the gross benefits to be £305 million over RIIO-2. This gives an NPV of £210 million over RIIO-2. The main areas of the quantitative benefit above are the following: • Estimating a five per cent improvement in managing constraints from enhanced situational awareness tools, delivering a gross benefit of £117 million. • Lowering consumer bills through unlocking the benefits of greater flexibility, delivering £109 million of gross benefit. • Reduced environmental damage from our control centre residual balancing actions, delivering a gross benefit of £51 million. • Upgrading our tools to better handle greater levels of interconnection, delivering £12 million of gross consumer benefit."
Role	1. Control Centre operations
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050
Key RIIO-2 Deliverables and progress	

Activity A1.2 – Enhanced Balancing Capability

Deliverable	Status
D1.2.1 Enhanced Balancing Tool	55% complete 50% not due to start yet
D1.2.2 Emergent technology and system management	27% complete 23% delayed 50% not due to start
D1.2.3 Future innovation productionisation	Continuous activity

Activity A1.3 – Transform Network Control

Deliverable	Status
D1.3.1 Develop and deliver new real-time situational awareness tool	64% complete 8% delayed 28% not due to start yet
D1.3.2 Enhanced network modelling tools (modules for D1.3.1)	Continuous activity
D1.3.3 Upgraded control centre video walls and operator consoles	Not due to start yet
D1.3.4 Increased operational liaison with DNOs	Continuous activity

Activity A1.4 – Control Centre Architecture

Deliverable	Status
D1.4.1 Creation of a data and analytics platform	33% delayed 67% not due to start yet 11% continuous activity
D1.4.2 Technology Advisory Council	Continuous activity

Forecasted benefits	**Forecasted in original CBA:**

Benefits £ millions	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Reduced CO2 emissions	0.8	3.6	10.8	16.1	19.8	51.0
Greater interconnection	0.2	0.8	2.3	3.6	5.0	11.8
Utilising flexible technology	2.0	10.1	24.1	32.2	40.2	108.5
Better inertia forecasting and needs management	14.4	1.2	N/A	N/A	N/A	15.6
Improved situational awareness	1.5	8.6	24.3	37.2	45.5	117.1
Reduced balancing mechanism outage downtime	0	0	0	0	1.0	1.0
Total	**18.9**	**24.3**	**61.5**	**89.1**	**111.5**	**305**

This shows that if our deliverables were progressing to plan, we would expect £18.9 m of benefit to be realised by the end of 2021/22.

We are continuing to progress with the delivery schedule as per RIIO-2 plans, however with the greater understanding we now have of the complexity of overarching deliverability of these plans with respect to balancing. To this end we are conducting a balancing strategy capability review to determine the best way forward to meet the requirements. We have already started a wider engagement piece with industry to validate, challenge, and review in order to agree the future delivery plan. Therefore, we will have a better view of the timeline for delivery of forecasted benefits once this review has been completed.

In terms of 2021-22 benefits, we have delivered £0m from the work that has been delivered to date compared to benefits capture in the original CBA. Work has delivered has been working on the building blocks required to realise the future value in the future RII0-2 period. We have realised £175 million of benefits in forecasting enhancements (not included in original CBA), and with the Balancing Mechanism R0 release, we have removed 8,000 hours of workarounds for our control room (not captured in original CBA. We are also currently updating CBA as part of BP2 submissions.

Related metrics/ Regularly Reported Evidence

Metric/RRE	**Impact on metrics/ RREs**	**Status**
1A Balancing costs	Expected to be favourably impacted by improvements to constraint management and by the benefits of greater flexibility.	£3,132 vs benchmark of £1,321 (below expectations). Most of the benefit will be delivered in the latter years of RIIO-2, in line with our delivery schedule. Forecasting enhancements, i.e. Platform for Energy Forecasting (PEF) has delivered £175m annual savings BM asset health have removed 8,000 hours of workaround for control room
1D Short notice changes to planned outages	Expected to be favourably impacted by improvements to constraint management and by the benefits of greater flexibility.	1.3 outages delayed or cancelled per 1000 outages (meeting expectations). Most of the benefit will be delivered in the latter years of RIIO-2, in line with our delivery schedule.

RRE 1F Zero Carbon Operability Indicator	Expected to improve due to reduced environmental damage from our control centre residual balancing actions	The ESO has accommodated up to 87% zero carbon in 2021-22 Benefits will be realised in later years with the delivery of enhanced balancing capability.
RRE 1G Carbon intensity of ESO actions	Expected to improve due to reduced environmental damage from our control centre residual balancing actions	During the 2021/2022 incentive year the average carbon intensity of balancing actions was 5.2 gCO2/kWh. Our work is expected to reduce carbon intensity when dispatching in cost merit order with greater effectiveness.
RRE 1I Security of Supply	Would be adversely affected if new Control Centre Architecture were not put in place but are not expected to improve as a direct result of these deliverables.	There have been no reportable voltage and frequency excursions between April 2021 and March 2022.
RRE 1J CNI outages	Expected to improve due to the delivery of our new control centre tools, but in our RIIO-2 CBA we estimated this benefit to start from 2025-26	3 planned CNI outages and 0 unplanned CNI outages. The timeline will depend on the outcomes of the balancing capability strategy review.

Sensitivity factors

The estimated consumer value we expect to deliver that is stated in the RIIO-2 CBA report was based on several assumptions. If those assumptions out turn different to expected, the actual consumer value delivered will be different to our original estimates, irrespective of the progress of our deliverables. The table below lists the assumptions made and notes whether the outturn is in line with our original estimates.

Sensitivity type	Assumption	Present	Commentary
Constraint costs	£600m in 2021/22	£1.4bn from April to March 2021/22[12]	Increase as a result of increased prices of constraint actions in line with increased wholesale prices.
Cost of carbon	£14.70/tonne CO2 equivalent	~£246/ tonne CO2 equivalent[13]	This will significantly increase benefits.
Progress of deliverables	As per the RIIO-2 plan	As above	Progress is behind original schedule however the fundamental building blocks to delivery future are being completed.

[12] https://data.nationalgrideso.com/backend/dataset/fb56b46e-cef3-4eb8-9294-0ca19769b7eb/resource/419337fb-f609-45e3-9097-798a41b4b3de/download/constraint-breakdown-2021-2022.csv Sum of columns B, C, D, E from 01/04/2021 to 31/03/2022

[13] BEIS has not provided an update to its carbon prices for modelling purposes. It has, however, updated its carbon prices for policy appraisal. For 2020 to 2030, these are between three and 20 times larger than the previous values. If similar updates to the modelling figures are updated, it will significantly increase the estimated benefit in the "reduced environmental damage from our control centre residual balancing actions" area.

Carbon intensity of ESO actions and expected demand	Carbon intensity is from Steady Progression and Two Degrees in FES 2019 Expected demand is from Two Degrees in FES 2019	Updated figures from FES 2021, replacing Two Degrees with Leading the Way	The difference in carbon intensity in FES 21 scenario is lower which will reduce benefit but will be more than offset by increase in carbon price.
Interconnector volume	15GW – 16.5GW by 2030 (FES 2019)	15.9GW – 21.55GW by 2030 (FES 2021)	Expect a slight decrease in benefits compared to 2019 due to slightly lower interconnection volumes using the benchmark of FES five-year forecast which best matched scenario used in original CBA.

* Because these benefits are estimated from a fixed percentage of constraints costs, as these costs decrease the amount of benefit delivered decreases (and vice versa), irrespective of our delivery.

Summary

As a result of the unprecedented increase in wholesale costs over the last few months, the monetary benefits for this CBA could vary significantly depending on the future trajectory of those costs.

Furthermore, the ongoing status of the balancing capability strategy review means that there is potential for the future benefits of this work to be updated to reflect the outcome.

Overall, we expect to deliver more than the £305m we had set out for the RIIO-2 period.

CBA: Control centre training and simulation (A2)

Benefit described in RIIO-2 business plan

"We estimate the gross benefits to be £35 million over RIIO-2. This gives a net present value of £16 million over RIIO-2. The quantitative benefits stated above have been calculated by:

- Estimating a two per cent improvement in managing response and reserve, from enhanced training and simulation capabilities, combined with new tools, resulting in £28 million of gross benefit.
- Updating our shift patterns, working arrangements and training delivers gross benefit of £7 million over RIIO-2. This is against a baseline assumption of continuing with the as is state of limited training and simulation capability.

This activity is dependent on the following transformational activity:

1. A1 Control Centre architecture and systems (Theme 1) – Allowing high skilled engineers to use their training for zero carbon system operation This also enables, through a highly skilled workforce which can operate a complex decentralised and decarbonised electricity system, the following transformational activity:

2. A1 Control Centre architecture and systems (Theme 1) - Providing real world experience for training and simulations

Delivery of this activity could pass on benefits and costs to third parties. There may be a cost to DNOs and TOs for training their staff using our facilities. However, this would likely be offset by savings from not having to run some or all of their own training programmes. They will benefit from having a greater pipeline of resource due to our enhanced academic partnerships attracting talent to the industry. Greater co-ordination and collaboration of training will help the industry make better whole system decisions, particularly in areas such as restoration and disaster recovery.

Our analysis suggests that accounting for market, delivery and third-party uncertainty the net present value could credibly be between -£2 million and +£42 million."

Role

1. Control Centre operations

ESO Ambitions

- An electricity system that can operate carbon free
- A whole system strategy that supports net zero by 2050
- ESO is a trusted partner

Key RIIO-2 Deliverables and progress

Activity A2.2 – Enhanced training material

Deliverable	Status
D2.2.1 Development of new modules and qualifications in system operation	50% complete 50% not due to start yet
D2.2.2 Enhanced training and simulation with DNOs and wider industry	20% complete 40% delayed 40% not due to start yet

Activity A2.3 – Training simulation and technology

Deliverable	Status
D2.3.1 Upgrades to current simulators, ahead of developing new simulator capability	38% complete 13% delayed 50% not due to start yet
D2.3.2 New training methods and platforms	60% complete 40% not due to start yet

Activity A2.4 – Workforce and change management

Deliverable	Status
D2.4.1 Personalised updates and automated shift logins	44% delayed 56% not due to start yet
D2.4.2 Content and infrastructure for personalised training plans	Continuous activity

Forecasted benefits	**Forecasted in original CBA:**

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Reduced resource costs	0.5	0.5	1.3	1.3	1.3	5
Lower training costs	0.1	0.1	0.3	0.8	0.9	2.2
Improved decision making	0.5	2.6	6.2	8.2	10.3	27.8
Total	**1.1**	**3.2**	**7.8**	**10.3**	**12.5**	**35**

The table shows that more benefits are realised in later years. At the end of 2021/22, we would expect to have delivered £1.1m of consumer benefit.

We have not been able to deliver all the expected benefits in 2021/22 for reduced costs due to delays to activity A2.4 due to a change of owner of the supplier. We have delivered the majority of the 2021-22 benefits on lower training costs and improved decision making, with some milestones delayed due to authorised resource availability and the impact of COVID-19.

Related metrics/ Regularly Reported Evidence

Metric/RRE	Impact on metrics/ RREs	Status
Metric 1A Balancing costs	Metric 1A is expected to be lower than would otherwise be the case as a result of these deliverables. New training and simulation capability will allow our control room engineers to make better decisions in a more complex operational environment.	£3,132 vs benchmark of £1,321 (below expectations). Most of the benefit will be delivered in the latter years of RIIO-2, in line with our delivery schedule. The improved decision making benefit line will help lower balancing costs compared with what would otherwise be the case.
RRE 1F Zero carbon operability indicator	Would be adversely affected if new training and simulation capability were not delivered but are not expected to improve because of it	The ESO has accommodated up to 87% zero carbon in 2021-22 Improved decision making is mostly on track, which benefits this RRE.
RRG 1G Carbon intensity of ESO actions	Would be adversely affected if new training and simulation capability were not delivered but are not expected to improve because of it	During the 2021/2022 incentive year the average carbon intensity of balancing actions was 5.2 gCO2/kWh. Improved decision making is mostly on track, which improves decisions made that impact carbon intensity.
RRE 1I Security of supply	Would be adversely affected if new training and simulation capability were not delivered but are not expected to improve because of it	There have been no reportable voltage and frequency excursions between April 2021 and March 2022 The fact that most of the training deliverables are on track gives us confidence that we'll be able to operate in an increasingly challenging environment.

Sensitivity factors (description)

The estimated consumer value we expect to deliver that is stated in the RIIO-2 CBA report was based on several assumptions. If those assumptions out turn different to expected, the actual consumer value delivered will be different to our original estimates, irrespective of the progress of our deliverables. The table below lists the assumptions made and notes whether the outturn is in line with our original estimates.

	Sensitivity type	Assumption	Present	Commentary
	Decreased training costs	Reduction in training time from 7 months to 4 months	Reduction in training time from 9 months to 6 months	Latest experience of recruiting power system engineers has shown a higher requirement for UK energy market familiarisation, increasing the overall training time.
		Training cost £75,000 per candidate, 30 candidates trained per year	Remains valid	Numbers of trainees may vary due to business need year on year. 30 would be the figure based on current projections
	Improved decision making	Response and reserve cost £514m in 2021-22	£510m in 2020-21[14]	Consistent with assumption.
		2% improvement in reserve and response spend	Remains valid	We still feel that our proposals will lead to a 2% reduction in reserve and response spend, as a result of better training and decision making.
Summary	Overall, we expect to deliver approximately equal to the £35m we had set out for the RIIO-2 period. We continue to deliver operational training using the existing training simulator and look to reduce training timescales where appropriate, but not at the cost of reducing the quality of the authorised roles within the ENCC. We are on track with the assumptions made that the training simulators will a) be delivered, b) work for the needs of the business, c) staff recruitment maintains projected numbers and attrition rates remain as expected.			

[14]Monthly Balancing Services Summary (MBSS) Mar-2021 https://data.nationalgrideso.com/backend/dataset/f89a12fc-94ef-4a09-bce2-c094c7212e1f/resource/931455ff-3de2-4aba-ac90-b48b3f9775fa/download/mbss-data-march-2021.xlsx Sum of "Operating Reserve", "STOR", "Negative Reserve", "Fast Reserve", "Response" and "Other Reserve" costs.

CBA: Restoration (A3)

Benefit described in RIIO-2 business plan	"We estimate the gross benefits to be £5 million over RIIO-2. This gives a net present value of negative £8 million over RIIO-2. Despite our proposals having a negative net present value, it is important we open our restoration services to more providers including DER. We must also comply with the new restoration standard and build tools that can minimise restoration times. Given the £115 million net benefit from 2025 to 2050 of our DER NIC project, we expect our proposals to deliver net benefits over the period to 2050. This is against a baseline assumption of continuing with current Black Start procurement activities."
Role	1. Control Centre operations
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050 • ESO is a trusted partner • Competition Everywhere
Key RIIO-2 Deliverables and progress	It should be noted that whilst all the A3 transformation activities (i.e. A3.2 and A3.3) were considered when calculating the A3 net present value, the benefits are only derived from A3.3. This is because A3.2 (like the concept of restoration overall) serves as an insurance policy. We did not feel it was appropriate to calculate the benefits from faster restoration, given the high-impact, low-probability nature of a such an event.

Activity A3.2 - Restoration standard

Deliverable	Status
D3.2.1 Facilitate and compile, on behalf of the GB industry, the annual assurance process for GB Black Start.	43% complete 14% delayed 43% not due to start yet
D3.2.2 Validate restoration timelines for GB using the assurance data.	33% complete 17% delayed 50% not due to start yet
D3.2.3 Maintain obligations and requirements against the new standard for Black Start capability provision.	50% complete 25% delayed 25% not due to start yet
D3.2.4 Restoration decision making support tool designed and developed to aid faster restoration times in line with stakeholder expectations.	17% complete 17% delayed 67% not due to start yet

Activity A3.3 - Innovation project in restoration (Distributed ReStart)

Deliverable	Status
D3.3.1 Trial case studies based on different technology types.	57% complete 29% delayed 14% not due to start yet
D3.3.2 (Subject to project findings) Proof of concept findings implemented and new system and communication methods implemented	100% not due to start yet

Forecasted benefits

Forecasted in original CBA:

Benefits £ millions	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Benefits from the Distributed Energy NIC project	0	0	0	0	4.6	4.6
Carbon savings	0	0	0	0	0.6	0.6
Total	**0**	**0**	**0**	**0**	**5.2**	**5.2**

The table shows that more benefits are realised in later years. At the end of 2021/22 we would expect to have delivered £0m of consumer benefit to be realised.

Some milestones are delayed, but they are not expected to have an impact on this timeline.

Related metrics/ Regularly Reported Evidence

Metric/RRE	**Impact on metrics/ RREs**	**Status**
Metric 1A Balancing costs	We expect competitive restoration processes to improve this metric. This will only be the case once the new contracts are operational.	£3,132 vs benchmark of £1,321 (below expectations). Not applicable until new contracts in place and operational.
RRE 1F Zero carbon operability indicator	Our activities will ensure all technology types, including zero-carbon, can provide restoration services. This helps enable our ability to operate a zero-carbon system. However, this will only be the case once the new contracts are operational.	The ESO has accommodated up to 87% zero carbon in 2021-22 Not applicable until new contracts in place and operational.
RRE 1G Carbon intensity of ESO actions	The actual carbon intensity of any restoration actions will depend on what is economic and efficient at the time.	During the 2021/2022 incentive year the average carbon intensity of balancing actions was 5.2 gCO2/kWh. Not applicable until new contracts in place and operational.
RRE 1I Security of supply	If we do not undertake the restoration activities described in our Business Plan, this may result in worse performance for RRE 1I, as it would take longer to restore the system to within its frequency and voltage limits after a blackout.	There have been no reportable voltage and frequency excursions between April 2021 and March 2022. Not applicable until new contracts in place and operational.
Metric 2A Competitive Procurement	We expect competitive restoration processes to improve this metric. This will only be the case once the new contracts are operational.	51% of all services procured through competitive means (meeting expectations). Not applicable until new contracts in place and operational.
RRE 2B Diversity of Service Providers	We expect competitive restoration processes to improve this RRE. This will only be the case once the new contracts are operational.	Varying diversity across different markets – see RRE section for details. Not applicable until new contracts in place and operational.

Sensitivity factors (description)	The estimated consumer value we expect to deliver that is stated in the RIIO-2 CBA report was based on several assumptions. If those assumptions out turn different to expected, the actual consumer value delivered will be different to our original estimates, irrespective of the progress of our deliverables. The table below lists the assumptions made and notes whether the outturn is in line with our original estimates.

Assumption	Status	Commentary
Industry participation in Black Start from DER project (Distributed Restart)	Better than expected	Additional value added activities – added trials Commercial service design is currently feeding into the south east regional tender work. The code drafting is seeking approval through the GC0148 industry consultation. There have been some delays to the live trial dates, but all are due to complete by Sept (still BP1) and none should impact the overall commercial service go live in 2025/26
Implementation of Restoration standard	Later than originally anticipated	Direction from Secretary of State to comply with the standard was received later than originally anticipated. We have until end of December 2026 to have sufficient capability and arrangements in place to meet the new ESR Standard
Industry participation in Black Start tenders	Our Northern tender received 22 submissions	SE Tender was delayed into 2022/23 following stakeholder input to ensure increased provider participation

Summary	Overall, we expect to deliver approximately equal to the £115m we had set out for the RIIO-2 period. As the benefits we state here are only derived from A3.3 (as stated above), and the delays within these deliverables are only minor (restoration from DER services is still expected to go live in 2025/26), we do not expect this to impact on the delivery of consumer benefit.

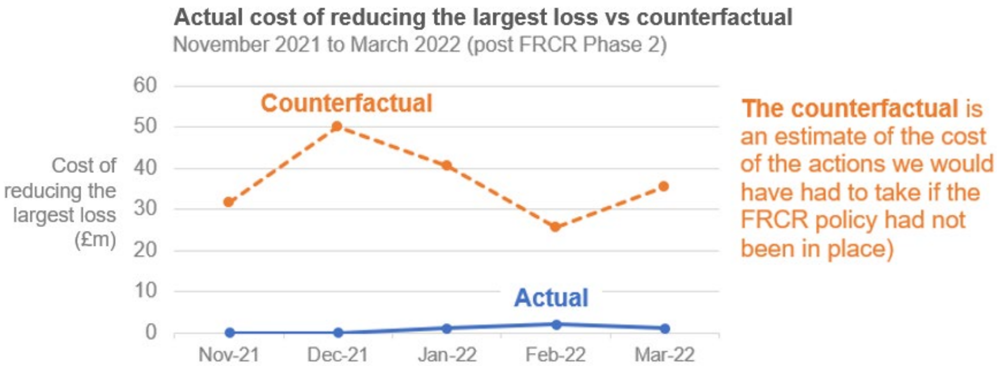
Consumer benefit case study for Role 1: FRCR

Activity	**Implementation of Frequency Risk and Control Report (FRCR)** Following the power disruption on 09 August 2019, the ESO worked with industry to implement changes to the codes and frameworks which govern the management of frequency risks on the GB system. An outcome of these changes was the requirement for the ESO to produce a Frequency Risk and Control Report (FRCR), assessing cost against risks and ensuring the network is appropriately protected from frequency events. Phase 1 of FRCR was implemented in May 2021 and Phase 2 followed in October 2021. The 2022 version of FRCR, which assesses the value of securing against simultaneous events, was submitted to Ofgem for approval on 1 April 2022[15]. Changes to the ESO's frequency policy as a result of FRCR implementation in 2021, combined with continued delivery of the Accelerated Loss of Mains Change Programme (ALoMCP) and growth in the number of participants in the Dynamic Containment (DC) service, have resulted in significant savings to how frequency risks are managed on the system. Prior to the implementation of FRCR, the ESO would prevent a system loss from causing a frequency deviation below 49.5Hz (for smaller infeed loss <= 1000MW) or 49.2Hz for larger infeed losses (>1000MW). This generally meant the ESO would not allow these risks to cause consequential RoCoF losses and would take bids to reduce the infeed loss and resulting RoCoF (Rate of Change of Frequency) to below 0.125Hz/s. As a result, the ESO would generally have held enough response to cover a maximum 1260MW loss. Post-FRCR 2021, the ESO has held a greater volume of response to cover larger total infeed losses and reduce market intervention to manage these losses with targeted bids.
Role	Role 1
ESO Ambitions	• An electricity system that can operate carbon free • Competition Everywhere
Key RIIO-2 Deliverables	FRCR is a requirement defined by the Security and Quality of Supply Standard (SQSS) as a result of changes made through modification GSR027 in 2020. FRCR delivery will become a deliverable for BP2.
Is the consumer benefit mainly this year or in future years?	Consumer benefit has been observed this year and will continue to provide benefits in future years.
Calculation of monetary benefit to consumers	Implementation of FRCR (alongside the introduction of DC and the progress of ALoMCP) has resulted in significant monetary savings for consumers. Without FRCR, the dynamic containment response service and the reduction in the RoCoF risk delivered through ALoMCP, the ESO would be still be required to constrain large units on the system in order to manage RoCoF risks. The relaxation of these RoCoF limits means that the ESO can now allow BMU-only infeed loss risks to cause a consequential RoCoF loss if the resulting loss can be contained to 49.2Hz and 50.5Hz. As a direct result of these changes in how we manage frequency, the ESO has reduced the volume of constraint actions on the system from 8TWh in 2020 to 1TWh in 2021 (calendar year). We estimate that this reduction represents a saving of £525m when compared with the actions we would have been required to take without the FRCR policy.

[15] https://www.nationalgrideso.com/document/248151/download

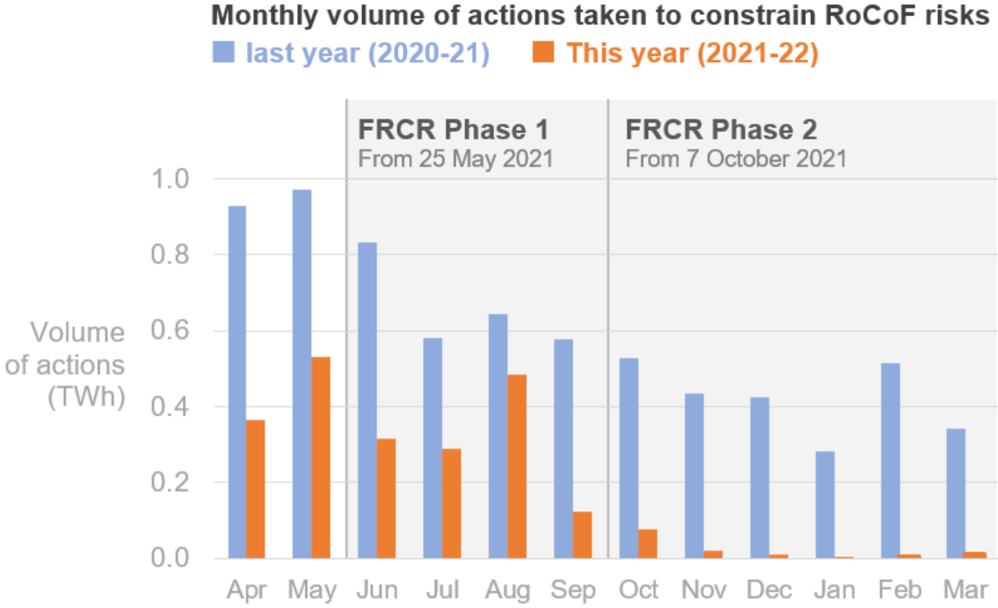
This cost saving is set against a complex market backdrop where key inputs are changing, such as the increasing response volumes and costs, driven by overall wholesale cost increases. The reduction in costs is partially offset by the procurement of response through the Dynamic Containment Low (DC-L) service. Note the total spend on DC-L in this period was £90m. This gives an estimated net saving of £435m.

Snapshot of savings since FRCR was fully implemented in October 2021



Assumptions made in calculating monetary benefit	To calculate the cost saving made by FRCR we applied a counterfactual scenario whereby, without the changes made through FRCR, we would be required to take direct market actions to manage large losses and their potential RoCoF risks. We estimate this to be in the region of at least 8TWh of managing largest losses (which would also have been compounded by the growth in low inertia periods and the addition of new large losses on the system). The cost of these actions was calculated at a price spread of £75/MWh.
How benefit is realised in the consumer bill	The reduction in operational costs will feed through into the consumer bill via lower BSUoS costs than would otherwise have been the case.
Non-monetary benefits	**Reduced market intervention by the ESO to constrain large losses:** Through the implementation of FRCR, the ESO have seen a significant reduction in volumes of intervention required in market dispatch (through trades or BM actions). The ESO are no longer required to take actions to constrain large losses on the system where this can be managed through other means, such as the use of response. In 2020, the ESO took a total of 8TWh of constraint actions (through trades of BM actions). In the first half of 2021 this reduced to 2.3TWh and just 935GWh in the second half of 2021. This ensures competitive markets can operate whilst at the same time, frequency risks are effectively managed.

The volume of actions required to constrain RoCoF risks has reduced significantly since the implementation of FRCR (Phase 1 and Phase 2) during 2021-22



Assumptions made in calculating non-monetary benefit	We have compared year-on-year volume of RoCoF actions to demonstrate the significant fall in 2021-22 particularly after Phase 2 was implemented.

Regularly Reported Evidence performance for Role 1

Table 6: Summary of RREs for Role 1

RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
1E	Transparency of Operational Decision Making	%	99.6%	99.6%	99.7%	99.8%	99.8%	99.7%	99.9%	99.7%	99.8%	93.5%	98.3%	94.8%
1F	Zero Carbon Operability indicator	%		Q1: 85%			Q2: 77%			Q3: 84%			Q4: 87%	
1G	Carbon intensity of ESO actions	gCO2 /kWh	2.1	6.2	4.5	4.5	6.9	1.0	4.8	9.4	3.4	6.4	10.6	3.1
1H	Constraints cost savings from collaboration with TOs	£m		Q1: £337m			Q2: £199m			Q3: £507m			Q4: £894m	
1I	Security of Supply	#	-	-	-	-	-	-	-	-	-	-	-	-
1J	CNI Outages - Planned	#	-	-	-	1	-	-	-	1	-	-	-	1
1J	CNI Outages - Unplanned	#	-	-	-	-	-	-	-	-	-	-	-	-

RRE 1E Transparency of operational decision making

April – March 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%	89.0%	88.4%	89.1%	92.6%	88.4%	91.2%	93.5%	98.3%	94.8%
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.6%	99.6%	99.7%	99.8%	99.8%	99.7%	99.9%	99.7%	99.8%	99.8%	100%	99.8%
Percentage of actions with no category applied or reason group identified	0.4% (173)	0.4% (147)	0.3% (56)	0.2% (87)	0.2% (81)	0.3% (109)	0.1% (61)	0.3% (232)	0.2% (93)	0.2% (95)	0.0% (27)	0.2% (85)

Supporting information

During 2021-22, 91.3% 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 0.2% of the total actions this year.

During the year, we sent 531,189 BOAs (Bid Offer Acceptances) and of these, only 1,246 remain with no category or reason group identified, 0.2%.

In March 2022, 94.8% of actions were taken in merit order, or taken out of merit order due to an electrical parameter. We were unable to allocate reason groups for 0.2% of the total actions this month.

RRE 1F Zero Carbon Operability Indicator

April – March 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.
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, the Accelerated Loss of Mains Change Programme, the implementation of the Frequency Risk and Control methodology and the voltage pathfinders. 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 in August 2021 was 95% on 14 August, settlement period 11. However, for that period the final ZCO dropped to 68% after our operational actions were taken into account, meaning that this was not the highest final ZCO of the month.

Figures 5 and 6 further below shows the underlying data by settlement period and highlights when the maximum monthly values occurred.

Table 9: April to September 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 and settlement period)	Date / Settlement Period
April	84.8%	91.7%	05 Apr / SP31
May	79.7%	89.9%	04 May / SP8
June	71.9%	76.6%	14 June / SP8
July	74.6%	85.9%	29 Jul / SP11
August	76.0%	92.9%	16 Aug / SP13
September	77.7%	89.0%	23 Sep / SP6
October	83.3%	90.2%	31 Oct / SP13
November	83.4%	94.5%	01 Nov / SP1
December	84.5%	90.8%	25 Dec / SP15
January	87.1%	93.0%	05 Jan / SP5
February	85.3%	85.7%	27 Feb / SP23
March	85.0%	91.3%	22 Mar / SP5

Note that the values can change between reporting cycles as the settlement data is updated by Elexon.

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

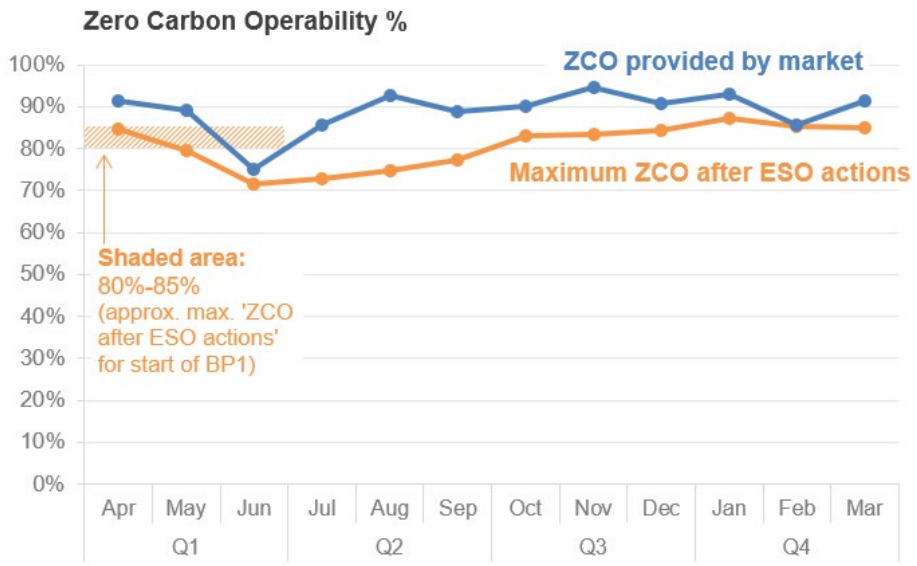
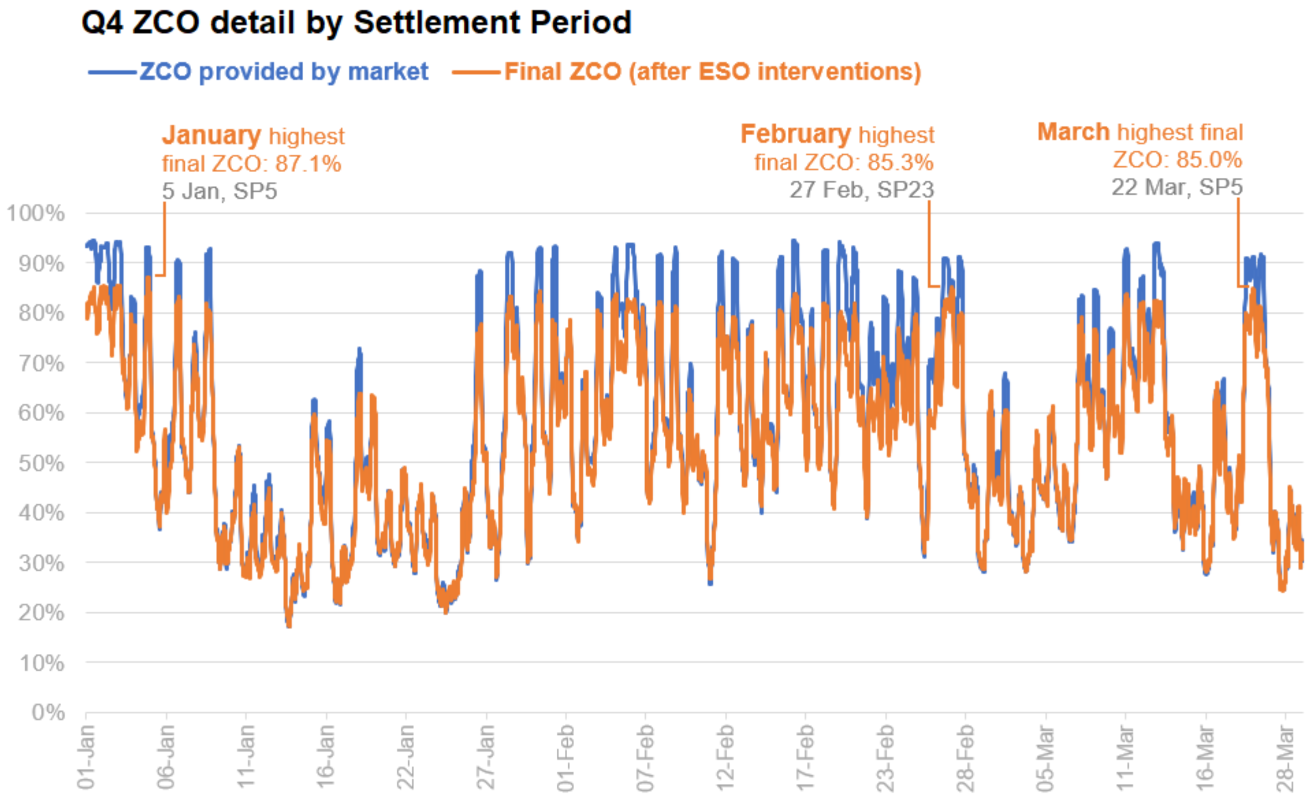


Figure 6: Q4 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

The highest zero carbon percentage outturn in Q4 following ESO actions was 87.1%. The maximum happened on 5 January 2022, Settlement Period (SP) 5. During that SP the market provided 93.0% ZCO, with actions taken by the ESO to manage the system reducing the final figure to 87.1%.

This is a new maximum for the year as the previous highest ZCO figure was 84.8% on 5th April SP31. This increase is due to the successful implementation of our operability strategy and the commissioning of new stability pathfinder phase 1 providers.

Since April 2021, three Stability Pathfinder Phase 1 service providers have gone live at Rassau, Deeside and Keith. Together they increase system inertia by ~4.4GVAs, which could potentially remove the need to synchronise 1-2 Combined Cycle Gas Turbine (CCGT) units for inertia. This usually occurs over the summer and shoulder months and would increase the ZCO figure by around 1.5% (depending on system conditions at the time). Going forward we expect to see further increases in ZCO as the other Stability Pathfinder Phase 1 projects commission.

As expected, the Q4 ZCO figures have increased since Q3 and are back to the level seen at the start of Q1. Q2 figures are lower because the demand (not shown on the graph above) was lower in Q2 due to the warmer weather. At times like these, when the demand is low 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) but these actions represent 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 the middle of December are clearly visible on the graph above where the ZCO% drops below 30%. Conversely, the maximum ZCO figures align with settlement periods of high renewable output, such as 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 still be needed, even though the ZCO figure provided by the market will appear relatively low as it will not include the solar generation.

RRE 1G Carbon intensity of ESO actions

April – March 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	Full Year
Carbon intensity (gCO2/kWh)	2.1	6.2	4.5	4.5	6.9	1.0	4.8	9.4	3.4	6.4	10.6	3.1	**5.2**

Supporting information

In March 2022, the average carbon intensity of balancing actions was 3.1 gCO2/kWh. The time with the largest decrease in carbon intensity due to the ESO's actions was 15:00pm on 31 March 2022 with a minimum of –21.7 gCO2/kWh. This was lower than January 2022's minimum value of -36 gCO2/kWh. In March, the time with the highest carbon intensity was 08:00am on 12 March 2022 with a value of 42.6 gCO2/kWh.

During the 2021/2022 incentive year the average carbon intensity of balancing actions was 5.2 gCO2/kWh. September 2021 was the lowest carbon intensity in the incentives year at 1.0 gCO2/kWh and February 2022 was the highest at 10.6 gCO2/kWh.

RRE 1H Constraints Cost Savings from Collaboration with TOs

April – March 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.

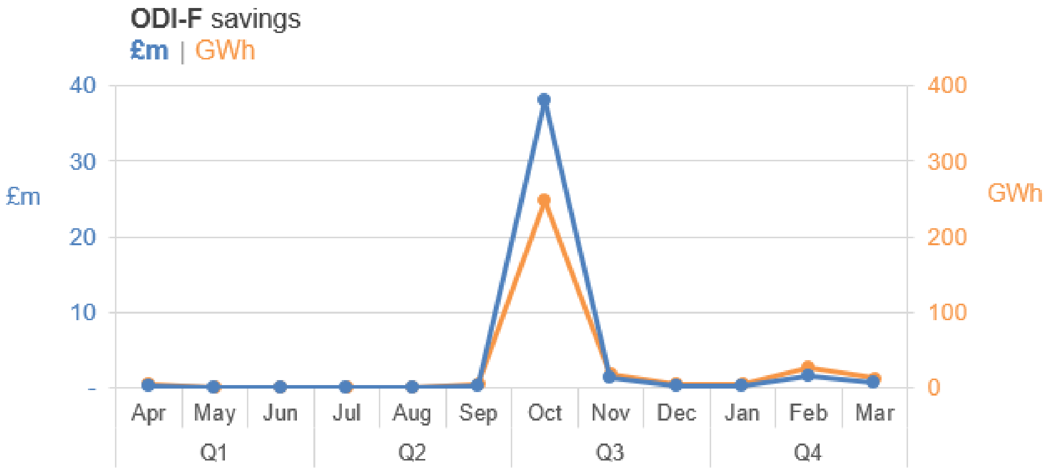
This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

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[16] 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)



[16] 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)

Note vertical axes scales are different from the ODI-F graph above.

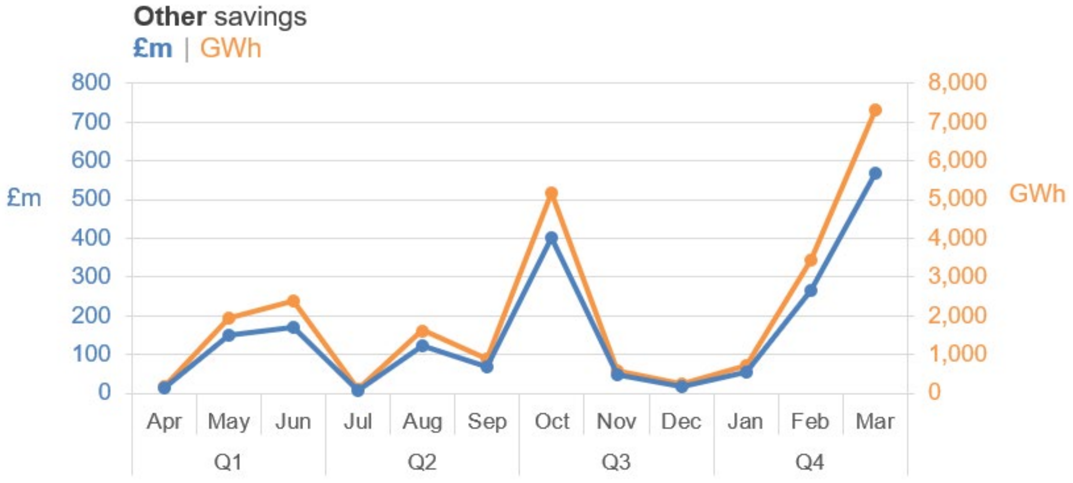


Table 11: Estimated £m savings in avoided constraints costs

	ODI-F savings	Other savings	ODI-F savings	Other savings
	£m	£m	GWh	GWh
Apr	0.2	15	4.4	189
May	-	151	-	1,942
Jun	-	171	-	2,391
Jul	-	6	-	107
Aug	-	124	-	1,618
Sep	0.2	69	4.4	873
Oct	38.0	401	248	5,177
Nov	1.3	48	18.4	592
Dec	0.2	19	4.4	247
Jan	0.2	55	4.4	720
Feb	1.5	267	27.3	3449
Mar	0.7	569	13.0	7308
Full Year	**43**	**1,895**	**324**	**24,613**

Note that figures from previous quarters may change as some savings are updated retrospectively with costs that were not available at the time that the activities were carried out.

Supporting information

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

The Network Access Planning (NAP) team has progressed and approved eight enhanced service provisions from TOs through STCP 11.4 that provide constraint cost savings this year. Details are provided below.

- Provision of dynamic weather-based rating increase on a circuit in the northwest of England. This was to reinforce a major boundary North of England (B7 boundary) during a proposed major circuit outage for critical substation and overhead line works. Rating recalculations, defect and lifecycle reviews, line walk to confirm asset health were carried out and then, daily ratings based on dynamic weather data were issued. This service was approved, and it provides £700k of constraint savings on the B7 boundary.
- The operational use of forced cooling on two super grid transformers in the northwest of England. This enables the ESO to direct the operation of fans and pumps on for forced cooling during periods of high Scottish flows to increase the B6 boundary thermal limit by approximately 100MW, creating a saving of approximately £15k for every hour that the boundary constraint is active. The actual savings provided by this service in the 2021-22 plan year are currently being calculated.
- A temporary operating regime was agreed with the TO which allowed sufficient time for manual post-fault actions to be taken to secure the network. This was over a two-week period, when there was a lack of generation available in a specific part of the network to provide voltage support post fault. The enhanced service delivered by the TO included providing additional personnel on site and in the control room, enhanced mitigation checks and dedicated monitoring equipment in place across three 400kV substations for a two-week period. This proposal was approved, alleviating the need to buy on 725MW of conventional generation and saving £37.8m
- Changing the overload protection setting on a circuit which is due to provide continuous improvement to a constraint in the Dumfries and Galloway area saving thermal constraint costs. The savings from this initiative span the entire year and will be prorated over the full 12 months at the end of year when the value of the savings will be calculated.
- The installation of an overload protection scheme will allow increased flow across the SSE-SP boundary. Again, the savings from this initiative span the entire year and will be prorated over the full 12 months at end of year.
- Provision of dynamic ratings on circuits 1 and 2 of a major transmission route in the north west of England to allow increased thermal loading based on expected weather conditions. The enhanced service provided by the TO included monitoring the limiting equipment, enhanced line checks and provision of daily ratings using dynamic weather data. This proposal has been approved as it is expected to increase the thermal boundary transfer capability in the local area by 200MW and will be used during future outages on either of these circuits. Estimated constraint costs savings are £24k per day during the next planned outage on the route.
- Increasing the rating on a circuit into the southeast of England which allows an increase in the southeast import constraint limit.
- Increasing the rating on circuits to allow the final high-priority decommissioning of circuits in central London.

In 2021-22, the Network Access Planning team in collaboration with the TOs realised £43m of constraint cost savings through STCP 11.4. Some of the above active enhanced service provisions (5, 8) are yet to realise constraint cost savings due to these constraints not being active during this period. Others, as detailed in points 2, 4 above cannot be captured in a single month in the ODI-F table above but rather have been prorated over the particular active period of the year.

However, some of the enhancements which are yet to realise savings will be useful in the near future and identifying and implementing these opportunities early has meant that the cost saving actions will be available over the periods that they are most valuable.

In some 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.

Other Savings (Customer Value Opportunities):

The Network Access Planning team has made excellent progress over the last year. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded over 190 instances where the ESO's actions directly resulted in adding value to end consumers, and where our innovative ways of working facilitated increased generation capacity to connected customers.

Such actions include moving outage dates, splitting/separating outages, reducing return to service times, obtaining enhanced ratings from TOs, re-evaluating system capacity, identifying and facilitating opportunity outages, aligning outages with customer maintenance and generator shutdowns, proposing, and facilitating alternative solutions for long outages that impact customers, and many more.

Some examples of these instances in 2021-22 include:

- The ESO together with a TO permanently altered the standard configuration of a substation in the North-East of England to 2-way rather than 3-way. This action increased the transfer across two major constraints in the North-East by 600MW and released approximately 5 TWh of renewable generation to the market.
- The ESO, working with a TO, facilitated the formation of a temporary circuit in the South of Scotland to restore the Main Interconnected Transmission System (MITS) to minimise constraint costs and improve network conditions. This temporary circuit was suggested to facilitate access to the network when typically, it would be difficult to release due to the impact it has on the system. This action released about 2.2 TWh of renewable generation to the market.
- The initial outage plan to deliver a new substation required a 29-week double circuit outage on a main transmission route. The ESO worked with the TO to review the scheme and find ways to reduce the impact on the system, which resulted in taking one single circuit out of service at a time. Through this approach we released about 2 TWh of renewable generation to the market, creating considerable value for the end consumer.
- The ESO suggested a change in the standard operating configuration of a substation in the south of Scotland, to improve the thermal capability limits of a constraint boundary for the duration of a major temporary circuit. This action released about 795 GWh of renewable generation to the market.
- On 17 occasions, the ESO optimised the outage plan by moving and rearranging scheme and maintenance outage dates to align with the customer's maintenance outages. These instances resulted in the release of more than 860 GWh of renewable energy.
- On 18 occasions, ESO re-planned and rearranged costly and inoperable scheme and maintenance outage combinations to ensure outages are operable and constraint costs are minimised. These instances resulted in the release of more than 1.6 TWh of renewable energy.

These and many more represent a total of 24.6 TWh of extra generation capacity, which would have otherwise been constrained at a cost to the consumer. This equates to approximately £1.8bn and is enough to power 8.4 million UK homes for a year.

(We assumed average values of £78/MWh for wind and £55/MWh for other generation)

RRE 1I Security of Supply

April – March 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. On a monthly basis we 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 ≤ f < 49.5	up to 60 seconds	2 times per year
48.8 < f < 49.2	Any	1-in-22 years
47.75 < f ≤ 48.8	Any	1-in-270 years

For this 2021-23 mid-scheme review, we also provide a summary of the ESO's compliance with its frequency control methodology and plans for any future changes to the methodology, as follows:

- The top three rows in the table below constitute the ESO's frequency management policy as set out in the FRCR. The bottom two rows are the monthly reporting requirements.
- The FRCR is produced at least annually. The latest version is due to be published in May 2022 and its recommendation does not change the existing frequency management policy.

Table 12: Frequency and voltage excursions

		Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
ESO frequency management policy as set out in the FRCR	Frequency excursions (more than 1.2 Hz away from 50 Hz)	0	0	0	0	0	0	0	0	0	0	0	0
	Frequency excursions (more than 0.8 Hz away from 50 Hz)	0	0	0	0	0	0	0	0	0	0	0	0
	Frequency excursions (more than 0.5 Hz away from 50 Hz) for more than 60 seconds	0	0	0	0	0	0	0	0	0	0	0	0
Incentives monthly reporting requirements	Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for more than 60 seconds	0	0	0	0	0	0	0	0	0	0	0	0
	Voltage Excursions defined as per Transmission Performance Report[17]	0	0	0	0	0	0	0	0	0	0	0	0

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

Supporting information

There have been no reportable voltage and frequency excursions between April 2021 and March 2022.

RRE 1J CNI Outages

April – September 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	0	0	0	0	0	0	0	0	0
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0	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	1 outage 216 minutes	0	0	0	1 outage 215 minutes	0	0	0	1 outage 196 minutes
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0	0

Supporting information

There were no unplanned outages during the year.

There were three planned outages to our CNI systems. In all three cases, the outages were required in order to deploy a software release of changes and enhancements to the Balancing Mechanism (BM) production systems. Each change impacted the key BM Suite components used for scheduling and dispatch of generation. As part of these outages, we were also able to plan and complete maintenance and configuration tasks to enable the continued focus on resilience of the system.

There were no other planned outages during the year.

Role 2

Market development and transactions

Role 2: Market development and transactions

Plan Delivery

- We have completed 49 out of the 65 milestones planned for this 12-month period. Of the 16 milestones which are not complete, 5 are ESO-related delays, 10 are outside of ESO control, and 1 is delayed in order to deliver an improved outcome for consumers. We have:
- Completed our suite of fast-acting frequency response products, with ongoing refinements
- Delivered the first release of our Single Markets Platform to allow onboarding
- Supported customers in migrating across to our new EMR Portal
- Progressed and delivered numerous code changes such as GC0137
- Updated DA STOR in response to market conditions

Metric performance

- 2A Competitive Procurement: 51% of all services procured through competitive means (meeting expectations)

Stakeholder evidence

Role 2 survey:

- 17% exceeding expectations
- 70% meeting expectations
- 13% below expectations

Highlights:

- Ongoing engagement with stakeholders on market reforms and product design
- Webpage created, webinars and bilateral discussions on our Stability Market Design NIA project.
- Working with GB stakeholders and TSOs following EU Exit to consider enduring UK-EU cooperation
- Engage with an external user group of industry volunteers to develop the EMR Portal
- Hosted dozens of events for Net Zero Market Reform project, engaging with over 1000 stakeholders

Demonstration of plan benefits

- Build the future balancing service and wholesale markets (A4) on track to deliver £106m consumer benefit over RIIO-2
- Transform access to the Capacity Market (A5) on track to deliver £74m consumer benefit over RIIO-2
- Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 (A6.5) on track to deliver £10m consumer benefit over RIIO-2
- Reforming Balancing Services Use of System (BSUoS) charges (A6.6) now expected to lead to an estimated saving of £68 million over RIIO-2
- Moving to more granular procurement of Dynamic Containment has resulted in a saving of around £18.7m

RREs:

- 2B Diversity of service providers: Varying diversity across the different markets
- 2C EMR decision quality: 1.6 overturned themes per 1000 applications (meeting expectations)
- 2D EMR demand forecasting accuracy: peak demand accuracy 6.6% for T-1 (below expectations), 4.1% for T-4 (below expectations)
- 2E Accuracy of forecasts for charge setting: Absolute Percentage Error of 20% (BSUoS) and of 0.5% (TNUoS)

Value for money

- Our forecast total expenditure for role 2 in BP1 is £160m, which is 1% higher than the benchmark of £159m.
- The main variances are increased costs associated with major IT programmes (Settlements, Charging and Billing and EMR). These are driven by a range of factor from changes to scope, improved understanding of complexity driven by greater regulatory change and delays to delivery.
- These increases are offset by reductions associated with EU Regulatory changes. Several planned activities (such as participation in TERRE or MARI) are no longer relevant following EU exit.

B.1 Plan Delivery for Role 2

Deliverable progress

For role 2, the RIIO-2 Delivery Schedule received an ambition grading of 4/5, providing the ESO with an ex-ante expectation of Ofgem's assessment of plan delivery if these deliverables are met. The Electricity System Operator Reporting and Incentives (ESORI) guidance states that the Performance Panel should consider that the ESO has outperformed the Plan Delivery criterion if the ESO has successfully delivered the key components of a 4- or 5-graded delivery schedule.

During the first year of the Business Plan 1 period, a few highlights of role 2 performance are:

Stability market development

The Stability Market Design innovation project began in September 2021, looking to investigate a potential enduring market design for the cost-efficient procurement of stability services, unlocking the potential of new, low-cost low-carbon stability technologies such as grid forming renewables. The project worked closely with industry through a series of workshops, webinars and surveys, and has recommended a preferred way forward. The next phase (planned to commence in Q1 2022-23) will assess the detailed market design and explore interactions between stability and other services such as reactive power and response. We will continue to work closely with industry as we progress through the next design phase.

Single Markets Platform

The foundational release of the Single Markets Platform (SMP) went live into production in February 2022. This is a key milestone for a project that is a vital deliverable through RIIO-2 to support us in becoming a better buyer of balancing services and part of a wider strategy to utilise digital ways of working to make it easier to do business with the ESO. This first release supports the onboarding process for new and enduring frequency response products (Dynamic Moderation, Dynamic Regulation and Dynamic Containment) and represents the first step in the development of the platform that ultimately will ensure a seamless and consistent user experience to access ESO markets for a diverse range of current and future participants.

Response Reform

We successfully launched Dynamic Containment (DC) low frequency in October 2020 and DC high frequency on 1 November 2021 as well as introducing day-ahead procurement. In September 2021 we launched DC low frequency on the EPEX auction platform, to introduce more granular, automated procurement. This is the same platform that hosted the weekly frequency response auction trial. The Auction Trial ended in November 2021 and we will use the tools and services available to us to secure our frequency requirements whilst we transition to the new suite of response and reserve products.

In March 2022 Ofgem approved the EBR Article 18 consultation documents for both Dynamic Moderation (DM) and Dynamic Regulation (DR). DM and DR are both pre-fault services, which form part of our new faster-acting frequency response products alongside DC. DM provides rapid response to keep frequency within operational limits whereas DR is designed to slowly correct continuous but small deviations in frequency with the aim to continually regulate frequency around the target of 50Hz.

Electricity Market Reform (EMR)

Capacity Market Auctions

- Building on the guidance that we co-created with customers, we ran the Capacity Market (CM) prequalification process for the T-1 and T-4 auctions and received 1,234 applications from our customers.
- Following eligibility assessments, successful applicants were able to enter into the capacity auctions which were held in February 2022.
- In May 2021 the EMR Delivery Body informed Ofgem where it had not achieved all Capacity Market (CM) obligations. These issues did not constitute a breach of Special Licence Condition 2.4. Each issue was investigated to understand the root causes and all remediation actions have been implemented to ensure appropriate controls are in place to remove risk of future issues.

Contracts for Difference (CfD) Allocation Round 4

- We have successfully opened and ran the applications process for CfD Allocation Round 4 and have assessed all applications. Working with BEIS, other EMR delivery partners and customers, we have ensured the smooth implementation of policy change into our business processes and auction system in readiness for Allocation Round 4, which opened in December 2021 and is ongoing.

EMR Portal

- We delivered the first release of the new EMR portal in March 2022. This covered the process for company and CMU registration and enables the ESO to work with customers to help them with the migration of their data from the legacy portal to the new solution.

EMR policy and change support

- We also continued to advise BEIS and Ofgem on their policy and regulatory change programmes for the CM and CfDs. As part of that, we are working with Ofgem and industry on the creation of a Capacity Market Advisory Group (CMAG) during 2022.

Whole System Technical Code

The Whole System Technical Code (WSTC) project is an opportunity to support the Energy Codes Reform (ECR) outcome on code simplification and consolidation, and also to address some of the challenges of using the technical codes. The first consultation proposed high-level solutions for digitalisation and increasing alignment or consolidation of technical. Potential solutions for code consolidation or alignment range from making no change to developing a new single Whole System Technical Code (WSTC). Phase 1 of this project concluded in March 2022 and focussed on stakeholder engagement to confirm the project scope. The next stage of this work will focus on digitalisation and working further with the industry wide Steering Group to consider areas of alignment and simplification.

Code changes

GC0137 Minimum specification for equipment providing grid-forming capability modification proposes to add a non-mandatory technical specification to the Grid Code, relating to what is referred to as Virtual Synchronous Machine ("VSM") or Grid Forming capability. This is a world first achievement for GB in setting a minimum specification to allow converter connected technologies to provide stability services facilitating the transition of the GB transmission system to net zero operation.

This specification will enable applicable parties (primarily those utilising power electronic converter technologies (wind farms, HVDC interconnectors, and solar parks) to offer an additional grid stability service which will enable their participation in a commercial market based system to provide this support. At the end of an involved development process the final report for this modification was submitted to Ofgem for a decision following approval at the October 2021 meeting of the Grid Code Panel. This has now been approved by the Authority and was implemented into the Grid Code in February 2022. This is a world first achievement for GB in setting a minimum specification to allow converter connected technologies to provide stability services.

Key challenges

Charging and access arrangements

After intensive analysis and assessment, we have made the decision to re-platform our charging and billing system. This new system will enable us to be more agile and efficient to implement and comply with the regulatory changes in charging methodology including the Transmission Charging Review (TCR) and Balancing Services and Use of System Charging (BSUoS) Taskforce decision. The project team has been mobilised and we are currently on track for system development and delivery. In the meantime, we have completed the improvement work in the current charging and billing system to ensure its stability and reliability until the new system is in place.

Reserve Reform

A suite of new reserve products are being designed to replace the existing positive and negative post-fault products: Short Term Operating Reserve (STOR) and Fast Reserve (FR). In November we presented our approach to launching new response and reserve products starting with Dynamic Regulation (DR) in March

2022, followed by Dynamic Moderation (DM) in April. We then planned to launch Negative Slow Reserve (NSR) as an optional service with other Reserve products and firm auction capability in later releases. We have reviewed the benefits of coordinating our delivery strategy for Reserve Reform with the potential impacts of not having NSR in operation during Summer 2022. We have identified that there is a cost saving to be made by taking a more holistic and considered release strategy for the new reserve product suite without impacting our ability to operate the system securely.

We therefore made the decision not be launch NSR directly after DM in Summer 2022, and instead took the time to further engage with the industry to identify the optimum approach to deliver the new reserve products. We consider that this approach will result in a better overall experience for providers whilst ensuring we have the necessary tools to operate the system at the lowest cost to consumers. Our first 'show and listen' event was held in April 2022 and will continue throughout the development of the new reserve services.

BSUoS forecasting

We've been publishing more detailed BSUoS cost forecasts in recent years. But we recognise that a new approach which provides even greater transparency and insight in our costs forecasts could be of even greater value to industry – particularly around costs incurred managing flows on the network. To address these challenges, we have now published a forecast based on a new improved methodology, this model moves away from the previous BSUoS forecasting linear model to a more comprehensive probabilistic model. It takes advantage of improved data inputs and we believe it will provide better insight into BSUoS costs over both short and longer timescales. We plan on making incremental improvements to the modelling and datasets included, including the 24 month ahead Constraint Limit dataset. This will provide increased accuracy in our modelling forecast inputs. We want to provide clarity of the changes for our customers and other users of the forecast.

New initiatives and changes

Net Zero Market Reform

Our Net Zero Market Reform programme was established at the beginning of 2021, with the objective of publishing recommendations on the future direction of market reform by April 2022. This project scope is broad, looking at all GB electricity markets, and is focussed on the longer term by looking to 2035 and 2050. The project was split into three phases. Phase 1 was an initial scoping phase where we carried out a high level analysis of the current GB landscape and international case studies, and we interviewed industry stakeholders to understand broad perspectives. Phase 2 was split into two elements: the case for market reform; and the development of a market options assessment framework. Phase 2 came to an end in November 2021 with the publication of an interim report and a large stakeholder event. Phase 3 kicked off in December 2021 and focused on assessing the operational market design elements (location and dispatch) in the first instance. Phase 3 culminated in our Markets Forum event in March 2022 where we presented conclusions. This is to be followed by a more detailed publication in May.

Local Constraints Market

Ahead of longer-term considerations for Regional Development Programme (RDP) functionality across Scotland, there is a growing need for a tactical solution to utilise Distributed Energy Resources (DER) to manage rising constraint costs on GB's most congested boundary. The Anglo-Scottish (B6) boundary currently has the highest constraints of any boundary across GB, and these are set to increase over time.

This work is looking to establish a local constraint management service (Local Constraint Market, or LCM) to specifically target B6 constraint costs. It looks to take learning from the simple construct of the Optional Downward Flexibility Management (ODFM) service and investigate the development of a light touch system to facilitate an accelerated DER market for targeted constraint management in Scotland.

Progress of our deliverables

Our RIIO-2 Deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables. The first column shows how our deliverables meet the requirements of the Roles Guidance set out by Ofgem.

For Role 2 (Market development and transactions), the Delivery Schedule lists 25 deliverables in total which are made up of 108 milestones. 65 of these milestones were due to be completed in 2021-22 of which 49 are now complete. Of the 16 milestones which are not complete, 5 are ESO-related delays, 10 are outside of ESO control, and 1 is delayed in order to deliver an improved outcome for consumers. We provide detail below about those activities where milestones are not on track:

ESO-related delays:

- A4.3 Deliver a single day-ahead response and reserve market (3 delayed milestones):
    - We have identified several dependencies that need to be met ahead of lifting the volume cap, which we've sign-posted in a recent volume requirements publication. We will reduce the volume of dynamic Firm Frequency Response (FFR) procured on a staged basis, this will begin when the volume caps are removed from the Dynamic Moderation (DM) and Dynamic Regulation (DR) services.
    - The design of enduring control and dispatch solutions has been delayed as we look to align the release of new reserve products with our other strategic priorities to deliver greater consumer benefit.
    - Standard Contract Terms (SCTs) for Negative Slow Reserve have been drafted, however there are a few remaining areas which are dependent on elements of service design which are not yet fixed, for example availability window lengths.
- D4.6.1 Complete design of IT solution for phase 2 (IT investment 130): Work to commence once gap analysis and requirements gathering work has completed. Stability Phase 2 contract start is expected to be April 2024. IT systems will be in place for contract commencement.
- D4.4.2 Reserve products integrated with foundational market platform for subset of processes: The delay to the launch of the new reserve product suite means that the products are not yet ready to be included on the Single Markets Platform (SMP).

Delayed due to issues which are outside of ESO's control in the short term:

- A6.1 Code management / market development and change (2 delayed milestones):
    - Post TCR modifications (CMP363/4 and CMP368/9) were raised in 2021 and have completed the Working Group stage of their development. We await Ofgem decisions following their consideration of related mods and now that the outcome of the SSE Judicial Review is known.
    - GC0137 was approved by Ofgem in January 2022, which is a world first achievement for GB in setting a minimum specification to allow converter connected technologies to provide stability services, GC139 is awaiting further information from the DNOs and GC145 (MARI) is on hold following EU exit.
- D6.2 Continued facilitation of EU driven code changes into Great Britain: We have been progressing industry workshops on Day Ahead Capacity Calculation in line with BEIS communications following the Trade and Cooperation Agreement. There has been limited further engagement from EU TSOs. The Specialised Committee of Energy may release further guidance on this topic following the meeting that took place on the 30th March.UK Direct Air Carbon Capture (DACC) options are ranked by operational effectiveness, these have been developed in collaboration with GB interconnectors. We are currently developing a strawman document that can be shared with EU TSOs.
- A6.3 Industry revenue management (3 delayed milestones):
    - After intensive analysis and assessment, we have made the decision to re-platform our charging and billing (CAB) system. This new system will enable us to be more agile and efficient to implement and comply with the regulatory changes in charging methodology including the TCR and BSUoS Taskforce decision. The project team has been mobilised and we are currently on track for system development and delivery. In the meantime, we have completed the improvement work in the current charging and billing system to ensure its stability and reliability until the new system is in place.

- In terms of Balancing and Settlement Code (BSC) P402, the alternative has been approved and the exact data requirement including the format from DNOs to ESO is being finalised following industry consultation.
- Changes associated with reform of residual network charging have been re-planned, as Ofgem has delayed implementation to April 2023. System changes to support this will now be delivered in Q3 2022-23.

- D6.4 Change from a code administrator to a code manager (4 delayed milestones): Delayed due to awaiting the outcome of the Energy Code Review consultation.

Delayed to deliver an improved outcome for consumers:

- D4.3.3 New Reserve Products Development and introduction of a new suite of products to provide reserve to the control room: The launch of the new reserve product suite has been delayed as we look to align the release of new reserve products with our other strategic priorities to deliver greater consumer benefit.

Innovation projects

As part of the agreement around the RIIO I NIA scheme, this year saw the conclusion of a few projects started towards the end of the previous regulatory period and as such do not qualify to be considered towards the RIIO 2 incentive scheme, these are however included for completeness as they do support work done in RIIO 2. Below is a list of the projects in the innovation portfolio which fall under Role 2. The references in the table below provide links to additional information about each project.

Innovation Project Name	Description	Progress update	Deliverables supported	Status	Funding
Control REACT	To provide information about forecast uncertainty, presented in real-time to Control Room engineers, to provide opportunities for them to make more economic and secure balancing decisions.	This project has successfully completed. We are currently planning to use the deliverables from this project to build a probabilistic forecasting platform on an ESO managed cloud environment. The platform will support the delivery of probabilistic forecasts of demand and generation and will facilitate their use for forecasting reserves and margins as demonstrated in the project. (Also mentioned in Role 1)	D4.1	Completed	RIIO-1
Dynamic Reserve Calculation[18]	Use AI and machine learning to set reserve levels dynamically, day ahead.	On track to deliver all outputs on time at the end March 2022. We are currently planning to use the deliverables from the project to build a day ahead forecasting system for operational reserves to support control room operations	D4.1 D4.3.3	Delivery	RIIO-2

[18] https://smarter.energynetworks.org/projects/nia2_ngeso003/

		(Also mentioned as part of Role 1)			
Crowdflex[19]	Assessing the amount of flexibility from domestic consumers, undertaking type testing as the most efficient and cost-effective path to simplifying access.	Project concluded in 2021. It showed that ToU tariffs and other price incentives can engage customers to materially change their domestic energy consumption profiles. If utilised in the right way, these can be useful tools with which to provide domestic flexibility. The outputs are being investigated further in the follow on Crowdflex SIF project.	D4.5.1	Completed	RIIO-2
Stability Market[20]	Aims to create a number of options for the delivery of a short-term stability market for the UK, assess these options, and provide a recommendation.	Initial project has concluded. Recommendations at this stage are for a combination of a long-term market design (based on the current pathfinder approach with some changes) and a new dedicated short-term market. Further analysis of the initial findings is needed.	D4.6.1	Delivery	RIIO-2
Reactive Power Design[21]	Investigating the possibility of a market-based solution to procure reactive power.	Initial project has concluded. Recommendations include a market framework with a combination of long and short term timescales. Further work needs to be undertaken before we can commit to a detailed plan of implementation.	D4.6.2	Delivery	RIIO-2

Note that the Control REACT and Dynamic Reserve Calculation projects also feed into role 1.

[19] https://smarter.energynetworks.org/projects/nia2_ngeso001/

[20] https://smarter.energynetworks.org/projects/nia2_ngeso005/

[21] https://smarter.energynetworks.org/projects/nia2_ngeso008/

B.2 Metric performance for Role 2

Table 15: Summary of metrics for Role 2

Metric		Measure	Unit	Benchmark	Actual	End of year status
2A	**Competitive procurement**	*% of services procured through competitive means (auctions and tenders) calculated by £ expenditure*	%	**50-60%**	**51%**	Meeting expectations

Metric 2A Competitive Procurement

April- March 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.
- **SO/SO Trades** are, by their nature, bilateral and therefore will always be reported as being bilaterally contracted. This means that in those quarters where more SO/SO trades are enacted, the percentage of Constraints & SO/SO Trades competitively procured is likely to reduce.

Figure 9: Percentage of £m spend by procurement method (April 2021 to March 2022)

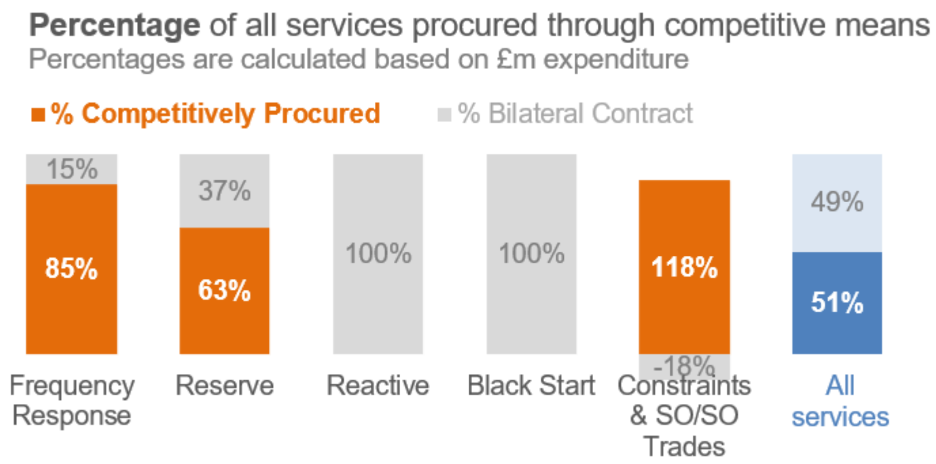


Figure 10: Absolute £m spend by procurement method (April 2021 to March 2022)

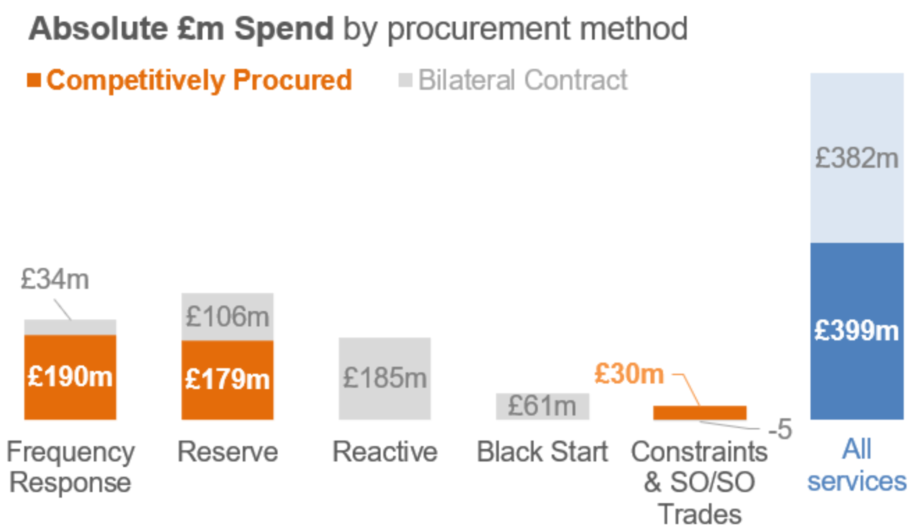


Table 16: Percentage of services procured through competitive means by Quarter

Services	Q1	Q2	Q3	Q4	Full Year
Frequency Response	91%	83%	84%	82%	85%
Reserve	61%	62%	62%	66%	63%
Reactive	0%	0%	0%	0%	0%
Restoration	0%	0%	0%	0%	0%
Constraints & SO/SO Trades	89%	376%[22]	42%	52%	118%[23]
All services	**57%**	**61%**	**46%**	**44%**	**51%**
Status (All services)	●	●	●	●	●

Performance benchmarks (Year 1)

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

Supporting information

Full year performance: Meeting expectations

The percentage of services procured through competitive means is 51%, which is in the 'meeting expectations' range of 50-60%.

In Q3 and Q4 the status has been below expectations, driven by the low spend on constraints and SO/SO compared to Q1 and Q2.

Average Market Prices

	Q1	Q2	Q3	Q4
Dynamic Containment (£/MW)	17 (Low)	17 (Low)	9.1 (Low)	17.3 (Low) 4.9 (High)
Firm Frequency Response (FFR) Weekly Auction - Dynamic Low High (DLH) (£/MW)	8.1	7.1	6.8	n/a*
FFR Weekly Auction - Low Frequency Static (LFS) (£/MW)	4.0	4.0	3.9	n/a*
Optional Fast Reserve (£/MWh)	102	123	280	297
Short Term Operating Reserve (STOR) Day ahead (£/MW)	3.3	2.5	6.0	10.1

*The **Weekly FFR Auction Trial** ceased in November 2021

[22] The figure is greater than 100% as Bilateral contract spend is negative (due to sending additional energy to Ireland via interconnectors in September). Absolute figures could be used instead, however this would be inconsistent with previously provided data.

[23] The figure is greater than 100% as Bilateral contract spend is negative (due to sending additional energy to Ireland via interconnectors in September). Absolute figures could be used instead, however this would be inconsistent with previously provided data.

Frequency Response

The average availability price for Dynamic Containment (DC) reflects the changes that have been implemented during the last year. During Q1 and Q2, DC was being procured against a constant daily requirement awarding 24-hour contracts. During Q3 DC was procured against a shaped requirement awarding Electricity Forward Agreement (EFA) block (4-hour) contracts. The reduction in the availability price in this quarter is a result of the change to procurement process, a reduction in requirements and a competitive market. In Q4 the average price increased for DC reflecting the increase requirements and the wholesale electricity price volatility. Over 2021-22 we have seen a substantial growth in market participant and the MW capable of delivering the service creating a competitive marketplace

Firm Frequency Response (FFR) and the weekly auction has seen a gradual decrease in the availability prices across 2021-22. This reflects the reduction in requirements and increased competition. This competition has been facilitated by providers being able to bid across different services through introduction of EFA block procurement in the DC service. It is worth noting that the FFR weekly auction ceased to be procured in November 2021 resulting in units in this service moving back into the monthly FFR tender

Reserve

The average availability price for Short Term Operating Reserve (STOR) increased further in Q4 to just over £10/MWh, reflecting the wholesale electricity price volatility and instances of tight operating margins experienced through the winter period, and in particular in early March 2022. Prices started to settle down in the last few days of March, more aligned with the average prices experienced through Q1 and Q2. Since the daily auctions for STOR went live in Q1 2021-22 we've seen a very liquid market with a large number of providers bidding in a large proportion of the total 200+ pre-qualified STOR units each day offering well in excess of the daily required volume of STOR.

For Fast Reserve, the average prices for procuring the overall service have increased during Q3 and Q4 in line with electricity price volatility. As we only procure the optional service (no firm procurement) the market has not changed in the last year and remains with a small volume of non-BM units.

Reactive

We have been working with a project partner to investigate market-based procurement of reactive power. The initial project has concluded, and recommendations include a market framework with a combination of long- and short-term timescales. The next steps of reactive market development have been published[24] and we will be mainly focusing on those areas in 2022-23.

Restoration

Contracts were awarded through open and competitive tenders for the South West and Midlands in 2020 and the Northern Region in early 2021, however the spend associated with them will be included in future reporting periods. We plan to launch a further competitive event in Q1 2022-23 for services in the South-East region, followed by procurement for services in the Northern region in Q2 2022-23.

Constraints & SO/SO Trades

Very little spend has been accrued on constraints and SO/SO trades this quarter, as shown in the chart above. This has led to a lower overall percentage of competitive spend, compared to previous quarters.

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[24] https://www.nationalgrideso.com/balancing-services/reactive-power-services/reactive-reform-market-design

B.3 Stakeholder evidence for Role 2

- Engagement is ongoing with stakeholders on market reforms and product design through consultations and 1:1s.
- Following the launch of Dynamic Containment, we are engaging with industry on improvements and how to introduce Dynamic Regulation and Dynamic Moderation.
- We have been working with GB stakeholders and connected TSOs following Brexit to consider enduring UK-EU cooperation mechanisms.
- For our Stability Market Design NIA project, we have created a webpage, held webinars, had a range of bilateral discussions, and shared the progress during ESO's Markets Forums.
- We have provided more explanation and context around the decision to review the strategy for the new reserve products through documents and presentations.
- In developing the EMR portal, we have been engaging with an external user group of industry volunteers.
- We've committed to raising STC modifications earlier where possible and we've invited TOs/OFTOs to be part of our whole system steering group.
- The Market Strategy team have hosted dozens of events for its Net Zero Market Reform project and engaged with over 1,000 stakeholders since its establishment.

The ESO incentive scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of the ESO's plan delivery. To demonstrate performance against this criterion, we report on our stakeholder satisfaction survey results, as well as describing how we worked with stakeholders during the year.

Stakeholder surveys

The ESO commissioned surveys from market research company BMG. These surveys measure satisfaction for each ESO role and are carried out on a six-monthly basis. The survey is targeted at senior managers, decision makers and experts, and includes a wide selection of relevant stakeholders who have had material interactions with the ESO's services.

For role 2, the following question was asked:

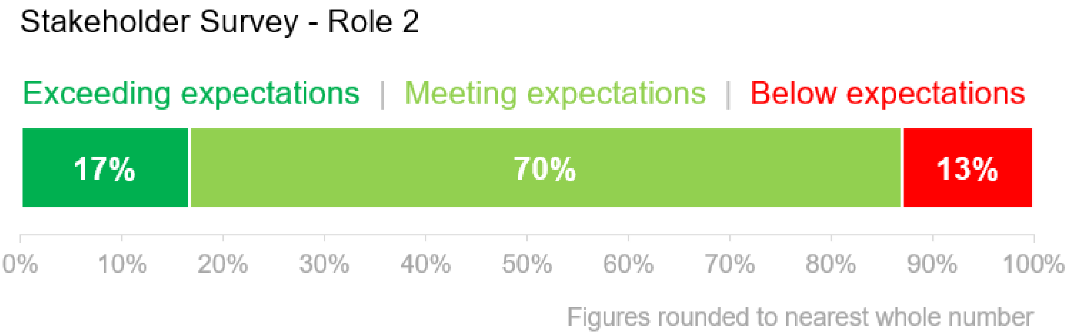
'One of the ESO Roles is focused on Market Development and Transactions, which includes key activities such as Market Design, Electricity Market Reform and Industry Codes and Charging. The ESO's recent activity in this area includes delivering T-1 and T-4 Capacity Market auctions and completing the prequalification assessment for Contracts for Difference (CfD) Allocation Round 4 in EMR. We have also launched the Single Markets Platform, completed the annual C16 consultation, finalised modifications to support BSUoS reform, worked with industry on key code reform such as GC137 (Grid Forming Capability) and hosted a third Markets Forum where we shared our conclusions from Phase 2 of the Net Zero Market Reform project. Overall, from your experience in these areas over the last 6 months, how would you rate their performance?'

Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

- If they rated the ESO as below expectations, they were asked what the ESO needed to do to meet their expectations.
- If they rated the ESO as meeting expectations, they were asked what the ESO needed to do to exceed their expectations.
- If they rated the ESO as exceeding expectations, they were asked that the ESO did that exceeded their expectations.

For Role 2, we contacted 185 stakeholders, and received 54 responses to this question, which were distributed as follows:

- 17% exceeding expectations
- 70% meeting expectations
- 13% below expectations



The survey results indicate that the ESO is meeting expectations for role 2, although Ofgem will also take into account other stakeholder evidence. Our analysis of survey responses is set out below:

“Exceeding Expectations” feedback

Stakeholders who scored us as ‘exceeding expectations’ were asked what the ESO did that exceeded their expectations. They raised the following points:

- Delivery of Dynamic Regulation and Dynamic Moderation was good.
- Progress on forward thinking and leadership on net zero market reform. As well as excellent engagement.
- Better than expected work on getting industry alignment on BSUoS reform.
- Processes for Capacity Market is well established now and with little issues or errors.

“Meeting Expectations” feedback

We asked all stakeholders who scored us as "meeting expectations" what would it take for the ESO to be exceeding expectations for them, here is a summary of that feedback for Role 2.

- More personal communication and regular meetings
- There is a degree of lots of engagement which is positive. However, there are some areas lacking evidence and analytical information would be more helpful.
- Stakeholders would like to see enhanced stakeholder management to allow them to prepare and manage future workloads effectively.
- The codes process needs to be more orderly as it is hard to engage
- The Markets design needs further work and considerations on invest ability impacts.
- More transparency and increased levels of engagement on market reforms
- Need to be more focused on some of the consultations and give sufficient time for consultations to be answered.
- Better whole system planning, people in the business need to know what other teams are doing to understand everything that the ESO does in making sure outcomes are simple to understand and the impacts of it.
- Progress on net zero markets is happening but it needs to be more holistic and direct relevant actions to avoid becoming a very costly end-correction.

“Below Expectations” feedback

In response to being asked what the ESO needed to do to meet their expectations, these points were raised:

- There has been good progress and consultations, but the development is slow, and we need to encourage the investment for a zero carbon grid.
- The ESO are very focused on new technology and ways of doing, we need to continue to focus on existing technology (low carbon).
- Regarding the commercial approach, looking for tendered rather than market approaches, this effectively excludes existing providers from these services.
- Communication around Dynamic Containment was poor. Transparency and better engagement are needed for future products

Stakeholder engagement during the year

The Stakeholder Evidence criterion also takes account of the ESO’s consultations and ad-hoc surveys throughout the year, whether the ESO has actively sought and considered the feedback of stakeholders throughout the business plan cycle, and the ESO’s explanations for feedback received.

Build the future balancing service markets

Area	Stakeholder feedback	Action taken by the ESO
Reform balancing and ancillary service markets	A more formal, consistent and engaged approach to consultation on balancing service reforms is needed. In particular, the approach to taking a decision on baselining and visibility across the entire product suite has been inadequate. The decision-making process and decision itself on aggregation limits for reserve and response has also been unsatisfactory.	Through stakeholder engagement we know industry want to understand the reasons behind our decisions and the other options that we have taken into consideration before we’ve come to a decision. Therefore, we’ve looked into how we can ensure there is more time spent discussing and taking feedback on service development and we want to improve our consultations by adding more structure to our engagement and more time in the plan. We will implement a standardised consultation process with structured engagement activities running throughout the year.
	Stakeholders suggested the ESO could take a more proactive approach to determining the needs of the system vs a reactive approach, and to drive more action across multiple market aspects.	We are working to coordinate our consultations across response and reserve for both new products as well as ongoing developments and improvements. We are also undertaking detailed ‘ways of working’ sessions to ensure that all elements of the product design and implementation journey, including decision-making and governance, are clear.
Dynamic Containment	They find that geographical aggregation is restricted. This restriction limits aggregation of demand-side providers because GSPs cover only small geographic areas. They encourage the ESO to be fully transparent about the reasons why and to work with market participants to refine its design.	GSP Aggregation is a topic we have engaged extensively with industry on over the last 12 months. We have discussed with stakeholders through various forums the challenges. Stakeholders told us they wanted to better understand the challenges and risks we faced, and we listened to them to understand how it was barrier to entry for some. In January 2022 we published[25] a GSP paper that highlighted our risks and issues but outlining our intention to allow aggregation at GSP Group for Dynamic

[25] https://www.nationalgrideso.com/document/234901/download

	They find that the 'Wave 2 reforms' did not materialise. They feel that a comprehensive view of the risks ESO are concerned about have not been set out. They are not aware of whether costs have already been incurred as a result of these risks and if not, why such limits are needed immediately.	Containment (DC) along with a commitment to moving DC procurement back to GSP Group. Since the launch of DC, we have made a number improvements to the service by engaging with stakeholders and listening to their feedback. We launched BM stacking a few months after the launch, we have engaged on Wave 2 topics such as GSP Aggregation and Baselines and we introduced DC High Frequency. With industry we have been exploring alternative baseline methodologies and we have held numerous workshops with ADE and their members to further analyse what could be changed to address stakeholder feedback and to ensure it would work for the ESO and industry. There is ongoing work to do on this and will be prioritised along with other activities and changes needed across response reform.
Product design	They raised concerns about the possibility of insufficient lead time between confirmation of product design (following formal industry consultation) and 'go-live' to allow market participants to develop their systems to fully reflect the final product design. They found that this was the case with Dynamic Containment (DC). This also applies to the Dynamic Moderation (DM), for Dynamic Regulation (DR), Quick Reserve (QR) and Slow Reserve (SR) products.	Following the launch of DC, we held 1:1s and attended industry forums to seek feedback from industry on what a suitable lead time would be for providers to ready themselves for launch of a new service. The majority of stakeholders told us that four weeks is the minimum period of time and six weeks was sufficient for onboarding. We allocated six weeks in our delivery plan for DR, and there is a ten week onboarding window for DM. In January, we announced that non-BM providers will need to update their systems to automate availability notifications, and we set a four month transition period, closing at the end of April. This was to ensure that providers had sufficient time to change their systems. We also asked for feedback on the deadline, and frequently attended the Operational Transparency Forum to remind providers of the upcoming change. The QR and SR products are still under development and we will apply learnings and industry feedback following the launch of DR and DM to the delivery timeline for reserve. We committed to delivering new response services in spring 2022. The first DR auction took place on 8 April, and the first DM auction is on track for 6 May. We learned from the quick delivery of DC that industry stakeholders wanted to understand reasons behind our decisions in product design, so we dedicated a lot of time during 2021 engaging with providers through industry forums, 1:1s, technical workshops and webinars. During the next financial year we will be focusing on introducing a more structured process for service design and we are looking to the C16 consultation process as a basis for the new structure. This will give industry stakeholders more time to engage, and should result in more predictable and reliable delivery schedules for new service development.

		The launch of the new reserve product suite has been delayed as we look to align the release of new reserve products with our other strategic priorities to deliver greater consumer benefit. Updates on new services development can be found on the Future of Balancing Services webpage[26]

Power Responsive

The virtual Summer Event was held on 9 September, where we hosted approximately 250 attendees providing opportunities for:

- network companies to discuss current and future market opportunities,
- aggregators to talk to DSR providers about what recent market changes might mean for them, and
- a ground level view of the current aggregator landscape.

We ran a survey with the attendees which received 11 responses, who scored primarily “extremely satisfied” followed by “somewhat satisfied” for the content, presenters, and length of the event. This engagement has helped provide a route for dialogue between the demand side community, and the ESO Subject Matter Experts (SMEs), ensuring the views of the demand side community are reflected in the development of new products and markets.

We are in the process of interviewing all our steering group members to determine our future direction, and as part of this process have proposed that we hold industry workgroups to discuss issues particular to the DSF community. The first workgroup will consider how operational metering standards can be changed to allow greater access to the Balancing Mechanism from aggregated demand portfolios.

The 2021 Annual Report[27] was published with our partner Everoze, looking back at the year’s developments and providing market intelligence for DSF providers. This year the report was published as an interactive online document to provide easier and more streamlined access.

Market development

Area	Stakeholder feedback	Action taken by the ESO
Cross border and EU Exit	The ESO takes its role to facilitate very seriously, but does not provide enough thought leadership when kicking off new initiatives. For the ESO to meet or exceed expectations, they need to drive the debate as well as host/facilitate it. Admittedly some teams demonstrate their subject matter expertise to do this better than others, it's just done inconsistently. I actually find that a neutral ESO (in 'facilitate' mode) is typically counter productive in helping to make progress on markets/code development matters, than where the ESO have a strong view.	An example where ESO has taken up a strong leadership role is on European matters. Following EU Exit, we have worked very closely with UK TOs, BEIS, Ofgem, EU TSOs and ENTSO-E to set up the required enduring UK-EU cooperation mechanisms, to the benefit of all UK TSOs.
Stability Market Design NIA project	Stakeholders suggested the ESO could exceed expectations by taking a more proactive approach to determining the needs of the system	The Stability Market Design project will consider current GB stability arrangements and investigate the best optimal design option for a stability market. This could allow the ESO to

[26] https://www.nationalgrideso.com/industry-information/balancing-services/future-balancing-services

[2727] https://powerresponsive.maglr.com/annual-report-2021/cover

	vs a reactive approach, and to drive more action across multiple market aspects (Stability Market NIA and Markets Roadmap).	start to develop a potential stability market and best optimise long term and short-term stability procurement.
Stability Market Design NIA project	Stakeholders would like to see continuous improvements to the quality of some of the webinars, and for the ESO to ensure the website is up-to-date, and that information is streamlined and simplified where possible	We have created a web-page for this NIA project acing as a platform to share slides, Q&A pack, and recorded versions of the webinar with the wider industry[28] In line with one of the RIIO2 BP actions, we engaged with wider industry on various occasions: • First webinar on 09 November 2021: Where we shared our plans and initial findings. We received positive feedback from different stakeholders including Ofgem.
Stability Market Design NIA project	Some feedback did reiterate the importance of working closely with customers, and ensuring all engagement is relevant to them (Stability Market NIA and Markets Roadmap)	• We launched a questionnaire which was open for more than five weeks asking wider industry to provide their views on the Stability Pathfinders and also their feedback on the scope and approach of this innovation project in order to enable us to co-create different design options with the wider industry • We have had a range of bilateral discussions with markets participants and the regulator • We also shared the progress of this NIA project during ESO's Autumn and March Markets Forums • We held our second engagement webinar on 08 February, where we shared the outcome of the qualitative and quantitative assessments of this NIA project. The webinar provided an opportunity to industry to provide their feedback and refine the assessment, if needed. We received positive feedback from different stakeholders.

Deliver a single day-ahead response and reserve market

Area	Stakeholder feedback	Action taken by the ESO
Reserve Reform	A few stakeholders requested more frequent communications in line with a faster release of information, such as more regular communication regarding reserve reform. They believe that more communication is needed as the updates they have seen are relatively infrequent.	We have committed to holding monthly virtual 'show & listen' sessions with the project team, so stakeholders can see the progress being made and give their views. The first session will be held in April.

[28] https://www.nationalgrideso.com/future-energy/projects/stability-market-design

Product services transparency	Feedback regarding transparency was also raised by stakeholders, requesting better justification for delays to products and services, such as reserve reform. A couple of stakeholders also requested that more information is made available, such as the Data Exchange.	We have provided more explanation and context around the recent decision to step back and review the strategy for the new reserve products through documents and presentations. We have also committed to holding regular 'show & listen' sessions to provide an insight into the ESO's live workstreams. Feedback from stakeholders on changes to services will be fed into a product backlog. A product backlog will be created, containing suggestions for new features and changes to existing parameters of the product or service design proposed by ESO and industry stakeholders. This list of changes will be assessed, the list of developments, and the order in which they will be delivered, will be shared with our stakeholders to improve transparency in our decision making.
Reform programmes	Faster progress with reform programmes and less time between things happening.	We acknowledge that the industry change process can sometimes not proceed as quickly as stakeholders would like and we are always looking at ways to address this. Our increased engagement activities will provide greater transparency into the timings of our reform programmes.

Transform access to the Capacity Market

Area	Stakeholder feedback	Action taken by the ESO
EMR portal	They notice that it continues to cause operational difficulties. They acknowledge that the portal has been improved. However, they find that it continues to deliver a poor user experience	We are pleased to hear that stakeholders recognise the improvements made to our existing EMR portal. As per our RIIO2 deliverables we have been working to replace the EMR portal to address this feedback and create a portal fit for the future. The first drop (enabling customer registration) went live on 30 March 2022. The next phase (covering CM prequalification) will be available for the forthcoming CM prequalification process beginning in July 2022. In developing the portal, we have been engaging with an external user group of industry volunteers to shape the process and development so we are confident this will be a significant step forward.
Capacity Market services	Stakeholders say that most things we do are okay, but the issue is with the capacity market services. We need to answer the phones and emails and be clear on the rules.	The EMR Delivery Body has taken the feedback very seriously and has made a series of improvements utilising accurate data gathered via our Customer Relationship Management system. We have improved a closure of all queries with 5 days from a performance level of 75% to over 92% with YTD figures evidencing nil going over 20 days. We will continue to improve with new SLA target being 100% of all queries to be closed with 5 days.

Develop code and charging arrangements that are fit for the future

Area	Stakeholder feedback	Action taken by the ESO
CMP361 & CMP362: BSUoS Reform has not been clearly justified	They enquired why we could not raise more as a credit facility and why it's cost-effective for the system for industry to bear so much of the cost when industry is likely to have higher borrowing costs	There is a limit on the maximum that the ESO can borrow, following feedback from the CUSC working group, we have also looked at different routes such as via insurance policy, none of these are viable options. The CUSC legal text sets out that the ESO will agree with Ofgem the amount of working capital facility which the ESO will provide for BSUoS reform, this allows flexibility should financing change in the future.
Code Administrator	Stakeholders told us that the modification tracker could be improved	Code Administrator set up co-creative workshops open to all industry to attend. We presented the old version of the modification tracker and asked stakeholders what information they would find most useful and why. We changed the format and made it better, following their guidance. A good example of creating a tool that works for our stakeholders, by working collaboratively with them.
Code change delivery	Be more wary of the impacts of code changes on the TOs/OFTOs and better facilitate the input of those impacts in the code changes they raise or facilitate so the full range of views are considered.	We've committed to raising STC mods earlier where possible and we've invited TOs/OFTOs to be part of our whole system steering group. This is an open item at the STC panel and we're looking to engage as widely as possible.
Transparency	Improve their engagement. They're happy to do general briefings but won't want to talk about specific issues and want to close down debates often. Other examples are public meetings. They have resisted taking actions and those are the kind of frustrations that I have. Not everyone is like that, but the one's I deal with are on the sharp end. So it's at the point we are talking about things that cost people less money etc. and they aren't always comfortable conversations for either party.	Over the past six months we've tried to work collaboratively in various areas such as with industry on development of the 6(4) pricing proposal and have taken away specific questions from OTF to provide fuller answers. We continue to provide our TCMF and GCDF forums to allow stakeholders to engage with us and have taken away actions and questions from those for when we cannot provide an answer.
Code change delivery	Believe we frequently don't take the time to understand stakeholders' positions. Also, we are equally not good at explaining our rationale why it is.	We have since September established and run multiple session on the TCA with all affected GB TSOs and also carried out bilateral sessions to understand specific concerns that stakeholders may have.
Code change delivery	We need to see customers perspective more clearly and find creative approaches to addressing challenges. Being more supportive of collaborative solutions.	We're committed to using our engagement forums to provide this service to customers and seek to engage on the issues that affect them. Through TCMF and GCDF in particular we encourage customers to engage with us on specific topics to help us in developing solutions that work for their needs

2021 Code Administrators Code of Practice (CACoP) Survey

Following a pause in 2020, the Ofgem led CACoP survey resumed in 2021. We were disappointed with the results in 2019 and since then, have worked hard on the areas that our stakeholders told us mattered to them the most. Throughout 2020, we sense checked the improvements that we had made, such as our documentation and web pages to ensure that these changes were truly helpful. As a result, we were delighted to receive significantly improved results for our three codes, CUSC, Grid Code and STC in 2021. Some of the scores in 2021, were the highest we have ever achieved and while we are satisfied that these results show a marked improvement, we will ensure that we continue on a journey of improvement, especially now as we work towards the future of energy code reforms. We are ever grateful of the feedback that our stakeholders take the time to provide and are committed to continuing to listen in the next year, aspiring to reach out more broadly to ensure we are able to hear from all parties.

Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025

Area	Stakeholder feedback	Action taken by the ESO
Whole System Technical Code (WSTC) project	They feel that we have informed code panels of our work rather than collaborated with them. They do not believe that the ESO is best placed to lead on this transformational reform activity- instead this should be Ofgem and BEIS.	Over the last 6 months the ESO has run a public consultation that took place in Sept-Nov 2021 and established a project Steering Group with representation from across industry; any stakeholders were able to put themselves forward to represent categories of users and licensees. This group met to guide development of the project and made a series of go/no go decisions in March 2022 on aspects of the scope, as well as directing the development of detailed scoping documents. We consider that this demonstrates our commitment to working with all stakeholders. In addition, progress updates have been delivered to the Grid Code Panel, the open attendance Grid Code Development Forum and the ESO's Markets Forum along with a continued invitation to engage with the work of the Steering Group.

Forecasting

Area	Stakeholder feedback	Action taken by the ESO
BSUoS Forecasting	They find it is unclear whether the increases in expected costs are due to poor forecasting, issues with cost management or a combination of both. They suggest more information is provided, particularly an explanation on the month-on-month variance in expected costs.	We recognised that recent BSUoS forecasts have shown large cost variances and accuracy without sufficient insight into costs and ultimately the charges system users will face. In our 5 point plan to manage constraints on the system we committed to improve transparency and insight into our forecasts of the costs incurred managing flows on the network. We revised our forecasting methodology to a probabilistic model which, combined with more regularly updated constraint impacts, should result in a more accurate and higher quality forecast. We communicated the change in methodology at the Operational Transparency forum over a number of weeks and will be implementing a monthly deep dive into the latest BSUoS forecast as a result of feedback.

Activities outside the Delivery Schedule

Net Zero Market Reform

Stakeholder feedback	Action taken by the ESO
Due to the broad and complex nature of the work being done there was feedback of inadequate time to digest material and provide feedback.	Pre-read material sent in advance of every engagement event. • Additional channels to provide feedback outside of the events themselves, e.g. online feedback forms. • Extended Q&A sessions in our large-scale events.
Some stakeholders pushed back on one of the market design options we eliminated in Phase 2, this was partially based on misinterpretation of message.	• Heightened focus on clear and concise messaging in comms and engagement. • Offered more detailed bilateral discussions with some stakeholders.
Stakeholders requested increased accessibility of workshop outputs and information	• Creation of a dedicated webpage with key outputs designed. • Creation of a dedicated mailing list.

The Market Strategy team have hosted dozens of events for its Net Zero Market Reform project and engaged with over 1,000 stakeholders since its establishment at the start of 2021. Overall feedback from stakeholder has been very positive and we received average scores of 8/10 at our most recent workshops.

We have received constructive feedback on some key elements of our strategy that we have subsequently made changes to.

Our first engagement of Phase 3 saw 250 attendees across two three hour workshops where we shared more detail on the options we are assessing. We conducted live feedback and also sent out an online survey.

nationalgridESO

ESO Net Zero Market Reform - Refined Market Design Options - Investment

The below survey is to provide feedback on the slides covering the Investment (Low Carbon, Capacity Adequacy and Flexibility) Market Design Elements.

Please select the option that best describes your organisation

- Aggregator / flexibility provider
- Thermal generator / developer

B.4 Demonstration of Plan Benefits for Role 2

The fourth evaluation criterion for the ESO incentive scheme is Demonstration of Plan Benefits, where the Performance Panel will consider the actual benefits the ESO has realised from delivering its Business Plan, or any outputs additional to the Business Plan.

At the time of publishing our original RIIO-2 Business Plan in December 2019, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the RIIO-2 Business Plan. The relevant CBAs for Role 2 are:

- Build the future balancing service and wholesale markets (A4)
- Transform access to the Capacity Market (CM) (A5)
- Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 (A6.5)
- Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges (A6.6)

In this section, we provide a progress update for each of the activities for which we originally provided a Cost-Benefit Analysis, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence, and describing any sensitivity factors which would impact on the delivery of the stated benefit. Deliverable activity statuses reflect the delivery of RIIO-2 milestones and do not recognise either work completed prior to April 2021 nor progress made towards yet to be completed milestones.

We also provide a specific case study on **Granular procurement of Dynamic Containment** which was not covered by the original Cost-Benefit Analysis document.

The Panel will also consider the ESO's Regularly Reported Evidence (RRE) as part of the Demonstration of Plan Benefits criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the Electricity System Operator Reporting and Incentives (ESORI) guidance. For Role 2, the items of RRE reported at mid-year are:

- 2B. Diversity of Service Providers
- 2E. Accuracy of Forecasts for Charge Setting – BSUoS

CBA: Build the future balancing service and wholesale markets (A4)

Benefit described in RIIO-2 business plan

"We estimate the gross benefits of the transformational activities set out in section 5.2.3 to be £106 million over RIIO-2. This gives a Net Present Value (NPV) of £67 million over RIIO-2. The quantitative gross benefits were calculated by:

Considering the liquidity of the reserve and response market – about £500 million on a 12-year average. Based on our Power Responsive work we have seen prices drop and estimate that a further five per cent reduction is credible for these activities

We have looked at buying optimal volumes of response – about £190 million on a 12-year average. Again, based on our previous experience of moving closer to real time we estimate a further five per cent reduction is credible.

- This is against a baseline assumption of the existing participation in balancing and CMs without a single platform or reduced participant size to 1 MW."

Role

2. Market development and transactions

ESO Ambitions

- Competition Everywhere

Key RIIO-2 Deliverables and progress

Activity A4.3 - Deliver a single day-ahead response and reserve market

Deliverable	Status
D4.3.2 Day ahead market for frequency response	70% complete 30% delayed
D4.3.3 New Reserve Products	100% delayed
D4.3.5 Auction capability	33.3% complete 33.3% delayed 33.3% on track

Activity A4.4 - Deliver a single, integrated platform for ESO Markets

Deliverable	Status
D4.4.2 Common standards, including interoperable systems, a common data model and shared minimum specifications between ESO and other flexibility platforms as well as at the distribution level.	60% complete 20% delayed 20% on track

Activity A4.6 - New services market development

Deliverable	Status
D4.6.2 Development of competitive approaches to procurement of reactive power	70% complete 30% on track

Benefits to be realised

Forecasted in original CBA:

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
More liquid response and reserve market	0.0	0.0	25.7	25.7	25.7	77.2
Buying the optimal volume of response	0	0	9.7	9.7	9.7	29.0

Related metrics/ Regularly Reported Evidence	**Metric/RRE**	**Impact on metrics/ RREs**	**Status**
	1A Balancing costs	We expect this to lead to lower constraint costs than would otherwise be the case	£3,132m vs benchmark of £1,321m (below expectations)
	2A Competitive Procurement	We would expect this activity to result in improved performance due to allowing us to move greater volumes of products into competitive markets from bilaterally agreed contracts. This should then lead to lower Balancing Costs, as competition should place downwards pressure on the costs of ancillary services.	51% of all services procured through competitive means (meeting expectations)

Sensitivity factors (description)

Assumption	Current status	Commentary
Participation would be increased	Launching more volume in Dynamic Containment	Consumer benefit expected to be in line with original assumptions
Value of the response and reserve market is £514 million per year	We spent £510m on response and reserve during 2020-21	Consumer benefit expected to be in line with original assumptions
Our actions deliver a 5 % saving in the response and reserve markets	5% saving will be assessed once the new services are embedded.	Consumer benefit expected to be in line with original assumptions
Benefits delivered from year three of RIIO-2	This is a reasonable assumption at this stage	Consumer benefit expected to be in line with original assumptions

Summary

We have reviewed the benefits of coordinating our delivery strategy for Reserve Reform with the potential impacts of not having Negative Slow Reserve in operation during Summer 2022. We have identified that there is a cost saving to be made by taking a more holistic and considered release strategy for the new reserve product suite without impacting our ability to operate the system securely.

We will therefore not be launching Negative Slow Reserve directly after Dynamic Moderation in Summer 2022, and instead we will be taking the time to further engage with the industry to identify the optimum approach to deliver the new reserve products.

We believe that this approach will result in a better overall experience for providers whilst ensuring we have the necessary tools to operate the system at the lowest cost to consumers. We do not anticipate any material changes to the benefits listed above as the new reserve services will launch in 2023 and we have seen excellent progress in competition in the new response markets.

CBA: Transform access to the Capacity Market (A5)

Benefit described in RIIO-2 business plan

"We estimate the gross benefits of this activity to be £74 million over RIIO-2. This gives an NPV of £62 million over RIIO-2. We calculated these quantitative benefits by firstly considering the enhanced modelling capability. In our analysis we consider the two possible scenarios of reduced risk of our recommendations on the capacity to secure being too low or too high:

1. Reduced risk of recommendations being too low: Save consumers the equivalent of purchasing at four-year ahead (T-4) an additional 1 GW of capacity, instead of at year ahead (T-1) or short term balancing markets.
2. Reduced risk of recommendations being too high: Save consumers the equivalent purchase cost of 1 GW of capacity at T-4.

Given the complexity (with limited data and more uncertainty) in determining scenario one's benefits we have used scenario two's benefit in our CBA calculation. The average clearing price over the four T-4 auctions held to date, £17.08/kW, applied to 1 GW this would save consumers £17 million per year.

Secondly, by reducing barriers to entry, we will remove the need for unnecessary resource for the around 400 CM customers, and this saving will ultimately be passed through to consumers. This is against a baseline assumption of the existing participation in CMs and only ongoing modelling capability. This activity is dependent on the following transformational activity: A4 Build the future balancing service and wholesale markets – Sharing the single markets platform. All of the costs for the single markets platform are realised in this activity. In order to deliver this activity, we require third parties to fully engage with the new system. There may be small costs associated with adapting to these new arrangements, but we believe these are within the scope of third parties' ongoing investments. Our analysis suggests that, accounting for market, delivery and third-party uncertainty, the net present value could credibly be between £22 million and £94 million."

Role

2. Market development and transactions

ESO Ambitions

- An electricity system that can operate carbon free
- The ESO is a Trusted Partner

Key RIIO-2 Deliverables and progress

Activity A4.4 - Deliver a single, integrated platform for ESO Markets

Deliverable	Status
D4.4.1 A market platform through which market participants will be able to participate in balancing and CMs. The markets platform will cover the end to end process for market participation including: communications, data input and management, messaging and validation	60% complete 30% delayed 10% on track

Activity A5.1 - Electricity Market Reform (EMR) Delivery Body

Deliverable	Status
D5.1.1 Continuation of EMR Delivery Body obligations	50% complete 50% on track
D5.1.2 An improved prioritisation process in how we implement change in the EMR Delivery Body. This is about embedding the process and not the delivery of specific changes for each year	70% complete 30% on track

Activity A5.2 - Deliver an enhanced platform for the Capacity Market within the single, integrated ESO markets platform

Deliverable	Status

D5.2 IT system to allow all participants in ESO markets (including CM and CfD) a single point of access for services and data	65% complete 10% delayed 25% on track

Activity A5.3 - Improve our security of supply modelling capability

Deliverable	Status
D5.3 Use of enhanced modelling and more granular data sets to improve security of supply modelling.	50% complete 50% on track

Benefits to be realised

Forecasted in original CBA:

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Enhanced modelling capability	0	17.1	17.1	17.1	17.1	68.3
Reduced barriers to entry and cost of participation	0	1.5	1.5	1.5	1.5	6.2

Our original CBA stated that benefits associated with activity A5 will start to be delivered from 2022-23. Regarding activities A5.1 and A5.2, we are developing a brand-new EMR portal and are refining our related business processes and customer guidance. In line with our Business Plan, we expect customers to benefit from this for the Capacity Market prequalification in mid 2022. For the modelling, this is associated with the delivery of enhancements under D5.3 for the milestone due Q4 2021-22 on the Delivery Schedule. These enhancements have been delivered and will be reflected in the 2022 Electricity Capacity Report due in Q1 2022-23 for the next round of Capacity Market auctions.

Related metrics/ Regularly Reported Evidence

Metric/RRE	Impact on metrics/ RREs	Status
RRE 2D EMR Demand Forecasting Accuracy	We would expect this activity to result in improved performance than would otherwise be the case as improved models will lead to a better ability to forecast demand.	Peak demand accuracy 6.6% for T-1 (below expectations), 3.8% for T-4 (meeting expectations)

Sensitivity factors (description)

The estimated consumer value we expect to deliver that is stated in the RIIO-2 CBA report was based on several assumptions. If those assumptions outturn different to expected, the actual consumer value delivered will be different to our original estimates, irrespective of the progress of our deliverables.

The table below lists the assumptions made and notes whether the outturn is in line with our original estimates. Overall, the estimated benefits remain in line with those stated in our RIIO-2 plan.

Assumption	Current status	Commentary
Clearing price of the T-4 Capacity Market is £17.08/kW per year	In progress	The average clearing price of the T-4 Capacity Market auctions has increased slightly to £17.41 (this includes the T-3

		auction for 2022-23 that was held instead of a T-4 auction)
Our actions save consumers the equivalent of purchasing an additional 1 GW of capacity	In progress	Our original CBA stated that benefits associated with activity A5 will start to be delivered from 2022-23. We have undertaken modelling enhancements in 2022-23 that will inform recommendations in the 2022 Electricity Capacity Report for auctions taking place in 2023. Concerns on delivery assurance (as covered in our 2021 Report) will place upward pressure on target capacity, but we believe our modelling enhancements are such that the balance of risk remains appropriate for consumers.
Benefits delivered from year two of RIIO-2	In progress	Our original CBA stated that benefits associated with activity A5 will start to be delivered from 2022-23.
Third parties will engage in the single markets platform	In progress	First release of new EMR portal went live in March 2022. Currently working on next release to enable customers to use it for the CM prequalification in mid 2022.

Another sensitivity outside of the original CBA is that some participants do not meet their obligations in the CM, therefore the ESO will have to procure more capacity, leading to higher costs for consumers, which will offset some of the savings resulting from improved modelling.

To fully realise the full benefits of integration into the Single Markets Platform (SMP), it would require regulatory change to the CM to align data requirements, taxonomy and designation. Without these regulation changes, our new EMR portal will still drive benefit by reducing time taken for applicants to enter and engage with the CM. Without the data changes, integration will still take place, but at a DEP level rather than CM acting as a market within the SMP.

Summary

Our original CBA stated that benefits associated with activity A5 will start to be delivered from 2022-23. We are on track to complete the deliverables that are necessary to realise the anticipated benefits. Regarding activities A5.1 and A5.2, the development of the new EMR portal is underway and customers will be able to use it for the first time for the 2022 Capacity Market prequalification process.

CBA: Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 (A6.5)

Benefit described in RIIO-2 business plan

"We estimate the gross benefits of this proposal to be £10 million over RIIO-2. This gives an NPV of £4 million over RIIO-2. These quantitative benefits have been calculated by considering how the reduced barriers to entry will save resource for Grid Code users, as it will be less complicated and easier to navigate, find, and use the relevant information. We estimate there are around 800 potential projects, based on around 400 transmission applications and an additional estimated 400 from distribution applications, which would need to access the Grid Code per year. Each resource saving will ultimately be passed through to consumers. This is against a baseline assumption of the Grid Code not being digitalised, with access remaining as it is today. It would also not extend to consider the whole energy system."

Role

2. Market development and transactions

ESO Ambitions

- The ESO is a Trusted Partner
- Competition Everywhere

Key RIIO-2 Deliverables and progress

Activity A6.5 - Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025

Deliverable	**Status**
D6.5 The Grid code combines transmission and distribution codes in an IT system with AI-enabled navigation and, document and workflow management tools.	70% complete 30% on track

Benefits to be realised

Forecasted in original CBA:

Benefits £ millions	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Digitised Grid Code	0	0	0	2.1	4.2	6.3

Related metrics/ Regularly Reported Evidence

Metric/RRE	**Impact on metrics/ RREs**	**Status**
RRE 2B Diversity of service providers	We would expect this activity to improve as simpler codes will lead to easier participation by more parties	Significant changes in STOR and DC

Sensitivity factors (description)

There have been no delays or changes to our deliverables, or external factors, that change the benefit we have forecast to deliver.

Assumption	Current status	Commentary
800 projects interacting with the whole system Grid Code per year	This is still a reasonable assumption in the future anticipated transformation of the Digitalised Whole System Technical Code	Consumer benefit expected to be in line with original assumptions
Our actions save one FTE month of time from each project	This is realistic assumption based on the reduction in time spent on the governance process today vs the future state of a digitalised code	Consumer benefit expected to be in line with original assumptions
Benefits delivered from year four of RIIO-2	This is a reasonable assumption at this stage	Consumer benefit expected to be in line with original assumptions

Summary	In this period, there was no funding for this project so in year one we have continued to engage with other industry code administrators who have embarked on the concept of digitalisation. We have also established a steering group where we consult stakeholders before embarking on any next steps with the project to ensure that there is support. The project will have more defined milestones once we progress into year 2, at this stage we believe we will deliver the benefits as set out above.

CBA: Fixing one or more components of Balancing Services Use of System (BSUoS) charge (A6.6)

Benefit described in RIIO-2 business plan	"We estimate the gross benefits of this activity to be £324 million over RIIO-2. This gives an NPV of £280 million over RIIO-2. These quantitative benefits have been calculated by considering the ongoing industry work that is focused on reducing BSUoS volatility and unpredictability. As this work is continuing – and we will work with industry and Ofgem to further refine it – we have used the lower estimates of gross benefits from the scenarios considered. This amounts to around £81 million per year in reduced risk premia held by industry. We also considered the higher ESO financing costs required to manage any new BSUoS arrangements – again to reflect the uncertainty – of around £4.8 million per year. This is an early estimate and is not reflected in our analysis of overall ESO financing costs, which is detailed in chapter 9 – Financing our plan. The difference in ESO financing costs, and benefits savings from reduced industry risk premia, is due to the number of parties that hold risk premia for BSUoS, which is now being managed though a single party, the ESO. This is against a baseline assumption of BSUoS arrangements remaining as they are today, with the price being set after the spending has taken place."
Role	2. Market development and transactions
ESO Ambitions	• The ESO is a Trusted Partner Competition Everywhere
Key RIIO-2 Deliverables and progress	**Activity A6.6 - Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS)**

Deliverable	Status
D6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges	100% complete

Benefits to be realised

Since our original CBA analysis was created in 2019, the ESO has raised modifications CMP361 & CMP362 ('BSUoS Reform: Introduction of an ex-ante fixed BSUoS tariff & Consequential Definition Updates') to introduce fixed BSUoS and has supported CMP308 ('Removal of BSUoS charges from Generation'), to enable full BSUoS Reform as per the recommendations of the BSUoS Task Force. We have therefore expanded and updated our CBA to reflect the total benefits associated with this BSUoS reform.

Ofgem commissioned analysis by independent consultants, Frontier Economics and LCP to support their assessment of the above modifications. The analysis included an 18-year NPV for CMP308 and CMP361. Unfortunately, different methodologies were used and hence it is not possible to easily combine the impacts to obtain a NPV of both modifications that reflects the total benefits of BSUoS reform. We have therefore chosen to focus on the CMP308 NPV using the Consumer Transformation FES as a basis, recognising that this gives a conservative estimate of the total NPV. To obtain an estimate of the NPV across the RIIO-2 period, we have annuitised the benefits from the analysis commissioned by Ofgem.

This gives an estimated NPV of £68 million over the 5-year RIIO-2 period.

The main drivers of change result from:

- The updated methodology uses refined assumptions that were unavailable at the time of our original CBA estimate. In particular, the value assumed for the BSUoS industry risk premia was reduced significantly in the analysis commissioned by Ofgem.
- Our original estimate was for BSUoS reform to be implemented by April 2022, resulting in 4 years of benefits across the RIIO-2 period. However, in progressing the required modifications, it was determined through the workgroup process that implementation would be April 2023, in line with the BSUoS Taskforce recommendations. This results in only 3 years of benefits across the RIIO-2 period.

Related metrics/ Regularly Reported Evidence	N/A
Sensitivity factors (description)	There are a number of sensitivities to our most recent assessment of the CBA for BSUoS reform. These include: • The actual BSUoS risk premia that industry used, the impact this had on costs in the market and the reduction in operational costs that would be passed through to consumers once the modifications are complete. Analysis of these sensitivities is extremely challenging. • BSUoS reform will not remove the risk of BSUoS costs from consumers, it will transfer it from multiple parties (generators and supplier) to a single party (the ESO). There is a cost associated with the ESO taking on this risk and this will impact the potential benefits to consumers. • Even once BSUoS tariffs are fixed, there remains a small chance that external market drivers will lead to the ESO having to reset the tariffs. This may result in some parties continuing to hold a small risk premia. How this impacts the costs that consumer face is uncertain.
Summary	BSUoS reform is being implemented via two modifications raised by the ESO, CMP361 & CMP362 ('BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates') and created the detail supporting CMP308 (‘Removal of BSUoS charges from Generation’). The ESO has been active in the workgroups for these modifications, developing proposed solutions for these modifications following engagement with industry and Ofgem. New analysis commissioned by Ofgem to support their assessment of these modification has been used to update the CBA which has resulted in a reduction to £68 million across the 5-year RIIO-2 period. This has been driven by the new methodology, an assumption of a lower BSUoS industry risk premia and implementation occurring in April 2023 rather than April 2022.

Consumer benefit case study for Role 2: Moving to more granular procurement of Dynamic Containment

Activity	**Dynamic Containment Low Procurement Changes** Dynamic Containment (DC) is designed to operate post-fault, i.e. for deployment after a significant frequency deviation in order to meet our most immediate need for faster-acting frequency response. Dynamic Containment Low (DCL) was launched in October 2020 and bought on a day ahead basis for contract lengths of 24 hours. This meant that to secure the system the maximum volume requirement for the day had to be procured for the entire contract length, despite the volume requirement varying across the day depending on system conditions. As the DCL market did not have sufficient volume offered in to meet the maximum volume requirement, the result of the auction was to accept almost all of the volume offered at the price cap of £17/MWh. In September DCL was moved to the EPEX platform which enabled more granular procurement and thus more targeted volume requirements and price caps to reflect the value of the service across the day. The DCL price cap was updated to reflect alternative costs by EFA block, at £17/MWh for EFAs 1-3, and £48/£48/£40/MWh in EFA 4/5/6. This resulted in reduced requirements across the day which led to competition and ultimately lower clearing prices in the auctions as a result. This resulted in a saving of around £18.7m during the period compared to the counterfactual scenario if the procurement granularity and costs had remained unchanged. Further benefit will also have been generated from ensuring more granular procurement was possible for DC High when it launched as a service in November 2021.
Role	2
ESO Ambitions	• Competition Everywhere • An electricity system that can operate carbon free • Trusted Partner
Key RIIO-2 Deliverables	A4.1 Manage existing balancing services markets
Is the consumer benefit mainly this year or in future years?	Consumer benefit has been observed this year and will continue to provide benefits in future years by enabling more optimal procurement (& reducing over holding).
Calculation of monetary benefit to consumers	Implementation of EFA block procurement for DC-L has resulted in significant monetary savings for consumers. During 1-Nov-2021 to 31-Mar-2022: - total ESO requirement was 1.62m MWh - total executed volume was 1.38m MWh If all-day procurement for DCL had continued with a revised price cap representative of the alternative cost averaged across the day (£31.17/MW/h) and the DCL market was still not liquid, the total cost on the executed volume for this period would have been around £43m[29] As a result of EFA block procurement the actual cost was £24.33m, resulting in a saving of around £18.7m during the period.

[29] This is a conservative view of the cost for this period, as if we were to assume the continuation of the previous approach secured the maximum ESO requirement, the cost would have been around £50.5m saving £26m

Assumptions made in calculating monetary benefit	To calculate the cost saving made by EFA block procurement we applied a counterfactual scenario whereby, without the changes made we would have procured the same volume at a revised daily price cap of £31.17/MW/h (equivalent to a £17 cap for EFA1-3, and £48/48/40 cap for EFA4/5/6) It is also assumed that DCL market liquidity would still not have been sufficient to meet the peak requirement and therefore the market continued to clear at the cap (which is in line with the market conditions of DCL prior to the EFA block procurement).
How benefit is realised in the consumer bill	The cost of Dynamic Containment contributes to overall balancing costs which is reflected in the BSUoS element of consumer bills.

Regularly Reported Evidence

Table 17: Summary of RREs for Role 2

RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
2B	Diversity of service providers	n/a	Varying diversity across different markets											
2C	RRE 2C EMR Decision Quality	#	1.6 overturned themes per 1000 applications: ● meeting expectations											
2D	RRE 2D EMR Demand Forecasting Accuracy	%	T-1 forecast accuracy of 6.6%: ● below expectations T-4 forecast accuracy of 3.8%: ● meeting expectations											
2E	Accuracy of Forecasts for Charge Setting (TNUoS)		Actual total TNUoS revenue for 2021/22 is within 0.5% of the budget											
	Accuracy of Forecasts for Charge Setting (BSUoS)	%	16%	17%	11%	0%	22%	31%	35%	45%	17%	11%	12%	12%

RRE 2B Diversity of Service Providers

April- March 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 megawatts (MWs) or megavolt amperes of reactive power (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. 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.

Methodology

Service	Sub Service	Methodology
Frequency Response	MFR	We report on contracted volumes for every unit. Figures only apply to a single day, not the whole month. For example, a 20MW MFR contract is only recorded as 20MW in the report, not as 600 MW (20MW x 30days).
	FFR	We report on the highest volume for each unit that has been contracted for a particular EFA block for the relevant month. The sum of those values is what we present on the monthly report.
	FFR Auction (Ended Nov 2021)	
	Dynamic Containment	
	EFR	We report on contracted MW. This doesn't change from month to month unless a contract starts or ends.
Reserve	STOR (Short Term Operating Reserve)	We report on contracted volumes rather than delivered volumes for any contracted unit that could be instructed or awarded a tender each month.
	Fast Reserve	We report on contracted volumes. We record the highest available volume for each unit for each month. Available volumes can change throughout the month for a unit. For example, a unit can be available at 60MW for 29 days in a month, and at 70MW for 1 day of the same month.
Reactive	Reactive	We report on contracted volumes for every unit. Figures only apply to a single day and not the whole month. For example, a 20MW Reactive contract is only recorded as 20MW in the report, not as 600MW (20MW x 30days).
Constraints	Constraints	We report on contracted volumes for all contracts that are live for any part of the month. Some are live for the whole month whereas others are live for part of the month. The highest available volume on a specific day for each unit for the relevant month is captured. The sum of those values is what we present in the monthly report.

Figure 11: Total contracted volumes by service type by quarter

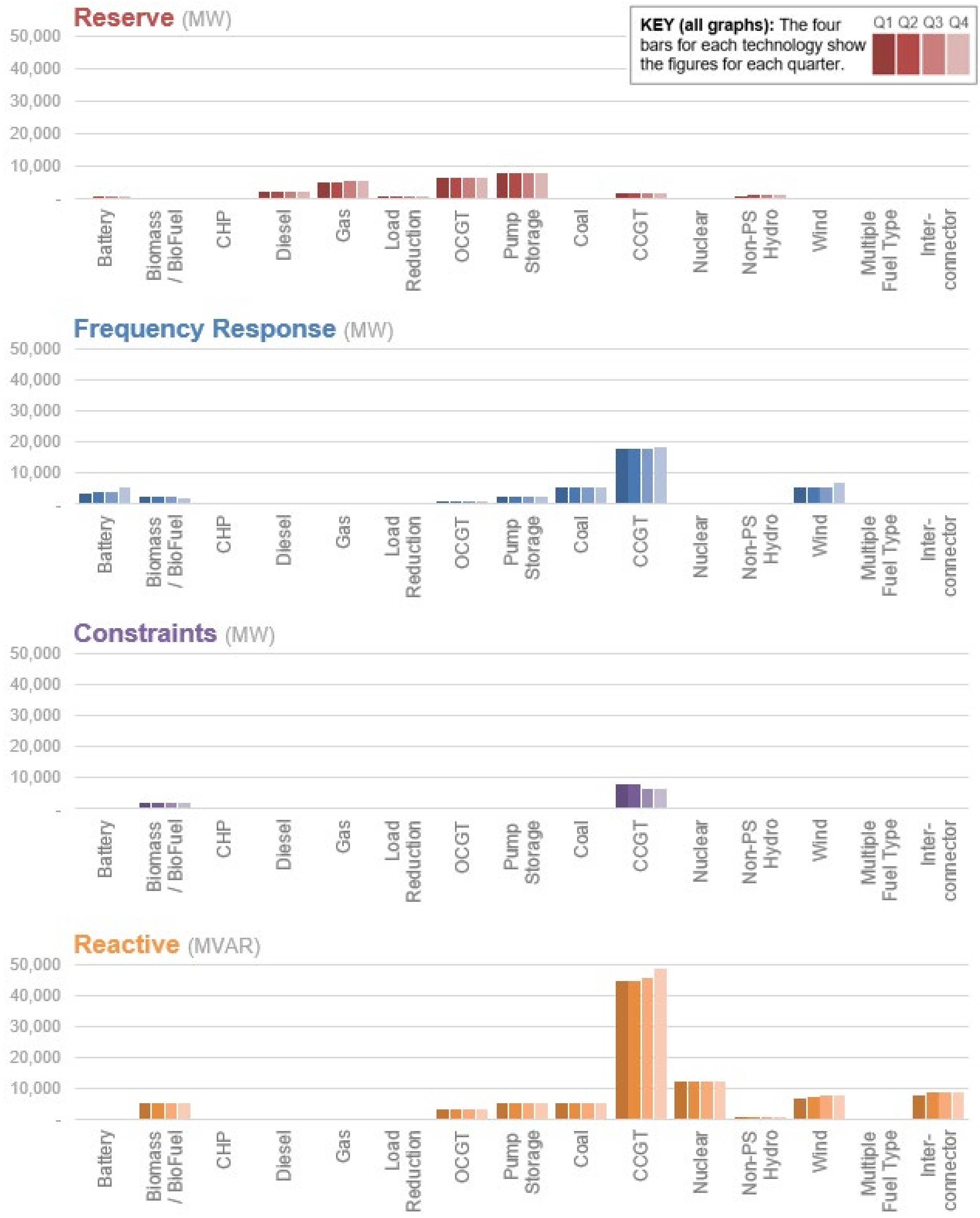


Table 18: Monthly contracted volumes provided to the ESO by service type

Reserve

MWs	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Q1	Q2	Q3	Q4	TOTAL
Total	7,788	7,786	7,786	8,000	8,000	8,001	8,045	8,049	8,049	8,092	8,092	8,092	23,360	24,001	24,143	24,276	95,781
Battery	-	-	-	20	20	20	28	23	23	45	45	45	-	60	74	135	269
Biomass/BioFuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	689	687	687	727	727	728	729	738	738	739	739	739	2,063	2,182	2,205	2,217	8,668
Gas	1,695	1,695	1,695	1,691	1,691	1,691	1,711	1,711	1,711	1,711	1,711	1,711	5,085	5,073	5,133	5,133	20,424
Load Reduction	72	72	72	50	50	50	65	65	65	85	85	85	216	150	195	255	816
OCGT	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	2,061	6,183	6,183	6,183	6,183	24,732
Pump Storage	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	7,800	7,800	7,800	7,800	31,200
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	479	479	479	479	479	479	479	479	479	479	479	479	1,437	1,437	1,437	1,437	5,748
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	192	192	192	372	372	372	372	372	372	372	372	372	576	1,116	1,116	1,116	3,924
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Frequency Response

MWs	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Q1	Q2	Q3	Q4	TOTAL
Total	13,146	12,808	13,047	13,195	13,013	13,088	13,232	12,780	13,331	14,009	13,987	13,971	39,001	39,296	39,343	41,967	159,607
Battery	1,360	1,038	1,246	1,390	1,258	1,331	1,475	1,033	1,618	1,808	1,761	1,767	3,644	3,979	4,126	5,336	17,085
Biomass/BioFuel	785	785	805	825	757	737	737	737	717	717	717	717	2,375	2,319	2,191	2,151	9,036
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	44	44	42	24	42	64	64	64	64	64	64	60	130	130	192	188	640
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	373	373	373	373	373	373	373	373	373	373	373	373	1,119	1,119	1,119	1,119	4,476
Pump Storage	728	728	728	728	728	728	728	728	728	728	728	728	2,184	2,184	2,184	2,184	8,736
Coal	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	5,346	5,346	5,346	5,346	21,384
CCGT	5,999	5,999	5,999	5,999	5,999	5,999	5,999	5,999	5,999	5,999	6,024	6,024	17,997	17,997	17,997	18,047	72,038
Nuclear	92	92	92	92	92	92	92	92	92	92	92	92	276	276	276	276	1,104
Non-PS Hydro	70	70	70	70	70	70	70	70	70	70	70	70	210	210	210	210	840
Wind	1,881	1,881	1,881	1,881	1,881	1,881	1,881	1,881	1,855	2,343	2,343	2,343	5,643	5,643	5,617	7,029	23,932
Multiple Fuel Type	32	16	29	31	31	31	31	21	33	33	33	15	77	93	85	81	336
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Constraints

MWs	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Q1	Q2	Q3	Q4	TOTAL
Total	3,123	3,123	3,253	3,448	3,650	2,765	2,685	2,685	2,685	2,685	2,685	2,685	9,499	9,863	8,055	8,055	35,472
Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass/BioFuel	595	595	595	595	595	595	595	595	595	595	595	595	1,785	1,785	1,785	1,785	7,140
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pump Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	2,505	2,505	2,635	2,845	3,055	2,170	2,075	2,075	2,075	2,075	2,075	2,075	7,645	8,070	6,225	6,225	28,165
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	23	23	23	8	-	-	15	15	15	15	15	15	69	8	45	45	167
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Reactive

MVARs	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Q1	Q2	Q3	Q4	TOTAL
Total	28,889	30,289	30,289	30,534	30,534	30,534	30,534	30,534	31,870	31,887	31,887	31,887	89,467	91,602	92,938	95,661	369,668
Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass / BioFuel	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	5,202	5,202	5,202	5,202	20,808
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	967	967	967	967	967	967	967	967	967	967	967	967	2,901	2,901	2,901	2,901	11,604
Pump Storage	1,630	1,630	1,630	1,630	1,630	1,630	1,630	1,630	1,630	1,630	1,630	1,630	4,890	4,890	4,890	4,890	19,560
Coal	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	5,193	5,193	5,193	5,193	20,772
CCGT	14,832	14,832	14,832	14,832	14,832	14,832	14,832	14,832	16,156	16,156	16,156	16,156	44,496	44,496	45,820	48,468	183,280
Nuclear	4,095	4,095	4,095	4,095	4,095	4,095	4,095	4,095	4,095	4,095	4,095	4,095	12,285	12,285	12,285	12,285	49,140
Non-PS Hydro	189	189	189	189	189	189	189	189	189	189	189	189	567	567	567	567	2,268
Wind	2,192	2,192	2,192	2,437	2,437	2,437	2,437	2,437	2,449	2,466	2,466	2,466	6,576	7,311	7,323	7,398	28,608
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	1,519	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919	7,357	8,757	8,757	8,757	33,628

Supporting information

Reserve

The STOR service has received two significant changes in the past year. Day ahead auction procurement was implemented on the 1st of April 2021, in line with the requirements of the Clean Energy Package. It achieved successful participation from providers throughout the year (approx.220 individual STOR units with over 6.5GW of capacity).

In August 21 after close monitoring of the auction results, a change to the auction platforms algorithm was introduced to include additional assessment steps whereby it will compare the curtailable result against overholding or underholding, this is to ensure we always select the lowest total cost.

Towards the end of the year and in to 2022, we received furthermore providers applying for participation in the STOR service, each incorporating a diverse mix of technology types, including battery storage and aggregated demand management for multiple assets.

For Fast Reserve, we still procure an optional service where a small number of (prequalified) more traditional technologies contract on the day to make their capacity available should it be required.

With the future reserve products intended to come online through 2022, initially with Negative Slow Reserve (downward service) and Positive Slow Reserve (upward service), we would expect to see new technologies and smaller plant entering the market.

Frequency Response

2021-22 saw several changes to the frequency products that we procure. In November 2021 we saw the 2-year trial for the weekly auction that procured Dynamic Low High and Low Frequency Static services come to an end. The providers of these services moved into the existing FFR service or Dynamic Containment.

Dynamic Containment saw some key changes during 2021-22. These changes were a move from pay as bid to pay as clear, the introduction of procuring in Electricity Forward Agreement (EFA) blocks (4-hour) instead of 24-hour contracts and the introduction of the Dynamic Containment High service. These changes have enabled the ESO to introduce shaped buy orders that better reflect requirements across the day. With over 1GW of capability, 2021-22 has seen a large increase in the number of MW that are capable of providing the DC service.

The monthly Firm Frequency Response tenders saw an increase in participation during Q3 and Q4, this was mainly due to the introduction of EFA block procurement and a reduction in requirements over the winter months for Dynamic containment

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. Historically, this service has been limited to the providers that are connected to the transmission network. In Q4 we had three windfarm providers delivering the Constraint Management Pathfinder service which will increase the number of technology types providing this service in 2022-23. These successful parties shall help to reduce network constraint costs across the B6 boundary.

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). The launch of the Voltage Pathfinders has proven that distribution network providers can also be effective to meet a transmission need. We expect contracts with more diverse technologies to be put in place in 2022-23.

RRE 2C Electricity Market Reform (EMR) Decision Quality

April-March 2021-22 Performance

This Regularly Reported Evidence (RRE) measures the number of themes of Capacity Market prequalification decisions taken by the ESO which were overturned by Ofgem in the Tier 2 disputes process per 1000 applications.

As part of our role as EMR Delivery Body, we support Capacity Market applicants through the prequalification process for the auctions. At the same time, we make sure that their applications meet the standards set by Government and Ofgem to ensure procedural fairness and minimise delivery risks. The quality of our decision making is key to promoting high levels of participation in the auctions and to providing appropriate assurance to ensure security of electricity supply at times of system stress. Our objective is to make the correct decisions ‘first time round’ but where an applicant does not agree with us, they have the option to ask Ofgem to review our decisions through the so-called ‘Tier 2’ disputes process.

The ESO’s performance against this measure is assessed upon the number of reviewable decisions by the ESO that are overturned by Ofgem. ‘Overturn theme’ refers to the number of unique decisions made by the ESO, which, upon appeal to Ofgem, are changed. This applies to specific grounds for dispute, within any given appeal (and not the whole appeal itself). Hence one ‘overturn theme’ could represent any number of prequalification applications, where the Authority deems the decision taken by the ESO is materially the same. The number of overturn themes per 1,000 applications is then assessed against the benchmark.

Table 19: EMR Decision Quality 2021-22

Number of Capacity Market applications received (T-1 & T-4)	Number of themes of overturned decisions at Tier 2	Overturned themes per 1,000 applications	Status
1,234	2	1.6	●

Performance benchmarks (Year 1)

- **Exceeding expectations:** <1.5 overturned themes per 1,000 applications
- **Meeting expectations:** 1.5 to 2 overturned themes per 1,000 applications
- **Below expectations:** >2 overturned themes per 1,000 applications

Supporting information

Over the past four years the number of overturns has significantly reduced due to the work we have done with BEIS, Ofgem and customers to clarify the Capacity Market rules as well as the enhanced levels of customer service provided by the Delivery Body.

Throughout the 2021-22 Prequalification round we continued to support applicants throughout the application submission window and with follow on activities such as lodging Credit Cover, submitting Relevant Planning Consents and appealing their Prequalification outcomes through Tier 1 and 2 disputes.

We implemented a number of customer driven improvements to our systems, processes, and user guidance during this period to enhance the service we provide to applicants, with the intention of reducing the number of disputes and overturned decisions. These enhancements to how we operate include, making our online-based services more efficient, co-creation of user guidance documents with our customers to ensure they are helpful as well as the creation of new supporting material such as ‘how to’ videos explaining the finer details of how to apply.

A key regulatory change for 2021-22 were the changes to Regulation 69, which now provides the Delivery Body with greater flexibility in considering information provided by applicants to correct administrative or clerical errors made in Prequalification applications and the introduction of a materiality threshold. The Delivery Body was instrumental in developing these changes with BEIS and customers for 2021 and we feel they have improved the overall process. The changes have allowed us to consider information provided by an applicant at Tier 1 disputes where it could resolve an error or omission. In previous years the Regulations would likely to have prevented us from being able to accept this information and more often than not would have meant an application would have had to progress through the disputes process.

The increased flexibility provided by the amended Regulations has changed how we are now able to assess information provided by an applicant and has allowed us to be more pragmatic in our approach whilst still maintaining application integrity. It has removed unnecessary administrative burden on applicants who no longer need to progress through to Tier 2 disputes and instead have their appeal resolved working directly with the Delivery Body.

In addition to supporting BEIS in developing the necessary regulatory changes, we produced specific guidance to support our customers in applying the new process. Our customers have shared that they have found the changes to Regulation 69 and the guidance we produced as a positive step forward and has meant they are now able to rectify clerical errors which are made during application submission more easily. It has also meant the overall process is shorter, allowing them to conclude the process and provide certainty to investors in quicker timescales. They have also shared that the updates we have made to our user guidance has been helpful and has helped with guiding them through the overall process.

In the coming period, the Delivery Body believes the applicant experience could be further enhanced through an increased level of collaboration between the Delivery Body and Ofgem teams in order to minimise difference in interpretation of Rules and Regulations and to also share best practice. This in turn should lead to a reduction in the number of disputes received, overturned decisions and improve the credibility of the overall submission and assessment process.

RRE 2D EMR Demand Forecasting Accuracy

April - March 2021-22 Performance

This Regularly Reported Evidence (RRE) measures the accuracy of the ESO's peak national demand forecast. This forecasting is done as part of the ESO's role as Electricity Market Reform (EMR) Delivery Body (DB). We aim to optimise the volume of capacity procured in the Capacity Market during RIIO-2 through more accurate forecasts of peak demand, which are used by the Secretary of State to determine the volume of capacity to procure.

The RRE measures the absolute percentage difference between our forecast and outturn of peak National Demand[30]. For outturn peak National Demand, we used Peak Average Cold Spell (ACS) i.e., peak weather corrected National Demand, as this is the most effective measurable proxy. This percentage gives a value greater than, or equal to, zero, and indicates how accurate the peak demand forecasts are. The closer to zero the percentage, the more accurate the forecast.

Over forecasting leads to unnecessary capacity being procured, which increases the cost to consumers. Under forecasting leads to either more capacity needing to be procured later (potentially at a greater cost) or risks security of supply.

All forecasts that outturn post 1 April 2021 will be assessed against this measure.

For 2021-22, the accuracy of two forecasts will be measured as follows:

- The T-1 forecast made in 2020-21, for delivery in 2021-22
- The T-4 forecast made in 2017-18, for delivery in 2021-22

In year 2 of BP1, 2022-23, the RRE will also measure the T-1 and T-4 forecasts for delivery in 2022-23.

Forecast accuracy is the absolute difference between forecast ACS Peak National Demand and outturn ACS Peak National Demand, given as a percentage of the outturn ACS Peak National Demand.

Table 20: Peak demand forecast accuracy

Auction	Forecast made in	Delivery Year	Forecast	Actual	Forecast accuracy	Status
T-1	2020-21	2021-22	43.8GW	46.9GW	6.6%	●
T-4	2017-18	2021-22	45.0GW	46.8GW	3.8%	●

The methodologies used in 2017-18 and 2020-21, to calculate forecast peak ACS National Demand, were different. The 'Actual' outturn for 2021-22 is different for T-1 and T-4 because they each use the methodology in place at time of forecast.

Performance benchmarks (2021-22)	T-1	T-4
● **Exceeding expectations**	<2%	<4%
● **Meeting expectations**	2%	4%
● **Below expectations**	>2%	>4%

[30] National Demand as defined in the Grid Code

Supporting information

Our peak demand forecast accuracy for T-1 and T-4 are below expectations and meeting expectations respectively for 2021-22.

The reasons for the higher than forecast actual ACS Peak National Demand appear to lie with the amount of embedded generation, but other elements are still being analysed. The hypothesis is that the following elements have a part to play, although the interaction between them is complex:

- The Covid-19 pandemic has made it difficult to assess consumer behaviour and demand usage compared to previous years – thereby making trend analysis very complicated for recent years
- Recent Grid Code modifications to remove the incentive for small, embedded generators to run at time of peak has significantly reduced the observed Triad Avoidance, but the specific impact from these generators at time of peak under ACS conditions is unclear
- The interaction between the ‘demand turn-down’ (related to avoiding Half-Hourly TNUoS charges) and Demand Side Response (related to high prices) needs to be reviewed further to better understand the interaction with ACS demand
- The actual output of the embedded generators (especially in the context of ACS conditions) needs to be reviewed to assess the appropriateness of existing assumptions of load factors compared to capacity ratings

Further work to better understand each of these elements and their interactions is planned for 2022. We will provide further information in subsequent performance reports.

RRE 2E Accuracy of Forecasts for Charge Setting – TNUoS and BSUoS

April- March 2021-22 Performance

This Regularly Reported Evidence (RRE) shows the accuracy of Transmission Network Use of System (TNUoS) and Balancing Services Use of System (BSUoS) forecasts used to set industry charges against the actual outturn charges.

1. Accuracy of forecasts for charge setting - TNUoS (reported annually)

The TNUoS tariff setting methodology describes how much of the total required revenue should be collected from Suppliers and Generators, which requires a wide range of tariffs to be calculated. These tariffs aim to reflect the costs of how, when and where Suppliers and Generators use the transmissions system. Final TNUoS tariffs are set by 31 January[31] for the next charging year commencing 1 April, and out-turn revenue is known by the end of April following the charging year.

Customer type	Liable for	Detail
Suppliers	TNUoS Demand charges	The Non Half-Hourly (NHH) demand tariff is charged for consumption between 4pm-7pm for every day of the charging year, and the Half-Hourly (HH) demand tariffs are applied to import or export over Triads (the three periods of highest net GB system demand).
Generators	TNUoS Generation charges	All Generators are liable for the Wider TNUoS Generation tariff. They may also be required to pay onshore local circuit and onshore local substations tariffs depending on where they connect to the transmission system. Offshore local tariffs are also created following asset transfer of the offshore transmission system, which are then charged to offshore generators.

The charging bases used to calculate TNUoS tariffs are the inputs that can be responsible for significant variance between budget and actual TNUoS revenue. The demand tariffs require an assumed demand charging base for each of the 14 demand zones and for each type of demand (NHH, HH gross demand and HH embedded export). The generation charging base is the best view of the amount of Transmission Entry Capacity (TEC) contracted by Generators for the charging year.

Table 21: Forecast vs. outturn TNUoS Performance

TNUoS charge	Forecast £m	Actual £m	Variance £m	Variance %
NHH Demand	1,619	1,607	-12	-0.7%
HH Demand	926	950	24	2.6%
Generation	774	744	-30	-3.9%
TOTAL	**3,318**	**3,301**	**-18**	**-0.5%**

For each charge type, the **Forecast** is what we aim to collect for each tariff and **Actual** is how much we actually collected.

Actuals are based on the latest available settlement metering.

Figures rounded to the nearest £m, therefore totals may differ slightly from the sum of the three components.

[31] Final TNUoS Tariffs for 2021/22

Supporting information

A number of events may impact out-turn TNUoS revenue once TNUoS tariffs have been set 14 months earlier. The most obvious recent impact on TNUoS demand was the continuing impact of Covid-19, particularly on HH demand due to lockdown. In addition, variations in the distribution of demand across location may also have been impacted by Covid-19. Generation revenue may be impacted by unforeseen delays to stations connecting to the transmission system or delays in the transfer of an offshore transmission system.

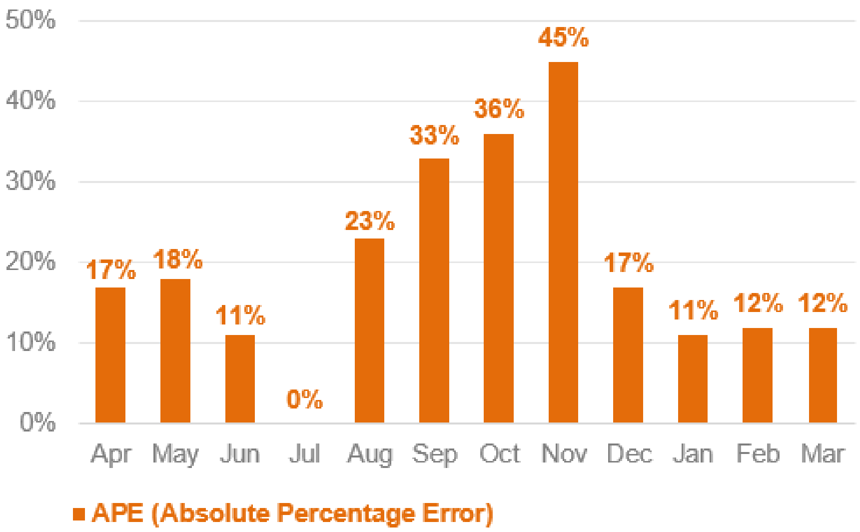
TNUoS charge	Explanation of variance
NHH Demand	A charging base of 24.9 TWh was assumed at tariff setting. Actual out-turn NHH demand is 0.8% lower, at 24.7 TWH, but slightly more NHH demand in zones with higher tariffs than assumed at tariff setting means that out-turn NHH revenue is 0.7% lower than the budget at tariff setting.
HH Demand	Considering the relatively small value of HH Embedded Export payments compared to HH Gross Demand, overall actual HH Demand revenue has out-turned at +2.6% above tariff setting budget. **HH Gross Demand:** • A charging base of 18.3 GW was assumed at tariff setting, which included an adjustment to reflect the expected impact due to Covid. This compares with actual out-turn at 18.9 GW, a 3.3% increase over our expectations, resulting in revenue from the HH Gross Demand tariff of £970.1m (+3.1% over budget). Again, it is expected that the distribution of actual demand by location varies slightly to our assumptions at tariff setting. **HH Embedded Export** • A charging base of 6.9 GW was assumed at tariff setting, which compares with actual out-turn at 7.8 GW (+13.1%). The level of embedded exports is not necessarily driven by demand and therefore not impacted by events such as Covid, but is influenced by a range of other factors including wind availability. Out-turn credits paid for exports (£20.4m) were 36.9% higher than budget at tariff setting (£14.9m). Comparing the difference between the variances for the charging base and the revenue suggests that more exports were made over Triads in zones with higher tariffs than anticipated at tariff setting.
Generation	The amount of Transmission Entry Capacity (TEC) assumed at tariff setting was 70.1 GW compared to actual TEC invoiced of 71.7 GW. This accounts for a small over-recovery of revenue for onshore stations. However, the delay of asset transfer for several offshore transmission systems means that offshore tariffs could not be introduced and charged to offshore Generators as soon as anticipated when Final tariffs were set. This means that overall TNUoS Generation revenue is 3.9% less than budget.

2. Accuracy of forecasts for charge setting - BSUoS (reported monthly)

Table 22: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Actual	3.9	4.5	4.6	4.3	5.8	7.1	8.6	12.6	7.5	8.2	8.9	6.7	n/a
Month-ahead forecast	3.2	3.7	4.1	4.2	4.5	4.7	5.5	6.9	6.2	7.3	7.9	7.5	n/a
APE (Absolute Percentage Error)[32]	**17%**	**18%**	**11%**	**0%**	**23%**	**33%**	**36%**	**45%**	**17%**	**11%**	**12%**	**12%**	**20%**

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



Supporting information

March performance:

In terms of the balancing costs component, the outturn for March was 22% lower than the outturn for February. Wind load factors for March (28%) were lower than in February (51%) which reduced the quantity of actions required for constraints, but this was partially offset by higher wholesale electricity prices (day ahead March price was £250/MWh compared to £170/MWh in February).

Balancing costs forecasting for March made at the start of February was £303m. March outturn costs were equivalent to approximately the 30th percentile of the forecast produced at the beginning of February. This is due to the lower than average wind generation during the month

Year to date performance:

Forecasting BSUoS, particularly forecasting the balancing costs element of BSUoS has been very challenging this year due to the volatile energy prices seen in the market due to increasing wholesale and carbon costs and due to scarcity pricing in periods of tight margins.

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

Work to revise the BSUoS forecasting methodology (balancing costs element) has been in progress through the year, particularly in the second half of the year and with the first forecast created using the new methodology for February 2022. A further update, incorporating a revised view of the constraints costs were included from the forecast for April 2022.

Improvements in the BSUoS forecast accuracy can be seen due to these methodology changes. In addition, greater insight is able to be shared about the drivers of changes. A regular monthly slot on the Operational Transparency Forum will look to further explain the BSUoS forecast.

Role 3

System insight, planning
and network development

Role 3: System insight, planning and network development

Plan Delivery

- We have completed 93 out of the 116 milestones planned for this 12-month period. Of the 23 milestones which are not complete, 10 are ESO-related delays, 9 are outside of ESO control, and 4 are delayed in order to deliver an improved outcome for consumers. We have:
- Made significant progress on constraint management pathfinder, with contracts awarded under Pennines Voltage and Stability Phase 2 pathfinders.
- Collaborated with DNOs to progress regional development plans.
- Delivered network planning activities via the Network Options assessment and FES.
- Had a leading role in whole systems planning, engaging with BEIS and Ofgem on their respective reviews (OTNR and ETNPR).
- Commenced new work investigating how we can better facilitate access for DER to ESO markets.

Stakeholder Evidence

Role 3 survey:

- 8% exceeding expectations
- 71% meeting expectations
- 20% below expectations

Highlights:

- Lessons learnt from Stability Phase 2 incorporated into improvements for Stability Phase 3
- Improvements to NOA 2021-22 to make it more concise and easier to understand
- Website publication for ETYS 2021 was well received and helped us reach a wider audience
- Virtual networking sessions and webinars to support FES 2021 and Bridging the Gap
- Connections team has grown to address growth and is working with TO's to find improved ways of working

Value for money

- Our forecast total expenditure for role 3 in BP1 is £141m, which is 1% higher than the benchmark of £139m
- The main cost variances are increases associated with delivering new activities that were not included in our BP1 such as Offshore Coordination and Early Competition.
- These increases are offset by reductions elsewhere, most notably with our Zero Carbon Operability project. This was due to a re-phasing of work to include a Discovery Phase, pushing spend from BP1 to BP2.

Demonstration of plan benefits

- Network Options Assessment (NOA) enhancements (A7-A11) on track to deliver £663m consumer benefit over RIIO-2
- Taking a whole electricity system approach to connections (A14) on track to deliver £8m consumer benefit over RIIO-2
- Taking a whole energy system approach to promote zero carbon operability (A15) on track to deliver £548m consumer benefit over RIIO-2
- Delivering consumer benefits from improved network access planning (A16) on track to deliver £224m consumer benefit over RIIO-2
- Stability Pathfinder Phase 2 successfully tendered, the bids chosen will deliver 11.55 GVA of SCL and 6.75 GVAs of inertia worth a total of £323 million. Potential future savings are £130m compared to the counterfactual.

RREs:

- 3A Future savings from operability solutions: £27m saved balancing costs in 2021-22, £13m saved infrastructure costs for each of RDPs 1 and 2, carbon reductions of £66m from pathfinders (2020-21 to 2024-25) and £42m from RDPs
- 3B Consumer value from the Network Options Assessment (NOA):
  £208m from ad-hoc CBAs, £313m from LOTI CBAs, NOA consumer benefit £212m
- 3C Diversity of technologies considered in NOA processes: 136 asset-based solutions (including 22 new options) and 8 commercial solutions submitted to NOA 2021/22. A wide range of solutions were considered in NOA pathfinders (NB this will be different from mid-year as we're at a different stage in the NOA process)

C.1 Plan Delivery for Role 3

Deliverables progress

For role 3, the RIIO-2 Delivery Schedule received an ambition grading of 4/5, providing the ESO with an ex-ante expectation of Ofgem's assessment of plan delivery if these deliverables are met. The ESORI guidance states that the Performance Panel should consider that the ESO has outperformed the Plan Delivery criterion if the ESO has successfully delivered the key components of a 4- or 5-graded delivery schedule.

During the first year of the Business Plan 1 period, a few highlights of role 3 performance are:

Constraints- 5 point plan

Our constraint management pathfinder, whose first phase launched in March, is engaging with industry and exploring new short and long term solutions for intertripping services that could contribute to managing constraints more effectively in the future. The first of these schemes has been live since March and in the first 2 weeks of April, the scheme has saved the consumer £6M.

Through the Regional Development Programmes (RDPs) we're already collaborating closely with DNOs to develop future regional constraint markets and solutions, with projects including Power Potential and an initiative to unlock more capacity for smaller, regionally-connected (and often renewable) power sources in more heavily-congested parts of the network. We have also initiated work to facilitate smaller providers into our markets and provide greater visibility of DER.

We're looking to carry out further system analysis to help us identify potential commercial models for a storage service that would help us manage constraints and bring best value to the consumer. This would build on a Network Innovation Allowance-funded collaborative project already underway at ESO to analyse the impact of a range of energy storage systems on network constraints.

Through our Network Options Assessment (NOA) we continue to support and highlight the benefits of new technology and network initiatives which could bolster the grid, deliver better value to consumers, and futureproof the system as we progress the clean energy transition.

Bridging the Gap

Our Bridging the Gap report looks at the FES key messages in more depth and identifies what industry needs to be doing in the next 5 to 10 years to meet Government net zero targets. We published our Bridging the Gap 22 report[33] in March. This built on the 2021 report on peaks and troughs and explores in more detail the flexibility requirements of a 2035 decarbonised electricity system. It is in two parts; the first a "Day in the Life" narrative of the electricity system on a cold, calm winter day, which illustrates what might be happening in terms of generation and demand. The second part is a timeline of actions and milestones required to be hit to reach a decarbonised power system by 2035, bringing together actions set out across a number of different industry publications into a single place. We held extensive external stakeholder engagement to make it a collaborative approach and ensure that the milestones and actions identified were credible. For the 2023 report we will be picking up different key messages from the FES 2022 to explore further.

Pathfinders

For the Pennines Voltage Pathfinder we ran a competitive process to manage voltage for a 10 year period. As part of introducing greater competition onto the network, our second voltage pathfinder compared market based solutions against transmission owner solutions. In February, we announced that Dogger Bank C and National Grid Electricity Transmission have been selected to deliver 700MVAr of reactive power capability between 2024 and 2034. This is necessary for keeping voltage stable and is the first time such reactive power capability will be provided by an Offshore transmission owner. The competition process was introduced to ensure that the most cost-effective services were selected, while maintaining our commitment to manage voltage within strict guidelines.

[33] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/bridging-the-gap-to-net-zero

The B6 Constraint Management Pathfinder (CMP) tender for the delivery year 2024/2025 completed in November 2021. Its aim was to reduce the thermal constraint boundaries experienced on the B6 boundary. It has secured approximately 1100MW capacity of services and should significantly reduce the cost of managing the B6 thermal boundary and increase the volume of renewable energy that can be accommodated on the system. For those providers that already have inter-trip infrastructure established we are able to make use of their services in advance of the formal service start in 2024 and so deliver both cost and carbon reduction value form April 2022. In the first two weeks of operation this scheme saved £6M.

The commercial submission window for the Stability Pathfinder Phase 2 opened to the industry in November 2021. Phase 2 sought to procure additional volumes of inertia, short circuit level and fast acting dynamic voltage support across Scotland between 2024 and 2034. This is due to the increase in asynchronous generation such as wind and solar and the closure of existing synchronous units in Scotland. We carried out an assessment to select the economic combination of solutions to meet the Stability requirement and in April we announced the results of the Stability Pathfinder Phase 2 tender which has been published[34].

Network Options Assessment (NOA)

In January 2022 we published our annual Network Options Assessment (NOA) 2021/22[35]. The NOA assesses the reinforcements required for the electricity transmission networks owned by the three onshore Transmission Owners (TOs) and recommends which reinforcement projects should receive investment. This NOA aimed to enable progress for the next six months, rather than a full year with a refresh of the NOA expected in June 2022. It provided recommendations for TOs to make progress with projects. NOA for 2021/22 is different in format and content than in previous years, this is because we needed to factor in outputs from the ongoing Offshore Transmission Network Review (OTNR).

Operational Visibility of DER

We have commenced new work investigating how we can better facilitate access for DER to ESO markets. A key enabler to this work is ensuring we have appropriate operational visibility of DER to ensure we can manage operational risks. Our work builds on initial work undertaken as part of the Open Networks project looking at use cases for DER visibility and an overall CBA. In this performance it has culminated in a consultation describing the ESO position and planned future work and inviting stakeholder views.

An early success for the project has been adopting a different approach to our treatment of Balancing Mechanism operational metering for aggregated portfolios. This has been welcomed by service providers and we believe it will promote standardisation and proportional investment costs for all market participants. This is now being progressed through a trial alongside a dedicated Power Responsive working group.

GC0151 Fault Ride Through

In the first few months of 2021 it was identified that a number of generators where not performing in line with their obligations in the Grid Code to 'ride through a fault'. So this meant that when there was a fault on the transmission network, generation was unexpectedly tripping off the system. The ESO moved swiftly and wrote to the industry reminding them of their obligation and that if generators tripped unexpectedly following a transmission fault that they would be not allowed to return to the system until they had proven that they had resolved the problem and would be able to ride through. This letter was closely followed by a grid code modification that has now been approved that has implemented the terms in the initial letter. Since this time, the performance of all generators has improved and following a transmission fault generators do 'ride through the fault'. The ESO moved swiftly to address an industry issue to ensure continued reliable operation of the network.

[34] https://www.nationalgrideso.com/news/scotlands-wind-success-story

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

Future Energy Scenarios (FES)

We published the 2021 FES in July and the launch event took place week commencing 12 July. 570 stakeholders joined us during the week and to watch the recorded catchups. We shared key messages, key insight from our analysis, and webinars provided the next level of detail from the main report. We received strong support to continue with an online launch for FES 2022.

Following the launch of FES 2021 we published a range of podcasts via the website and social media, providing the opportunity for stakeholders to listen to a range of views and discussions on topics like heat, electric vehicles, and hydrogen. We also made changes to the website to make it easier for stakeholders to read and absorb the content.

We have made a number of modelling enhancements aligned with feedback we have been receiving from our stakeholders and the customers of FES. We introduced the results from our new Regional Heat Model for the first time in FES 2021. The model and the results produced enable us to understand, to a greater level of detail than previously possible, the various pathways that exist for decarbonising heat. The model also introduces more granular regional modelling into the FES process which will increasingly become a focus area in future iterations of the FES. Alongside this we have also developed a new Hydrogen supply model, enhancing the whole system focus of the FES.

For FES 2022 we have engaged with a total of 1020 stakeholders representing all nine of our stakeholder categories from 329 organisations. Of these 329 organisations, 204 were new to FES for 2022. We have gained valuable insight from the engagement which has provided input into our FES 2022 scenarios which will be published in July 2022.

Challenges

Customer Portal

Workshop sessions with TOs are being held to obtain insight on their needs and requirements, which has been factored into the design assumptions. During the design and development phase, we learned that the build of the new portal was more complex than originally anticipated and reviewed its level of functionality to ensure that the final product will meet our customers' needs and expectations. This had an impact on the delivery date for the phase 1a of the Customer Portal. Development and user acceptance testing with Customers, Transmission Owners and Customer Connections Teams is currently underway, with the initial release of the portal phase 1a now anticipated in July 2022, which shall be followed by Phase 1b in October 2022.

N-3 Intertripping

The N-3 project faced challenges on implementing the ICCP links with WPD and SSEN. ICCP links are a key part of the project which provides the medium to exchange data between ESO and DNOs. WPD security requirements meant that additional encryption was needed on the ICCP link to WPD. The ESO IT team also faced challenges while replacing the existing ECR routers so the project was delayed whilst waiting for this to be resolved. After this delay, the necessary routers are now in place and tested successfully to allow the ICCP implementation to proceed.

New initiatives and changes

The RIIO-2 Delivery Schedule was originally published in October 2020. Since this, the ESO has continually prioritised its projects to deliver the best value for consumers. This has resulted in some new activities, which were not included in the RIIO-2 business plan, Delivery Schedule, or cost benchmark.

Offshore coordination:

Since the start of the RIIO-2 period the Offshore Coordination project has been working closely with BEIS and Ofgem to lead and deliver the parts of the Offshore Transmission Network Review (OTNR) that are within the ESO's remit. In the last six months we have established additional routes for stakeholders to provide feedback to us and engage in our work. These routes have taken the form of open invite monthly sessions on both code changes and commercial matters relevant to offshore wind coordination.

Early Opportunities - We have continued to work closely with developers that have proposed coordination opportunities to refine their proposals and confirm the benefit the projects could bring. We have undertaken a detailed analysis of the gaps and challenges associated with the present codes, standards and processes that need to be overcome, and have put in place plans to address them. An example would be the first of the Connection and Use of System Code (CUSC) code modifications which are planned for mid-2022. We have also undertaken a detailed review and put plans in place to address the changes to internal processes and technical challenges to facilitate these new ways of working. On the 08 April 2022 we updated BEIS and Ofgem on our progress via our Early Opportunities Action Plan and a non-confidential version of the Action Plan will be published in May 2022.

Pathway to 2030 - We have continued to engage with the Central Design Group, its various sub-groups, and stakeholders more generally to develop the Holistic Network Design (HND) in accordance with the associated Terms of Reference. The HND will be published in June 2022 and we are well on the way to achieving this deadline. Over the past six months we have developed, engaged upon, modelled and refined numerous radial and co-ordinated options. We have started to consider the impact of the HND on developers in relation to potential changes to codes, standards and connection contracts. In January 2022 we published an open letter on our plans for a connection contract update programme. We also published information on the outcome of the ScotWind leasing round and its interactions with the HND process. We are continuing to listen to stakeholder feedback in relation to this and other more general suggestions on the overall process, prior to finalising our plans for a follow-up design process. The work of the ESO and other key stakeholders over the past six months within the Pathway to 2030 workstream will allow recommendations to be made in relation to the HND in the near future and this is expected to support Government offshore wind ambitions and the delivery of consumer benefits.

On 11 October 2021 we published our autumn update document to update industry and wider stakeholders on progress across the offshore coordination project. This was followed by a webinar on 21 October to talk through the document and answer questions. We also ran a webinar on the same day specifically for offshore wind developers to provide an update on progress with the HND. We also presented at the OTNR webinar on 31 January 2022 to provide industry, community and environmental stakeholders with an update on progress on the HND.

Early Competition:

Since mid 2021-22 we completed and submitted our Early Competition 'low regrets' activities to Ofgem in December and published on our website in March. We have also worked closely with Ofgem to help them form their views on aspects of Early Competition, such as how criteria for project identification can be defined as they prepared their decision on Early Competition. Our other key focus during this period has been to agree an implementation plan with Ofgem and prepare to quickly mobilise a sizable delivery team in anticipation of a decision from Ofgem to implement Early Competition.

Stakeholder engagement has been quieter on Early Competition this year as Ofgem and BEIS were conducting their own stakeholder engagement in this area. However, since mid 2021-22 we continued to work with TOs to discuss elements of Early Competition that affect them directly (such as identification of asset replacement projects). We also worked closely with the ENA to explore how the transmission model of competition could be applied at distribution level. Bilateral conversations were also held with two parties who participate in competitions overseas who approached us to share their views. We provided a general progress update on our low regret activity to all stakeholders in November, including follow up discussions with stakeholders who raised questions during that webinar. Finally, we updated all stakeholders following Ofgem's decision in late March to proceed with implementation of Early Competition.

Progress of our deliverables

Our RIIO-2 Deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables. The first column shows how our deliverables meet the requirements of the Roles Guidance set out by Ofgem.

For Role 3 (System insight, planning and network development), the Delivery Schedule lists 43 deliverables in total which are made up of 234 milestones. 116 of these milestones were due to be completed in the first year of the Business Plan 1, of which 93 are now complete. Of the 23 milestones which are not complete, 10 are

ESO-related delays, 9 are delayed for reasons outside of ESO control, 4 are delayed to deliver an improved consumer benefit. We provide detail below about those activities where milestones are not on track:

ESO-related delays:

- A16.2 Enhance the Network Access Policy (NAP) process with TOs (1 delayed milestone): The STCP 11-4 process and costing methodology were reviewed and implemented from 1 April 2021. We are working on the implementation of two year ahead constraint cost forecasting which has been delayed with the assurance and testing phase taking longer than expected, it is now expected to deliver early in Q1 2022-23. Then we will determine whether any further cost information needs to be shared, and how we can implement process improvements.

- D9.1 Developed and trialled connection wider works (CWW) processes with TOs: Work on this deliverable has been slightly delayed due to the primary focus being the alignment of the NOA and Holistic Network Design as part of the OTNR workstream. Work on this deliverable has now started in Q4 2021/22. We do not see this delay materially impacting the delivery of this task.

- D11.1 Improved identification of when is the most economical time to invest and the most efficient solution (2 delayed milestones): We have gathered current and future requirements for a tool and have started a tender exercise in order to procure a solution (either from the existing provider, Afry, or another) that fulfils those requirements. Due to procurement timescales, completion will be in 2022/23. This will not materially impact the deliverable.

- D11.4 Improved assessment of stability requirements across the network: Deliverables on the project have been rebased due to complications within the innovation project and Work Package 4 was removed. As we continue with the workstream in 2022-23, we will develop an implementation roadmap.

- D16.4.1 Scoping exercise concluded for delivery of enhancements to outage notifications: Initial milestone date made no allowance for the completion of activity A16.3.2. This activity is now expected to start in Q2 2022/23.

- D7.1 Electricity Ten Year Statement (ETYS): We have undertaken a review on whether pathfinder needs should be included in the ETYS. In order to finalise the preferred approach, we are looking to utilise the outcomes of the Future of Reactive and Stability markets reviews which are looking to establish regular markets for voltage and stability. The future of reactive for example, has made recommendations on methodology and following completion of the initial markets review in March 2022, we will be working to review and develop the appropriate end to end processes to facilitate the communication of long-term system needs to feed into regular markets. Milestone delayed to Q2 2022/23 to allow sufficient time to develop an end to end process that utilises the proposed methodology and undertake appropriate stakeholder engagement.

- A15.6 Transform our capability in modelling and data management (1 delayed milestone): The Q3 2021/22 deliverable (CACM and short-circuit go live in offline network modelling) was delayed due to further optimising the future and current offline modelling works. The combined OLTA hardware and software upgrade was sanctioned in December 2021. It is expected to be completed in Q2 2022/23.

- D8.1 Constraint management pathfinder outputs are incorporated into the NOA methodology: The latest cost information from the B6 constraint management pathfinder tender were successfully utilised in the latest NOA analysis. Constraint Management Pathfinder methodology has been drafted and is included in the draft NOA methodology 2022. This milestone is delayed because of the timing of the NOA methodology consultation and publication cycle. NOA methodology 2022 is usually published in July following consultation with the transmission owners and stakeholders. This year's process is ongoing and the milestone will complete in July 2022 (Q2 2022/23).

Delayed due to issues which are outside of ESO's control in the short term:

- A14.3 Further enhance the customer connection experience, including broader support for smaller parties (3 delayed milestones): Following the setup of the new GB Demand Team engagement with

DNOs and customers, internal engagement with the Whole System team is an ongoing activity. The first DNO / DER specific Customer Seminar is to be held in July 2022. Feedback gained from stakeholders at this event will drive process / service improvements. Seminars were planned for February 2022, however uncertainty around COVID-19 and our ability to hold in person seminars has meant this has now been pushed back. Whilst the in person seminars were postponed, we have delivered a new initiative (Customer Agora's) these are monthly virtual sessions for us to deliver short presentations on topics and allow our customers to engage and ask questions, these have been welcomed by all our customers and we are expanding the topics on a monthly basis.

- A15.6 Transform our capability in modelling and data management (2 delayed milestones): Work depends on D15.8.1 GC0139 (Enhanced Planning-Data Exchange to Facilitate Whole System Planning). We await Ofgem decisions following their consideration of related mods and now that the outcome of the SSE Judicial Review is known.

- A15.10 Develop a regime for an integrated offshore grid (2 delayed milestones):

  - In September 2021 we agreed to work with The Crown Estate and Crown Estate Scotland to facilitate a focus on the priorities and opportunities for alignment and collaboration as they arise through the evolution of the policy and regulatory arrangements for the connection of offshore wind projects, primarily in enduring regime timescales. One area of particular focus is the consideration of how the approach to seabed leasing and grid connection processes might help support more coordination in offshore wind development activities. We are now progressing work with the two organisations to develop proposals, to inform and in preparation for the OTNR enduring regime if that approach is taken forward by BEIS in future. We are also helping shape recommendations on this topic in the relevant OTNR Enduring Regime expert sub-groups. Once BEIS has published their views on the enduring regime in early 2022/23 we will consider how best to further develop and implement any process changes.
  - The milestone for D15.10.4 are considerations within all of the three main OTNR workstreams; Early Opportunities, Pathway to 2030 and Enduring Regime. We will be assessing this along with other considerations in line with the OTNR timeline in relation to the impact on User Commitment of the various network design models within Early Opportunities and of the Holistic Network Design within Pathway to 2030. To date we have worked closely with Ofgem to outline the current ways of working and together begun to analyse where the risk for financial liabilities best sits. Further work on this topic will be progressed by the ESO in early summer 2022 once Ofgem has published their consultation. Our work on the Early Opportunities Action Plan on required codes and standard changes suggests this work will take the form of a modification of CUSC, covering Anticipatory Investment and the need for and timing of changes to user commitment arrangements related to offshore transmission.

Delayed to deliver an improved outcome for consumers:

- D15.5.3 Develop Regional Development Programmes (RDPs) (3 delayed milestones):

  - We have held further discussions with WPD about an RDP in the Midlands and appropriate timescales for progression. We have revisited the needs case and identified a subset of potential sites where a need is arising. In order to increase efficiency of delivery we propose to align the timescales of RDP3 and RDP4 from April 2022/23 and will progress solutions in parallel.
  - As a result of the delay to milestones: ‘Viability of market solution confirmed’ and ‘Detailed RDP development starts’, this is also delayed but as set out above, we have reprioritised RDPs to align development of RDPs 3 and 4. There is no cost to consumers of a delay to these two deliverables. In this quarter we have also been able to progress detailed discussions on a further possible RDP as set out in the commentary for RDP4. This includes work on connection of battery storage DER which will also benefit work with WPD in the Midlands.

- A14.4 Facilitate development of the customer connections hub (1 delayed milestone): Workshop sessions with TOs are being held to obtain insight on their needs and requirements, which has been factored into the design assumptions. During the design and development phase, we learned that the build of the new portal was more complex than originally anticipated and reviewed its level of functionality to ensure that the final product will meet our customers' needs and expectations. This had an impact on the delivery date for the phase 1 of the Customer Portal. Development and testing is currently underway, with the initial release of the portal now anticipated in July 2022. The customer focus group and overall stakeholder engagement will take place continuously between January and December 2022. We will engage with customers during the first stage of delivery in July, so we can take the opportunity to undertake any fixes or enhancement to the portal to complete phase 1 delivery in October 2022. Following this, any updates identified by stakeholders post implementation will be reviewed and implemented where possible.

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 3. Some of these projects are funded as part of the RIIO-2 price control and are therefore eligible for consideration as part of the RIIO-2 incentive scheme. Other projects were funded as part of the ESO's RIIO-1 innovation funding, but are included for completeness as they support some of the ESO's RIIO-2 deliverables. The references in the table below provide links to additional information about each project.

Innovation Project Name	Description	Progress update	Deliverables supported	Status	Funding
Optimal Outage Planning System[36]	Developing a tool for the outage planning process that facilitates the most efficient economic decision-making from the year-ahead plan to three-weeks ahead, and tracks risks from year-ahead to day-ahead.	The project is progressing well; Edinburgh University has provided us with the first draft version of the outage planning tool. The new tool is being tested and refined with the Network Access Planning teams and will help to free up time, allowing the team to concentrate on more complicated outages. The project is on track to complete October 22.	D16.1.1, D16.1.2	Delivery	RIIO-1 and RIIO-2
Advanced Modelling for Network Planning Under Uncertainty[37]	Developing the LWWR (Least Worst Weighted Regret) tool that will help automate part of the Network Options Assessment (NOA) process to make more informed decisions, and be more economically efficient with network planning recommendations.	The project's initial phase produced a report that gave several recommendations for improving the NOA process. A project extension was approved, and Melbourne University developed a functioning tool to perform the LWWR robustly and efficiently. The business has now adopted the tool, forming part of the NOA process, and the Network Development team is also using it to develop CBAs.	D7.2 D11.2	Complete	RIIO-1

36 https://www.smarternetworks.org/project/NIA_NGSO0037

37 https://www.smarternetworks.org/project/nia_ngso0028

Resilient EV Vehicle Charging[38]	The project will analyse the impact of EV charging on grid short term frequency and voltage stability, and cascade fault prevention and recovery.	This project is progressing well, and WP1 has been completed. We received the final report and held a dissemination event with over 150 attendees. The report highlighted fundamental ways electric vehicle chargers could present a risk to grid security. WP2 is expected to complete in December and will look at ways in which we can mitigate these potential risks and recommend grid code changes.	D15.1.2	Delivery	RIIO-2
DETECTS[39]	The project is seeking to understand the risk of converter instability by assessing the behaviour of actual manufacturer-provided converter models	As many of the black box EMT models required for WP1 were commercially sensitive, arranging agreements with various manufacturers took longer than anticipated. The new expected completion date for the project is May 2022. In the meantime, work has continued on WP2,3 and 4, which have provided reports on the use of advanced models and techniques for conducting stability analysis and early warning tools and investigated whether the representation of grid demand needs to be updated.	D15.1.2	Delivery	RIIO-1
Probabilistic planning for stability constraints[40]	Cutting-edge techniques combining traditional power systems stability analysis and statistical modelling, will allow the ESO to better understand the risk and uncertainty associated with angular stability on the GB electricity system.	The project is due to complete at the end of March. The developed tools will allow the ESO to evaluate stability constraints and provide snapshots for more regions accurately and efficiently. Upon completion of the project, the tool will be validated and trialled within the existing ESO systems. However, further work will be required to iterate and fully integrate the tools into BAU (Business as Usual) for the 2022/23 planning cycle, as outlined in the final roadmap report.	D11.4 D15.1.2	Delivery	RIIO-1
SHEDD[41]	Assessing better Low Frequency Demand	Project has now completed. Final outputs were validated by a sub-project undertaken by	D15.1.2	Closure	RIIO-1

[38] https://smarter.energynetworks.org/projects/nia2_ngeso006/

[39] https://www.smarternetworks.org/project/nia_ngso0031

[40] https://www.smarternetworks.org/project/nia_ngso0036

[41] https://www.smarternetworks.org/project/nia_ngeso0034

	Disconnection (LFDD) solutions.	Strathclyde University. Of the final shortlisted alternative LFDD design options, the “Optimisation of LFDD relay settings” solution was determined to be the most optimal alternative LFDD design solution to upgrade the existing LFDD scheme.			
TOTEM (SHET led)[42]	Developing and validating a full-scale model of electromagnetic transient (EMT) behaviour for the GB transmission system.	A multi-party contract has been agreed upon, enabling the GB Transmission Owners to work together to acquire and validate a new system model that will enhance and de-risk the integration of technologies that lower the system inertia. However, due to unforeseen complexity issues with the NGET (National Grid Electricity Transmission) network, only the Scottish network will be completed by MHI (Manitoba Hydro International) within the TOTEM 1 period. Therefore, an extension of the project will start from April 2022 till the end of March 2023 to deliver the rest of the deliverables, including (the NGET network, validation, additional studies, hardware and software setup and documentation, etc.).	D15.1.2	Delivery	RIIO-1
VSM Battery[43]	The functional needs as defined in the VSM work group may be delivered in a variety of ways, this project will deliver the testing, modelling and specification need to ensure appropriate performance is delivered.	The project completed in 2021 and was the first trial in GB to demonstrate a working industry standard VSM prototype in a highly realistic testing environment. The findings of the tests indicate that VSM is a promising technology that can certainly be part of the suite of tools that can be used to address the upcoming challenges associated with the decline of synchronous generation on the system. It also highlighted the importance of establishing minimum specifications for the behaviour of VSM/ Grid Forming Converters which reinforces the work being done as part of the Grid Code Modification proposal (GC0137).	D15.1.2	Closure	RIIO-1

[42] https://www.smarternetworks.org/project/nia_shet_0032

[43] https://www.smarternetworks.org/project/nia_ngso0026

Year-round Voltage Assessment Tool[44]	Developing and testing convex optimisation models and machine learning algorithms that adequately represent voltage and reactive power in the system.	Project completed in April 2021.The project made use of the recent advances in convex optimisation of optimal power flow together with data clustering techniques to assess year-around OPEX (Operational Expenditure) of operating a power system. The project is part of the NOA enhancement plan and outputs include a framework to enable the NOA team to assess the reactive power requirements of a given system. Further investment will be required from NGESO (National Grid Electricity System Operator) to integrate this proof of concept into the current analysis workflow.	D11.3 D15.1.2	Complete	RIIO-1
Coordination of ANM schemes with Balancing Services markets[45]	Thorough review of existing Active Network Management (ANM) schemes and identification of any conflicts which have arisen historically. Developing a series of test cases which represent the range of different ANM scheme configurations and simulating the outcomes in different scenarios.	The project was completed in 2021 and identified three potential solutions to optimise coordination of ANM schemes and balancing services market development, including Improved information exchanges, reconfiguration of ANM schemes and changes to market rules. Delivering the three shortlisted solutions to BAU will require NGESO to work with different industry stakeholders. The identified stakeholders are Generators, DNOs (Distribution Network Operators), Ofgem and third-party providers of ANM solutions. Further follow-on projects are currently in development to test and validate the solutions in a real environment.	D4.5.1	Complete	RIIO-1

WPD's EFFS NIC project has been removed from the table above, this is due to ESO involvement being reduced from an active partner to stakeholder/advisory role.

[44] https://www.smarternetworks.org/project/nia_ngso0029

[45] https://www.smarternetworks.org/project/nia_ngso0035

C.2 Metric performance for Role 3

There are no Metrics for Role 3

C.3 Stakeholder evidence for Role 3

- Following Stability Pathfinder phase 2 delays, we have shared the lessons learnt on a programme level for subsequent pathfinders and this has already been implemented for Stability Pathfinder phase 3.
- We have made the NOA 2021-22 report easier to interpret and more concise as well as improving our methodology website.
- For the FES 2021 launch we hosted a series of virtual networking sessions and allocated a longer time period for Q&A.
- Our website surveys showed that the website publication for ETYS 2021 was well received and helped us to reach a wider audience. We continue to make improvements.
- We launched Bridging the Gap and at the webinar event we requested and received feedback regarding what the project should consider in the future.
- Connections team has grown to address growth and is working with TO's to find improved ways of working.

The ESO incentive scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of the ESO's plan delivery. To demonstrate performance against this criterion, we report on our stakeholder satisfaction survey results, as well as describing how we have worked with stakeholders during the year.

Stakeholder surveys

The ESO has commissioned surveys from market research company BMG. These surveys measure satisfaction for each ESO role, and are carried out on a six-monthly basis. The survey is targeted at senior managers, decision makers and experts, and includes a wide selection of relevant stakeholders who have had material interactions with the ESO's services.

For Role 3, the following question was asked:

'One of the ESO Roles is focused on system insight, planning and network development, which includes key activities such as Connections and Network access, Strategy and Insight and long-term Network Planning. The ESO's recent activity in this area includes progress on the Constraints Management Pathfinder, progressing activities in 5-point plan to manage constraints including the constraints management pathfinder, network development through the Offshore Transmission Network Review (OTNR) Holistic Network Design and Electricity Transmission Network Planning Review, work on the DSO transition including Open Networks and Regional Development Programmes, consulting on the Security and Quality of Supply Standards (SQSS) review, engaging on the development of the new Connections Portal, engaging on the 2022 Future Energy Scenarios including ongoing Regionalisation activities and delivering the Winter Outlook. Overall, from your experience in these areas over the last 6 months, how would you rate their performance?'

Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

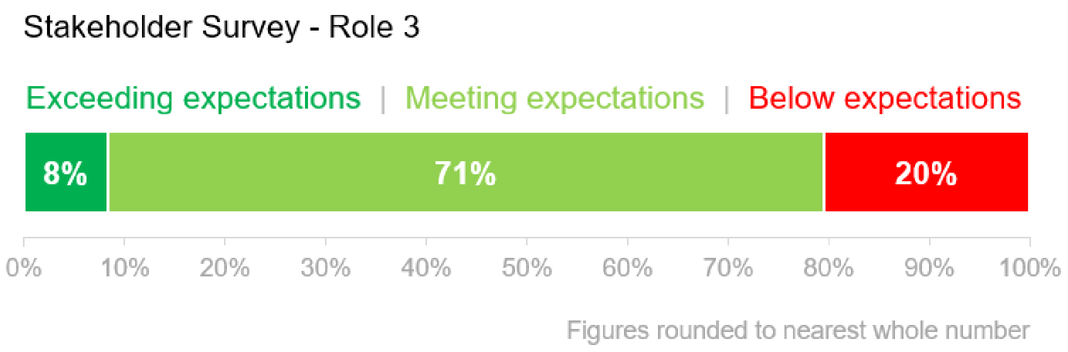
- If they rated the ESO as below expectations, they were asked what the ESO needed to do to meet their expectations.
- If they rated the ESO as meeting expectations, they were asked what the ESO needed to do to exceed their expectations.
- If they rated the ESO as exceeding expectations, they were asked what the ESO did that exceeded their expectations.

For Role 3, we contacted 427 stakeholders, and received 83 responses to this question, which were distributed as follows:

- 8% exceeding expectations

- 71% meeting expectations
- 20% below expectations

(Percentages rounded to the nearest whole number)



The survey results indicate that the ESO is meeting expectations for role 3, although Ofgem will also take into account other stakeholder evidence. Our analysis of survey responses has suggested the following themes:

"Exceeding Expectations" feedback

Stakeholders who scored us as 'exceeding expectations' were asked what the ESO did that exceeded their expectations. They raised the following points:

- The forward thinking of the ESO was admired by stakeholders in relation to the ESO taking a proactive approach to adapt to zero emission system operation and progressive thinking in planning and consideration of non-traditional options.
- A few stakeholders provided good feedback on the clarity and transparency of our communications and exceeded expectations in terms of collaboration, particularly on OTNR Pathfinders.
- The ESO was praised for tailoring our connections solutions to our customers needs.

"Meeting Expectations" feedback

We asked all stakeholders who scored us as "meeting expectations" what would it take for the ESO to be exceeding expectations for them, here is a summary of that feedback for Role 3.

- Some stakeholders called for greater openness and communication, with some referencing the coordination of comms between different parties within the TOs and a general lack of availability or accessibility of timely information. There is also a request for increased transparency on long term development of the transmission system and network planning.
- Some of the feedback for how we could exceed expectations provided by stakeholders focused on pace of delivery, with a focus on delays to Holistic Network Design/Offshore Transmission Network Review and Regional Development Programmes. Whilst the standard of work delivered is of high quality, stakeholders urged for faster progress. There was also reference to inconsistency of delivery pace, with Outage Planning praised but improvement needed for Customer Connections.
- Other areas stakeholders fed back on for how we could exceed expectations included improving engagement and co-creation with our stakeholder groups, with publications called out. Stakeholders requested greater opportunity to provide feedback on key projects in customer workshops, such as FES and network development planning, and asked for more collaborative decision-making. DNOs, developers and automotive stakeholders specifically asked for greater levels of engagement on projects that impact them.
- There was further commentary related to a need for process improvements, policy review and adherence, and a need for a reduction in siloed working.

- Stakeholders noted that they had high expectations for system insight, planning and network development and the ESO met those, with others adding that they were happy to have their expectations met for Role 3.

- It was felt that the stability pathfinder tendering process with respect to the changing rules for required connections could have been smoother and quicker.

"Below Expectations" feedback

In response to being asked what the ESO needed to do to meet their expectations, these points were raised:

- Some feedback called for greater ownership of a whole system strategy and planning, especially taking a role in technical and thought leadership in this area.
- Comments highlighted the need for greater communication, familiarity of stakeholder needs and more meaningful engagement and collaboration.
- A few stakeholders remarked on process inefficiencies of the connections process, with some comments related to lack of innovation for DNO solutions, poor data quality and lack of visibility of forecasting for connections issues.

Stakeholder engagement during the year

The Stakeholder Evidence criterion also takes account of the ESO's consultations and ad-hoc surveys throughout the year, whether the ESO has actively sought and taken into account the feedback of stakeholders throughout the business plan cycle, and the ESO's explanations for feedback received.

Pathfinders

Area	Stakeholder feedback	Action taken by the ESO
Treatment of competing projects in Stability Pathfinder Phase 2 and Phase 3 tenders	They are concerned with our approach to hypothetical system reinforcement costs arising from high fault levels based on numbers of competing projects being assumed to connect to the network. They submitted a separate proposal and seeking to discuss.	From a Stability Phase 3 perspective, we have reviewed and understood this stakeholder feedback in relation to the reserved bays connections approach that is adopted for this tender. Whilst we have been unable to amend the reserved bays approach for Stability Phase 3 tender due to the specific way in which reserved bays are allowed for Stability Phase 3, we have sought to imbed the feedback received into the amendment to the STCP codes change made that will enable bay reservation on an enduring process. We believe the codes change made will improve how bay reservations can be done in the future based on the feedback received.
Stability Pathfinder phase 2	At a later stage in the tender process, ESO compounded these effectiveness factors. They feel this has had a detrimental effect on development of suitable projects and could result in extra costs to consumers through imperfect competition and wasted efforts by developers.	Phase 2 SCL effectiveness was published for the first time at the RFI stage in June 2019 where we consulted with the industry on the tender development. Following the RFI feedback, we updated the industry at the EOI stage in Oct 2019 that we will consider retained voltage factors alongside SCL effectiveness to correctly reflect a solution's contribution to the areas of needs. We received industry feedback to provide this information ahead of the EOI

		closure in Jan 2020 which we considered and provided this information in Nov 2019. We have further considered this feedback to improve the Stability Pathfinder Phase 3 process where all information has been provided at the tender launch stage.
Stability Pathfinder phase 3	During the tender window we have conducted further webinars for registered bidders to go through the shared assessment methodology and go through the updates made to the technical specification and contract terms since the pre-tender consultation and the feedback that was received. Following these webinars we circulated feedback forms where ESO received an average NPS feedback score of 7.68 out of 10 where 10 was 'Excellent'. The consistent theme of feedback however was to allow more time for questions in the webinars.	While no further webinars will be held on Stability Phase 3, this has been logged as a lesson for future Pathfinder tender webinars such that the way Q&A sessions are managed can be improved. The Stability Phase 3 team have also continued to engage with tenderers and respond to their raised queries as effectively as possible to enable continued clarity through the tender window.
Pennine pathfinder	1) NGESO ran a consultation period during the initial stage of the tender to allow tenderers to provide feedback on the tender with particular focus on the standard contract terms and commercial assessment methodology. 2) Communications with tenderers have overall been well received. The highlight was holding webinars for each of the stages of the tender which gave the opportunity for tenderers to ask questions as well as publishing the recordings of the webinars on our website. 3) During the tender, NGESO received request to carry out site visits for sites with non-operational land. This was the first time Pathfinders had carried out site visits. Tenderers found this new initiative useful and should be incorporated for future pathfinders but advised that these should have been organised earlier on in the tender process	1) Upon review of the consultation feedback, we published the key themes of the consultation on our website[46] and via email to tenderers and NGESO's position on these themes. Some highlights of the consultation included changing the treatment of network constraints; the Scheduled Commercial Operations Date; and Post Tender Milestones as well as clarifying NGESO's right to remedies. 2) We have shared this lessons learnt on a programme level for subsequent pathfinders and already been implemented for Stability Pathfinder phase 3. This will also be included in the lessons learned report once published. 3) We have shared this lessons learnt on a programme level for subsequent pathfinders and already been implemented for Stability Pathfinder phase 3. This will also be included in the lessons learned report once published.

[46] https://www.nationalgrideso.com/document/211221/download

	4) A number of tenderers were concerned of awarding the West Yorkshire region of the tender to the counterfactual.	4) NGESO has reinforced our commitment to be as transparent as possible and continue to seek feedback on assessment process in the future.

Mersey Pathfinder

Industry participant: *'We appreciate the early engagement that the NGESO initiated on our October licence consultation to highlight their position and concerns. Whilst the NGESO held different views on the legislative requirement to licence Mersey Reactive Power Limited (MRPL), the discussion and exchange of ideas on issues was open and constructive and contributed to the refinement of our final licensing approach of MRPL.*

Despite the difference in views on the licensing requirement, the NGESO was proactive in identifying a pathway for MRPL to transition from having a bilateral connection contract under the CUSC to a party of the STC once it became a licenced ETO. The STC does not have an explicit provision for managing the connection and required interfaces between MRPL and NGET i.e. the connection of a new onshore ETO to another onshore ETO. To bridge this gap, the NGESO led a process, working with NGET and MRPL, to develop a model agreement based on the existing STC process of connecting a new offshore ETO to an onshore ETO.

Our NGESO colleagues have kept us up to date on progress with developing the model agreement with NGET and MRPL, and also getting the agreement of the other STC parties to this proposed process. An added challenge to this work has been the compressed timescales for developing and implementing the accession agreement in time for April 2022.

Overall, the NGESO has worked constructively with us on our licensing consultation about MRPL's ET licence application. And following our decision to grant the licence, the NGESO has played an essential role in the process for MRPL to become a party to the STC and fulfil this licence obligation in time for the start of its reactive power services provision contract in April.'

Network Options Assessment (NOA)

Stakeholder feedback	Action taken by the ESO
Stakeholders requested that the report size be reduced	When we wrote the NOA 2021/22 report, for publishing on 31 January 2022, we took the opportunity to reduce the report size from over 150 pages to 41 pages, making the report easier to interpret and more concise. We did this by putting material that is constant from year to year onto our NOA webpage so that we can focus the report on its results and key messages. As part of this, we removed the appendix of results to a downloadable spreadsheet on the website that was also in accordance with feedback.
More detail was requested	This is in very specific areas that we addressed by direct correspondence.
There were concerns about the size of the methodology	We held our annual NOA methodology review in summer 2021 and went on to improve our methodology website in November. Our revised website summarises the main parts of the methodology on separate webpages. This helps us to see where our stakeholders' interests are, and which sections of the methodology are most important to them.

We received the following feedback from the TOs about the NOA process:

'Good communication at QA stage and ease of updating submission as a result.'

'Early models and methodology are good.'

'Weekly updates useful and helped identify discussion point as results emerged.'

'We are happy with the changes made, and the additional clarification around the tipping point year for each scenario is very useful.'

Our monthly Network Development newsletter that updates on NOA, ETYS, NOA pathfinders and Early Competition has 1689 subscribers at the end of April 2022, an increase of well over 100 over the last 12 months.

Electricity Ten Year Statement (ETYS) publication

Stakeholder feedback	Action taken by the ESO
Stakeholders asked for a clearer and easier way read our report	ETYS 2021 was the second web-based publication of the ETYS, we have utilised all the feedback we received on ETYS 2020 to shape ETYS 2021. Our website surveys showed that the website publication was well received and helped us to reach a wider audience, we have continued to make improvements so that our web version of ETYS 2021 is easier to use for our readers. Through our formal consultation process and website surveys, we received and acted on feedback specifically about making certain pieces of content easier to find, namely by making the report more concise and reducing the number of webpages. This year, we have seen an 8% increase in the amount of traffic to the webpages and a 12% increase in the number of downloads, further building on the success of our website publication in helping the ETYS to reach a wider audience. Our website surveys have continued to capture feedback from our readers on the ETYS content and the development of the website publication. Our website surveys have received 98 responses since the ETYS 2021 was published at the end of November, these help us to capture feedback from our readers on the changes we had made since the previous year's publication. The survey showed that this was well received, and we achieved a 87% positive feedback rating out of the 98 responses. Going forwards, we will be continuing to use our website surveys on the ETYS webpage to engage with our readers across the year and will look at how we might tailor the website surveys to support the upcoming formal ETYS consultation process.
There were requests to provide an indicative boundary transfer capability in the ETYS boundary charts	We have now included this in the ETYS boundary charts based on the 2020/21 NOA optimal path. These were recently updated based on the 2021/22 NOA optimal path, following the publication of NOA 21/22, after agreement with the TOs. This will provide a clearer view to industry of the gap in system needs and to identify opportunities for future years, when accounting for NOA options.

Leading the debate

Future Energy Scenarios (FES)

Stakeholder feedback	Action taken by the ESO
They missed the networking and 1:1 aspect of a face-face event.	For the FES 2021 launch we did host a series of virtual networking sessions on Wednesday and Thursday in between the deep-dive presentations. These were welcomed by those that attended.
Stakeholders asked for longer time for the Q&A section of the launch event, as well as visibility of all the questions asked by the audience.	For each of the deep-dive presentations we did host a 35min Q&A slot on that topics. All Q&A's were then captured in the Q&A document published during August. We also used Sli.do during all the Q&A sessions so that all questions were visible to attendees. Stakeholders were able to vote for the most popular questions.

As there are many documents that makeup the suite of FES, stakeholders asked for a document overview	For FES 2021 we made changes to the website to provide clearer visibility on the full suite of documents. In the main FES document we provided better signposting and titles for all documents in the suite that will be taken forward for FES 2022
They were confused why the ESO is covering gas supply	FES is a whole energy document, and the scenarios cover all energy aspects and wider economy when considering carbon emissions in our calculations for meeting net zero. Taking a view of gas as well as electricity is essential for considering the whole energy system. The importance of whole system thinking was one of our Key Messages in FES 2021.
In the FES in 5 document, they wanted to know when each scenario will achieve net zero	The 2021 FES in 5 included the dates that each of the scenarios met the net zero target (as well as a chart showing the trajectory between 2020 and 2050).
Stakeholders asked us to publish our sources and supporting evidence used in the scenarios	For FES 2021 we published a breakdown of the stakeholder categories that provided feedback for the scenarios, however this did not include the individual sources or evidence. This is something we will consider for FES 2022.

Carry out analysis and scenario modelling on future energy demand & supply

Area	Stakeholder feedback	Action taken by the ESO
Regional FES program	More transparency to be provided on what the Regional FES program is trying to achieve	• We have committed to providing an explainer document and have advertised this to stakeholders, this is in direct response to feedback. We have also launched a dedicated website for the regional FES program and kept FES stakeholders up to date through the regular FES newsletter. This was published at the end of April[47] • Network companies were asked how they would like to be kept informed of regional FES developments and common consensus was the network forum and the ENA, both of which we are using regularly. We also use bilateral engagement to keep stakeholders up to date. • We have published two thought pieces on spatial heat, which includes details of what we are trying to achieve through the regional FES program • We have worked with the DNOs and published a paper agreeing how we are going to align our Grid Supply Point definitions • We are working with the DNOs on a feedback mechanism between FES and DFES as part of the ENA "Open Networks Project" • We will be publishing additional data and visualisations through 2022 to get broader stakeholder feedback to feed into our regionalisation activities for FES 2023 • We used the 'Call for evidence' for FES 2022 to ask for specific regional areas of focus and

[47] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/regionalisation-fes/explainer

		we have outlined our plans and response to stakeholder feedback in the "stakeholder feedback document", which was published last month.
Bridging the Gap	• Three external stakeholder workshops were held, where stakeholders gave feedback on what the milestones should contain. • Specific feedback to adjust some of the actions from BEIS • Requests for additional detail in relation to the Day in the Life report	• The milestones developed reflected the feedback given and before publication, these were shared with all of the stakeholders again and tweaked where necessary, so that the resulting milestones represented industry views. The milestones are the basis of our flexibility timeline and therefore stakeholder support and agreement is vital. • We worked with BEIS to ensure that the actions were supported and owned by the right BEIS teams. • Held an additional webinar just about the Day in the Life, where all questions could be answered. At the launch webinar, we asked and received feedback about what the project should look into next time and we will incorporate stakeholder suggestions about the next project into the upcoming scoping work.

Take a whole electricity system approach to connections

Area	Stakeholder feedback	Action taken by the ESO
Account Management response to queries has been lacking	They recognised that, given the significant reforms being undertaken, resources are stretched. However, it should be improved to aid market certainty.	In the last 12monthts the ECC Team has grown by approximately 47% to address growth and work load; We have also actioned changes to the Team Structure to enable better segmentation of work and also creation of Policy Team to enable more strategic approach to change [look into the future to action change]. New structure will come into force on 11 April 2022 [delayed to recruitment processes] Further increases to Team Headcount agreed, with another 11 Full Time Employees to join the team in 2022-23
Customer connections proactive but inconsistency in other roles Is impacting progress	The have found the Customer Contract Manager has been very proactive on many interactions. However, interruptions in other roles are impacting progress. Legal separation still causes complexities. Delays are still being encountered when the ESO seeks technical input from the TO.	We are working with all the TOs to find ways to improve ways of working, however current workload [+50% increase in Licensed and Unlicensed connections related work] has impacted the ability for TOs to respond as quickly they wish. Failings of current connections process have been identified and raised with OFGEM. Requirement for Connections Reform has been included in BP2 however we shall work in 2022-23 with TOs to find interim improvement opportunities, including better definition of Roles and Responsibilities.

High level of connections activity this last year has led to many GSPs becoming constrained	They feel because of this, modification application works have been required to facilitate these new connections. There have been some challenges with the time taken to develop and then implement solutions for connection. We now have regular monthly meetings to better manage these situations and to look at how we can improve associated processes	Due to the volume of connection applications we are indeed seeing an increase in the number of offers that have connection dates in late 2020 and early 2030's; Focus is placed not only on working with TOs to support submission LOTIs and MSIPs but also on what other options are available to enable earlier connections; We have started the process to review the Construction Planning Assumptions which are supplied by ESO to TOs to enable the relevant network studies by TOs as part of the process. the expectation is that the review of this CPA will enable improvement of the outcomes of network assessments and earlier connection dates. Target for CPA on Battery Storage is June/July 2022 with other types of technology to follow up to the end of 2022
Connection and modification offers	We are getting connection offers out in the 3 month target period. However, they have observed that modification offers are experiencing severe delays. They feel that there is an inconsistent approach between contracts, and we don't always call out specific changes in offer documents. They also find that that there are frequent errors in contracts.	Modification Offers are not Licenced Offers consequently we are not able to demand a response within a licensed framed work from TOs and current workload forces TOs and ESO to prioritise the licensed offers. We, ESO Connections Team, recognise that this process doesn't deliver on the needs and expectations of Customers so we have highlighted this as one of the areas to be addressed as part of the Connections Reform.
Engagement with customers in connections and network access	They believe that we have effective engagement with customers and a solid relationship with management. However, they feel that we are unable to push back or challenge the TOs on the customer's behalf.	Current STC, Licence Conditions and different regulative frameworks prevent us from being able to do something beyond what has been attempted so far. We expected that as part of development of FSO and Connections Reform these matters shall be addressed.
Treatment and assessment of connections and market operation for storage systems	The find that there may be a potential issue which can both import and export, potentially decreasing (or increasing) network constraints.	We recognise the limitations on how we model and assess Battery Storage, and as per the communication to Customers and Stakeholders at the Customer Connections Agora in March 22, we are working with ESO Network Operability Team and TOs on the process to review the Construction Planning Assumptions which are supplied by ESO to TOs to enable the relevant network studies by TOs as part of the process. The expectation is that the review of this CPA will enable improvement of the outcomes of network assessments and earlier connection dates. Target for CPA on Battery Storage is June/July 2022 with other types of technology to follow up to the end of 2022

Whole System Network

Area	Stakeholder feedback	Action taken by the ESO
Develop Regional Development Programmes (RDPs)	It was felt that there needs to be a more proactive approach to resolving the RDP we have for the North of Scotland.	We have increased the level of resourcing supporting this work to take a more proactive approach.
Distribution System Operators (DSO)	For DSO a key element is consistent and aligned approaches to DSO and flexibility markets.	We continue to support the ENA Open Networks project which focuses on alignment of flexibility markets and lead on many of the relevant work packages. Regional Development Programmes provide our learning by doing approach to co-ordinated procurement of constraint management services with DNOs and service providers. Through sharing of RDP experiences at the Joint Forum we ensure that these local constraint markets develop in a consistent manner.
ENA Open Networks	For the most part, we see the ENA Open Networks project as the common forum to facilitate this co-ordination in many of the key areas highlighted.	We continue to work as an integral part of the ENA Open Networks project leading work on procurement processes, standard agreement and primacy rules.
Distribution System Operators (DSO)	We note the suggestion that automated systems may be in place to manage these conflicts (between ESO and DSO requirements) but unless, and until all markets for flexibility are coordinated (or have some form of hierarchical structure), there will remain a risk of conflicting dispatch actions leading to the possibility of one service negating another, and/or over-procurement through multiple parties contracting for services which are likely to overlap in terms of dispatch periods. Market-based mechanisms with clear roles and responsibilities provide price signals that allow transparent decision-making by system operators (for both grid development and operations) and distributed energy resources (DER) service providers (for investment and participation).	We are leading the work in Open Networks to deliver primacy rules which will ensure service co-ordination. These will then be rolled out into ESO processes to manage any potential service conflicts.
Distribution System Operators (DSO)	The ADE support the views set out around operational liaison and real time transfer of data, including improved real time visibility of DER operations for both transmission and distribution system needs." "Coordination of procurement of DSO and ESO markets and stacking across markets are very important	DER visibility has been recognised as a key enabler for DSO by Ofgem and can create significant benefit to the ESO. A new team is proposed to progress this area of work and progress roadmap in the paper we intend to publish shortly. We are leading relevant work in Open Networks to co-ordinate and align procurement activities between ESO and DSO markets.

	factor to allow optimisation of assets."	
	We need to deliver a step up in alignment between distribution flexibility, transmission flexibility procurement and ESO ancillary services. Networks and the system operator will develop and implement a set of primacy rules to resolve service conflicts.	We have lead the creation of a standard framework agreement for ESO and DSO services and now lead the Open Networks procurement processes development. We are also leading the Open Networks work on the development of primacy rules.
Develop Regional Development Programmes (RDPs)	Need to implement changes arising from Open Networks including service co-ordination and DER visibility. Learnings from RDPs including contractual arrangements and CBA approaches.	The RDPs are very much implementing changes from Open Networks and will be the first trial for the primacy rules that it is developing. The ESO led Whole Electricity System joint forum is sharing the learnings from RDPs with other DNOs to ensure consistency.
Distribution System Operators (DSO)	DSO strategies have been published by DNOs indicating further areas to coordinate and support the DSO transition	We have reviewed all the DSO strategies and offered bilateral meetings with all DNOs to provide feedback. We have also provided feedback to Ofgem as part of their RIIO-ED2 call for evidence.
Develop Regional Development Programmes (RDPs)	How are all these activities making any impact with the developer like solar, battery? Will these help anyway to NG and DSO move away from the pessimistic deterministic network assessment? Will it accelerate new connection i.e. earlier connection date by having the actual view of the constraint?	The regional development programmes are our way of unlocking additional regional capacity, through new approaches and services. Our RDP development work explores a range of options to facilitate the connection of DER. This includes reviewing the underlying assumptions in network design processes. In 2021-22 we have commenced new works in East Anglia, South Wales and the North East..
Develop Regional Development Programmes (RDPs)	When will the new MW Dispatch or Transmission Constraint Management product launch?	The first MW dispatch project, in the south west of England, is due to be released later this year.

Network Access Planning

Area	Stakeholder feedback	Action taken by the ESO
eNAMS	There was some frustration expressed around the eNAMS roll out delays.	Since eNAMS go-live in September last year, we secured funding to finance 5 months' development and 2 releases into production of eNAMS enhancements. We have had weekly engagement calls scheduled with the three main on shore TOs; NGET, SP and SHET and with representatives from the TNCC and ESO's ENCC. Through these calls, we encouraged eNAMS users to submit requests for enhancements to the product to improve efficiency and reduce risk in areas of confidentiality, business process and transmission system operation. Prioritising the enhancement requests we received, we populated a total of 5 separate updates with enhancement requests. The first two updates were released successfully into production in February with the latest updates released on 07 April 2022.

Activities outside the Delivery Schedule

Early Competition

Stakeholder feedback	Action taken by the ESO
Some potential bidders questioned whether the ESO is sufficiently independent from National Grid Group to be able to run the tender process	Determining who should run early competition tenders is ultimately a matter for BEIS. Ofgem have indicated their view is that the ESO is likely to be the most appropriate body. This is an important consideration within the Future System Operator work.
Some TOs felt the proposed implementation timescale is too tight, while some potential bidders felt the timescales are too long.	In order to facilitate the prompt implementation of Early Competition where we can, the ESO has been progressing low regrets activity ahead of Ofgem's decision to proceed. We have also been utilising our existing NOA Pathfinder procurement processes to begin introducing some elements of the Early Competition model. Furthermore, we prepared mobilisation of an implementation team in order to progress as soon as Ofgem made a decision. Our implementation plan also seeks to progress activity as far as possible ahead of legislation in order to move forward quickly once legislation is in place. Now we have a decision from Ofgem we will involve TOs in relevant aspects of our implementation planning.
Some potential bidders felt TOs should not have a role in network planning if they are providing solutions as part of early competitions and that the ESO should undertake this role instead. TOs however, felt that it is important that they retain a role in planning the networks they own.	The TO role in Early Competition was debated extensively during the development of the Early Competition Plan, including with our stakeholder group. Ofgem have been considering roles and responsibilities for network planning as part of their Network Planning Review.

Offshore coordination

Stakeholder feedback	Action taken by the ESO
They would value more timely and transparent communication on timelines for the Offshore Coordination project.	Provided greater visibility of our project activities and opportunities for engagement. Examples from the last three months include: • communicating updates via the ESO Offshore Coordination website, supported by six updates to our mailing list of 300 stakeholders. Our website has had 3,300 page views and 580 document downloads (1 November 2021 – 31 January 2022). • stakeholders across the industry. • Facilitating eight workshops with more than eighty external industry participants, relating to potential code modifications, Offshore Transmission Owner (OFTO) connections and the electrification of oil and gas platforms. • Participation in the BEIS-led Offshore Transmission Network Review (OTNR) industry wide webinar and on a panel at the Global Offshore Wind Conference in September 2021. We will continue to provide regular updates on relevant topics. We have also committed to responding to queries in a timely manner, providing regular updates and reasons for any delays.

<table>
<tr><td></td><td>Be clear and transparent with our messages, providing context on how a decision has been made, and the roles and responsibilities of those involved.
We have published our Holistic Network Design (HND) Methodology document, providing an overview of our approach to how we will deliver the HND.
We have set up a Developer Forum to inform and engage developers in scope of the HND, to ensure timely and consistent messaging across a volume of developers in a short period of time and utilise the expertise of developers in scope.
We will continue to work with the OTNR project partners to agree and publish the terms of reference for delivering the Holistic Network Design as the foundation for the decisions we make.
As mentioned above, we have published our responses to recent Offshore Coordination consultations to give stakeholders visibility of our views and positions on relevant topics.</td></tr>
<tr><td>ESO could demonstrate greater empathy for and understanding of stakeholders and the impact of the project on their businesses.

Striking the balance between leading industry change and utilising the existing expertise of stakeholders; and</td><td>We plan to engage with industry to develop a deeper knowledge of businesses, seeking to understand early on the potential impact of our activities, and what type of communication is most valuable.</td></tr>
<tr><td>ESO could play a greater role in helping stakeholders to understand how the project’s workstreams interact with each other and wider industry activities.</td><td>We will provide greater visibility of how the elements of the Offshore Coordination project fit together, how and where they sit within the OTNR, and how they relate to other work being undertaken by the ESO.</td></tr>
</table>

C.4 Demonstration of Plan Benefits for Role 3

The fourth evaluation criterion for the ESO incentive scheme is Demonstration of Plan Benefits, where the Performance Panel will consider the actual benefits the ESO has realised from delivering its Business Plan, or any outputs additional to the Business Plan.

At the time of publishing our original RIIO-2 Business Plan in December 2019, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the RIIO-2 Business Plan. The relevant CBAs for Role 3 are:

- Network Options Assessment (NOA) enhancements (A8-A11)
- Taking a whole electricity system approach to connections (A14)
- Taking a whole electricity system approach to promote zero carbon operability (A15)
- Delivering consumer benefits from improved network access planning (A16)

In this section, we provide a progress update for each of the activities for which we originally provided a Cost-Benefit Analysis, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence, and describing any sensitivity factors which would impact on the delivery of the stated benefit. Deliverable activity statuses reflect the delivery of RIIO-2 milestones and do not recognise either work completed prior to April 2021 nor progress made towards yet to be completed milestones.

We also provide a specific case study to the **Stability Pathfinder phase 2**, which was not covered by the original Cost-Benefit Analysis document.

The Panel will also consider the ESO's Regularly Reported Evidence (RRE) as part of the Demonstration of Plan Benefits criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the ESORI guidance. For Role 3, the items of RRE reported in our mid year 2021-22 report are:

- 3A. Future Savings from Operability Solutions
- 3B. Consumer Value from the NOA
- 3C. Diversity of Technologies Considered in NOA

CBA: Network Options Assessment (NOA) enhancements (A8-A11)

Benefit described in RIIO-2 business plan

"The net-present value of our A8 - A11 NOA enhancements activities is £663 million over the RIIO-2 period and £1.3 billion over ten years. Sensitivity analysis suggests an NPV range of £463 million to £906 million over the RIIO-2 period.

Our proposed investment in extra resources at the start of BP1 will enable us to support at least twice as many tenders. It will ensure (parties who may submit an option) receive a quality service that encourages them to participate, offer and deliver competitive solutions. Solutions that will ensure we have a network that is always ready for the demands placed on it and can operate securely as we transition to a zero-carbon electricity system. The £429 million gross benefit has been calculated by comparing the outputs of the NOA process with and without commercial solutions added in. We have used historic costs of previous commercial solutions as the benchmark for our analysis. This is against a baseline assumption of the current NOA process, without commercial solutions and only current network solutions considered, in line with our licence conditions."

Role

3. System insight, planning and network development

ESO Ambitions

- An electricity system that can operate carbon free
- A whole system strategy that supports net zero by 2050
- Competition Everywhere

Key RIIO-2 Deliverables and progress

Activity A8.1 - Rollout of pathfinder approach and optimise assessment and communication of future needs

Deliverable	Status
D8.1 New areas of need identified, and 3-6 tenders run.	50% complete 10% delayed 40% on track

Activity A8.2 - Enhance tendering models

Deliverable	Status
D8.2 Improved tender approaches that enable more participants to enter the market.	50% complete 50% on track

Activity A8.3 - Support Ofgem to establish enabling regulatory and funding frameworks

Deliverable	Status
D8.3 Frameworks based on competitive regime not monopoly regime.	70% complete 30% on track

Activity A9.1 - Expand network planning processes to enable more connections wider works to be assessed

Deliverable	Status
D9.1 Developed and trialled connection wider works (CWW) processes with TOs.	30% delayed 70% on track

Activity A9.2 - Trial assessment of all connection wider works in one region

Deliverable	Status
D9.2 Completed and published connection wider works trials, in selected geographic regions, in NOA.	50% delayed 50% on track

Activity A9.3 - Expand to all Connections Wider Works (CWW)

Deliverable	Status
D9.3 Incremental expansion of the process (following trials) which results in making recommendations on all connections wider works in NOA 2026.	100% on track

Activity A9.4 - Develop process with TOs to input into ESO analysis of end of life asset replacement decisions

Deliverable	Status
D9.4 Efficient planning process agreed with TOs	100% on track

Activity A10.1 - Support DNOs to develop NOA type assessment processes

Deliverable	Status
D10.1 NOA expertise shared with DNOs	50% complete 50% on track

Activity A11.1 - Refresh and integrate economic assessment tools to support future network modelling needs

Deliverable	Status
D11.1 Improved identification of when is the most economical time to invest and the most efficient solution	25% complete 50 % delayed 25% on track

Activity A11.2 - Implement probabilistic modelling

Deliverable	Status
D11.2 Improved identification of network needs	50% complete 50% on track

Activity A11.3 - Build voltage assessment techniques into an optimisation tool

Deliverable	Status
D11.3 Improved assessment of voltage requirements, and ability to look across a range of network needs at the same time	20% complete 80% on track

Activity A11.4 - Build stability assessment techniques into an optimisation tool

Deliverable	Status
D11.4 Improved assessment of stability requirements across the network.	20% complete 20% delayed 60% on track

Benefits to be realised

Forecasted in original CBA:

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Consumer benefit of implementing commercial solutions	127.5	60.8	94.9	81.1	64.4	428.8
Extending NOA to end of life asset replacement decisions	0	0	29.5	29.5	59.0	118.0

Extend NOA approach to all connections wider works	0	37.0	37.0	37.0	37.0	148.0
Support decision making for investment at the distribution level	0	0	10.0	10.0	10.0	30.0

Once the commercial solution has been given a recommendation in the NOA, the constraint management pathfinder (CMP) identifies a route to deliver the benefit. Presently the B6 CMP has completed the tender and contract award for generators based in Scotland who can be intertripped in the event of a constraint on B6 and the results are published here[48]. Once the infrastructure needed to deliver this the pathfinder is built by the transmission owners, the savings can be realised however, presently the forecasted savings if all of the commercial solutions are delivered could be about £127.5M.

Related metrics/ Regularly Reported Evidence

Metric/RRE	Impact on metrics/ RREs	Status
Metric 2A Competitive Procurement	We would expect to report a higher percentage of competitive procurement than would otherwise be the case	51% of all services procured through competitive means (meeting expectations)
RRE 3A Future savings from Operability Solutions	We would expect enhancements to the NOA to lead to a higher consumer benefit being reported under RRE 3A (for Pathfinders)	£27m saved balancing costs in 2021-22, £13m saved infrastructure costs for each of RDPs 1 and 2, carbon reductions of £66m from pathfinders (2020-21 to 2024-25) and £42m from RDPs
RRE 3B Consumer Value from the NOA	We would expect enhancements to the NOA to lead to a higher consumer benefit being reported under RRE 3B (for other NOA processes).	£208m from ad-hoc CBAs, NOA consumer benefit £429m
RRE 3C Diversity of Technologies Considered in NOA	As we remove barriers to entry for pathfinders, we would also expect to report greater diversity of technologies	136 asset-based solutions (including 22 new options) and 8 commercial solutions submitted to NOA 2021/22. A wide range of solutions were considered in NOA pathfinders

[48] https://www.nationalgrideso.com/document/247836/download

Sensitivity factors (description)	Assumption	Current status	Commentary
	Facilitate competition by embedding pathfinding projects into the NOA		
	Generic intertrip solution cost	Used costs from CMP B6 2023-24 tender in NOA7	Consumer benefit expected to be in line with original assumptions
	Commercial solutions provide 1000MW from FY24 onwards	Procurement of 1,7GW usable from 1st October 2023	Consumer benefit expected to be in line with original assumptions
	Extending NOA to end of life asset replacement decisions		
	TOs provide asset replacement data	This activity is planned later in BP1	No update: benefit still as expected
	Greater information provision will help the decision-making process	This activity is planned later in BP1	No update: benefit still as expected
	Extend NOA approach to all connections wider works		
	TO will complete additional work through studying more boundaries and creating more options	This activity is planned later in BP1.	No update: benefit still as expected
	We will find issues on the newly-created boundaries. We may find no issues, resulting in no benefits because no actions would be needed	This activity is planned later in BP1	No update: benefit still as expected
	Support decision making for investment at the distribution level		
	Expected level of investment at the 132kV level is £40 million per year	This activity is planned later in BP1	No update: benefit still as expected
	60% of investment options would be on the optimal path	Based on latest NOA data this remains accurate	Consumer benefit expected to be in line with original assumptions
	DNOs can take commercial actions against network costs	This assumption is still considered appropriate	Consumer benefit expected to be in line with original assumptions

Summary

Our deliverables are generally proceeding to plan, and we would therefore expect to deliver the consumer benefits originally set out. NOA consumer value in RRE 3B provided as part of the 2021-23 mid scheme report.

We have concluded the Constraint management B6 tender and have published the results. We have included the costs from this tender in the NOA assessment and have updated the NOA methodology to reflect this.

The total benefit reported of £429m across the RIIO2 period was based on NOA 2018-19 data. The NOA 2021-22 data shows a gross benefit of at least £212m, over the RIIO-2 period. We undertake the NOA process each year which provides an updated set of investment recommendations, and this will be reviewed annually. Our proposed investment in extra resources at the start of BP1 will enable us to support at least twice as many tenders.

CBA: Taking a whole electricity system approach to connections (A14)

Benefit described in RIIO-2 business plan	"We estimate the gross benefits to be £8 million over RIIO-2. This gives a net present value of £2 million over RIIO-2. Our proposal enhances and extends our current connections processes. It establishes new online systems to provide more support in coordination with distribution network organisations for parties wishing to connect to networks. They will benefit from easier access to front-line support and coordinated information, making it simpler to navigate around complex industry processes. These quantitative benefits have been calculated by considering the efficiency savings for customers who use the connections process (estimated at around 450 applications per year) and the resulting reduction in FTE requirements, with these savings being passed on to consumers. This is against a baseline assumption of continuing with our ongoing connections process, with no additional online support or connections hub. In order to deliver this activity, we will require customers to engage with the new hub and systems and that connections customers pass any reduced operational costs onto consumers. Our analysis suggests that accounting for market, delivery and third-party uncertainty the net present value could credibly be between -£2 million and +£3 million."
Role	3. System insight, planning and network development
ESO Ambitions	• Competition Everywhere • The ESO is a Trusted Partner
Key RIIO-2 Deliverables and progress	

Activity A14.1 - Provide contractual expertise and management of connection contracts including provision of connection offers to customers

Deliverable	Status
D14.1.1 Managing an increasing volume of connection offers for customers	Continuous activity
D14.1.2 Compliance monitoring of new connections in accordance with Grid Code provisions	Continuous activity

Activity A14.3 - Further enhance the customer connection experience, including broader support for smaller parties

Deliverable	Status
D14.3.1 Establish dedicated Distributed Energy Resource (DER) account management function	50% complete 25% delayed 25% on track

Activity A14.4 - Facilitate development of the customer connections hub

Deliverable	Status
D14.4.1 Implement first phase of the ESO connections hub, including online account management and integration with other network organisation websites	35% complete 15% delayed 50% on track
D14.4.2 Phase 2 of the connections hub concluded	100% on track

Benefits to be realised	**Forecasted in original CBA:**

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
ESO and customer efficiency saving	0.6	0.7	1.0	1.4	4.4	8.1

The benefits for 2021-22 will be realised in the next financial year as portal delivery of stage 1 is delayed.

Related metrics/ Regularly Reported Evidence N/A

Sensitivity factors (description)

Assumption	Current status	Commentary
The number of connection applications grows 8 per cent per year	We are still seeing a continual increase in connection applications. There has been a 20% year on year increase between 2017/18 and 2020/21. This year has seen a + 40% increase in connection applications on 2020/21 levels.	A large number of recent applications are for new, smaller scale and flexible energy storage projects. Consumer benefit expected to be higher than original assumptions
Roll out of our secure online account management (Customer Portal) facility in April 2025 brings a 30% cost saving	Customer Portal Phase 1a release has been pushed back from April 22 to July 22 to enable the first release to provide a more complete and enhanced experience to Customers on using the Portal, instead of initial limited system usability. The Project is still on track for complete Phase 1 Delivery by end of FY23 / BP1	Consumer benefit expected to be in line with original assumptions
Information across the transmission distribution interface will reduce our direct resource requirements by 10% from 2022	This is associated with delivery of Phase 2 of Customer Portal, due in FY24 and FY25	There is a dependency on being able to create platforms for communication between Transmission and Distribution Organisations to enable data reporting. We hope to be able to realise consumer benefit by enabling data to be improved and find fit for purpose data platforms that deliver on value but which don’t attract increase in expenditure with IS Project

Summary	On Customer Portal, following a review of the product that would be ready for delivery to Customers in December 2021, we took the decision to delay the first stage from April to July 2022 so we could: • provide a product that would meet Customers expectations • enable a more complete experience as part of the application process, as initial plans were only going to see part of the process going live due to delays at design stage • enable more time spend on User Acceptance Testing and Focus Groups to improve product ahead of delivery The Customer Portal is still on track to complete Phase 1a and 1b delivery by end of BP1 (2022-23) as per original programme. The assumptions originally made regarding the increase in customer connections applications have increased from an average growth of 8% to over 49% in 2021-22. However, this has no impact on delivering the overall benefit. Total of connections received in 2021-22 was **1102.** The increase in workload has been sustained all throughout 2021-22 and we have seen further increase in the change to existing connection contracts to accommodate co-location / mix in technologies. Our response to this sustained increase and complexity was as follows: • Engagement with TOs to provide early visibility of the trends in the increase in the applications, identify peaks of workload and define strategies that address peaks and identify risks to ESOs ability to meet licence conditions whilst ensuring that the quality of the connection customer offer is not compromised [in December 2021 a bulk Licence Condition for Sec 8 was provided due to NGETs delay to supply to TOCO on time] • We are also working with OFGEM to address the challenges the increase in workload and number of Connections Applications to look at ways to create an alternative License Condition extension process • We are developing a new Pre-Application Process that enables change to a standard approach to Pre-Application across GB TOs and lead by ESO – this will look to improve response time and prevent or reduce speculative applications • The Connections Team Structure has been changed and number of FTEs increased, and continues to increase Concerns persist with regards to TOs performance on supply of TOCOs within STC timescales and quality of the information supplied in the TOCOs. We are looking at Ways of Working and opportunities to enable improvement prior to undertaking a review and reform of the Connections Process.

CBA: Taking a whole energy system approach to promote zero carbon operability (A15)

Benefit described in RIIO-2 business plan	“We estimate the gross benefits in this area to be £548 million over RIIO-2. This gives a net present value of £466 million over RIIO-2. This is from quantifying benefits in two areas, RDPs and conducting a whole system operability NOA-type assessment. Regional Development Programmes (RDPs) RDPs provide significant value in this area. For future RDPs, we have assumed they deliver the same benefit from avoiding build costs as the RDPs in RIIO 1. This is £13 million and the carbon savings from the extra renewable generation of 278 MW. We have avoided ‘double counting’ by assuming half the RDPs have avoided build savings with the other half achieving carbon savings. This is against a baseline assumption of operating the system as today and not embedding RDPs. This gives gross benefits of £39 million over RIIO-2. More broadly, our responsibilities for system operability mean that we need to ensure we are looking for new ways of sourcing system needs. Increasingly we are considering market-based solutions and in a decentralised and digitalised future this provides many new opportunities. Examples of this work include Power Potential, where we are working with UK Power Networks to develop a coordinated market solution for transmission and distribution voltage needs. We are also exploring new markets through our voltage and stability pathfinder projects. Whole system operability NOA-type assessment The quantitative benefits for this area have been calculated by first considering the EFCC innovation, which forecasts benefits of £420 million over the RIIO-2 period. This gives a benchmark as to the scale of the benefits we could find in whole system operability. As EFCC provides a single aspect of system operability this CBA looks more generally at how system operability can be improved. This is by considering the cost of the current operability challenges, of around £600 million. As an example, in our recent stability pathfinder we estimate that these challenges could be solved with an investment of £2.25 billion. We further assume that this cost will be spread over a potential 40-year asset life, which leads to a discounted net benefit of around £10 billion over 40 years. To reflect the uncertainty here, we have assumed that 50 per cent of these net benefits are realised, giving £125.5 million a year net benefits from 2022/23, which equates to £503 million over RIIO-2. This is commensurate with the EFCC benchmark. Our work in this area depends on two other transformational activities: • A1 Control Centre architecture and systems (Theme 1) – ensuing the Control Centre has the tools required to operate a zero carbon system • A4 Build the future balancing service and wholesale markets (Theme 2) - ensuing the new markets have been developed to support zero carbon system operation In order to deliver in this area, we require third parties to deliver solutions, which could either be investment in assets or commercial solutions. Our analysis suggests that accounting for market, delivery and third-party uncertainty the net present value could credibly be between £331 million and £603 million.” No change since our last analysis.
Role	3. System insight, planning and network development
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050 • Competition Everywhere
Key RIIO-2 Deliverables and progress	**A1.1.Ongoing activities**

Deliverable	Status
D1.1.6 Assessment of future operability challenges communicated through the Operability Strategy Report	Continuous activity

Activity A4.6 - New services market development

Deliverable	Status
D4.6.1 Development of competitive approaches to procurement of stability	70% complete 10% delayed 20% on track
D4.6.2 Development of competitive approaches to procurement of reactive power	70% complete 30% on track

Activity A15.1 - Develop the System Operability Framework (SOF) and provide solutions up to real time of network related operability issues.

Deliverable	Status
D15.1.1 System Operability Framework (SOF) documentation	100% complete
D15.1.2 Innovation projects developing new operability solutions	100% on track

Activity A15.3 - Assess the technical implications of framework developments and implement changes into business procedures and systems.

Deliverable	Status
D15.3.2 Lead the Loss of Mains Protection setting programme	50% complete 50% on track

Activity A15.5 - Develop Regional Development Programmes (RDPs)

Deliverable	Status
D15.11.1 Forward Plan 2020-21 RDP – N3	100% complete
D15.11.2 Forward Plan 2020-21 RDP - Generation Export Management Scheme (GEMS)	100% delayed
D15.5.1 Start RDP1 of RIIO-2	70% complete 30% on track
D15.5.2 Start RDP2 of RIIO-2	70% complete 30% on track
D15.5.3 Start RDP3 of RIIO-2	100% delayed
D15.5.4 Start RDP4 of RIIO-2	30% complete 70% on track
D15.5.5 Development of roadmap to deliver GB rollout of functionality (visibility & control of DER) developed through initial RDPs.	50% complete 50% on track

Activity A15.7 - Deliver an operable zero carbon system by 2025

Deliverable	Status
D15.7.1 Commence System State Targeted Monitoring and Control System (MCS) stage roll out[49]	50% complete 50% delayed

[49] Note that the MCS project builds on the EFCC project referred to above. This is also linked to investment 500 "Zero Carbon Operability".

	Activity A15.9 - Identify Future operability needs across whole energy system

Deliverable	Status
D15.9.1 Trial new innovation projects for whole energy system operability	50% complete 50% on track

Benefits to be realised

Forecasted in original CBA: Whole system operability NOA-type assessment

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26
Operability savings	0	125.8	125.8	125.8	125.8

Forecasted in original CBA: Regional Development Programmes – Asset savings

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Asset Saving	No RDP	12.9	No RDP	12.9	12.9	38.7

Benefits are realised at the time when an RDP is sufficiently developed that it has a clear solution to facilitate DER connection and an identification of capacity released. We are currently working in a number of regional areas on new RDP capability which we anticipate will release benefits in 2022-23.

Related metrics/ Regularly Reported Evidence

Metric/RRE	Impact on metrics/ RREs	Status
Metric 1A Balancing Costs	Progress on Whole System Operability will lead to savings in balancing costs- leading to improvements in the long term.	£3,132m vs benchmark of £1,321m (below expectations)
RRE 1I Security of supply	Successfully addressing operability needs should enable us avoid voltage excursions, avoiding a deterioration in performance	0 incidents
RRE 1F Zero Carbon Operability indicator RRE 1G Carbon intensity of ESO actions	Progress on Regional Development Programmes and operability solutions will both lead to carbon reductions. This will be reported under RRE 3A (in the short term). This will also make it easier to operate a low carbon system, leading to improvements in RREs 1F and RRE 1G as the ESO will be able to operate the system with a high proportion of renewable generation, without taking actions for operability reasons which lead to increased carbon emissions.	ESO has accommodated up to 87% zero carbon generation Monthly average of 5.2 gCO2/kWh of actions taken by the ESO

Metric 2A Competitive Procurement	Lead to increased competition for operability needs, which will lead to improvements in the long term	51% of all services procured through competitive means (meeting expectations)
RRE 2B Diversity of service providers	Where these activities lead to operability needs being provided by different technologies, this will lead to improvements	Significant changes in STOR and DC
RRE 3A Future Savings from Operability Solutions	Progress on Whole System Operability will lead to savings in balancing costs- leading to improvements in RRE 3A in the short term Progress on Regional Development Programmes will lead to savings in infrastructure costs, which will be reported under RRE 3A (in the short term), and flow through to lower transmission and distribution network charges in the future	£27m saved balancing costs in 2021-22, £13m saved infrastructure costs for each of RDPs 1 and 2, carbon reductions of £66m from pathfinders (2020-21 to 2024-25) and £42m from RDPs
RRE 3C Diversity of technologies considered in NOA processes	Where these activities lead to operability needs being provided by different technologies, this will lead to improvements	136 asset-based solutions (including 22 new options) and 8 commercial solutions submitted to NOA 2021/22. A wide range of solutions were considered in NOA pathfinders

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Sensitivity factors (description)

Whole system operability NOA type assessment

Assumption	Current status	Commentary
Forecast operability costs of £596 million per year	Current operability costs are lower than forecast ~£410m in 2020/2	Operability challenges are expected to increase year on year due to the changing system conditions.
Cost of a 0.2 gigavolt ampere (GVA) solution is £25 million (£125m/GVA)	In the Phase 1 Stability Pathfinder, 12.5 GVA of additional inertia was procured for a cost of £328m (£26.4m/GVA).	Operability solutions are cheaper than anticipated, leading to a higher consumer benefit.

Benefits of RDPs

Assumption	Current status	Commentary
Value of RDP avoided asset build is £12.9 million	This is still our most recent assessment	Consumer benefit expected to be in line with original assumptions
Additional renewable capacity unlocked by each RDP is 278 MW	RRE 3A states the following DER capacities have been unlocked by each RDP: WPD	This suggests that each RDP unlocks on average 1170MW,

	MW dispatch: 1544MW UKPN MW dispatch: 797MW	leading to a higher consumer benefit.
Carbon intensity assumption from FES 2019 Steady Progression	Carbon intensity from FES 2021 Steady Progression are between 20 and 50g CO2/kWh lower	This reduces the estimated benefit from £7m to £4.5m. It would be offset by any increase to the carbon price (see below).
Six RDPs will be delivered over the RIIO-2 period	This is still our intention; RDP3 has been rephased to align with RP4 delivery. There is no operational driver to complete earlier and project delivery will be more efficient with both projects developed in parallel.	Consumer benefit expected to be in line with original assumptions
BEIS short-term traded carbon values	In line with assumptions[50]	See footnote

General

Third parties contribute to asset/commercial solutions	We are working collaboratively with third parties to ensure delivery ahead of system need	Consumer benefit expected to be in line with original assumptions

Summary

RDPs remain on track to deliver the benefits originally set out, although RDP3 has been realigned to be delivered in parallel with RDP4. There is no driver to complete this work to the earlier timescale, and alignment of two projects will reduce overall ESO delivery costs.

For the Whole system operability NOA type assessment, our projects are on track, and we are looking to refresh the assessment next year when our solution design for Enhanced Frequency Control Capability (EFCC) is completed.

[50] 0 BEIS has not provided an update to its carbon prices for modelling purposes. It has, however, updated its carbon prices for policy appraisal. For 2020 to 2030, these are between three and 20 times larger than the previous values. If similar updates to the modelling figures are updated, it will significantly increase the estimated benefit from our RDPs.

CBA: Delivering consumer benefits from improved network access planning (A16)

Benefit described in RIIO-2 business plan	"We estimate the gross benefits to be £224 million over RIIO-2. This gives a net present value of £204 million over RIIO-2. Our proposal will bring significant benefits. For example, transmission and distribution connected parties will receive better notification of planned outages and their impacts on the networks. DNOs, meanwhile, will benefit from increased liaison, including greater procurement and coordination of flexibility services from DER. The quantitative benefits stated above have been calculated by taking the benefits realised though rolling this proposal out through Scotland then extrapolating that the percentage savings across England and Wales. This saving has been calculated at 11.5 per cent. Taking these percentage savings, we then used forecast constraint costs from NOA for England and Wales to estimate the consumer benefits. Further benefits could potentially be derived from extension of Network Access Planning (NAP) process across transmission and distribution. This is against a baseline assumption of not rolling out the STC cost recovery mechanism to England and Wales. This activity requires code modifications and financial arrangements to be in place to support it. We also require DNOs and TOs to engage with the new process, for which there may be a cost to implement the new arrangements. Our analysis suggested that accounting for market, delivery and third-party uncertainty the net present value could credibly be between £310 million and £98 million."
Role	3. System insight, planning and network development
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050 • Competition Everywhere

Key RIIO-2 Deliverables and progress

Activity A16.1 - Manage access to the system to enable the TOs to undertake work on their assets, liaising with customers where access arrangements impact them.

Deliverable	Status
D16.1.2 Detailed week and day ahead operational documentation produced for National Control	Continuous activity

Activity A16.2 - Enhance the Network Access Policy (NAP) process with TOs

Deliverable	Status
D16.2.1 GB wide NAP process goes live including extension of the existing SO-TO payment mechanism to the whole of GB.	50% complete 20% delayed 30% on track

Activity A16.3 - Work more closely with DNOs and DER to facilitate network access

Deliverable	Status
D16.3.1 Conclude trials on closer working relationships with DNOs and DER	100% complete
D16.3.2 Learnings from trials shared alongside recommendations for GB roll out such that best practice is applied to ongoing processes	70% complete 30% delayed

D16.3.3 Finalise new processes in readiness for approval of code modifications to facilitate closer working relationships and data exchange/modelling. This will ensure that frameworks support any new enduring processes developed in A16.3.1 and A16.3.2	30% complete 70% on track
D16.3.4 Deeper access planning go-live	50% complete 50% on track

Activity A16.4 - TOGA / Whole system outage notification

Deliverable	Status
D16.4.1 Scoping exercise concluded for delivery of enhancements to outage notifications	25% complete 25% delayed 50% on track

Benefits to be realised

Forecasted in original CBA:

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Consumer savings based expanding the process into England and Wales with a 11.5% reduction.	40.0	36.3	41.7	49.2	56.7	224.4

Our original CBA stated that benefits associated with activity A16 will start to be delivered from 2021/22. In the period, the delivery of milestone A16.2 has provided a GB wide Network Access Planning Policy and rolled out the benefits of STCP11.3 and STCP 11.4 across England and Wales. The constraint costs for England and Wales in 2021/22 amount to £137m. This is a 39% reduction against £225m that was spent in 2020/21 and a reduction overall of £88m.

Related metrics/ Regularly Reported Evidence

Metric/RRE	Impact on metrics/ RREs	Status
Metric 1A Balancing Costs	We expect this to lead to lower constraint costs than would otherwise be the case	£3,132m vs benchmark of £1,321m (below expectations)
RRE 1H Constraints Cost Savings from Collaboration with TOs	We would expect this to improve because more than four enhanced service provisions from TOs through STCP 11.4 have progressed that are expected to provide constraint cost savings this year.	Constraints cost savings from collaboration was £1,938m

Sensitivity factors (description)

The ability of the DNOs to resource the activities required for enhanced data transfer should be noted as a sensitivity. DNOs are at varying levels of maturity with their engagement with DSO transition and deeper access engagement. The progress with the trial DNOs is showing positive results but draft code modifications are not due to take place until 2022-23.

The TOs' ongoing engagement with the enhancements to the Network Access Planning (NAP) policy is a sensitivity but has been shown to be positive to date.

Assumption	Current status	Commentary
England and Wales constraint costs of average £380m per year over the RIIO-2 period	E&W Constraint costs during 2021-22 were £137m excluding the B6 constraint boundary	Consumer benefit expected to be higher than original assumptions

Code modifications and financial arrangements are in place	The code modifications and financial arrangements for activity A16.2.1 implementing a GB wide NAP process including extension of the existing SO-TO payment mechanism to the whole of GB are complete.	Consumer benefit expected in line with original assumptions
DNOs and TOs engage with the new process	All DNO parties have been initially engaged with positive feedback, and a follow up with two DNO partners is organised for the end of April 2022. The engagement plan will continue to October 2022 to develop the new process through three customer journey iterations.	Consumer benefit expected in line with original assumptions

Summary

The activities in relation to A16.2 and the roll out of the Network Access Planning Policy to England and Wales have contributed to a constraint cost saving within the England and Wales area during the period of £88m.

Furthermore, the improvement of the activities around D16.4.1 coupled with the progress made with A16.3 are still expected to realise the consumer saving of £224m.

The Network Access Planning team made good progress this year, the team in collaboration with our stakeholders (TOs and DNOs) identified and recorded over 190 instances where its actions directly resulted in adding value to end consumers and its innovative ways of working facilitated increased generation capacity to connected customers. This amounted to just over 24,000GWh which can be assumed equivalent to approximately £1.8bn of savings.

During 2021/22 we have therefore seen an uplift in Customer Value Opportunity (CVO) constraint cost savings with 45% increase in savings from 16,940GWh in 20/21 to 24,613GWh in 21/22 which can be assumed equivalent to over £600m in constraint cost savings across activities.

Such actions include moving outage dates; splitting outages; reducing return to service times; obtaining enhanced ratings from TOs; re-evaluating system capacity; identifying and facilitating opportunity outages; outage duration reductions; aligning outages with customer maintenance and generator shutdowns; proposing and facilitating alternative solutions for long outages that impact customers; and many more.

Consumer benefit case study for Role 3: Stability Pathfinder phase 2

Activity	The commercial submission window for the Stability Pathfinder Phase 2 opened on 9 November. Phase 2 sought to procure additional volumes of inertia, short circuit level and fast acting dynamic voltage support across Scotland between 2024 and 2034. The tender stage was the final step in the Phase 2 process following the completion of the Expression of Interest and Feasibility Study stages in 2021-22. These previous steps allowed interested participants to submit and demonstrate the capability of their proposals and also allowed them to provide feedback on various documents. On 06 April 2022 we announced we have secured long-term stability to the electricity system in Scotland through world-first use of technology which will help manage growing wind farm capacity and help facilitate the transition to green energy. Following a successful tender, the ESO has awarded 10 contracts to four companies, the tender attracted 225 proposals from 21 separate companies. The bids chosen will deliver 11.55 GVA (Giga Volt Ampere) of SCL and 6.75 GVAs (Giga Volt Ampere seconds) of inertia worth a total of £323 million which provide net zero solutions to stability issues. The imminent closure of nuclear power stations in Scotland and northern England, and the rising number of onshore and offshore wind farms in Scotland, will lead to a loss of inertia which poses a potential stability risk as inertia is needed to maintain frequency on Britain's electricity system. The winning 10-year contracts, starting in April 2024, will solve this issue in two ways. They will primarily solve insufficient Short Circuit Levels (SCL) - the amount of current that flows on the system during a fault - in various locations across Scotland. They will also provide a "green" form of inertia to help keep the electricity system stable, such as after a rare trip at a large power station. Previously, inertia has been provided by coal or gas power plants but the ESO is now procuring inertia from carbon-free sources, which is not only significantly cheaper for consumers, but allows for greener system operation and more renewable energy to run. The green solutions will provide the equivalent combined SCL and inertia of almost four coal-fired power stations. Five of the successful solutions are synchronous condensers – 'green' motors with free-spinning flywheels which boost inertia and SCL. The other five solutions will comprise what is thought to be a world-first use of new grid forming converters at multiple locations across a region to improve inertia and SCL when disturbances occur in the electricity system. Grid forming converters allow for a non-synchronous technology, such as batteries, wind, and solar to connect to the system, and mimic the effect of a power station but without using fossil fuels to provide inertia and SCL. This is particularly significant as assets, that would already be connecting to the network to provide low carbon electricity or other ancillary services, with some adaption, can provide stability services. This is likely to reduce the amount of additional connections that are needed to accommodate these services (connection requests are currently significantly over subscribed) as well as creating greater competition and potentially a lower price point for the delivery of the stability service. This in turn is likely to benefit end consumer costs
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050 • Competition Everywhere
Key RIIO-2 Deliverables	D4.6.1 Development of competitive approaches to procurement of stability
Is the consumer benefit mainly this year or in future years?	The benefit is for future years over the contract length period of 2024 – 2034.
Calculation of monetary	Potential costs savings of £130m has been achieved compared to TO counterfactual solution spend over the contract length. This is the net present value resulting from comparison of the cost of the awarded pathfinder contracts to a hypothetical TO-asset based solution, with

benefit to consumers	additional options extrapolated from the TO options submitted as a counterfactual to the pathfinder process.
Assumptions made in calculating monetary benefit	The tender process did not see TO counterfactual solutions submitted for all locations of needs. Therefore, the hypothetical TO-only solution was based on the assumption that similar sized machines at different locations in Scotland would cost a similar amount to the actual options submitted by SPT to the pathfinder. It was also assumed these could be placed in effective locations, using substations where other non-TO options were proposed. The estimate is uncertain due to the lack of more specific data on TO costs.
How benefit is realised in the consumer bill	The Stability Pathfinder will lead to savings in BSUoS charges, due to reduced balancing costs that otherwise would have been incurred because of control room mitigating actions.
Non-monetary benefits	Phase 2 procurement supports our 2025 ambition to have an electricity system that can operate carbon free by reducing the need to pay carbon-intensive synchronous generation to come on in place of renewable non-synchronous generation- thereby contributing to reduced environmental damage. By increasing regional SCL in Scotland, Phase 2 solutions will enable connection of more renewable non-synchronous generation in Scotland. Phase 2 is procuring the equivalent inertia and SCL as that provided by approximately 4 coal fired power stations.
Assumptions made in calculating non-monetary benefit.	Ability of the Scottish transmission system to remain stable after expected nuclear power station closures in Scotland and northern England. **Improved safety and reliability:** Phase 2 solutions will improve system performance by increasing system inertia and allow cost effective management of stability in Scotland. **Reduced environmental damage:** All Phase 2 solutions are carbon free and will allow connection of more renewable generation such as wind in Scotland and further lower the carbon savings **Improved quality of service:** Phase 2 solutions will enable renewable generation and other users of the network to remain stable under different network conditions.

Regularly Reported Evidence for Role 3

Summary of RREs for Role 3

Table 23: Summary of RREs for Role 3

RRE	Title	Performance	
3A	Future savings from Operability Solutions	i) Saved balancing costs	Estimated £27m (2021-22): Stability Pathfinder Phase 1 £8.6m Mersey Voltage Pathfinder £12.6m Loss of Mains programme £6m
		ii) Saved infrastructure costs	Estimated £13m per RDP (RDP avoided asset build)
		iii) Monetised carbon reductions	Pathfinders: Estimated £66m (2020-21) to 2024-25). RDPs: Estimated £42m (2021-22 to 2025-26) from RDP1 and RDP2
3B	Consumer Value from the NOA	£208m from ad-hoc CBAs, £313m from LOTI CBAs, NOA consumer benefit £212m	
3C	Diversity of Technologies Considered in NOA	136 asset-based solutions (including 22 new options) and 8 commercial solutions submitted to NOA 2021/22. A wide range of solutions were considered in NOA pathfinders	

RRE 3A Future savings from Operability Solutions

April - March 2021-22 Performance

This Regularly Reported Evidence (RRE) outlines the forecast medium to long term benefits from new operability measures including:

i. Saved balancing costs
ii. Saved infrastructure costs
iii. Monetised carbon reductions

Below we also set out how we have calculated the forecast benefits.

i. Saved balancing costs

Table 24: Estimated saved balancing costs in 2021-22 from new operability measures

Operability Solution projects	a **Contract Cost** (£m)	b **Counterfactual Spend** (£m)	b - a **Savings** (£m)
Stability Pathfinder Phase 1	54.7	63.3	8.6
Mersey Voltage Pathfinder	1.0	13.6	12.6
Loss of Mains programme	4.0	10.0	6.0
TOTAL	**59.7**	**86.9**	**27.2**

Supporting information

Stability Pathfinder Phase 1 and Mersey Voltage Pathfinder

We have implemented commercial service contracts under Stability Pathfinder phase 1 and the second year of the Mersey Voltage Pathfinder, and as a result, we have estimated balancing cost savings of £8.6m and £12.6m respectively for 2021-22. The savings are estimated based on the counterfactual spend forecast if the relevant new operability solution was not brought in. We then annualise the figure through the contract length based on the assumption that all contracts will be delivered on their contractual dates. The Stability Phase 1 contract was awarded in April 2020 with 6 years contract length, and Mersey Voltage contract was awarded in May 2020 with 9 years contract length. Both have been implemented and given estimated saving figures for 2021-22.

In the last 6 months, we have also awarded contracts for the Pennine Voltage Pathfinder and Stability Pathfinder phase 2 (Scotland). The Pennine High Voltage Pathfinder has procured 700 MVAr reactive power capability in the Pennines regions (North East and West Yorkshire) between 2024 and 2034. The Stability Pathfinder Phase 2 has procured 8.4 GVA of Short Circuit Level (SCL) and 6 GVA seconds of inertia in the Scottish regions from April 2024 to March 2034 to manage stability on the system. We expected both will deliver significant amount of balancing cost saving from April 2024 onwards, which will be reported in due time.

Loss of Mains programme

Loss of Mains programme The Loss of Mains protection change programme has progressed well. So far, over 14.0.9GW of generation at over 8300 sites have now applied to the programme, with changes already made at sites with a combined capacity of over 11.8GW. With the addition of generators contacted and known to have achieved compliance, this takes the total engaged to 21.2GW, or 76% of the total generation capacity that is within scope. These changes have already impacted on Balancing Costs and give an estimated saving of £6m for 2021-22.

Method of calculating benefits

For the above three projects (Stability Pathfinder 1, Mersey Voltage Pathfinder, Loss of Mains Program), the counterfactual spend is the forecast cost of balancing the system based on the forecast of future system conditions such as those contained within the Future Energy Scenarios (FES) and other relevant market intelligence information, If no new commercial solution were implemented. After introducing the new commercial solutions through an open market tender, that counterfactual spend would disappear, but there would be additional contract costs relating to the payment for the service providers who deliver those new commercial solutions. Therefore, the savings are calculated as the difference between the counterfactual spend and the contract cost.

ii. Saved infrastructure costs

a) RDPs

The value of RDP avoided asset build was quoted as £12.9m in the ESO RIIO-2 Business Plan Annex 2 Cost Benefit Analysis Report[51]. This will vary depending on the scope of the RDP.

Supporting information

Benefits are realised at the time when an RDP is sufficiently developed that it has a clear solution to facilitate DER connection and an identification of capacity released. We are currently working in several regional areas on new RDP capability which we anticipate will release benefits in 2022-23.

b) Enhanced Operability Assessment

The increasing volume of generation capacity to be connected on the South East coast has triggered major transmission reinforcement works which could cost hundreds of millions of pounds, and take more than 10 years to build. In order to ensure the optimal outcome for consumers, ESO is undertaking an enhanced operability assessment will explore an operational solution to connect this generation without the need for reinforcement works, which if successful will lead to savings in infrastructure costs.

[51] https://www.nationalgrideso.com/document/158061/download

iii. Monetised carbon reductions

a) Pathfinders

Stability Pathfinder Phase 1	Unit	2022-23	2023-24	2024-25	TOTAL
Avoided CCGT output in MW	MW	1,250	1,250	1,250	3,750
Avoided CCGT output in TWh (assuming **30%** availability during the year)	TWh	3.3	3.3	3.3	9.9
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	394	394	n/a
CO2 in tonnes	tCO2	1.3m	1.3m	1.3m	3.9
Carbon price (RIIO-2 CBA)	£/tCO2e	15.3	15.8	16.6	n/a
Savings	**£m**	**20**	**20**	**22**	**62**

Supporting information

In Stability Pathfinder Phase 1, the ESO procured 12.5GVAs of inertia. If the Stability Pathfinder had not taken place, the most economic option for increasing system inertia would be for the ESO to bring Combined Cycle Gas Turbines (CCGTs) onto the system.

To provide 12.5GVAs of inertia, it would be necessary to bring approximately 5 x 250MW units onto the system. In order to calculate the carbon reductions associated with the Stability Pathfinder, we assume that when the Pathfinder providers are supplying inertia they displace CCGTs, as synchronising this fuel type is usually the most cost-effective way to raise system inertia. However, their services are not always needed as the market can provide sufficient inertia avoiding the need for any additional operational actions.

We have used the ESO's Carbon Intensity Forecast methodology to convert the MWh of avoided CCGT generation into avoided tonnes of carbon. We have subsequently used the BEIS short-term traded carbon values (converted from calendar years to financial years) to convert this into monetised carbon savings. Therefore, across 2022-2025 this equates to an estimate of:

- Avoided generation from CCGTs: 9.9TWh
- Avoided CO2: 3.9 Tonnes
- £ Savings: £62m

Short-Term Mersey Pathfinder	Unit	2020-21	2021-22	TOTAL
CCGT generation output avoided in MW	MW	220	220	440
CCGT generation output avoided in GWh (220 nights at 8 hours per night)	GWh	387	387	774
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	394	n/a
CO2 in tonnes	tCO2	152,557	152,557	305,114
Carbon price (RIIO-2 CBA)	£/tCO2e	14.0	14.7	n/a
Savings[52]	**£m**	**2.1**	**2.2**	**4.4***

Supporting information

The Short-Term Mersey Pathfinder is a contractual arrangement where a contract with Inovyn avoids the need to bring on generation at Rocksavage power station (a CCGT).

The Stable Export Limit (SEL) of Rocksavage power station is 220MW. It is generally at night-time that it is necessary to enact the Pathfinder contract: we have assumed that this is an 8-hour period.

An update of the calculations provided in the mid-year 2021-22 Report shows that the contract was enacted on 202 out of 334 nights studied: this is 60% of the time. When extrapolated to a full year, this gives the assumption that the contract is used 220 times over a year.

As above, we have used these figures to calculate the MWh of CCGT generation avoided. We have used the ESO's Carbon Intensity Forecast methodology 93 to convert the MWh of avoided CCGT generation into avoided tonnes of carbon. We have subsequently used the BEIS short-term traded carbon values 94 (converted from calendar years to financial years) to convert this into monetised carbon savings.

[52] Total savings figures are rounded to 1 decimal place. Unrounded figures are 2,135,795 (2020-21), 2,242,585 (2021- 22) and 4,378,380 (Total)

b) RDPs

Table 25 Carbon savings calculation for UKPN:

UKPN	Unit	2021-22	2022-23	2023-24	2024-25	2025-26	YTD
Additional capacity connecting per year	MW	328	169	229	21	50	797
Cumulative additional capacity	MW	328	497	726	747	797	797
Additional capacity in GWh (8760 hours / year and Load factor of 40%)	GWh	1,149	1,741	2,545	2,618	2,793	10,846
Carbon intensity 'Steady Progression' (FES 21)	gCO2/kWh	112	88	89	88	86	N/A
CO2 in tonnes	tCO2	56,403	55,427	127,385	126,041	137,323	502,580
Carbon price (RIIO-2 CBA)	£/tCO2e	14.7	15.3	15.8	16.6	19.2	N/A
Savings	**£m**	**1.9**	**2.3**	**3.6**	**3.8**	**4.6**	**16.3**

Table 26: Carbon savings calculation for WPD:

WPD	Unit	2021-22	2022-23	2023-24	2024-25	2025-26	YTD
Additional capacity connecting per year	MW	-	758	401	167	219	1544
Cumulative additional capacity	MW	-	758	1159	1325	1544	1544
Additional capacity in GWh (8760 hours / year and Load factor of 40%)	GWh	-	2,656	4,060	4,644	5,411	16,771
Carbon intensity 'Steady Progression' (FES 21)	gCO2/kWh	112	88	89	88	86	N/A
CO2 in tonnes	tCO2	61,596	161,616	251,912	295,909	372,233	1,143,267
Carbon price (RIIO-2 CBA)	£/tCO2e	14.7	15.3	15.8	16.6	19.2	N/A
Savings	**£m**	**0.0**	**3.6**	**5.7**	**6.8**	**8.9**	**25.0**

Supporting information

These carbon saving calculations are consistent with the calculations undertaken in our original RIIO-2 business plan. Savings are based on the assumption that capacity released through RDPs replaces fossil fuel generation.

Data is provided for connecting DER in South West (RDP1) and South East (RDP2) regions. These DER are required to provide visibility and control to the ESO as a condition of connection. This provides the ESO with assurance that the local network can be operationally managed through use of local constraint markets involving these DER.

RRE 3B Consumer Value from the NOA

April - March 2021-22 Performance

This Regularly Reported Evidence measures the level of forecast savings created by the ESO through actions to encourage alternative solutions in the NOA (not including NOA pathfinders).

In addition to encouraging alternative solutions in the NOA, the ESO also carries out considerable activities on behalf of the TOs and other stakeholders to ensure maximum value for the consumer, such as bespoke cost benefit analysis to find the most cost-effective solution power system reinforcement.

Below we set out how we have calculated the forecast benefits.

Supporting information

The NOA 2021-22 data shows a gross benefit of at least £212m, over the RIIO-2 period.

NOA Methodology improvements

For the NOA this year, we have changed the way we assess outage requirements for NOA options based on our experience with congested parts of the electricity transmission network. This means our recommendations will use a more realistic set of assumptions in relation to outages providing a more robust set of NOA recommendations hence supporting value for end consumers.

The Least Worst Weighted Regret (LWWR) process has been tested in NOA 2020/21 to support the NOA Committee in its scrutiny of marginal or sensitive NOA options. LWWR enables an exploration of the effect of changing the probability of each of the Future Energy Scenarios occurring and is used to help in our decision making. LWWR gives confidence in our recommendations when a Least Worst Regret is marginal. This is now a permanent part of the process and ensures that NOA committee members can make well-informed decisions.

We currently consult on our proposed NOA methodology for six weeks starting in late spring each year, but our NOA methodology consultation process will be more flexible in the future to allow different parts to be consulted on at times that suit that process and stakeholders while meeting our C27 licence obligations. This will enable a more constant dialogue with our stakeholders, enabling the industry to have their say more easily. By improving the NOA methodology and its consultation process, we ensure we provide the consumer the maximum benefit from the NOA analysis.

Interested Persons' Process Improvements

A large improvement for the NOA 2021/22 methodology is the changes made to the NOA Interested Persons' process, based on our discussion with industry last year. The Interested Persons' (IP) options process is a submission process allowing options from non-TO parties to be submitted and potentially assessed in the annual NOA process. This is designed to increase the diversity of options considered within the NOA process through academic and industry participation. The revised process accommodates option proposals at any time while requiring them to be viable in time for annual NOA submission deadlines. The revised process supports a collaborative approach to developing the option proposals by enabling a constant dialogue with the industry. We will also be working in partnership with Interested Persons to explore how their solutions can provide benefit to consumers and the whole system. We have provided clarity around the option delivery of Interested Persons' submissions - options will be led by either the ESO or incumbent TO in collaboration with the Interested Person, depending on who is best placed to support.

Illustrative example:

The following is a worked example using dummy data to illustrate our methodology for calculating the benefit of the ad-hoc CBAs.

As we don't know for certain what the energy landscape will look like in the future, we use the four FES scenarios to give the likely range of possibilities. The table below shows the potential range of costs for two options, across four FES scenarios. These costs are the sum of the capital costs of building the option (CAPEX) and the operational costs for running the network (OPEX) with that option in place. The CAPEX is fixed across the four FES scenarios as those costs are not dependent on the variables within the FES, such as generation connected to the network. Conversely, the OPEX costs change per FES scenario as it is dependent on the variables within the FES, such as generation connected to the network. Therefore, options may have different total costs in different scenarios, as seen below.

Dummy data – total costs for two options across four FES scenarios

	FES scenarios			
Option	**Steady Progression** (£m)	**System Transformation** (£m)	**Consumer Transformation** (£m)	**Leading the Way** (£m)
1 (TO preferred)	140	130	120	125
2	100	100	100	110

The lowest possible cost across these two options and four scenarios is **£100m.**

Dummy data – 'Regret' analysis for two options across four FES scenarios

We then calculate the difference between each of the possible costs and the lowest cost option (in this case, £100m). This difference is what we call the 'Regret' figure (see table below). For example, for Option 1, using Steady Progression, the 'Regret' figure is calculated as:

Estimated cost - lowest cost option = **Regret**

£140m - £100m = **£40m Regret**

In other words, if option 1 was built and the energy network in the future was similar to the FES scenario Steady Progression, the regret would be £40 million. This is because option 2 could have been £40 million less expensive.

Finally, we establish the 'Worst Regret' figure, which is the most expensive possible outcome for each of the two options (i.e. the worst for the consumer). See below:

Option	**Steady Progression** (£m)	**System Transformation** (Regret in £m)	**Consumer Transformation** (£m)	**Leading the Way** (£m)	**Worst Regret** (£m)
1 (TO preferred)	40	30	20	25	**40**
2	-	-	-	10	**10**

In this example the 'Worst Regret' for option 1 is **£40m** and for option 2 is **£10m**. Therefore, we would recommend option 2, as it has the least 'worst regret'.

We calculate the consumer benefit to be **£30m**, which is the difference between our recommended option and the TO's initial preferred option, as can be seen below.

Recommended option's Worst Regret - TO preferred option's Worst Regret = **consumer benefit**

£40 million - £10 million = **£30 million consumer benefit**

Consumer benefit from Large Onshore Transmission Investment (LOTI) CBAs

A key role for the ESO is undertaking independent cost benefit analysis for transmission investments, to support TOs in their need cases for major reinforcements. This year, we have undertaken significant studies for all three TOs, to support them delivering the network capacity needed to enable the low carbon transition.

We have calculated the consumer benefit of our analysis as **£312.5m** across five projects.

Details of the specific schemes we have supported are:

- For all the TOs, we have worked extensively on the Final Needs Case for the first two Eastern HVDC links, as part of our continued work on the broader East Coast Strategy. These key links will provide around 4GW of capacity to transfer renewable electricity from Scotland to northern England, reducing constraints in a key part of the network from 2027 and 2029. Our independent and robust analysis is a detailed assessment of the suite of potential route options and timings, against the impact of the FES scenarios and other sensitivities. We compare the total capital cost of the schemes with the long run benefit the scheme provides in reducing constraints. Overall, we have demonstrated the need and significant benefit of delivering the required options on time saves the consumer hundreds of millions of pounds in avoided constraint costs, and delivers around **£200m** of consumer benefit.

- For NGET we have worked together to define the CBA for the Initial Needs Case for Yorkshire Green Energy Enablement project (a key onshore enabler for the Eastern Links) and undertaken detailed routing options studies for SEALink - a new HVDC route between Suffolk and Kent required to reinforce multiple network boundaries and to enable the connection of future generation and interconnectors off the East and South Coasts. We have also undertaken analysis to support options development on other key projects in the North and East of England, which will provide additional capacity on key boundaries to facilitate increased volumes of renewable generation. Yorkshire Green has consumer benefit of **£19.7m**, and the studies for SEALink of **£5m**.
- We have worked in close collaboration with SSEN Transmission to complete detailed analysis for the Initial Needs Cases for both Skye Reinforcement (**£62m** of consumer benefits) and the Argyll and Kintyre strategy (**£26m** of consumer benefits). Both projects deal with replacement and upgrade of old network; the need to develop a cost-effective solution for asset upgrades; investment in capacity to allow for future expected renewable growth, against a background of some of the most challenging terrain in GB.

Improvements to the Connections and Infrastructure Options Note (CION) process

The CION is the process the ESO follows to determine the most economic and efficient connection location for an individual offshore project (typically wind farms or interconnectors). In late 2020, BEIS and Ofgem initiated the Offshore Transmission Network Review (OTNR) to enable greater coordination in the connection of offshore projects. This year, the requirements for CIONs has been superseded by the ESO developed Holistic Network Design (HND) as part of the BEIS-led Offshore Transmission Network Review (OTNR).

For context, the consumer benefit calculated from CION process activities and reported in last year’s end of year report was greater than £900m, and this will be captured in the HND and OTNR processes in the short term, with the future process captured in the Electricity Transmission Network Planning Review.

Consumer benefit of Commercial Solutions

Commercial solutions drive consumer value by providing an alternative to asset-based solutions. Currently, these take the form of intertrips (where we form an agreement with generation plant to alter their output if required) but in the future, there may be additional solutions. Commercial solutions are also highly useful as they can often be implemented more quickly than an asset can be built, meaning they can address the growth in network constraint costs sooner, saving consumers more money. It is however important to note that these solutions do not provide network resilience or help towards compliance with the SQSS. Commercial solutions should continue to be explored in a limited range of network conditions because expanding their use into more areas of the network could erode the much valued network resilience we currently have, resulting in consumers being worse off. Should system requirements change in the future, these commercial solutions can be adapted more easily than asset-based solutions.

We forecast that the consumer benefit of the commercial solutions in NOA is, on average, **6.5%** of the overall consumer benefit of all options in the NOA CBA. This is the average of the expected benefit across the three FES scenarios that meet the Net Zero target (Leading the Way, Consumer Transformation and System Transformation). The benefit was calculated using the ‘Anti-regret’ method, which is consistent with the previous year.

Consumer benefit from ad-hoc cost benefit analysis (CBAs)

Below are the estimated consumer benefits from the ad-hoc cost benefit analysis we have conducted over the last 12 months. These have been calculated using the method detailed further below.

Ad-hoc CBA	Estimated Consumer Benefit
North of Beauly	£10,000,000
Burwell ANM and SGT assessment	£140,000,000
Dinorwig to Pentir cable replacement programme	£400,000
Necton circuit assessment	£300,000
Bramford to Norwich circuit assessment	£43,000,000
Harker and Penwortham assessment	£14,000,000
Total	**£207,700,000**

RRE 3C Diversity of Technologies Considered in NOA

April – March 2021-22 Performance

This Regularly Reported Evidence details the number and type of different solutions considered each year through the NOA and any NOA pathfinder tenders, as well as the ESO's explanations of action taken to increase the pool of solutions. Should include number of parties that:

i. Express interest
ii. Are participants within NOA / NOA pathfinder tenders
iii. Are successful / receive contracts

Numbers for NOA and NOA pathfinders are reported separately for transparency.

Where number and type of different solutions are not available because a NOA process has not occurred, we provide an update on actions we have taken over the preceding six-months to increase the pool of solutions.

a) NOA

The expression of interest process does not apply to the NOA so here we report on solutions submitted by participants in the NOA process. The table below shows the number of options submitted by participants in NOA 2021-22, and of those, how many are new to the NOA this year. Most new options are submitted by TOs, with the ESO providing the future requirements of the network based on our FES projections and working closely with the TOs to ensure that appropriate solutions are submitted into the NOA process. Commercial solutions have been created by the ESO.

Table 27: Options submitted by participants in NOA 2021-22

Technology Main Category	**Total Number** Submitted in NOA 21/22	Number that are **new** to NOA this year (included in total)
Circuit	110	20
Route modification	2	2
Transformers	3	-
Substation & switching	3	-
Flexible AC transmission system (FACTS)	18	-
New technology	0	-
Total asset-based solutions	**136**	**22**
Commercial solutions	8	2

Supporting information

Please note that the deliverables under activities A8 – A11 contribute to this consumer benefit as set out in the 'Consumer benefit from ad-hoc cost benefit analysis (CBA)' section.

b) NOA Pathfinders

	i) Express interest *(a count of how many expressions of interest)*	**ii) Are participants with NOA/NOA pathfinders** *(how many participated in the commercial tender)*	**iii) Are successful / receive contracts** *(how many contracts we awarded)*
Constraints management pathfinder	**TOTAL: 51** (7.4GW) Battery: **15** (1757.7MW) Hydro: **2** (2.6MW) Combined Heat and Power (CHP): **2** (12.7MW) Steam: **1** (15.4MW) Wind: **29** (4386MW) Combined Cycle Gas Turbine (CCGT): **2** (1.2GW) **Transmission / Distribution split:** Transmission-connected: **37** (7.0GW) Distribution-connected: **14** (331.4MW)	**TOTAL: 10** (1.7GW) Wind: **9** (1.7GW) Battery: **1** (50.0MW) The above is all connected to (or expecting to connect to) a Transmission breaker (132kV or 275kV or 400kV)	**TOTAL: 10** (1.7GW) Wind: **9** (1.7GW) Battery: **1** (50.0MW) The ESO's aim is to build liquidity in this service, so contracts have been awarded to all assets that participated in the commercial tender process. There were 15 contracts awarded (for the 15 BMUs) across 9 onshore wind assets and 1 battery storage facility. Note that this tender process was specifically for B6 (Anglo-Scottish boundary) for delivery between 01 October 2023 through to 30 September 2024; except 4 of the 9 successful onshore wind assets can provide this service before October 2023, owing to an existing connection to the intertrip scheme.
Stability phase 1	Synchronous: **104** Non-synchronous: **46** Hybrid: **6** Stability Pathfinder RFI feedback	**46** bids were submitted by 11 different parties. TOs did not participate in the tender. Stability Phase 1 tender - results table	**12 bids** were accepted from 5 parties
Stability phase 2	Synchronous machines: **514** Grid forming convertors: **723** Hybrid: **338**	222 solutions were submitted by 20 separate commercial companies and 3 solutions submitted by one of the 2 Scottish TOs (SPT).	4 commercial providers were awarded 10 contracts between them. Split of 5 synchronous machines and 5 battery grid forming converters.
Stability phase 3	Expression of interest window is currently open and will close on 22 October 2021.	One-stage tender window yet to open. This metric can be provided and confirmed in March 2022 following the tender submission deadline.	Not at this stage in the tender process. Phase 3 contracts will be awarded in 2022.
Voltage: Mersey	**40** Transmission connected solutions and **15** Distribution connected solutions	**40 bids** were submitted by 11 different parties. NGET were one party and offered 9 different solutions. Many different technology types	2 successful contracts awarded

		connecting at different networks	
Voltage Pennine	**93** Transmission solutions **13** Distribution solutions	**21** Participants including NGET	3 Solutions from NGET 1 Solution from SSE Dogger Bank C

Supporting Information

The Pathfinders procurement strategy is deliberately technology neutral to ensure that innovative solutions that can demonstrate the ability to meet our requirements can participate in the tenders.

This innovation is demonstrated by the results of the Stability 2 pathfinder whereby we have secured stability services from Grid Forming technology in what we believe is a world first utilisation of this technology to ensure a secure network.

This success was achieved due to collaboration between industry and our engineering teams to validate the approach and develop a standard that would allow the efficient and effective use of this technology. The diversity of technologies that can fulfil this requirement also leads to greater competition in the provision of these services and drives value for the end consumer.

D. Value for money

Value for money

Value for money

The ESO incentive arrangements for RIIO-2 include a new criterion, Value for Money. The ESO must report on its outturn and forecast costs for each role against cost benchmarks. As the reporting for the Value for Money criterion relates to all 3 roles, we have brought this together in one section rather than providing a separate Value for Money chapter for each role. All figures in this section are in 2018-19 prices.

It is important to note that the Regulatory Reporting Pack (RRP) remains the formal cost report for the ESO, and final numbers will be formally reported in the 2021-22 RRP which will be submitted to Ofgem in July 2022.

The reported spend to date has been reviewed as part of our normal monthly management review process but has not been formally audited or been subject to the formal governance process for submission that would normally be used for Cost and Outputs reporting. The ESO uses the methodology, as set out in the ESORI guidance, to allocate costs to each role.

The ESO's cost benchmark was set at £504.1m as part of the Final Determinations process, but has since been adjusted to £506.0m following agreement with Ofgem as outlined in their report on the six-month review of ESO performance.

The following table sets out the revised cost benchmark by role as well as our spend to date and forecast for the RIIO-2 BP1 period.

		Role 1	Role 2	Role 3	**Total**
Cost benchmark	(£m)	208	159	139	**506**
Spend to date (up to end of March 2022)	(£m)	110	72	58	**240**
Forecast spend for remainder of BP1	(£m)	136	88	83	**306**
Forecast total spend for BP1	(£m)	246	160	141	**548**
Forecast deviation from cost benchmark	(£m)	+38	+2	+2	**+42**
Forecast deviation from cost benchmark	**(%)**	+18%	+1%	+1%	**+8%**

Below we set out the main activities driving the variances for each role.

Summary of activities driving overall variances by role

Role	Activity	Variance £m
Role 1	Balancing Programme	42
	Network Control Programme	5
	Other	(9)
	Total	**38**
Role 2	EMR Portal Improvements	7
	Ancillary Services Settlements Refresh	5
	Charging and Billing Asset Health	4
	EU regulatory changes	(6)
	GB regulatory changes	(3)
	Other	(6)
	Total	**1**
Role 3	Offshore coordination	5
	Early Competition	4
	Zero carbon operability (500)	(6)
	Other	(1)
	Total	**2**
ALL	**Grand Total**	**41**

Numbers rounded to nearest £1m, small rounding differences may arise in totals

More detail about each role

Role 1 (Control centre operations) expenditure

For Role 1, we are currently forecasting to spend **£38m** more than the cost benchmark over the BP1 period. This is due to two main factors: increased expenditure on the Balancing Programme **(+£42m)** and the Network Control Programme **(+5m),** offset by reductions elsewhere.

We provide more detail here about the main factors leading to the deviation from the benchmark.

Balancing Programme (+£42.2m)

Cost benchmark for BP1	£28.1m
Forecast expenditure over BP1	£70.3m
Variance	**£42.2m**

Background The aim of our Balancing Programme is to maintain and bring change into our existing balancing capabilities to support Control Room operations whilst we transform to new balancing capabilities that the ESO needs to deliver reliable and secure system operation, facilitate competition everywhere and meet our ambition for net-zero carbon operability. The programme consists of several IT investment lines from the ESO's RIIO-2 Business Plan: Enhanced Balancing Capability (180), Balancing Asset Health (210), Forecasting Enhancements (260), and Ancillary Services Dispatch (480). We provide more detail about the overall programme here, and specific information about Enhanced Balancing Capability in the Amber Projects section below. A significant proportion of the Balancing Programme spend and effort is, of course, focused on delivering future balancing capability. This future balancing work is held within the Enhanced Balancing Capability project and was identified as a high-value project at the time of Final Determinations.

Drivers of change

Since the Final Determinations in 2019, we have completed the foundation and blueprint phases of the programme. Combined with a clearer view of the future needs of the system, markets and industry, we now have a much better understanding of the scale and complexity of capability change required.

In our Business Plan, we predicted that the energy mix would change rapidly, with higher numbers of small units and increased volumes of variable, asynchronous generation. Alongside this, we planned for an ambitious market reform. We designed a Balancing Programme to accommodate this change, with the initial stages of the programme intended to produce a detailed assessment on how to deliver the outcomes we needed.

Since the submission of our plan, the energy landscape has continued to evolve at a faster pace than expected which has required an upwards shift in efforts to deliver these changes into our balancing systems:

- We are progressing our market reform activities, creating new services and products, opening up markets so new technologies can compete with the traditional providers. This requires the ability to optimise multiple services across 1000s of units at the same time. The complexity involved in optimising the system has increased more than predicted, in terms of the number of instructions required and the mathematical optimisation for our dispatch process.
- The volume of regulatory and other market driven change has also impacted how much complex change needs to be represented in balancing in the next two years. The numerous required changes are also complex and so are difficult to model effectively for optimisation.
- In addition, the increased volume of renewable generation and interconnector capacity with a one-hour ahead gate, has significantly increased the requirement to optimise and instruct larger volumes of energy within the balancing gate to control the system frequency, as both generation and demand fluctuate due to commercial and weather drivers. The volatility and amount of change that happens in the market in the time between preparation of optimised operational plans in scheduling timescales, to those plans closer to real time dispatch is so high that it reduces the value of our scheduling capability and increases the value of our dispatch capability for our control room engineers.
- We now know that the importance of forecasts is much greater than we previously anticipated. Embedded wind and PV units create demand volatility at Grid Supply Point (GSP) level. Suppliers are using financial mechanisms to adjust how and when customers use Demand. The creation of Virtual BMU units and aggregators operating across multiple GSP points to provide energy and ancillary services facilitate competition but also increase constraint flow volatility. All of these factors require more data to be used to calculate and forecast demand and generation within each GSP to calculate constraint flows across the system.

Impacts on the Balancing Programme

Our original Business Plan described how we would be delivering ongoing activities required to run and maintain our existing Balancing systems (A1.1) while we developed and delivered a new enhanced balancing capacity (A1.2). Here, we also explained how during BP1 we would be exploring and defining the technology roadmaps, strategies and system architectures required to enable the successful delivery of our overall plan.

This exploratory phase revealed that some of the key assumptions and projections provided in our original plan were not materialising as expected, resulting in a significant upward driver in the efforts and costs required to deliver our plans. The drivers of change described above, combined with our improved understanding of the design and capability of our systems, following our foundation and blueprint phase, led us to conduct a strategic review of our balancing programme:

- We have identified the need for further investment on our legacy dispatch system, the BM system, than was anticipated. Our original plan accounted for asset upgrades to keep system health in good order while we transitioned to our new balancing tools. However, additional efforts have been required in order to deliver market and regulatory change prior to transformation. A number of manual workarounds that are currently used in the Control Room are also being removed which have delivered additional strong benefits.
- Our Business Plan assumed that our existing EBS would become our primary scheduling tool, providing 4-hour ahead schedules and being fully integrated to our existing and future balancing tools, until it could be replaced. Our review established that EBS and its proposed future capabilities will not be able to deliver the required market modelling and balancing capability changes in a timely and cost-effective way. The shift from 4-hour ahead scheduling to more and more balancing instruction being made within the 90-minute BM window means the value for EBS is significantly lower than anticipated. However, whilst the value from the central scheduling functionality of EBS has reduced as a result of the impacts described above, EBS currently enables a number of additional ESO business processes both in and beyond the control room.
- The stronger case for the delivery of a dispatch capability, steered by the changes explained above, have driven a higher prioritisation of the delivery of our proposed Open Balancing Platform (OBP) (enhanced balancing capability). Cost increases to deliver OBP reflect the now known scale and complexity to deliver this capability.

These changes are the primary drivers of the cost escalations and we recognise the need to ensure our plan continues to deliver value for money for consumers over the BP1 and RIIO-2 period. We have initiated a process of engagement, our Balancing Strategy Capability Review[53] with industry as we want to work transparently and collaboratively to find better ways to deliver the systems transformation required. Options come with different costs and benefits – we want to work efficiently, effectively and meet the goals of our customers and the Control Room and create an industry endorsed plan.

The work we have done throughout our foundation and blueprint phases has clearly identified the need for additional resources and activities required to deliver build from the bottom-up. These models can be tracked going through the staged delivery of our programme of work.

The OBP has been designed to have the flexibility to allow us to iteratively add functionality and business support to enable the transition to the future zero-carbon market. It provides the control room with the modern tools they need to manage an increasingly complex system.

Investment forecast against RIIO-2 BP1 benchmark (£m GBP 2018-19 pricing)

Existing balancing (210 Balancing asset health)

RIIO-2 BP1 benchmark	£2.8m
Forecast for BP1	£17.6m
Variance	**+£14.8m**

[53] https://www.nationalgrideso.com/industry-information/balancing-services/balancing-programme/strategic-capability-review

Explanation of variance	The cost and effort of maintaining and developing the existing capabilities was significantly underestimated in the original Business Plan. The BM, our existing manual scheduling and dispatch system, continues to operate in a challenging and changing environment. A product capability has been established and is operating to deliver new market changes, critical upgrades and fixes as efficiently as possible while the transformation takes place. This includes additional scope as a result of the changes driven by market reforms, as well as a number of prioritised enhancements to remove manual workarounds in the control room. Our original forecast did not account for these changes as some were not known at the time. Therefore, these increases account for investment on the BM capabilities to meet these changes and improve deliverability and reliability. As explained under our Drivers of Change, our review determined that the value of our current scheduling capability has significantly reduced due to increased dynamic operations in dispatch timescales. Therefore, using EBS as a 4-hour scheduling tool will no longer meet our operational needs. However, other elements of EBS enable a number of current ESO business processes both in and beyond the control room, including Inertia, STOR contracts and demand data feeds and processes feeding into our trading activities. Migration of any EBS dependencies into future enhanced balancing capability will require careful consideration and planning which would increase cost and time to deliver. Additionally, this potentially would require development/change work and delivery in other legacy balancing tools. Therefore, it is still necessary to make some investment in EBS over the BP1 period to ensure it continues to function until our enhanced balancing capability transformation is delivered. The project to deliver this upgrade is expected to cost £6m.
Impact of changes on consumer benefit	Balancing Asset Health delivers both direct benefits and enables benefits in other areas. For the BM, direct benefits come from the ongoing maintenance work to avoid an unplanned outage (i.e. cost avoidance), reducing risk through the removal of manual workarounds in the control room and the delivery of new system and control room user functionality. Examples of this are provided in the evidence chapter under Release R0. We expect this to deliver at least **£23.4m** of consumer benefit over the RIIO-2 period. In addition, BM asset health work also enables indirect benefits in other areas, for example ASR, Pathfinders, interconnectors and RDPs. This is because, as new functionality is added to the BM, a corresponding programme of asset health and control room improvements are necessary to ensure safe and secure system operation and to make sure the IT systems can handle the increased functionality. For EBS, in our 6-month report, we stated that enhancements could deliver up to £14.5m benefits each year, leading to an overall benefit of £72.5m over the RIIO-2 period. These were based on EBS being able to optimise our schedules at 4 hours ahead in our control room. As stated above, our strategic review determined that under current balancing operations and as we continue to see an increase in the number of smaller generation units in the system, the value delivered by our current scheduling capability will significantly reduce. Furthermore, we also found that enabling EBS to optimise new services under these conditions will require more complex and costly structural changes. We, therefore, plan to review and validate the benefits to be delivered by this capability, based on current and future requirements to ensure our investments deliver value to the consumer. Note that Balancing Asset Health benefits were not included in the RIIO-2 CBA because it was considered business as usual activity.

Future balancing (180 Enhanced balancing capability)

RIIO-2 BP1 benchmark	£20.3m
Forecast for BP1	£40.2m
Variance	**+£19.9m**

Explanation of variance

Balancing enhancement costs have exceeded the estimates made as part of BP1. We have now completed the blueprint phase, and as a result, the scale and complexity involved to deliver the required capabilities are firmer and clearer.

Assumptions made as part of BP1 were based on the scheduling capabilities of EBS being enhanced to 4-hour ahead and integrated, along with the BM with a new modular platform which would replace the BM by 2024.

Due to the increase in forecast costs and the choices available, we have stepped back and are undertaking a strategic balancing capability review to create a consolidated view of our future requirements to enable net-zero and how we will deliver these. The platform solution proposed for delivery as part of enhanced balancing capability is the Open Balancing Platform (OBP). The OBP is modular which enables the ESO to make discrete functional changes to individual business services without impacting other services. Components are developed in-house, modular, and do not use hard-coded designs. This ensures that the systems can adapt to future change.

We understand that further change is necessary and inevitable and concepts such as local marginal pricing and demand dispatching have demonstrated that the ESO needs to deliver balancing capabilities that continue to be highly flexible. We need to ensure our systems are future proofed so that they can be scaled up and have new components added easily, allowing us to adapt to future challenges.

We also have an increased understanding of the complexity and scope of transitioning from our legacy systems to our new enhanced balancing capability. The increase in complexity and change in both systems have resulted in the transformation being more complex than anticipated.

Impact of changes on consumer benefit

+£81.4m benefit (over RIIO-2, including benefits from mid-year report)

This is half of the increase in the A1 Control Centre Architecture and Systems CBA (as it covers both Balancing and Network Control)

We estimate that A1 will now deliver £467m of benefits, up from £305m in the December 2019 submission. This is driven by:

- An increase in the carbon price, reflecting the importance of our projects in getting to net-zero
- An increase in constraint costs, which we estimate will be 5% higher than would otherwise be the case if we do not proceed with the transformational plan.
- The changes in our approach in moving to the OBP will take more time to deliver compared to our original plan which aimed to deliver a new dispatch system by FY2022. Our aim is now to deliver the OBP by FY2026. This produces an offsetting reduction in benefit.

260 Forecasting enhancements

RIIO-2 BP1 benchmark	£0.5m
Forecast for BP1	£6.4m
Variance	**+£5.9m**

Explanation of variance

The original estimation of costs in our original business plan assumed that the forecasting enhancements would be mostly complete at the end of RIIO-1, however there were delays in the time required to implement the Platform for Energy Forecasting (PEF). This has resulted in an increase to the forecast for BP1 as costs have continued to be incurred in RIIO-2.

Forecasting enhancements is a continuous improvement investment to develop and implement ESO's new forecasting capability. We have already developed and implemented national solar power generation and demand forecasting products. The output from these products is shared with the market through the ESO data portal or BMRS (where possible).

However, the increased importance of forecasting, further driven by increases in balancing costs, has led to further improvements being required beyond those originally anticipated in our business plan. The ESO aims to open up competition to a wider range of participants, including aggregators and virtual BMUs operating across multiple Grid Supply Points (GSPs). A new plan to integrate GSP data into existing balancing systems is being executed while the development of balancing transformation is underway. This has created a need for improved forecasts at the GSP level rather than GSP-group level, to calculate constraint flows across the system. The increased scope will deliver additional benefits, that will also drive an increase in delivery costs.

Impact of changes on consumer benefit

+£1.05bn additional benefit (over RIIO-2 period, above mid-year report)

The Forecasting platform remains a highly beneficial initiative. The benefits will include continuous improvements to ESO forecasting capability, situational awareness of local constraints, improved voltage studies, enhanced transmission outage planning & offline study setups. In BP1 so far, we have delivered and maintained a 20% improvement in the National Demand forecasts. In our original business plan, benefits for this investment were calculated assuming £50MWh day-ahead energy prices. Since then, we have seen an increase to these prices to ~£200MWh, which reiterates the importance of maintaining improved accuracy in our forecasts. During the first year of BP1, these forecasts improvements have meant savings of up to £175m in balancing costs. We expect these to increase to up to £200m in FY23, as we delivered improved GSP products in our forecasting capability.

Note that this benefit number will vary depending on energy prices, which remain volatile.

480 Ancillary services dispatch

RIIO-2 BP1 benchmark	£4.5m
Forecast for BP1	£6.0m
Variance	**+£1.5m**

Explanation of variance

The Ancillary Service dispatch service is a mature product, which is being used to deploy new non-BM services to the ENCC while the transformation to our new balancing capability is taking place. Since our original business plan, we have gained a better understanding of resource, hardware and software license costs required to deliver this investment, which are higher than we originally estimated.

Impact of changes on consumer benefit

The investment enables the delivery of other market services, for example P399 Compliance for Role 2 and Deployment of new services for Role 2 ancillary services reform.

Risks and mitigation

The transformation of the ESO Energy Balancing System is a key milestone in reaching the ESO's zero carbon objectives.

Risk / Uncertainty	Response / Mitigation
There is a risk that the ESO underestimates the complexity of the Transformation objective	The ESO has delivered the blueprint for the transformation and has built product teams which include Product Owners and SMEs with industry and operational expertise. We are also undertaking an external assurance audit on the programme as well as engaging with industry.
There is an uncertainty that the Balancing transformation costs and plan will meet industry and regulatory requirements	The programme is undertaking an external engagement initiative with industry and Ofgem with the objective of delivering an industry endorsed plan that is in the best interest of consumers
Energy system optimisation delivery has failed in the past, with EBS.	We have built a specialist Optimisation team with internal and external specialists, who are working on solving the complex Engineering and scientific problems.
There is a risk that critical changes will be required to existing balancing systems before Transformation is complete.	A BM development capability is expected to be retained to ensure critical changes can be made during transformation.
There is a risk that industry engagement will delay or change the direction of the transformation	Delays or changes will probably delay the zero-carbon objective and related benefits case. Should the programme stop now, the team would need to be dissolved which would take 6-12 months to re-staff. Analysis and feature design could continue.
There is a risk that the Open Balancing Platform will not satisfy the requirements of a changing energy market	The Open Balancing Platform has been built on highly resilient, highly flexible (RedHat OpenShift) technology that is easy to change and deploy. The system is designed to adapt to changing energy market and operational conditions.
There is a risk that the Balancing Transformation programme will deliver in silo, lose focus on other transformational programmes	The Balancing Transformation is at the heart of ESO / FSO operations. The programme team are actively working with the internal transformation teams and industry through the TAC and wider engagement. Our backlog is currently shared amongst Market Reform, Commercial, Network Control and Regulatory product teams.
There have been challenges in completing the ESO components of the Critical National Infrastructure Data Centre (CNI-DC), have also increased costs.	We are working with the National Grid Infrastructure and Operations team to complete the CNI-DC base infrastructure. We have set-up an ESO provisioning team, who are working with Vodafone to prioritise our networking requirements
There is a risk that the global shortage of semi-conductors could delay the deployment and go-live of the Open Balancing platform.	We are looking at technical choices (with Industry) possibly deploying the new Open Balancing Platform on hardware planned for the Modern Dispatch Analyser and Ancillary Service Dispatch Platform, which would then be planned to be integrated with OBP during FY24 and FY25.

Network Control (+4.6m)

Cost benchmark for BP1	£9m
Forecast expenditure over BP1	£13.6m
Variance	**+£4.6m**

Background

The Network Control Programme will replace our current real-time situational awareness tool, the Integrated Energy Management System (IEMS) with new products that include improved online and offline modelling capabilities, including whole electricity system simulation aided by machine learning and probabilistic analysis.

Enhanced look-ahead capabilities will allow us to predict transmission problems in a more volatile operating environment. We have also committed to improve our Control Centre video walls and operator consoles to ensure we can visualise the real-time state of the network.

Upgrades are needed given the increased data coming into the Control Centre that our engineers must be able to understand and analyse to make optimal decisions.

Support for our current IEMS tool is scheduled to end in November 2022 and this Programme will extend the system life out until our new products are operational.

Explanation of variance

Cyber Security: We need to ensure continued secure operation of the existing IEMS until our new Network Control Management System is operational. Our review of the existing suite has included the latest cyber security intelligence for Critical National Infrastructure. This area is rapidly developing, and we have identified a new resilience option to enhance security of the existing IEMS system until it is replaced in 2026. We propose to build an additional environment, separated from all other environments, in order to improve our resilience to cyber-attack.

CNI Data Centre Enhancements: For our new Network Control Management System (NCMS) our IT infrastructure teams have proposed a more modern virtualisation of our architecture. This will be deployed in our new CNI Data Centres and will unlock potential for improved cyber security, performance, and more evergreen maintenance options for our new tools. To achieve this, we have proposed a higher level of investment in hardware to ensure the foundations we build on are the most suitable for future operation. This will also be of benefit to future developments such as the Virtual Energy System. Further investment will be required in BP2 to complete the transformation.

This increased activity will also require an increase in IT resource and Business resource to develop and deliver this new technology, with further investment requested in BP2.

Risks / Uncertainty

Cyber Security: The cyber security landscape continues to rapidly develop and there is potential for additional investment in order to keep pace. This may be further accelerated by escalating global events (e.g. Ukraine conflict).

CNI Data Centre Enhancements: The ongoing semiconductor shortage and subsequent increased lead times to procure hardware will increase the risk of both escalating cost and delayed delivery of new products.

Resource: The market for IT resources is highly competitive right now and this is likely to have an above-inflation impact on the cost of resourcing this programme.

Role 2 (Market development and transactions) expenditure

For Role 2, we are currently forecasting to spend **£1m** more than the cost benchmark over the BP1 period. This is due to four main factors: EMR Portal improvements **(+£7.5m)**, Ancillary Services Settlements Refresh **(+£4.5m)** and Charging and Billing Asset Health **(+£4.1m)**, partly offset by EU Regulatory Changes **(-£6.4m)**.

We provide more detail here about the main factors leading to the deviation from the benchmark.

EMR Portal improvements (+£7.5m)

Cost benchmark for BP1	£3.5m
Forecast expenditure over BP1	£11.0m
Variance	**£7.5m**

Background

The ESO, as EMR Delivery Body, has an obligation to comply with the latest Ofgem and BEIS regulations to ensure effective and compliant management of EMR processes, including updating the IT platform (EMR portal) to meet latest rules and customer needs.

We are investing in a new replacement EMR portal during FY22 and FY23 that will enhance the customer experience, whilst also ensuring that it can be updated more quickly to implement new regulatory changes at an efficient cost.

The EMR portal replacement is something our customers and stakeholders have been asking for and we have been working with them to design, verify and test the system throughout its development.

Explanation of variance

Development of the new EMR portal was moved from RIIO-1 into the RIIO-2 period. This development and investment was allowed for in RIIO-1, and not included in the RIIO-2 cost benchmark for BP1.

In 2019/20 and 2020/21, the ESO was required to deliver a large volume of mandatory changes to the current EMR portal to facilitate the restart of the Capacity Market following renewed State Aid approval. We also supported customers through the COVID-19 pandemic, and implemented other regulatory changes required by BEIS and Ofgem. The ESO is returning unspent allowances for EMR for that period through the RIIO-1 close-out process which has been agreed with Ofgem.

Until the transition to the replacement EMR portal is completed, the ESO must continue to invest in and maintain the current EMR portal in parallel with development of the new portal. This is to ensure the current portal supports the ongoing delivery of CM and CfD processes, and remains compliant with regulatory changes required by BEIS and Ofgem.

The volume of regulatory change for EMR in RIIO-2 is also greater than originally expected in BP1, including for CM auctions and agreement management as well as CfD Allocation Round 4 and, following a recent BEIS announcement, the move to annual CfD rounds.

The updated cost for investment 320 over the BP1 period is £11.0m. This includes £7.1m for work on the new EMR portal during 2021/22 and 2022/23. The development of the new EMR portal and reporting capability will continue into the BP2 period. The cost of investment in the current portal during the BP1 period is £3.9m and it is expected to be decommissioned in FY24.

Risks / Uncertainty

The volume, nature and timing of CM/CfD rule changes by BEIS and Ofgem for FY23 and beyond are uncertain; this may affect the size, nature and timing of changes in the EMR portal and associated costs.

IT market conditions are driving cost increases which is impacting the total cost to complete the project as well as the wider portfolio.

ESO product transformation is underway, meaning changes to resourcing structures and ways of working are likely to be subject to change.

Ancillary Services Settlements Refresh (+£4.5m)

Cost benchmark for BP1	£3.8m
Forecast expenditure over BP1	£8.3m
Variance	**£4.5m**

Background

The Settlements system calculates payments for ancillary services provided to the ESO in order to operate the system. We expect a significant increase in the number of new services and participants and have identified consumer benefit from increasing the flexibility of the system to meet these needs.

Creating a product that will be scalable and configurable will allow us to introduce new ancillary services faster to the market and adapt existing services with far greater cost and time efficiency. Over the next 5 years, this system replacement is expected to deliver £13m of consumer value through reduced ESO Totex spend.

Explanation of variance

In BP1 we committed to the replacement of, and ongoing investment in, the ancillary services settlement system. As part of this process, in November 2018, a feasibility study was initiated to assess options and solutions for an enduring solution followed by an extensive procurement exercise to the wider market being initiated whilst indicative costs were submitted.

A project to replace the existing system was in the requirements stage when BP1 was submitted, and was expected to complete early in the RIIO-2 period. Costs included in BP1 were highly indicative due to the following factors; niche product availability, limited scope of discovery / analysis of requirements, early stage of procurement exercise and delayed outcome of feasibility. The original costs were based on the Gartner benchmark range due to uncertainties at that time.

Selection of the preferred new solution and delivery partner in April 2020, gave us more certainty on the process of standing-up a new product on the NG ESO IT infrastructure (data migration, onboarding resources, environments), and clarity on business strategy and the technology landscape. However, further scrutiny of costs was conducted to leverage benefits from installing a flagship product and existing ADAM partner arrangement.

The end result was that, whilst the scope has not changed, our approach to delivery has adapted to enable agile delivery, customer insight and faster removal of grey IT. These changes have led to a revised forecast of £8.3m over the 2-year period, an increase of £4.5m.

Risks / Uncertainty

There is a risk that due to the size and complexity of the full scope foundational releases may not be delivered in time leading insufficient funding. Setting up a new platform on the ESO IT infrastructure may also uncover further complexities during testing leading to extended timescales.

The speed of new services being introduced may impact our ability to deliver the prioritised foundational releases leading to a delay in delivering our roadmap.

There is a risk that project resources leave, leading to disruption in cadence and ability to deliver.

Charging and Billing Asset Health (+£4.1m)

Cost benchmark for BP1	£3.0m
Forecast expenditure over BP1	£7.1m
Variance	**+£4.1m**

Background	The Charging and Billing (CAB) system manages the TNUoS, BSUoS and Connections charges. It generates invoices for market participants to pay the ESO. We expect increasing complexity in these revenue streams to keep up regulatory changes and therefore creating a sustainable and adaptable system that can easily be reconfigured will allow us to introduce new calculations quickly and at a lower cost to benefit consumers. It will improve customer experience, and to improve financial integrity with integrated Controls. Over the next 5 years, this system replacement will enable key regulatory charging reform, which will unlock material consumer value (including Fixed BSUoS and TCR TNUoS) and deliver £8m of consumer value through reduced ESO Totex spend.
Explanation of variance	Our original BP1 forecast costs were based on re-engineering the current CAB system through the Revenue 21 project. In summer 2019, we ran an informal RFI to the market, whilst also asking the existing supplier to re-assess the health of the current system and propose options for re-engineering. The result of these processes was that the replacement of the existing solution would be more cost effective due to complexity of existing system architecture. In parallel, Settlements conducted a procurement exercise (410), and its outcome would help inform possible solutions for the enduring CAB solution, as requirements were closely aligned. This would also reduce additional time and cost for a 2nd procurement exercise for a similar niche product. Urgent regulatory changes (CMP264/265/268) and the impact of COVID-19 resulted in reprioritisation of activities, leading to the project starting June 2021. Moving from re-engineering the existing solution to building a replacement system also resulted in increased costs for integration, onboarding resources, data transfer, additional licences and increase in size of environments.
Risks / Uncertainty	There is a risk that, as the project started later than planned, the timescales may extend into BP2. There is a risk that the size and complexity of the full scope of foundational releases may not be delivered in time leading to insufficient funding Setting up a new platform on the ESO IT infrastructure may uncover further complexities during testing, leading to extended timescales. There is a risk that critical project resources leave leading to disruption in cadence and ability to deliver. Urgent Regulatory and non-Regulatory activity could be added to the backlog leading to unclear funding, extended timescales and resource for deliver.

EU Regulatory changes (-6.4m)

Cost benchmark for BP1	£18.0m
Forecast expenditure over BP1	£11.6m
Variance	**-£6.4m**

Background	The UK withdrawal from the European Union has caused uncertainty, not only for the ESO but also the industry at large and BP1 is proving to be a transitional period as the ESO seeks to understand the implications of UK exit from the EU and the obligations under the TCA.

As such in FY22, the ESO has started work to understand and align to the Trade and Cooperation Agreement (TCA) obligations and to ensure compliance with retained regulations in UK law.

Explanation of variance	The underspend is due to the fact that the benchmark numbers were submitted prior to Brexit. With the UK leaving the European Union (EU) and ENTSO-E, the ESO relationship with our European counterparts has fundamentally changed. This has led to the UK not being able to take part in TERRE or MARI, which were forecast to cost a considerable amount during the BP1 period. In FY22 (and throughout FY23) the ESO will continue to carry out analysis and implementation of system changes required as a result of regulations that are retained within UK law in FY22. In addition, the work to ensure compliance to the TCA has so far revolved around supporting the ESO business to develop, define, and agree with internal and external stakeholders the options required to operationalise technical procedures brought about by the TCA. Whilst this work is vital to deliver compliance, no actual changes to IT systems have been made, which has meant lower spend. It is expected that this work is set to continue in FY23. As the ESO work through the various options, actual systems change delivery may start in FY23 for both Capacity Calculation and Cross Border Balancing (interim solution) activities, providing an agreement of the details of each technical procedure can be reached with all relevant 3rd parties.
Risks / Uncertainty	There is a risk that Clean Energy Package derogations are not granted. If this were the case spend in FY23 and into the BP2 period could be significantly higher than current forecast. The working assumption supporting the FY23 forecast is that IT will have to start to deliver changes for the Cross Border Balancing interim solution and Day Ahead Capacity Calculation from Aug 2022, this would require agreements to be made with EU TSO's, which given the political landscape means that there is low confidence on gaining any firm delivery dates. Should those dates change, spend may move back into BP2.

Role 3 (System insight, planning and network development) expenditure

For Role 3, we are currently forecasting to spend **£2m** more than the cost benchmark over the BP1 period. This is due to 3 main factors: Offshore Coordination **(+£4.9m)** and Early Competition **(+£4.2m),** partly offset by Zero Carbon Operability **(-£6.0m)**.

We provide more detail here about the main factors leading to the deviation from the benchmark.

Offshore Coordination (+£4.9m)

Cost benchmark for BP1	£0.6m
Forecast expenditure over BP1	£5.5m
Variance	**£4.9m**

Background	The ESO Offshore Coordination project has a key role in ensuring the government target of 40 GW of offshore wind by 2030, and net zero carbon emissions by 2050 are met. In Ofgem's Decarbonisation Action Plan in February 2020 the ESO was asked to carry out an options assessment for offshore transmission. We delivered that in December 2020 and it demonstrated significant cost, environmental and community benefits from taking a coordinated approach to the onshore and offshore transmission systems.

Whilst the options assessment was carried out, BEIS established the Offshore Transmission Network Review (OTNR), which sets out activities to deliver a coordinated offshore transmission network. Our primary activities across the three main OTNR workstreams are:

Early Opportunities - Supporting offshore wind and interconnector developers with their proposals for early coordination opportunities, assessing benefits and barriers, and removing the barriers within the ESO's remit

Pathway to 2030 – Delivering the Holistic Network Design (HND) and identifying and considering and implementing required changes to codes, standards and ESO processes.

Enduring Regime – providing relevant input to the OTNR, developing proposals within the ESO's remit.

Explanation of variance

The resources included in the 2-year benchmark for offshore coordination were effectively to carry out the options assessment activity, which ended up being delivered in the RIIO-1 period.

We have been asked to carry out additional roles and activities by BEIS and Ofgem across the OTNR workstreams, leading to the new expected cost of £5.5m over the 2-year period.

The delivery of the HND in particular is a significant task both in terms of delivery and stakeholder engagement, which is reflected in the resource requirement.

We worked closely with Ofgem and BEIS to discuss the scope of our activity and have regular progress meetings as the work is continuing.

Consultancy spend to support the work has been competitively tendered or has used framework agreements that have previously been competitively tendered to ensure we are efficient.

Risks / Uncertainty

The OTNR and our role within it continues to evolve as decisions are made by BEIS and Ofgem on consultations that have already taken place and are yet to come. The outcome of these may impact resource requirements.

We have recently committed to carry out a second design exercise to account for the higher than expected levels of offshore wind coming from the ScotWind leasing round. We are currently developing our detailed plan on this but there may be a requirement for additional resources to run parts of the first and second design exercises in parallel and ensure it is meeting requirements for a second transitional Centralised Strategic Network Plan under Ofgem's Electricity Transmission Network Planning Review (ETNPR).

Government's British Energy Security Strategy may also have an impact on our role and the required resources in future.

Early Competition (+£4.2m)

Cost benchmark for BP1	£0m
Forecast expenditure over BP1	£4.2m
Variance	**£4.2m**

Background

In May 2019 as part of their RIIO-2 Sector Specific Methodology Decision Document, Ofgem requested the ESO develop proposals for how an Early Competition could be run.

Early Competition refers to competition that occurs prior to the detailed design, surveying and consenting phases of solution development. This means organisations could compete for the design, build and ownership of onshore transmission solutions.

Early competition will help encourage new ways of working and aims to seek the best solutions at a fair cost for consumers.

In April 2021, we submitted our Early Competition Plan to Ofgem, describing an end-to-end process of how early competition may work, proposing how models for early competition could be implemented and outlining the roles and responsibilities of all parties in the end-to-end process.

Explanation of variance

Early Competition was not originally included in the RIIO-2 benchmark as insufficient work had been completed at the time of the RIIO-2 submission to understand the scope of work required.

We have been working closely with Ofgem through the development of proposals for Early Competition and had agreement, through Ofgem's open letter in May to continue with low regret activities, following the submission of our Early Competition Plan in April 2021, to maintain momentum.

Through this year we have continued with a small internal team to progress low regret activities whilst waiting for Ofgem to consult and decide whether to implement the proposals. The size of the team and the activities were agreed with Ofgem in May 2021.

Following Ofgem's decision to implement Early Competition, published 28 March, through the second year of BP1 our expenditure on Early Competition will increase as we grow the team for implementation. Indicative team size and expenditure has been shared with Ofgem, who were comfortable with what we are proposing.

Consultancy spend to support the implementation phase has been competitively tendered to ensure we are efficient.

Risks / Uncertainty

The key risk and uncertainty for Early Competition is the legislative timetable. We are still anticipating this to occur in Spring 2022, however any delays would have an impact on implementation timescales and costs.

Zero Carbon Operability (-£6.0m)

Cost benchmark for BP1	£10.2m
Forecast expenditure over BP1	£4.2m
Variance	**-£6.0m**

Background

There were 5 phases in the original plan, with phase 1 being development of non-operational demonstration. Since we began phase 1 in 2020, we have seen new technologies and different delivery mechanisms emerging from the market. As a result, we decided in quarter 3 2020 that there was a need to add a Phase 0 as a Discovery stage.

Phase 0 started from April 2021 and is due to finish in December 2022. It will run in parallel to Phase 1.

Explanation of variance

During our start up activities, the plan was re-shaped with the introduction of a Discovery phase to include

- assuring the project objectives
- more optioneering of different designing solutions
- developing the business case
- engaging across industry with more service providers to establish a core delivery team.

It was also agreed to run the Non Operational Demo for a longer period of time before commencing further roll out, in order to ensure the test results are more comprehensive and the solution adapted where required before further investment/ramp up is undertaken.

This has resulted in an overall re-phasing of the delivery and the bulk of the capex investment (£4.7m) moving from BP1 into BP2. We do not expect this to impact the timeline for the delivery of the benefits of this activity.

Risks / Uncertainty

Though some activities have been moved back, we actually explore wider technology development and alternative suppliers, which will de-risk our delivery in later stages.

The benefits were assessed in 2018 and have not been refreshed, but we would expect benefits to increase due to the increasing volume of renewables.

Indirectly Attributable Costs (All roles)

Our assessment for value for money is not only based on costs which are directly driven by activities within a particular role. Some activities support all roles equally and a summary of these costs and our forecast against benchmark is given below.

	Activity	BP1 cost Benchmark £m	BP1 Forecast £m	Variance £m	Variance %
	ESO Opex	15	21	+6	+38
	Capex	43	33	-10	-23
	Total Business Support	126	126	-	-
Business Support sub-categories	IT & telecoms	94	88	-6	-6
	Property management	11	8	-3	-27
	HR & non-operational training	5	6	+1	15
	Finance, audit & regulation	6	9	+3	37
	Insurance	2	1	-1	-15
	Procurement	1	1	-	-
	CEO & group management	7	13	+6	94
	Other Price Control Costs	28	27	-1	-2
	Total	**212**	**207**	**-5**	**-2**

Our ESO opex costs relate to ESO’s Business Change, Innovation, Assurance, Regulation and Customer teams. The key drivers of increased cost compared to benchmark are more innovation resources required to support Virtual Energy Systems and SIF projects as well as generally increased levels of supporting activities due to faster growth of the business.

Indirectly attributable capex costs relate to Business Services systems, Hosting, IT Operations and Tooling, Enterprise Data Networks and End User Computing as well as spend on property. Spend on Business services systems is broadly in line with benchmark with higher spend on our ERP system being offset by lower spend on smaller IT systems. The lower forecast cost compared to benchmark is largely driven by lower investment in Hosting and Enterprise Data Networks.

Business Support costs are overall in line with Benchmark with lower IT spend being offset by a higher than forecast allocation of corporate centre costs.

Other price control costs mainly relate to cyber security costs and are in line with Benchmark.

Amber projects (All Roles)

Ofgem's ESORI guidance also defines 4 specific IT projects for which additional reporting on delivery and latest costs forecast is required. These are high-value projects which Ofgem will track more closely due to the uncertainty of scope at the time of Final Determinations. This follows on from Ofgem's assessment of ESO's IT projects, which is set out in Appendix 4 of Final Determinations[54].

These projects are:

1. 110 - Network Control
2. 180 - Enhanced Balancing Capability
3. 220 - Data and Analytics Platform
4. 500 - Zero Carbon Operability

1. 110 - Network Control

110 Network Control is delivering two primary projects: the Integrated Energy Management System (IEMS) Life Extension project and the Network Control Strategy project. The former will maintain the service life of the existing IEMS platform, the latter will develop the strategic replacement to IEMS. This will incorporate new Situational Awareness functionality and separate Transmission and System Operator features.

Investment forecast status:	Higher than cost benchmark

We are **£4.6m** above our investment benchmark of **£9.0m** for BP1 (£8.1m capex, £0.9m opex). Commentary is provided above, under Role 1.

This supports the delivery of the following overarching milestones:

Role 1	A1.3	Transform Network Control	D1.3.1, D1.3.2, D1.3.3
	A2.3	Training simulation and technology	D2.3.1
Role 2	A4.3	Deliver a single day-ahead response and reserve market	D4.3.3

2. Future balancing (180 - Enhanced Balancing Capability)

This investment delivers a new balancing platform to enable Electricity National Control Centre (ENCC) engineers to perform the balancing actions needed to operate a zero carbon system.

Investment forecast status:	Higher than cost benchmark

Our current investment forecast for BP1 is **£40.2m** which is higher than the Final Determinations position of **£20.3m**. Commentary is provided above, under Role 1.

This supports the delivery of the following milestone:

Role 1	A1.2	Enhanced Balancing Capability	D1.2.1

3. 220 - Data and Analytics Platform

220 Data and Analytics Platform is foundational work to unlock the value of the data we hold. It will be the key technology underpinning all our internal and external data management, pulling together data from a variety of sources and ensuring there is only one source of the truth. This includes critical national infrastructure (CNI) and non-CNI data and analytics platforms as well as their associated integration platforms.

[54] https://www.ofgem.gov.uk/system/files/docs/2021/02/final_determinations_-_eso_annex_revised.pdf

Investment forecast status:	In line with cost benchmark

Our current forecast is **£10.9m** which is **£0.2m** lower than the investment benchmark of **£11.1m** for BP1 (£8.9m capex, £2.2m opex).

Good progress has been made with respect to the DAP platform build; the conceptual solution architecture has been agreed and multiple design patterns have been developed and tested; several PoC's have been successfully executed, and a comprehensive backlog of user-stories has been developed. An implementation partner has been selected to complete the build and configuration of the platform and we are on track to stand up an MVP capability within the agreed BP1 timeframes

This supports the delivery of the following overarching milestones:

Role 1	A1.3	Transform Network Control	D1.3.1, D1.3.3
	A1.4	Control Centre Architecture	D1.4.1
	A17	Transparency and Open Data	D17.1, D17.2
Role 2	A5.3	Improve our security of supply modelling capability	D5.3
Role 3	A11.1	Refresh and integrate economic assessment tools to support future network modelling needs	D11.1
	A11.2	Implement probabilistic modelling	D11.2
	A11.3	Build voltage assessment techniques into an optimisation tool	D11.3
	A11.4	Build stability assessment techniques into an optimisation tool	D11.4
	A13.1	Carry out analysis and scenario modelling on future energy demand & supply	D13.1
	A13.2	Conduct mathematical and modelling and market research on local and wider geographic demand information	D13.2
	A13.5	FES: Integrating with other networks and supporting DNOs to develop their own DFES processes	D13.5.1, D13.5.2
	A15.6	Transform our capability in modelling and data management	D15.6.1, D15.6.2, D15.6.3, D15.6.4, D15.6.5, D15.6.7
	A16.3	Work more closely with DNOs and DER to facilitate network access	D16.3.4

4. 500 - Zero Carbon Operability

Consistent with our proposal in Final Determinations, project 500 Zero Carbon Operability is delivering the monitoring and control system and services which will improve frequency stability, increase system reliability, and in turn lead to a reduction in the expenditure on managing frequency events. Phase 0, which is understanding the Zero Carbon Operability capability of the GB network, has commenced. This will determine the requirements, design and approach for Phase 1, which is a non-operational demonstration.

Investment forecast status:	Lower than cost benchmark

Our investment forecast for BP1 is **£4.2m** (totex) which is **£6.0m** below our investment benchmark of **£10.2m** for BP1 (£9.2m capex, £1.0m opex).

Commentary is provided above, under Role 3

This supports the delivery of the following milestones:

Role 3	A15.7	Deliver an operable zero carbon system by 2025	D15.7.1

Cost Benchmark Summary

This information comes from Cost Benchmark Summary in the ESO Costs and Outputs Regulatory Reporting Pack (RRP)
All figures are in 2018/2019 prices

	Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	Forecast 2022/23 Costs £m	Forecast Total £m	Higher / (Lower) £m	Variance % %
TOTAL	Total Role 1 Costs	**208.0**	**110.0**	**136.2**	**246.2**	**38.2**	**18.4%**
	Total Role 2 Costs	**158.6**	**72.1**	**88.3**	**160.4**	**1.8**	**1.1%**
	Total Role 3 Costs	**139.4**	**58.0**	**83.1**	**141.1**	**1.7**	**1.2%**
	Total Price Control Costs	**506.0**	**240.1**	**307.6**	**547.7**	**41.7**	**8.2%**
Role 1	ESO Opex	61.6	27.8	29.2	57.0	(4.7)	(7.6%)
	Capex	63.5	49.1	63.4	112.5	48.9	77.0%
	BSC	12.0	1.8	5.8	7.6	(4.4)	(36.5%)
	Total Directly Attributable to Role 1	**137.2**	**78.7**	**98.4**	**177.1**	**39.9**	**29.1%**
	ESO Opex	5.2	3.6	3.6	7.1	2.0	38.4%
	Capex	14.4	6.5	4.5	11.0	(3.3)	(23.2%)
	BSC	42.1	17.4	24.6	42.0	(0.1)	(0.2%)
	Other Price Control Costs	9.2	3.9	5.1	9.0	(0.2)	(2.4%)
	Total Indirectly Attributable to Role 1	**70.8**	**31.3**	**37.8**	**69.1**	**(1.7)**	**(2.4%)**
Role 2	ESO Opex	35.1	16.1	17.6	33.7	(1.4)	(4.0%)
	Capex	35.3	23.2	29.2	52.5	17.2	48.8%
	BSC	17.5	1.5	3.6	5.2	(12.3)	(70.5%)
	Total Directly Attributable to Role 2	**87.8**	**40.8**	**50.5**	**91.3**	**3.5**	**4.0%**
	ESO Opex	5.2	3.6	3.6	7.1	2.0	38.4%
	Capex	14.4	6.5	4.5	11.0	(3.3)	(23.2%)
	BSC	42.1	17.4	24.6	42.0	(0.1)	(0.2%)
	Other Price Control Costs	9.2	3.9	5.1	9.0	(0.2)	(2.4%)
	Total Indirectly Attributable to Role 2	**70.8**	**31.3**	**37.8**	**69.1**	**(1.7)**	**(2.4%)**
Role 3	ESO Opex	38.2	21.4	26.0	47.4	9.2	24.1%
	Capex	25.5	4.8	15.6	20.4	(5.1)	(20.0%)
	BSC	4.9	0.5	3.6	4.1	(0.7)	(15.2%)
	Total Directly Attributable to Role 3	**68.6**	**26.7**	**45.2**	**71.9**	**3.3**	4.9%
	ESO Opex	5.2	3.6	3.6	7.1	2.0	38.4%
	Capex	14.4	6.5	4.5	11.0	(3.3)	(23.2%)
	BSC	42.1	17.4	24.6	42.0	(0.1)	(0.2%)
	Other Price Control Costs	9.2	3.9	5.1	9.0	(0.2)	(2.4%)
	Total Indirectly Attributable to Role 3	**70.8**	**31.3**	**37.8**	**69.1**	**(1.7)**	(2.4%)