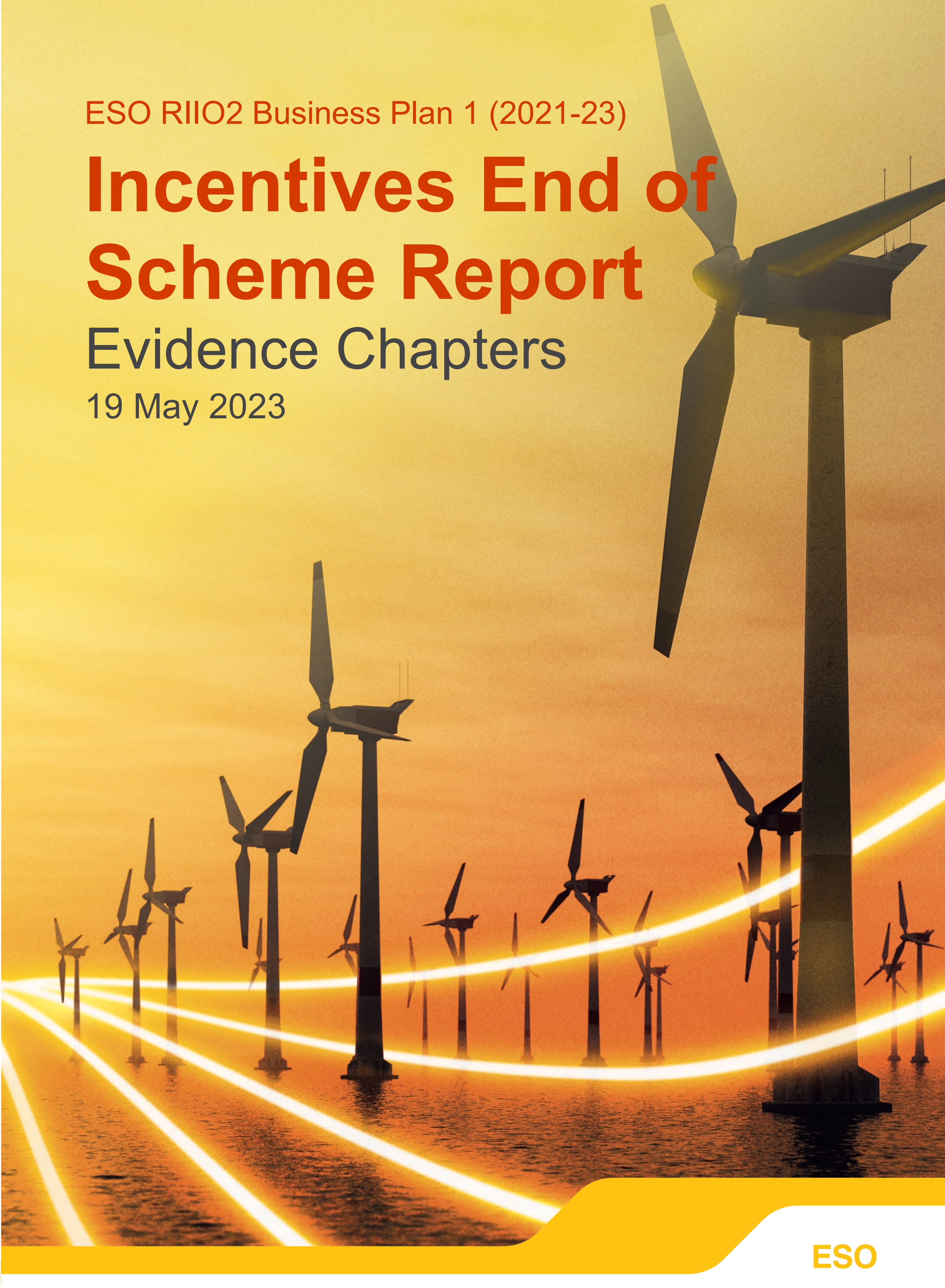
ESO RIIO2 Business Plan 1 (2021-23)

Incentives End of Scheme Report

Evidence Chapters

19 May 2023



Contents

Role 1

Control Centre operations

Role 1: Control centre operations

Plan Delivery

- We have completed 178 out of the 198 milestones planned for the two-year period. Of the 20 milestones which are not complete, 1 is delayed in order to deliver an improved outcome for consumers, 10 are delayed for reasons outside of ESO control, and 9 are ESO-related delays. We have:
- Successfully operated a secure reliable electricity system through unprecedented conditions.
- Developed a suite of preparedness activities for winter 22/23.
- Improved transparency of decision making through our Operational Transparency Forum (OTF).
- Driven consumer benefit through our market monitoring function.
- Delivered the first successful Distributed ReStart project.
- Delivered energy forecasting improvements.

Metric performance

Over the 2-year period:

- 1A Balancing costs: £6,967m vs benchmark of £3,020m (below expectations)
- 1B Demand forecasting: 2.3% vs benchmark of 2.1% (below expectations)
- 1C Wind generation forecasting: 4.66% vs benchmark of 4.75% (meeting expectations)
- 1D Short notice changes to planned outages: 1.8 per 1000 outages vs benchmark of 1 to 2.5 per 1000 (meeting expectations)

Stakeholder evidence

Role 1 survey (Mar-23):

- 31% exceeding expectations
- 62% meeting expectations
- 8% below expectations

Highlights:

- Strong skew towards 'exceeding expectations' in our March 2023 survey.
- Positive feedback regarding the OTF which has become a valuable information source for our stakeholders.
- Engagement from our colleagues is seen as very good with very clear processes.
- Open, transparent and good quality information was noted by some stakeholders.

Demonstration of plan benefits

- Control centre architecture and systems (A1) to deliver £1.5bn consumer benefit over RIIO-2 with £417m already delivered in BP1.
- Control centre training and simulation (A2) to deliver £25m consumer benefit over RIIO-2 with most of the benefit to be delivered from BP2.
- Restoration (A3) to deliver £115m of net benefit from 2025 to 2050.
- Implementation of our Frequency Strategy will drive at least £1.8bn of savings in 2023.

RREs:

- 1E Transparency of Operational Decision Making: 99.7% of actions have reason groups allocated
- 1F Zero Carbon Operability (ZCO) indicator: ESO has accommodated up to 90% zero carbon generation
- 1G Carbon intensity of ESO actions: Monthly average of 4.7gCO2/kWh of actions taken by the ESO
- 1H Constraints cost savings from collaboration with TOs: £4,182m
- 1I Security of Supply reporting: 0 frequency excursions and 4 incidents where frequency was 0.3 – 0.5 Hz away from 50Hz for more than 60 seconds
- 1J CNI outages: 6 planned and 0 unplanned BM outages

Value for Money

- Our total expenditure for role 1 in BP1 was £226.0m, which was 8.6% higher than the benchmark of £208m.
- The main driver of the overall increase in investment costs for BP1 is the Balancing Programme, where we have spent £33.0m more than our BP1 benchmark.
- The cost included in our RIIO-2 business plan which was developed in 2019, was a high-level estimation underpinned by key market, operational and technology assumptions, some of which did not materialise.
- During BP1, through engagement with and support from industry, we have developed a Roadmap to deliver a new Open balancing Platform (OBP) which deliver our operational capability to support our zero carbon operability requirements.

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.

See below an overview of key highlights and challenges for role 1 over the two years of the Business Plan 1 period.

Highlights

Preparing for Winter 22/23 (including new activities in BP1)

Throughout this document there are many references to the effort put in across the business to prepare for winter 2022-23. This was a particularly challenging period due to the illegal Russian invasion of Ukraine and significant changes in the energy landscape. Recognising these challenges, we published an early view of winter in July 2022 and led a GB and Europe industry plan to meet security of supply needs. Following the publication of our Winter Outlook in the autumn of 2022, we took action to design, procure and implement enhanced services to protect electricity margins over the winter peak periods (November to March).

We went outside of normal market arrangements to put in place winter contingency contracts for four coal generating units (up to 2GW) and grew, tested and implemented the new Demand Flexibility Service (DFS). We stepped up our regular communication with TSOs neighbouring GB with daily market and operational intelligence calls, and created a new function and processes to forecast tightening electricity margins. Throughout the winter we kept stakeholders informed via weekly briefings at our Operational Transparency Forum (OTF) where we have consistently had over 500 participants. There were five occasions during the winter when we invoked the enhanced actions to recover electricity margins, of which we only ran coal units once. On all occasions we maintained good communications with stakeholders and market participants.

Below we go into more detail on DFS and the winter contingency contracts:

DFS (Roles impacted: All)

- DFS was developed and implemented in four months (July-October) in the run up to winter as a key tool in helping preserve security of supply. In total 1.6 million homes and businesses signed up across 31 providers to be part of this critical operational service.
- During the winter, two live uses of the product were made on 23 and 24 January, where just under 300MW of demand flexibility was provided. Between the live events and test events we spent approximately £11m through to the end of March 2023.
- 5,333 consumers averaged 1MW of DFS delivered.
- We made the right decisions to expedite development and deliver the product in time to make a difference for this winter. The introduction of this will act as a major catalyst to unlock the enduring value of flexibility, and the potential for reducing future balancing costs and support the transition to net zero. We are analysing the results from this winter, and bringing more suppliers on board for an improved product being designed for next winter.

Winter Contingency Contracts (Roles impacted: 1 and 2)

- Winter contingency contracts were put in place at the request of the Secretary of State to help enhance system resilience during the Winter. Contracts were struck with three different organisations (EDF, Drax and Uniper), covering five generator sets. To minimise market distortion, the units were held in reserve and would only be dispatched following the rules set out in our 'Order of Actions'. We warmed the units where there were tighter margin periods throughout the winter. We ran two of the units at West Burton (EDF) on 7 March, which was the only time we ran the coal. Each unit ran for approximately six hours.

In preparation for the winter, all Electricity Control Room staff undertook extensive training on how to enact enhanced and emergency measures including emergency services from interconnectors, enacting electricity demand control and practicing on the training simulator how to restore the electricity system following a national power outage. We participated widely in the three-day energy sector gas supply emergency exercise (Exercise Degree) in October. This tested the interaction between national gas and electricity supplies, tested new information sharing tools (co-created by the ESO and the Gas System Operator (GSO)), played out the outcomes and optimised the impacts of gas and electricity load shedding. Our Silver and Gold Commands were stood up to liaise with Government, the regulator, GSO and communication teams and direct tactical and strategic responses. The learnings from the exercise were taken forward and integrated into our winter preparation plans.

Two examples of how we managed difficult events on the electricity system successfully are as follows:

- During the early hours of 29 December 2022, due to the interaction of wind generation commercial arrangements (Contracts for Difference) and negative market prices, large steps in wind generation ramping off and on unexpectedly were experienced (up to 2.4GW). We maintained security standards for system frequency throughout. We shared this with the Wind Advisory Group to develop industry best practice.
- On 25 January 2023, whilst the transmission system was being stretched by market conditions, a critical 400kV north to south transmission circuit faulted at the same time as a major system fault in the north of Scotland. We had to invoke emergency measures on continental interconnectors, manage rapidly changing system conditions and reconfigure both Scottish and English transmission networks to maintain security standards.

We provided a large amount of proactive support to commission the faulted IFA Interconnector Bipole in January (ahead of forecast). We received really positive customer feedback from National Grid Ventures thanking all staff concerned for their help to expedite its return.

Market monitoring and review of the Balancing Market (new activity in BP1)

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 we are a Person Professionally Arranging Transactions (PPAT). We have had a small team of experienced staff in place to fulfil this obligation since November 2021. We have rolled out monitoring procedures across all of our markets and products, which vary in accordance with the findings of risk assessments which are refreshed every six months.

The Market Monitoring team have worked at pace to deliver a suite of tools and dashboards which give visibility across our markets and products, including a tool which allows us to monitor the Balancing Mechanism (BM) by extracting data daily and querying it against market participants' dynamic parameters in line with REMIT and other market rules. This BM monitoring tool has been developed in partnership with a third party, whereas other elements of team monitoring capability have been developed internally at low cost. 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. To date we have has processed over 600,000 alerts, conducted further investigations on approximately 3,500 of these, and submitted 44 STRs to Ofgem. We continue to develop new tools allowing us to monitor for more complex suspicious behaviour which may be exhibited over a long period of time, or across several units.

Our Market Monitoring team also conducted a review of the balancing market following significantly high balancing costs in the winter of 2021-22. After extensive stakeholder engagement on the reasons driving these high costs, the review found that they were a result of system tightness combined with inflexibility of marginal units. Whilst no conclusive evidence was found of rule breaches, the report made some concerning market behaviour visible, and we have since been supporting Ofgem on the creation of a new license condition which would prevent this behaviour in the future. we have focussed on engaging with market participants wherever possible. In July 2022 we held a further listening session on balancing costs so that participants were able to voice their concerns.

Following the volatility of last winter and the learnings we took regarding market behaviour, we have been proactively conducting monthly reviews of the balancing market, focussing on costs and behaviour patterns. We shared our findings via the Operational Transparency Forum. At the end of winter, we will also be conducting a full winter review and sharing these findings with stakeholders. As part of our regular processes, we reach out directly to market participants wherever possible to understand their data, ask for explanations of unexplained findings and ultimately drive improvements in the quality of data received into the(BM). By working collaboratively with the market, we have seen an improvement in data across 37 units in the BM, which has contributed to better situational awareness for our control room staff and therefore a more efficiently functioning market.

Frequency Risk and Control Policy

The following deliverables, combined, have transformed how we manage frequency risks on the system, resulting in consumer savings of £1.8bn: the Frequency Risk and Control Report (FRCR), the Accelerated Loss of Mains Change Programme (ALoMCP), the implementation of Dynamic Containment (DC) and phase 1 of our Stability Pathfinder programme.

The ALoMCP began in 2019 and changed the loss of mains relays on distributed generation, ensuring the right settings were applied to avoid any unwanted disconnection of embedded generation. To date, 94% of the generation capacity in scope has confirmed compliance with the required changes. This represents changes to a total of 24GW of capacity.

The first FRCR was published in 2019 and the policy changes that this report recommended were largely facilitated by the ALoMCP. The resulting improvement in system stability meant that we were able to change our policy for managing system frequency events. Without the ALoMCP, we would not have been able to make some of the fundamental changes recommended through FRCR.

In 2021 we implemented DC, a fast-acting frequency response service. This provided us with a further tool to manage how we manage system frequency risks.

Finally, the first phase of our Stability Pathfinder programme procured inertia services for England and Wales, all of which are now operational. Without these, we would have been required to buy additional inertia capability in the BM in order to meet our minimum inertia policy.

A combination of these four projects has enabled us to achieve approximately £1.8bn in balancing cost savings, compared with what would have been the case had none of these changes been made.

FRCR is now an annual process in which we consult on changes that could be made to ensure we are achieving the right balance of cost versus risk when managing frequency deviations. We have a list of topics that could be considered through the FRCR process to continually improve our policies.

We continue to grow our pipeline of DC providers, improving how we manage frequency risks and also improving the cost to consumers by increasing competition in the DC market.

Finally, whilst the ALoMCP has now concluded we continue to liaise with Distribution Network Operators. We aim to establish the loss of mains compliance status for as much as possible of the remaining 6% of embedded generation capacity that is within scope of the G59/3-7 loss of mains protection requirements. This allows our system risk studies to be updated with the latest data from embedded generators to minimise balancing costs incurred managing frequency risks.

For more detail on the £1.8bn savings driven by these changes, please see our Consumer benefit case study for Role 1: FRCR / Frequency Strategy (FRCR + LoM + DC + Stability Pathfinder Phase 1).

Go live of interconnector capacity

We worked closely with RTE and the IFA2 project teams over winter 20/21 to ensure the successful go live of the IFA2 interconnector in January 2021.

We also worked with North Sea Link (NSL) teams 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 2021.

Similarly close liaison was maintained with Eleclink to ensure successful go live in May 2022, and the introduction of an intra-day market in October 2022. During the commissioning phases regular liaison took place between affected teams including our real time teams in the Electricity National Control Centre to ensure that system security and operability costs were managed during this critical phase.

Following the catastrophic fire on IFA1, we worked closely with NGV and RTE to ensure the restoration of IFA1 on full capacity was facilitated and expedited in January 2023.

The commissioning of these links provided additional capacity for winter operation.

Restoration

Below are details of several activities from the BP1 period.

Electricity Restoration Standard	In October 2021, changes to the ESO licence came into effect, requiring that we implement the new Electricity System Restoration Standard (ESRS). In April 2022 we established the Grid Code and Distribution Code industry working group (GC0156) for Facilitating the Implementation of the Electricity System Restoration Standard. The workgroup has been meeting monthly to discuss and agree the legal changes required to see two codes to meet the new restoration timescales set out in the ESR Standard. These changes will be critical in helping to deliver industry improvements to resilience and restoration capability, supporting compliance with the new ESR Standard by the end of December 2026. Further working groups to implement changes to other code frameworks have been formed throughout 2022-23. We are aiming to have all code changes submitted to Ofgem, as planned, by September 2023.
System Restoration 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.
Restoration Tenders	In 2022 we launched SE and Northern Tenders, as well as a wind specific tender, incorporating output from the Distributed Restart project and opening the Restoration market to distribution-connected providers. Nearly 300 Expressions of Interest were received for these tenders across seven technology types, connected at both transmission and distribution levels. We are continuing to work with the relevant DNOs to assess the feasibility of the distribution-connected submissions to form our first Distribution Restoration Zones, as trialled and defined by the Distributed Restart Project.
Distributed Restart findings published, and project extended	The Distributed Restart project has been extended with Ofgem's approval to undertake one more industry-first live trial which is planned for mid-2023 that goes beyond the original project remit. This live trial will involve a battery energy storage system (BESS) with grid-forming technology to restart the network. It will also use the prototype Distribution Restoration Zonal Controller (DRZC) to stabilise and maintain the power island within voltage and frequency limits. We published our Final Findings report covering the original project scope in November 2022 summarising our final findings and proposals. In this report we highlighted the key learnings delivered by the project and highlighted the resources that provide a basis for the industry to implement these learnings. Findings from this additional trial will be published within a follow-on Power Engineering and Trials report, which will be available on the project' website in late-2023.

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

During BP1, we completed initial releases for National Demand and Grid Supply Point (GSP) forecasting products and delivered enhancements to PEF in the Control Room.

The National Demand product has successfully delivered estimated year-on-year savings of £175m in balancing and reserve costs through improved forecasting models. This was achieved by maintaining an improved level of forecasting performance compared to the RIIO-1 period.

The GSP Forecasting product comprises three components: GSP Net Demand, GSP PV (photovoltaic), and GSP Wind. We have already successfully integrated the GSP Net Demand product through two releases into operational systems. This offers forecasts with a half-hourly resolution, updated every hour for up to 14 days ahead period, whereas the legacy system (EFS) provides forecasts updated only four times a day and up to a seven-day period. The remaining GSP PV and Wind components will be implemented in BP2 on the Azure cloud to align with other ESO initiatives, such as the Data and Analytics Platform (DAP) and Open Balancing Platform (OBP). This is expected to deliver additional year on year annual savings of around £17m on balancing costs.

In addition, we delivered new features and enhancements to PEF, enabling benefits which include enhanced security and system performance, improved forecasting accuracy, and new functionalities to reduce approximately 500 hours of manual workarounds in the Control Room.

We also published a revised roadmap for forecasting, including PEF, to enable early delivery of consumer value and maximise benefits from our delivery milestones. The new roadmap was included in our BP2 submission, and it's based upon the adoption of a product model and agile ways of working.

Data and Analytics Platform (DAP)

The Data Analytics Platform will deliver a single source for all ESO data, providing accessibility and transparency for business users. It will provide a consolidated data source and analytical user interface for our Control Centre engineers and all other internal stakeholders, allowing them to better visualise and analyse the operational data. It is a critical programme of work to be delivered as part of our RIIO-2 commitments and will provide the base for several other RIIO-2 investments.

The platform comprises various products and services that will enable us to capture, curate and consume data, 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 DAP Minimum Viable Product went live at the end of Q3 2022/23 with the inclusion of the first Use Case for Inertia Monitoring. This implementation was delivered to time and within budget using the expertise of Avanade (DAP strategic partner & Managed Service Provider) in collaboration with Adam Partners and National Grid permanent resources. A roadmap of Use Cases for inclusion over 2023/24/25 has been defined, with the second release due in Q4 2022/23 to include functional connectivity for Single Markets Platform, Platform for Energy Forecasting and the Data Portal. Subsequent releases due in 2023/24 will include EUDAs (End User Developed Applications), Network Monitoring, Data Catalogue and integration with the Digital Engagement Platform (DEP). To support innovation and the inclusion of emerging technologies, significant focus has also been given to additional capabilities such as Artificial Intelligence, Machine Learning and Power Platform Capabilities.

Digital Engagement Platform

Our Digital Engagement Platform (DEP) sits at the heart of our vision for digital capability, providing a common engagement experience for all stakeholders, and a secure single point of access into our systems and external facing processes. It provides visualisation of open and subscribed content and data, compliant with data classification policies and standards.

DEP lays the foundations for the FSO's digital presence by replacing the existing website (nationalgrideso.com), which is hosted on a shared National Grid platform with a dedicated ESO website. It provides management capability for all internet engagement channels. It will enable external customers and stakeholders to access our data and services in a simple, intuitive, predictable, personalised, manner, offering a frictionless user experience and making it easier to do business with us. It will serve as a 'digital concierge' providing accessibility to our markets, data and new insights, as well as enabling more engaging ways to collaborate and participate in our journey to net zero.

DEP went live in Q4 2022-23. The foundational release included our new web platform, enhanced navigation, advanced search and new architecture and templates for balancing services content. This release has made our content more accessible and discoverable for a wide range of stakeholders.

This release also lays the foundations for enhanced features including an ESO account dashboard, integrated query management, and personalisation. These features will be prioritised according to customer value, and released with a regular cadence throughout 2023-24.

Artificial Intelligence (AI) and open data developments

In 2022, we launched a new Innovation project called ‘Artificial Intelligence Centre of Excellence’ (AI CoE) which replaced the ‘ESO Lab team’. Previous machine learning projects that were delivered by the ESO Labs team are in the process of being moved into business-as-usual and being distributed across relevant ESO teams. The AI Centre of Excellence will focus on developing an ongoing pipeline of talent by building partnerships with academia, energy companies and tech ecosystems that will help us and the wider energy sector. The goal of the AI CoE is to streamline problem solving for net zero challenges by leveraging cross-industry partnerships which specialise in data science. In addition, the AI CoE ambition is to enable data science maturity growth across the energy sector in the UK by establishing a data science resource exchange across the market.

Some of our new and ongoing data science projects include:

Solar Nowcasting	With the Solar PV Nowcasting project, a collaboration with Open Climate Fix, we are aiming to create the world's best PV ‘nowcasts’ (close to real-time forecasts) using cutting edge machine learning, 5-minutely satellite imagery, near-real-time Solar PV power data and numerical weather predictions. The national solar generation forecast developed over the course of this project is 2.8 times better than our existing PV forecast (for forecasts up to two hours ahead). The best national PV forecasts developed from this project have a mean absolute error (MAE) of 190 MW, compared to existing national solar PV forecasts which have an MAE of 650 MW.
National Demand AI Model	Introduced in May 2021, this model 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 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%. Improved forecast accuracy can lead to savings in balancing costs. For example, by reducing the chance of expensive control room actions being required, and in a reduced reserve requirement. The forecasting algorithm is used alongside the pre-existing advanced statistical demand model by the operational forecasting team. Their day-ahead forecasts are reported under Metric 1B Demand Forecasting.
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. This helps raise public awareness of what makes up the electricity that we use and the resultant carbon emissions, and informs users of the greenest time to consume energy.

Domestic flexibility trials - Octopus trials, Powerloop Vehicle-to-Grid trials (new activity in BP1)

By proactively seeking opportunities to trial new technologies and processes we have been able to gain crucial learnings at pace. The trials we completed over BP1 have paved the way for how we adopt domestic assets into our markets, a huge step to a smarter and greener energy system. We continue to look for opportunities where we can develop, design, and implement trials across the ESO, adopting a learn-by-doing approach to bring benefits at pace.

The trials that took place over the last two years have set the scene to unlocking new sources of flexible energy from the domestic sector in system balancing.

1. Octopus Energy flexibility trials:

   The flexibility trials we ran with Octopus Energy laid the foundations for the world leading Demand Flexibility Service, which was implemented in five months as a live service in November 2022.

   Across February and March 2022, we ran eight 'demand turn down' events with Octopus Energy, inciting over 200 MWh of volume reduction across all the two-hour windows. The trial worked with over 100,000 households to prove the flexible potential of this energy resource, showing the active role domestic households could have in system balancing activities. It was the first time we had been able to link Control Centre operations with day-to-day consumer behaviours, promoting energy habits that support the security of the grid. Scaling the results to a national level, we predict that we could expect a potential demand turndown volume greater than 500MW today. This pioneering real-time project proved to be a testbed for the Demand Flexibility Service, a world-leading product that acted as a key emergency tool for us during the challenging Winter 2022-23 period.

2. Powerloop Vehicle-to-Grid trials

   These trials led to the first instances of domestic Electric Vehicle (EV) charge points altering their behaviour in response to a direct signal from our Control Centre. They showed that this new technology type has the potential to play a role in our current markets and highlighted the direct benefits to the whole energy system, from system operations to reduction in all consumer bills. Our latest Future Energy Scenarios (FES) predicted that before 2030, charging from EVs at an average cold spell winter peak could exceed 5GW. This highlights the importance of visibility and management of this emerging energy resource, as well as ensuring the correct market dynamics are in place to protect system security.

   A detailed final report that covers the background, methodology and findings from the trial will be published on our website in Q1 2023/4. The high-level findings are detailed below.

Capability of V2G enabled EV acting as an aggregated unit	Together with Octopus Energy we demonstrated that V2G enabled EV can respond to signals sent from our Control Room, proving the potential of this asset type. Through trial sessions with up to 135 households, we were able to show the Control Room altering individual charge patterns to meet energy balancing requirements, whilst still protecting the end consumers desired charging preferences. The trial demonstrated that, when aggregated, these domestic assets can meet the data requirements necessary for the Balancing Mechanism (BM), as well as providing and delivering energy in response to an instruction from the Control Room.
Barriers to entering the market	Several barriers were highlighted in the requirements of the current BM market framework and registration process. The majority were deemed to be short-term barriers that will be overcome, such as minimum threshold and aggregation requirements, as the market for V2G enabled EVs matures over time. But the current operational metering standards to enter the BM, in particular the types of measurements required and the accuracy an asset must take readings at, has been highlighted as the key blocker that needs addressing to unlock this new energy resource for balancing actions.
Cheaper system costs	Through several live tests with consumers, it was shown that EVs could offer a cheaper alternative to balance the system than traditional fossil fuel burning alternatives, reducing consumer bills and emissions from system operations.
Economic value for consumers	Customers participating in the trial realised a saving of up to £180 per year, compared to smart charging, or £840 per year compared to unmanaged charging on a flat tariff, when adjusted to an annual mileage of 10,000 miles.

Development of new Inertia Monitoring tools

During BP1 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 us to have a clearer view of the inertia on the system, moving away from our traditional estimation methods. This will help us to manage inertia and safely connect more zero carbon power.

The first tool, GE Digital’s Effective Inertia tool, uses phasor measurement units (PMUs) that are being installed across RIIO-2 by Transmission Owners (TOs) to monitor the transmission network. The addition of operational data from our existing tools enables an inertia up to 24 hours ahead. GE Digital’s Effective Inertia tool has been operating since October 2021, providing live inertia monitoring and 24-hour ahead forecast of the inertia contribution for Scotland. Rollout of this tool to cover all of the GB network is dependent on the availability of PMUs from NGET which have been deprioritised and are now intended to start being rolled out in 2023/24.

The second new tool, developed in partnership with Reactive Technologies, uses a different approach. This system requires 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 via a range of specialised measurement devices installed across GB within the distribution network. This system has been operating since July 2022.

Both tools are available for our Control Room teams to view as additional situational awareness, however, as innovative solutions we need to ensure their accuracy before incorporating into operational processes. We are working with the National Physical Laboratory (NPL) on an innovation project looking at Inertia Measurement Optimisation (NIA2_NGESO023) which includes assessing the accuracy of the two tools. Following the initial period of assessment, we will incorporate the tools into our processes in Summer 2023.

New power system modelling tools

Working towards our ambition to operate a zero carbon system, we will need to facilitate the connection and secure operation of more renewable generation. Most of this generation is what’s known as ‘Inverter Based Resources’ (IBR), in other words, resources that depend on power electronics technology with fast switching to exchange power between AC and DC systems. To study the impact of these resources, we will need to use more time domain simulation, or ‘Electromagnetic Transients’ (EMT) approach, compared to the phasor domain simulation, or ‘Root Mean Square’ (RMS) approach that is currently used. One of the most renowned tools used globally for the EMT analysis is the PSCAD software.

Therefore, we have been acquiring new PSCAD software licenses and developing our internal capability to be able to run more advanced EMT simulations in PSCAD. Once the models are ready, this new capability will be applied in system disturbances analysis on a few cases. By conducting EMT studies in PSCAD, we can investigate thoroughly the emerging operational and planning issues when the system moves towards zero carbon operation, such as voltage oscillations, system interaction and power quality. We can identify the root causes more accurately and hence recommend more effective and efficient operational and planning solutions, instead of applying a more conservative approach which may either increase the system operational cost or capital cost for system users.

We have developed and delivered new capability as early as possible in response to emerging needs in the system, and have been establishing some regional network models in the new PSCAD software. We have had positive engagement with the software supplier in terms of training and capability development for all system users who can contribute more to the development of a full GB system model in PSCAD. We have also collaborated closely with three onshore TOs to achieve the most efficient way of developing this new GB system model. We are planning to complete the development of this capability and be ready to carry out full GB wide EMT analysis and co-simulated RMS/EMT in PSCAD by end of 2024/25. We are also planning to complete an innovation project with the software supplier to significantly increase the efficiency and run time of the models.

Transparency and Data – Operational Transparency Forum and sharing of datasets

We continue to run our weekly Operational Transparency Forum (OTF), providing transparency of operational decisions and an opportunity for stakeholders to ask questions. During 2022 we moved the forum to a Webinar solution which enables us to manage larger numbers of participants and over 1000 are now registered. These events continue to be shaped in response to participant feedback, in particular the questions raised each week. In Q3 and Q4 of 2022-23, we delivered extended presentations on the Winter arrangements, transmission outages, and Interconnectors, in addition to deep dives into operational activities on specific days of interest to the participants.

We've listened to feedback and in December 2022, published the latest version of our Digitalisation Strategy and Action Plan [1]. The updated plan gives us a clear roadmap that continuously improves our products and services.

Our Data Portal has led the way in the UK Energy Industry for access, use and understanding of energy data, and supports meeting the expectations of Data Best Practice. The number of datasets published on the Data Portal now stands at almost 100. We have also established functional connectivity between the Data Portal and the Data and Analytics Platform (DAP).

We have continued to publish the Dispatch Transparency data set on our Data Portal each week. This provides transparency of dispatch decisions and reasons why units are dispatched outside of simple merit order. This data set also provides the figures for our Regularly Reported Evidence (RRE) 1E later in this report.

We have been publishing information to support understanding of our data processing methods and algorithms such as the Dispatch Transparency Methodology[1] and Dynamic Containment Performance Monitoring scripts[2].

In response to questions at the OTF we held an in-person Dispatch Transparency event on 5 December 2022. 29 industry colleagues joined us in Wokingham for a transparent discussion about how we currently dispatch, improvements we have made to skip rates in existing systems, and the future of dispatch with the solutions to be delivered under the balancing programme. All materials, including the Q&A have been published on the OTF webpage and we have committed to run two further events online in 2023-24.

Skip rates in existing balancing systems (new activity in BP1)

Building on the engagement that has been done through the publication of the Dispatch Transparency dataset and in-person event on the 5 December 2022 as well as the Balancing Programme's industry engagements events (Balancing Strategy Capability Review), we prioritised 'skip rates' as an area of focus within our co-created roadmap.

As part of our engagements, we have showcased the improvements we have made to existing balancing systems to address skip rates. These all result in allowing more time to make dispatch decisions based on improved situational awareness and have resulted in forecast benefits of £48m in reduced balancing costs. These improvements have been made as part of the activities of the Balancing Programme.

As documented in the Dispatch Transparency methodology, reasons for actions which could potentially have been accepted in place of other actions, or 'skips' which is the term adopted by the industry, are varied. We have articulated the potential set of reasons as follows:

- User Experience & presence of manual workarounds
- Gaps in situational awareness
- Requirement for Improvements in dispatch advise
- Improvements needed in Dispatch Mechanism
- Improvements needed in the data required for capture
- Improvements needed in processes and policies

Within BP1 we have made the current improvements in six releases to the existing balancing systems, all of which aim to address the elements above and have resulted in:

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[1] https://www.nationalgrideso.com/document/273911/download

- £48m reduction in Balancing Costs
- 13,000 hours per year of Control Room time is being saved as a result of removed workaround
- Automatic Instruction Repeater (AIR) has been implemented; 80% reduction in Zonal Balancing Engineer (ZBE) workload during busy times.
- 40% estimated performance improvement of EDL (Electronic Data Transfer) and EDT (Electronic Dispatch & Logging) as a result of system improvements.
- Implemented Power Available 2, resulting in better use of wind power for response.
- Changes to dispatch algorithm (Flex Flag) allowing better use of small BMUs.
- Improvements to dispatch advice handle more efficiently the situations when level of power generation is away from PN.
- Improved situational awareness and user experience achieved by various incremental usability changes across systems.
- Changes to metering visibility of IEMS (Integrated Energy Management System) overrides resulting in better quality of data and improved situational awareness.

Addressing dispatch efficiency will be a continual focus through BP2 with additional functionality provided through our new Open Balancing Platform.

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), we discussed with ENTSO-E 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, the Minimum Viable Solution, Verification Platform and the Regional Services Coordination multi-lateral agreement were amended and signed in Q2 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 the approval and subsequent implementation of the working arrangements under the framework of the TCA.

Delivery schedule updated to reflect Brexit (new activity in BP1)

As a result of Brexit, methodologies that we had previously drafted (Channel & IU Capacity IntraDay & Day Ahead Calculation Methodologies, Channel & IU Coordinated Security Analysis Methodology) and other processes (Outage Planning Coordination, Identification & Submission of Critical Network Elements to ENTSOE and Yearly Submission of Interconnector MPTCs) have been discontinued.

The Trade and Co-operation Agreement (TCA) requires setting up a Technical Procedure for Day Ahead Capacity Calculation and ensuring this Technical Procedure outlines all the requirements as expected from the TCA and the guidance provided by BEIS and the European Commission. To this purpose we engage in the Day Ahead Capacity Calculation workgroup with all UK TSOs (NGV, NEMO, Britned, SONI, Eigrid, Eleclink etc) to develop the Capacity Calculation Methodology for Day Ahead and Intraday that works for all UK TSOs. We have developed three options for Day Ahead Capacity Calculation, which was presented to UK TSOs and BEIS and OFGEM. These options remain on the table while we await EU TSOs to engage in discussion. Lately, discussions within the UK TSOs workgroup have centred on Interconnector TSOs being averse to NTC curtailment, although they have signed to an NTC compensation methodology when their capacity is reduced at Day Ahead. These discussions are ongoing with deep dives into the Interconnectors commercial agreements, and potential costs associated with having to withdraw capacity from the market.

Ongoing impacts of COVID-19 (new activity in BP1)

The early part of BP1 was clearly marked by the uncertainty driven by COVID-19. Despite having continued delivering our core function throughout unprecedented times, we successfully managed significant risks, namely those linked to the protection of our Control Centres (activation of pandemic social distancing plans in conjunction with relevant Government guidance, and a range of other safety measures), the availability of generation and extraordinary demand behaviours. Our enhanced communications and engagement with the wider Industry throughout this period proved invaluable. Some activities like the Operational Transparency Forum ended up transitioning to normal operation and are now an integral part of our activities.

Changes to our suppliers (new activity in BP1)

Frequency and Time Error (FATE) is an IT system we use in the Control Room to support second-by-second energy / demand balancing functions. FATE has been developed and supported by our supplier, Staunton Systems Engineering (formerly Utility Telematics Ltd), since the early 2000s. In May 2021, Staunton Systems Engineering informed us of a decision to step back from the FATE product from 31 August 2021. In response, we have reviewed the internal support available, moved forward deliverables to further develop our systems in this area, and procured a replacement product from GE Digital. A complex design process has now been completed and we are aiming for a revised delivery date of November 2023.

Challenges

Balancing Programme

The Balancing Programme was established to develop the balancing capabilities that our 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.

We have delivered a significant amount within BP1. The foundations of what we have delivered is based on our newly co-created industry roadmap which was put together as part of our Balancing Strategy Capability Review in Spring 2022, and our ongoing quarterly engagement events with the industry. This new revised roadmap and subsequent plan allows us to deliver against the original ambitions of our original BP1 plan whilst:

- Focussing on delivering early value by continually reviewing and updating our roadmap
- Building the right capability to enable commitments across the initiatives in our Business Plan
- Ensuring our Control Room has the tools we need to perform our roles, removing inefficiencies in how we work and building the insights needed reflecting the changing behaviours of the collective marketplace
- Delivering the needs of the industry e.g. incorporation of improvements to current systems with the aim of improving dispatch efficiency of the control room i.e. skip rates

Our revised approach enabled us to continue to maintain and incorporate functionality in our current systems, focussing on delivering value for money for the end consumer. In parallel, we are working on delivering our new Open Balancing Platform with an approach where functionality will be built and released in increments. We have employed a Scaled Agile approach which seeks to validate the solution at key stages during the roadmap lifecycle. We will transition over time so that an increasing amount of balancing functionality will be performed by the Open Balancing Platform.

In meeting the objectives of our revised plan, the programme has delivered extensive work to modify our current balancing systems to meet changing market conditions and customer requirements. Examples include enabling market services such as Dynamic Containment, Dynamic Moderation and Dynamic Regulation, Regional Development Programme, and our Pathfinders. In addition, we have made improvements which have removed inefficiencies in our Control Room which all result in allowing more time to make dispatch decisions based on improved situational awareness. The latter focus area (Skip rates in existing systems) was added to our co-created roadmap following the strategic review.

For the Open Balancing Platform, the completion of the blueprint phase allowed us to identify the technology required for our new platform and a comprehensive bottom-up resource plan to ensure we can keep effective controls over costs.

Additionally, delivery of the “Core” skeleton of the platform sought to prove the concepts of Bulk Dispatch, Service Harmonisation, and Flexibility, supported by new technology and architecture for a scalable solution to meet today’s Control Room needs and a changing ESO and Electricity Market. This was a key milestone in confirming the approach and roadmap for delivery for our first Release in Q3 2023-24, as well as providing assurance that future needs can be satisfied. As we progress to Release 1.0 of the Open Balancing Platform, we are continually validating our delivery via programme Increments (quarterly deliveries) to ensure that the programme is on track with its roadmap, as well as aligning with industry via engagement sessions, and soon to be started industry validation and testing. This approach provides assurance that we continue to be on track with our commitments, as well as enabling flexibility in our plans if the industry moves in a direction different from original expectations.

We have also created sandbox environments which have allowed us to test the link between current the BM and the new system which is a key milestone in demonstrating the ability of the Open Balancing Platform to receive and utilise market and operational data for dispatch.

Our Platform for Energy Forecasting has been continually developed and new forecasting products have been delivered in BP1 enabling significant benefits for the consumer. National demand, solar demand and Grid Supply Forecasts have been implemented during this period and we are continuing to build functionality through BP2, while ensuring cost efficient strategic alignment of technology across our Balancing Programme products and beyond.

The resultant impact of delivering the co-created roadmap is a £982m increase in benefits during RIIO-2,with an associated increase in our forecast costs of £33m more than the BP1 benchmark. We have delivered the priority milestones in BP1 which align with our roadmap and have re-prioritised remaining activity into BP2.

As we enter BP2, we will continue to engage with the industry through quarterly engagement events and our new stakeholders’ groups (storage, optimisation, forecasting and technology), the outputs of which will enable us to continually review and refine our plan. We will demonstrate the value of what we have delivered through improved transparent reporting of the benefits which are being realised. With our new way of working aligned to agile principles, and controls in place we will continue to build and implement functionality in our Open Balancing Platform while ensuring current systems remain fit for purpose while we transition to it.

Balancing Costs

Balancing Costs increased significantly in BP1 from £1.8bn in 2020/21 to £3.2bn in 2021/22 and £4.1bn in 2022/23. These increases were largely driven by external trends. Over the period of BP1 we have seen an unprecedented increase in wholesale prices (from £163/MWh on average in 21/22 to £196MWh on average in 2022/23) which led to a significant increase in balancing costs in the Balancing Mechanism (BM). Scarcity pricing was another factor contributing to higher balancing costs, particularly in the winter periods of 2021/22. We saw extreme peaks in prices submitted in the BM during periods of tight system margins or on high wind generation (e.g. £8,300/MWh on 20 Jul 2022 at 17:00). These extreme peaks in prices occurred far less frequently in the winter of 2022/23.

While increases to wholesale prices and scarcity pricing are out of our control to influence, we have delivered a range of key initiatives during BP1, across all roles, to mitigate these rises. We estimate that these initiatives have resulted in total benefits of c£5.6bn during BP1. These initiatives include benefits from Outage Optimisation (£3.9 bn), Trading (£549 m) and the Balancing Programme (£352 m). These initiatives range from short term improvements, such as instigating a run-back scheme on the Western Link HVDC to increase available capacity over winter 2022/23, to long-term improvements that have come to fruition in BP1, such as our Pathfinders projects.

Unlike wholesale prices, the volume of balancing actions is to a greater extent within our ability to manage and we have seen an overall trend of a reduction in balancing volumes over the BP1 period. We have achieved this reduction through delivery of key initiatives under our balancing costs strategy. A significant reduction came from the change in policy introduced as a result of our first Frequency Risk and Control Report (FRCR). This change in policy was also facilitated by the introduction of Dynamic Containment and Accelerated Loss of Mains Change Programme. As a result, the combined volume of constraints and constraint margin replacement has reduced from 37TWh in 2020/21 to 17.9TWh in 2021/22 and slightly higher in 2022/23, with ~20 TWh of actions carried out. We estimate that this resulted in £435m of savings to the consumer during BP1. Please see our Consumer benefit case study for Role 1: Frequency Strategy where we estimate future savings as a result of our overall frequency strategy.

Despite having a strong impact on factors within our control, we recognise our performance is measured using the 1A benchmark methodology which has consistently deemed that we are underperforming in BP1. We welcome the recognition from Ofgem that the methodology for the 1A benchmark needs to be improved in BP2 to better reflect changes to factors outside of the ESO's control, so it can be an efficient measure of our efforts to minimise balancing costs. We will continue to explore new ways of measuring and communicating our efforts and to develop a more appropriate benchmark collaboratively with Ofgem.

Role 1 - Progress of our deliverables

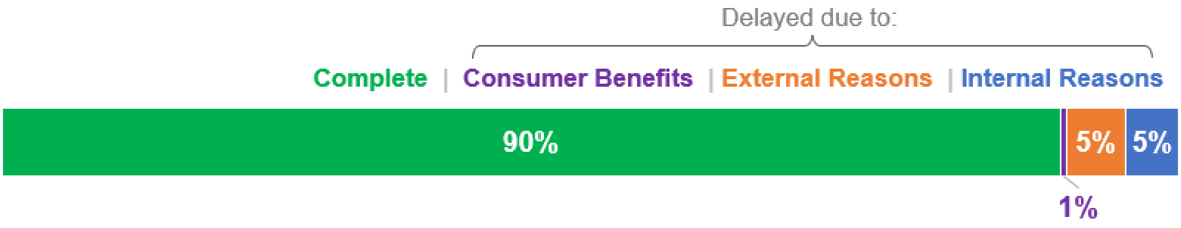
Our RIIO-2 deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables, with commentary including explanations for all delayed milestones.

For Role 1 (Control Centre Operations), there are **198** milestones. Of these:

- **178** (90%) are now complete
- **20** (10%) are not complete which break down as follows:
- **1** (1%) is delayed in order to deliver an improved outcome for consumers
- **10** (5%) are delayed due to reasons outside the ESO's control
- **9** (5%) are delayed due to ESO related delays

These results are illustrated below:

Role 1: Status of **198 milestones** due to be completed by the end of 2022-23



This excludes milestones which have been agreed with OFGEM as no longer being valid

Delayed milestones

Deliverable	Delay type	Reason for delay
D1.1.4 - Liaise with ENTSO-E and CORESO on the ESO's European operations – **1 milestone**	External Reasons	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. It will require an agreed co-ordinated approach by both the UK and the EU.
D1.1.5 - Upgraded legacy balancing and situational awareness tools – **1 milestone**	Internal Reasons	We've decided to build this into the new system rather than the legacy system due to the cost and complexity of a legacy update. The new data that the platform will receive will also need industry approval via code changes.
D1.1.7 - Produce and publish detailed forecasts and analysis – **1 milestone**	Internal Reasons	We have successfully integrated national demand, national solar power generation, and Grid Supply Point (Net demand) forecasts during BP1 period. To ensure alignment with our other strategic initiatives, including the Data Analytics Platform (DAP) and Open Balancing Platform (OBP), we have chosen to construct the remaining forecasting products & features within our strategic cloud architecture (Azure).
D1.1.7 - Produce and publish detailed forecasts and analysis – **1 milestone**	Consumer Benefits	Forecasting Platform delivery is now re-prioritised to maximise consumer benefits through reducing technical debt by delivering PEF on our strategic cloud platform, and by integration with our other strategic initiatives Data analytics platform (DAP) and Open Balancing platform (OBP) in BP2.

D1.2.2 - Develop inertia monitoring capabilities and other tools - **4 milestones relating to Stability Phase 2**	External Reasons	As the Stability Phase 2 contracts are not scheduled to start until April 24, therefore the original milestone date is not suitable.
D1.2.2 - Develop inertia monitoring capabilities and other tools – **2 milestones relating to Pathfinders**	Internal Reasons	By their nature Pathfinder projects are exploratory, and the IT delivery milestones were best estimates at the time. As the project developed it became apparent that the TOs would only be able to deliver the intertrip solutions in 2023, hence the service start date was scheduled for then. Therefore, these IT milestones no longer needed to be delivered by the original dates, so were delayed with no cost to the consumer.
D1.2.2 - Develop inertia monitoring capabilities and other tools – **1 milestone (visibility of state of energy signal)**	Internal Reasons	This milestone is about visibility of the state of energy signal which is also delayed as explained above under D1.1.5.
D1.2.2 - Develop inertia monitoring capabilities and other tools – **1 milestone (work with TOs to improve data quality)**	External Reasons	NGET have delayed their PMU rollout impacting the likelihood of the system expanding to cover England & Wales in FY23. Now not expected until at least end of FY24.
D1.2.1 - Enhanced balancing tool built and developed in a modular fashion – **2 milestones**	Internal Reasons	The delivery of this milestone has been re-prioritised to be align with the first release of the Open Balancing Platform in Q3 2023/24.
D1.3.1 - Develop and deliver new real-time situational awareness tool – **1 milestone**	Internal Reasons	Delays in vendor on-boarding and resourcing challenges to progress with design work. There have also been delays with our data centre enablement project in making the infrastructure available.
D3.2.2 - Validate restoration timelines for GB using the assurance data – **1 milestone**	External Reasons	Ofgem shared its final decision in August 2021 and Secretary of State directed the ESO to implement the new Restoration Standard in October 2021. We will now need to comply with the standard by no later than 31 December 2026.
D3.2.1 - Facilitate and compile the annual assurance process for GB Black Start – **1 milestone**		
D3.2.3 - Maintain obligations and requirements against the new standard for Black Start – **2 milestones**		
D3.2.4 - Restoration decision making support tool designed and developed – **1 milestone**	Internal Reasons	Scoping of the restoration decision support tool was delayed in order to allow us to gather valuable input from stakeholder working groups set up to discuss all aspects of changes needed across industry to implement the Electricity System Restoration Standard. This feedback has been incorporated into the customer requirements being used in the tendering phase to find a suitable system and vendor.

Milestones no longer valid

Section 5.6 of the ESORI guidance states: ‘If any changes are made to the delivery schedule during the business planning cycle they should be clearly identified and outlined in the reporting documents (e.g. in a separate sub-section), so it is clear where additional amendments have been made in comparison to the original Business Plan. This can ensure Ofgem, stakeholders and the Performance Panel understand the reasons for any changes to plans in advance of its evaluation of the ESO’s performance.’

In December 2023, we introduced a new process for managing milestones that are no longer valid. For Role 1 there are zero milestones that are no longer valid.

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 [2]	Research and develop the use of machine learning & satellite images to nowcast PV at GSP-level.	Work Package 2 resulted in a further 20% accuracy improvement from Work Package 1 with a mean absolute error of 233 MW vs 650MW. Work Package 2 also included the creation of the UI & UX, first released to ESO in July. Work Package 3 focused on testing and delivering the forecast running in real-time to the control room, this included initial development of national forecasting models to further improve the accuracy. A project extension is now in progress to incorporate further accuracy, probabilistic forecasts, further UI development, impact assessment and a proposal for development of the PV nowcast into BAU.	D1.2.3	Delivery	RIIO-2
Control REACT [3]	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	D1.2.3	Complete. Follow-on activity now managed by the business	RIIO-1

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

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

		will facilitate their use for forecasting reserves and margins as demonstrated in the project. (Also mentioned in Role 2)			
Distributed Restart (NIC) [4]	Process and market for procuring restoration capability from distributed resources.	Through a combination of detailed off-line analysis, stakeholder engagement & industry consultation, desktop exercises, and real-life trials of the re-energisation process, Distributed ReStart has tackled the technical, organisational and commercial challenges in delivering black start from DERs. The project has successfully met all its agreed objectives and deliverables and has also gone further to include the build and test of a Distribution Restoration Zone Controller (DRZC) prototype that allows for automation of the creation and stabilisation of a local power island. All final findings and proposals have been published in a report available on the Distributed Restart website. Following the close down of the project, one more live trial is planned for mid-2023 involving a battery energy storage system (BESS) with grid-forming technology and the prototype DRZC to restart the network. Finding will be published with a follow on report.	D3.3.1, D3.3.2	Delivery	RIIO-1
Short-term System Inertia Forecast [5]	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	Complete. Follow-on activity now managed by the business	RIIO-1

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

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

Dynamic Reserve Calculation[6]	Use AI and machine learning to set reserve levels dynamically, at the day ahead stage.	The initial project delivered successfully in April 2022 and was then extended to allow the development of a proof-of-concept model, using live data, with the intention to implement in the Control Room for use from July 2023. (Also mentioned in Role 2)	D1.2.3	Delivery	RIIO-2

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

A.2 Stakeholder Evidence for Role 1

Our incentive scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of our 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

We have commissioned surveys from market research company BMG. These surveys measure satisfaction for each of our roles 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 our services.

For role 1, the following question was asked:

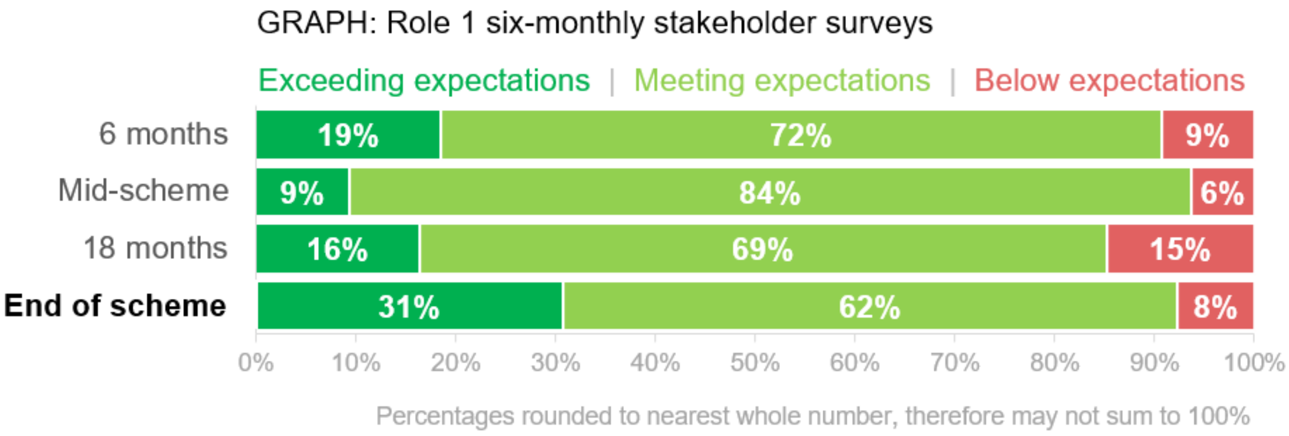
> "One of the ESO Roles is focused on Control Centre Operations, which includes key activities such as real-time system operation, system restoration, balancing mechanism review and provision of data and forecasting. Overall, from your experience in these areas over the last 6 months, how would you rate ESO's performance?"

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

For Role 1, we contacted 201 stakeholders, and received 39 responses to this question, which were distributed as follows:

- **31%** exceeding expectations
- **62%** meeting expectations
- **8%** below expectations

(Percentages rounded to the nearest whole number)



"Exceeding Expectations" feedback

Out of 39 responses, twelve stakeholders scored us as "Exceeding expectations". In response to being asked what we needed to do to meet their expectations, these points were raised:

- Several of the comments relate to the Operational Transparency Forum (OTF) as being a big factor as to why expectations were exceeded. Comments stated that the OTF provides detailed updates which are a valuable information source. Queries off the back of the OTF are answered and provide stakeholders the clarity they require.
- Some stakeholders commented that our staff engagement was very good. We also demonstrated good communication, with Stakeholders recognising clear communication and engagement activity improving.

- One stakeholder commented “their ability to make quick decisions on overnight forecasting of load and wind causing network constraints on the network was impressive.”
- Being open and transparent with information, together with quality of our work was also noted by stakeholders.

“Meeting Expectations” feedback

Out of 39 responses, 24 stakeholders scored us as “meeting expectations”. We asked all stakeholders who scored us as ‘meeting expectations’ what would it take for us to be ‘exceeding expectations’ for them, here is a summary of that feedback for Role 1:

- Some stakeholders feel that communication could be improved, specifically identifying the correct people with the required knowledge. Slow response is partly caused by lack of continuity of contacts, access to suitably experienced teams who understand stakeholder needs and a lack of routine and rigour of the overnight communications.
- Transparency on processes is another key theme with stakeholders praising the OTF and open data portal as key improvements in this area. However, some comments show more transparency is needed going forward, with emphasis on a better understanding of the wider market context.
- Several stakeholders were happy with the service and said we are delivering what they expect.
- A couple of comments refer to updating IT systems, developing systems which enable us to despatch smaller providers in the balancing mechanism and having a focus on digitalising our processes quicker.
- Other feedback suggests we need to respond and act on feedback faster and be more proactive than reactive.

“Below Expectations” feedback

Out of 39 responses, three stakeholders scored us as “below expectations”. In response to being asked what we needed to do to meet their expectations, a summary of the points raised were:

- One stakeholder said “They need to digitise and open up the balancing market to small scale aggregated assets. They will then have more transparency.” this highlights the need to improve IT services to create greater transparency.
- IT improvements are a common theme, noting our IT systems are outdated and need modernising.
- One stakeholder went further suggesting the whole business process needs looking at, and Ofgem should be involved in that review to come up with a better way of working going forward.

Addressing stakeholder feedback in BP1

The above survey is the fourth and final instalment of the stakeholder satisfaction surveys conducted for BP1, with surveys being conducted every six months throughout the delivery of the business plan. We’ve delivered our business activities while taking into consideration the results of previous surveys. We’ve also continued to listen to and engage with our stakeholders while delivering our projects and business activities. On further analysis of previous surveys, we found that across Role 1 feedback can be grouped into a selection of key themes. They include:

1. Improving balancing decisions and transparency around them
2. Greater coordination with TOs and industry partners
3. Increasing engagement with stakeholders and closer collaboration on key projects
4. Improving transparency on data and analytical information to support industry knowledge and decision making

Below we outline how we’ve been working to address these feedback themes gathered from the stakeholder surveys throughout BP1.

Theme 1: Improving balancing decisions and transparency around them

During BP1 we have worked with Ofgem, BEIS and industry stakeholders to do everything we can to reduce balancing costs over the short, medium and long term. While balancing costs have risen significantly over the past two years, they are lower than they would be without our actions. Please see our Balancing costs section above, where we lay out in detail how we have undertaken work to reduce balancing costs.

Balancing the system often requires complex decision making. We use the Operational Transparency Forum to provide more detail and explain the rationale behind our balancing decisions. This may include providing stakeholder with more information such as policy and process changes, transparency on choices we make in dispatching generation and sharing appropriate data sets. Specific information we have provided to stakeholders can be found in our section on Transparency and Data above. Through this regular engagement we keep our stakeholders informed and give them more understanding around our decision making.

Theme 2: Greater coordination with TOs and all industry partners

With the anticipation of a challenging winter we took a proactive approach to the discussion of our winter outlook with our European TSO stakeholders. Meetings took place both bilaterally and in conjunction with European and UK governments – and at all levels within our respective organisations. These meetings were an opportunity to discuss, at an early stage, winter risks and how TSOs could mutually support each other during the winter period. We also published the principles we would adopt to manage winter risks and challenges on our website and discussed them at our Operational Transparency Forum.

To compliment this extensive engagement, we established a TSO daily call to manage winter challenges. During discussions with neighbouring TSOs that we share interconnectors with, we decided that regular daily communications would be useful to help manage system margins and system challenges through winter.

- We set up a daily call to discuss the margin situation with all of the GB connected TSOs including Ireland, Northern Ireland, France, Netherlands, Norway, and Belgium.
- During these calls we discuss system margin for the next few days along with and solutions to support each other over the winter period.
- We have also arranged Ad Hoc meetings to deal with any specific issues on the network.

This had a significant impact in enabling us to better manage the system. We received positive feedback from our partner TSOs and due to its success over Winter 2022/2023, we plan to keep this TSO coordination channel open for the following winter. We may also use it for managing other system conditions in the future.

We participated in weekly calls with all European TSOs to understand margin and system risks across Europe. Senior level engagement was established with the Ukrainian TSO to discuss what support the ESO could provide or facilitate.

Theme 3: Increasing engagement with stakeholders and closer collaboration on key projects

Balancing Programme engagement – The Balancing Programme is developing the future balancing capabilities of our Electricity National Control Centre. These capabilities are needed to deliver reliable and secure system operation, facilitate competition and meet our net zero ambition. Through the early phases of this programme, we developed a much greater understanding of the complexity and scale involved in transforming our balancing capability. So, in Spring 2022 we paused the programme to undertake a strategic review of activity and costs. During this review we engaged extensively with internal and external stakeholders to:

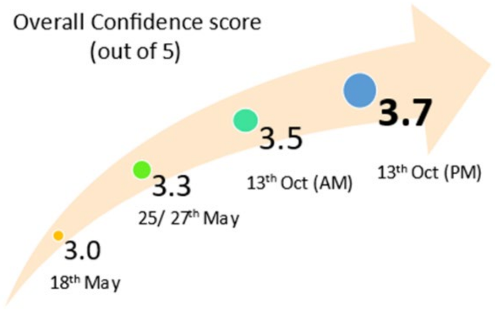
- provide an understanding of the current challenges in the Control Centre
- seek a common understanding of why we need to transform the balancing capabilities
- understand all the benefits of the transformation
- produce a co-created, industry endorsed roadmap
- build support for our approach

- create a framework for continued industry engagement while we transform.

We will continue to engage and collaborate with our stakeholders quarterly through focus groups sharing how our work will transform the way the control room operates, seeking feedback on the proposed platforms and endorsement of any changes to activities in the roadmap. The feedback we collate during our stakeholder focus groups will also be crucial in how we continue to develop and progress the new Open Balancing Platform capabilities, solve challenges related to storage and create our platform for energy forecasting.

Our engagement approach has helped improve stakeholder confidence that we can deliver what we have committed to in our balancing roadmap (see the figure below).

Figure: Overall confidence level of our stakeholders in our Balancing Roadmap, taken at different stages of the Open Balancing Platform Capabilities engagement programme.



Engaging to develop the Mega Watt Dispatch service – This service is being developed jointly by us and National Grid Electricity Distribution (NGED) and will go live later in 2023. The service will manage pre-fault thermal transmission network constraints. It will give the National Control teams the capability to instruct third party Distributed Energy Resource providers (DERs) to curtail their generation output to zero megawatts.

To develop the service our RDP team brought together the requirements, knowledge, thinking and expertise from across multiple parties. This work included:

- Coordinating across DNOs to deliver Inter Control Room Communications Protocol (ICCP) links which support data transfers between us and other external parties.
- Drafting, socialising and putting in place ground-breaking tri-partite service term contracts to support the implementation of the Mega Watt Dispatch service
- Collaborating with a DNO to jointly design and build the processes and technical capability to enable the implementation of the service.

Telling the winter story - Russia's devastating invasion of Ukraine created a global energy crisis. In response, across Winter 2022/2023, we delivered quality engagement and communications to external audiences to demonstrate our actions to keep the lights on under unprecedented circumstances. Key stories we communicated and actions we took included:

- The Early View of Winter and the full Winter Outlook which told the story of the ESO as a prudent System Operator
- Messaging and communicating around the world-leading Demand Flexibility Service and Winter contingency contacts. 94% of the general public were aware of the DFS service, according to government polling.
- Expert media handling and stakeholder engagement fielding 1000's of calls and inquiries, including out-of-hours, around margin updates, the operational use of winter contingency coal and the DFS Live and Test events.
- We also kept our key stakeholders/parliamentarians briefed and updated over what was a fast-moving and uncertain/challenging winter period, including extensive engagement with the energy industry ahead of winter and throughout including two CEO-level roundtables with 30+ in attendance. We received very positive feedback on our engagement and handling of Winter Comms from the highest levels of the UK Government, including Number 10, BEIS and the Cabinet Office, and the Devolved Administrations

further strengthening our relationships, reputation and profile. This work has helped keep the Energy Bill moving through Parliament.

- Working with the Control Room we have allowed national broadcasters to film and learn more about the important work we do and to reassure the nation about the layers of protection and buffer we work to secure to protect the integrity of our power system. We took part in a recent C4 documentary with Guy Martin that tells the story of our role in operating the system and how we are helping to deliver net zero.
- We created a state-of-the-art media suite at our Wokingham office to improve the speed and ease of our communications, especially during critical system events.

We reached a diverse audience of stakeholders through our extensive media coverage. Downing Street called out the success of our media campaigns and we've built even stronger relationships with government stakeholders. We were also called out at COBR during the Mighty Oak exercise for our excellent communications.

Working in partnership with industry on Distributed ReStart - The Distributed ReStart project is a world-first initiative exploring how distributed energy resources (DER) such as solar, wind and hydro generation, can be used to restore power to the transmission network in the unlikely event of a blackout. Working in partnership with stakeholders such as DER developers, network operators and specialist consultants we undertook power system analysis of case studies to establish the technical viability of restoring the network from DERs. We then worked with our partners to deliver live trial demonstrations with DERs to energise the network. These demonstrations included the Galloway Live trial and Chapelcross Live trial.

By working in partnership with these stakeholders, we have been able to:

- Understand what it takes to deliver a Distributed ReStart across a number of particular use cases.
- Gain confidence that these use cases and wider applications can be implemented.
- Discover and overcome some unexpected engineering challenges.

We have also done a range of engagement on Distributed Restart, sharing our findings at European industry events and presented to external graduates from Herriot-Watt, University of Edinburgh Smart Grids Course and Brunel University. We also held a workshop with Australia Energy Market Operator (AEMO) in 2021.

We will continue to work with our partners to carry out more trials using a Battery Energy Storage System throughout 2023 and will report on further findings.

Improving transparency of our decision making through the Operational Transparency Forum (OTF) – The OTF is a weekly webinar which provides industry with quality operational insight. It is designed to improve our stakeholders' understanding of the rationale behind the decisions we take to operate the system. It 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. During the second year of BP1:

- Weekly attendance from a diverse group of stakeholders has continued to rise to over 330 attendees
- The highest attendances recorded were for the "Deep Dive of Winter 2022: Managing the Power System" on 9 November 2022 at 414 and the "Interconnectors" presentation on 8 March 2023 at 444.
- We were asked and answered over 1000 questions through the Q&A sessions.

In continuing to develop the OTF we have listened to stakeholder feedback, so that:

- Content and topics scheduled in the forum are driven by questions asked by stakeholders
- We have focused on improving the accessibility of material presented by using clearer language and graphics.
- We now host the OTF on a platform which provides more effective webinar functionality, including the option to email updates to all participants directly.
- We have continued to expand the team of experts available for the Q&A to increase the range of specialist knowledge contributing answers at the live event.

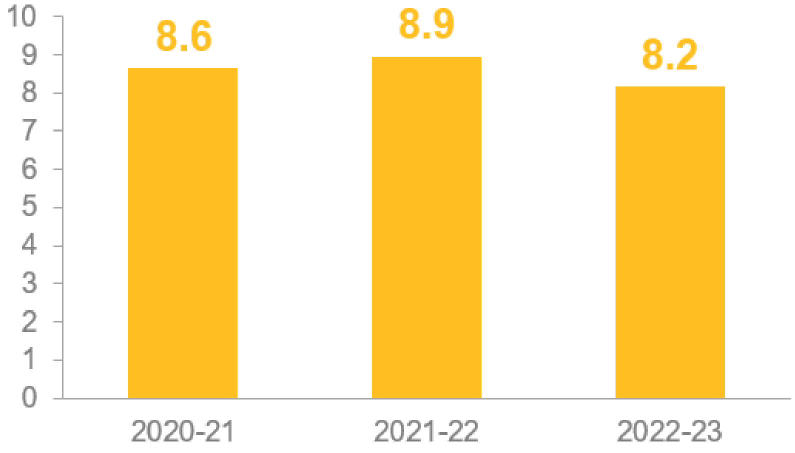
- We have also introduced an online form for advance questions so stakeholders can ask more technical and specific questions than the live event tool allows.
- We hosted a Dispatch Transparency event for industry specifically to address concerns raised about how we dispatch and “skip rates”.

A copy of all slide decks and webinar recordings from the 50 events hosted this year can be found on the OTF webpage, alongside links to subscribe for updates or download an invitation: Operational Transparency Forum | ESO (nationalgrideso.com)

Feedback received - In the past year, we have continued to use a post-event survey which tracks overall quality of the event, quality of the responses to questions and relevance of topics discussed. Below are the average scores for the last three years, all of which exceed the target of 8.15 out of ten.

Operational Transparency Forum: Average feedback scores by year

Annual average weekly scores since the OTF began in June 2020



However, the response rate has dropped significantly from around 30 per month when we began the survey in 2020 (5%) to under 15 per month in BP1 (1%). The survey is potentially less representative of the participants views and we intend to explore what other options for regular feedback could be used.

One survey response we received neatly demonstrates some of the value the OTF gives to our stakeholders. When asked why they were bringing non-operational questions to the OTF, the response we received was attendees had confidence the accountability of the forum structure would ensure they would get an answer.

Theme 4: Improve data and analytical information to support industry knowledge and decision making

Focusing on our digital platforms - We have a wide range of external customers who use our data resources. These include the majority of our current stakeholders as well as members of the public, academics and journalists. Making this information available to our stakeholders is only part of the challenge. Ensuring that they can find and access the data that will enable them to make informed commercial decisions, innovate or gain further understanding, is important. We listen to and action feedback on how easily stakeholders are using and managing the information we are providing.

The feedback below was gathered from data across various engagement sources:

- Users struggle to find what they are looking for on our website and data portal having to resort to using external search engines rather than navigating through the website itself.
- Data visualisations are important, but some users just want to see the numbers – flexibility of data format and joining up our content and data is important.
- Users don’t feel in control of their email and newsletter subscriptions – they don’t know what they are signed up for, or how to make informed choices about the information they receive from us.

- Users are looking for more detailed, richer information about us and energy-related events. They often feel that events and updates that are relevant to them are missed.
- Participants in the Balancing Services markets find it hard to keep up to date and informed about auctions, settlements and upcoming tenders.
- Stakeholders requested more information around the 'what', 'why' and 'how much', to make sense of the instructions in the Balancing Mechanism (BM).

To improve our systems using the feedback received, we have created:

- Improved navigation which has been user tested. All pages will have a "breadcrumb trail" of related pages to simplify user journeys on the website.
- An improved website search function, offering more visibility to events and news items.
- A personalised account dashboard to manage user subscriptions.
- More prominence for events on the website, to drive both engagement and user satisfaction.
- A review and refresh of the Balancing Services section user journeys and content, with a focus on clarity of key information for market participants.
- More locational information on service providers through our data portal and will continue this work on new services.

Addressing feedback from the technology advisory council (TAC)[7] – The TAC was set up in December 2020, to help guide our digital, data and technological transformation. It ensures we work with the industry on the development of new systems and provide transparency and accountability for their development. We have been using the TAC to gather information across many of our technology investments and used the feedback to address themes that have emerged through our engagement with stakeholders over BP1. For example, we've used feedback from the TAC to help:

- Improve our data harmonisation (combining data from many sources for easier comparison and in-depth analysis) which we're looking to achieve in creating the Digital Engagement Platform. The TAC challenged us further to make sure we analyse who is using this data so we can prioritise visualisations and insight. We use analytics software to give us this insight which we use to better inform what we release.
- Improve communication and engagement by listening to and learning from other sectors and collaborating with transmission and distribution operators.
- Manage our digital analytics platform requests via a new engagement framework and continuing to partner with universities on innovative solutions. There has been positive feedback from various TAC members on our Open Data initiatives. TAC members are heavy users of the datasets and have provided us with lots of feedback and suggestions on how to improve in this area.
- Change our governance framework for our data, digital and technology programme of delivery.
- Create an Open Balancing Platform (OBP) which focuses on operational user feedback via regular engagement.

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[7] https://www.nationalgrideso.com/who-we-are/stakeholder-groups/technology-advisory-council

A.3 Metric Performance for Role 1

Table: Summary of metrics for Role 1

		2021-22 Total			2022-23 Total			**BP1 Overall**
Metric		Benchmark	Actual	Status	Benchmark	Actual	Status	Status
1A	Balancing Costs	1,321	3,132	🔴	1,699	3,834	🔴	🔴
1B	Demand Forecasting *Absolute Percentage Error*	2.1%	2.2%	🟢	2.1%	2.4%	🔴	🔴
1C	Wind Generation Forecasting *Absolute Percentage Error*	4.7%	4.2%	●	4.8%	5.1%	🔴	🟢
1D	Short Notice Changes to Planned Outages *Number of outages delayed or cancelled per 1000 outages*	1 - 2.5	1.3	🟢	1 - 2.5	2.3	🟢	🟢

Below expectations 🔴
Meeting expectations 🟢
Exceeding expectations ●

Metric 1A Balancing cost management

April 2021 to March 2023 Performance

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

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

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

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

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

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

Benchmark formula for 2022-23:

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

Benchmark formula for 2021-22:

- Total Balancing Costs *(£m)* = (Outturn Wind *(TWh)* x 25.254 *(£m/TWh)*) + 15.972 *(£m)* + 50.4 *(£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: We host 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 experts from Markets, Networks and National Control. Details of how to sign up, recordings of previous meetings and the Q&A documents are available here.

Overall BP1 performance:

● **Below expectations:** Total balancing costs of £6.9bn vs benchmark of £3bn for the two-year BP1 period.

Graph: Two-year view of monthly balancing cost outturn versus benchmark

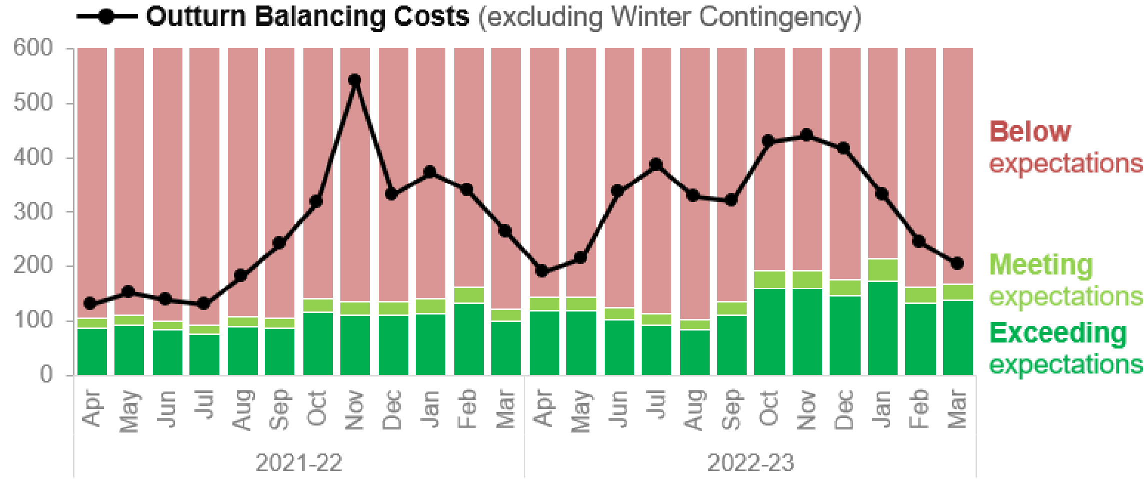

Table: 2022-23 Monthly balancing cost benchmark and outturn

(See our Mid-Scheme review for final 2021-22 figures)

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Benchmark: non-constraint costs (A)	50	50	50	50	50	50	50	50	50	50	50	50	**605**
Indicative benchmark: constraint costs (B)	97	89	90	81	101	107	146	133	151	156	182	138	**1,470**
Indicative benchmark: total costs (C=A+B)	147	139	140	132	152	158	196	183	201	206	233	188	**2,075**
Outturn wind (TWh)	3.8	3.9	3.1	2.8	2.2	3.5	5.6	5.6	5	6.3	4.5	4.7	**51**
Ex-post benchmark: constraint costs (D)	80	80	62	52	42	73	125	125	110	143	98	103	**1,094**
Ex-post benchmark (A+D)	130	130	113	103	93	123	176	176	161	194	148	153	**1,699**
Outturn balancing costs (excluding Winter Contingency)[8]	188	214	335	386	327	319	430	440	416	332	244	203	**3,834**
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

Monthly figures are rounded to the nearest whole number, except outturn wind which is rounded to one decimal place. Previous months' outturn balancing costs are updated every month with reconciled values.

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

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[8] Winter Contingency costs are excluded from the outturn balancing costs for comparison to the benchmark as agreed with Ofgem. However, in the rest of this section we continue to include those costs for transparency and analysis purposes.

Supporting information

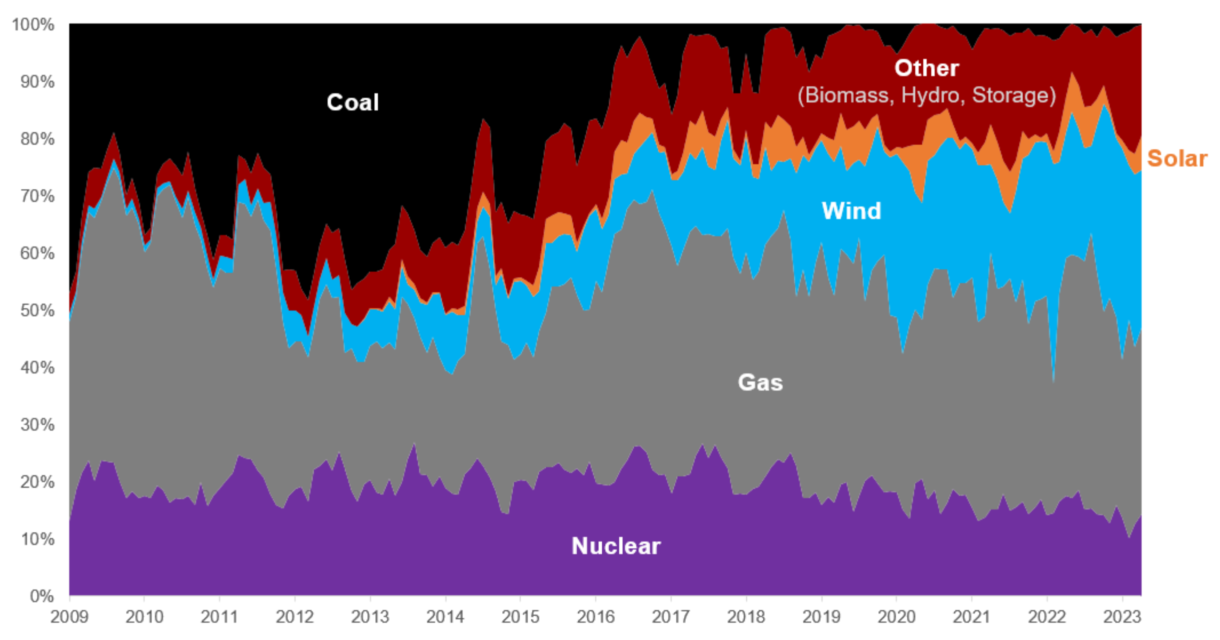
Due to the complexity and importance of this metric, below we provide a significant amount of background, analysis and commentary which is broken down as follows:

Contents of this section:

1. Transition to a sustainable net-zero power system and impact on balancing costs

The GB electricity system is undergoing a fundamental change to a sustainable net-zero power system.

Graph: Changing GB generation mix, 2009 - 2023



Wind generation in particular has rapidly expanded:

- Between 2016 and 2022, wind generation increased by over 150%
- Britain's daily wind record was set at 21.6 GW in January 2023

Some facets of decarbonising the GB power system led to higher balancing costs in the short / medium term. We have been proactively mitigating this impact throughout BP1.

2. ESO influence on balancing costs drivers

Our ability to mitigate the impact of the transition is dependent on the level of influence we have over balancing costs drivers, as shown in the table below.

KEY:

✓ Ticks indicate the **Drivers** (columns) for increases in **Balancing Costs Components** (rows).

High / **Medium** / **Low** - The bottom rows indicate the level of influence that we have over these drivers and therefore over the balancing costs components.

Balancing Costs Components	**Drivers of balancing costs:**								
	Operating Margin	Products & Services	Balancing Actions	Boundary Transfers	Wholesale Prices	BM Prices	Renewable Outputs	Generator Outages	Demand
Positive Reserve	✓		✓				✓	✓	
Negative Reserve	✓		✓				✓	✓	
Constraints			✓	✓					✓
Frequency Control		✓	✓		✓	✓			
Energy Imbalance			✓						✓
Other (e.g. Restoration, Minor Components)			✓						
Our level of influence	**High**	**High**	**Medium**	**Medium**	**Low**	**Low**	**Low**	**Low**	**Low**
Explanation	The level of operating margin required to cover demand changes or generation breakdowns is defined by ESO. However, the price of operating margin is set by the market.	We are responsible for launching and managing its suite of products and services, working with regulators and the market to ensure these are feasible and compliant	We are required to secure the system to SQSS standards and take actions in a defined order to manage system operability and maintain security of supply.	We work closely with TOs to manage necessary system outages. These impact on network capacity but are essential to maintain system and asset operability.	Set by the market based on supply, demand, the generation cost stack and participants risk appetites.	Driven mainly by generation fuel costs (gas/carbon) when plentiful generation supply and scarcity pricing when margins are tight.	Driven by weather patterns that we forecast as accurately as possible	Providers and generation will determine when they will take outages in line with their own maintenance cycles and requirements.	Driven by societal norms, major events, etc. However, we are developing our ability to influence demand e.g. Demand Flexibility Service

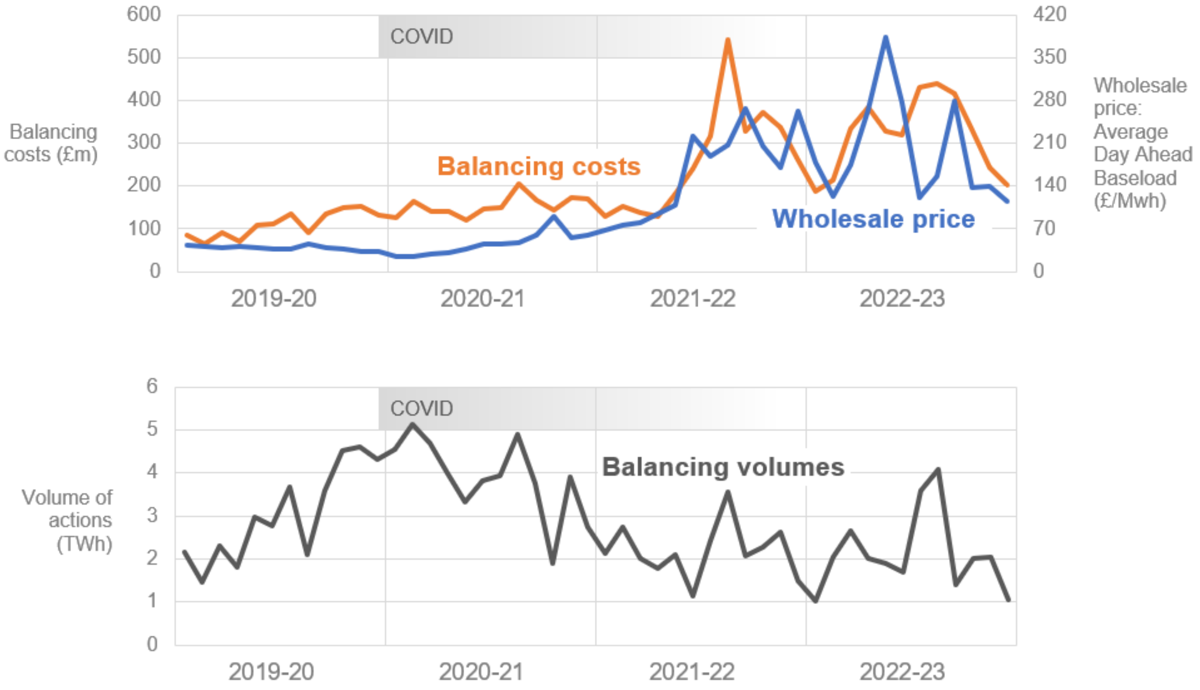
3. Why have balancing costs increased since 2019?

Since 2019, global, unexpected and unprecedented events (The pandemic, the energy crises and the illegal Russian invasion of Ukraine) have resulted in an increase in balancing costs.

- The pandemic and subsequent lockdowns led to the need to operate a low power system. This is harder and more costly to balance. This period led to an increase in the volume of our balancing actions, and balancing costs as a result.
- The subsequent rebound of global economic activity following the initial phases of the pandemic caused unpredictable levels of demand and crucially the start of the global gas shortage that is still occurring today. This shortage is a key driver behind the rapid increase to wholesale energy prices since late 2020.

- Russia's devastating invasion of Ukraine in February 2022 led to further gas and energy supply shortages as use of Russian energy was curtailed and/or hit by sanctions. These further shortages, coupled with general market uncertainty caused by the war, further accelerated increases to wholesale energy prices in 2022.
- Finally, due to shifts in energy flows across Europe during summer 2022, brought about by the war in Ukraine, GB became a net exporter of electricity 7 or 8 years before we were expecting to. Analysis is ongoing to quantify the impact of this on balancing costs.

The impacts of these events on wholesale prices and subsequently to balancing costs are shown in the following graphs:



Four-year view of balancing costs / volumes, and wholesale prices

Balancing costs and volumes include:
BM, ancillary services, trades and Winter Contingency costs

During this same period, we have decreased our volume of actions by about a third (2019/20 vs 2021/22), driven by key long-term initiatives to improve our system operation:

- Our changes to Frequency Risk Management (via FRCR) reduced the combined volume of constraints and constraint margin replacement from 28.3TWh in 19/20 to 17.9TWh in 21/22
- Delivery of our accelerated loss of mains change programme was critical to implementing FRCR changes and achieving the above reduction in volumes.
- Volumes increased in 2020-21 as we put in place mitigating measures to manage a low energy system as a result of the pandemic, which impacted on constraint costs. These measures were removed in 2021-22, leading to a drop in volumes.
- This reduction has been sustained in 2022/23, with 22 TWh of actions carried out March 2022 – January 2023, equal to the volumes in the equivalent period of 2021/22.

4. Delivery of activities to minimise balancing costs during BP1:

During BP1 we have made significant progress with the delivery of a number of activities that have minimised balancing costs. We have highlighted a series of key initiatives in the below table, many of which were started before BP1 but have come to fruition in BP1 or will do in BP2.

Category	Initiative / Activity	Started	Complete	Balancing Costs benefits begins
Network Planning & Optimisation	Five-point plan to manage constraints *(Inter-trip capability; ASTI; Whole-system operability; Regional Development Programmes; Fixed BSUoS;)*	Feb 21	Dec 25	FY 23/24
	NOA Network Services Procurement (Pathfinder) projects *(Stability, Voltage & Constraints)*	May 19	Apr 24	FY 21/22
	Connections Reform	Mar 22	Jun 25	FY 23/24
	Outage Optimisation	n/a	n/a	n/a
	Review Transmission Operators' Outage Optimisation Performance	Mar 22	Jan 24	FY 23/24
	Western Link HVDC *(Outage Optimisation & Run-back scheme)*	Jun 22	Feb 23	FY 22/23
Commercial Mechanisms	A4: Build the future balancing service and wholesale markets *(Reserve Reform; EAC; SMP; Response Reform [DR, DR, DM]; Whole electricity system market access for DER)*	Dec 19	Dec 24	FY 20/21
	Local Constraints Market	May 20	Dec 25	FY 23/24
	Balancing Reserve	Sep 22	(TBC)	TBC
	Balancing Market Review *(Review of the BM in response to high costs experienced in Nov 21)*	Jan 22	Jul 22	*Subject to Ofgem next steps*
	CfD interaction with BM review	Feb 23	TBC	*Subject to Ofgem next steps*
Control Room Actions	Trading activities	n/a	n/a	n/a
	Constraint Boundary Optimisation *(D1.6.1, Constraints Optimisation Engineer)*	Mar 22	Mar 24	FY 22/23
	Operational Metering	Sep 22	Dec 23	FY23/24
	Inertia monitoring and forecasting	Aug 16	Mar 23	FY 23/24
Innovation & Technology	Reform of Frequency Response *(FRCR, ALoMCP)*	Dec 17	Sep 22	FY 18/19
	SO:TO Optimisation trial *(ODI-F / STCP11.4)*	May 16	May 21	FY 21/22
	Balancing Programme *(PEF, Open Balancing Platform, Balancing Asset Health)*	Jan 21	Dec 26	FY 22/23
	Operational visibility of DER *(A15.8)*	Apr 23	Dec 25	FY 25/26

Impact of activities to minimise Balancing Costs during BP1

The delivery of these activities has had a significant impact during BP1 delivering balancing costs benefits of c£5.6bn. The total balancing costs for BP1 were £7.0bn, so these benefits have significantly mitigated the forecast rises to balancing costs. These benefits were possible because of initiatives we delivered that ensure we were able to safely operate the electricity network while minimising costs to the consumer:

Category	Initiative / Activity	Balancing Costs benefits (£m) during BP1
Network Planning & Optimisation	NOA Network Services Procurement (Pathfinder) projects (Stability Phase 1; CMIS B6 Interim contracts; Mersey Voltage Voltage;)	132
	Outage Optimisation	3,888
	Western Link HVDC (Outage Optimisation & Run-back scheme)	80
	Network Planning & Optimisation Total	**4,100**
Commercial Mechanisms	Frequency Risk and Control Report	435
	Commercial Mechanisms Total	**435**
Control Room Actions	Trading activities	549
	Constraint Boundary Optimisation (D1.6.1)	12
	Control Room Actions Total	**561**
Innovation & Technology	SO:TO Optimisation trial ODI-F / STCP11.4	144
	Balancing Programme (PEF, Open Balancing Platform, Balancing Asset Health)	352
	Innovation & Technology Total	**496**
	BP1 Total (£m)	**5,592**

Looking ahead, we forecast that delivery of activities that have been completed or started in BP1 will deliver further balancing cost benefits of £5.2bn in the time period 2023/24-2025/26. As balancing costs are directly linked to wholesale prices, this is an estimate that may change in correlation with changes in wholesale prices.

5. Explanation of the ESORI benchmark for BP1

The benchmark for this metric was derived using three years of historical balancing costs and wind generation output data. This 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.

We have seen unprecedented rises in wholesale electricity prices over the BP1 period, which has had a direct impact on balancing costs. There has also 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.

Recognising these changes, over the last few months we have worked with Ofgem to agree a new benchmark to measure our performance against during BP2. The benchmark will be derived using two external factors as inputs: wholesale price and wind generation. It may also be appropriate to adjust the benchmark again during BP2, so we will continue our analysis and engagement with Ofgem and agree changes as needed.

In our regular reporting we also compare monthly balancing costs against the previous year and the previous month to help identify trends and outliers to explain the drivers of balancing costs and the impact of our actions.

6. Categorisation of balancing costs

Our reporting sets out our balancing costs across the different categories described in the table below.

Current control room systems provide engineers with the option to indicate which actions are taken for Energy or System. The Energy actions make up the Energy Imbalance cost (defined under 2. Non-

Constraints costs below). Further analysis is necessary to allocate on average 17,500 remaining daily control room System actions to categories.

These System actions are analysed post-event using legacy tools which apply a categorisation algorithm to allocate them to the categories below. Where the tool outputs for specific actions are inconclusive, this is checked manually using the Control Room reports and may also require queries to be raised with the engineers on duty.

New enhanced optimisation tools are being developed for the Control Room by the Balancing Programme. We want to increase transparency and so a key feature of new optimisation tools is to make certain the tool gives reasons for decisions which can be shared.

i) Constraint costs:

A constraint occurs where a part of the network between generators and demand consumers would not have the capability to carry all the energy safely and securely if the particular generators were to operate at their full capacity. We restrict generation to suit the constraint limit and take actions to manage the impact on the wider electricity system. Costs are allocated to these categories when they are incurred specifically to manage the constraint situation.

Category	Definition
Constraints – E&W	Energy flows on networks within England and Wales
Constraints – Cheviot	Energy flows between Scotland and Northern England in either direction
Constraints – Scotland	Energy flow on networks within Scotland
Constraints – Ancillary	Ancillary services cost related to constraint management: e.g. commercial intertrips
ROCOF	Rate of Change of Frequency – actions taken to manage the rate of change of frequency to protect distribution connected assets
Constraints Sterilised HR (Headroom)	Reducing generation inside of the constraint boundary and replacing this by increasing generation outside of the constraint boundary.

ii) Non-constraint costs

These are balancing costs which are incurred for reasons other than managing the impacts of constraints upon the electricity system

Category	Definition
Energy Imbalance	Energy imbalance is the difference between the amount of energy generated in real time, the amount of energy consumed during that same time, and the amount of energy sold ahead of the generation time for that specific time period. The monthly energy imbalance cost can be negative or positive depending on whether the market was predominantly long or short.
Operating Reserve	Providers commit to keep some of their capacity unused to ensure that our control room has access to sources of extra power in the form of either increased generation or demand reduction. Having power in

	reserve enables us to manage a greater than forecast electricity demand on Britain's transmission system.
STOR (Short Term Operating Reserve)	Specific reserve services with providers offering Minimum of 3 MW of generation or steady demand reduction Response to an instruction within a maximum of 20 minutes Ability to sustain the response for a minimum of two hours Ability to respond again with a recovery period of not more than 1200 minutes
Negative Reserve	A Negative Reserve service can provide the flexibility to reduce generation or increase demand to ensure supply and demand are balanced. The service is held in reserve to cover unforeseen fluctuations in demand, or generation from demand side PV and wind.
Fast Reserve	Specific reserve service with providers offering: Active power delivery starting within two minutes of the dispatch instruction Delivery rate in excess of 25MW/minute Reserve energy sustainable for a minimum of 15 minutes Ability to deliver minimum of 25MW.
Response	Ensuring there is sufficient generation and demand held in readiness to manage system frequency variations away from 50Hz including the management of system inertia
Other Reserve	Correction for failure to delivery energy as contracted. Other Reserve Costs associated with reversing a previously agreed BOA
Reactive	Generators or other asset owners provide services to either absorb or generate reactive power. This is how our control room manages voltage levels on the system
Restoration	Ensuring contingency arrangements are in place to enable electricity supplies to be restored in a timely and orderly way following a partial or complete network shutdown
Minor Components	Not captured by other categories
Winter contingency	Winter contingency contracts with coal BMUs

7. Two-year performance – detail

Data issue: Please note that a data issue was identified in May 2022. We discovered the Minor Components line in Non-Constraint Costs has been capturing some costs which should be attributed to different categories for data since July 2022. Although the categorisation of costs is not correct, we are confident that the total costs are correct in all months.

The root cause of the issue is in the categorisation algorithm inside the legacy tool used to allocate on average 46,000 plus daily control room actions to categories. We are currently unable to update the existing tool and are therefore exploring alternative options, including if necessary, developing a replacement tool.

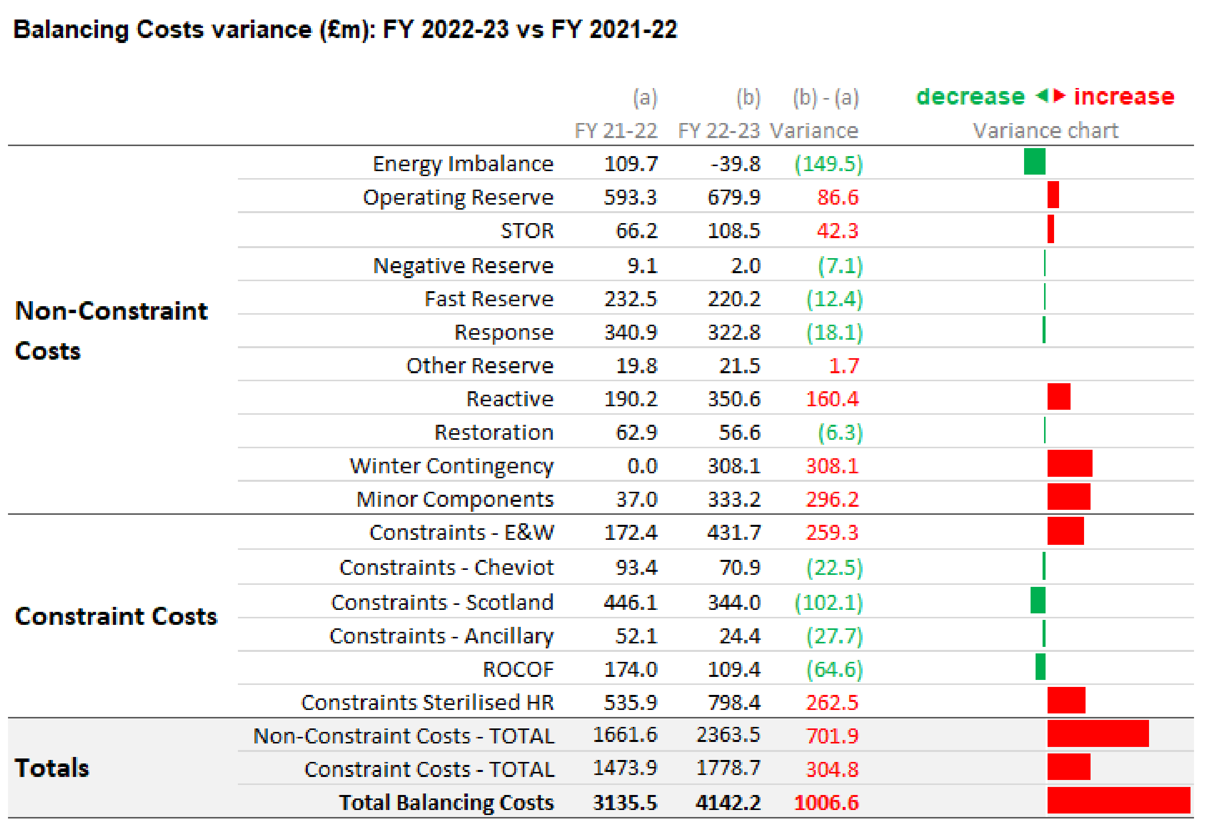
March 2023 update: We have identified that, of the £333m of balancing costs that we reported as Minor Components between in 2022-23, at least £126m should have been reported as Operating Reserve (a ~19% increase in reported figures) and at least £2.5m should have been reported as Response (an increase of 1%). We have not updated the report at this stage as the analysis is still ongoing.

Overall BP1 performance:

Below expectations: Total balancing costs of £7.0bn vs benchmark of £3bn for the two-year BP1 period.

Breakdown of total balancing costs for 2022-23 vs 2021-22

Note that here we include Winter Contingency costs in the totals for the purpose of analysis and insight into performance. The Outturn Balancing Costs reported against the benchmark do not include the Winter Contingency costs.



Balancing Costs variance (£m): FY 2022-23 vs FY 2021-22

		(a) FY 21-22	(b) FY 22-23	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Non-Constraint Costs	Energy Imbalance	109.7	-39.8	(149.5)	🟩
	Operating Reserve	593.3	679.9	86.6	🟥
	STOR	66.2	108.5	42.3	🟥
	Negative Reserve	9.1	2.0	(7.1)	🟩
	Fast Reserve	232.5	220.2	(12.4)	🟩
	Response	340.9	322.8	(18.1)	🟩
	Other Reserve	19.8	21.5	1.7	
	Reactive	190.2	350.6	160.4	🟥
	Restoration	62.9	56.6	(6.3)	🟩
	Winter Contingency	0.0	308.1	308.1	🟥
	Minor Components	37.0	333.2	296.2	🟥
Constraint Costs	Constraints - E&W	172.4	431.7	259.3	🟥
	Constraints - Cheviot	93.4	70.9	(22.5)	🟩
	Constraints - Scotland	446.1	344.0	(102.1)	🟩
	Constraints - Ancillary	52.1	24.4	(27.7)	🟩
	ROCOF	174.0	109.4	(64.6)	🟩
	Constraints Sterilised HR	535.9	798.4	262.5	🟥
Totals	Non-Constraint Costs - TOTAL	1661.6	2363.5	701.9	🟥
	Constraint Costs - TOTAL	1473.9	1778.7	304.8	🟥
	Total Balancing Costs	**3135.5**	**4142.2**	**1006.6**	🟥

Balancing costs for 2022-23 have been higher than 2021-22. 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 volume of the actions taken (1.3TWh more than last year) was the driver of the spend. The key categories of Constraint costs which have increased are the ‘Constraints – E&W’ and therefore 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 Consumer benefit case study for Role 1: Frequency Strategy) along with the launch of Dynamic Containment and continued delivery of the ALoMCP.

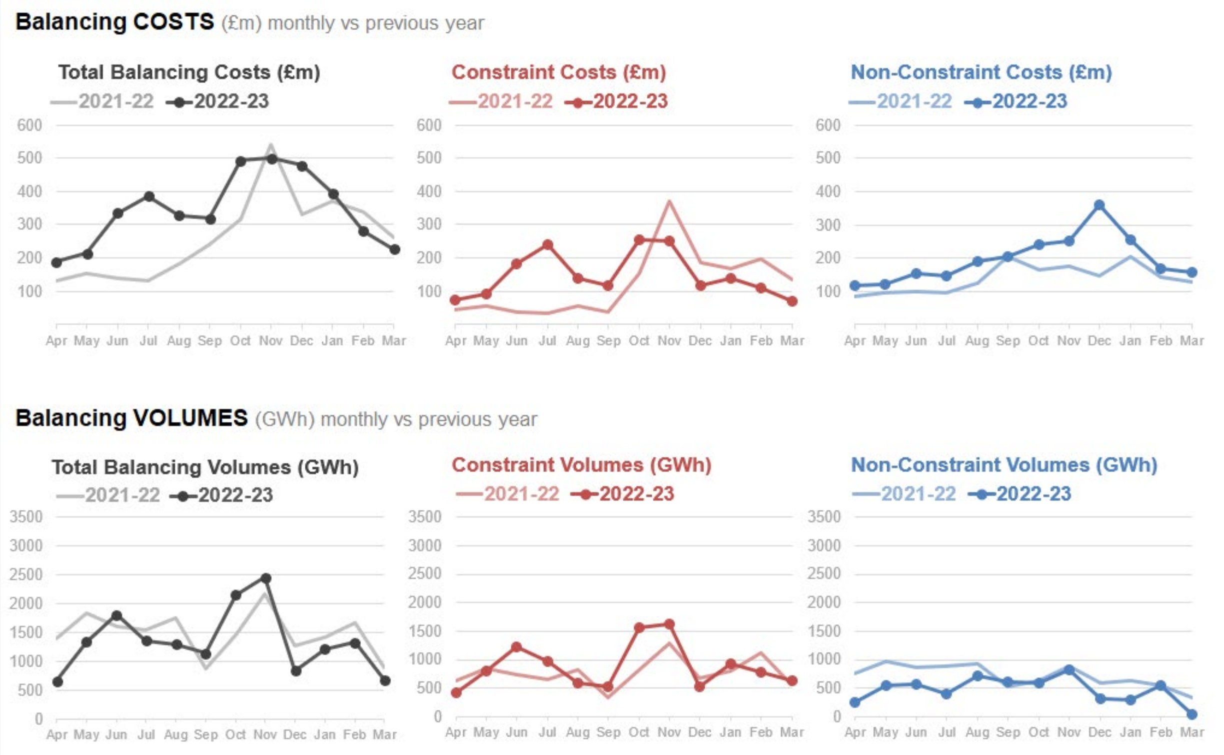
Non-constraint costs were the larger driver of the increase in total spend, as the table above shows. Increasing wholesale prices throughout the year, and particularly on the 2nd quarter of the year, drove the price of actions available to be taken higher. This was further impacted by very high prices 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.

A new category – Winter contingency – was introduced since October 2022 which appears as the highest spread in the table above.

Also, the Minor Components category showed a difference of ~300m, but this is not correct, due to the data issue we have identified and analysed above.
The highest real non-constraint cost category increase compared to last year was Operating Reserve. This was clearly driven by the increased prices submitted in the Balancing Mechanism, particularly during periods of tight margins or perceived tight margins, rather than an increase in volume.
Reactive costs were higher than last year due to ~2.4TWAh more volume of actions and significantly higher cost per MWAh.

Balancing costs and volumes (including Winter Contingency)

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, but the cost has not adopted the same behaviour.

More than half of the year, constraint costs were higher than 2021-22. 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) and the volume of actions being higher this year than last year.

Non-constraint costs remained above last year's level for each month, with the volume of actions lower or the same as last year for most of the year.

Scarcity pricing

Below we show the prices submitted in the BM throughout the BP1 period, to highlight the periods where prices were in the £1000s per MWh during periods of tight system margins due to market scarcity.

Prices accepted in the BM by settlement period, 2021-23

For volumes of more than 10MWh

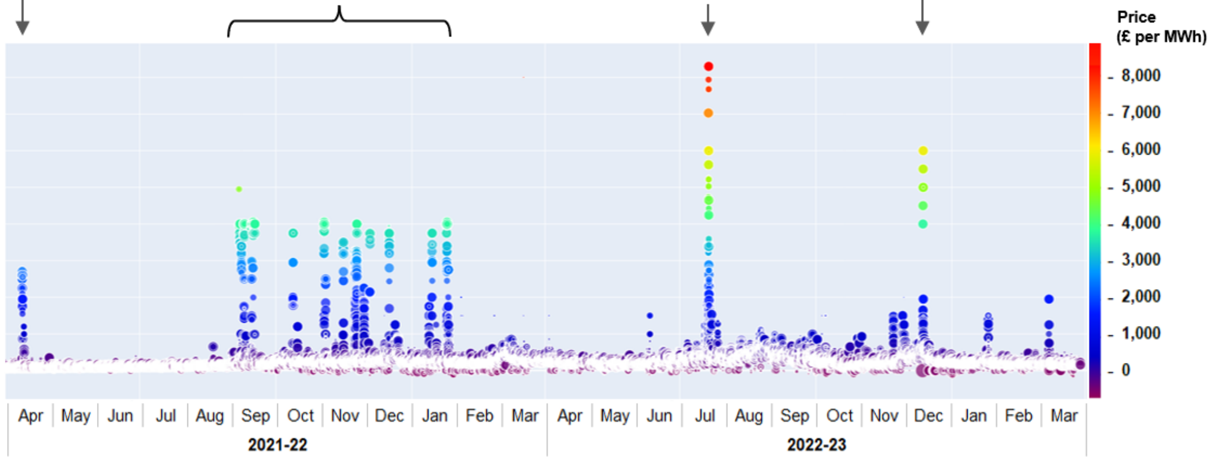
●●• **Size of bubble** indicates volume of BM actions at given price

12 April 2021
National lockdown ends. Margins were tight, with demand very difficult to forecast and outturning higher than expected

September 2021 to January 2022
Multiple settlement periods with extreme prices submitted and taken in the BM

20 July 2022
High power prices from the continent drove all South East interconnectors to export power to the continent. This, combined with London demand, drove power flows across network boundaries that were weakened by unplanned outages.

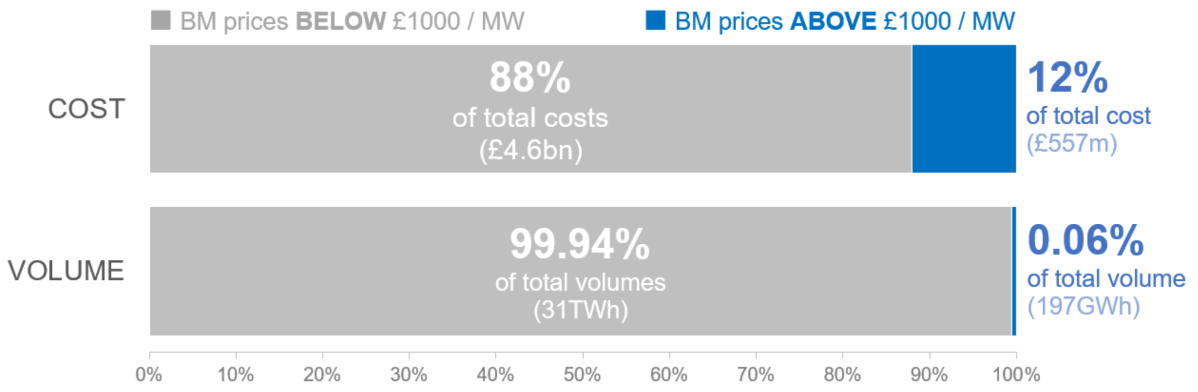
12 December 2022
Low wind and high demand, with unsuccessful trades on continental interconnectors and having to cover possible import reductions due to France being in alert state



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.

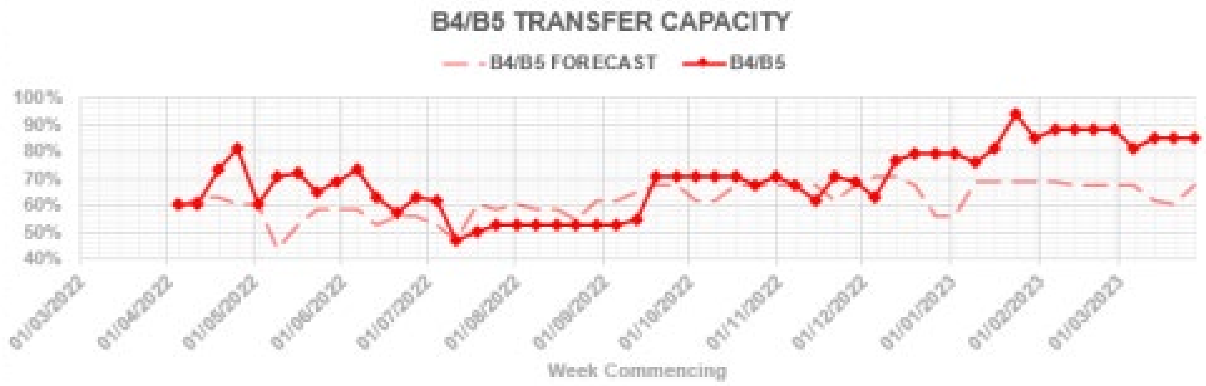
12% of the total BP1 balancing costs were spent on the 0.06% of actions that were taken when the BM price was above £1000 per MW

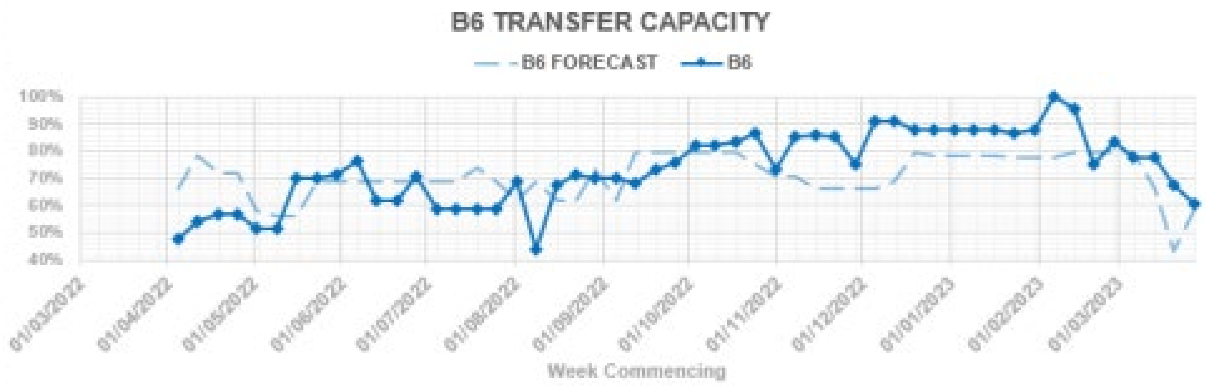
Graph: Total 2021-23 balancing costs and volumes, split by actions taken when BM prices were below or above £1000 / MW

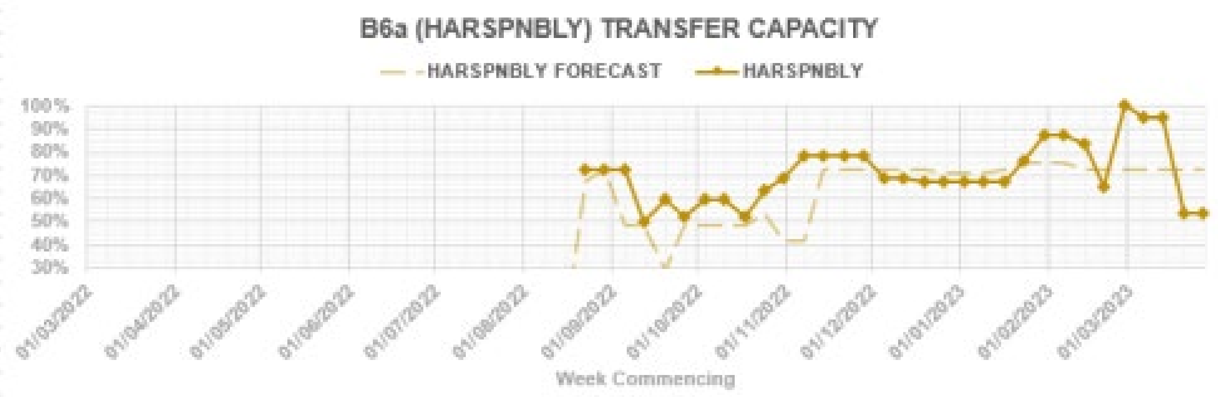


Based on the figures above, we estimate that approximately 86% of the total variance of this period is driven by high wholesale prices, and the remaining 14% is driven by periods of scarcity pricing. This is based on total variance of £3.9bn (actual balancing costs of £6.9bn vs benchmark £3bn), compared to approximately £560m (one seventh of £3.9bn) driven by scarcity pricing as shown above.

Network availability 2022-23

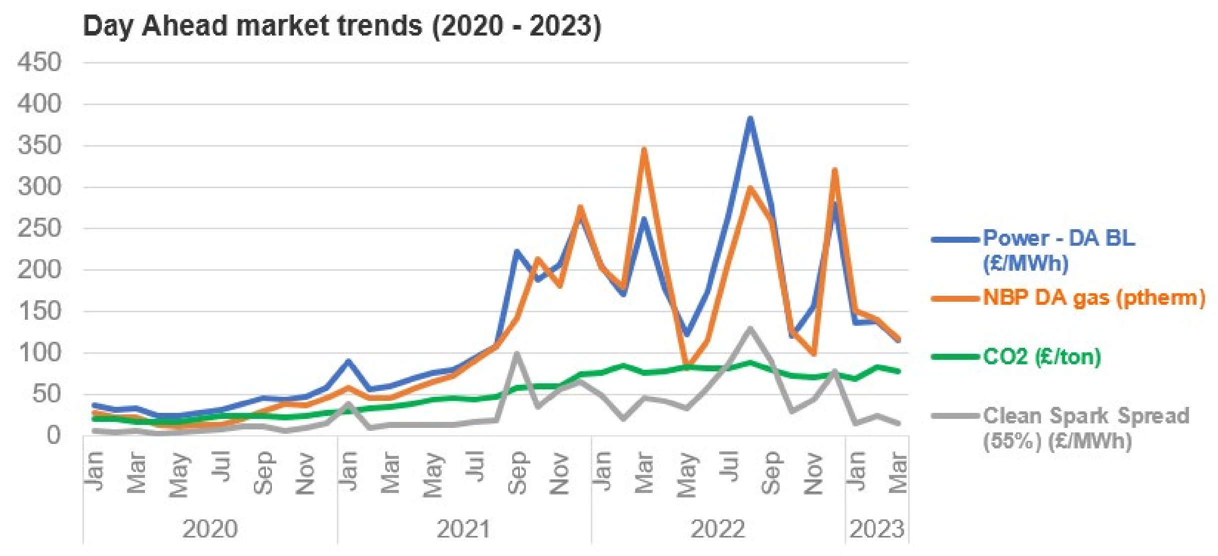






Data is unavailable prior to April 2022. Transfer capacity is discussed in more detail at each week's Operational Transparency Forum. Details of how to sign up, and recordings of previous meetings are available here.

Changes in energy balancing costs



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

Power day ahead prices have dropped in March and remain at the previous year levels. The day ahead gas prices have followed a similar trend and it is lower in comparison with the earlier parts of the year and at the same level as the previous year. Carbon prices have small deviations compared to last year and Clean Spark Spread prices are at significantly lower levels than the same period from the last year and lower compared to the previous month.

Drivers for unexpected cost increases/decreases

The changes in Margin prices (the amount paid for a single MWh) this year were smoother than last year, even though until September there were significant deviations from last year. This year's peak was in December 2022.

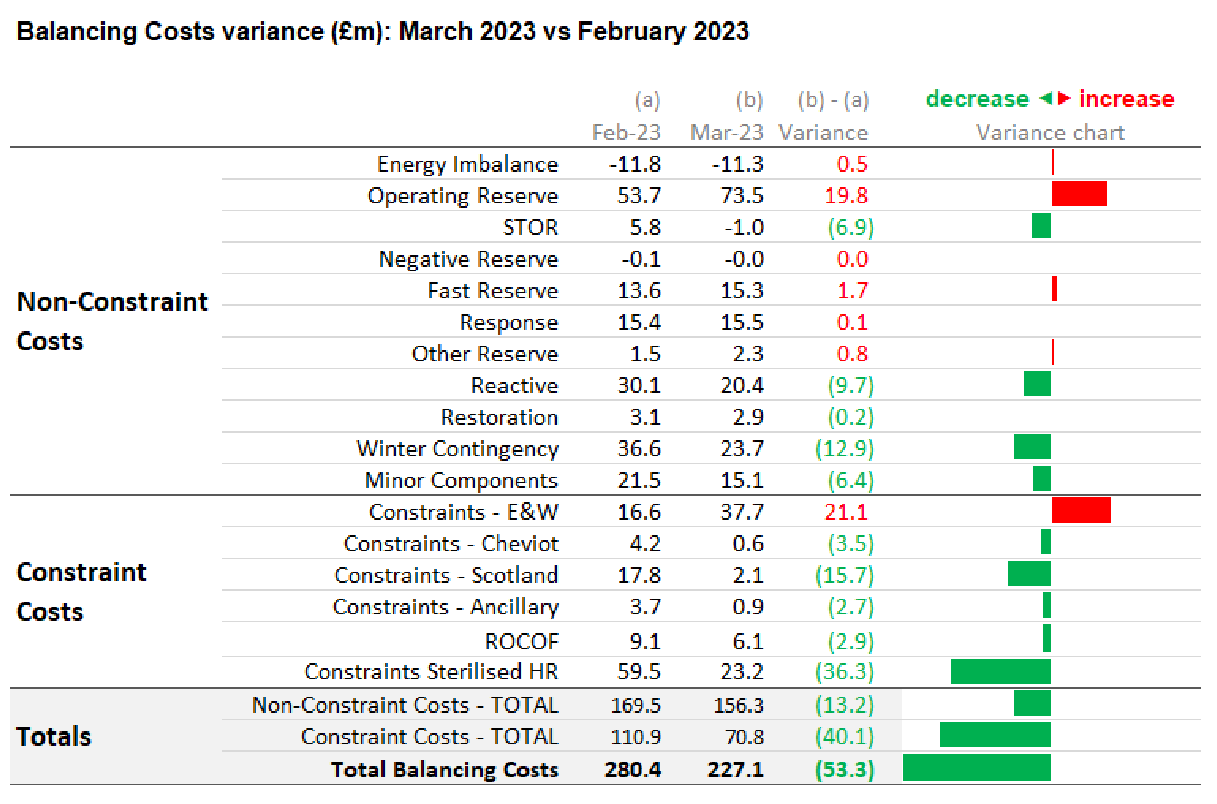
8. Latest month's performance - March 2023

The balancing costs for March were £227m, which is £53m lower than February.

Both constraint and non-constraint costs remain higher than last year but lower than the previous month. The non-constraint volume of actions was lower than both the previous month and the same period last year. The underlying non-constraints costs have decreased this month compared to February but remain higher than last year (excluding Winter Contingency).

Constraint costs decreased this month and remained lower than last year. The total volume of actions and the total cost were both lower this month compared to the corresponding period last year.

Breakdown of costs vs previous month (including Winter Contingency)



Balancing Costs variance (£m): March 2023 vs February 2023

		(a) Feb-23	(b) Mar-23	(b) - (a) Variance	decrease ◀ ▶ increase Variance chart
Non-Constraint Costs	Energy Imbalance	-11.8	-11.3	0.5	🟥
	Operating Reserve	53.7	73.5	19.8	🟥
	STOR	5.8	-1.0	(6.9)	🟩
	Negative Reserve	-0.1	-0.0	0.0	
	Fast Reserve	13.6	15.3	1.7	🟥
	Response	15.4	15.5	0.1	
	Other Reserve	1.5	2.3	0.8	🟥
	Reactive	30.1	20.4	(9.7)	🟩
	Restoration	3.1	2.9	(0.2)	
	Winter Contingency	36.6	23.7	(12.9)	🟩
	Minor Components	21.5	15.1	(6.4)	🟩
Constraint Costs	Constraints - E&W	16.6	37.7	21.1	🟥
	Constraints - Cheviot	4.2	0.6	(3.5)	🟩
	Constraints - Scotland	17.8	2.1	(15.7)	🟩
	Constraints - Ancillary	3.7	0.9	(2.7)	🟩
	ROCOF	9.1	6.1	(2.9)	🟩
	Constraints Sterilised HR	59.5	23.2	(36.3)	🟩
Totals	Non-Constraint Costs - TOTAL	169.5	156.3	(13.2)	🟩
	Constraint Costs - TOTAL	110.9	70.8	(40.1)	🟩
	Total Balancing Costs	**280.4**	**227.1**	**(53.3)**	🟩

As shown in the total rows above, most of this month's cost reduction came from the constraint costs which reduced by £40.1m, while non-constraints costs fell by £13.2m.

Constraints in Scotland & Constraints Sterilised Headroom (HR) were the main factors behind the decreased in Constraint costs. All the other constraint categories showed little deviation from the previous month.

For Non-Constraint costs, Operating reserve and Winter Contingency were the categories with the higher variation. All other categories experienced a decrease in cost or showed small variance from the previous month.

Constraint costs: The main driver of the variances this month are detailed below:

- Constraints Scotland £15.7m decrease, due to lower cost offers accepted to replace the energy removed from the system to manage these constraints and the lower volume of actions.
- Constraints Sterilised Headroom (HR) £36.3m decrease. The cost reduction is in line with the reduction of constraint actions because less headroom had to be replaced elsewhere outside the constraint through BM actions

Non-constraint costs: The main drivers of the biggest variances this month are detailed below:

- Operating Reserve: £19.8m increase, due to high BM prices being submitted by units which were required to maintain reserve levels.
- Winter Contingency: £12.9m decrease. This was the last month of the winter contingency contracts and the decline that started after the first half of the previous month continued this month with daily spend falling from £2m to £0.8m.

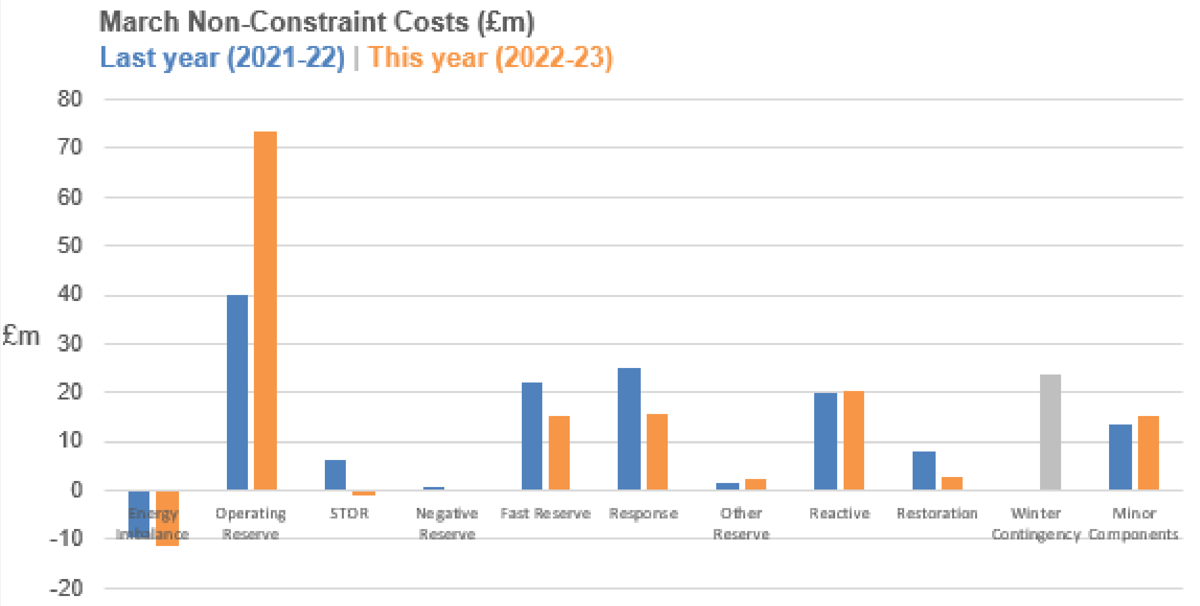
Constraint costs

Compared with the same month of the previous year:	Constraint costs were £64m lower than in March 2022 due to: • Lower wholesale prices compared with last year
Compared with last month:	Constraint costs were £40.1m lower than in February 2023 due to: • An overall reduction in the wholesale prices in March. • Lower volume of actions

Non-constraint costs

Compared with the same month of the previous year:	Non- Constraint costs were £4.5m higher than March 2022 due to: • High BM prices being submitted by units which were required to maintain reserve levels.
Compared with last month:	Non-constraint costs were £13.3m lower than in February 2023 due to: • Lower volume of actions. • Lower daily spend for the winter contingency contracts

Non-Constraint Costs – March 2022 vs March 2023



Comparing the non-constraint costs of March 2023 with those of March 2022, we can see that Operating Reserve and Minor Components showed an increase, whilst all the other categories showed a decrease in cost or a small deviation from the previous month.

We do not cover the variation in Minor Components here as it is driven by the data issue referenced earlier.

- Operating Reserve £33.3m increase due to high BM prices being submitted by units which were required to maintain reserve levels.

Daily costs trends

As discussed above, March balancing costs were £36m lower than the previous month. Less constraint volume of actions, less cost for the winter contingency contracts and less spent on the Reactive and STOR. However, we counted seven days that recorded a spend of more than £10m.

On Wednesday 22 March when out-turned costs were around £21m, the major cost component was the Constraints due to high wind speed resulting in more BM actions required to curtail generation in order to manage thermal constraints and to support system inertia.

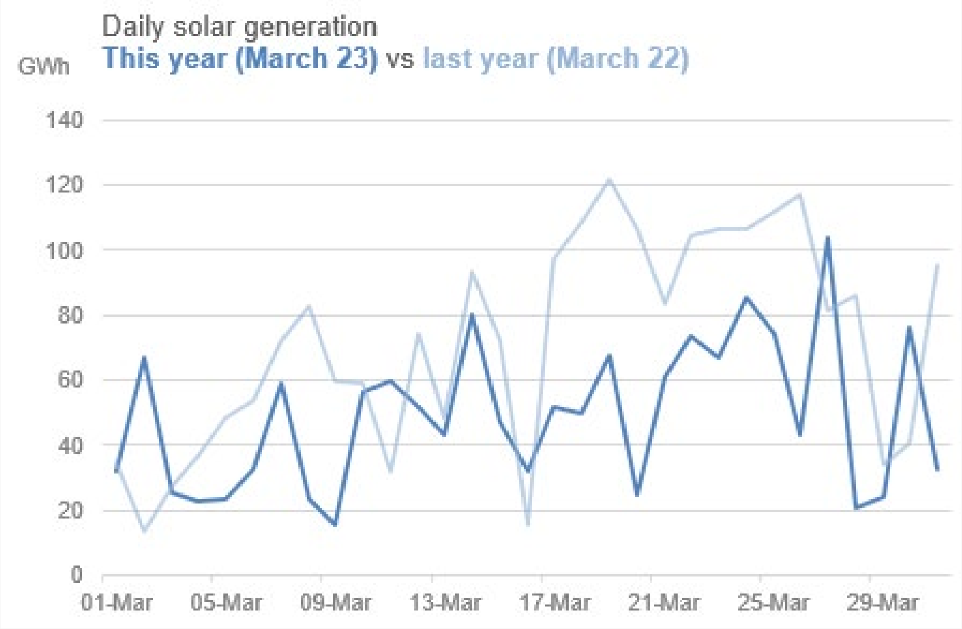
There was a similar picture for the other expensive days, namely 12, 13, 23, 24, & 25 March, with thermal constraints being the main drivers behind costs with the only exception on March 14, when the main driver was the operational reserve that was necessary to secure the network from lower-than-predicted wind generation.

The average daily cost for the month was £7.3m, a £2.7m decrease from the previous month.

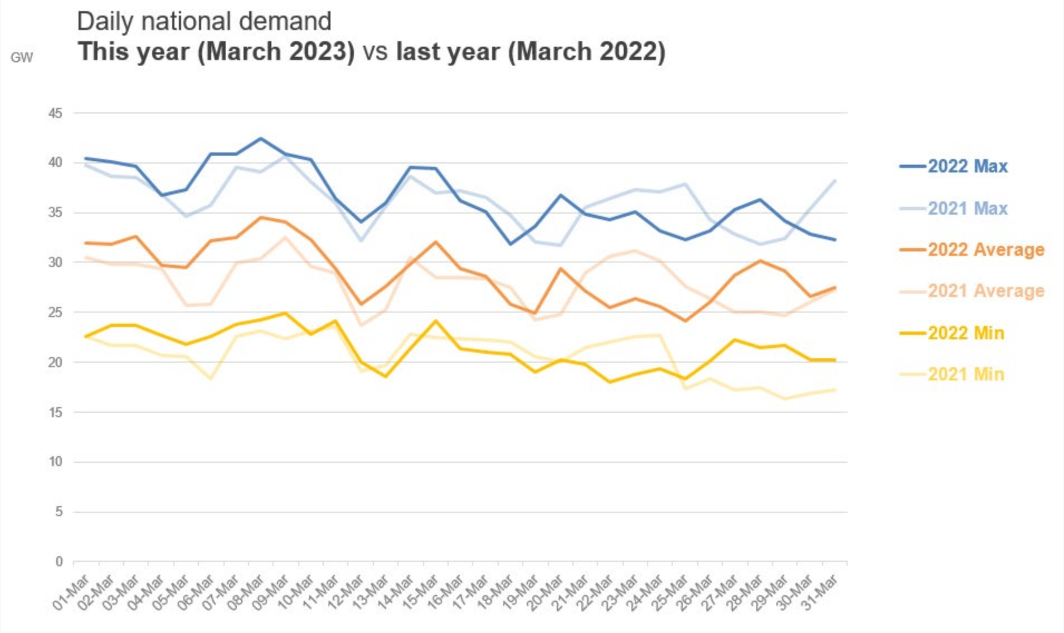
The minimum cost of £3.4m observed on 18th March.

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 control room actions.

Solar generation - March 2023 vs March 2022



Outturn Demand – March 2023 vs March 2022



Metric 1B Demand forecasting accuracy

April 2021 to March 2023 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.

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 is 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.

Overall BP1 performance:

🔴 **Below expectations:** Below expectations with an average absolute percentage error of 2.3% versus a benchmark of 2.1% (benchmark calculated based on an average of year 1 and year 2 benchmarks)

Graph: Two-year view of monthly APE (Absolute Percentage Error) vs Indicative Benchmark

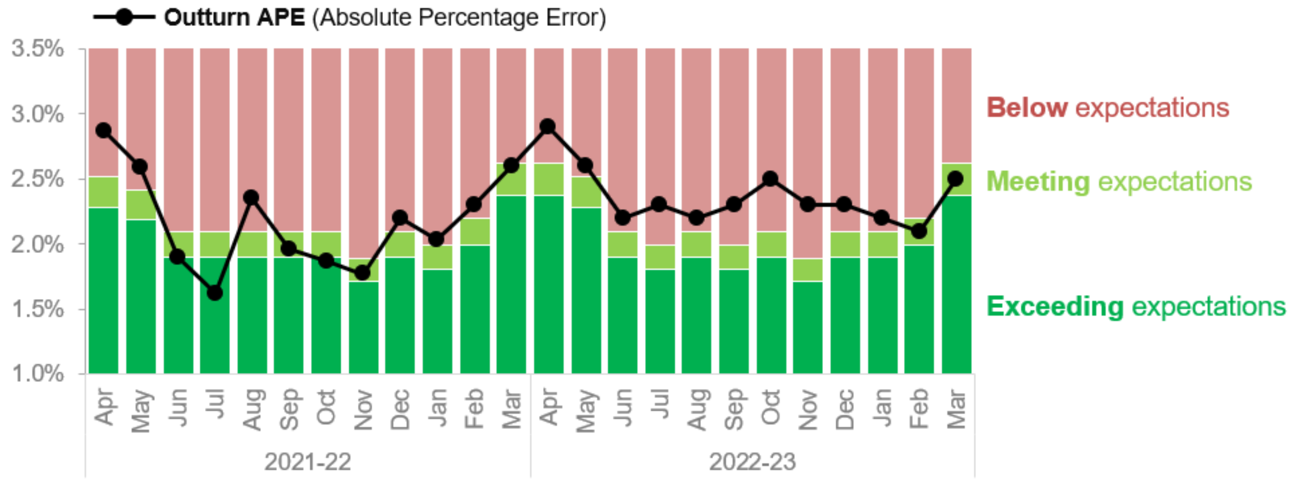


Table: 2022-23 Monthly APE (Absolute Percentage Error) vs Indicative Benchmark

(See our Mid-Scheme review for final 2021-22 figures)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
Indicative benchmark (%)	2.5	2.4	2.0	1.9	2.0	1.9	2.0	1.8	2.0	2.0	2.1	2.5	**2.1**
APE (%)	2.9	2.6	2.2	2.3	2.2	2.3	2.5	2.3	2.3	2.2	2.1	2.5	**2.4**
Status	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🟢	🟢	🔴

Performance benchmarks

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

Supporting information

2021-22	Meeting expectations	APE of 2.18% versus benchmark of 2.1%
2022-23	Below expectations	APE of 2.4% versus benchmark of 2.1%
BP1 Overall	Below expectations	APE of 2.3% versus a benchmark of 2.1% (benchmark calculated based on an average of year 1 and year 2 benchmarks)

There was one missed deadline: 30 Oct 2021 (due to technical issues since fixed)

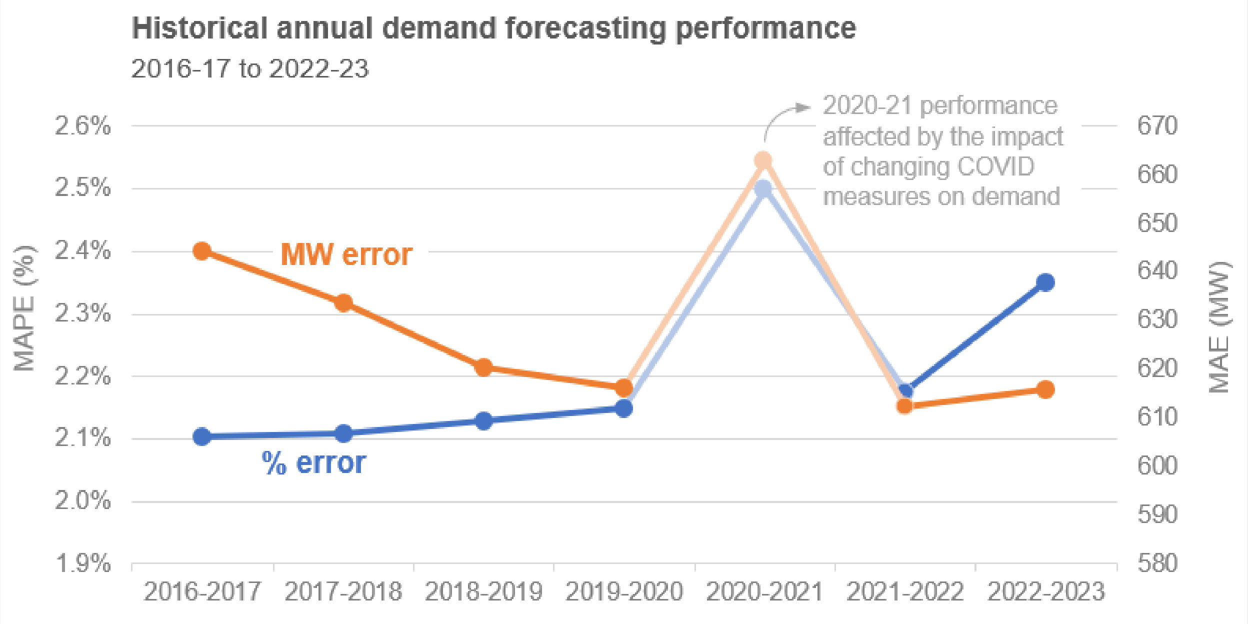
Summary

This metric measures the average absolute percentage error (APE) between the day-ahead forecast demand and outturn demand, averaged over every half hour settlement period. The source used for outturn demand is the Initial National Outturn Demand (INDO), which is the demand on the transmission system (excluding station load, pumped storage and interconnector export). This does not account for the 'unseen' demand that is met by embedded generation.

Although our performance has improved when measured on a MW basis, on a % basis errors have increased. This is largely driven by increased ‘unseen’ embedded generation which has two impacts; First, it increases the amount of irreducible weather forecasting error, and second, it reduces the INDO figure which the MW error is divided by to create the % error.

As shown below, with the exception of 2022-21 which was an outlier due to the impacts that changing COVID measures had on demand, performance on a MW error basis has either improved or remained relatively stable year on year since 2016-17. On a % basis, errors have increased over the same period.

2022-23 brought a slight reduction in error on MW scale compared to the pre-covid period (2022-23: 616, 2021-22: 612, previous 5-year average: 629), however when calculated on a % scale using Initial National Demand Outturn (INDO) as denominator, this shows as an increase in error in almost all months.



2022 had a very large drop in INDO versus previous years (rivalled only by covid 2020 lockdown, which bounced back in 2021). A large part of this appears to be due to the energy price spikes related to the illegal Russian invasion of Ukraine, and general cost-of-living crisis pressures. Weather conditions in autumn/early winter were particularly mild, further reducing the national demand.

Whilst INDO has fallen, the volume of embedded generation (solar, wind and other non-renewable assets) has continued to rise. Our estimates show that embedded generation outturn has grown to around 45% the size of INDO, compared to around 30% in 2017. Embedded generation is inherently more difficult to forecast due to the lack of metering data and the reliance on external weather conditions and forecasts. Increasing embedded generation is visible as a decrease in national demand, since this energy doesn't need to be supplied from the transmission network.

Forecast error derives from all parts of this 'total' demand (national demand + embedded wind & solar + other embedded) but is normalised by dividing by only the falling INDO. This means there is a double effect – increasing forecasting difficulty by the increase of the more variable and weather dependant embedded generation, and then dividing by a falling number (INDO) rather than the 'total' demand.

This ever-increasing difficulty was partially masked in 2021-22 due to the wind 'drought' in 2021 (there was a 19% drop in embedded wind versus 2020). Lower embedded wind means the INDO was higher, and dividing by this higher value caused lower percentage errors.

Whilst errors on the % scale have increased over the last 7 years due to the factors described above (excluding 2020-21 which was impacted by COVID), errors on the MW scale have decreased over the same period. This is the result of improvements we have made over the last two years:

- New machine learning model introduced. This can assess the relationship between demand and weather every 30 mins with new data
- New statistical model (GAM – Generalised Additive Model) introduced, replacing previous linear models. This can better model non-linear effects on demand of input variables. Temperature for example causes an increased demand at both low (increased heating demand) and high (increased cooling demand) values, and this is better modelled with a GAM.
- Continued benefits of the PEF (Platform for Energy Forecasting) project including more forecasts, more frequently and at a higher level of detail. This includes GSP (Grid Supply Point) modelling to forecast localised demand and aid with constraint management.
- Increased transparency with new dataset published on data portal (Day ahead half hourly demand forecast performance)
- Forecasting workshops with experts from outside the ESO
- Further improvements to the Machine Learning models, including modelling Grid Supply Point (GSP) level demand
- Experience sharing between forecasters, including how to account for cost of living, fuel cost crisis, Demand Flexibility Service, and work from home behaviour change effects
- Experience gained at retraining GAM models for BST and GMT. These models are updated twice yearly (on clock change day), and additional data and experience has helped in re-training the GAM models since their introduction in 2021

We have not yet been able to incorporate DFS (Demand Flexibility Service) values into our reported statistics. This is because of a technical database issue taking longer than expected to resolve. When we do account for DFS amounts, we expect our accuracy to slightly increase. As DFS only occurred on a small number of settlement periods and was a relatively small amount, the effect of this correction is likely to be minor.

Additional weather forecast/actual dataflows have been acquired, and the integration of these into the demand forecast models is progressing.

Latest's month's performance - March 2023

For March 2023, the average absolute percentage error (APE) of our day ahead demand forecast was 2.5% compared to the indicative performance target of 2.5%, and therefore meeting expectations.

According to the Met office "March began cold and dry, under the influence of high pressure, but from the 8th onwards it was predominantly unsettled… from mid-month it was broadly mild everywhere. After transitory fine weather on the 27th, the month ended with a westerly pattern, very unsettled with low pressure close to the UK". These unsettled weather conditions, in addition to the lengthening and brightening of days as we head into summer, as well as the occurrence of clock change day all make for March to be a difficult month for forecasting. This is reflected in the monthly targets, for which March has the highest value of the whole year (2.53%).

The distribution of settlement periods by error size is summarised in the table below:

Error greater than	Number of SPs	% out of the SPs in the month (1486)
1000 MW	401	27%
1500 MW	173	12%
2000 MW	62	4%
2500 MW	19	1%
3000 MW	3	0%

The days with largest average absolute percentage error were 14 March and 31 March. 14 March was affected by large wind and solar errors, and uncertainty around the unsettled low pressure system towards the end of the month contributed to the errors on 31 March.

Clock change day is traditionally one of the trickiest to forecast accurately, due to altered behaviours, different number of settlement periods, fewer similar profile days to choose from, and the changing over of forecast models. However the error for Sunday, 26 March was 2.5% - the same as the average for the whole month – which is a good result for a clock change day.

Work is under way on implementing the recently increased amount of weather data we receive and feed into our forecast models. Model improvements are currently being developed, though this will take time to collect enough data to robustly measure the impact of these forecast improvements (at least one full quarter), and accuracy improvements won’t be seen immediately.

There were 0 occasions of missed or late publications in March.

Metric 1C Wind forecasting accuracy

April 2021 to March 2023 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.

Overall BP1 performance:

● **Meeting expectations**: Two-year absolute percentage error of 4.66% versus a benchmark of 4.75% (benchmark calculated based on an average of year 1 and year 2 benchmarks)

Graph: Two-year view of BMU Wind Generation Forecast APE vs Indicative Benchmark

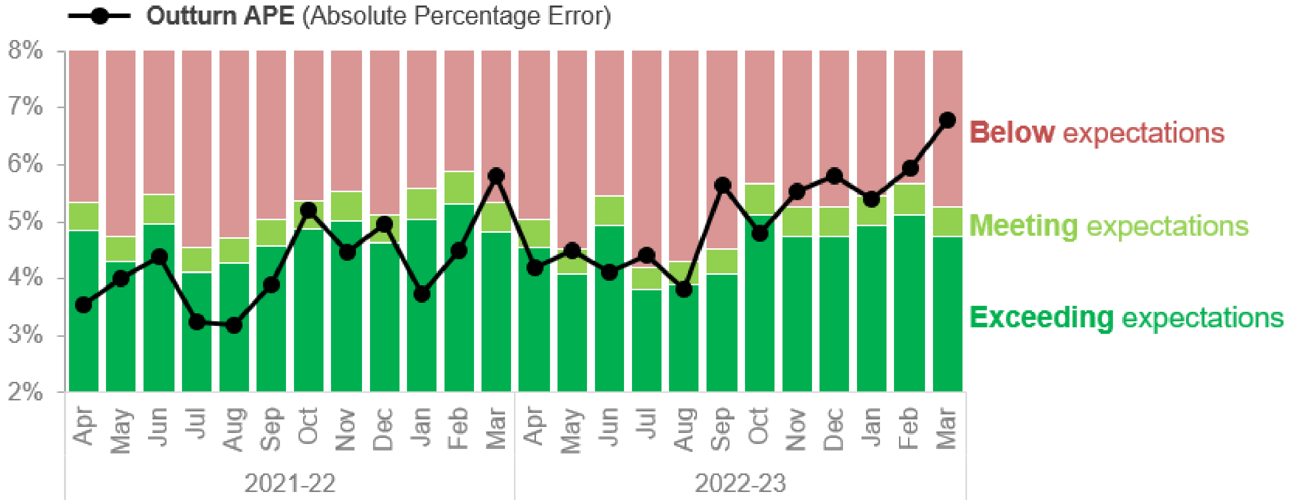


Table: 2022-23 BMU Wind Generation Forecast APE vs Indicative Benchmarks

(See our Mid-Scheme review for final 2021-22 figures)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
BMU Wind Generation Forecast Benchmark (%)	4.8	4.3	5.2	4.0	4.1	4.3	5.4	5.0	5.0	5.2	5.4	5.0	**4.8**
APE (%)	4.2	4.5	4.1	4.4	3.8	5.7	4.8	5.5	5.8	5.4	6.0	6.8	5.1
Status	●	●	●	●	●	●	●	●	●	●	●	●	●

Performance benchmarks

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

Supporting information

Overall performance:

2021-22	Meeting expectations	APE of 4.2% versus benchmark of 4.7%
2022-23	Below expectations	APE of 5.1% versus benchmark of 4.8%
BP1 Overall	Meeting expectations	APE of 4.66% versus a benchmark of 4.75% (benchmark calculated based on an average of the year 1 and year 2 benchmarks)

Brief summary of 2021/22

The indicative monthly target was 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 was 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.

Summary of 2022/23

The year started reasonably well with four out of the first seven months of the year meeting or exceeding expectations. From November onwards it was more difficult to achieve the target as, although some seasonality is built into the target, this year's Winter weather was stormier and more unpredictable than the typical Winter.

During the year we have worked hard to both understand the nature of wind power forecast error and to devise strategies to mitigate and minimise that error.

Forecasting of lightning	We often mention in monthly reports that lightning is a good indicator of atmospheric instability, and this can lead to forecast error. Our forecasting of lightning has improved over the past 18 months thanks to the efforts of the ECMWF (European Centre for Medium-range Weather Forecasting), and we can now have a reasonable certainty of the likelihood and location of thunderstorms at the day ahead stage. It's useful for our control room colleagues to know that there's an increased risk of wind power forecast error at the day ahead stage. We currently use our knowledge of lightning activity as a warning mechanism. Taking the further step and using this information to improve the accuracy of the wind power forecasts will require a great leap in the world of data science.
Other significant weather features	Another common theme in the monthly reporting is the timing of arrival of weather features such as named storms, low pressure systems and fronts, squall lines and troughs. Differences in arrival time, and the intensity and path of the weather feature can bring forecasting errors. To improve in this area we are making progress in the use of 'ensemble' forecasts. Ensemble Forecasting is a process advocated by many weather companies by generating multiple forecasts. An approach using percentiles is currently used in our operational forecasting. It is clear that there is more to be done before the full potential of ensemble forecasting will be realised in our operational systems.

Decaying tropical cyclones	These are storms that are normally formed in the Caribbean and, due to the action of the Jet Stream, travel all the way across the Atlantic and arrive over the UK after several days. As they make this journey they decay and lose their energy but by the time they arrive their remnants still represent a spell of wind, rain and stormy conditions. The supercomputers used in weather forecasting have a particularly difficult time with the small weather features that are presented in the mix of a decaying tropical cyclone. We're continuing to work with the Met Office in the search for better ways to be accurate about the weather under all circumstances.
Market arrangements	Market arrangements have been a driver of increased wind power forecast error this year. For the newer large offshore wind farms, their commercial arrangements involve Contracts for Difference (CfD). On days where the Intermittent Market Reference Price is negative for more than 6 hours, the income for these wind farms is reduced. As a result, they often chose to shut down. With the current metrics in place this action by wind farms appears as forecast error and means that a large number of MWs are unavailable to the system should they be needed. Plans are being formed to address this. One option is to remove windfarms that take independent action from the performance statistics. Another option is to develop a method of forecasting the occurrence of negative prices in the Intermittent Market Reference Price and then use that to improve the wind power forecasts. The number of occasions that a wind farm switches off for these reasons will increase as greater wind farm capacity is installed. We have also explored the possibility of increasing the number of weather forecasts that we receive. As more wind farms are installed both onshore and offshore, a greater level of detail is required to maintain wind power forecast accuracy. Work has been ongoing through the Winter to enhance the weather data feed so that forecasts for more weather locations would be available. This work was completed at the end of November 2022 and as a result it becomes possible to forecast the recently constructed wind farms more accurately than before. At the current rate of progress improved accuracy will be expected by Summer 2023.

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 two years.

Month	Number of occasions when the electricity price went negative
April 2021 to September 2021	None
October 2021	Three consecutive hours on one occasion.
November 2021	One occasion, for three consecutive hours.
December 2021	One occasion, for 2 consecutive hours.
January 2022	Three occasions, each on a different day, durations of 5 hours, 1 hour and 5 hours respectively.
February 2022 to May 2022	None
June 2022	One occasion, for one hour.
July 2022 to October 2022	None
November 2022	One occasion, for 2 consecutive hours.

December 2022	One occasion for 7 consecutive hours.
January 2023	Two occasions, each occasion on a difference, both occasions with a duration of 2 hours.
February 2023 to March 2023	None

The electricity price used for this analysis is the Intermittent Market Reference Price. Market price data can be downloaded here.

No missed / late publications

During the reporting years 2021-22 and 2022-23 there were zero instances of missed or late publication of forecast data.

Latest's month's performance - March 2023

March performance was below expectations, with an APE of 6.8% versus the benchmark of 5.0%.

At the beginning of March Northerly winds prevailed. This is a less common wind direction, and our forecasting models are optimised for the more common wind directions of Easterly and South-easterly. Due to this effect, the wind power forecast error was marginally higher than it would have been otherwise. On the 7th and 8th March there was an active front passing across the South of England bringing stormy conditions. This caused the out-turn to be about 20% greater than the forecast for most of the day. This front gradually worked its way northwards as the week progressed. By 13 March the weather had turned again, and a cold front was progressing southwards. This battle of the fronts also generated some of the largest forecasting errors in March where the 14th had many half hours where the wind out-turn was 30% below the forecast.

Lightning activity is normally an indication of atmospheric instability and also increased risk of wind power forecast error. On the 15 March there was some lightning activity with thunderstorms in Manchester and a scattering of lightning strikes over a wide area of GB. A similar pattern of lightning happened on 18 March. On the 22nd there was a scattering of lightning across the Western Isles and on 23 March, lightning activity could be seen across North Wales and East Anglia. The 31st had a smattering of lightning strikes to the west of London and in Humberside.

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

Metric 1D Short Notice Changes to Planned Outages

April 2021 to March 2023 Performance

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

Overall BP1 performance:

🟢 **Meeting expectations:** A total of 1.8 delays or cancellations per 1000 outages due to an ESO process failure over the two-year BP1 period, versus the benchmark of 1 – 2.5.

Graph: Two-year view of number of outages delayed by > 1 hour, or cancelled, per 1000 outages

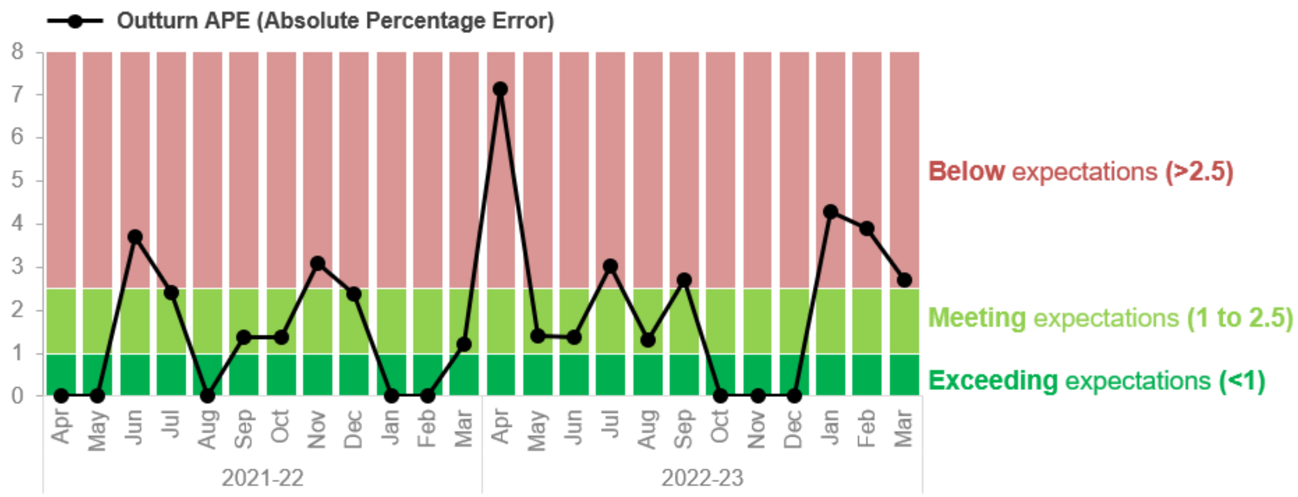


Table: 2022-23 Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

(See our Mid-Scheme review for final 2021-22 figures)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	700	709	730	660	766	739	684	635	441	465	512	743	7784
Outages delayed/cancelled	5	1	1	2	1	2	0	0	0	2	2	2	18
Number of outages delayed or cancelled per 1000 outages	7.1	1.4	1.4	3	1.3	2.7	0	0	0	4.3	3.9	2.7	2.3
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

Overall performance

2021-22	Meeting expectations	1.3 delays or cancellations per 1000 outages due to an ESO process failure , versus the benchmark of 1 – 2.5
2022-23	Meeting expectations	2.3 delays or cancellations per 1000 outages due to an ESO process failure , versus the benchmark of 1 – 2.5.
BP1 Overall	Meeting expectations	1.8 delays or cancellations per 1000 outages due to an ESO process failure over the two-year BP1 period, versus the benchmark of 1 – 2.5.

We have successfully released 16,260 outages for the two-year period which is broken down to 8476 in 2021/22 and 7784 in 2022/23.

All the below events that have been caused due to an ESO process failure have been followed up with an Operational Learning Note (OLN). These explain the event and identifies corrective actions. The OLNs are distributed across the planning department and control room to share best practice and spread awareness of these events. Furthermore, the events and corrective actions are followed up a monthly Planning to Control Room liaison meeting.

The 11 events in 2021/22 can be summarised as:

- Two delays based on modelling issues between the planning software called Off-line Transmission Analysis and the real-time contingency software used by the control room. The real-time software identified operational challenges that required the outages to be re-assessed. It was identified that the demand within the offline model was different to the real-time software exacerbating the contingency results beyond acceptable limits.
- Two delays based on a generator or Distribution Network Operator (DNO) not fully understanding the risks to their site(s), and when prompted by the control room overnight they request additional mitigations to secure the site(s). This was either undertaking further analysis to re-assure the customer of the impact or expanding on the operational challenges. This is due irregular network configurations that are driven by outages and specific faults resulting in abnormal power flows.
- Two delays based on an automatic protection scheme that would not operate for a particular fault. This occurred during an abnormal network configuration due to the outages required to facilitate the works. This was not identified during planning timescales and pre-fault actions were required to be agreed with the Transmission Owner to secure the network.
- Two delays where outages have had a constraint limit calculated by the planning department that were unable to be achieved by the control room. Due to the impact on transmission network and high Emergency Return To Service (ERTS) time provided by the transmission owner, the outages were sent back to planning department to re-study and verify the constraint limits.
- Three delays where a third party was either not agreeable to the outage or was not informed of the outage before they were planned. This was due to human error where it was missed during the planning process.

The 16 events in 2022/23 can be summarised as:

- Five delays based on a generator or Distribution Network Operator (DNO) not fully understanding the risks to their site(s,) and when prompted by the control room overnight they request additional mitigations to secure the site(s). These irregular network configurations that are driven by outages are unique case by case on the network, with specific faults resulting in abnormal power flows that require a high-level of detail to identify and highlight to the affected customers.
- Two delays based on modelling issues between the planning software called Off-line Transmission Analysis and the real-time contingency software used by the control room. The real-time software identified operational challenges that required the outages to be re-assessed. It was identified the

demand within the offline model was different to the real-time software exacerbating the contingency results beyond acceptable limits. This was at different sites to that of 2021/22.

- One delay based on an outage that needed the busbar protection to be modified to cater for the abnormal substation configuration. The problem was not identified within planning timescales due to human error and further liaison was required to enact this modification.
- Three delays based on substation re-configurations that were required to be modified to what was proposed and agreed during the planning phase. This was either to optimise power flows across the network or to re-configure the site to a more secure configuration for demand security.
- Two delays where a third party was either not agreeable to the outage or was not informed of the outage before they were planned. This was due to human error where it was missed during the planning phase for one delay. The second delay the DNO was not agreeable to the proposed switch out method by the control room that would put demand at risk.
- One delay where a protection depletion was submitted without sufficient information provided by the transmission owner and the work was misunderstood. This required further information and clarity before the control room was prepared to agree to the work.
- One delay on a cross-boundary outage that was not communicated with the other transmission owner to organise switching resource. When the outage was requested, there was not any available resource to isolate and earth the circuit to allow the requested works to proceed. Consequently, the outage was delayed by one day.
- One delay related to concerns of a particular site exceeding the fault levels and clear guidance on how to manage the site was not provided to the control room. As the fault levels were on the limit, the control room requested further guidance on how to manage before agreeing to switch the outage out.

All of the above events that have been caused due to an ESO process failure have been followed up with an Operational Learning Note (OLN). These explain the event and identifies corrective actions. The OLNs are distributed across the planning department and control room to share best practice and spread awareness of these events. Furthermore, the events and corrective actions are followed up a monthly Planning to Control Room liaison meeting.

Latest month’s performance – March 2023

For March, we successfully released 743 outages. There were two occurrences of delays or cancellations due to ESO process failure. The number of stoppages or delays per 1000 outages for March was 2.7, which is outside of the ‘Meets Expectations’ target of less than 2.5. However, the cumulative number of stoppages or delays per 1000 outages for 2022/23 has concluded at 2.3 which is within ‘Meeting Expectations’ target.

The March events are summarized below:

- The first delay occurred on an outage which was planned concurrently with several others in the region. Despite the high volume of existing outages in the area, this outage was still accepted as there was a safety implication for personnel working on site. The outage combination resulted in generator site supplies being left at single circuit risk. Due largely to human error, this was not identified in planning timescales. The control room conducted their usual overnight liaison at which point it became clear that the generator was not aware of the single circuit risk. Consequently, the outage was delayed until one of the other outages had returned, thus reducing the risk to the generator. An operational learning note has been written capturing some guidance on identifying these scenarios and the correct process to follow before accepting the outage.
- The second delay occurred due to a discrepancy between the tool used within planning timescales (Offline Transmission Analysis) and the real-time software used by the control room (Power Network Analyser). There were unacceptable high post-fault voltages for a specific fault which were observed in the real-time software but not in the planning software. This discrepancy was further complicated by a transmission generator in the proximity which reduced its reactive power absorption capability. The high voltages were not identified within planning timescales or within the preliminary offline assessment performed by the control room. The outage was delayed until a more robust reassessment could be undertaken. An investigation to the cause of the discrepancy between the two tools is ongoing.

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 our **Frequency Strategy** 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

Summary

We now estimate total gross benefits of £1.5bn over the five years of RIIO-2, which is an increase of £1.2bn compared to the original estimate of £305m

In line with the original CBA, we have updated benefits relating to the activities Enhanced Balancing Capability and Transform Network Control. We also include benefits from Platform for Energy Forecasting and BM Asset Health Developments, neither of which were included in the original CBA, as explained below.

The original assumption in the original CBA was that the purpose of BM Asset Health investment was to keep the BM systems maintained. However, we have implemented several developments which add value to improve situational awareness due to the evolving market and therefore these should be included in the benefits for this CBA. Our strategy has been to consider the transformational journey from existing to future balancing capability in delivering for the consumer, and therefore developments to existing systems have been essential. In essence Enhanced Balancing Capability has been delivered via existing systems. In addition, benefits from our Platform for Energy Forecasting were not documented in the original CBA despite the existence of the investment at that time. Recognising the substantive benefits from this area is important and so these have been captured in this updated CBA.

Therefore, we will be realising benefits of £932m from our Platform for Energy Forecasting and £48m from BM Asset Health Developments, not accounted for in the original CBA. These deliveries are all aligned with our co-created industry roadmap. The original forecast benefit for deliveries in the Platform for Energy Forecasting (not in the original CBA) was £175m.

Table: CBA gross benefits during RIIO-2 *(All figures in £m)*

Included in original CBA?	Activity	Original CBA	End of scheme	Difference
✓	Enhanced Balancing Capability & Transforming Network Control	305	570	+265
✗	Platform for Energy Forecasting	-	932	+932
✗	BM Asset Health Developments	-	48	+48
	CBA Total	**305**	**1550**	**+1245**

Although the overall benefits from Enhanced Balancing Capability & Transforming Network Control have increased, in the first two years the benefits are lower than assumed in the original BP1 CBA.

In BP1 we estimated £43m gross benefit during the first two years but we now estimate £1.7m. This reduction is due to delayed realisation of benefits from the delivery of our Open Balancing Platform and removal of the benefits from better inertia forecasting and needs management. We also expect reduced benefits from utilising flexible technology and improved situational awareness in 2023-4 and 2024-25.

Despite these reductions, the overall CBA benefits over five years have increased, mainly due to the increase in benefits from CO2 reductions, which have gone up from £51m to £415m

Please note that of the total £1.5bn benefits now expected, £1.1bn is made up of activities included in the Balancing Programme (Enhanced Balancing, Platform for Energy Forecast and BM Asset Health Developments), with the remaining £416m attributable to Transform Network Control.

Calculation of monetary benefit to consumers

Calculation of the benefits of Enhanced Balancing Capability and Transform Network Control are on the basis of the original CBA[9] with updates to the underlying assumptions as documented in the sensitivity figures below.

Benefits from the Platform for Energy Forecasting are on the basis of an improvement of the MW error of National Demand plus Solar and Grid Supply Point forecasts and the value of these improvements based on wholesale power prices, which have increased significantly (~300% increase since 2019).

Benefits from BM Asset Health Developments are based on reductions in balancing costs.

Key RIIO-2 Deliverables and progress

Activity A1.2 – Enhanced Balancing Capability

Deliverable	Status of associated milestones
D1.2.1 Enhanced Balancing Tool	83% complete 17% delayed – external reasons
D1.2.2 Emergent technology and system management	64% complete 23% delayed - external reasons 14% delayed - internal reasons
D1.2.3 Future innovation productionisation	100% complete

Activity A1.3 – Transform Network Control

Deliverable	Status of associated milestones
D1.3.1 Develop and deliver new real-time situational awareness tool	96% complete 4% delayed – internal reasons
D1.3.2 Enhanced network modelling tools (modules for D1.3.1)	100% complete
D1.3.3 Upgraded control centre video walls and operator consoles	100% complete
D1.3.4 Increased operational liaison with DNOs	100% complete

Activity A1.4 – Control Centre Architecture

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[9] https://www.nationalgrideso.com/document/153631/download

Deliverable	Status of associated milestones
D1.4.1 Creation of a data and analytics platform	100% complete
D1.4.2 Technology Advisory Council	100% complete

Forecasted benefits

1. 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	-	-	-	15.6
Improved situational awareness	1.5	8.6	24.3	37.2	45.5	117.1
Reduced balancing mechanism outage downtime	-	-	-	-	1.0	1.0
Total	**18.9**	**24.3**	**61.5**	**89.1**	**111.5**	**305**

2. End-of-scheme view (Enhanced Balancing Capability & Transforming Network Control)

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Reduced CO2 emissions	-	0.3	30.8	140.6	242.8	414.5
Greater interconnection	-	0.1	0.4	1.5	1.9	3.8
Utilising flexible technology	-	0.1	9.0	21.1	33.2	63.4
Better inertia forecasting and needs management	-	-	-	-	-	-
Improved situational awareness	-	0.9	7.8	22.4	54.7	85.0
Reduced balancing mechanism outage downtime	0.2	0.1	0.7	0.7	0.7	3.1
Total	0.2	1.5	48.7	186.4	333.2	569.8

3. Variance (end-of-scheme view vs original CBA)

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Reduced CO2 emissions	-0.8	-3.3	20.0	124.5	223.0	363.5
Greater interconnection	-0.2	-0.7	-1.9	-2.1	-3.1	-8.0
Utilising flexible technology	-2.0	-10.0	-15.1	-11.1	-7.0	-45.1
Better inertia forecasting and needs management	-14.4	-1.2	-	-	-	-15.6
Improved situational awareness	-1.5	-7.7	-16.5	-14.8	9.2	-32.1
Reduced balancing mechanism outage downtime	0.2	0.1	0.7	0.7	-0.3	2.1
Total	-18.7	-22.8	-12.8	97.2	221.8	264.8

For Transforming Network Control, we have had some delays against the original plan which are reflected in the variances above, however we have delivered benefits through:

- Delivering Fault Level Enhancements to our existing tool set within the control room
- Improved our current situational awareness tools by adding Voltage Stability analysis. This allows us to optimise our spend on generators and interconnectors for potential Voltage issues.
- Provided several enhancements to the Control Training Unit to speed up snapshot build and scenario creation. This will allow us to run more training throughout the year and run more realistic scenarios for control room and industry partners.

We have also delivered the following:

- Run a competitive dialog procurement event for the ESO's new Transmission situational awareness tools (NCMS), onboarded GE as the vendor and moved into delivery.
- We have set-up an AWS cloud instance with the converted ESO data set to begin functional demos of existing and new functionality committed in the vendor road map.
- We have also been working on requirement clarification and design for new functionality of the system including; lookahead, intelligent Alarming and process improvement with system release.
- We have also evaluated the existing SCADA control room system and put in place a number of mitigations to increase its design life to allow a switch over to a System Operator focused system.
- The operator console has begun to look at the future of how our control engineers interact with our future systems including NCMS and OBP. This has completed its requirements phase and is now moving to delivery of a new platform to help unify our control room experience.
- DAP Minimum Viable Product went live at the end of Q3 FY22/23 with the inclusion of the first Use Case for Inertia Monitoring.

The benefits for 'Better inertia forecasting and needs management' have been removed from this CBA. The inertia monitoring tool was expected to be available from the start of the RIIO-2 period to help minimise spend on RoCoF, which is increasingly challenging to manage due to ever decreasing inertia levels. In the original BP1 CBA we had only claimed benefits until May 2022 because that was when the Accelerated Loss of Mains Projection Programme was due to have completed and coincided with the day 1 launch of the new response products. This meant it was difficult to accurately forecast the benefits from May 2022 onwards with respect to RoCoF spending. The tools provide improved accuracy of the residual inertia (provided by the distribution network) enabling greater transparency of balancing costs for managing stability and mitigating the risks associated with managing frequency events. The improved inertia accuracy will also deliver benefits by ensuring we buy the optimal levels of response to manage frequency events. Initial assessments are that this could result in annual savings to the consumer of around £200k.

As explained in the summary above, in addition to the £570m benefits from Enhanced Balancing Capability and Transform Network Control, we also estimate an additional £980m combined benefits from Platform for Energy Forecasting and BM Asset Health Developments:

Platform for Energy Forecasting:

- We have delivered benefits of £368m in the BP1 period (£932m across the RIIO-2 period) with a forecast error improvement of 100MWs, which is on average approximately a 20% improvement for each half hour National Demand and Solar Forecasts across the full day and a reduced 8-hour requirement for voltage support of 100MWs due to improvement of Grid Supply Point forecasts with an assumed value of £200MWh.

BM Asset Health Development:

- We have delivered extensive work to modify our current balancing systems to meet changing market conditions and customer requirements. The collective impact from these improvements has been a benefit of £48m from reduced balancing costs.

Related metrics/ Regularly Reported Evidence

Metric/RRE	Impact on metrics/ RREs	Status
Metric 1A Balancing costs	Expected to be favourably impacted by improvements to constraint management and by the benefits of greater flexibility.	Total balancing costs of £6.9bn vs benchmark of £3bn for the two-year BP1 period (below expectations).
Metric 1D Short notice changes to planned outages	Expected to be favourably impacted by improvements to constraint management and by the benefits of greater flexibility.	A total of 1.8 delays or cancellations due to an ESO process failure over the two-year BP1 period (meeting expectations)
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 90% zero carbon in the two-year BP1 period.
RRE 1G Carbon intensity of ESO actions	Expected to improve due to reduced environmental damage from our control centre residual balancing actions	Average carbon intensity of balancing actions was 4.7 gCO2/kWh over the two-year BP1 period.
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.	Over the two-year BP1 period, there were zero frequency excursions, and four instances where the frequency was 0.3 – 0.5 Hz away from 50Hz for more than 60 seconds.
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	Six planned outages and zero unplanned outages to our CNI systems

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	Current view	Commentary

Constraint costs	£600m in 2021/22, £764m in 2022/23	£1.4bn in April to March 2021/22 £1.8bn from April to March 2022/23 [10]	Overall constraint costs have increased in line with increased wholesale prices. This has significantly increased benefits from Improved situational awareness and PEF improvements.
Cost of carbon	£14.70/tonne CO2 equivalent	~£246/ tonne CO2 equivalent [11]	This has significantly increased benefits for reduced CO2 emissions
Progress of deliverables	As per the RIIO-2 plan	As above (Key RIIO-2 Deliverables and progress), the majority of milestones have been delivered, with some delays	We have strategically prioritised deliverables to deliver release 1 of our Open Balancing Platform and delivery additional functionality within our existing platforms as part of the transformation strategy aligned with our co-created industry roadmap.
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 2022, replacing Two Degrees with Leading the Way and Steady Progression with Falling Short	The difference in carbon intensity in FES 22 scenario is higher which significantly increases benefit in combination with the increases in carbon price.
Interconnector volume	15GW – 16.5GW by 2030 (FES 2019)	13GW – 19 GW by 2030 (FES 2022)	We 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.

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[10] https://data.nationalgrideso.com/backend/dataset/fb56b46e-cef3-4eb8-9294-0ca19769b7eb/resource/efb633ae-f6d7-444b-8759-449ac0539dd0/download/constraint-breakdown-2022-2023.csv

Sum of columns B, C, D, E from 01/04/2022 to 31/03/2023

[11] 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.

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

Summary

We now estimate the gross benefits over RIIO-2 to be £25.1m, which is £9.9m lower than the benefits of £35m estimated in BP1.

The reduction in overall benefits is driven in the main by a reduction in the benefits associated with improved decision making. The phasing of the assumed 2% benefit has been updated to align to the phasing of benefits in CBA A1 (Control centre architecture and systems), as this will be providing the necessary tools to enable the improvements. This alignment reduces the benefits overall as more of the benefits are delivered in later years than previously assumed. It is partially offset by an increase in the assumed response and reserve costs which this part of the overall benefits is attached to.

The reduction in benefits for this CBA is also partially driven by a delay in delivery of reduced resource costs as a result of delays to activity A2.4 caused by a change of owner of the supplier, which meant that the system went live in March 2023. Future benefits relating to the base system (£0.5m per year) are expected to start to accrue from 2023/24 with the additional benefits from developments starting to be realised from 2024-25 (£0.8m per year).

To date we have delivered £0.2m gross benefits which is £4.1m lower than BP1.

Calculation of monetary benefit to consumers

Benefit type	Calculation
Reduced resource costs	A2.4 Phase 1 = £0.5m/year benefit from base system A2.4 Future phases = £0.8m/year benefit from base system developments Benefits based on proposals and expected efficiencies.
Lower training costs	**A** - Expected training spend (30 FTE at £75k/FTE) **B** - Improvement in training time (42% - based reduction in training time) **C** - % of benefit claimed in each year, phased as follows: Y1 = 5% Y2 = 15% Y3 = 35% Y4 = 80% Y5 = 100% Lower training costs = **A x B x C**
Improved decision making	**A** – Response and reserve costs (12 year average) **B** – Improvement in decision making (2%) **C** - % of benefit claimed in each year (now aligned to CBA A1 benefits), phased as follows: Y1 = <0.1% Y2 = 0.3% Y3 = 8.8% Y4 = 41.5% Y5 = 100% Improved decision making = **A x B x C**

Key RIIO-2 Deliverables and progress

Activity A2.2 – Enhanced training material

Deliverable	Status of associated milestones
D2.2.1 Development of new modules and qualifications in system operation	100% complete
D2.2.2 Enhanced training and simulation with DNOs and wider industry	100% complete

Activity A2.3 – Training simulation and technology

Deliverable	Status of associated milestones
D2.3.1 Upgrades to current simulators, ahead of developing new simulator capability	100% complete
D2.3.2 New training methods and platforms	100% complete

Activity A2.4 – Workforce and change management

Deliverable	Status of associated milestones
D2.4.1 Personalised updates and automated shift logins	100% complete
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

End of Scheme view:

Updated benefits in April 2023, based on the updated assumptions documented in sensitivity factors documented below.

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Reduced resource costs	0	0	0.5	1.3	1.3	3.1
Lower training costs	0.1	0.1	0.3	0.8	0.9	2.2
Improved decision making	0.0	0.0	1.1	5.3	13.4	19.8
Total	**0.1**	**0.1**	**1.9**	**7.4**	**15.6**	**25.1**

Reduced Resource costs:

We have not been able to deliver the expected benefits in 2021/22 and 2022/23 for reduced resource costs due to delays to activity A2.4 caused by a change of owner of the supplier, which meant that the system went live in March 2023. Future benefits relating to the base system should start to accrue from 2023/24 with the additional benefits from developments on the base system starting to be realised from 2024/25.

Lower training costs:

The average time to train staff into operational roles in 2020/21 was 8 months. The figure improved in 2022/23 to 6.3 months, although there was significant variation depending on the background of the trainee and role being trained for.

There was no change to our plan, but we experienced increase in the time taken to recruit as many of the new starters came from outside the UK and that incurred delays due to Right to Work requirements. We also learnt that although candidates had experience as PSEs they required a higher level of training time to learn about the complexities of the GB system.

Improved decision making:

During the period 2021/22 and 2022/23, there were significant changes to the management of Response and Reserve with the introduction of the Frequency Risk and Control Report methodology together with new products such as Dynamic Containment.

Control Centre Architecture & Systems (A1) has delivered three key changes that have had a positive impact on improved decision making in ENCC:

- Automatic Instruction Repeater (AIR)
- Integration of small BMUs
- PEF forecasting improvements

Whilst these changes will have had a positive impact by freeing up control engineer time, including additional generation and providing better situational awareness respectively, it is not possible to allocate specific savings to any of these improvements.

Phasing of the benefits has been aligned to CBA A1 (Control centre architecture and systems) and therefore benefits will be seen in the final 3 years of BP1.

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.	Total balancing costs of £6.9bn vs benchmark of £3bn for the two-year BP1 period (below expectations).
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 90% zero carbon in the two-year BP1 period.
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	Average carbon intensity of balancing actions was 4.7 gCO2/kWh over the two-year BP1 period.
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	Over the two-year BP1 period, there were zero frequency excursions, and four instances where the frequency was 0.3 – 0.5 Hz away from 50Hz for more than 60 seconds.

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
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. Change is not significant, so we have kept benefits in line with forecast.
	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	12 year historic average with higher forecasted costs in the future included	Response and reserve cost £1.2bn in 2022-23	Costs for the final 3 years of RIIO-2 have assumed to be c£1bn which increases the 12 year historic average.
	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.
	Percentage of annual maximum annual benefit claimed	Updated so it is aligned to phasing of CBA A1 (Control centre architecture and systems) benefits	CBA A1 benefits related to the necessary tools to enable the improvements to decision making.

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 Restoration 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

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.

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 of associated milestones
D3.2.1 Facilitate and compile, on behalf of the GB industry, the annual assurance process for GB Black Start.	80% complete 20% delayed - external reasons
D3.2.2 Validate restoration timelines for GB using the assurance data.	83% complete 17% delayed - external reasons
D3.2.3 Maintain obligations and requirements against the new standard for Black Start capability provision.	50% complete 50% delayed - external reasons
D3.2.4 Restoration decision making support tool designed and developed to aid faster restoration times in line with stakeholder expectations.	83% complete 17% delayed - internal reasons

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

Deliverable	Status of associated milestones
D3.3.1 Trial case studies based on different technology types.	100% complete

D3.3.2 (Subject to project findings) Proof of concept findings implemented, and new system and communication methods implemented	100% complete

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	-	-	-	-	4.6	4.6
Carbon savings	-	-	-	-	0.6	0.6
Total	-	-	-	-	5.2	5.2

We expect the estimated benefits to remain in line with those set out in the original CBA above.

The table above shows that more benefits are realised in later years. At the end of 2022/23 we would expect to have delivered £0m of consumer benefit.

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.	Actual total balancing costs of £6.9bn vs benchmark of £3bn for the two-year BP1 period (below expectations).
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 90% zero carbon in the two-year BP1 period.
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.	Average carbon intensity of balancing actions was 4.7 gCO2/kWh over the two-year BP1 period.
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.	Over the two-year BP1 period, there were zero frequency excursions, and four instances where the frequency was 0.3 – 0.5 Hz away from 50Hz for more than 60 seconds.
Metric 2A Competitive Procurement	We expect competitive restoration processes to improve this metric. This will	Year 1 (2021-22), 55% of

	only be the case once the new contracts are operational.	all services procured through competitive means (meeting expectations) Year 2 (2022-23) 43% of all services procured through competitive means (below expectations)
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.	See RRE 2B in Demonstration of Plan Benefits section

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 southeast and northern regional tender work. The code drafting is seeking approval through the GC0156 industry consultation. There have been some delays to the live trial dates, with an additional trial planned for June 2023, involving a battery energy storage system (BESS) with grid-forming technology to restart the network. It will also use the prototype Zonal Controller to stabilise and maintain the power island within voltage and frequency limits. These delays should not 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. Changes to the Grid Code and Distribution Code for implementation of the restoration standard will be delivered through GC0156 and subsequent changes to the other codes.
Industry participation in Black Start tenders	Better than expected	SE and Northern regional tenders and a wind specific tender were launched in 2022 including opportunities for DER to participate. Just below 300 Expressions of Interest received for these tenders across 7 technology types connected at transmission and distribution levels.

Consumer benefit case study for Role 1:

Frequency Strategy - Frequency Risk and Control Report (FRCR), Loss of Mains, Dynamic Containment and Stability Phase 1 Pathfinder

Activity

Implementation of Frequency Strategy

Since 2019, there are numerous projects that have been delivered and which have shifted the way we manage system frequency risks. We have fundamentally changed how we manage frequency risks both in terms of reducing the risks on the system, as well as reducing the costs for managing those risks. This has been achieved through a clear, long running strategy, comprising of four key projects:

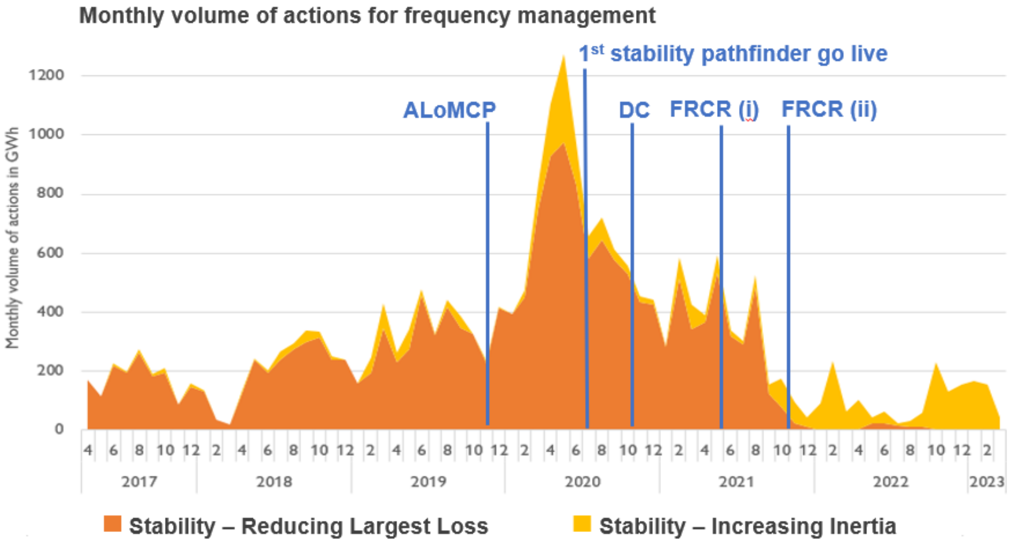
Accelerated Loss of Mains Change Programme (ALoMCP)	The Accelerated Loss of Mains Change programme commenced in 2019 and has made changes to the loss of mains relays on distributed generation. The programme has changed protection settings across 8430 sites (totalling 13.2GW). In addition, 6059 sites (11GW) have reported compliance with LoM requirements. Together this totals 24GW of capacity in scope of the programme that has confirmed compliance. These changes were made to ensure the protection settings of distributed generation acts in the right way, in the event of any system disturbance. This represents 94% of the generation capacity in scope of the project confirming compliance with the changes. These changes have been fundamental in reducing our vector shift loss risks, and the way we secure the system.
Implementation of Dynamic Containment (DC)	DC was launched in 2021 and is a fast-acting response service. It contains frequency within the statutory range of +/-0.5Hz in the event of a sudden demand or generation loss. Since we launched DC, we have been steadily growing the pipeline of providers, improving how we can manage frequency risks on the system.
Frequency Risk and Control Report (FRCR)	The first FRCR was produced in 2021, with phase 1 implemented in May 2021 and phase 2 in October 2021. FRCR provides an annual assessment of the magnitude, duration and likelihood of transient frequency deviations, the impacts and the cost of securing the system. It confirms which risks will or will not be secured operationally.
Stability Phase 1 Pathfinder	The first phase of our stability pathfinder procured inertia services, all of which are now operational. The Pathfinder projects proactively targeted known network issues that would increase balancing costs.

As individual projects, these developments have saved on balancing costs and improved how we manage the system. However, if we consider how these three projects are interlinked, we have been able to fully optimise how we manage frequency risks in totality. In addition, there are enablers within each project that facilitated the changes required to reduce these balancing costs and as a collective achieve considerably larger benefits than a sum of their parts.

For example, without LoM, we would not have been able to change our operational policy approved in the 2021 FRCR. The changes made through ALoMCP changed this, and in conjunction with new, faster response in DC, enabled us to make fundamental changes to our approach to system frequency risks.

	Prior to the implementation of FRCR, we would have also ensured that any system loss did not cause a frequency deviation below 49.5Hz. This generally meant we would either take bids to reduce the infeed loss and resulting RoCoF (Rate of Change of Frequency) to below 0.125Hz/s, and/or increase system inertia to manage RoCoF risks. A combination of changes to policy through FRCR plus the launch of DC, has changed the actions we are required to take. Finally, without stability pathfinder phase 1, we would have been required to buy additional inertia capability in the BM in order to meet our minimum inertia policy. **Note regarding our mid-scheme case study on FRCR:** We previously reported savings of £435m, achieved through FRCR by reducing the volume of actions required to manage the largest loss. This figure was a backward-looking view of the savings achieved, from the point of implementing FRCR in October 2021 and considered only the savings realised from the reduction in actions required to reduce loss sizes. We are widening the scope of these savings, by considering all changes made to improve our frequency strategy. This incorporates the progress from ALoMCP and growth of DC as well as FRCR. We have provided a forecast estimate of the savings that have been achieved as a combined saving from all three deliverables.
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 is also a deliverable in BP2.
Is the consumer benefit mainly during BP1 or in future years?	The costs calculated, are an estimation of what the potential cost for managing frequency risks in the 2023 calendar year could have been, had the changes not been made. Consumer benefits will have been realised during BP1, as the projects delivered (dates highlighted on the chart below). Had none of the projects delivered, and changed how we manage the system, this benefit could be also realised in in future years. FRCR is not, however, a cost forecasting tool. Therefore, the future year savings are indicative. The reality is that other actions or interventions would have been taken to manage costs associated with managing frequency, had LoM, DC, FRCR and stability phase 1 not been in place, and had costs continued to increase. We would not have considered it a prudent decision to operate at potential costs of approximately £2.2bn.
Calculation of monetary benefit to consumers	We have modelled a ‘worst case’ baseline scenario (using the FRCR cost vs risk model) for managing frequency deviations. This scenario assumes no policy changes from FRCR, no DC, no changes in the LoM risks from the ALoMCP. It also does not include any contribution from stability pathfinders, and we have applied a minimum inertia policy of 140GVA.s. We estimate that the costs for managing system frequency in 2023, using this scenario, could have been £2.2bn with 5.1TWh of actions required to manage our largest loss and secure the system against unwanted frequency deviations. We then ran a scenario where FRCR was implemented, DC is available, the changes applied from ALoMCP were accounted for, as well as contribution from stability phase 1 pathfinder. Minimum inertia is set at 140GVA.s. With this, our FRCR cost estimate for the same time period is £330m. This means that the combined savings from FRCR, ALoMCP, DC and stability phase 1, is approximately £1.8bn (£2.2bn minus £330m) The 2023 FRCR is also recommending a lower minimum inertia policy from 140GVA.s to 120GVA.s. The total cost for the same time period, with a lower inertia holding reduces the cost to £260m, meaning cost savings could be even higher.

	Please note that RRE 3A also includes forecasted future balancing cost savings resulting from Stability Pathfinder Phase 1 and the Loss of Mains Programme. However, the purpose of this case study is to calculate the combined benefits resulting from several different activities using the method set out above.
Assumptions made in calculating monetary benefit	To calculate the cost savings achieved through a combination of these projects, we conducted a cost benefit analysis, using a baseline 'worst case' scenario. This baseline was calculated using a one-year data set, between June 2021-May 2022, and used the FRCR model as a mechanism to assess different scenarios and provide a cost comparison. We used the dataset to calculate what the costs of managing frequency could have been in 2023, had no changes been made. The FRCR model takes a range of inputs, including costs for response and targeted actions, LoM load factors and fault statistics. The analysis uses historic scenarios adjusted for known or expected changes in the 1 year period of study (i.e. new connections). Using this model, we calculated the cost of managing frequency risks assuming that no changes had been made to how we improve system operability (no Loss of Mains changes, no DC, no changes to policy through FRCR and no stability pathfinder contribution). Minimum inertia was 140GVA. The total cost is calculated as a sum of: • The bid costs we would have taken to constrain the largest losses on the system via BM actions, • The cost of holding sufficient response, and, • The costs for accessing additional inertia.
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 and increase inertia:** The following chart plots a timeline of when each project was implemented and demonstrates the reduction in volume of intervention required in market dispatch (through trades or BM actions) as well as a reduction in the additional inertia we are required to buy to meet our minimum inertia policy We are no longer required to take actions to constrain large losses on the system as this can now be managed through other means, namely the changes in policy from FRCR, facilitated by LoM and DC. The stability pathfinders have provided inertia contribution that we no longer are required to buy via BM actions. The first FRCR in 2021 fundamentally changed our policy for how we manage system frequency. In mid-2020, we took 9TWh of constraint actions (through trade BM actions). After the implementation of FRCR in 2021 (facilitated by LoM changes and the availability of DC), the volume of actions required reduced to manage system frequency reduced to 4TWh. This reduced further in 2022 to less than 1TWh of actions.

	 **FRCR (i):** Removal of VS policy. **FRCR (ii):** Removal of RoCoF policy Whilst 2020 volumes can be partially attributed to the COVID period of low demands and low inertia periods, the reduction in actions taken to manage loss sizes can also be directly attributed to our policy for how we managed system frequency, post FRCR implementation. This is evident in the continual decline in volume of actions we are required to take. We are also observing more and more periods where no direct actions are required to manage loss sizes.
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: Summary of RREs for Role 1 for 2021-22 and 2022-23

Role 1 RREs don't have performance benchmarks.

2021-22

RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
1E	Transparency of Operational Decision Making	%	90%	88%	89%	89%	88%	89%	93%	88%	91%	94%	98%	95%
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
	CNI Outages - Unplanned	#	-	-	-	-	-	-	-	-	-	-	-	-

2022-23

RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
1E	Transparency of Operational Decision Making	%	92%	93%	93%	89%	89%	90%	93%	88%	89%	91%	94%	97%
1F	Zero Carbon Operability indicator	%	Q1: 84%			Q2: 74%			Q3: 85%			Q4: 90%		
1G	Carbon intensity of ESO actions	gCO2 /kWh	3.2	2.2	4.2	0.3	0.4	2.4	7.4	6.0	4.7	8.8	6.2	4.9
1H	Constraints cost savings from collaboration with TOs	£m	Q1: £353m			Q2: £607m			Q3: £723m			Q4: £576m		
1I	Security of Supply	#	1	1	1	1	-	-	-	-	-	-	-	-
1J	CNI Outages - Planned	#	-	-	-	1	-	-	-	1	-	-	-	1
	CNI Outages - Unplanned	#	-	-	-	-	-	-	-	-	-	-	-	-

RRE 1E Transparency of operational decision making

April 2021 to March 2023 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.

Graph: Two-year view - Percentage of balancing actions taken in merit order in the BM

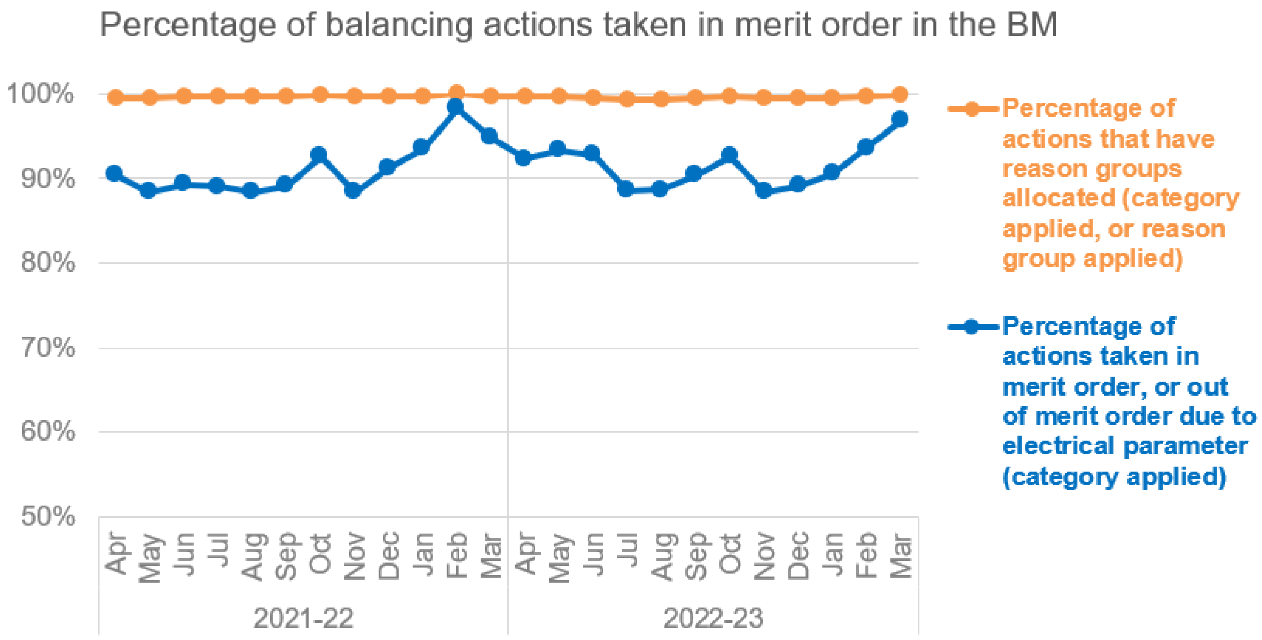


Table: 2022-23 Percentage of balancing actions taken outside of merit order in the BM

(See our Mid-Scheme review for final 2021-22 figures)

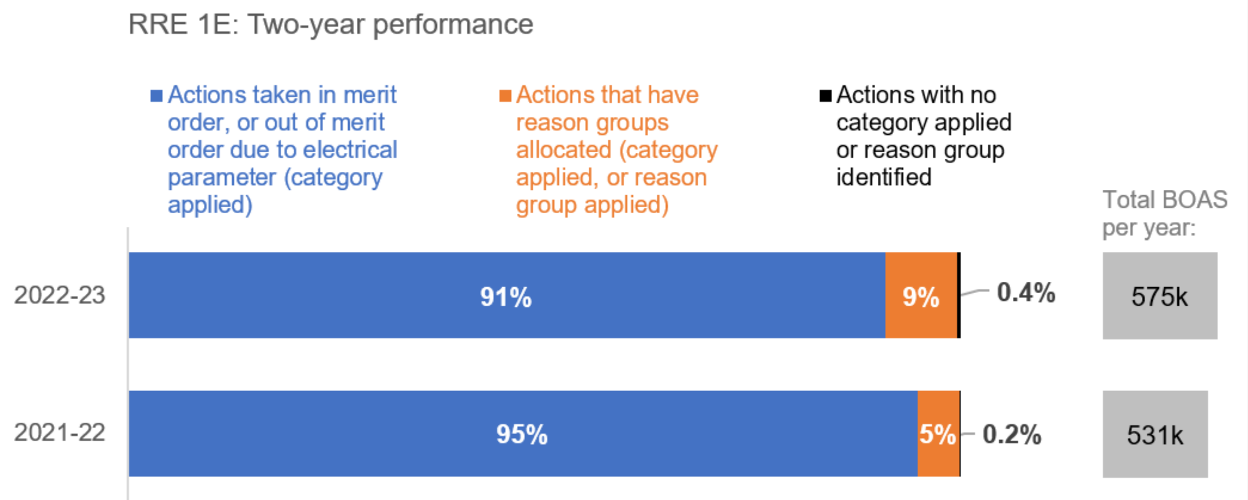
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	92.3%	93.3%	92.8%	88.6%	88.7%	90.4%	92.6%	88.4%	89.1%	90.6%	93.6%	96.8%
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.7%	99.6%	99.4%	99.4%	99.6%	99.7%	99.6%	99.6%	99.6%	99.7%	99.9%
Percentage of actions with no category applied or reason group identified	0.3%	0.3%	0.4%	0.6%	0.6%	0.4%	0.3%	0.4%	0.4%	0.4%	0.3%	0.1%

Supporting information

Overall performance

During the two-year period, 91.4% of actions were taken in merit order, or taken out of merit order due to an electrical parameter. For the remaining actions, where possible, we allocate actions to reason groups for the purposes of our analysis. We were unable to allocate reason groups for 0.3% of the total actions this year.

Over the two years combined, we sent 1,105,700 BOAs (Bid Offer Acceptances) and of these, only 3,396 remain with no category or reason group identified.



March 2023 performance

In March 2023, 96.8% of actions were taken in merit order or taken out of merit order due to an electrical parameter. For the remaining actions, where possible, we allocate actions to reason groups for the purposes of our analysis.

During March 2023, we sent 46,142 BOAs (Bid Offer Acceptances) and of these, only 47 remain with no category or reason group identified, which is 0.1% of the total.

Data issue: As mentioned in our October report, we recently identified an issue with the data used to support this metric. The impact of this issue is minor and is very unlikely to affect the reported figures.

- Over the 19-month period from April 2021, 11 days were not captured by the dataset.
- We have identified the cause in the data which is provided by an ESO legacy tool, and we have implemented countermeasures to ensure any future missing days are flagged promptly and included into the dataset.
- We are unable to recreate the previous missing days due to the time elapsed.

RRE 1F Zero Carbon Operability Indicator

April 2021 to March 2023 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. 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 was required to 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: 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 reports 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 June 2022 was 95% on 11 June, settlement period 29. However, for that period the final ZCO dropped to 74% after our operational actions were taken into account, meaning that this was not the highest final ZCO of the month.

Graph: Two-year view of maximum monthly ZCO% after ESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred)

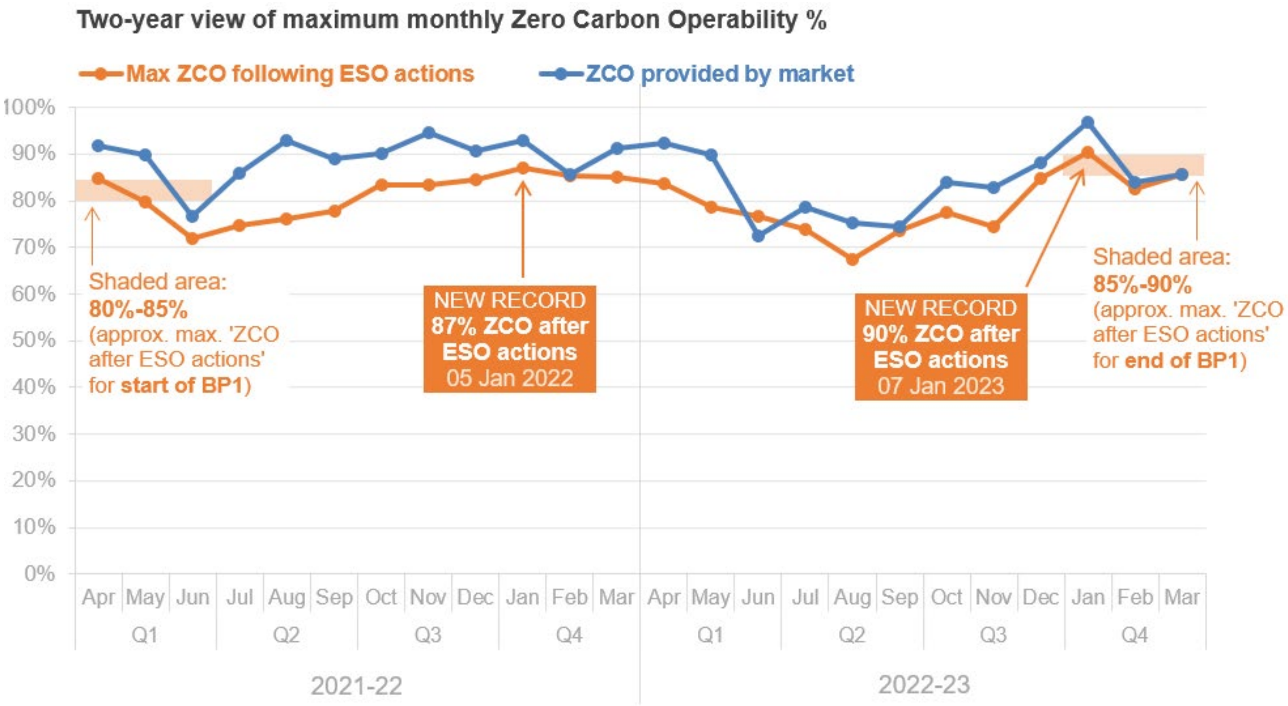


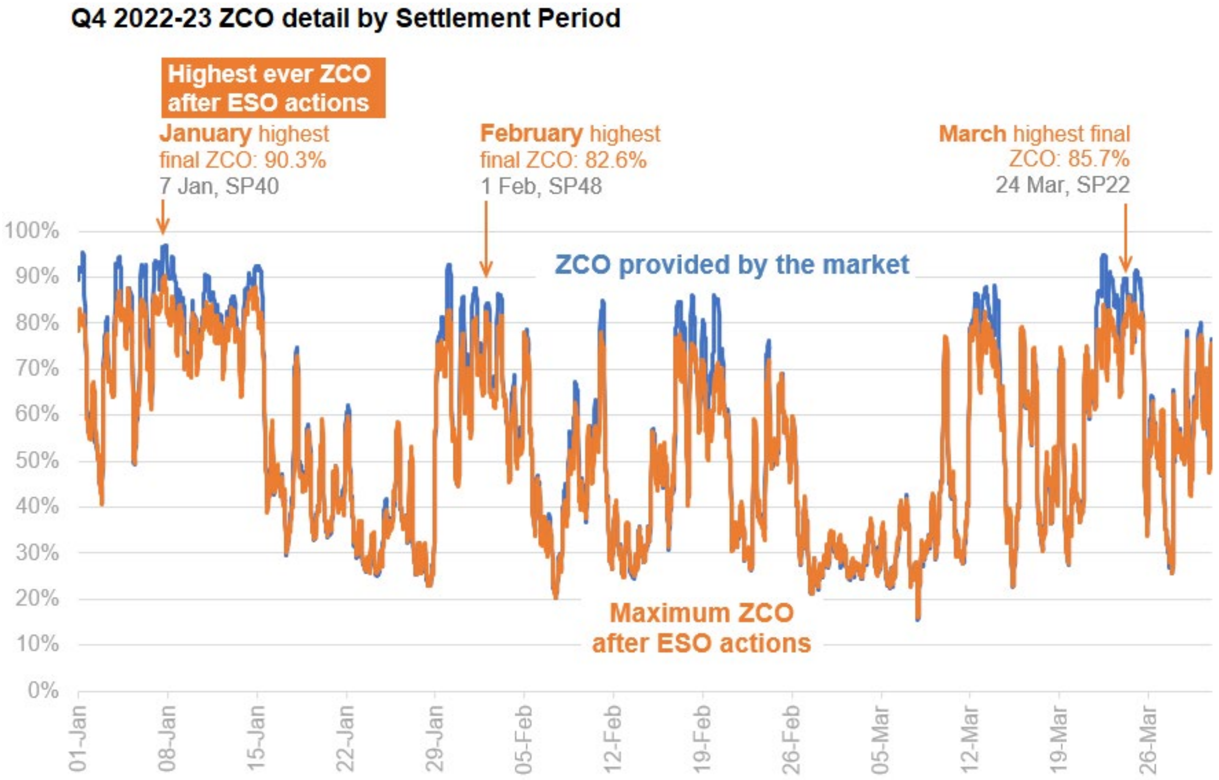
Table: 2022-23 maximum zero carbon generation percentage by month

(See our Mid-Scheme review for final 2021-22 figures)

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	83.7%	92.3%	23 Apr / 28
May	78.5%	89.7%	27 May / 8
June	76.7%	72.5%	25 Jun / 9
July	73.9%	78.5%	24 Jul / 22
August	67.3%	75.3%	03 Aug / 7
September	73.5%	74.3%	17 Sep / 30
October	77.6%	83.9%	01 Oct / 31
November	74.3%	82.7%	02 Nov / 7
December	84.8%	88.1%	26 Dec / 34
January	90.28% (record)	96.8%	07 Jan / 40
February	82.6%	83.8%	01 Feb / 48
March	85.7%	85.5%	24 Mar / 22

Note that the values can change between reporting cycles as the settlement data is updated by Elexon. However, for consistency we have not updated the figures reported in previous quarters.

Graph: Q4 2022-23 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

Overall performance – two-year period

Since April 2021, the maximum ZCO figure that the system can accommodate has been rising steadily and new records have been set every year. Our new highest figure is now ~90%. This was achieved on 26 December Settlement Period (SP) 34 and beaten marginally on 7 January 2023, SP40. This significant increase is due to the successful implementation of our operability strategy. There are many components within that strategy, but the most impactful are the pathfinder programmes

In Stability Pathfinder Phase 1, we procured 12.5GVAs. These have all commissioned now and are supplying inertia and the other key stability services. This could potentially remove the need to synchronise 3-5 Combined Cycle Gas Turbine (CCGT) units for inertia. This would usually occur over the summer and shoulder months and would increase the ZCO figure by around 5% (depending on system conditions at the time).

This significant increase is because we are pushing forward innovative, world-first approaches to transform how the power system operates. We are delivering frequency services that are fit for operating a zero carbon network where system frequency will, at times, be more variable. Our stability and voltage pathfinders reduce our reliance on dispatchable generation for critical transmission system services. We can already maintain our system restoration capability without warming or running fossil fuelled generation.

This means that we will be ready to meet our 2025 zero carbon ambition. Our innovative approaches and the plans we have put in place across each operability workstream, mean that by 2025, there could feasibly be periods where we will be able to operate a zero carbon system if the transmission generation scheduled by the market is zero carbon. Initially this maybe for a few settlement periods throughout the year, but these periods will grow as our capability to operate a zero carbon system expands and the market provides more zero carbon dispatch solutions. This could potentially happen in a manner similar to the phasing out of coal, where we initially observed rare zero coal settlement periods. Within a few years after coal began to come off the system, these periods started to become the new normal.

This year our ability to operate a zero carbon network has again increased. We saw an increase to a new zero carbon generation maximum of 90% on 5th January 2022 after our operational interventions. During these periods, we synchronised six carbon units for system reasons (voltage and minimum inertia). However, the need for these additional carbon units will be removed for settlement periods such as these, through our on-going voltage and stability work. This means that by 2025 we will have the ability to operate a zero carbon network, reducing our reliance on carbon generation for ancillary services and also reducing operational costs.

RRE 1G Carbon intensity of ESO actions

April 2021 to March 2023 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.

Graph: Two-year view of average monthly gCO2/kWh of actions taken by the ESO

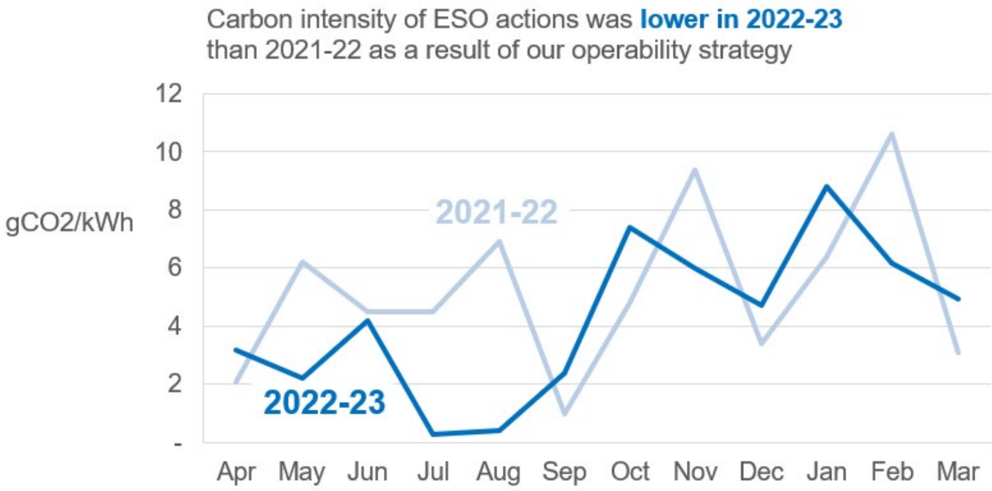


Table: 2022-23 average monthly gCO2/kWh of actions taken by the ESO

(See our Mid-Scheme review for final 2021-22 figures)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	3.2	2.2	4.2	0.3	0.4	2.4	7.4	6.0	4.7	8.8	6.2	4.9

Supporting information

Overall performance – 2021-2023

Since 2021 we have come a long way in the decarbonisation of the electricity system. This progress can be seen in the reduction in average monthly carbon intensities of our actions. While individual months can be higher in 2022-23 compared with 2021-22, as a trend we see that the average monthly impact of our actions was about 1.1gCO2/kWh (or ~21%) lower in 2022-23 compared to 2021-22. This progress is because of the success of our operability strategy. As explained in RRE1G, this significant increase is because we are pushing forward innovative, world-first approaches to transform how the power system operates. We are delivering frequency services that are fit for operating a zero-carbon network where system frequency will, at times, be more variable. Our stability and voltage pathfinders reduce our reliance on dispatchable generation for critical transmission system services.

Additionally, changing system conditions also impact this metric. The increased exports to the continent in 2022 meant that carbon generation has been synchronised which also provides the needed network ancillary services. This reduces our interventions and means that if we do take operational actions pulling back carbon generation, the market carbon figures for this RRE will also reduce significantly.

Latest month's performance - March 2023

In March 2023, the average carbon intensity of balancing actions was 4.9 gCO2/kWh. This was a drop of 1.2 percentage points from February but is relatively normal for this time of year as temperatures drop and the demand rises. In addition, wind levels have meant that we have had to constrain off wind generation due to thermal export constraints and replace the missing energy with carbon generation. This increases the carbon intensity of our actions.

2022-23 performance

For Q1, Q2, Q3 and Q4, the average carbon intensity was 3.2 gCO2/kWh, 1.0 gCO2/kWh, 6.1gCO2/kWh and X respectively. Q2 saw a reduction in the carbon intensity as we were taking significantly fewer operational actions compared with previous months. In addition, carbon generation has been supporting the increased exports from GB and they also provide the needed network ancillary services. This reduces our interventions and means that if we do take operational actions pulling back carbon generation, the market carbon figures for this RRE will also reduce significantly.

In March, the largest decrease in carbon intensity due to ESO's actions was at 23:00 on 15th February with a minimum intensity of ESO actions at –24.7 gCO2/kWh. The biggest reduction of this financial year remains -41.2gCO2/kWh on 29th January.

RRE 1H Constraints Cost Savings from Collaboration with TOs

April 2021 to March 2023 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.

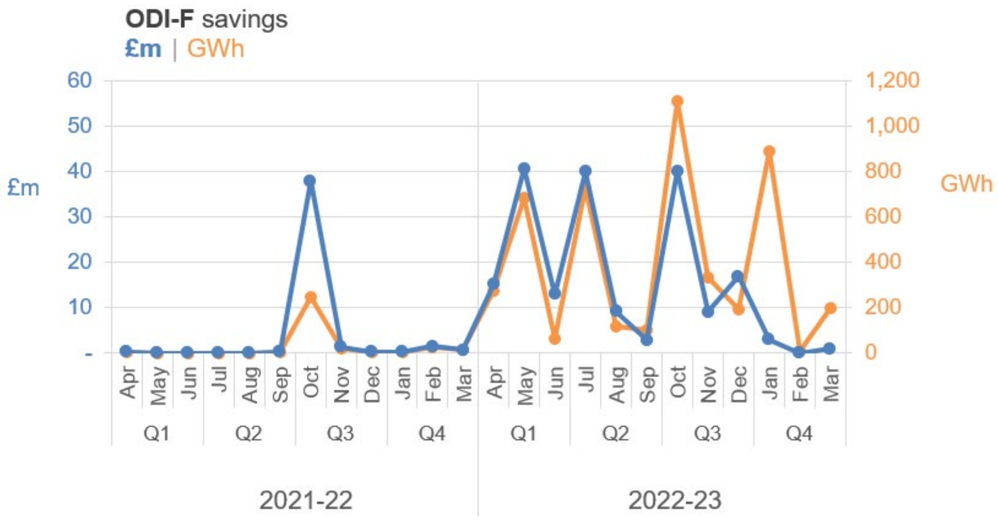
This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

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
   i. 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).
   ii. 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 [12] 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.
   iii. 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
   iv. 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.

Graph: Two-year view of estimated £m savings in avoided constraints costs (ODI-F)

(Estimated savings in GWh are also shown for context)



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[12] 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.

Graph: Two-year view of estimated £m savings in avoided constraints costs (Other)

(Estimated savings in GWh are also shown for context)

Note vertical axes scale below is different from the ODI-F graph above.

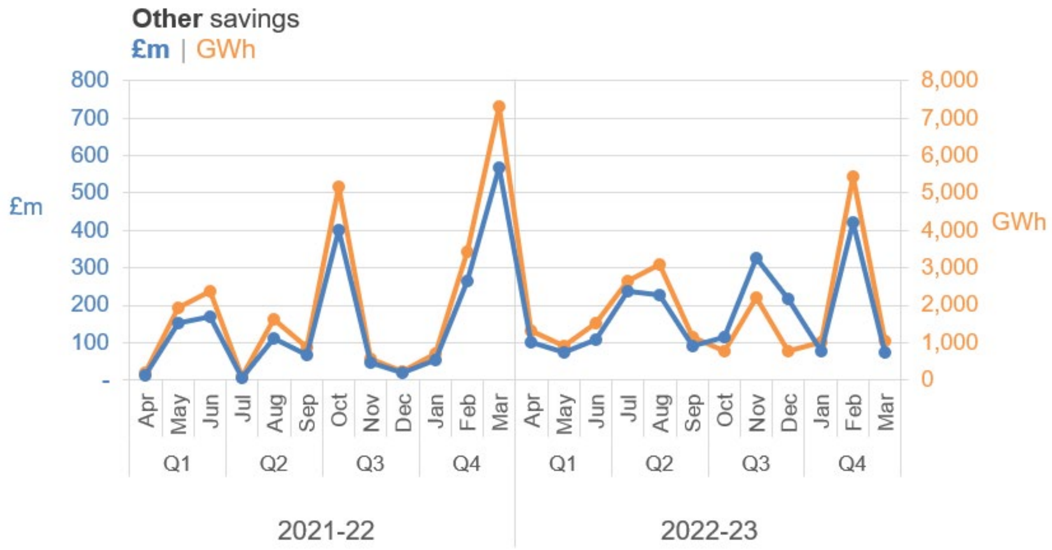


Table: 2022-23 monthly estimated £m savings in avoided constraints costs

(See our Mid-Scheme review for final 2021-22 figures)

	ODI-F savings	Other savings	ODI-F savings	Other savings
	£m	£m	GWh	GWh
Apr	15.1	101	273	1,316
May	41	74	685	913
Jun	13	109	64	1,527
Jul	40	237	727	2,651
Aug	9	227	120	3,107
Sep	2.8	92	102	1,149
Oct	40.2	116	1,111	784
Nov	9.0	325	336	2,219
Dec	16.9	216	192	793
Jan	3.0	77	893	1,033
Feb	-	420	11	5,459
Mar	0.9	75	200	1,039
TOTAL	**191**	**2,068**	**4,714**	**21,990**

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. Prices of £55 per MWh are used for conventional generation and £77 per MWh for renewable generation.

Supporting information

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

Overall performance (two-year period)

The Network Access Planning (NAP) team has progressed and approved 42 enhanced service provisions from TOs through STCP 11.4 that provide constraint cost savings over the past two years. Details are provided below:

i. In 2021-22, 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.

ii. In 2021-22, the operational use of forced cooling on two super grid transformers in the northwest of England. This enables us 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.

iii. In 2022-23, the commissioning of the Western Link HVDC Runback Scheme is actively improving the B6 boundary limit with approx. £3M of savings recorded for the current financial year and continued savings in the future anticipated. An estimation of energy saving is 892.8 GWh.

iv. In 2022-23, removal of a lamppost on a motorway in South East England allowed for an improved rating on an onerous part of the network. The removal of the lamppost allowed for greater clearance on the circuit to be met allowing the line to sag more and thus be loaded to a higher rating. The increase in the limit is 1100 MW which is estimated to save up to £14M. The savings will continue into future years. The maximum saving per day for this change is 26.4 GW, which equates to the energy used by 2.6M average UK homes in a day.

Across 2021-23, the Network Access Planning team in collaboration with the TOs realised £233.3m of constraint cost savings through STCP 11.4. Some of the enhanced service provisions started this year are still in use. Where this is the case, forecast savings have been used. The data will be updated with outturn constraint cost savings for these 11.4 actions once they become available. Many of these savings span several months. Where this is the case, the full saving has been tracked against the start date of the 11.4 action. For example, Harker SGT forced cooling, active between 01/04/22 and 31/03/23, has its savings tracked in April 22. Additionally, as this time period has not finished, outturn savings are not available and so forecast savings have been used instead.

There have been 3 enhancements which did not deliver any savings. This is because the constraints that they increased boundary flows across were not active during the availability of the enhancements. This does not mean that the enhancements were without value, however. These enhancements allowed us to take associated outages with the assurance that limits had been increased and the network was secure for the worst fault.

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.

Latest quarterly update: Q4 2022-23 performance

The Network Access Planning (NAP) team has progressed and approved 29 enhanced service provisions from TO’s through STCP 11.4 that provide constraint cost savings this year. Some of these provisions are highlighted below:

i. In January 2023, the Western Link Runback Scheme was commissioned for use on the network. This enables SQSS compliance post fault at higher levels of north to south export on the link. This is because the runback scheme allows for automatic curtailment of the Western link post fault to prevent circuit overloads and commutation failure of the link. This increases the maximum export across the B6 boundary. This 11.4 was driven by NAP with close support and collaboration from SPT to provide an increase on the B6 boundary capacity. It took a significant amount of work and close liaison from all parties to bring this scheme into actuality. This network enhancement is under continuous use. As such, no outturn cost is available however the 11.4 is estimated to deliver 892.8 GWh of savings, approximately £4.3 million saved for the end consumer.

ii. In February 2023, a weather-based rating enhancement was agreed on a circuit in the Southeast of England for 9 days. This enhancement assisted with easing boundary constraints on EC5. This is forecast to save 32.4 GWh but realise around £0.4 million of cost savings.

iii. In March 2023, a rating enhancement has been agreed on a key circuit in the Northeast of England. This enhancement has yet to be delivered at the time of this report. The enhancement will assist with boundary constraints on and behind B7 for an expected saving of 142.2 GWh and £0.7 million.

Across 2022-23 NAP has realised approximately £190.8m of constraint cost savings through STCP 11.4 from 4714GWh of extra capacity released.

Please note that the figures for previous quarters have changed as these have been updated with calculated outturn costs that were not available in the previous report. The previous report used forecast figures for Q3.

At the time of this report, the enhancements for Q4 are majority forecast costs only. This is due to these enhancements still being used on the system and therefore no outturn costs are currently available in most cases. Where outturn costs are available, they have been used.

2. Other Savings (Customer Value Opportunities):

Overall performance (two-year period)

We have made excellent progress over the last two years. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded over 389 instances where our 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 across the two years include:

i. We, 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.

ii. We, in liaison with the relevant TOs, agreed 53 temporary topological changes to the network to reduce the impact of outages. In most cases, this acted to uplift the constraint limits in the area around the outages on the network. The majority of these changes are temporary changes to substation running arrangements, but this also includes switching out circuits, and adding temporary circuits to the network. These make up around 11.6 TWh of the recorded savings.

iii. We have removed 82 inoperable or expensive outage clashes proposed by the TO. This includes scheme and maintenance work submitted by the TO. In these cases, the outages have been de-clashed to sit at separate times. These make up approximately 11.4 TWh of the total savings.

iv. Working with the relevant TO, we have moved 100 outages from their original requested dates to times when they sit better in the plan to optimise their placement. This usually includes nesting works to avoid outages on the network, but also includes small scale change by moving outages in week to a preferred time window based on wind forecast data and network conditions. These amount to 8 TWh of energy savings, as this energy did not have to be constrained on the network.

v. We have tracked 126 occurrences of minor optimisations to the plan. This category contains myriad reasons for optimisation. Some of these are: ratings enhancements on assets, OCLR agreements, voltage optimisations, duration reductions, post fault actions, and innovative ways of working. These amount to 8.4 TWh of savings on the network.

Across the past 2 years, these and many more represent a total of 45.5 TWh of extra generation capacity, which would have otherwise been constrained at a cost to the consumer. This equates to approximately £3.9bn and is enough to power 15.6 million UK homes for a year.

(We assumed average values of £77/MWh for renewable and £55/MWh for conventional generation, except where full commercial costing was available at the point of action by ESO planning)

Latest quarter's performance: Q4 2022-23:

The Network Access Planning team has made good progress over the last three months. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded 33 instances this quarter, and 215 instances in the past 12 months, where our actions directly resulted in adding value to the end consumers and its innovative ways of working facilitated increased generation capacity to the 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 customer, and many more.

Some examples of these instances include:

i. In January 2023, a pair of outage alignments were made by ESO to align topline inspections in the Northeast of Scotland with a large, combined cycle gas turbine plant shutdown at Peterhead. By doing this, the TO were able to gain access to the network without having to constrain the plant at additional cost to the end consumer. This action equates to a saving of 420.5 MWh and approximately £32.4 million to the end consumer.

ii. In February 2023, an innovative solution was proposed in the Southeast of England to offload a circuit on the main interconnected system in order to remove it as the limiting factor on a variation of the LE1 constraint. This action increases the constraint limit by 550 MW. As the outage causing this limiting factor is very long (till August 23) the forecast saving from this action is very large, standing at approximately 2.4 TWh of additional generation released to the network saving approximately £184 million for the end consumer.

iii. In February 2023, 11 actions that had been taken over the course of this financial year, by the year ahead planning team in Scotland, impacting the main interconnected system, were costed. It is usual for major actions taken during the year ahead plan to be costed post plan freeze. As such, they have all been added to the actions for this quarter. All 11 of these are ESO actions to move outages in the 23/ 24 plan year to remove clashes with other outages and provide improved alignment of outages behind one another. This required close liaison between the ESO, SPT, and SSEN-T. These actions provide an estimated saving across the B4 and B6 boundaries of 2.4TWh to the end consumer equating to approximately £187.4 million.

This report includes actions tracked up to 27/03/23 only. Therefore, the final figures for March are expected to be significantly higher than the values in this report. The end of March historically includes a disproportionate amount of value opportunities because of the rapid increase in outages as the new plan year begins and therefore there are more opportunities to optimise the plan.

The above and many more represent a total of 21,989,699 MWh (approximately £2068m) of extra generation capacity across the 22-23 financial year, which would have otherwise been constrained at a cost to the consumer.

The savings figures are calculated per outage. £55 per MWh is used for savings on conventional generation, £77 per MWh is used for renewable generation. Where full commercial cost benefit analysis assessment is available these figures are used instead. Due to the high price per MWh in fully costed CVOs and the increase in renewable generation on the network, the average price per MWh is approximately £95.2.

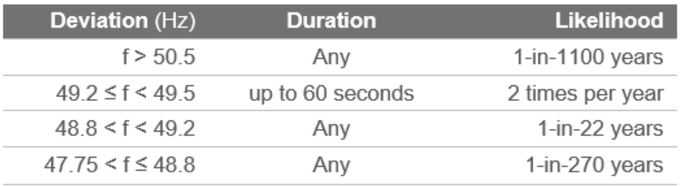
RRE 1I Security of Supply

April 2021 to March 2023 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 end-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: Two-year view of frequency and voltage excursions

		21-22	**2022-23**											
Zeros are indicated by dashes		**Total**	**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)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Frequency excursions (more than 0.8 Hz away from 50 Hz)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Frequency excursions (more than 0.5 Hz away from 50 Hz) for more than 60 seconds	-	-	-	-	-	-	-	-	-	-	-	-	-
Incentives monthly reporting requirements	Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for more than 60 seconds	-	1	1	1	1	-	-	-	-	-	-	-	-
	Voltage Excursions defined as per Transmission Performance Report [13]	-	-	-	-	-	-	-	-	-	-	-	-	-

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

Supporting information

Frequency:

During the two-year period there were zero frequency excursions as set out in the Frequency Risk and Control Report (FRCR). There were four instances where the frequency was 0.3 – 0.5 Hz away from 50 Hz for more than 60 seconds, which is an Incentives reporting requirement.

Several initiatives on the frequency management side enable us to operate the system more safely and cost-effectively. The main contributors are as follows:

Accelerated Loss of Mains Change Programme (ALoMCP)	ALoMCP is a programme to pay generators to make necessary protection setting changes, removing the risks of inadvertent tripping of loss of mains protections, with assurance by DNOs and iDNOs. ALoMCP applications went live in October 2019 and closed in September 2022. During the period, over 8000 sites have completed the works required to remove the risk of loss of mains.
New response services: Dynamic Containment, Dynamic Moderation, Dynamic Regulation	Dynamic Containment (DC) was launched in October 2020 as a fast-acting post-fault service to contain frequency in the event of a sudden generation or demand loss. DC is more effective on lower inertia systems and able to contain the loss with its fast-acting capability. Dynamic Moderation (DM) and Dynamic Regulation (DR) were introduced later in May 2022.
The Frequency Risk and Control Report	FRCR was introduced in April 2021 to assess the magnitude, duration and likelihood of transient frequency deviations, forecast impact and the cost of securing the system, confirming which risks will and won't be secured operationally. This allowed a change in the security standards to allow the effective management of the LoM risks using the new response products. This is updated annually.

Below are details of the four instances during the two years where the frequency was 0.3 – 0.5 Hz away from 50 Hz for more than 60 seconds:

- On 18 April 2022 @ 17:25 , Sizewell units trip caused frequency to drop 0.3 – 0.5 Hz away from 50Hz for more than 60 seconds.
- On 4 May 2022 @ 02:12 , IFA1 Bipole 2 tripped while exporting 1000 MW to France. The frequency reached 50.341Hz but returned to operational limits,50.2 Hz by 02:16. The root cause of the trip was due to protection issues which were subsequently fixed.
- On 10 June 2022 @ 02:07, North Sea Link interconnector tripped while exporting 700MW to Norway. The frequency reached 50.318Hz but returned to operational limits,50.2Hz by 02:10. The root cause of the trip was a control value fault.
- On 19 July 2022 at 22:11, IFA2 tripped while exporting 1029MW from GB to France. Frequency increased to 50.352Hz and returned to operational limits by 22:15.

Voltage:

The Electricity National Control Centres manages all aspects of reactive control, the defined levels of system voltage, and MVAr reserves in each identified zone and constraint group in real-time. As a result, there were zero voltage excursions in the two-year period.

RRE 1J CNI Outages

April 2021 to March 2023 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: Two-year view of Unplanned CNI System Outages (Number and length of each outage)

	2021-22	2022-23												2022-23
Unplanned	TOTAL	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	TOTAL
Balancing Mechanism (BM)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Integrated Energy Management System (IEMS)	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table: Two-year view of Planned CNI System Outages (Number and length of each outage)

	2021-22	2022-23												2022-23
Planned	TOTAL	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	TOTAL
Balancing Mechanism (BM)	3[14]	-	-	-	1[15]	-	-	-	1[16]	-	-	-	1[17]	3
Integrated Energy Management System (IEMS)	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Supporting information

Overall performance (for two-year period)

Throughout the two years there have been six planned outages to our CNI systems. In all cases, the outages occurred on our BM system, and were required in order to deploy a software release of changes and, in some cases, enhancements to the production systems.

Any such planned outages were communicated to the market via BMRS and email notifications in advance, in line with our obligations to report these events. Additionally, we have worked closely with Elexon throughout, highlighting the known impact upon any of their systems that utilise data from BM.

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[14] July 2021: 1 outage, 216 minutes
November 2021: 1 outage, 215 minutes
March 2022: 1 outage, 196 minutes

[15] July 2022: 1 outage, 186 minutes

[16] November 2022: 1 outage, 165 minutes

[17] March 2023: 1 outage, 172 minutes

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, where required, to enable the continued focus on resilience of the system.

There were no unplanned outages during the two-year period.

We believe we have performed well over the period, avoiding any unnecessary planned outages, and not encountering any unplanned outages.

System monitoring improvements have been implemented to the systems throughout the period, to include monitoring of new changes and low-level incidents to increase the capability to identify and resolve system issues.

A continued schedule of regular maintenance activities has remained in place throughout the period, aiding ongoing system availability.

Latest month's performance - March 2023

In March 2023 there was one planned CNI system outage. The outage was part of regular planned maintenance activities and major software delivery on the BM production systems and impacted the key BM Suite components used for scheduling and dispatch of generation.

Role 2

Market developments and transactions

Role 2: Market development and transactions

Plan Delivery

- We have completed 69 out of the 108 milestones planned for the two-year period. Of the 39 milestones which are not complete, 3 are delayed in order to deliver an improved outcome for consumers, 5 are no longer valid, 17 are delayed for reasons outside of our control, and 14 are ESO-related delays. We have:
- Developed and delivered a new suite of response products.
- Successfully delivered the record-breaking Contracts for Difference Round 4.
- Delivered the innovative and world leading DFS.
- Launched our NZMR programme.
- Facilitated the delivery of £250 million of financial relief for Generators and Suppliers.
- Published our Early View Winter Outlook.

Metric performance

- 2A Competitive Procurement: 48% of all services procured through competitive means (below expectations)

Stakeholder evidence

Role 2 survey (Mar-23):

- 16% exceeding expectations
- 65% meeting expectations
- 19% below expectations

Highlights:

- Stakeholders commented that the DFS was a great introduction and were impressed with its design and the pace of implementation.
- A number of stakeholders commented on our great communication, engagement and feedback on product development.

Demonstration of plan benefits

- Build the future balancing service and wholesale markets (A4) to deliver £81m consumer benefit over RIIO-2 with benefits being delivered from BP2.
- Transform access to the Capacity Market (A5) to deliver £132m consumer benefit over RIIO-2 with £60m already delivered in BP1.
- Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 (A6.5) to deliver £10m consumer benefit over RIIO-2 with benefits being delivered from BP2.
- Reforming Balancing Services Use of System (BSUoS) charges (A6.6) to deliver net present value benefits of £68m over RIIO-2 with benefits being delivered from BP2.
- The B6 Constraint Management Intertrip Service will deliver a total estimated benefit of £226-£256m between Apr-22 and Sep-25.

RREs:

- 2B Diversity of service providers: Varying diversity across the different markets
- 2C EMR decision quality: 0.8 overturned themes per 1,000 Capacity Market applications (exceeding expectations)
- 2D EMR demand forecasting accuracy: peak demand accuracy 3.5% for T-1 (below expectations), 3.0% for T-4 (exceeding expectations)
- 2E Accuracy of forecasts for charge setting: Absolute Percentage Error of 27% (BSUoS) and of -4% (TNUoS)

Value for money

- Our total expenditure for role 2 in BP1 was £143.5m, which was 9.5% lower than the benchmark of £158.6m.
- The main variances are decreases in both EU and GB regulatory changes. EU changes underspend is driven by a change in relationship with our European counterparts due to Brexit. GB changes underspend has been largely due to the fluid nature of regulatory change with some of the original changes included in the benchmark number being withdrawn.
- These decreases are offset by increases with major IT programmes (Settlements, Charging and Billing and EMR). These are driven by a range of factors including re-scoping, improved understanding of complexity driven by greater regulatory change, and delays to delivery.

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 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.

See below an overview of key highlights and challenges for role 2 over the two years of the Business Plan 1 period:

Highlights

Winter 2022/23 (including new activities in BP1)

Overview

Through late Spring and into early Summer it was evident that the energy crisis was escalating and that there was to be no quick conclusion to the illegal Russian invasion of Ukraine. To respond as an organisation, we committed significant resources to enhance our resilience for Winter 22/23 and looked to best counteract the challenges in the energy markets. Within role 2 we took the decision to prioritise those activities that would support security of supply and de-prioritised a number of activities such as Reactive Reform to transfer resource to our Winter response. Acting with conviction and pace we looked to help lead an industry wide response.

We recognised that our convening power would be essential in helping drive collaboration and coordination across the industry to mobilise a response. In support of this we published an early view of our Winter outlook, and looked to align with our National Gas colleagues, to provide a holistic energy wide perspective for the wider industry to respond to. Through existing forums such as our Operational Transparency Forum (OTF) and Markets forum, and supplementing through broader industry engagement such as CEO level round tables, we continued this engagement throughout the Winter period. In tandem we worked with multiple government departments, European TSOs and Ofgem to agree on appropriate preparation actions.

Two of the major interventions that we put in place to enhance resilience was delivering the Demand Flexibility Service and contracting for incremental capacity with Coal power stations. Further details are provided below.

Demand Flexibility Service (DFS)

As part of our wider Winter preparedness we took the decision to develop a new ancillary service that would provide us access to a source of flexibility that we haven't historically been able to access. In less than four months we designed, developed and implemented a first of its kind demand flexibility product, which allowed consumers with smart meters and industrial and commercial users to voluntarily time shift their use of electricity in return for payment.

We couldn't have done this on our own and so focussed on collaborating with the industry on the rapid design and implementation of the product. We created a multi pronged engagement strategy where we engaged directly, utilised industry trade bodies such as EUK and the MEUC and also reached out to consumer groups. Throughout the Winter period we grew the pipeline of participants in the service, starting with just 4 providers in the first test, to an end of Winter position where over 30 differing organisations were participating in the service, aggregating up demand flexibility from over 1.7milion individual end consumers.

On two separate occasions the product was used to manage tight margin days, and in total the product has grown in size to offer up to 300MW of demand flexibility. While a key component of our resilience for this Winter, this product will have a lasting legacy – it will help further encourage the take up of Smart meters and has acted as a major catalyst for unlocking the enduring value of demand flexibility.

Winter Contingency Contracts

In response to a formal request from the Secretary of State, we looked to enhance resilience by contracting for significant volumes of non – gas capacity that was declared unavailable to the market. This challenging task entailed negotiating contracts with 3 separate commercial organisations (Drax, EDF and Uniper) to extend the life of coal fired power plants for the Winter period.

There were multiple factors and challenging interplays to manage to deliver these critical contracts that simultaneously supported resilience and security of supply, while promoting the integrity of the existing power markets, delivering consumer value and being conscious of environmental factors. Working collaboratively with the regulator, government departments and the generator stations, we delivered contracts that bought an extra 2.2GW of capacity into the market for the duration of the winter, creating an insurance policy for GB consumers for the Winter.

Balancing Reserve

We proposed a new ancillary service called Balancing Reserve (BR) because we identified it could provide potential system balancing cost efficiencies. This is because the service provides a market incentive, which is not currently present, for plant selling in the wholesale market to also offer capacity to the ESO day ahead to meet reserve requirements. Balancing costs have risen significantly in the last four years, from £1.3b in 19/20 to £4.2bn in 22/23. In this context, Balancing Reserve presented a significant opportunity for us to reduce balancing costs, which in turn reduces the impact of these high costs on end consumers. The introduction of a BR-type service was additionally highlighted by Ofgem when they consulted in their Call for Input on options to address high balancing costs, which we were strongly in support of.

Our proposal was to procure Balancing Reserve on a firm basis at day ahead. This would help reduce balancing costs and improve system security as the unit headroom and footroom are guaranteed for the control room to access when needed, rather than being subject to potentially very high costs in the balancing mechanism (BM). To support the development of the proposal, we engaged an external consultant (LCP) to model the impact on the BM and the wholesale market, and quantify the benefits for the end consumer. LCP forecast a substantial balancing cost efficiency of on average ~£300m a year due to the introduction of Balancing Reserve.

Normally the development of such a new complex product like this would take at least a year. However, we recognised the significant potential benefits to the end consumer if we introduced Balancing Reserve early, which was supported by LCP's assessment that BR could reduce balancing costs by c£20m-25m/month. Therefore, we took the decision to prioritise its development, working together with industry, to deliver at an accelerated pace. This meant we were aiming to go live with the service ~6 months after project initiation. We are grateful to Ofgem and our industry partners for their time and effort in taking a proactive part in engaging with us throughout the development of the Balancing Reserve service and facilitating such an accelerated development.

Whilst Ofgem commended our intent to prioritise development of a service which could reduce balancing costs, there were concerns with some elements of the design of the service which had been necessary in order to deliver at pace, particularly related to barriers to entry for small flexible providers, which led them to reject the service. We still see substantial end consumer benefit in introducing a service of this type and are continuing to explore and review options that address Ofgem's concerns. We are committed to continuing to work with industry to open up access to markets for flexible units and removing barriers across all our services.

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 used the tools and services available to us to secure our frequency requirements whilst we transitioned to the new suite of response and reserve products.

In March 2022 Ofgem approved the European Benchmarks Regulation (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.

Following the successful delivery of the three new frequency response services, DC, DR and DM, our focus moves to further developing these services: upgrading the supporting IT infrastructure, increasing participation by removing barriers to entry and improving the user experience across the end-to-end process. We achieved our first step towards this goal, receiving approval from Ofgem of our EBR Article 18 consultation submission in February 2023. Release 1 delivers a number of changes to our new dynamic services; market improvements in the form of fairer performance monitoring calculations, permitting GSP Group aggregation for DC, and improving user experience by consolidating 15 contractual documents into one suite of service terms for DC, DM and DR. IT system changes include delivering the functionality for arming and disarming of response units as well as operational metering which provide the control room with improved real-time view of the services. These changes enable a step towards the transition away from dynamic Firm Frequency Response (FFR).

As part of Release 1, changes were also made to the existing FFR service. The dynamic side of the service remains unchanged as it will be replaced in the coming months with our new suite of dynamic services. The static FFR service continues to offer value and so is being moved from monthly procurement to a compliant day-ahead model. These changes went live on 1 April 2023.

Since the launch of the new dynamic services, we have been able to secure increasing grid losses at a lower overall response cost. This is partly due to improved market liquidity which has reduced the market clearing price.

In previous years it was noted, internally and by industry, that our consultation timelines did not allow for adequate engagement or flexibility to make changes and so we trialled an innovative annual development cycle with the aim of creating a repeatable, reliable plan for industry consultations with extended engagement periods in the months leading up to the consultation window including hosting in-person drop in sessions in London and Edinburgh to ensure that all industry parties are given the opportunity to share their views and feedback. This first cycle has been met with much approval and support, from service providers, internal ESO teams and the regulator. In light of this success we are proceeding with the next cycle this year including some further improvements.

Net Zero Market Reform (new activity in BP1)

Our Net Zero Market Reform (NZMR) programme was established in early 2021, to examine holistically the changes to GB electricity market design that would be required to achieve the power sector’s 2035 decarbonisation targets cost-efficiently and securely, while laying the foundation for a net zero economy by 2050. We are currently in our fourth phase. Phase 1 was an initial scoping phase where we carried out a high level analysis of the current GB landscape including interviews with industry stakeholders and case study reviews. Phase 2 considered the case for change and identified three key challenges: 1. Investment: there is a need to invest at unprecedented scale and pace; 2. Location: assets must locate and dispatch where they can minimise whole system costs; and 3. Flexibility/Operation: dramatic energy imbalances must be managed with flexible and firm technologies across both supply and demand. Phase 2 concluded in November 2021 with a publication on our findings. In the December 2021, for phase 3, we dove deep into the location and flexibility/operation challenges and found evidence that the status quo market design results in inefficient investment and dispatch outcomes. We concluded that real-time, dynamic locational signals are needed to ensure efficient dispatch and investment and that the combination of locational wholesale energy pricing with centralised scheduling would provide the best market design foundation to achieve this. We presented these conclusions at our Market’s Forum event in March 2022 and followed this up with an in-depth publication in May of the same year.

We are currently in phase 4 of the NZMR programme and this started in June 2022. We are assessing how investment policies could evolve to better complement a stronger role for the wholesale market, as recommended in our Phase 3 report. To assist us with this we commissioned Baringa to undertake a qualitative assessment of individual policy options and coherent market design and policy packages against our assessment criteria that include the Government’s REMA (Review of Electricity Market Arrangements) objectives. We presented Baringa’s initial findings at our Market’s Forum event in September 2022 and invited feedback from stakeholders that was generally positive in relation to the logic for compiling market design and policy packages. Baringa’s assessment was published in February of 2023 along with a Foreword outlining ESO’s reflections. We received feedback from our Markets Advisory Council that our foreword reflected the fact that we have clearly taken on board stakeholder feedback regarding concerns about the implementation challenge for wholesale market reform.

We intend to publish our conclusions from phase 4, which will draw from our previous work and commissioned studies as well stakeholder feedback and evidence, in the summer of 2023. Alongside our work on investment policy, we are continuing to assess how locational pricing could be best implemented in GB, focusing on efficient scheduling and dispatch in operational timescales. Throughout this process we have conducted various stakeholder engagement activities to ensure our approach, assessment and findings are sound, well-evidenced and coherent.

Stability Market Development

Phase 1 of 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.

Phase 2 of the Stability Market Design Network Innovation Allowance (NIA) project is nearing its conclusion. The project recommends at least 3 discrete markets – Long-term (Y-4), Mid-term (Y-1), and Short-term (D-1) – to procure stability services in an effective way. For each of these markets, fundamental questions on eligibility and contract structure have been answered, and there is a core recommendation to launch the Y-1 Mid-term market as a priority. This is to harness additional inertia capability from existing units, to provide an enduring route to market for existing assets currently contracted under the Pathfinder framework, and to build investor confidence that stability services will be procured on a regular basis. The plan for launching the Y-1 market is set out in the 2023 Markets Roadmap publication which signposts industry to key reforms across operability themes, including stability.

We have conducted 3 industry expert panel sessions to gather initial feedback on our market design approach as part of the innovation project. Next, the imminent step following the publication of the roadmap is to share a Y-1 mid-term market technical specification with wider industry and to resource the project team internally to deliver the Y-1 market, as outlined. In parallel to initiating the delivery of the Y-1 stability market in 2023, ESO will be completing further process mapping and system impact assessments to establish achievable plans for developing the short-term stability market and a regular framework for initiating new-build procurement in the long-term, if required.

Electricity Market Reform (EMR)

As the EMR Delivery Body, we play a crucial role in strengthening security of supply and achieving net zero ambition in the UK through operating the Capacity Market (CM) and Contract for Difference (CfD) regimes on behalf of the government. Our EMR role also includes modelling where we use our expertise to provide recommendations to Government on how much capacity to secure in the CM, as well as the contributions that different technologies make to security of supply through their de-rating factors.

Capacity Market (CM)

Over the BP1 period, we successfully operated 4 Capacity Market Auctions and secured a total 96GW for the relevant Delivery Years ensuring medium term security of supply is maintained for GB Consumers. We implemented a suite of regulatory changes to the CM Regulations and Rules and provided updated customer guidance timely to support customers compliance. We have improved the CM application and assessment processes significantly through enhanced customer services and co-created guidance with customers, stakeholders and Delivery Partners. As a result, the disputes of the pre-qualification have continued to reduce over the years. In 2022/23, over 84% of the CM applications qualified to enter the auction and we have seen a record low Tier 2 disputes to Ofgem, and our decisions were upheld. The overall improvement is also evidenced by three years of continuous upwards trend for the CM Customer Satisfaction survey.

Contracts for Difference Allocation Round 4

We completed CfD Allocation Round 4 (AR4) in 2021/22 with a record high number of applications, due to an increase in the number of eligible technologies able to participate. Nearly 11GW over 93 projects was secured, meeting both the capacity and monetary targets set by government.

We worked closely with government, other EMR delivery partners and customers to establish a new annual auction process; advising on and influencing complex commercial, political and regulatory changes to ensure the smooth implementation into business processes and systems, taking on board Industry feedback as appropriate.

Throughout AR4, we took calculated risks consciously by developing policy changes and system changes in parallel, rather than sequentially to ensure timely and efficient implementation in order to meet strict regulatory deadlines.

We strengthened our relationship with government and advised on both the short-term deliverability of the individual round and also the longer term/wider implications of the CfD scheme against an ever-evolving energy and political environment.

Great focus was given to enhance customer understanding of the rules and customer experience throughout the process. Building on guidance that was co-created with customers, we also ran a number of customer events which directly contributed to a high application approval rate, 94.8% and Customer Satisfaction score of 8.1.

All regulatory milestones were met during the round and the results signed off by an independent auditor.

The results of AR4 will boost British energy security and independence and contribute to the government's ambition of 50GW of offshore wind by 2030. It will also ensure a more secure and resilient energy system that supports the UKs transition to net zero through an increased and more diverse range of energy sources.

The success of AR4 has laid a solid foundation for us to operate future allocation rounds, with AR5 opening on 30 March 2023.

Modelling

We have delivered the 2021 and 2022 Electricity Capacity Report setting out our recommendations on how much capacity to secure and technology de-rating factors for the CM auctions in the BP1 period. We have taken significant steps to improve our modelling through a set of development projects that we set out in our reports. These projects have improved our modelling in several areas including: peak demand forecasting and uncertainty; non-delivery risk; exploring new data sources to determine de-rating factors for some embedded generation technologies; as well as our pan-European market modelling used to recommend de-rating factor ranges for interconnectors. Our modelling has continued to be scrutinised by BEIS' independent Panel of Technical Experts who publish their own report on our work. Their report has continued to provide support for our modelling expertise and have remain very satisfied with our open and constructive engagement with them.

Operational metering requirements for aggregation

Operational metering requirements, as set out in the Virtual Lead Party (VLP) and Bilateral Contract Agreements (BCA), have been developed for large transmission connected generators that have high accuracy meters at an asset level. Aggregators seeking to enter the Balancing Mechanism (BM) with domestic flexibility are finding it hard to satisfy the operational metering standards due to having lower meter accuracy, latency and read frequency.

This year Power Responsive (PR) have worked closely with aggregators and suppliers to understand the key issues and find a suitable 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 is in its initial trial phase and is being supported by the first dedicated industry workgroup formed under Power Responsive. The revised approach aims to set standards at the aggregate metering feed level with the understanding that once aggregated, the metering percentage error band will get significantly smaller whilst also reducing the read frequency required for each individual asset. Trials are set to conclude in Q1 (FY 2023/24), and the results will be reviewed by the Power Responsive workgroup to inform whether unique aggregated assets can meet the operational metering requirements in their current form or if any changes to the operational metering standards are required for BM access. If standards are reformed and prove to be successful in the BM, then we will look to roll this out to other Ancillary Services where appropriate.

Launch of TNUoS Task Force

The Transmission Network Use of System ("TNUoS") Task Force was established by Ofgem and the ESO (National Grid Electricity System Operator) in 2022. It is made up of a diverse group of participants with a range of strengths and expertise to ensure balanced representation across different interests and roles within the industry. The key focus of the Task Force is to look at the issues of predictability and cost-reflectivity in current transmission charging arrangements, whilst considering the balance of and inherent trade-off between these two elements. Following successful launch of the Task Force in July 2022, ESO worked closely with Task Force members through a series of meetings, identifying potential areas for review or specific defects within the current TNUoS charging methodology for the Task Force to then consider.

In November 2022, as part of a Ofgem prioritisation exercise given the forthcoming demands of winter work, Ofgem set out that there would be no further meetings of the Task Force for the remainder of 2022, and confirmed that ESO would continue to build upon the work of the Task Force in the interim so as to keep momentum. During this period, innovation funding has been successfully approved, consultants subsequently appointed and successfully onboarded to support a review of some of the key defects identified by the Task Force. Currently the analytical phase is now underway with the plan being for the output of this work (review, identification of issues, potential solutions, and impact analysis) to then be taken back to the Task Force when meetings resume in April 2023, with the aim being to support members discussions and help when considering further the issue of how to improve predictability in charges.

Settlements and Revenue (STAR) programme

The STAR programme is a key enabler of some of the core processes that we undertake on behalf of the industry. The programme is looking to replace the existing Charging and Billing System as well as the existing Settlements system. Though both of these systems we process in excess of £8bn per annum. During the BP1 period we have established the foundation of the system and migrated across to a new platform, Oracle MSM.

Utilising an agile delivery model we have now successfully deployed 3 separate business releases allowing us to: settle our main reserve service, run our billing for Assistance for areas with High Electricity Distribution Costs (AAHEDC) and to deploy the major regulatory change of introducing bands to TNUoS demand calculations. While great progress has been made in deploying this new capability, it has been challenging to deliver the full scope of our BP1 commitments given the complexity of implementation, coupled with a changing back log of compulsory regulatory change. Throughout the BP2 period we will continue to release further capability onto the STAR platform in an agile manner reflecting regulatory and customer priorities.

Single Markets Platform

Single Markets Platform (SMP) is a vital deliverable through RIIO-2 to support in becoming a better buyer of balancing services and is part of a wider strategy to utilise digital ways of working to make it easier to do business with the ESO. SMP aims to deliver a seamless and consistent user experience and removal of any barriers to entry with an initial focus on day ahead markets. The foundational release of the SMP went live into production in February 2022 and facilitated the onboarding processes for the suite of new day ahead frequency response services. Across the multiple deployments in the 2nd half of BP1 we have delivered functionality to improve the user experience as well support the onboarding more services including the first Regional Development Programme (RDP) as well as tactical products such as the new Demand Flexibility Service (DFS). Access to a consistently engaged user base has been central to our experience and we will continue to co-create and prioritise user-value functionality in our four weekly “show and listen” industry webinars. Feedback during these events has highlighted the importance of Application Programming Interfaces (APIs) for which we release technical documentation, a sandbox and the first two production APIs between November 2022 and January 2023.

SMP is an example of our transitioning to the “product” model and developing functionality within an “agile” framework. This ensures an approach that values “progress over perfection” with a regular cadence of delivering enhanced functionality as evidenced with our 8 deployments between February 2022 and January 2023. We have largely delivered our BP1 objectives on time and to budget; as we look forward to BP2 we have a well defined product backlog but retain the flexibility to re-prioritise as is necessary. Alongside enhancing the user experience and supporting additional balancing services, the integration with parallel projects across the ESO will be critical including with the Enduring Auction Capability that is due later in 2023.

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 WSTC project entered its delivery phase in April 2022. Various Industry parties to the Technical Codes nominated representatives to a Project Steering Group, with the aim of the group to provide strategic direction. The group voted to progress three workstreams, as these workstreams were considered to deliver most value to Industry.

Code Digitalisation has progressed towards solutions design which has been informed by Industry engagement through user research. The next steps are user experience design, leading to a minimum viable product by Q1 of FY 2024-2025.

Guidance and Training in the use of the Technical Codes has progressed with industry leading on which of the current Guidance Documents, if updated, will deliver most value to the code users. These identified documents will be reviewed and updated with the collaboration and input from Industry parties.

The industry-led Alignment, Simplification and Rationalisation (ASR) Workstream has successfully redrafted Operating Code No2 (OC2) from the Grid Code. The OC2 word count has been reduced from approximately 10,700 words to 7,900 words, with the number of pages reduced by 13%. Extensive repetitions have been reduced by the use of flowcharts and footnotes, sections with timelines have been replaced with diagrams which are easier for Users to identify their specific requirements and obligations, using plain English to clarify the parties that the code applies to. These improvements have been made while still retaining OC2’s legal integrity.

The redraft is awaiting a proposed code modification which will follow the standard code governance route. This workstream has identified challenges and potential improvements in the Technical Codes. These valuable findings will be shared with The Authority to support the ongoing Energy Codes Reform (ECR) work. The next step is to assess and consider a further section of the Grid Code that could benefit from simplification and rationalisation, while working with the Distribution Code Administrator on the alignment of the Definitions used in the Grid Code and the Distribution Code.

These workstreams have been entirely stakeholder led, with 10 Workgroup sessions for the ASR workstream, 13 Steering Groups, focus group sessions, engagement with Code Panels, Code Administrators, Industry forums, 5 trade associations, wider industry, consumer groups, The Authority, and bilateral sessions.

Local constraints management service (LCM)

Ahead of longer-term Regional Development Programme (RDP) functionality we have made substantial progress rolling-out a tactical solution to help address the growing need to manage rising costs constraint costs in Scotland – to harness more flexible energy assets and mitigate some of GB’s highest cost constraint boundaries.

LCM is configured as a tactical product complementing the Balancing Mechanism, with a remit to simplify and focus where ESO can begin to ease constraints costs straight away, using readily accessible market approaches. LCM actions will be in close collaboration with our DNO partners.

Trials of the new Local Constraint Market (LCM) are now opening to Distributed Energy Resources (DER) above our Anglo-Scottish (B6) boundary allowing wider market participation and now set to improve competition for ESO actions on rising constraint costs. The agile approach and light touch scoping seeks to adapt an existing energy market platform from a 3rd Party to avoid delays in delivery. Extensive consultation with market stakeholders (conducted over three rounds, touching over 50 flex providers) has helped ESO shape the service design to industry needs: the traditional minimum 1000 kW unit size has been eliminated in order to allow smaller assets to participate. The service has successfully sought approval to be included in the C16 Relevant Balancing Services statement to bring industry benefits to Applicable Balancing Services Volume Data (ABSVD) participants.

With Trials now open (https://picloflex.com/dashboard) and set to grow in 2023 the project remains on track to facilitate an accelerated DER market for targeted constraint management in Scotland.

Code Changes

Grid Forming

GC0137 Minimum specification for equipment providing grid-forming capability modification has been approved by the authority this adds 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 is a world first achievement for GB in setting a minimum specification to allow converter connected technologies to provide stability services.

Compliance Processes and Modelling amendments following 9th August Power Disruption

The GC0141 modification was raised by ESO to address concerns raised from the Ofgem and BEIS Reports relating to the 9*th* August 2019 Power Disruption that occurred across England and Wales and some parts of Scotland, which impacted over 1 million consumers.

The modification spanned across a number of specific areas, relating to compliance and modelling processes:

- Improving the robustness of the modelling process with the introduction of new control system modelling requirements, and the sharing of data models between users to facilitate sub-synchronous studies to support complex connection arrangements.
- Support system stability by clarifying User understanding of the Fault Ride Through obligations and enhancing current Fault Ride Through studies to ensure compliance can be demonstrated by Power Park Modules and HVDC systems for all foreseeable running arrangements.
- The introduction of a “Compliance Repeat Plan” which will require Users to ensure they are compliant with the Grid Code Compliance and European Compliance Process, along with improvements to the commissioning process for large wind farms.

This modification was approved on the 12th December 2022 and implemented on the 5th January 2023

Targeted Charging Review (TCR)

CMP343: 'Transmission Demand Residual bandings and allocation' was approved by Ofgem for implementation from 1st April 2023. This change delivers part of Ofgem's Targeted Charging Review (TCR) which considered reform to the framework for the ‘residual charges’ which recover the fixed costs of providing existing pylons and cables, as well as a review of the differences in charges faced by smaller distributed generators and larger generators (known as Embedded Benefits).

The changes concerning the Transmission Demand Residual (TDR) included the creation of a methodology by which the residual element of demand Transmission Network Use of System (TNUoS) tariffs can be apportioned to final demand sites, and a separate methodology to determine the ‘Bands’ against which the residual element of demand TNUoS is to be levied. The demand residual banded charges will now make up majority of the TNUoS demand charge, in the form of a set of p/site/day charges across the banding categories and thresholds. As part of the TDR suite of changes, CMP389 was also approved by Ofgem which looked to update the TDR band boundaries. It should be noted that CMP389 will not affect the total amount of TNUoS residual revenue collected across the population of transmission connected sites but will affect the distribution of charges between transmission-connected users within the new TDR charging bands.

Implementation of Fixed ex-ante BSUoS

Following the BSUoS Taskforce in 2018, code modifications were raised to amend how BSUoS charges work. Previously generators and suppliers both contributed to BSUoS. The tariffs were charged each month based on what the previous month of BSUoS costs had been. Due to how BSUoS works, the charges had large fluctuations, making it difficult to forecast for suppliers and generators, and therefore adding in a large risk premia for contracts. CMP308 moved BSUoS charges to final demand from April 2023, alongside CMP361/362 which amended the BSUoS tariff to a fixed, ex ante tariff, enabling suppliers to reduce their risk premia, therefore benefitting consumers overall as bills should decrease as a result. In order to get these changes implemented, we provided a large amount of data and analysis to show the impact of these changes to both industry and the regulator.

These changes have now been implemented from April 2023, and should result in an increase to consumer benefit following a reduction in risk premia.

Work continues to look at the enduring solution to fixed BSUoS through CMP408 and a TCF sub-group with industry collaborating to how it can be improved further.

Cap BSUoS costs and Defer payment to 2023/24 (new activity in BP1)

An urgent modification was raised by Triton Power in Aug 2022 proposing a cap to Balancing Services Use of System (BSUoS) to protect GB consumers from high energy costs over the winter period. Following a workgroup process where we extensively engaged with industry, a number of Workgroup Alternative CUSC Modifications (WACM) were raised ranging from £15/MWh to a £40/MWh cap and a potential reassessment of the cap by either Ofgem or ESO. We were able to secure a liability limit of £250m (this was in addition to the £300m Working Capital Facility that is required for the running of Fixed ex-ante BSUoS which will be implemented from 1st April 2023).

WACM3 - a £40/MWh cap with no reassessment was approved by Ofgem for implementation between 1st October 2022 and 31st March 2023.

The cap protects consumers from exceptional BSUoS costs that cannot be foreseen by market participants. This helps to support consumers during the cost of living crisis. At the time of writing, £1.5m of costs have been deferred and will be charged to both generators and suppliers throughout 2023/2024. Generators will be charged via an offline process following the implementation of fixed ex-ante BSUoS moving to final demand.

This has been a success as consumers have been protected from exceptional costs over winter. During the workgroup process, we worked proactively with industry to find a solution that worked best for industry and consumers, providing data to support decision making and driving the discussion forward.

B6 Constraint Management Intertrip Service (CMIS) Intertrip (new activity in BP1)

Renewable electricity generation has more than doubled in the last decade. Much of this has been delivered through windfarms. Due to its geographical advantages, Scotland has seen particularly strong growth in wind generation.

On windy days, the electricity generated by Scotland’s windfarms flows south to satisfy the demand in England. However, there is a limit to the amount of electricity that the network can safely transmit across the Scottish/English boundary (this network bottleneck is called a ’constraint’).

Every day we forecast the amount of electrical transmission capacity available to transport generation across the boundary. If we determine that there is a constraint risk, our Control Room will pre-emptively instruct Scottish generators to stop or lower their generation output.

This means that we pay to both curtail green energy from windfarms, and replace it with gas fuelled generation. As a result, there is less green electricity generation on the system and more electricity from carbon-based sources. The Constraint Management Pathfinder (CMP) team was formed in August 2020 with the aim of reducing this issue.

The service has been designed as a post-fault intertrip service, which means that generators are rapidly disconnected from the Transmission System if there is a network fault. This lowers the risk to the Transmission Network as the system is rapidly secured and allows the Control Room to transmit more power over the constraint pre-fault.

The team awarded the first annual CMP contracts in 2021, with a service start date of October 2023 (to allow time to build the intertrip connections). Fortunately, six units already had intertrip schemes in place, so these contracts were able to start as early as April 2022.

The team recently awarded the second round of constraint management contracts for service delivery in October 2024 and is currently designing the next iteration. To reflect the service’s somewhat established position, it has been renamed the ‘Constraint Management Intertrip Service’ (CMIS).

The service is already demonstrating its importance, supporting new wind output records, lowering the carbon intensity of our electricity generation and aiding our ambition of operating a zero-carbon network by 2025. In the first ten months alone, with only six units partaking, almost 32GWh of extra green energy was generated that would otherwise have been curtailed and replaced by gas. This equates to a saving of 139,924 tonnes of carbon, which is the same as 84,802 return flights between London and New York. Moreover, there has been an estimated consumer saving of £80m!

The CMIS was a brand-new and much-needed service and so the Pathfinders ‘learning by doing’ approach has been crucial in establishing the service quickly, whilst simultaneously developing the best possible solution. The approach promoted collaboration with the Industry, Ofgem, and multidisciplinary ESO teams to create a workable solution and furthermore, to flex the service requirements as live service data was analysed.

For full details see our Consumer benefit case study for Role 2: CMIS B6 Intertrip.

Challenges

EMR Portal

In our Electricity Market Reform activities, our planned delivery of a new IT portal within the BP1 period has been partially delayed into BP2 in order to ensure that the deployment and cutover of the new system itself does not detrimentally impact customers.

We completed the first phase delivery of functionality for the new EMR Portal in March 2022 covering company and CMU registration. We have also established a dedicated customer user group to help us design and test the system. Positive feedback from customers have been received on the new Portal and our engagement approach. However, due to internal and external factors we have experienced delays to the project.

Internal Factors

Highly regulated environment	The EMR regimes are highly regulated, and the regulation and rules are prescriptive and detailed and evolve every year. Since 2014, there have been numerous updates and changes to the Electricity CM regulation and the EMR Rules and different versions of the regulations and rules are applicable to the agreements awarded at the time. All the historical and current versions need to be designed and implemented in the new system linked to over 2400 live agreements we are managing which takes significant time to map across all the functionalities in the system correctly.
Enhanced understanding of the business requirement	The BP1 submission are based on high-level EPICs and features, using a small, medium, large t-shirt sizing estimation model for Salesforce based solutions. Now we have undertaken a detailed reviews of features and technical components which have indicated much bigger challenge in size and complexity to deliver the new portal. We believe that we need to develop over 100 features for the end-to-end CM process. It therefore takes more time and effort to define the business requirements and turn the requirements into design and then take forward for development.
Limited implementation window	The operational timescale is strict and tight which means that we have a very short window to implement the new system and it doesn’t allow any errors or slips in the design or implementation.

External Factors

High level of uncertainty of regulatory	During the development of the project, government launched their CM Reform Consultation with 19 regulated changes which we could be required to implement by July 2023. Some changes are well defined, but some are still at principle level and lacking significant details for implementation. The CM Advisory Group has been introduced at the end of 2022 which is to gather and prioritise industry change proposals to the CM Rules. Although this open and transparent engagement approach is well received, it also introduces risks along with the CM Consultation that we may need to re-design the functionalities in the new portal to ensure continued compliance leading to delays.

Improvements in the cross-organisation processes	Through the engagement with the delivery partners we have also identified a number of processes across multiple organisations can be optimised and streamlined such as metering aggregation. This will provide enhanced services to the CM participants. We would like to take a bit longer time to scope out the work and deliver a more efficient and effective process for the customers.
Customer Feedback	Through our intensive engagement with customers, we have learnt that majority of the customers would like to see the new portal to be able to support the end of end process rather than using the existing and new systems in parallel. We therefore believe that it is the right approach to delay in launching the new portal until the whole process is implemented to minimise any compliance risks and inconvenience to customers.

Taking into account the factors above and stakeholders and customer feedback, we have undertaken a detailed replanning exercise and are now aiming to have the new EMR portal live in time for CM Prequalification in 2024 and review the implementation timescale for Contract for Difference in the new portal once the REMA outcome is published.

BSUoS forecasting

In recent years we have recognised that a new approach to our BSUoS cost forecasts, which provides even greater transparency and insight would be of value to industry. To these ends, we now publish a forecast based on a new improved methodology which has been developed with regular engagement with the wider industry. This model moves away from the previous linear model to a more comprehensive probabilistic model and also takes advantage of improved data inputs including the newly developed 12-month ahead constraint cost forecast.

This development has provided increased accuracy in the short-term BSUoS cost forecasts: the mean error in the month-ahead forecast has reduced by approximately 10%. Furthermore, we believe it will provide better insight into BSUoS costs over longer timescales. The development of this new forecast has better enabled us to set the new BSUoS fixed tariffs for the financial year 23/24, and provide insight on risks of tariff reset to support decision making around the structure of the tariffs.

Reserve Reform: Negative Slow Reserve (NSR) and Positive Slow Reserve (PSR) development

A suite of new reserve products are being designed to replace the existing positive and negative post-fault products. Slow Reserve (SR) will look to replace the existing Short Term Operating Reserve (STOR) service, whilst Quick Reserve(QR) will replace the existing Fast Reserve service.

Development of the Quick and Slow Reserve was reprioritised throughout the summer of 2022 in order to align IT deliverables and focus resource on winter preparedness. The programme of work to deliver Quick and Slow Reserve reconvened in September 2022.

Following co-creation design workshops and consultations with industry throughout 2020 and 2021, we held 4 Show and Listen webinars throughout 2022 to finalise the draft designs which have now been signed-off internally.

We continue to engage with Ofgem on the service design and general progress updates, whilst two dedicated industry webinars have taken place in March to engage with industry ahead of launching the EBR consultation at the end of April 2023, of which document drafting is underway.

Requirement detailing for IT system changes across the end-2-end service delivery has progressed since August 2022. High-level requirements are almost complete ahead of an assessment of the impact analysis. Key deliverables will include the delivery of the Enduring Auction Capability, as well as BM and ASDP system updates.

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 regulatory changes and the reform of network charges through packages such as the Transmission Charging Review (TCR) and Balancing Services and Use of System Charging (BSUoS) Taskforce decision. In January

2023, our first charging release saw the go live of the Assistance for Areas with High Electricity Distribution Costs (AAHEDC) charge and in March 2023 the new system facilitated the changes from the Transmission Charging Review with the go live of Transmission Network Use of System (TNUoS) demand charges. Alongside this, we implemented changes related to BSUoS Reform in the current charging and billing system and improvement work to ensure its stability and reliability until the new system is fully in place.

Role 2 - Progress of our deliverables

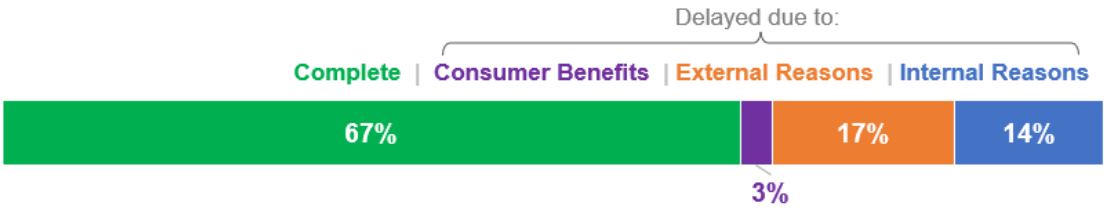
Our RIIO-2 deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables, with commentary including explanations for all delayed milestones.

For Role 2 (Market development & transactions), there are **108** milestones, **5** of these are no longer valid, leaving a total of **103**.

- **69** (67%) are complete
- **34** (33%) of those are not complete which break down as follows:
- **3** (3%) is delayed in order to deliver an improved outcome for consumers
- **17** (17%) are delayed due to reasons outside the ESO's control
- **14** (14%) are delayed due to ESO related delays

These results are illustrated below:

Role 2: Status of **103 milestones** due to be completed by the end of 2022-23



This excludes milestones which have been agreed with OFGEM as no longer being valid

Delayed milestones

Deliverable	Delay Type	Reason for Delay
D4.3.2 Day ahead market for frequency response – **1 milestone**	Internal Reasons	Deprioritised as a result of winter preparedness 2022-23.
D4.3.3 New Reserve Products Development and introduction of a new suite of products to provide reserve to the control room – **3 milestones**	Internal Reasons **(Control and dispatch solutions for reserve)**	Deprioritised as a result of winter preparedness 2022-23.
	Internal Reasons **(Standard contract terms for reserve)**	
	Consumer Benefits **(New reserve products go live)**	- Winter Operability has impacted the January 2023 delivery for Quick and Slow Reserve. The delivery plan dates of each service have been redrawn as a result. The plan is to deliver Firm/ Optional BM/ NBM Quick Reserve in 'Oct '23 and Slow reserve in Nov '23. - Key dependencies include EAC delivering in Sept '23 and Balancing transformation (IT) providing the changes required for multi-despatch functionality as well as BM/ ASDP changes to include the new services.

		- Consultation documentation commencing; Begun engagement with Ofgem and exploring where we need to seek derogations.
D4.3.4 Full co-optimised auction for Response and Reserve at day ahead or even closer to real time – **1 milestone**	Internal Reasons	Delayed due to lengthier procurement process due to large number of clarifications and covid. Revised timings of ancillary service reform work due to winter contingency re-prioritisation. This work is on track to be delivered for autumn 23.
D4.3.5 Auction capability – **2 milestones relating to Auction capability development, testing and implementation**	Internal Reasons	Delayed due to lengthier procurement process due to large number of clarifications and covid. Revised timings of ancillary service reform work due to winter contingency re-prioritisation. This work is on track to be delivered for autumn 23.
D4.4.1 (shared with D5.2) - A market platform through which market participants will be able to participate in balancing and capacity markets – **1 milestone**	External Reasons	Delayed due to Single Markets Platform prioritising functionality focusing on day ahead and tactical products (such as Demand Flexibility Service). This was agreed in close collaboration with our user base.
D5.2 (shared with D4.4) IT system to allow all participants in ESO markets (including CM and CfD) a single point of access for services and data – **1 milestone**	Internal Reasons	Please refer to the Plan Delivery Section on the EMR Portal
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 – **2 milestones**	Internal Reasons **(Reserve products integrated with foundational market platform for subset of processes)**	Delayed due to the associated delays to the development of the new enduring Reserve product suite.
	External Reasons **(Procurement of all ESO balancing and ancillary services through single markets platform for full range of processes)**	Delayed due to Single Markets Platform prioritising functionality focusing on day ahead and tactical products (such as Demand Flexibility Service). This was agreed in close collaboration with our user base.
D4.6.1 Development of competitive approaches to procurement of stability – **2 milestones relating to design & implementation of IT solutions**	External Reasons	As the Stability Phase 2 contracts are not scheduled to start until April 24, the original milestone date is not suitable. We are progressing on the necessary IT design and development work to support the go-live of these contracts.
D4.6.2 Development of competitive approaches to procurement of reactive power – **1 milestone**	Internal Reasons	Deprioritised as a result of winter preparedness 2022-23.
D5.1 .1 Continuation of EMR Delivery Body obligations – **2 milestones related to EMR Portal**	Internal Reasons	Please refer to the Plan Delivery Section on the EMR Portal

D6.1 Continued facilitation of industry changes to the industry codes. Also, delivery of Great Britain driven regulatory change through the open governance process – **2 milestones**	External Reasons **(GC0137/139/145 and post TCR modification proposals identified)**	Please refer to the RIIO-2 deliverables tracker for further information relating to a number of code changes.
	External Reasons **(Access and Forward Looking Charges Modifications and** **Clean Energy Package non-BM imbalance correction proposal)**	Ofgem have changed the scope of the Access SCR, it is no longer expected that any TNUoS related modifications are required at this stage as a result of the SCR. Therefore, this milestone is no longer required. P412 - Proposal to put P412 on hold until the Open balancing Platform is complete. The reason it is on hold/delayed is because of the lack of consumer benefit this change brings.
D6.2 Continued facilitation of EU driven code changes into Great Britain market – **3 milestones**	External Reasons **(Develop a Technical Procedure for Day Ahead Capacity Calculation)**	Delayed because EU TSOs are not yet engaging on Capacity Calculation. A technical procedure that is fit for purpose for UK and EU TSOs cannot be drafted until EU TSOs start engaging on this topic.
	External Reasons **(Develop Technical Procedure for Cross Border Balancing and other time frame Capacity Calculation in collaboration with UK TSOs and EU TSOs)**	Delayed due to limited to no engagement from EU TSOs.
	Consumer Benefits **(IT investment 270 clean energy package development and testing)**	Clean Energy Package: P412. Proposal to put P412 on hold (delay P412) until the Open balancing Platform is complete. The reason it is on hold/delayed is because of the lack of consumer benefit this change brings. This change will cost several millions to deliver for no real benefit other than compliance. The BSC panel granted the ESO a 9 month extension in January 2023.
D6.2 Continued facilitation of EU driven code changes into Great Britain market – **1 milestone**	Consumer Benefits **(Full compliance with Article 6 of the Clean Energy Package)**	Article 6.5 (P412) Delayed. Proposal to put P412 on hold (delay P412) until the Open balancing Platform is complete. Article 6.9 (up and down) MFR - Derogation has been granted until 2025. Article 6.9 - derogation approved by OFGEM for Dynamic FFR 10th March 2023.
D6.3 Continued managing, collecting and disbursing charges relating to the operation of the transmission system. Also delivering a refresh of charging and billing IT system and changes to the charging regime	External Reasons	Delayed due to delivering foundational releases on the strategic solution platform and compliance with the regulatory changes in charging methodology including the Transmission Charging Review (TCR) and Fixed BSUoS.

for CUSC. **– 3 milestones relating to Requirements, Design, Development, Testing & Implementation**		
D6.4 Change from a code administrator to a code manager. **– 7 milestones**	External Reasons **(Code change process development)**	Delayed due to awaiting the outcome of the Energy Code Review consultation.
	External Reasons **(Initiate licence)**	Delayed whilst awaiting more guidance on how the larger, more fundamental moves such as licence changes will take place.
	External Reasons **2 milestones** **(Begin detailed scoping and prioritising work; Q4 go live)**	Detailed scoping and prioritisation of work for the new process can only take place once more information comes out of the Energy Code Reform
	External Reasons **(Strategic and incremental industry change plan implemented)**	Delays in ECR versus original BP1 expectation this allows us to incorporate stakeholder feedback into our change process to realise quick wins.
D6.5 The Grid code combines transmission and distribution codes in an IT system with AI-enabled navigation – **2 milestones**	External Reasons **(First code modifications and licence changes initiated)**	We have descoped significant changes to the codes as a result of the WSTC in BP1, therefore this objective will not be met but has been overtaken by other priorities. This is in line with stakeholder feedback and expectations and the external WSTC steering group.
	External Reasons **(Continue to deliver against plan by raising and progressing code modifications and licence changes, and digitalising codes)**	Due to the approach adopted by the steering group and the focus on digitalisation this will not lead to code modification proposals as first envisaged . We will continue to work with stakeholders on the benefits of and timing for any Whole System Technical Code including engaging with Ofgem and DESNZ's Energy Code Reform programme, however, this milestone no longer appears valid due to this stakeholder led prioritisation activity.

Milestones no longer valid

Section 5.6 of the ESORI guidance states: ‘If any changes are made to the delivery schedule during the business planning cycle they should be clearly identified and outlined in the reporting documents (e.g. in a separate sub-section), so it is clear where additional amendments have been made in comparison to the original Business Plan. This can ensure Ofgem, stakeholders and the Performance Panel understand the reasons for any changes to plans in advance of its evaluation of the ESO’s performance.’

In December 2023, we introduced a new process for managing milestones that are no longer valid. Below are details of milestones that have become no longer valid over the last quarter:

Sub-activity	Deliverable	Milestone	Reason no longer valid
A5.1 Electricity Market Reform (EMR) Delivery Body	D5.1.2	EMR Delivery Body runs informal consultation with industry to refine the improved prioritisation process for changes that are deliverable and ensure transparency of those that are not.	In light of Ofgem's plans to establish a Capacity Market Advisory Group (CMAG) with industry in October 2022, we will not undertake a separate engagement exercise regarding the prioritisation process with industry. We are also mindful that BEIS is now reviewing the wider EMR policy and change governance, incl. the CM Policy Board and RCAB. The Delivery Body will therefore capture rule improvement ideas based on feedback received from customers and feed this into the CMAG process as appropriate where these can be discussed with industry.
A5.1 Electricity Market Reform (EMR) Delivery Body		Improved change prioritisation process is published by EMR Delivery Body.	
A5.1 Electricity Market Reform (EMR) Delivery Body		Industry take part in prioritisation process.	
A6.1 Code management / market development and change	D6.1	Submit Access and Forward Looking Charges Modification Proposals to Authority	Ofgem have changed the scope of the Access SCR, it is no longer expected that any TNUoS related modifications are required at this stage as a result of the SCR. Therefore, this milestone is no longer required and is being re-drafted following the agreed process.
A4.3 Deliver a single day-ahead response and reserve market	D4.3.5	Auction capability	We are unsure if a single day ahead response and reserve market is the correct answer. These may need to be separate markets depending on auction tender exercise, and further thinking around what the new products look like and how they can interact from an operational perspective.

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 2. 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
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	Complete, follow-on activity now managed by the business	RIIO-1
Dynamic Reserve Calculation	Use AI and machine learning to set reserve levels dynamically, day ahead.	The initial project delivered successfully in April 2022 and was then extended to allow the development of a proof of concept model, using live data, with the intention to implement in the Control Room for use from July 2023	D4.1 D4.3.3	Delivery	RIIO-2
Crowdflex	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 Time of Use (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	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.	The original project, due to conclude April '22, was extended into a Phase 2. Phase 2 is now nearing its conclusion. The project recommends at least 3 discrete markets – Long-term (Y-4), Mid-term (Y-1), and Short-term (D-1) – to procure	D4.6.1	Delivery	RIIO-2

	stability services in an effective way. The project has answered fundamental questions on eligibility and contract structure, and there is a core recommendation to launch the Y-1 Mid-term market as a priority. The plan for launching this is being set out in the 2023 Markets Roadmap publication which signposts industry to key reforms across operability themes, including stability.	

B.2 Stakeholder Evidence for Role 2

Our incentive scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of our 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

We commissioned surveys from market research company BMG. These surveys measure satisfaction for each of our roles 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 our 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, Balancing Services, Electricity Market Reform (EMR) and Industry Codes and Charging. Overall, from your experience in these areas over the last 6 months, how would you rate ESO's performance?"

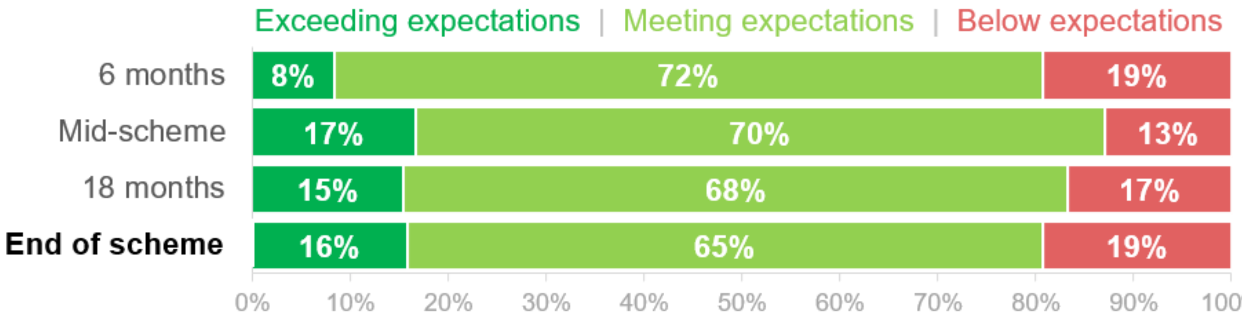
Survey participants were given the options of rating our performance for each role as below expectations, meeting expectations, or exceeding expectations.

For Role 2, we contacted 472 stakeholders, and received 114 responses to this question, which were distributed as follows:

- **16%** exceeding expectations
- **65%** meeting expectations
- **19%** below expectations

(Percentages rounded to the nearest whole number)

GRAPH: Role 2 six-monthly stakeholder surveys



Percentages rounded to nearest whole number, therefore may not sum to 100%

"Exceeding Expectations" feedback

Out of 114 responses, 18 stakeholders scored us as "Exceeding expectations". They were asked what we did that exceeded their expectations. They raised the following points:

- The majority of stakeholders have commented that the demand flexibility service was a great introduction. The design and speed in which it was produced was impressive. One commented that we have come to the market taking a bit of a risk with an actual product instead of just a white paper or theoretical product which has made flexibility come to life.
- A number of stakeholder surveys made reference to our great communication, engagement and feedback on product development.

“Meeting Expectations” feedback

Out of 114 responses, 74 stakeholders scored us as “Meeting expectations”. 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.

- The main focus of feedback is around Market Design. Several stakeholders commented that our work on Market Design should be improved calling out a willingness to collaborate on how to develop market designs, taking into considerations the needs from both parties. More analysis, consultation and stakeholder involvement are needed. We need to slow down the pace of change to come to a more informed decision instead of just meeting very tight timescales. Other stakeholders said they would like more transparency, e.g. better accessibility to key information, more data and more detail on service design, provide clearer information on webinars, especially the rationale behind some new service designs
- We ask stakeholders for feedback which is then not acted on/ignored. Stakeholders would like us to be more open to feedback and genuinely engage with industry parties.

“Below Expectations” feedback

Out of 114 responses, 22 stakeholders scored us as “Below expectations”. Below is a summary of what stakeholder said we need to do to meet their expectations:

- A few comments singled out a failure in listening to customer feedback. Customers feel we have done a lot of work and put a lot of information out however they think we don’t listen to feedback, respond in a timely manner or act upon it especially around market design and Net Zero.
- Several respondents have said even though improvements have been made, services still require a lot more work and need to be delivered much quicker than they are, incorporating lessons learnt from other balancing service delivery.
- Other themes include the need to improve transparency, communication (responsiveness to queries) better prioritisation and making decisions without deferring to Ofgem.

Addressing stakeholder feedback in BP1

The above survey is the fourth and final instalment of the stakeholder satisfaction surveys conducted for BP1, with surveys being conducted every 6 months throughout the delivery of the business plan. We’ve delivered our business activities while taking into consideration the results of these surveys. We’ve also continued to listen to and engage with our stakeholders while delivering our projects and business activities. On further analysis of previous surveys, we found that across Role 2, feedback can be grouped into a selection of key themes which are a priority for our stakeholders. They include:

1. Delivery at pace needed
2. Net zero leader and provide great transparency
3. Greater coordination with providers
4. Improve data and analytical info to support industry knowledge and decision making
5. Increasing engagement with stakeholders and closer collaboration on key projects

Below we outline how we’ve been working to address these feedback themes gathered from the stakeholder surveys throughout BP1:

Theme 1: Delivery at pace needed

Enabling easier access to our new dynamic services – We continue to develop our suite of services designed to give us better control over system frequency. These include dynamic containment (DC), dynamic moderation (DM) and dynamic regulation (DR). Stakeholders gave feedback that we needed to find a quick solution to allow providers that do not have metering systems (systems measuring active power or energy) directly connected to their assets to participate in our dynamic services.

In response to feedback gathered through industry consultation, we:

- Developed a proposal to get the required operational information from meters connected across multiple generating assets (known as boundary point meters), to indicate how much energy was being generated/consumed by the asset.
- Worked to refine this solution with technical experts to solve the challenge of being able to verify and corroborate what energy the generating units should have provided with what was actually provided during the service.
- Planned further engagement with stakeholders to finalise the roll out of this functionality.

Stakeholders have reacted positively to the actions we've taken and there are currently no objections to the proposal. We are waiting for final approval and will then make the necessary IT changes to roll out this functionality - ultimately enabling more stakeholders to participate in our dynamic response services.

Responding to the winter energy crisis by creating the demand flexibility service - We developed the world-first Demand Flexibility Service (DFS) to access additional flexibility when national demand is at its highest, during peak winter days.

This innovative service was created at pace in response to concern from government, industry and the public about the ability of the electricity system to manage under a potential scarcity of gas due to the invasion of Ukraine. In developing this service, we:

- Co-created the scheme through in person events, virtual events, bi-lateral and large group sessions and constant communication with industry, academia, Suppliers, Regulators and BEIS.
- Worked with an Energy UK working group to seek ideas for resolving technical issues. We then used these ideas to update our participation guidance document with information on how to resolve issues.

As a result of the Energy UK engagement we dramatically decreased the number of registered duplicated users of the service, allowing more users to participate in the service without being blocked.

As well as the positive feedback received through our most recent stakeholder surveys, feedback from project stakeholders included: Your engagement with industry has been exemplary, and very helpful', "The ESO's Demand Flexibility Service allows us to continue our commitment to helping our clients reduce costs, carbon emissions and move forward in taking an active role in the future of the UK's Smart Grid."

Theme 2: Net zero leader and providing greater transparency

Leading electricity market reform - Our Net Zero Market Reform project looks holistically at the changes needed to the current GB electricity market design to achieve net zero. This wasn't part of our initial BP1 commitments, but we recognised the risk to net zero of not doing this work and launched the programme in early 2021.

Throughout the programme we've been leading the discussion on the future direction of market reform, listening to stakeholder feedback and working closely with BEIS as a trusted strategic partner in the Review of Electricity Market Arrangements (REMA). Stakeholders asked for greater transparency on the qualitative assessments and scoring that we carried out across the different policy options in the Net Zero Market Reform Phase 3 report, release in May 2022.

Working with our consultant, Baringa we:

- Presented the rationale and methodology behind our consultant's assessment to over 300 stakeholders at our Autumn Markets Forum in September 2022
- Ran deep dive sessions at the same event to gather feedback from stakeholders which was then used to update and finalise the assessment methodology.
- Hosted online workshops in November 2022 to get views on the preliminary results from Baringa's assessment. The same workshop was run twice, limited to one person per organisation, to ensure as many stakeholders as possible could attend, and as wide a range of views considered. In total we had 144 external attendees at these workshops and the feedback gathered helped to complete the final assessment which was published in February 2023.

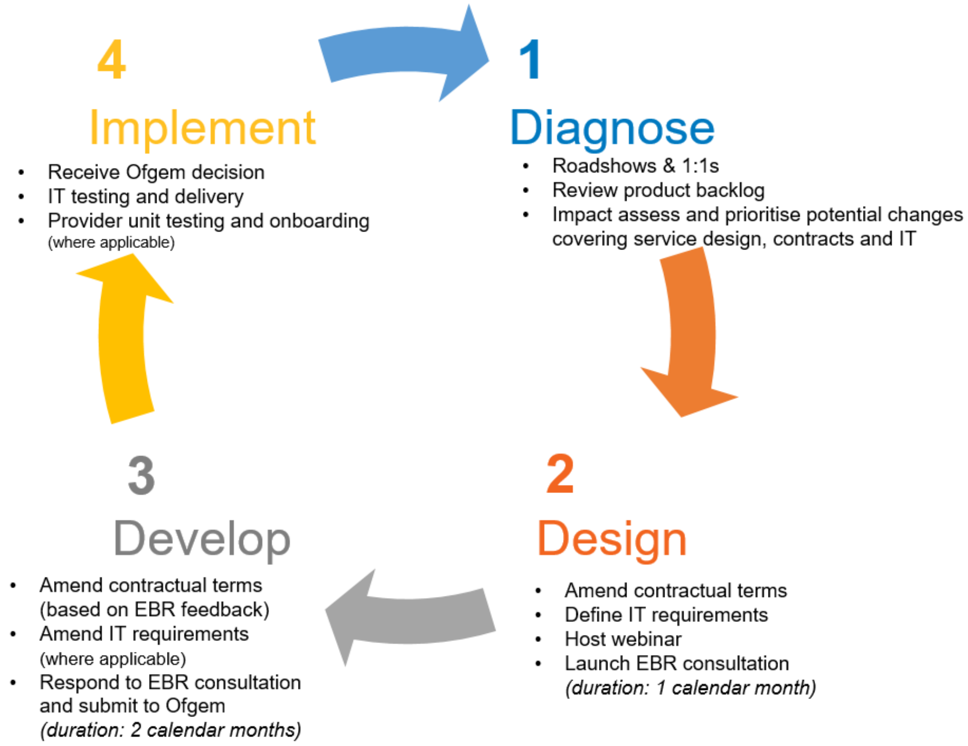
The final assessment has helped to inform the market reform debate and has been used as a tool for discussion across the sector on appropriate market reform packages.

Creating efficient engagement processes to further develop out dynamic response services - Since the launch of the Dynamic Containment low frequency service in 2020, we've undertaken a comprehensive programme of engagement and analysis which has enabled us to respond to stakeholders needs and continuously improve our dynamic services throughout BP1.

In December 2022, we have sought to coordinate our engagement with industry. We are therefore introducing an annual service development cycle for our frequency response services, which if effective, will also be rolled out to other markets. This was in response to a range of feedback from industry that they would like sufficient time and notice to plan for engagement so they can resource it appropriately.

The aim of introducing an annual cycle gives all stakeholders a repeatable, reliable plan which takes into account the fixed timelines for the formal Electricity Balancing Review consultation (consultation on amendments to the terms and conditions of our dynamic services). It also aims to provide sufficient timelines for engagement, onboarding and systems development. Thorough engagement activities will be held ahead of consultation, ensuring all voices are heard, and importantly, most changes are developed by the ESO ahead of the consultation launch. This will help ensure that barriers to entry can be addressed and we are able to respond to stakeholders' needs in a timely manner.

The following diagram shows the four stages of the annual development cycle including energy balancing review consultation.



1

Diagnose

- Roadshows & 1:1s
- Review product backlog
- Impact assess and prioritise potential changes covering service design, contracts and IT

2

Design

- Amend contractual terms
- Define IT requirements
- Host webinar
- Launch EBR consultation

(duration: 1 calendar month)

3

Develop

- Amend contractual terms (based on EBR feedback)
- Amend IT requirements (where applicable)
- Respond to EBR consultation and submit to Ofgem *(duration: 2 calendar months)*

4

Implement

- Receive Ofgem decision
- IT testing and delivery
- Provider unit testing and onboarding (where applicable)

Engaging with customers on BSUoS - Balancing costs find their way to users as BSUoS charges which are passed through to consumers. BSUoS charges have increased significantly over the last decade as the electricity transmission system has become more complex to manage. Industry have been calling for us to take a wider role in the management of balancing costs over the last 10-15 years. Since 2018, we've been working to solve problems related to BSUoS charging through the BSUoS taskforce. Over BP1, we've been addressing specific concerns of tariff resets, erosion of consumer benefits and ESO financeability. In December 2022, Ofgem approved CMP361/362 covering a 9-month tariff notice period, 6-month fixed period and no industry fund. They noted that further changes would be required for an enduring solution. We've led on communicating these changes to industry in the following ways:

- Transmission Charging Methodology Forum (TCMF) updates
- TCMF BSUoS sub-group

- Webinars were held by the Revenue and Modelling teams on the draft tariff and balancing cost forecasting.
- The Revenue team developed new tariff publications to tight deadlines and coordinated billing system implementation with IT, involving significant additional hours worked.

The CUSC panel appreciated the innovative ways we've engaged throughout the final stages of the process. Following feedback from the TCMF an enduring fixed BSUoS TCMF sub-group was set up to help co-create solutions with industry.

On 31 January 2023 we published the first fixed BSUoS prices that will apply from April 2023.

The process was acknowledged across industry as a success. We took a leading role and demonstrated our commitment to meeting stakeholder needs and reducing consumer bills.

Theme 3: Greater coordination with providers

Procuring Energy System Restoration services - The new Energy System Restoration Standard requires us to have sufficient capability and arrangements in place to restore 100% of Great Britain's electricity demand within five days. Using DER and green energy sources to restore GB's electricity system and increasing the diversity of providers would save millions of pounds in costs for consumers through increased competition. In November 2022, we launched a nationwide tender for restoration services from large scale transmission connected wind generators, to be delivered by December 2026. However, some providers told us that due to the scale of their wind generation project, they would not be able to meet the 2026 start date as their wind farm would not be operational in time. Taking a leadership role in this space, we coordinated across industry to put in place measures which would satisfy stakeholders and increase the participation in this market. As a result of the feedback we received, we looked at different options and put in place two different start dates, December 2026 and December 2028.

This enables all current providers to remain in the tender whilst also opening the tender up to new eligible providers. Developers who can deliver restoration services by 2026 are rewarded sooner whilst keeping the opportunity open for other developers who haven't come online yet. This helps us sustain longer resilience and use wind contracts in different areas of GB.

Theme 4: Improve data and analytical info to support industry knowledge and decision making

Alignment, Simplification and Rationalisation (ASR) of codes – The Grid Code details the technical requirements for connecting to and using the National Electricity Transmission System (NETS). As the code administrator for the Grid Code, we maintain the code and oversee any proposed changes to it**.** In BP1, we proposed developing a digitalised Whole System Technical Code (dWSTC) which would amalgamate the existing Distribution Code and the Grid Code. We've engaged with stakeholders to share progress of this work which includes the alignment, simplification and rationalisation of the codes. An example of this work is the improvements made to Operating Code No.2 of the Grid Code:

- In September 2022 we used stakeholder insights to simplify Operating Code 2.
- We've included footnotes, figures and diagrams to simplify timelines and make the code text easier to read and understand.
- We've provided updates at Trade Association forums on our code simplification work, including our work on Operating Code 2. Using Trade Associations helps all relevant organisations proactively engage with us on these topics, provide their input and help us develop solutions in code simplification.

Stakeholders have responded positively to these improvements. We will continue to work with industry to make improvements to our codes, proposing modifications at appropriate times.

Improving our procurement process in ancillary services - We are continually looking to develop our services to improve the transparency and efficiency of our markets. We have gone through several stages of refinement of our dynamic services for example, which have been coming online throughout BP1. As mentioned previously, we've taken care to refine our engagement and consultation to give participants opportunities to feed into this market development. We've also been looking at ways information and data is being used in these services. This is to enable our stakeholders to have the best access to data to facilitate sound decision making, drive competition and provide value for the consumer.

We’ve worked on the following improvements which have been received well from stakeholders. They include:

- The creation of the frequency services suite (DC/DM/DR) dashboard on the ESO Data Portal. Providing transparency on response procurement costs, market share, etc.
- Moving from a set price for services to a more dynamic buy order – stimulating competition
- Introducing a 4-day rolling forecast for Dynamic Containment helping to improve transparency for providers, enabling them to understand our needs better and bid in more markets
- Creating new webpages for balancing services through the Digital Engagement Platform project – changing the customer journey on our site and updating the content based on the audience.

Stakeholders have fed back their approval of the information and the way it is presented in the data portal. This is valuable for parties with smaller capacities and less in house analysis capability.

In terms of how our systems process data in our markets, stakeholders fed back concerns that they found, although they submitted the cheapest bid for a service, it wouldn’t necessarily be accepted by our systems. We subsequently investigated the reasons for this, found our algorithms were selecting bids in an inefficient way and amended the algorithm to prioritise cheaper prices instead of for the simplest orders.

Theme 5: Increasing engagement with stakeholders and closer collaboration on key projects

Developing the markets forum and roadmap - We are committed to working together with stakeholders as we reform our markets to be fit for a net zero future. During BP1 stakeholders including the Performance Panel, told us that we needed to provide a clearer overview of what our plans are across markets and transactions (particularly past 2025). Stakeholders wanted to see more DSO and ESO interactions and whole system thinking, the annual publication of a Markets Roadmap and clearer market signals to provide investor confidence enabling flexibility in the future.

In response to this stakeholder feedback, we have:

- Set up a Markets Forum to provide an overview of our plans across markets and transactions. We’ve held five Market Forum events over BP1, with hundreds of delegates attending each event and having the opportunity to engage in meaningful conversations around our market’s activity. Our most recent forum in September 2022 covered topics including our approach to Winter 2022, updates on new projects e.g. Demand Flexibility and continued the conversation with stakeholders on Net Zero Market Reform. We’ve had positive feedback from stakeholders on these events with 80% of the September event attendees saying they would recommend to colleagues. To improve for the next forum, we will make sure our date doesn’t clash with other major industry events, allow more time for questions and set up better ways for online participants to ask questions.
- Published an annual Markets Roadmap to set out our market design objectives, principles and transformational process to reform balancing services markets. We understand that our ancillary services and balancing markets are an increasingly important revenue stream for market participants, so the roadmap is designed to provide a clear view of how we see these markets developing. We intend to give the markets the ability to build investment cases and provide confidence in our design decisions. We received the following feedback in our customer and stakeholder satisfaction survey that our “markets roadmap document is great and stakeholder engagement on publications and system operability challenges have been communicated well.”

Using the views of industry to shape our market reforms through the Markets advisory council (MAC) – The MAC was established at the start of the second year of BP1 (April 2022) to inform our approach to strategic market design and delivery, based on robust evidence, international best practice, and the needs of and impacts on wider industry.

The group is made up of experts from all parts of the electricity value chain including networks, generators, flexibility providers and academia.

We’ve engaged across a range of GB energy market related issues such as: net zero market reform, review of electricity market arrangements, markets with FSO, markets roadmap, distributed flexibility strategy, the winter outlook and EU market reform.

Feedback from the MAC across key areas includes:

Markets Roadmap

- More transparency, we should provide the rationale on why we procure particular products, where our priorities lie and why we take the strategic decisions we do. Within the Markets Roadmap we summarised how changing system operability requirements are informing the transformation of what we're procuring.
- Our products should align with the broader set of flexibility products that are available to the market, such as with DSO flexibility products. We continue to apply the Market Design Framework to our balancing and ancillary service market design, which includes a 'coherence' principle to ensure we are designing markets in a way that is coherent with wider markets. We also engaged the consultancy LCP-Delta to undertake an independent assessment of our Markets Roadmap against the Framework. Finally, we are engaging with Ofgem on their proposals to create an independent Market Facilitator to coordinate flexibility markets across transmission and distribution.

Market reform

- We should respond to the EU consultation on reform, which we acted on.
- A suggestion that the Council should discuss and propose shorter-term quick wins for us to focus on – we are setting up sub-groups to deliver this.

Demand side flexibility

- A request to see success metrics for DFS which has been fed back internally for the future development of the service.

B.3 Metric Performance for Role 2

Table: Summary of metrics for Role 2

	Full year 2021-22			**Full year 2022-23**			**BP1**
Metric	Benchmark	Actual	Status	Benchmark	Actual	Status	Status
2A Competitive Procurement	50-60%	55%	●	<65%	43%	●	●

Below expectations ● Meeting expectations ● Exceeding expectations ●

Metric 2A Competitive Procurement

April 2021 – March 2023 Performance

This metric measures the overall % of services procured through competitive means (auctions and tenders) calculated by £ expenditure. It should be noted that due to the way in which the metric is measured – as a proportion of total £ spend – the outcome can be influenced by high power prices or increasing liquidity in a market (as detailed below). The measurement approach for this metric has been changed for the BP2 period.

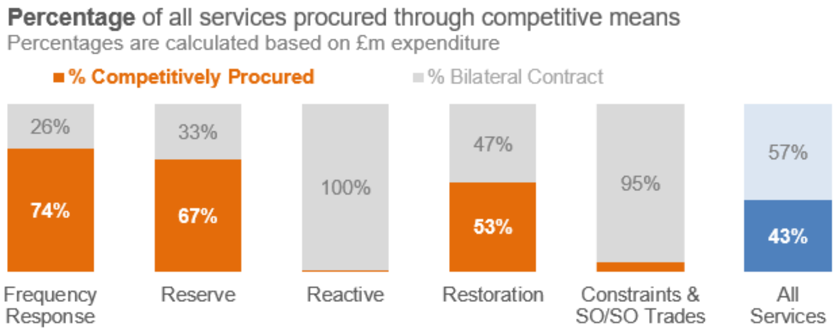
Please note the following points when interpreting the data for this metric:

- For **Reactive**, most of our needs are met by the Obligatory Reactive Power Service (ORPS) or delivered by TO reactors already connected to the Transmission network at zero cost to the ESO. For this BP1 reporting period we ran a tender for the Mersey region as a pathfinder to establish if market based solutions could be more economic than ORPS or the counterfactual TO solutions. As this was a relatively small requirement in a specific region, the % of services through competitive means appears small and this as a % measure has decreased in 22/23 as the default payment for ORPS has increased. The ORPS payment is derived from the forwards power prices and in Q3 22/23 we saw very high power prices. This large increase in prices on this non-competitive service has resulted in a reduction in the performance benchmark in 22/23.
- For **Restoration**, following the competitively run Tenders in 2018 for the South West and Midlands region and in 2019 for the Northern regions, 11 of the successfully awarded contracts have commenced their services from Q1 2022. These new contracts are now providing restoration requirements alongside the historic bi-lateral contracts from before these tenders. From the competitive tenders, the last remaining station to commence service is live from February 2023. In Q2 2022, brand new regional competitive tenders were launched, and we should see the outcome of these contracts in 2025. This is because, 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.

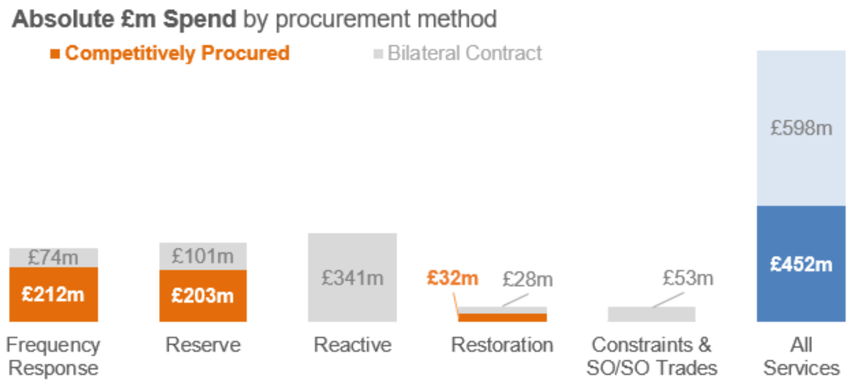
Overall BP1 2021-23 performance:

● **Below expectations:** The average percentage of services procured through competitive means is 48% over the BP1 period, which is in the 'Below expectations' range for both performance benchmark years.

Graph: Full year 2022-23 view of percentage of £m spend by procurement method



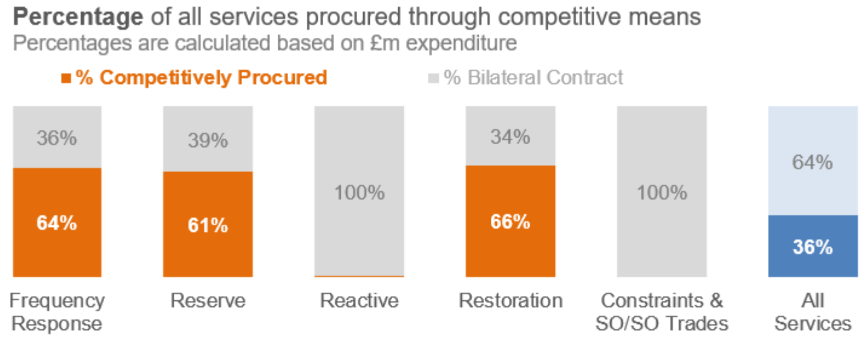
Graph: Full year 2022-23 view of absolute £m spend by procurement method (full year 2022-2023)



Latest quarterly performance:

● **Below expectations:** The average percentage of services procured through competitive means is 43%, which is in the 'Below expectations' range.

Graph: Q4 percentage of £m spend by procurement method (January 2023 to March 2023)



Graph: Q4 absolute £m spend by procurement method (January 2023 to March 2023)

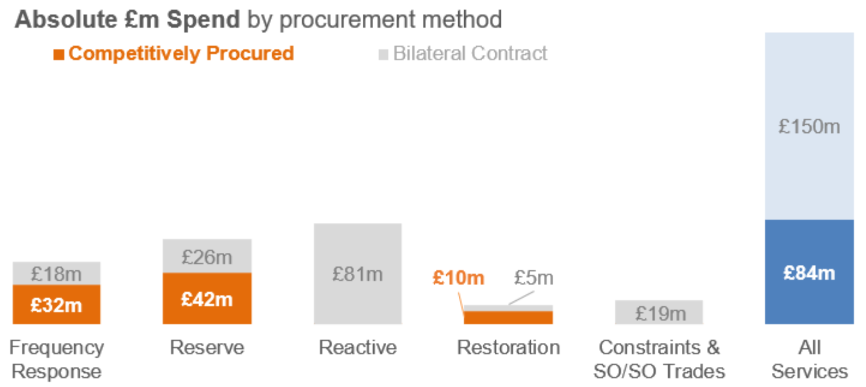


Table: Two-year view of percentage of services procured through competitive means by Quarter

Year	2021-22					2022-23					BP1 Overall
Services	Q1	Q2	Q3	Q4	**Total**	Q1	Q2	Q3	Q4	**Total**	Total
Frequency Response	91%	83%	84%	82%	85%	82%	76%	70%	64%	74%	79%
Reserve	61%	62%	62%	66%	63%	60%	70%	73%	61%	67%	65%
Reactive	3%	2%	2%	2%	2%	1%	0%	0%	0%	0%	1%
Restoration	36%	46%	57%	46%	46%	55%	36%	50%	66%	53%	50%
Constraints & SO/SO Trades	88%	451% [18]	26%	33%	121% [19]	25%	1%	0%	0%	5%	37%
All services	**61%**	**64%**	**50%**	**48%**	**55%**	**49%**	**48%**	**39%**	**36%**	**43%**	**48%**
Status (All services)	🟢	🟢	🟢	🔴	🟢	🔴	🔴	🔴	🔴	🔴	🔴

Performance benchmarks - Year 1

- 🟢 Exceeding expectations: >60%
- 🟢 Meeting expectations: 50-60%
- 🔴 Below expectations: <50%

Performance benchmarks - Year 2

- 🟢 Exceeding expectations: >75%
- 🟢 Meeting expectations: 65-75%
- 🔴 Below expectations: <65%

BP1 data updated: Please note that for this end of scheme report, the data has been recalculated for the whole of the BP1 period. This has caused changes throughout this time that are different to what has been reported in previous quarterly reports.

Within our spend on Restoration and Reactive services in particular, there are contracts that have gone live recently or that were assigned to a different service that have been procured via competitive tenders. These contracts were not reflected within the figures reported in previous reports and in some cases has changed the values reported previously. This has not changed previous RAG statuses.

The winter 2022/23 contingency coal contracts have been excluded from the reporting due to their exceptional nature.

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[18] 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. For reference, the absolute figures for Constraints & SO/SO Trades in Q2 2021-22 were: £15m competitively procured, -£11m bilateral contract.

[19] 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. For reference, the absolute figures for Constraints & SO/SO Trades for full year 2021-22 were: £30m competitively procured, -£5m bilateral contract.

Supporting information

Overall BP1 2021-23 performance: Below expectations

The average percentage of services procured through competitive means is 48% over the BP1 period, which is in the ‘Below expectations’ range for either performance benchmark years.

2021-22 performance: Meeting expectations

The percentage of services procured through competitive means is 55%, which is in the ‘Meeting expectations’ range of 50-60%.

2022-23 performance: Below expectations

The percentage of services procured through competitive means is 43%, which is in the ‘Below expectations’ range of <65%.

Latest quarterly reporting update, Q4 2022-23 performance: Below expectations

The percentage of services procured through competitive means is 36%, which is in the ‘Below expectations’ range of <65%.

Average Market Prices 2021-22

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

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

Average Market Prices 2022-23

	Q1	Q2	Q3	Q4
Dynamic Containment Low Frequency (DCL) (£/MWh)	23.5	21.1	8.2	3.96
Dynamic Containment High Frequency (DCH) (£/MWh)	4.1	3.6	3.2	2.55
Dynamic Moderation Low Frequency (DML) (£/MWh)	5.2	5	4.6	3.52
Dynamic Moderation High Frequency (DMH) (£/MWh)	7.9	11.9	7.5	3.25

Dynamic Regulation (£/MWh) Low Frequency (DRL) (£/MWh)	25.6	29.6	15.7	13.39
Dynamic Regulation (£/MWh) High Frequency (DRH) (£/MWh)	26.2	18.4	11.8	2.71
Optional Fast Reserve (£/MWh)	228.8	423.4	270.18	215.09
STOR DA (£/MWh)	4.6	10	23.91	8.66

Frequency Response

The volumes or response procured through competitive means has increased over the 2 year period with the introduction of the Dynamic Containment (DC), Moderation (DM) and Regulation (DR) services. The majority of the volume procured is made up of Dynamic Firm Frequency response (550MW reducing down to 350MW), Static Firm frequency response (250MW) and Dynamic Containment (up to 1GW) required daily. The rest of the volume is through the DM and DR service and a few optional bi-lateral contracts. Across the frequency services over this period there has been a general decrease in the cleared prices as liquidity in these market increases, the exception being periods where system margins were tight or when day ahead power prices spiked, DC DM and DR cleared pricing reflected market conditions during these periods. It is worth noting that after Q1 and Q2 in 2021 DC went from awarding day ahead 24hr contracts to EFA block contact awards which reflects the sudden change in Q3 after 2 consecutive months averaging £17/MWh.

Reserve

The volume of reserve procured through competitive means has remained pretty static across the 2 year period at between 60% and 70%, being made up mostly of the STOR day ahead and Optional Fast Reserve products, with a small volume of long term STOR contracts (~400MW of the STOR daily requirement of ~1700MW). The remaining volume comprising of other mostly bilateral contracts (e.g. Spin/Pump Gen, etc).

The STOR market moved to day ahead procurement in April 2021 with a ‘pay as clear’ daily auction. The market is very liquid and whilst the number of units regularly participating has reduced slightly during the 2 year period, we have always seen between 50 and 100 units bidding in each day.

In the first 12 months from 1 April 2021 there were ~2GW of providers placing bids in each auction, and a relatively consistent clearing price of around £5/MWh. Over the last 12 months it is clear that the market, particularly over the winter, has become increasingly reactive to forward margin and price signals with parties seeking to maximise revenue opportunity when system margins were tight or when day ahead power prices spiked. Whilst the typical clearing price is still between £5 and £10/MWh there have been a handful of instances where the daily auctions cleared at well over £100/MWh and in the more recent winter 22/23 months we had a peak clearing price of £175/MWh, and a low cleared volume of 282MW, further evidence that the market is seeking to maximise revenue opportunity.

The Optional Fast Reserve market has not changed during the 2 year period and remains with a small volume of non-BM mainly gas units, with some price fluctuation across period

Reactive

In 2020 we launched a Short term tender for Reactive Power Services for the Mersey Region to deliver between April 21 to March 22 as a pre-cursor to the enduring Long-Term tender that was being developed concurrently. The successful provider was a CHP from Inovyn and was contracted to deliver 70MVAr for 2021-22. During this process we also contracted on an Optional basis with Rocksavage CCGT, which was more economic than the alternative of being instructed in the Balancing Mechanism.

The Long-Term Mersey tender completed in Q3 2020, and we awarded a nine-year Reactive Power Service to PeakGen (200MVAr Shunt reactor at Frodsham) and Zenobe (40MVAr Battery at Capenhurst) , both originally expected to commence from April 2022. This was a competitive procurement and was assessed against a Transmission Owner (TO) counterfactual as well as other market solutions. There was a slight delay to the PeakGen shunt reactor going live (May 22), and a longer delay to the Battery project which started in Jan 23. Both projects have been delivering a valuable service to the Mersey Region.

Shortly after the conclusion of the Mersey Long Term Pathfinder, we also launched the Pennine Pathfinder for Reactive Power services from 2024 to 2034. Again the TO, NGET was able to participate against market solutions. We awarded contracts to three NGET solutions in the West Yorkshire region and to a market solution Dogger Bank C Windfarm. All projects are currently on track to deliver valuable reactive power in Q4 2024.

We continue to develop our thinking around market-based procurement of Reactive Power. The Reactive Market Design Project phase 1 was concluded in March 2022 with the initial view of the proposed design and all outputs shared on our website8. The next focus of the project is to assess the feasibility of implementing an enduring reactive market, along with analysing what solutions need to be developed to support it. We continue to work with the stability market design project to support the analysis of common questions on subjects such as Transmission Owner competition and broader asset eligibility. The outputs of this next phase of work will be used to inform a proposed plan of how the enduring reactive market can be delivered.

The Reactive Power Market Design project team were reallocated to the Balancing Reserve (BR) project to support development of the BR service, lead industry engagement, run the consultation process and deliver the implementation of the service. The Reactive Power Market project was chosen to re-prioritise due to the low immediate impact the project had on ESO costs for last winter. The project team are now starting to pick back up working on the Reactive market design whilst supporting ongoing Balancing Reserve work.

Restoration

Electricity System Restoration - ESR (formerly known as Black Start) service contracts from Q1 2021 to now, are 59% through the various competitive tenders launched in the Northern, South West and Midlands regions. The remaining 41% are bi-lateral contracts ongoing from before, most of which will be replaced with new competitive tenders that launched in 2022 for the South East and Northern regions.

The Restoration spend in Q2 and Q3 2022 was much higher, because we cleared works contribution payments for the new contracts from the South West and Midlands Tender 2018 and Northern Tender 2019, that have commenced their services in 2022-23. The rest of the spend is based on the monthly availability payments made to the contracted generators based on the payments rates agreed in their contracts.

In Q3 2022, the new competitive ESR Tenders in the South East and Northern regions were launched to include technical requirements for distribution-led restoration services from Distributed Energy Resources (DER) alongside the usual primary restoration services from transmission-led generators. Alongside these two regional tenders, a one-off wind specific tender targeting wind generators capable of providing the technical solutions equivalent to primary service requirements at transmission level, was also launched. All three tenders are running on-track and aiming for service go-live by Q3 2025 for a five year contract to 2030. The expressions of interest in all these tenders have been extremely high and we are working closely with the relevant DNOs to shortlist the best technical and commercial solutions to fulfil the Electricity System Restoration Standards that come into effect in 2026.

To dovetail the existing contracts in a timely manner with the new tenders going live, some contract extensions were negotiated in Q2-Q4 2022. Therefore in Q3 and Q4 2022-23, we continued to pay the availability payments for these stations until Q3 2025 when their contracts are due to end.

In Q4 2023, the last of the successful contracts from the South West tender came into service having completed their building works and passing their commissioning assessment. In this period two stations came to the end of their contract terms and were not extended. As it stands from the South West and Midlands as well as the Northern Tender all the successfully awarded contracts from open competitive events are now providing restoration services. The number of contracts per region provides assurance that there will be sufficient provision of restoration services even if any of the plants need to go on planned outages in the summer months.

Constraints & SO/SO Trades

In 21/22 we awarded the first competitive tender service for a Constraint Management Intertrip Service (CMIS). The service is due to begin in October 23 and last for a year, however, six units were able to go live early in April 22.

The service reduces constraint costs across the B6 (SCOTEX) boundary by implementing a post-fault intertrip service, which means that generators are rapidly disconnected from the Transmission System if there is a network fault. This lowers the risk to the Transmission Network, as the system is rapidly secured, and allows the Control Room to transmit more electricity over the constraint boundary pre-fault.

As a result, there is a reduction in the pre-emptive curtailment of renewable electricity in Scotland and also in the costs of replacing this electricity with carbon-based generation in England and Wales.

In the first ten months of the service (April 22 to January 23), we have reported savings of £80m for the consumer and 139,924 tonnes of carbon. The savings from the service are expected to continue to improve as the remaining parties that are awaiting new intertrip connections are fully connected by October 23.

The service's second competitive tender was awarded in 22/23, with a service term of October 24 to September 25. The new tender contracted with additional generators and moved from bilateral contracting to framework agreements.

In addition, we have taken learnings from the B6 (SCOTEX) tender and are now applying these to East Anglia.

The NOA 2021/22 Refresh identified that there will be a need for a new service in the East Anglia region to mitigate constraints from 2025 until the area's network reinforcements are completed. We will therefore be launching a market wide tender in late-2023 that will aim to contract for an EC5 (East Anglia) CMIS to begin in 2025.

The Project Team are currently in the design phase of the tender and have identified that there is a value opportunity to begin the EC5 CMIS early by adopting the same approach as B6 with generators that already connected to the intertrip scheme.

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 **B6 Constraint Management Intertrip Service**, 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

Summary

We now estimate gross benefits of £81.4m over the RIIO-2 period which is £24.6m lower than the original estimate of £106m.

Table: End of scheme view of benefits versus original BP1 view:

All figures in £m	RIIO-2 gross benefits
BP1	106
End-of-scheme view	**81.4**
Difference	24.6

*Figures are rounded to the nearest £0.1m*change in estimated benefits compared with the original BP1 CBA?

Reserve Delivery:

- Following co-creation design workshops and consultations with industry throughout 2020 and 2021, we held four Show and Listen webinars throughout 2022 to finalise the draft designs which have now been signed-off internally.
- We continue to engage with Ofgem regularly on the service design and general progress updates, whilst a dedicated industry webinar re-engaged industry following a period of project reprioritisation and to re-communicate timelines.
- Significant work has been undertaken to conclude the draft Service Terms ahead of launching the EBR Article 18 consultation.
- Requirement detailing for IT system changes across the end-2-end service delivery has progressed since August 2022. A number of low-level requirements are almost complete ahead of impact analysis assessments,

Reserve Change Drivers:

- Development of the Quick and Slow Reserve was deprioritised throughout the summer of 2022 in order to align and optimise IT deliverables and developments across the ASR (Ancillary Service Reform) programme and ensure cost savings.
- In order to meet winter operability challenges, Reserve Reform delivery was deprioritised throughout mid-2022 to re-assign resource to more operationally critical deliverables, including the Demand Flexibility Service.
- Furthermore, we have come to the decision to further delay the delivery of the new Reserve reform products, Slow and Quick Reserve – originally planned for October

and November 2023. This decision has been taken in light of the significant changes that would have been required in our existing, legacy balancing systems and processes, given the complexity of the new service designs. In the midst of a complex and rapidly evolving systems change environment, we believe it is more prudent to re-evaluate these changes to consider if implementation into our legacy systems is still appropriate, as opposed to direct implementation into our Open Balancing Platform (OBP).

- Postponing the rollout of our new Reserve services grants us the opportunity to re-examine our proposed service designs, evaluate our IT options, and collaborate more effectively. This will ensure that the best solutions are delivered and that the necessary updates to our balancing systems are apt for enhancing our operational toolkit and are better aligned with the implementation of our future systems.
- We believe that these adjustments are appropriate strategic steps forward in our progress towards delivering an enhanced suite of Ancillary Services across both Reserve and Response, aligning more closely with the capacities and capabilities of both our current and future systems to deliver the best outcome.

Updated CBA for Reserve

- Having reconvened the Reserve Reform programme in September 2022, we have been working across the business to refine requirements and work with ESO IS delivery teams to design appropriate solutions in the necessary IT systems. As a result, our indicative timeline to implement and deliver Quick and Slow Reserve targets late FYQ4 23/24 at the earliest. Therefore, we do not anticipate realising the £17.15m per annum until FY 24/25, which constitutes £34.3m over the course of the scheme. Please note that £34.3m is the Reserve element of the £54.7m of ‘More liquid response and reserve market’ highlighted in the ‘End-of-scheme’ table below.

Response Delivery:

- We have launched a suite of new dynamic frequency response products in 2021 and 2022 to better meet the needs of the changing electricity system, increase market liquidity and deliver value to consumers, Dynamic Containment (DC), Dynamic Regulation and Dynamic Moderation
- We have also made enhancements to these markets including:
    - A change in procurement from 24-hour contracts to EFA-block granularity as well as the market maturing have allowed us to purchase more if the dynamic products and increased the number of participants in DC markets have increased, in part due to
    - Providing a 4-day rolling forecast of our needs, which helped to improve transparency for providers, enabling them to understand our needs better and bid in more markets.
    - We implemented a new dynamic buy order, effective from 1st Apr 2022. In September 2021, when we launched DC-high and introduced the EFA blocks, our buy curve was static and predictable to attract new participants and grow the market. The new dynamic buy order meant we were able to meet our requirements more cost effectively by establishing multiple thresholds, based on our willingness to pay for capacity. This reduced hockey stick bidding and drove clearing prices down.
    - Merit order constraints were removed in March 2022, which led to a marked decrease in rejected volumes and ultimately to lower clearing prices and procurement costs.

Updated CBA for Response:

- Response has begun delivering benefit following the introduction of its full suite of dynamic Frequency Response products in 2022/23. A total benefit of £47.1m is expected to be delivered by the end of the scheme, consisting of £20.48m from ‘More liquid Response Markets' and £26.7m from 'Buying the optimal volume of Response' (see tables below).

Additional comments/benefits not reported:

Reserve reprioritisation:

- Reserve was deprioritised to allow ESO to develop Balancing Reserve: Balancing Reserve would have allowed ESO to procure regulating reserve on a firm basis at day ahead. This would have helped minimise balancing costs and improve system security as the unit headroom and footroom is guaranteed for the Control Room to access when needed. By procuring the service, reserve volume is locked in ahead of the day ahead energy market and the energy is not available to be sold into other continental markets over the interconnectors. LCP forecast a substantial balancing cost efficiency of on average ~£300m a year due to the introduction of Balancing Reserve.

Step change to our frequency control policy:

- As reported in our frequency strategy case study which includes FRCR, ALoMCP, Stability pathfinder and Dynamic Containment, we expect £1.8bn in benefits to be realised in 2023. Changes to the procurement of our response services has helped to enable these savings.

Dynamic Containment Low Procurement Changes:

- Before moving to EFA block procurement, DCL was contracted daily for 24 hours, the ESO requirement was a static 1100MW throughout the day and the price cap was set at £17/MW/h. As the DCL market was not liquid during the period, it always cleared at the price cap, with almost all offers being accepted.
- DCL moved to EFA block procurement on 16-Sep-2021, and since 1-Nov-2021, our requirement for DCL started to vary by EFA and by day, whilst the DCL price cap was updated to reflect alternative costs by EFA block, at £17/MW/h for EFAs 1-3, and £48/£48/£40 per MW per hour in EFA 4/5/6.
- 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.

Calculation of monetary benefit to consumers

Decarbonisation of the electricity system is leading to challenges such as lower inertia and larger and more numerous losses. Compared with the Response and Reserve market in 2020, the changing system conditions, the launch of new faster acting Dynamic Frequency Response Services (Dynamic Containment, Dynamic Moderation and Dynamic Regulation) as well as the introduction of Frequency Risk and Control Report (FRCR), changed our reserve, frequency response and inertia holding strategy. This means that producing a CBA using the original metrics would not represent an accurate view of savings made through changes to our services.

The original CBA was forecast to deliver £106m of benefit by 2025/26. This comprises of two elements; a 'more liquid response and reserve market' and 'buying the optimal volume of response'.

Calculation for 'More Liquid Response and Reserve Market':

- The original calculation considered the annual cost across Response and Reserve (£514m) as published in the ESO Monthly Balancing Services Summary (MBSS) in Dec 2020. Assuming a 5% reduction in spend was then applied to give us a proposed annual benefit of £25.7m. Our 5% assumption is based on evidence from early trials, as evidenced in the 2019/21 Forward Plan[20].
- The 'end-of-scheme' calculation shares the same methodology, using updated MBSS costs (£479m) as our baseline. Whilst this proposes an annual benefit of

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[20] Forward Plan 2019/21 - https://www.nationalgrideso.com/document/140736/download - page 111

£23.95m per annum, delivery of Reserve will not be implemented until late FY 23/24 at the earliest, and we have therefore removed £17.15m of forecast annual Reserve benefit FY 23/24.

Calculation for 'Buying the optimal volume of Response':

- The same methodology has been used to calculate the 'Buying the optimal volume of Response' benefit.
- The original calculation considered the average Response costs over the previous 12-month period (£193m) and assumes a similar 5% reduction in spend (again based on evidence from early trials, as evidenced in the 2019/21 Forward Plan1). An annual benefit of £9.7m was therefore proposed.
- The 'end-of-scheme' calculation shares the same methodology, using an updated baseline of £178.5m and therefore an estimated benefit of £8.93m per annum.

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	75% complete 25% delayed – internal reasons
D4.3.3 New Reserve Products	66% delayed – internal reasons 33% delayed – consumer benefit
D4.3.5 Auction capability	66% delayed – internal reasons 33% no longer valid

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.	78% complete 11% delayed – internal reasons 11% delayed – external reasons

Activity A4.6 – New Services Market Development

Deliverable	Status
D4.6.2 Development of competitive approaches to procurement of reactive power	86% complete 14% delayed – internal reasons

Forecasted benefits

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	25.7	25.7	25.7	77.2
Buying the optimal volume of response	0	0	9.7	9.7	9.7	29.0
Total	**0**	**0**	**35.4**	**35.4**	**35.4**	**106.2**

End of Scheme view:

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
More liquid response and reserve market	0	0	6.8	23.95	23.95	54.7
Buying the optimal volume of response	0	0	8.9	8.9	8.9	26.7
Total	**0**	**0**	**15.7**	**32.8**	**32.8**	**81.4**

Commentary:

We have reviewed the benefits against the original forecast and identified that there is a reduction in cost benefit by £24.6m (23.2%) over the course of the scheme. This is a result of primarily our revised delivery strategy for Reserve Reform, and also a result of recalculated baselines and combined reduced spend in Response and Reserve markets since original forecasts were published.

The total cost benefit to be realised by the end of 2025/26 is now estimated to be £81.4m.

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	Total balancing costs of £6.9bn vs benchmark of £3bn for the two-year BP1 period (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.	Year 1 (2021-22), 55% of all services procured through competitive means (meeting expectations) Year 2 (2022-23) 43% of all services procured through competitive means (below expectations)

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.

Assumption	Current view	Evidence
Participation would be increased	Launching more volume in Dynamic Containment and removing existing volume cap	Consumer benefit expected to be in line with original assumptions
Value of the response and reserve market is £514 million per year	Value of the response and reserve market is £479 million per year	Based on more recent view of ESO spend as published in MBSS.

	Our actions deliver a 5 % saving in the response and reserve markets Benefits delivered from year three of RIIO-2	No change from original assumption	Our 5% assumption is based on evidence from early trials, as evidenced in the 2019/21 Forward Plan[21].

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[21] Forward Plan 2019/21 - https://www.nationalgrideso.com/document/140736/download - page 111

CBA: Transform access to the Capacity Market (CM) (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

Summary

Our original CBA estimated gross benefits of this activity to be £74 million over RIIO-2. We estimate that we are on track to deliver higher benefits of £132 million over RIIO-2.

The increase in benefits is driven by the much higher clearing prices of the T-4 Capacity Market auctions, which is outside the ESO's control. The higher auction prices mean that the modelling enhancements to reduce the risk of over-procurement are more important.

Supporting evidence from BEIS' Panel of Technical Experts published report is provided below setting out an independent view that we have not exploited our privileged position to secure additional unnecessary capacity.

The higher benefits have been partially offset by the delay to 'Reducing barriers to entry and cost of participation' through the new EMR portal. Due to the delay in launching the new system, the benefits of £2.2m/per annum based on the original CBA methodology would be postponed to BP2. However, in addition to the benefit of reduction of cost of participation (£2.2m/per annum), we believe that there would be other benefits which would be delivered in the future through the new EMR portal once in place, such as efficiency in implementing regulatory changes. The value would be depending on the number and level of complexity of the future regulatory changes.

Calculation of monetary benefit to consumers

The calculation of the enhanced modelling capability benefit is based on 1GW of capacity procured multiplied by the clearing price of the auction.

This was originally assumed to be £17.08/kW/per year and has increased significantly over the period due to the increases in the clearing prices of the auctions as shown in the End of Scheme view table below This is the only assumption that has changed compared with the original CBA for the modelling.

Key RIIO-2 Deliverables and progress

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

Deliverable	Status of associated milestones
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	88% complete 12% delayed – external reasons

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

Deliverable	Status of associated milestones
D5.1.1 Continuation of EMR Delivery Body obligations	50% complete 50% delayed - internal reasons
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	57% complete 43% no longer valid

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

Deliverable	Status of associated milestones
D5.2 IT system to allow all participants in ESO markets (including CM and CfD) a single point of access for services and data	67% complete 33% delayed internal reason

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

Deliverable	Status of associated milestones
D5.3 Use of enhanced modelling and more granular data sets to improve security of supply modelling.	100% complete

Forecasted benefits

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

TOTAL	**0**	**18.6**	**18.6**	**18.6**	**18.6**	**74.5**

End of Scheme view:

Benefits £ millions	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Enhanced modelling capability	0	60	22.5	22.5	22.5	127.5
Reduced barriers to entry and cost of participation	0	0	0	2.2	2.2	4.4
Total	0	60	22.5	24	24	131.9

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 was 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 were reflected in the 2022 Electricity Capacity Report in Q1 2022-23.

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.	Year 1 of BP1: Forecast accuracy 6.6% for T-1 (below expectations), and forecast accuracy of 3.8% for T-4 (below expectations) Year 2 of BP1: Forecast accuracy 0.4% for T-1 (meeting expectations), and forecast accuracy of 2.2% for T-4 (meeting expectations)

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.

Assumption	Present	Commentary
Clearing price of the T-4 Capacity Market is £17.08/kW per year	In progress	The average clearing price of all the T-4 Capacity Market auctions has increased to £22.48/kW per year (this includes the T-3 auction for 2022-23 that was held instead of a T-4 auction) The clearing price for the 2023 T-4 Capacity Market auction for delivery in 2026/27 was £60/kW. We have used the actual clearing price for 2022/23 and an updated average for subsequent years in the RIIO-2 period.
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 2021-22 and 2022-23 to inform recommendations in the 2022 and 2023 Electricity Capacity Reports. Concerns on delivery assurance (as covered in our Reports) have placed upward pressure on targets, but we believe our modelling enhancements are such that the balance of risk vs cost remains appropriate for consumers. BEIS' independent Panel of Technical Experts (PTE) have continued to support our modelling and recommendations. The PTE have publicly stated in their report that: "We note that National Grid ESO would bear some of the loss of reputation for any blackouts, and bears none of the costs of over procurement, and so could be expected to weight the possible risks of procuring less capacity more than they might credit the cost-savings. The PTE, however, has no evidence that would make us believe that National Grid ESO has substantially exploited its privileged position and hence there has been no conflict of interest concern up to the time of writing this report." We therefore consider that our modelling enhancements have saved over-procuring of capacity.
Benefits delivered from year two of RIIO-2 Third parties will engage in the single markets platform	In progress	Our original CBA stated that benefits associated with activity A5 will start to be delivered from 2022-23. First release of new EMR portal went live in March 2022. However, we have experienced delays in the new portal project. Having engaged and agreed with the stakeholders and customers, we have re-planned the project and currently aim to launch the new portal by Q1 FY25. As such the associated benefits would be materialised from then.

To fully realise the 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.

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
Summary	We hope to deliver £10m gross benefits and an NPV of £4m over RIIO-2 in line with the BP1 assumptions. Although some of the work has been deprioritised as explained below, we still expect to deliver some of the benefits in 2024-25 and 2025-26 as per BP1 through the digitalisation of the codes. However, further benefits from the Alignment, Simplification and Rationalisation of the codes are heavily reliant on pending decisions around energy code reform. The Digitalised Whole System Grid Code (dWSGC) project is divided into 3 sections: Digitalisation, Alignment Simplification and Rationalisation (ASR), and Training and Guidance. After conversations with Ofgem and wider industry it was determined that in the face of the post covid world and the cost of living crisis the ASR workstream should be de-prioritised, as significant ASR work had already been undertaken on section OC2 of the grid code, and the dWSGC Steering group determined that we should continue to look at improving OC2 as best as we could given the lack of external engagement due to the de-prioritisation. . The steering group will then weigh the evidence and make a decision on what to do next pending any new information from Ofgem on the Energy Code Review. Due to the deprioritising of the project, we have not recruited a team to deliver this (as was in the original plan), but instead run it with 1 FTE as part of the wider grid code team. Digitalisation of the technical code will continue to run through a Digitalisation lead. On 1 April 2023 we assigned the lead to run on an initial six month secondment basis with a view to making the role a permanent one when we have an agreed plan for the wider code digitalisation project. We have engaged with the steering group on digitisation and conducted some initial stakeholder engagement workshops to ensure we know what we are going to deliver is at least the minimum viable product The Training and Guidance workstream is effectively waiting for the other two projects to deliver so that it can determine how best to upskill industry in all of the changes this project will eventually bring.
Calculation of monetary benefit to consumers	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

Levels of new entrants to the industry are lower now than when this CBA was completed, and the steering group highlighted this in their decision to delay.

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 of associated milestones
D6.5 The Grid code combines transmission and distribution codes in an IT system with AI-enabled navigation and, document and workflow management tools.	66% complete 33% delayed – external reasons

Forecasted benefits

Forecasted in original CBA:

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Digitised Grid Code	-	-	-	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	See RRE 2B in Demonstration of Plan Benefits section

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.

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	Although facing a delay we still think 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	We believe this benefit will now be delayed due to de prioritisation

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
Summary	The benefits for A6.6 have now been re-quantified and will be delivered in BP2 under A6.7 as part of the on-going fixed BSUoS tariff management. We now expect to deliver an NPV of £68m which is £212m lower than the BP1 figure of £280m. BSUoS reform has now been 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 final approval came on 15 December 2022, which was later than expected in the original plan. The approval by the Panel and Ofgem was a necessary step for ESO to commission and begin work on these changes. The approval process included new analysis, commissioned by Ofgem, to support their assessment of these modification for approval has been used to update the CBA. This 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, moving the benefit timeline onwards. 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. We were very active in the workgroups for these modifications, developing proposed solutions for these modifications following engagement with industry and Ofgem.
Calculation of monetary benefit to consumers	Moving to a fixed tariff allows suppliers to price contracts with a reduced risk premia as their BSUoS costs are less volatile. This reduction should be passed through to consumers.

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

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).
- Even once BSUoS tariffs are fixed, there remains a 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.

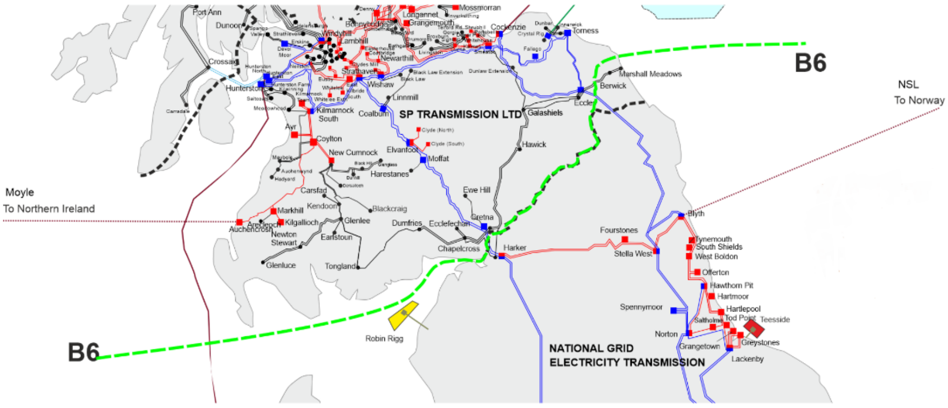
Consumer benefit case study for Role 2 B6 Constraint Management Intertrip Service

Activity

Background:

Renewable electricity generation has more than doubled in the last decade. Much of this has been delivered through windfarms. Due to its geographical advantages, Scotland has seen particularly strong growth in wind generation.

On windy days, the electricity generated by Scotland’s windfarms flows south to satisfy the demand in England and Wales. However, there is a limit to the amount of electricity that the network can safely transmit across the Scottish/English (B6) boundary (this network bottleneck is called a ’constraint’).



The Problem:

Every day our Network Access Planning team forecasts the amount of electrical transmission capacity available to transport generation across the boundary. If they determine that there is a constraint risk, our Control Room will pre-emptively instruct Scottish generators to stop or lower their generation output.

This means that we pay to both curtail green energy from windfarms and to replace it with gas fuelled generation. As a result, there is less green electricity generation on the system and more electricity from carbon-based sources. The Constraint Management Pathfinder (CMP) team was formed in August 2020 with the aim of reducing this issue.

The Service:

The service has been designed as a post-fault intertrip service, which means that generators are rapidly disconnected from the Transmission System if there is a network fault. This lowers the risk to the Transmission Network as the system is rapidly secured and allows the Control Room to transmit more power over the constraint pre-fault.

Contracts:

The team awarded the first annual CMP contracts in 2021, with a service start date of October 2023 until September 2024 (to allow time to build the intertrip connections). Six units already had intertrip schemes in place, so these contracts were able to start early as ‘Interim’ contracts in April 2022.

The team recently awarded the second round of constraint management contracts for service delivery from October 2024 until September 25.

Next Steps:

The next iteration of the service is currently being designed by taking lessons learnt from the previous tenders and further developing the design of the service to ensure that it meets the needs of the system and maximises consumer value.

To reflect the service’s somewhat established position, the service has been renamed the ‘Constraint Management Intertrip Service’ (CMIS).

	Communication: The team communicate updates on a regular basis to the Industry through Press Releases, the Future of Balancing Services Newsletters, the Strategic Network Development Newsletters, Webinars, and Renewable UK Wind Advisory Group meetings.
Role	Role 2
ESO Ambitions	• An electricity system that can operate carbon free • Competition Everywhere
Key RIIO-2 Deliverables	D8.1 - New areas of need identified, and 3-6 tenders run
Is the consumer benefit mainly this year or in future years?	We have awarded contracts for two yearlong services, which will run from October 2023 until September 2024 and October 2024 until September 2025. The early ‘Interim’ service first went live in April 2022, and it saved £80.3m in the first ten months. We have therefore forecasted a final saving of £96m for FY22/23. Savings are expected to continue once the remaining contracts go live in October 2023.
Calculation of monetary benefit to consumers	**Total estimated benefit:** Apr 2022 – Sep 2025: £226.3 - £256.3m **‘Interim’ Actual:** Apr 2022- Jan 2023: £80.3m **‘Interim’ Forecast:** Feb 2023 – Mar 2023: £16m – (used an average £8m a month from the live 10 months) Apr 2023 – Sep 2023: £20-£30m – (halved the Oct 2023 - Sep 2024 forecast) **Service Forecast:** Oct 2023 – Sep 2024: £40-£60m Oct 2024 – Sep 2025: £70m *Calculations in Assumption section below
Assumptions made in calculating monetary benefit	**Benefits Formula** The benefits are calculated using this formula: *Cost saving = (Cost of alternative BOAs that would have been taken in the BM if the I/T had not been armed) – (cost of arming the I/T)* • BOA – Bid Offer Acceptance • BM – Balancing Mechanism • I/T - Intertrip • Cost of intertrip arming = hours of arming * arming fee in £/hr **Interim Benefits Calculation** The ‘Interim’ benefits were therefore calculated using the formula and the following data:

Cost of alternative BOAs that would have been taken if the intertrip had not been armed:

1. MWh of avoided curtailment for that unit between Apr22 and Jan 23 = {Total hours a unit was armed} * {65% (expected unit generation when armed)} * {TEC Registered MWs}
2. Total MWh Available for Service = 355kMWhr
3. Cost of replacing 355kMWh with BOA actions = {Proxy BOA price for CCGTs} * 355MWh = £89.7m.

Cost of arming the I/T

1. Amount paid to windfarms for arming = £9.4m

Cost Saving:

1. £89.7m - £9.4m = £80.3m savings

Interim Benefits Calculation Limitations

1. The methodology only looks at one constraint in isolation

Service Forecast Benefits Calculation

The Service Forecast was created using the formula and the following data:

1. The effectiveness of the intertrip on raising the constraint limit, which is determined by power flow studies i.e. if 800MW of generation to intertrip is armed, there is a 200MW increase in the constraint limit, then the Intertrip is 25% effective.
2. Total MW volume of generation than can be armed to the intertrip
3. The constraint limit without the arming of the intertrip – this can be determined from the 24 month constraint limit forecast.
4. Typical generation running patterns and demand level for Summer and Winter, within the constraint boundary

Typical Bid and Offer prices

Forecasted Benefit Calculation Limitations

1. The methodology only looks at one constraint in isolation
2. The actual wind output will vary against the forecast, which will affect the constraint and usage of the intertrip.

Due to the limitations the savings forecasts have a margin of error of +/-30%.

How benefit is realised in the consumer bill

Reduction in BSUoS costs, as windfarms will not be paid by Balancing Mechanism to lower generation, and gas generators will not be paid to replace this generation.

These are value-add benefits, rather than hard benefits. This means that the benefit is in the form of money which would otherwise have been spent if the service had not been created.

Non-monetary benefits

In the first ten months (Apr 22 – Jan 23) there was a CO2 saving of approximately 139,924 tonnes.

The service will continue to reduce the production of CO2 while the service is live, but the amount will vary depending on the level of wind, and therefore constraints, that occur each month.

Assumptions made in calculating non-monetary benefit	The benefit has been determined by calculating the MW of electricity that would have been produced from carbon-based generators, rather than from renewable generators, if the service did not exist.

Regularly Reported Evidence

Table: Summary of RREs for Role 2

Most RREs don't have performance benchmarks, with the exception of 2C and 2D which are reported annually.

2021-22

RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
2B	Diversity of service providers	n/a	See 2B section below for details											
2C	RRE 2C EMR Decision Quality	#	1.6 overturned themes per 1,000 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%: ● below expectations											
2E	Accuracy of Forecasts for Charge Setting (TNUoS)	%	Actual total TNUoS revenue for 2022/23 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%

2022-23

RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
2B	Diversity of service providers	n/a	See 2B section below for details											
2C	RRE 2C EMR Decision Quality	#	0 Overturned themes per 1,000 applications ● exceeding expectations											
2D	RRE 2D EMR Demand Forecasting Accuracy	%	T-1 forecast accuracy of 0.4%: ● exceeding expectations T-4 forecast accuracy of 2.2%: ● exceeding expectations											
2E	Accuracy of Forecasts for Charge Setting (TNUoS)	%	Actual total TNUoS revenue for 2022/23 is within 0.5% of the budget											
	Accuracy of Forecasts for Charge Setting (BSUoS)	%	106%	32%	17%	2.4%	30%	49%	4%	11%	2%	40%	29%	52%

RRE 2B Diversity of Service Providers

April 2021 – March 2023 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).

We report on the following services:

- Frequency Response (MFR, EFR, FFR, Dynamic Containment, Dynamic Regulation, Dynamic Moderation)
- 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.

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	
	Dynamic Containment	
	Dynamic Regulation	
	Dynamic Moderation	
	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 the total volume of pre-qualified units that are eligible to take part in the day ahead tenders. Not all prequalified units will win day ahead tenders.
	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.

Graph: Two-year view of total contracted volumes by service type by quarter

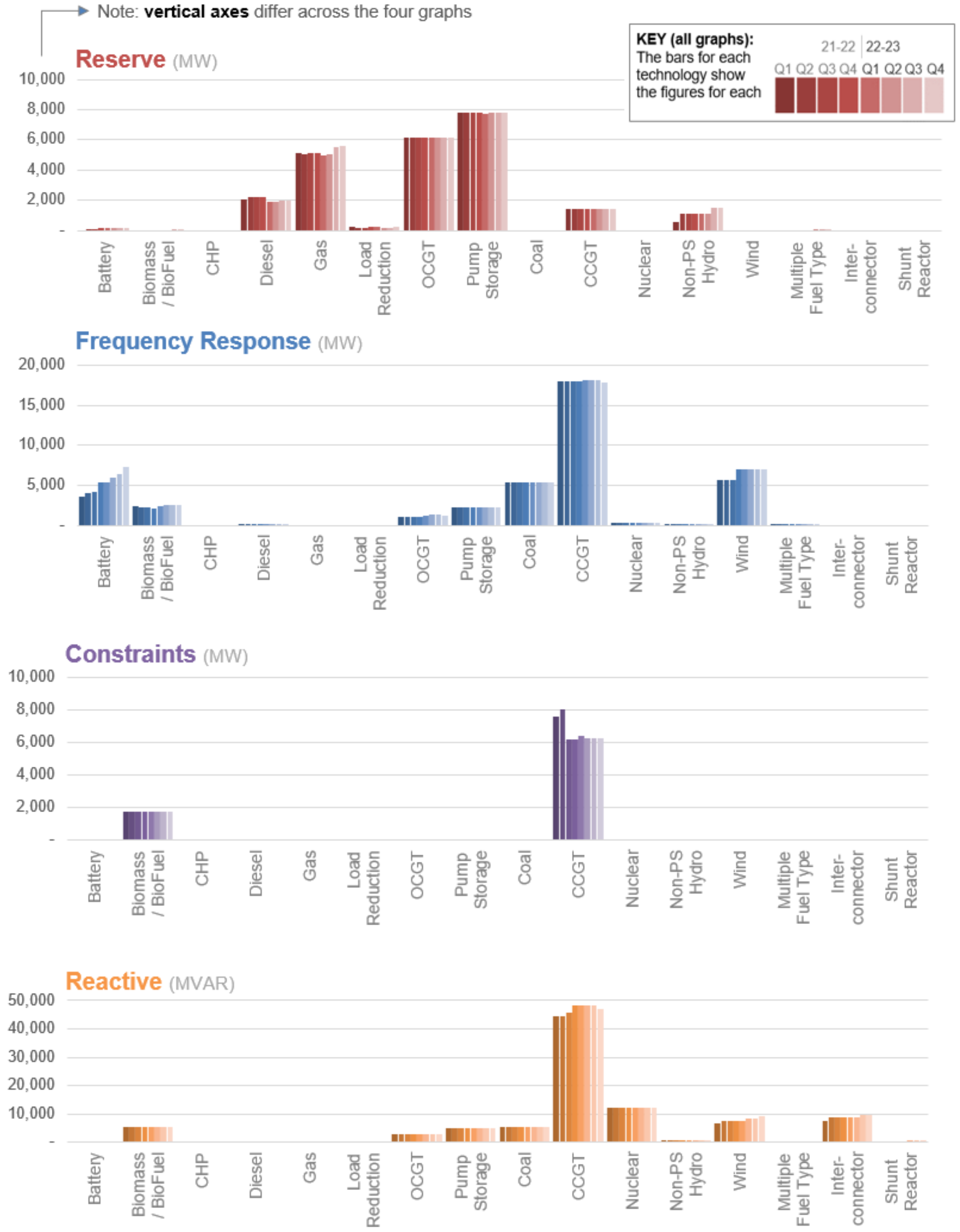


Table: Two-year view of monthly contracted volumes provided to the ESO by service type

Reserve

				2021-22				2022-23					
MWs	Jan-23	Feb-23	Mar-23	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021-22	2022-23
Total	8,331	8,331	8,331	23,360	24,001	24,143	24,276	23,576	23,731	24,860	24,993	95,781	97,160
Battery	45	45	45	-	60	74	135	134	135	135	135	269	539
Biomass/BioFuel	20	20	20	-	-	-	-	-	-	60	60	-	120
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	670	670	670	2,063	2,182	2,205	2,217	1,890	1,864	2,009	2,010	8,668	7,773
Gas	1,860	1,860	1,860	5,085	5,073	5,133	5,133	4,964	5,031	5,508	5,580	20,424	21,083
Load Reduction	85	85	85	216	150	195	255	225	150	195	255	816	825
OCGT	2,061	2,061	2,061	6,183	6,183	6,183	6,183	6,117	6,183	6,183	6,183	24,732	24,666
Pump Storage	2,600	2,600	2,600	7,800	7,800	7,800	7,800	7,716	7,800	7,800	7,800	31,200	31,116
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	481	481	481	1,437	1,437	1,437	1,437	1,427	1,443	1,443	1,443	5,748	5,756
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	506	506	506	576	1,116	1,116	1,116	1,104	1,116	1,518	1,518	3,924	5,256
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	3	3	3	-	-	-	-	-	9	9	9	-	27
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-

Frequency Response

				2021-22				2022-23					
MWs	Jan-23	Feb-23	Mar-23	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021-22	2022-23
Total	14,683	14,784	14,695	39,001	39,296	39,343	41,967	42,282	43,150	43,465	44,162	159,607	173,059
Battery	2,394	2,486	2,395	3,644	3,979	4,126	5,336	5,382	5,986	6,363	7,275	17,085	25,006
Biomass/BioFuel	837	837	837	2,375	2,319	2,191	2,151	2,351	2,511	2,491	2,511	9,036	9,864
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	56	56	58	130	130	192	188	183	147	142	170	640	642
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	373	443	443	1,119	1,119	1,119	1,119	1,189	1,329	1,329	1,259	4,476	5,106
Pump Storage	728	728	728	2,184	2,184	2,184	2,184	2,184	2,184	2,184	2,184	8,736	8,736
Coal	1,782	1,782	1,782	5,346	5,346	5,346	5,346	5,346	5,346	5,346	5,346	21,384	21,384
CCGT	5,999	5,938	5,938	17,997	17,997	17,997	18,047	18,072	18,072	18,072	17,875	72,038	72,091
Nuclear	92	92	92	276	276	276	276	276	276	276	276	1,104	1,104
Non-PS Hydro	70	70	70	210	210	210	210	210	210	210	210	840	840
Wind	2,343	2,343	2,343	5,643	5,643	5,617	7,029	7,029	7,029	7,029	7,029	23,932	28,116
Multiple Fuel Type	9	9	9	77	93	85	81	60	60	23	27	336	170
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-

Constraints

				2021-22				2022-23					
MWs	Jan-23	Feb-23	Mar-23	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2021-22	2022-23
Total	2,705	2,705	2,705	9,499	9,863	8,055	8,055	8,309	8,115	8,115	8,115	35,472	32,654
Battery	-	-	-	-	-	-	-	-	-	-	-	-	-
Biomass/BioFuel	595	595	595	1,785	1,785	1,785	1,785	1,785	1,785	1,785	1,785	7,140	7,140
CHP	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-	-	-	-	-
Pump Storage	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	2,095	2,095	2,095	7,645	8,070	6,225	6,225	6,455	6,285	6,285	6,285	28,165	25,310
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	15	15	15	69	8	45	45	69	45	45	45	167	204
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-	-

Reactive

					2021-22				2022-23						
MVARs	Jan-23	Feb-23	Mar-23		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		2021-22	2022-23
Total	32,424	32,424	32,424		**89,467**	**91,602**	**92,938**	**95,661**	**96,155**	**97,146**	**98,136**	**97,272**		**369,668**	**388,709**
Battery	16	16	16		-	-	-	-	-	-	-	**48**		-	**48**
Biomass / BioFuel	1,734	1,734	1,734		**5,202**	**5,202**	**5,202**	**5,202**	**5,202**	**5,202**	**5,202**	**5,202**		**20,808**	**20,808**
CHP	-	-	-		-	-	-	-	**70**	-	-	-		-	**70**
Diesel	-	-	-		-	-	-	-	-	-	-	-		-	-
Gas	-	-	-		-	-	-	-	-	-	-	-		-	-
Load Reduction	-	-	-		-	-	-	-	-	-	-	-		-	-
OCGT	928	928	928		**2,901**	**2,901**	**2,901**	**2,901**	**2,901**	**2,901**	**2,901**	**2,784**		**11,604**	**11,487**
Pump Storage	1,630	1,630	1,630		**4,890**	**4,890**	**4,890**	**4,890**	**4,890**	**4,890**	**4,890**	**4,890**		**19,560**	**19,560**
Coal	1,731	1,731	1,731		**5,193**	**5,193**	**5,193**	**5,193**	**5,193**	**5,193**	**5,193**	**5,193**		**20,772**	**20,772**
CCGT	15,628	15,628	15,628		**44,496**	**44,496**	**45,820**	**48,468**	**48,492**	**48,492**	**48,492**	**46,884**		**183,280**	**192,360**
Nuclear	4,095	4,095	4,095		**12,285**	**12,285**	**12,285**	**12,285**	**12,285**	**12,285**	**12,285**	**12,285**		**49,140**	**49,140**
Non-PS Hydro	189	189	189		**567**	**567**	**567**	**567**	**567**	**567**	**567**	**567**		**2,268**	**2,268**
Wind	3,025	3,025	3,025		**6,576**	**7,311**	**7,323**	**7,398**	**7,398**	**8,259**	**8,229**	**9,075**		**28,608**	**32,961**
Multiple Fuel Type	-	-	-		-	-	-	-	-	-	-	-		-	-
Interconnector	3,248	3,248	3,248	-	7,357	8,757	8,757	8,757	8,757	8,757	9,777	9,744	-	33,628	37,035
Shunt Reactor	200	200	200		-	-	-	-	**400**	**600**	**600**	**600**		-	**2,200**

Supporting information

Reserve

The STOR service transitioned to ‘day ahead’ procurement from 1 April 2021, to align with the requirements of the Clean Energy Package. Throughout the last 2 years STOR has remained a very liquid market with a total of 213 separate units prequalified (122 non-BM and 91 BM) providing a total of 7.2GW of generation and 187MW of demand reduction capability. Each day we see between 50 and 100 units bidding in offering well in excess of the daily required volume of STOR ~1400MW.

The STOR market remains dominated by traditional thermal forms of generation. Open-cycle gas turbines (OCGT) and gas reciprocating engines provide the majority of capacity, with the remainder taken up with Combined-cycle Gas Turbine (CCGT), diesel generators and demand reducers.

For Fast Reserve, we only procure the optional service where a small number of NBM gas plant and a single (aggregated) Customer Load Active System Services (CLASS) unit meet the daily requirement through the within day arming/dispatch process.

With the future reserve products expected to come online towards the end of 2023 (initially in parallel with STOR and Fast Reserve), with 1MW minimum requirement, shorter more frequent service windows and a quick (2 mins) and slow (15 mins) response time, we would expect to see new technologies and smaller plant entering the reserve market.

Frequency Response

Since April 2021 frequency services have grown with the introduction of the Dynamic Moderation (DM) and Regulation (DR) services which followed the launch of Dynamic Containment (DC) service in October 2020. The DC, DM and DR services are procured on a day ahead / pay as cleared basis to comply with Clean Energy Package and EBGL legislation as well as providing providers with more tendering opportunities. Since the introduction of DC, DM and DR services the liquidity of these markets has grown with 100+ pre-qualified units providing 2.4GW of response, these are a mix of BM and Non-BM. The DC, DM and DR markets are dominated by Battery Storage assets which are mainly DNO connected although there is an increase in Transmission connections

During this period we have continued to procure Dynamic (DFFR) and Static (SFFR) FFR through the monthly tenders. Since April 2021 the MW requirement for DFFR has reduced as the newer frequency product markets have established. This reduction of DFFR requirement will continue until the DFFR service is phased out during 2023. During this period the requirement for procured SFFR has increased with volumes now at 250MW each month, which is due to continue as the procurement of this service moves from monthly tendering to day ahead tendering from 1st April 2023.

2021-23 has seen a continued increase of assets participating in Frequency tenders and we expect this trend to continue going forward particularly as increased stacking of services is rolled out in 2023

December 2021 saw the conclusion of the successful trial of the EPEX auction platform to procure Dynamic High Low and Low frequency Static services on a week ahead basis. As a result of this trial we used the EPEX auction platform for day ahead procurement of DC DM and DR services.

Constraints

Constraint costs occur when we pay 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 and by requiring providers to change their MW generation levels, with most Constraint actions being taken in the Balancing Mechanism.

The Constraint Management Intertrip Service (CMIS), previously known as Constraint Management Pathfinder, reduces the actions required by the ENCC to manage the constraint across the B6 (SCOTEX) boundary. The CMIS was a brand-new and much-needed service, and the Pathfinders 'learning by doing' approach has been crucial in establishing the service quickly, whilst simultaneously developing the best possible technology agnostic solution. The approach promoted collaboration with the Industry, Ofgem, and multidisciplinary ESO teams to create a workable solution and furthermore, to flex the service requirements as live service data was analysed.

The technology that is part of the B6 CMIS is mainly wind farms with one battery energy storage system, and these contracts will provide the service October 2023 – September 2024. Six units (all windfarms) were able to start delivering the service earlier than their contracted start date (October 2023) in April 2022.

Reactive

The reactive power service is delivered primarily by providers who have Mandatory Service Agreements (MSA) and are typically connected to the Transmission Network. These providers would also be in the Balancing Mechanism. The launch of the Voltage Pathfinders has proven that distribution network providers can also be effective to meet a transmission requirement if located in the area of need.

Traditionally those providers who have MSAs are CCGT, OCGT, Hydro, Wind, Nuclear and other conventional technology types, however during this past BP1 period we received a great deal of interest from other technologies such as Battery Energy Storage Systems (BESS) and have started to sign MSAs with BESS providers, with many more of these in the pipeline, and we expect to have significant volumes in BP2. There has also been a considerable growth of Interconnector capability during this timeframe. At the start of April 21, we had approx 1.5GVAr of capability and this has grown to approx 3.7GVAr in Feb 23.

Prior to the launch of the Long-Term Mersey Pathfinder, we ran a Short-Term tender for services in the Mersey region for delivery from April 2021-March 2022. The outcome of the tender concluded, and we contracted with a distribution connected CHP provider Inovyn who provided 70MVAr and an optional contract with Rocksavage Power Station. The PeakGen shunt reactor service went live in Q1 2022-23, and the Zenobe Battery started delivering in Q4 2022-23 in the Mersey region. In January 2022 we also awarded contracts to NGET and Dogger Bank C Offshore windfarm to meet reactive needs in the Pennines region that are due to commence in 2024.

RRE 2C Electricity Market Reform (EMR) Decision Quality

April 2021 – March 2023 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: Two-year view of EMR Decision Quality

Period	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
Year 1 (2021-22)	1,234	2	1.6	●
Year 2 (2022-23)	1,281	0	0	●

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

Performance benchmarks (Year 2)

- ● **Exceeding expectations:** <1.3 overturned themes per 1,000 applications
- ● **Meeting expectations:** 1.3 to 1.5 overturned themes per 1,000 applications
- ● **Below expectations:** >1.5 overturned themes per 1,000 applications

Supporting information

During BP1, the number of overturns has significantly reduced due to the work we have done with the government, Ofgem and customers to clarify the Capacity Market rules as well as the enhanced levels of customer service provided by the Delivery Body.

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 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 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 government and customers and we feel they have improved the overall 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 government in developing the necessary regulatory changes, we produced specific guidance to support our customers in applying the new process which were well received by our customers.

All the improvements work has led to great outcomes of the CM pre-qualification for BP1 period with a noticeable record low number of Tier 2 disputes to Ofgem for 2022 pre-qualification assessment and for the first time, all our decisions were upheld.

During the BP2 period, in conjunction with our customer user group, we continue to develop the new EMR system that will address key customer’s pain points, enhance the user experience as well as ensure continued compliance with the Regulations and Rules. Furthermore, we will continue to work with the government and Ofgem to provide further clarity on the interpretation of the Regulations and Rules to the industry through the Capacity Market Policy Board and Capacity Market Advisory Board.

These in turn will further improve the application quality and reduce the number of disputes received and improve the credibility of the overall pre-qualification process.

RRE 2D EMR Demand Forecasting Accuracy

April 2021 – March 2023 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[22]. 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

For 2022-23, the accuracy of two forecasts will be measured as follows:

- The T-1 forecast made in 2021-22, for delivery in 2022-23
- The T-4 forecast made in 2018-19, 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: Two-year view of peak demand forecast accuracy

Auction	Forecast made in	Delivery Year	Forecast	Actual	Forecast accuracy	Status
T-1	2020-21	2021-22	43.8 GW	47.3 GW	6.6%	●
T-4	2017-18	2021-22	45.0 GW	47.3 GW	3.8%	●
T-1	2021-22	2022-23	44.4 GW	44.6 GW	0.4%	●
T-4	2018-19	2022-23	45.6 GW	44.6 GW	2.2%	●

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

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[22] National Demand as defined in the Grid Code

Supporting information

2022-23 performance

Our peak demand forecast accuracy for T-1 and T-4 are exceeding expectations in both cases. In both cases, there is a significant improvement in accuracy since the last business plan period. This is mainly due to increased diligence on input data for peak demand and better understanding of the drivers of peak demand. Core modelling has improved but has had a lesser impact. A large part of this improvement is a good set of predictions about how the economy would develop after COVID-19, despite a very wide margin of uncertainty.

Improving data input Quality	We have conducted statistical analysis on our sub-sector (transport, heat etc.) modelling to quantify the inherent uncertainty in different parts of our modelling. This has allowed us to prioritise where to focus our quality checking, scrutiny and stakeholder testing.
Understanding the drivers of peak demand better	We have developed a dynamic dashboard (PowerBI) to visually identify, quantify and explain the constituent components of peak and annual electricity demand. In simple terms, this has allowed us to have more frequent, targeted and clear conversations with our stakeholders to test assumptions and outputs for constituent components of demand before overall peak demand is finalised.
Core modelling improvement	We've reviewed our tools and models to increase standardisation and efficiency of the processes which has allowed us to focus more on areas of uncertainty or data quality issues and ensure that these are minimised in the final forecast The tool/process for aggregating overall peak demand had grown organically over many years and many users. This had made the process inherently inefficient over time with many opportunities to make errors, driving down the overall accuracy of the process. We conducted a thorough risk / root cause analysis for errors in this tool and removed a significant number of potential failure modes. We standardised data layouts and removed redundant or conflicting parts of the process and associated data set. This made the process more reliable overall but also made any results easier to trace and check for quality. Other improvements have also helped improve accuracy, even though they haven't been fully implemented. Ongoing work on improving models for lighting, heat and transport demand have all helped to inform decisions about our assumptions and to quality check our core demand data. We look forward to seeing more benefit from this continued investment in modelling capability.
Accurately predicting world events	Our predictions about how the economy would develop after COVID-19 were generally correct. This was a product of robust research, stakeholder engagement and checking against several benchmarks, including ones purchased specifically for FES. However, making predictions through the amount of volatility we have seen in energy has been difficult for anybody to do with absolute certainty and we acknowledge that we could still have got it wrong, despite our preparation and diligence. We did not foresee the invasion of Ukraine and resulting effects on cost of living when demand modelling was conducted for T-1 and T-4 years, but our scenario framework led us to ask what the credible extremes of change would be. The observed level of consumer behaviour change for 2022-23 and resulting reduction in demand in the face of a cost-of-living crisis was in line with predictions we had made in the Leading the Way scenario, albeit driven by affordability rather than a conscious choice to use energy more efficiently for the sake of the environment.

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

April 2021 – March 2023 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 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: Two-year view of forecast vs. outturn TNUoS Performance

TNUoS charge	Forecast £m		Actual £m		Variance £m		Variance %	
	2021-22	2022-23	2021-22	2022-23	2021-22	2022-23	2021-22	2022-23
NHH Demand	1,619	1,669	1,607	1,556	-12	-143	-0.7%	-8.4%
HH Demand	926	1,053	950	998	24	-55	2.6%	-5.2%
Generation	774	842	744	801	-30	-41	-3.9%	-4.8%
TOTAL	**3,318**	**3,594**	**3,301**	**3,356**	**-18**	**-239**	**-0.5%**	**-5.4%**

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 final available settlement metering.

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

Supporting information

Several events can impact out-turn TNUoS revenue once TNUoS tariffs have been set 14 months earlier. For 2021-22, this was largely the continuing impact of Covid-19. However, for 2022-23, the most obvious recent impact on TNUoS demand has been the continuing impact of the war in Ukraine which has resulted in lower overall demand due to pressure on energy prices. 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 24.96 TWh was assumed at tariff setting for 2022-23, slightly increasing from 24.9 TWh 2021-22 charging base. Actual 2022-23 out-turn NHH demand is 9.7% lower at 22.5 TWh. However, due to slightly more NHH demand in zones with higher tariffs than assumed at tariff setting, out-turn NHH revenue is 8.4% lower than the tariff setting budget. This can be compared with 2021-22 out-turn whereby demand was 0.8% and revenue was 0.7% below expectation.
HH Demand	Considering the relatively small value of HH Embedded Export payments compared to HH Gross Demand, overall actual 2022-23 HH Demand revenue has out-turned at 5.2% below tariff setting budget (compared with 2.6% above for 2021-22). **HH Gross Demand:** • A 2022-23 charging base of 19.4 GW was assumed at tariff setting (2021-22 out-turn was 18.9 GW versus expectation of 18.3 GW), which included an adjustment to reflect the expected impact due to Covid. This compares with actual out-turn at 18.4 GW, a 5.4% decrease below our expectations, resulting in revenue from the HH Gross Demand tariff of £1,013m (5.2% under budget). It is expected that the distribution of actual demand by location varies slightly to our assumptions at tariff setting. **HH Embedded Export** • Following the 2021-22 out-turn of 7.8 GW (13.1% above expectation), a charging base of 7.4 GW was assumed at tariff setting, which compares with actual out-turn at 7.2 GW (3% below expectation). The level of embedded exports is not necessarily driven by demand and therefore not impacted by events such as Covid-19, rather it is influenced by a range of other factors including wind availability. Out-turn credits paid for 2022-23 exports (£16.5m) were 5.5% higher than budget at tariff setting (£15.6m). A similar, albeit more extreme pattern, was seen in 2021-22 (36.9% above budget). For both years, 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 2022-23 tariff setting was 72.4 GW compared to actual TEC invoiced of 71.4 GW. In 2021-22 70.1 GW was expected versus 71.7 GW invoiced due to a small over-recovery of revenue for onshore stations. For both years, the delay of asset transfer for several offshore transmission systems means that offshore tariffs could not be introduced and charged to offshore Generators as early as anticipated when Final tariffs were set. This means that in 2022-23 overall TNUoS Generation revenue is 4.8% less than budget (compared to 3.9% less than budget for 2021-22).

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

April 2021 – March 2023 Performance

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

Graph: Two-year view of monthly BSUoS forecasting performance (Absolute Percentage Error)

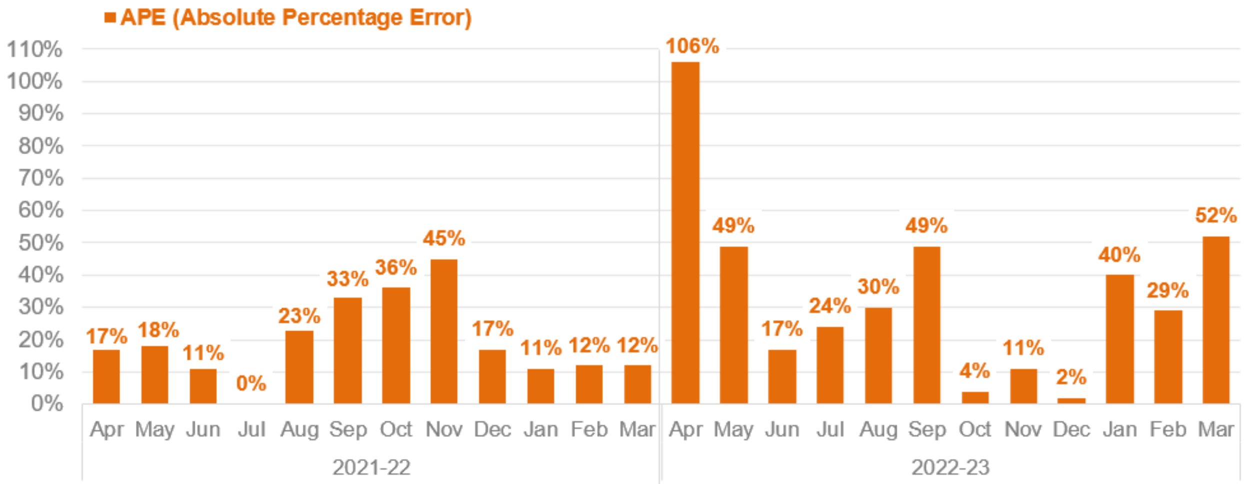

Table: 2021-22 Month ahead forecast vs. outturn BSUoS (£/MWh) Performance

	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) [23]	**17%**	**18%**	**11%**	**0%**	**23%**	**33%**	**36%**	**45%**	**17%**	**11%**	**12%**	**12%**	**20%**

Table: 2022-23 Month ahead forecast vs. outturn BSUoS (£/MWh) Performance

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Actual	5.3	6.0	9.4	10.3	9.2	8.5	12.5	11.7	10.5	8.9	7.5	5.8	n/a
Month-ahead forecast	11.0	9.0	7.7	7.8	11.9	12.7	12.1	13.0	10.3	12.4	9.7	8.8	n/a
APE (Absolute Percentage Error) [24]	**106%**	**49%**	**17%**	**24%**	**30%**	**49%**	**4%**	**11%**	**2%**	**40%**	**29%**	**52%**	**34%**

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[23] 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.

[24] 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.

Supporting information

The BSUoS charge (£/MWh) depends on the total BSUoS cost and the total volume. The BSUoS cost forecast is probabilistic and therefore produces percentile values. The published forecast for each month is based on the central value of the BSUoS cost forecast (50th percentile). If the outturn BSUoS costs are below the 50th percentile of the cost forecast, then we expect the actual BSUoS charge to be lower than the forecast provided the actual volume is at or above the estimate (and vice versa).

Overall performance:

Forecasting BSUoS, particularly the balancing costs element has been very challenging over the last 2 years due to the volatile energy prices seen in the market due to increasing wholesale costs and due to scarcity pricing in periods of tight margins.

Since February 2022, the BSUoS forecast has been produced based on a new updated methodology. The new model is sensitive to the drivers of balancing costs, and so responded to big changes in wholesale electricity prices in a more dynamic way than the previous model. However, given the high volatility in the wholesale electricity price forward markets, the absolute percentage errors were higher for the period using the new model (30%), than the months preceding (21%).

An innovation project is underway with the aim of further improving BSUoS forecasting. In this project, Machine Learning techniques will be implemented to better capture the relationships driving balancing costs and wholesale price volatility. This will complement the methodology utilised in the current forecasting model.

Latest month’s performance - March 2023:

March outturn costs were close to the 15th percentile of the forecast produced at the beginning of February. This is due to two factors: (1) the wholesale electricity prices being 23% lower in outturn (£114/MWh) than the forward market prices available at the beginning of February (£148/MWh) and (2) the renewable proportion of demand being lower in outturn (18%) than the forecast at the beginning of February (31%).

Role 3

System insight, planning and network development

Role 3: System insight, planning and network development

Plan Delivery

- We have completed 185 out of the 234 milestones planned for the two-year period. Of the 49 milestones which are not complete, 4 are delayed in order to deliver an improved outcome for consumers, 19 are no longer valid, 19 are delayed for reasons outside of ESO control, and 7 are ESO-related delays. We have:
- Taken on new projects, such as the Holistic Network Design and Early Competition.
- Delivered >£300m of savings via the SO:TO Optimisation Incentive Scheme.
- Run five Pathfinder projects, opening up new ways for the industry to help us meet system needs.
- Accelerated our connections reform work.
- Included a Grid Forming capability specification in the GB Grid Code.
- Collaborated with TOs to plan system access which has released over 33,000GWh of generation capacity on to the network.

Stakeholder Evidence

Role 3 survey (Mar-23):

- 17% exceeding expectations
- 54% meeting expectations
- 29% below expectations

Highlights:

- Positive comments around our work in Connections namely our approach to the two-step offer process.
- Feedback on how well we effectively collaborate, share information and have open dialogue with our stakeholders.
- Positive comments related to our work on innovation with the support provided by innovation team, planning around the Virtual Energy System and our general openness to innovation all being singled out.
- Positive feedback on our extensive engagement regarding the Future Energy Scenarios.

Value for money

- Our total expenditure for role 3 in BP1 was £121.2m, which was 13.1% lower than the benchmark of £139.4m.
- The main variance is a decrease in spend for Enhanced Frequency Control where we identified that our Dynamic Containment product already provided the necessary requirements. Our NOA enhancements project also saw a decrease in spend due to efficiencies in our modelling.
- These decreases were offset by increases associated with delivering new activities that were not included in our BP1 such as Offshore Coordination, Early Competition and Centralised Strategic Network Plan.

Demonstration of plan benefits

- Network Options Assessment (NOA) enhancements (A8-A11) to deliver net present value benefits of £728m over RIIO-2 with £80m already delivered in BP1.
- Taking a whole electricity system approach to connections (A14) to deliver £18m consumer benefit over RIIO-2 with £3.7m already delivered in BP1.
- Taking a whole energy system approach to promote zero carbon operability (A15) to deliver £1bn consumer benefit over RIIO-2 with £759m already delivered in BP1.
- Delivering consumer benefits from improved network access planning (A16) to deliver £368m consumer benefit over RIIO-2 with £219m already delivered in BP1.
- The Holistic Network Design will deliver overall net consumer savings of approximately £5.5bn. These cost savings are calculated over a 40-year asset life period, starting in 2030

RREs:

- 3A Future savings from operability solutions: i) Saved balancing costs: £726m in the period 2021-26 from new operability measures. ii) Saved infrastructure costs: RDP avoided asset build estimated at £12.9m as per RIIO2 Business Plan. iii) Monetised carbon reductions: Pathfinders: Estimated £5.2bn (2021-22 to 2025-26). RDPs: Estimated £260m (2023-24 to 2025-26).
- 3B Consumer value from the Network Options Assessment (NOA): £1.6bn from ad-hoc CBAs (2021-22 to 2022-23), £1.7bn from LOTI CBAs (2021-22 to 2022-23), NOA consumer benefit £212m (over RIIO-2 period).
- 3C Diversity of technologies considered in NOA processes: 29 asset-based solutions (including 21 new options) and 8 commercial solutions submitted to NOA 2021/22. A wide range of solutions were considered in NOA pathfinder.

C.1 Plan Delivery for Role 3

Deliverable 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 two years of the Business Plan 1 period, a few highlights from role 3 performance are as follows:

Highlights

Offshore coordination and Holistic Network Design (new activities in BP1)

Towards the end of the RIIO-1 period we initiated the Offshore Coordination project with the aim of assessing whether there is a more beneficial way to connect offshore wind to the transmission network than the existing radial approach. The analysis and report we published in RIIO-1 fulfilled the activities that had been included in the RIIO-2 business plan in this area.

BEIS as it was then, established the Offshore Transmission Network Review (OTNR) to ensure that the transmission connections for offshore wind generation are delivered in the most appropriate way, with a view to finding the appropriate balance between environmental, social and economic costs. Since the start of the RIIO-2 period, we have been leading and delivering the parts of the OTNR that are within our remit. This is significantly beyond the original commitment in the RIIO-2 business plan and has seen us play a key role in the OTNR across its four main workstreams.

As part of the 'Pathway to 2030' workstream we agreed to deliver the Holistic Network Design (HND) to enable the connection of 50GW offshore wind by 2030 when combined with offshore wind further advanced in its development. The HND is a first and significant step towards centralised strategic network planning and for the first time in GB and potentially elsewhere, makes recommendations for both connecting the offshore wind to the transmission network and transporting its output to where it will be used. It also brings assessments of the impact on the environment and communities into network planning at a much earlier stage than previously.

We took the lead in delivering of the HND to result in a recommended network design for the 23GW offshore wind within its scope, which we published in July 2022. This involved setting out the new, innovative methodology; rapidly building new capabilities, including on network design and environmental and community assessment; leading other stakeholders through the establishment of the Central Design Group and its subgroups as well as direct engagement; working with the TOs on their inputs; and building new stakeholder relationships, such as with environmental stakeholders. We also quickly became a valued OTNR project partner. For more detail on HND, see our Consumer benefit case study for Role 3 - Holistic Network Design.

We assess that the HND could save consumers a total of £5.5 billion from 2030 onwards, and reduce CO_2 emissions by a total of 2 million tonnes between just 2030 and 2032. It also provided the basis for Ofgem to be able to approve £20 billion of investment through their Accelerated Strategic Transmission Investment (ASTI) process in December 2022.

We are now progressing the second HND (the 'HND follow up exercise' or 'HND2') to make recommendations for the network that is required to connect an additional 24GW offshore wind. We have listened to feedback on HND1 on how the TOs and in-scope developers would like to engage throughout the process, and are taking that into account in the development of HND2. HND2 is progressing well, and we have developed and assessed 152 network designs to connect the in-scope developers. These have now been narrowed down to a shortlist of six and our documentation of the options considered, rationale behind the shortlisted options and why we aren't progressing alternatives shared with in scope developers at the end of March 2023.

We have also made significant progress on other aspects of the OTNR. This includes:

- Identifying codes and standard changes required to enable coordination in the HND and early opportunities projects, with a plan for the code modifications needing raising. Two code modifications have been raised to date, with more planned over the course of this year.
- Supporting developers proposing coordination opportunities in the early opportunities workstream to help them refine and understand the potential benefits of their proposals. In May 2022 we published our Early Opportunities Action Plan summarising our work up to that point and next steps.
- Setting out a programme of work to remove barriers to the progression of multi-purpose interconnectors (MPIs) that are within our remit. This includes establishing and leading a workstream on operability within Ofgem's MPI Framework Discussion Group and contributing to other workstreams.
- Working with the Crown Estate to pilot taking a more coordinated approach to seabed leasing and connection agreements in the Celtic Sea, with a view to establishing an enduring approach under DESNZ's Future Framework.

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 2022, 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.

The B6 Constraint Management Pathfinder (CMP) tender for the delivery year 2024/2025 completed in November 2022. It will reduce 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 have made use of their services in advance of the formal service start in October 2023. The service delivered both cost and carbon reduction value from April 2022. (The consumer benefits are captured in the CMP B6 table of RRE 3A Future savings from Operability Solutions section)

The Stability Pathfinder Phase 2 tender completed in May 2022. 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 winners included batteries with grid forming technology and was the first time such technology had been successful in a competitive tender. This was supported by the development of a Grid Forming minimum specification within the Grid Code. This gave clarity and confidence to potential developers and investors in the submission of these technologies within the Pathfinder tender .(See Grid Forming Capability section)

In November 2022 we concluded the tender for the Stability 3 Pathfinder. This secured contracts for the delivery of 12.7GVA's of SCL and 17.1GW's of inertia between 2025 and 2035. Based on stakeholder feedback from previous tenders, this pathfinder introduced a new approach to the connections process. In collaboration with NGET, and agreement from Ofgem, we introduced the concept of bay reservation. Under this approach the ESO would temporarily reserve substation bays in advance of providers bidding. They could nominate to use these bays if successful in the tender at which point the normal connections process would proceed. This had a number of positive impacts. It reduced the number of speculative providers in the connections queue and hence connections dates were more credible. It reduced the bidder uncertainty and reduced risk premium they needed to apply to their bid. It reduced workload for the ESO and NGET and it meant that the most efficient solution would win rather than the solution that had managed to secure the earliest place in the queue.

Network Options Assessment (NOA) & Centralised Strategic Network Plan (CSNP)

Throughout BP1, we have met our deliverables around the Network Options Assessment. The NOA has continued to assess the reinforcements required for the electricity transmission networks owned by the three onshore Transmission Owners (TOs) and recommends which reinforcement projects should receive investment. We have worked collaboratively with the Transmission Owners throughout the period, to improve and enhance the NOA. We also undertook early work on conceptual offshore wider works in the NOA published in January 2021. We have continued to innovate our NOA methodology each year, including Offshore Wider Works and how we present and communicate our recommendations. The NOA is a well-regarded and recognised piece of analysis, as is recognised as ‘state of the art’ in how it plans network under uncertainty.

In June 2022, we published an additional NOA Refresh, as part of the suite to documents which for the first time produced a Holistic Network Design for connecting 50GW of offshore wind by 2030, in line with the government ambition.

We have continued to go beyond the expectation of BP1 in how we have used our expertise in network planning to shape the future for net zero. We have worked with DESNZ on hydrogen, CCUS and nuclear siting strategies – considering the impact of proposed new connections on the transmission network. We have worked with Ofgem in delivering analysis to support the Interconnector Cap and Floor round. We are working collaboratively with The Crown Estate Scotland and the Marine Management Organisation on strategic seabed leasing to bring together and inform further offshore decisions, given the impact onshore.

Further, and completely new for BP1, we have made significant progress in the development of the Centralised Strategic Network Plan (CSNP). Recognising that the NOA needs to change to become more strategic and anticipatory, if we hope to deliver net zero, and building on the strong foundations of the Holistic Network Design, we are leading work to define a new approach to planning from 2024 onwards. Our approach has been to engage a wide range of industry stakeholders to help to shape and understand the issues of the current processes, and to define a forward looking strategic plan for electricity transmission infrastructure. Furthermore, we are also considering how methane gas, hydrogen and cross-vector planning could fit in to this framework as part of the transition to FSO.

Grid Forming Capability (new activity in BP1)

In 2019-2022, ESO successfully established and led the GC0137 Expert Group of ~40 global members to develop the GC0137 Legal Text “Minimum Specification Required for Provision of GB Grid Forming (GBGF) Capability”. It was approved by Ofgem in January 2022, making the GB Grid Code the world’s first TSO to include a Technical Specification for Grid Forming. The work continued to evolve when we successfully built and led a new GB Grid Forming Best Practice Group (GBGF BPG), including experts across 50+ organisations in the UK and wider, to provide necessary guidance on the GC0137 Legal Text as well as capture suggestions for future Grid Code modification into the documented GB Grid Forming Best Practice Guide. This document was published in April 2023.

Furthermore, ESO have been the world-first to have successfully procured long term service contracts with Grid Forming converter technologies in ESO’s Stability Pathfinder in Scotland. As a conclusion of a competitive tender process, in April 2022, ESO signed contracts with five GFM solutions (around £60m investment in total over 10 years) across multiple locations in Scotland to boost our stability needs with delivery from 2024. This is a significant milestone for ESO to be able to operate a Zero Carbon system in 2025 and beyond.

Regional Development Programmes (RDPs) and Whole System

The first two RDPs, with UKPN and NGED, are now in delivery and we forecast that they will have facilitated the connection of around 2GW of Distributed Energy Resource (DER) at 13 GSPs in the south of England.

We are expecting the remaining N-3 intertripping works to conclude within the next quarter, with the NGED system to go-live in May 2023. The NGED system will introduce a DER intertripping scheme in the South West of England with a potential capacity of 1.3GW of DER by the end of 2023. This will help facilitate transmission outages in this region and will be followed by a similar system with SSE-N in June 2023.

Despite some delays associated with communications systems, the first MW Dispatch project with NGED has proceeded well. This project will allow DER in the South West of England to provide constraint management services to the ESO similar to a BM party. This will help lower operational costs in this part of the system.

The overall project initiation document was agreed and published in 2021. Since then, we have agreed a tri-partite framework agreement with NGED and service providers after a number of successful webinars, and the registration functionality is now built into the ESO’s Single Market Platform. We are expecting this service to go live in summer 2023.

The second MW Dispatch Service with UKPN is taking a consistent form to the NGED model. Its Project Initiation Document has been agreed and is now published on our website. The ESO functionality is consistent with the NGED project, and a high speed data link already exists with the UKPN control centre. We are therefore anticipating a fast delivery, hopefully later this calendar year.

We have also worked with UKPN on new systems and methodologies to get DER connected more quickly in East Anglia. This has required the existing Inter Control Centre Protocol (ICCP) links to be extended into UKPN's Eastern region which is now in final commissioning. We have also agreed new system with both UKPN and NGET to facilitate interim non-firm connection of DER at certain Grid Supply Points (GSPs) ahead of enabling reinforcement works.

Learnings from all these projects are shared with all GB DNOs and TOs through our dedicated Whole Electricity System joint forum. This ensures consistent development of projects across GB and has been recently supported by our paper describing the MW Dispatch service details including visibility and control requirements.

Transmission Constraints 5-point Plan

In February 2021, we launched our five point plan for transmission constraints. Through our NOA process we identified that over the coming years, as more onshore and offshore zero carbon generation connects to the system in the north and east of Britain, constraint costs (particularly for the movement of power from north to south) are likely to increase. We wanted to explore ways we can start to introduce new mechanisms, markets or approaches that aim to reduce the congestion costs ahead of new boundary reinforcements. We did this through targeting 5 areas, our work on these completed by May 2022.

1.	Cost forecasting	We identified that introducing cost forecasting of our constraints actions and wider BSUoS charges could increase transparency, decision making and support wider discussions around the costs. During the time period we built a new team to focus on constraint forecasting. We started publishing a rolling 24 month forecast for Constraint limits on the ESO Data portal in December 2021. Using these limits we have produced a corresponding 24 month constraint cost forecast. The constraint forecasts are included in the monthly BSUoS forecast and now feeds into the fixed BSUoS Tariff.
2.	Increasing existing capability	We have put in place a new competitively tendered intertrip service for the B6 constraint. This increases the capability of the boundary by paying generators to be ready to disconnect from the system in the event of a fault. This required working across providers and the Transmission Owners to deliver a service. The service went live in April 2022 and has so far saved over £80m in constraint costs. For more detail on the B6 Constraint Management Pathfinder (CMP) tender , please see the Pathfinders section above, and our CBA: Network Options Assessment (NOA) enhancements (A8-A11).
3.	Local Constraint Market	We have now released a tactical solution to help manage growing constraints in Scotland by harnessing more flexible energy assets and mitigate some of GB's highest-cost boundary constraints. Trials of the new Local Constraint Market (LCM) are now open to Distributed Energy Resources (DER) above our Anglo-Scottish (B6) boundary and will improve competition to the Balancing Mechanism. We have expedited LCM delivery using an agile approach by adapting an existing energy market platform. Extensive consultation with market stakeholders (conducted over three rounds, touching over 50 flex providers) has helped ESO shape the service design to industry needs: the traditional minimum unit size (1 MW) has been eliminated in order to allow much smaller assets to participate. LCM will use readily accessible market approaches and day-to-day actions enable close collaboration with our DNO partners. We have also gained consent to list LCM in the C16 Relevant Balancing Services statement to bring industry benefits to ABSVD participants. With Trials now open (https://picloflex.com/dashboard) and set to grow in 2023 the project remains on track to facilitate an accelerated DER market for targeted constraint management in Scotland.

4.	Storage for constraints	We wanted to confirm if storage would be useful to manage constraints and commissioned an independent piece of work to verify this. It found that storage operating exclusively to provide constraint management would get low utilisation and is unlikely to be cost effective. Stacking constraint management with other services is possible, but this is unlikely to deliver high utilisation in very constrained locations. We confirmed that we will continue working with storage companies to understand and remove any barriers to them competing with other technologies to provide services. Overall, we will not seek long-term, bilateral contracts with storage companies exclusively for constraint management
5.	TO Solutions	We wanted to work with Transmission owners to see what other options could be deployed to reduce constraints. Working as part of the Joint Planning Committee-Investment planning we identified two key routes. Accelerating Infrastructure (EISD advancement) and Outage optimisation. 5 reinforcement options were identified which could save approx. £2.5bn of constraint costs by being advanced by 1 year. 4 schemes outages were identified as being suitable for co-ordination realising savings of £1.4bn. We have continued to deploy this thinking and applied a similar methodology to support the recent Ofgem ASTI (acceleration of Strategic Investment) Analysis.

The additional part to the plan was through our system optimisation activities related to network access planning which are included later under Outage Optimisation and System Operator: Transmission Owner (SO: TO) Optimisation incentives scheme sections.

Future Energy Scenarios (FES)

FES 2021	In the first year of BP1, we published our FES 2021 in July of that year with an online launch event in the same month. 570 stakeholders either joined the event or watched 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.
FES 2022	The Future Energy Scenarios (FES 2022) sets out credible ways that the UK can achieve Net Zero by 2050, as well as the UK Government's commitment to a decarbonised electricity system by 2035. Based on extensive stakeholder engagement, research and modelling, each scenario considers how much energy we might need; where it could come from; and how we maintain a system that is reliable. We published and launched FES 2022 on the 18 July 2022 and were joined by around 400 stakeholders for the online executive launch event. Following the main launch event, we held four separate webinars which took a deeper dive in to the FES 2022 Key Messages, joined by 965 stakeholders across all four events. The launch event received a Net Promoter Score (NPS) of +37. As part of our engagement for FES 2023, we were delighted to welcome 61 stakeholders to our Topic Table Talks event in January 2023. A brand new event which invited views on various topics for FES 2023 analysis and received a NPS of

+52. We saw a 33% increase in responses to the FES 2023 Call for Evidence compared with the previous year and 59% increase in the number of different stakeholders across all engagements due to increasing our reach and targeting new stakeholders. Through feedback received, we have implemented a number of improvements for FES 2023 which include additional analysis and energy articles to complement and enhance our modelling and provide additional insight (e.g. consumer archetypes) and the launch of a new Energy Background Document which will complement FES 2023, to be published in July. We have improved the visibility and transparency of our FES data through providing more regional data through our online interactive maps.

Alongside successful delivery of all existing licence obligations, we have been focussing on developing the changes required to FES to feed into the future Centralised Strategic Network Plan (CSNP) which has involved collaboration across all parties involved in the Electricity Transmission Network Planning Review (ETNPR).

Bridging the Gap

Our Bridging the Gap project 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. Since the start of BP1, a new UK energy target was introduced, which states that we should be able to operate a fully decarbonised electricity by 2035. Bridging the Gap has looked at how this can be achieved, in terms of the flexibility required to operate this zero carbon system. We worked with stakeholders from across industry to produce three reports over the two years of BP1: a day in the life of 2035, a flexibility timeline to 2035 and a deep dive into two key elements of flexibility: consumer engagement and hydrogen.

The aim of the project is always to find areas of consensus across a range of stakeholders from industry and other related sectors, from which we can then build and make recommendations for government, the ESO and other organisations. Across both projects in 21/22 and 22/23, we worked with well over 50 different organisations and facilitated workshops online and in-person, where we could discuss the question of what good looks like in 2035, what the key milestones are along the way and what the barriers to progress are. For both projects, we received really positive feedback from those who attended our workshops and report launches (NPS +20) and we had in excess of 300 people sign up to listen in to the launch webinars or receive the report and webinar recording. Additionally, our stakeholders at BEIS/DESNZ were also very supportive of our work and have found the work we are doing to keep track of our recommendations for actions as well as the other key actions identified from other plans/projects particularly useful (our flexibility tracker). This tracker is intended to see how much progress is being made and whether we are on track to achieve the flexibility milestones identified.

Early Competition (new activity in BP1)

In December 2021 we completed and submitted our Early Competition ‘low regrets’ activities to Ofgem 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 was 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.

In April 2022 Ofgem approved our early Competition Plan (ECP) proposal and directed us to implement it with the aim of having a tender solution available to be used in 2024. This will allow Ofgem to determine, subject to the passing of relevant legislation, whether a competition should be initiated once the FSO is established.

To accomplish this, we have established a delivery team to support implementation of Early Competition including the introduction of new skillsets not previously utilised in the ESO.

We have significantly increased our stakeholder engagement to understand the market appetite to participate in network competition and ensure that the detail of the solution meets both the objectives of being attractive to investors and value for the end consumer. We are engaging with a wide range of potential consortium parties including infrastructure funds, Original Equipment Manufacturers (OEM’s), design houses and developers. We are also working with Transmission Operators to better clarify roles and responsibilities within an Early Competition model and develop a proposal for the regulatory structure that will underpin it.

As part of the ECP plan we are developing an operating model that identifies the roles and responsibilities for running an Early Competition tender. Subject to Ofgem agreement, we will start to establish this tender team in the latter half of 2023.

System Operator: Transmission Owner (SO: TO) Optimisation incentives scheme

The SO:TO Optimisation incentive encourages the Electricity Transmission Owners (ETOs) to proactively identify and provide solutions to the Electricity System Owner (ESO) to help reduce constraint costs. Ofgem are currently consulting on extending the service out for a further 3 years to maximise the benefits that the service can brings. This year we have been working with the TOs to provide additional information that can help identify more potential outages that could benefit from enhanced services.

The first 2 years of the incentive have been very successful with over £42.5m being saved in year 1 across 8 separate solutions. In year 2, we have processed 38 solutions with a forecast cost saving of £293m. A number of solutions were offered to increase the capacity of the SEIMP boundary, which was of particular benefit this year due to the high level of Interconnector exports that were seen. These increases to this constraint limit have a forecast cost saving of over £90m. Another example solution was to minimize outage time during installation of a new Quad Booster at Tealing 275kV substation. It was proposed to install a temporary by-pass circuit which significantly shortened the outage, as the majority of works were completed offline. This work has a forecast saving of £30m.

Operational Visibility of DER

In June 2022 we published our Operational Visibility of DER thought paper explaining the potential benefits to the ESO of DER visibility which we quantified as up to £150m per annum.

We presented a roadmap and invited stakeholder views. 12 parties responded and we have used this feedback to inform both our work on operational visibility of DER and the related work on operational metering standards.

Since then we have continued to engage with stakeholders including the ENA Open Networks work in this area, as well as bilateral engagements with DNOs to inform their RIIO-ED2 business plan requirements. This includes the need for high speed inter control room communication links (ICCP) which are key enablers for many of the benefits.

Earlier in 2023 we formed the initial project team for this work who are now building on our roadmap. We have also launched an innovation project with the Hartree foundation to forecast DER service provider behaviour, DERIVE.

Outage optimisation

Our Outage Optimisation activities are recorded as Customer Value Opportunities (CVO). The figures recorded for 2021/22 were £1,881m and 24.6TWh, which represent the savings made by optimising the requests for system access and efficiently planning the topography of the system. In 2022/23 the CVO is £2,068m and 22TWh. Some examples included below.

An extensive programme of asset management and construction works were required in South West Scotland in order to remove a network based restriction to the capability of the Western Link HVDC subsea cable. Commercially, the Western Link is a crucial transmission asset as it increases the transfer capability across the B6 boundary. The B6 boundary lies between the Scottish Power and the National Grid license areas.

For the duration of the construction works the capability of the Western Link must necessarily reduce to zero due to a reduced fault level infeed to that part of the network. The Network Access Planning team, in co-ordination with Scottish Power had programmed this complex work package into the December and January period. This being the earliest date that the transmission owner would have the workforce capability and equipment available to deliver the system reinforcements.

In the context of high energy costs in the 22/23 financial year, within year cost benefit analysis exercise was performed across our outage plans. This resulted in a signal to delay the reinforcements into the spring 23 period with a consumer saving of £70 million due to reduced constraint costs. Approximately 20 transmission outages were re-planned as a direct impact of this decision, and we worked very closely with SPT and NGET to coordinate the updated plan.

This was a major part of a wider initiative to review our planned outages taking place in the winter months. Again, in the context of managing constraint costs, but also with an understanding of the additional challenges being imposed by increased interconnector exports as a result of fluctuations in the cost of energy due to the war in Ukraine. The transmission owners were engaged early and regularly to optimise plans through the challenging 22/23 winter. Over 100 positive outage changes were made as a result of this regular and intensive liaison.

Challenges

Connections

In a relatively short time, we've seen the electricity system transform from a small number of large fossil fuel generators to a diverse range of technologies, including renewable generation and storage, as well as new needs for electricity demand. Consequently, Connections is one of the areas where we have experienced some of our greatest challenges in the first two years of RIIO T2. However, we have achieved a great deal in the development and delivery of initiatives, driving much needed change, taking a leading strategic role in the industry, whilst working collaboratively with Ofgem, government, network organisations, customers and stakeholders.

Over the last two years we have seen a considerable number of changes at both the UK and worldwide level impacting the work done we do in Connections. The COVID-19 pandemic has changed consumer behaviour and accelerated the shift towards hybrid working, and the war in Ukraine has increased uncertainty in the energy market The UK economic outlook has changed, with greater emphasis being placed on investment in renewables and the re-development of industrial parks, and we've seen the Government accelerate net zero targets.

The key challenges for connections are as follows:

Increasing volumes of applications	When BP1 was submitted, we expected the volume of applications to grow by 8% per year. However, the volume went up 67% in Year 1 of BP1 and a further 77% YTD in Year 2.
More diversity of generation technologies, collocation, and the growth in direct demand connections	During BP1, the diversity of generation technologies has increased, with 60% of new applications now coming from battery storage, and varying greatly in size (49MW to +1GW). We have also seen applications for large scale demand connections associated with investment in manufacturing industry, data centres, housing, and commercial developments, which were not all forecasted in BP1.
Exponential growth in contracted generation	Contracted generation has increased from 216GW in April 2021 to 353GW in March 2023. Our Future Energy Scenarios (FES) modelling shows that Great Britain needs between 123GW and 147GW of low carbon transmission generation by 2030 to be on a net zero compliant pathway, with 83GW currently connected.
Delays to connection dates	Connections face longer lead times to connect due to the number of constraints identified as result of network studies. These are driven by the exponential growth in contracted generation (TEC Queue), concentrated large demand connections, and the challenges associated with the build of required enabling transmission network assets which are outside our influence and control.
Inability of the legacy approach to effectively cope with changing market needs	We operate within a framework which has remained largely unchanged for the last 20 years. The framework is agnostic on the treatment of different technologies, alignment with government driven targets (i.e. Offshore Wind, accelerated Net Zero ambition), management of speculative projects to enable progression of real projects, and overall ability to evolve and change at the same pace as we are observing change in the energy policy and market.

At the beginning of BP1 we set out to find ways of improving the connections process. We needed to do more, quicker, whilst continuing to manage the challenging volume of ‘BAU’ connections. Below we summarise the work we’ve done to date:

Team growth and capability improvement	We’ve grown the team by 94% since Q1 2021, restructuring and focussing more on retention, training and continuous recruitment.
Improvements to customer experience and engagement	**(1) Connections Portal** We have digitalised the connections process via our Connections Portal, with Phase 1 delivered successfully on 13 March 2023. This platform allows quick and easy submission and management of new connection applications, pre-applications and queries, and gives customers access to information on their projects. We are working on developing more functionality, with engagement and support from customers, as we did for Phase 1. **(2) Communication and Engagement Plan** We’ve been communicating and engaging with customers and stakeholders via a number of routes to suit different needs (monthly webinars with Q&As, by-yearly seminars, newsletters, subject matter related webinars, improvement of website content, campaigns on strategic initiatives);
Exponential growth of TEC Queue	**(1) TEC Amnesty** In September 2022 we introduced a TEC Amnesty following engagement with TOs and Ofgem; For projects on the TEC register which are unlikely to reach delivery, this process gives parties the opportunity to terminate the contract at no or reduced cost. A total of 5.5GW of projects have applied so far. We have previously tried to run TEC Amnesties since 2012 without support. **(2) Queue Management (QM) CUSC Modification (CMP376)** We also need more effective queue management arrangements. To that end, we raised a code modification, CMP 376, under the Connection and Use of System Code (CUSC), to formally introduce QM arrangements. This is subject to approval. QM will mean that projects which are ready to connect can do so ahead of those customer projects that may have applied earlier but are not ready or able to progress – currently we are unable to prioritise the queue based on readiness to connect. QM will introduce contractual milestones that customers must meet to retain their place in the connection queue, which will benefit everyone.
Transmission Reinforcement Works (TRW) Review & Two Step Offer	We have been working with TOs to identify areas for improving the connections process, and on 1 March 2023 we introduced a new interim two-step offer process [25] for England and Wales. In February 2023 we instructed TOs to apply the new Construction Planning Assumptions (CPAs) and the modelling of Battery Energy Storage System (BESS) projects to review existing contracted connections (TRW). We expect this will enable some connection dates to be moved forward .
Non-Firm Connections	We are developing a policy which aims to enable all technologies to connect under a restricted profile ahead of enabling transmission works being completed. This is noted in our 5 Point Plan [26], to which effect we released an ‘Expression of Interest’ letter to industry to better understand what level of

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[25] https://www.nationalgrideso.com/industry-information/connections/two-step-offer-process

[26] https://www.nationalgrideso.com/industry-information/connections/connections-challenges-what-are-we-doing-now

	restrictions and type of instruction would be most advantageous to Customers (Transmission and Distribution).
Connections Reform Project[27]	In July 2022 we created a new BP2 deliverable to address the fundamental need for reform to Connections. The start of the programme was accelerated by six months to October 2022. We have engaged extensively with industry, released a 'case for change' report in December 2022, and are now in the design phase. We will consult with industry in June 2023, and then an implementation phase will begin in Q4 2023. Details of the new process and implementation strategy will depend on the outcome of the consultation and code review process that will follow. This project is aligned with the Centralised Strategic Network Plan (CSNP), FES, the Review of Electricity Market Arrangements (REMA) and other ESO transformational activities and projects.
Wider context	We are also actively working with the ENA, DNOs and TOs as part of the ENA Strategic Connections Group, and with Ofgem and DESNZ. Our experiences in challenging and pushing boundaries of existing processes to deliver changes and improvements has proved essential for developing strategies and engaging with wider industry.

In summary, all of our initiatives will deliver the following benefits:

- Improvements and changes to the Connections process.
- Projects being able to connect at the pace to meet government targets for renewable generation, for energy security and resilience in GB.
- Support for development and diversification of the energy market to enable innovation and investment in energy.
- Support for efforts to reduce costs to consumers of the management of the GBs Energy System.
- Readiness to be able to act early and evolve with the changes in the market and needs of energy industry to ensure we continue to deliver on the role of strategic leader in Connections, whilst retaining the focus to improve engagement with customers and stakeholders.

Delivery of co-ordinated visibility and control systems with DNOs

Our work on the RDP MW Dispatch and N-3 Intertripping projects has required close working with DNO partners to create secure real-time data links between our control centres. In the case of NGED and SSE-N these data links have not previously existed, and we have experienced additional complexities and challenges in establishing and testing the appropriate systems and protocols. Whilst some of these challenges have been internal, for example, working with our telecoms provider, the majority have been externally driven, either due to DNO unfamiliarity with the requirements, or unexpected security needs. However, the links are now established with both DNOs, and final commissioning is underway.

Once established these links can be used for other use cases such as restoration from Distributed Energy Resources (DER). We will ensure that learnings and best practice from these projects feed into data link development with other DNO control centres in BP2.

Regional Development Plans (RDP) delays

Our plans for future RDP development have been complicated by the unprecedented increase in connection applications at transmission and distribution across GB. Whilst at some standalone GSPs we have been able to develop quicker solutions, others have proven more complex to understand and resolve. We are now taking whole system solutions through initially as interim non-firm solutions to connect Battery Energy Storage Systems, one of the medium term initiatives to get parties connected.

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[27] https://www.nationalgrideso.com/industry-information/connections/connections-reform

Generation Export Management Scheme (GEMS) delays

We are working closely with SPT to deliver GB's first automated control system for use on the main transmission. GEMS has been developed as a more efficient way to get generation connected in south west Scotland compared to traditional transmission grid reinforcement. We developed a high level technical specification and project timeline with SPT. Unfortunately, given this is a GB first system, SPT's procurement exercise took significantly longer than had been anticipated causing around a 12-month delay to the project. Further delays have also since been identified. These are primarily associated with harmonising the high level agreed specification with SPT's vendor requirements.

Enhanced Frequency control (EFC)

EFC investment was to deliver a Monitoring and Control System (MCS) to provide fast and coordinated frequency response for the low inertia system to achieve zero carbon operation. The assumption for this investment, at the time of the original RIIO-2 submission (BP1), was that a post-event fast frequency response service can only be delivered through EFC services. Since the 9 August 2019 event, the frequency response strategy led to the development of a suite of pre and post fault frequency management services including Dynamic Containment (DC). DC is a post fault frequency services that has already been implemented by Markets (Role 2), which covers the same solution space for the post fault frequency response as EFC.

The EFC project had six different phases; Phase 1 to Phase 5 in the original submission and during BP1 a new Phase 0 was introduced. Phase 1 is to develop non-operational prototype to demonstrate MCS, funded through a Network Innovation Allowance (NIA) project. Phase 0 was introduced to design Phase 1 and develop a strategy and roadmap for the remainder of the programme.

The project team evaluated EFC against already existing post-fault frequency services such as DC. Results concluded that DC was sufficient as a post fault frequency response for a network with minimum post event inertia of 90 GVA-s, as long as the response was spread regionally across GB. Through our internal governance, it has been decided to cancel EFC Phases 2 to 5 providing opportunities to reduce spend that will save £21m for consumers. Due to these additional evaluative works between EFC and DC, the non-operational demonstration of EFC (Phase 1) is delayed and to be completed by Q3 of 2023-24.

Role 3 - Progress of our deliverables

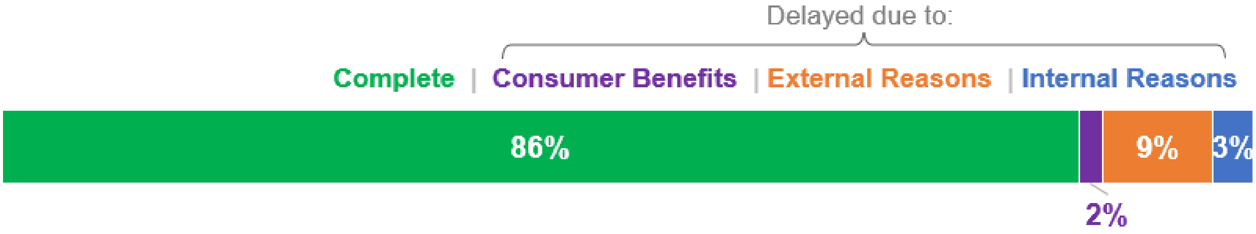
Our RIIO-2 deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables, with commentary including explanations for all delayed milestones.

For Role 3 (System insight, planning and network development), there are **234** milestones. **19** of these are no longer valid, leaving a total of **215** Of these:

- **185** (86%) are now complete
- **30** (14%) are not complete which break down as follows:
- **4** (2%) is delayed in order to deliver an improved outcome for consumers
- **19** (9%) are delayed due to reasons outside the ESO's control
- **7** (3%) are delayed due to ESO related delays

These results are illustrated below:

Role 3: Status of **215 milestones** due to be completed by the end of 2022-23



This excludes milestones which have been agreed with OFGEM as no longer being valid

Delayed milestones

Deliverable	Delay Type	Reason for Delay
D11.1 - Improved identification of when is the most economical time to invest and the most efficient solution **- 1 milestone**	Internal Reasons	Work is ongoing to deploy a new pan-European market dispatch model (economic assessment tool). Deployment at the standard we require has proven more challenging than first anticipated.
D12.1 - SQSS updated to ensure it is designed to enable decarbonisation of the electricity system **- 1 milestone**	Internal Reasons	Deprioritised as a result of winter preparedness 2022-23.
D13.5.2 - Developed new energy demand model – this brings together all energy demand data in one place **- 3 milestones**	Internal Reasons	Delayed as we are focussing on integrating our new dispatch model within the FES processes which will enhance our abilities to model key aspects of flexibility within the energy sector. It will also ensure that the models we have align with strategic priorities, such as FSO and ETNPR outcomes.
D15.5.1 - Start RDP1 of RIIO-2 - **1 milestone**	Internal Reasons	MPLS link delivery delays have delayed release of our ASDP (dispatch) functionality until after March 2023.
D15.5.3 - Start RDP3 of RIIO-2 - **4 milestones**	Consumer Benefits	Regional Development Programmes are established through identification of suitable needs cases. In the case of RDP3, at the time of BP1 plan development this was envisaged to be around facilitation of storage connections in the Midlands. This needs case did not materialise, so the project progression was delayed until the needs case arose. This has also proven to be a more efficient solution as it has

		allowed much of the enabling work in the development of non-build solutions to be matured through RDPs 1&2. The needs case for RDP3 then arose later in RDP1 as part of the broader connections issue, and will now be progressed through the non-firm developments part of the Connections 5 point plan.
D15.5.4 - Start RDP4 of RIIO-2 – **1 milestone**	Internal Reasons	This deliverable has been delayed to better align with other RDP and connections initiatives. It is now undertaking a feasibility assessment of the proposal to connect battery storage non-firm.
D15.6.2 - Further Grid Code mods **- 1 milestone**	External Reasons	Work depends on D15.8.1. GC0139 (Enhanced Planning-Data Exchange to Facilitate Whole System Planning) is currently at Working Group stage and was delayed due to external factors. GC changes need consultation and rely on a joint working group within the industry to develop a proposal. It took longer than originally planned due to the complexity of the changes, as well as external parties resource constraints. The GC139 modification is in final stages of drafting, which is expected to be concluded by the working group in May 2023 and then submitted for Industry consultation and approval. Anticipated completion is now Summer 2023.
D15.6.7 - Deeper Outage Planning go live in Offline Network Modelling **- 1 milestone**	External Reasons	'Delayed external reasons' has been agreed with Ofgem. This milestone should have been identified for completion in BP2 from the outset.
D15.11.2 - RDP - Generation Export Management Scheme (GEMS) **- 3 milestones**	External Reasons	The project timeline for GEMS included allowance for SPT to select a vendor for their equipment and work with this party to develop the detailed functional design specification. This process took longer than anticipated in the original timeline which has delayed these three milestones.
D16.3.3 - Finalise new processes in readiness for approval of code modifications to facilitate closer working relationships and data exchange/modelling **- 3 milestones**	External Reasons	'Delayed external reasons' has been agreed with Ofgem. These milestones should have been identified for completion in BP2 from the outset.
D16.3.4 - Deeper access planning go-live **- 2 milestones**	External Reasons	'Delayed external reasons' has been agreed with Ofgem. This milestone should have been identified for completion in BP2 from the outset.
D15.11.1 - RDP – N-3 **- 1 milestone**	External Reasons	SSEN has had some technical issues which have delayed the delivery of this element of work and will mean the milestone will not be completed until later in 2023.
D15.10.3 - Package or coordinate connection offers **- 2 milestones**	External Reasons	The milestones were developed before the OTNR was initiated and they became dependent on the Enduring Regime/Future Framework direction, hence we haven't completed them in the originally proposed timescales.
D16.4.1 - Scoping exercise concluded for delivery of enhancements to outage notifications - **3 milestones**	External Reasons	This can be started after the output of D16.3.3 is available (see D16.3.3 below)

D16.4.2 - Delivery of enhancements to outage notifications **- 3 milestones**	External Reasons	This can be started after the output of D16.3.3 is available (see D16.3.3 below)

Milestones no longer valid

Section 5.6 of the ESORI guidance states: 'If any changes are made to the delivery schedule during the business planning cycle they should be clearly identified and outlined in the reporting documents (e.g. in a separate sub-section), so it is clear where additional amendments have been made in comparison to the original Business Plan. This can ensure Ofgem, stakeholders and the Performance Panel understand the reasons for any changes to plans in advance of its evaluation of the ESO's performance.'

In December 2023, we introduced a new process for managing milestones that are no longer valid. Below are details of milestones that have become no longer valid over the two-year period:

Sub-activity	Deliverable	Milestone	Reason no longer valid
A15.9 Identify Future operability needs across whole energy system	D15.9.2	N/A - initial scoping for this activity to take place in 2023/24 so no milestones applicable here	These activities were scheduled to start after BP1. They have subsequently been removed from our BP2 business plan submission.
	D15.9.3	N/A - work to commence on this activity in 2024/25	
A15.7 Deliver an operable zero carbon system by 2025	D15.7.1	Phase 2	EFC and Dynamic Containment (DC) covers the same solution space. In Phase 0, further studies have been carried out and studies concluded that DC was sufficient as a post fault frequency response for a network with minimum post event inertia of 90 GVA-s. RAPID process recommended to cancel Phase 2 - Phase 5. It has been approved by Design Authority and presented to OFGEM.
		Phase 3	
		Phase 4	
		Phase 4 Requirements	
A9.1 Expand network planning processes to enable more connections wider works to be assessed	D9.1	All 7 milestones	These deliverables will be picked up in the whole network planning review process (NPR) which will look at improving the whole network planning process including identifying wider transmission investment works driven by new connections.
A9.2 Trial assessment of all connection wider works in one region	D9.2		
A9.3 Expand to all Connections Wider Works (CWW)	D9.3		

A9.4 Develop process with TOs to input into ESO analysis of end of life asset replacement decisions	D9.4		
A15.10 Develop a regime for an integrated offshore grid	D15.10.1 D15.10.2 D15.10.5	All 6 milestones	Since proposing these deliverables, the Offshore Transmission Network Review has progressed significantly, and our deliverables have changed as a result. In the shorter term (in line with the DESNZ/Ofgem set Terms of Reference), the Holistic Network Design process in the Pathway to 2030 workstream has replaced the traditional CION process for in-scope projects. In the longer term we will aim to develop a new coordinated offshore connection offer process, to enable the agreed future framework, and ensure it has the appropriate level of formalisation. This will come out of decisions on the back of DESNZ's September 2021 Enduring Regime consultation and any subsequent consultations and policy developments. In September 2021 we published an open letter to offshore developers setting out that this is the case.

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 [28]	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 has been extended until the end of May with additional development focussed on the risk model, which shows the highest maturity. Innovation and IT are discussing routes to operational development which may follow the conclusions of this project.	D16.1.1, D16.1.2	Delivery	RIIO-1 and RIIO-2
Advanced Modelling for Network Planning	Developing the LWWR (Least Worst Weighted Regret) tool that will help automate part of the Network Options	The project's initial phase produced a report that gave several recommendations for improving the NOA process. A project extension was approved, and Melbourne	D7.2 D11.2	Completed, follow-on activity now managed by the business	RIIO-1

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[28] https://www.smarternetworks.org/project/NIA_NGSO0037

Under Uncertainty [29]	Assessment (NOA) process to make more informed decisions, and be more economically efficient with network planning recommendations.	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.			
Resilient EV Vehicle Charging [30]	The project will analyse the impact of EV charging on grid short term frequency and voltage stability, and cascade fault prevention and recovery.	The REV project concluded in December 2022 and revealed significant insights into the impact of EV chargers and V2G generation on grid stability, expanding ESO's understanding of potential risks and challenges. This knowledge will aid future network planning, including updates to grid codes and standards for smart energy appliances. The project identified several potential issues, such as Step, Ramp, Oscillations, Degraded Stability, Demand Control and Restoration, which warrant further exploration. Numerous UK Government and Automotive Society reports have also highlighted the findings.	D15.1.2	Completed, follow-on activity to be determined	RIIO-2
DETECTS [31]	The project is seeking to understand the risk of converter instability by assessing the behaviour of actual manufacturer-provided converter models	The project has concluded and provided helpful insight regarding stability risk on the South Coast of England network. We found it essential to follow up with the Consultancy that delivered the project to understand the developed model further, get the relevant training on the model, and validate some of the critical findings within the ESO. We have kicked off DETECTS 2, which will provide the license to the advanced SE coast model and the required training to run and update the models.	D15.1.2	Completed	RIIO-1

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[29] https://www.smarternetworks.org/project/nia_ngso0028

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

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

		DETECTS 2 will also support our ambitions to develop and upskill the Electro Magnetic Transients (EMT) area.			
Probabilistic planning for stability constraints [32]	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 has concluded, and the innovation partner has provided the proof of concept of the stability assessment tool. The tool has been tested on the planning models (Electricity Ten Year Statement) during the project. It is undergoing further testing and evaluation with more accurate operational models within the ESO. Integrating into BAU and planning cycles will require improvements in the dynamic models, which are being investigated by the Network Modelling teams in the ESO.	D11.4 D15.1.2	Completed, follow-on activity now managed by the business	RIIO-1
SHEDD [33]	Assessing better Low Frequency Demand Disconnection (LFDD) solutions.	Project has now completed. Final outputs were validated by a sub-project undertaken by 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.	D15.1.2	Completed, follow-on activity now managed by the business	RIIO-1
TOTEM (SHET led) [34]	Developing and validating a full-scale model of electromagnetic transient (EMT) behaviour for the GB transmission system.	The innovation partner has developed the full GB EMT model, steady state and dynamic validations are showing promising results. The model will be further tested and validated by the ESO and the TOs before being integrated into the ESO processes. A discussion between the ESO, TOs and the innovation partner is ongoing to scope TOTEM 2 to expand the model into the	D15.1.2	Completed	RIIO-1

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

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

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

		HND offshore network. The project will conclude in April 2023, with all models, reports, and training to be provided by the innovation partner.			
VSM Battery [35]	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	Completed, follow-on activity now managed by the business	RIIO-1
Year-round Voltage Assessment Tool [36]	Developing and testing convex optimisation models and machine learning algorithms that adequately represent voltage and reactive power in the system.	Since the completion of the project in April 2021, we have taken the learnings and deliverables around convex optimisation of optimal power flow together with data clustering techniques and further improved and expanded them for business use, specifically to assess year-around OPEX (Operational Expenditure) of operating a power system. We are currently scoping n IT project on Voltage Optimisation based on the learnings from this and other NIA projects to develop an IT product for NOA enhancement.	D11.3 D15.1.2	Completed, follow-on activity now managed by the business	RIIO-1

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

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

Coordination of ANM schemes with Balancing Services markets [37]	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 us 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	Completed, follow-on activity now managed by the business	RIIO-1

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

C.2 Stakeholder Evidence for Role 3

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:

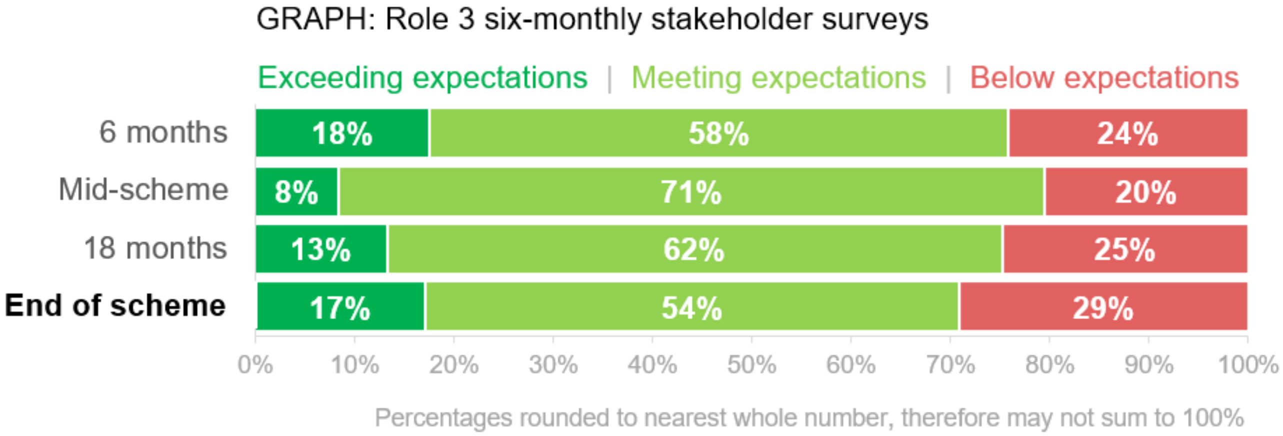
> "One of the ESO Roles is focused on system insight, planning and network development, which includes key activities such as Connections and Network access planning, Strategy and Insight (e.g. FES) and long-term Network development. Overall, from your experience in these areas over the last 6 months, how would you rate ESO's performance?"

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

For Role 3, we contacted 448 stakeholders, and received 134 responses to this question, which were distributed as follows:

- **17%** exceeding expectations
- **54%** meeting expectations
- **29%** below expectations

(Percentages rounded to the nearest whole number so may not sum to 100%)



"Exceeding Expectations" feedback

Out of 134 responses, 23 stakeholders scored us as "exceeding expectations". They were asked what we did that exceeded their expectations. They raised the following points:

- We received three positive comments related to our work on Innovation with the support provided by Innovation team, planning around the Virtual Energy System and our general openness to innovation all being singled out. They also found the new graphical interface on future network plan very useful.
- There were also three comments regarding FES, with stakeholders commenting that we engaged extensively around FES, that it's a known source for the UK Energy Forecast and that we were happy to talk at length with a stakeholder about our future energy scenarios.

- There were also positive comments around our work in Connections namely our approach to the two-step offer process, this stakeholder also offered some suggestions around timings on the TEC amnesty. Another stakeholder commented that we were thinking outside the box on connection reform. We also had a stakeholder commenting that they've made various connections applications and 6 months in they are very happy with the process.
- We also had general positive comments around how well we effectively collaborate, share information and have open dialogue with our stakeholders.

"Meeting Expectations" feedback

Out of 134 responses, 72 stakeholders scored us as "Meeting expectations". 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.

- Eight respondents commented that they wish to see improvements to the connections process particularly in areas such as accelerating the connections reform, improve coordination with network access planning and the time it takes to connect to the Grid.
- Respondents felt our network planning was too slow in some instances and more resource and coordination was needed to join many projects together. There were also comments around communicating transmission constraints better so industry could plan where best to make investments.
- We had mixed comments on our communication, engagement and transparency which included sharing data. Some stakeholders were pleased with our progress, but others felt that we could do more like sharing more information across a range of projects, increase resource for engagement and be more transparent on network outages.
- We also received comments that we needed to improve response times and partner more with key stakeholders and be more transparent on our projects in general

"Below Expectations" feedback

Out of 134 responses, 39 stakeholders scored us as "Below expectations". In response to being asked what the ESO needed to do to meet their expectations, these points were raised:

- At least eighteen responses expressed dissatisfaction over slow speed of response and lack of communications/clarity around the connections process. Many stakeholders saying we need to be more proactive in this space.
- Although not project specific, we received a number of responses calling out our lack of or delayed response to queries. There were further responses which included general comments about improving our communications, engagement and transparency of data sharing.

Addressing stakeholder feedback in BP1

The above survey is the fourth and final instalment of the stakeholder satisfaction surveys conducted for BP1, with surveys being conducted every six months throughout the delivery of the business plan. We've delivered our business activities while taking into consideration the results of these surveys. We've also continued to listen and engage with our stakeholders to make sure our projects and business activities are developed with industry at the heart of their design. On further analysis of previous surveys, we found that across Role 3, feedback can be grouped into a selection of key themes which are a priority for our stakeholders. They include:

1. Improve our data and analytical information to support industry knowledge and decision making
2. Improvements needed in communications and engagement
3. Greater coordination with TOs and all industry partners

Below we outline how we've been working to address these feedback themes gathered from the stakeholder surveys throughout BP1:

Theme 1: Improve our data and analytical information to support industry knowledge and decision making

Developing our Regional Future Energy Scenarios – Our stakeholders have continued to be supportive of the development of regional future energy scenarios. These are similar to the national FES but broken down across geographical regions, also known as distributed future energy scenarios (DFES). Feedback shows we need to continue to focus on improving the interaction and alignment between both the FES and the DFESs, as well as better incorporating information we receive directly from customers and network companies. As a result, we have plans to:

- Provide more granular data in the future. We will be adding additional data to our visualisation platform, including the visualisation of our models to show the evolution of how heating systems can be decarbonised, regionally and nationally.
- We're also running a "Consumer Building Blocks" project in parallel to our FES 2023 cycle. This will help us to create a standardised set of consumer behaviour 'archetypes' which will support a better understanding of how consumer behaviour around energy consumption will vary with time and across geographical locations.
- Apply the consumer archetype knowledge to future scenario development for both distribution and transmission network planning.

Considering challenging system phenomena in our future energy scenarios - We received feedback that extreme weather events, such as Dunkelflaute (a long period of still, cloudy weather resulting in very little wind and solar generation), are recognised as a real risk to a future decarbonised energy system. The best method and mix of technologies to secure the system against these events is not yet clear.

Stakeholder feedback suggested that more work needed to be done by the FES team in this area. To address this, we have:

- Been working on analysis around how the system responds to Dunkelflaute periods. The findings will be published in FES 2023.
- Investigated this in our Bridging the Gap 'Day in the Life 2035' project, looking at a cold, calm and cloudy winter day with high energy demand and low renewable energy generation.
- Published an article on the impact of different weather conditions on historical residential demand.

Creating a more 'whole system' Bridging the Gap document - The FES Bridging the Gap project is an annual stakeholder-led process taking the implications of the key messages from FES and developing a set of recommended actions so we can make progress to net zero. We've previously received feedback that we were too focused on electricity and needed to take a more 'whole energy system' approach. With this in mind:

- Between September 2022 and March 2023, we worked with partners from outside of the electricity sector (Citizens Advice, Energy Savings Trust and National Gas Transmission) to broaden our 'whole system' remit.
- We've focused on broader energy topics, domestic consumer engagement and hydrogen.

This approach helped us to develop a set of recommended actions which will be integrated into the BtG flexibility timeline tracker (which tracks industries progress towards GB's net zero by 2035 targets). Recommendations from this work have also been shared with DESNZ who will consider them as they develop policy proposals for 2023/2024.

Theme 2: Improvements needed in communications and engagement

Offshore Coordination – Holistic Network Design (HND) development – The HND is a first of its kind, integrated network planning approach for connecting 23GW of offshore wind to Great Britain. We've worked with multiple organisations and stakeholder groups in developing the HND and have looked to make continuous improvements in how we engage on this topic. In response to feedback from the development of first phase of the project, HND1, we refined our engagement approach for second phase, HND2. Offshore wind developers asked for in person regional workshops once an initial set of designs were available. We incorporated this into our engagement plan and took a flexible approach, seeking input from our stakeholders as the design progresses. A summary of the engagement touch points for HND1 and HND2 can be found below:

For HND1 we:

- Established and used a Central Design Group (CDG) as a main way of engaging, which included a developer forum.
- Held over 100 individual meetings with developers and transmission owners.
- Provided some feedback opportunities on the methodology, draft recommendations and through code change workshops.

In our engagement for HND2 we:

- Made improvements to the CDG membership to add membership for offshore wind developer, community, environment and technology provider representatives.
- Held quarterly face to face workshops in Glasgow for all impacted stakeholders. Over 60 stakeholders attended each workshop to discuss challenges, give feedback and ask questions.
- Improved transparency by providing our thinking/workings to key stakeholders to help them understand our conclusions.
- Provided additional feedback opportunities with two formal feedback windows on the initial designs, interface sites and the design shortlist to help us inform the final design recommendation.

We will continue to offer stakeholders more opportunities to feedback on our initial Options Appraisal Summary Tables and once the draft final design recommendation is available.

Developing the engagement for Connections Reform - We brought forward our connections reform project by 6 months to address the need for fundamental change to the Connections application process and underpinning industry codes. During phase 1 of the project (September to December 2022), we engaged extensively with stakeholders from across industry to determine the pain points and issues with the current process. In our Case for Change report in December 2022, we set out our findings and noted that a clear set of themes for the case for change had emerged: 1. Options need to be collaboratively developed throughout the connections lifecycle; 2. Rapid connections need to be progressed on their merits; and 3. There needs to be a simple, transparent and coordinated approach to connections. In addition, stakeholders indicated they want easy access to self-service tools, consistent data and quality insight, and consistent, skilled and well-resourced engagement.

Through the delivery of the project so far, we have looked to improve the way that we engage with stakeholders and co-create solutions. We have:

- Used phase 1 to gather stakeholder views on the problems with the existing process. We spoke to over 100 people across 32 bilateral and multilateral workshops.
- Worked collaboratively with stakeholders in phase 2 (from January 2023) to design solutions to these problems via:
- A series of four design sprints with four or five working group meetings per sprint, with membership drawn from across industry
- A steering group, which has met every two to three weeks, with membership drawn from across industry and an independent chair
- A delivery partners executive group, with membership from key delivery partner organisations (Transmission Owners, Distribution Network Operators, Ofgem and Government).

These will ensure appropriate challenge of approach from industry and support effective implementation of proposed solutions.

We will publish our recommendations in June and open them to consultation. The decision to launch a consultation at the end of phase 2 was informed by feedback from stakeholders who wanted the opportunity to provide a more structured and considered input.

Developing our Network Planning Review with stakeholders - The Network Planning Review (NPR) has been established by us to make sure that network design and investment processes in GB are fit for the future. As part of the Network Planning Review, we are considering the identification of system needs, the identification of options for addressing system needs and how to make decisions on which options to progress.

We've been holding a series of workshops with stakeholders using techniques of creating 'strawman' (draft) proposals designed to stimulate discussion and ideas. We held workshops reviewing how our supply and demand backgrounds (Future Energy Scenarios) are to be further developed to provide insight to determine what investment may be required on the Electricity Transmission network. Within the strawman proposal, we suggested:

- Alternative options on how to manage the future uncertainty on the sources and uses of electricity
- Consideration of network constraints when determining the future supply and demand backgrounds (currently FES does not model constraints or 'bottlenecks' in stability or voltage on the network).
- Change the modelling methods to allow insight on events which may be low probability but high impact events on the system. This could be extended periods of low wind and low available sunlight resource to harness for example.

Stakeholders were broadly supportive of the approach of engaging around a strawman proposal. This stimulated feedback across a range of criteria such as short-term cost estimates, what time horizon do we run FES until i.e. until 2050, relationship with other key publications such as NOA and the impacts on whole system planning. This has enabled us to work on a more detailed proposal for the future of FES, creating different options to then bring back to stakeholders for further review.

Theme 3: Greater coordination with TOs and all industry partners

Working with the TOs more effectively on Early Competition and other projects - In August 2022 we met with the TOs and Ofgem to discuss the role TOs needed to play in the delivery of Early Competition. At the time, TOs raised concerns about the amount of work we were asking them to deliver and suggested we could take a more coordinated approach. We were asked to develop a joint action plan across all our activity so that TOs can resource effectively and approach Ofgem for additional resource when needed.

To address this, we have:

- Developed an ESO wide TO deliverables action plan – known as the TO / ESO pinch points database. This action plan gives a 12-24 month view of our activities with clarity of whether they are BAU or new activities.
- Shared a high-level version at a monthly meeting led by Network Competition which was received positively. However, the high-level plan did not give enough detail to plan resource, particularly around upcoming Network deliverables. Something we took away for review.
- Used this feedback to start developing a Network specific plan, with key TO deliverables and their timelines shared. If successful, we would look at opportunities to roll out across other relevant teams within the business.

In person engagement across network access planning - Our Network Access Planning team assess, co-ordinate the planned release of assets from the National Electricity Transmission System (NETS), for maintenance and commissioning of new connections and equipment. Pre-pandemic, this team held face to face forums engaging around the Operating Code 2 (operational planning and data provision) of the Grid Code. We've received feedback from stakeholder meeting and surveys that these should be reinstated to enable better engagement moving forward. In response to this feedback, we held an in person forum on 7 March 2023, attended by a very broad range of our key customers where we:

- Shared details of our ongoing Network Access Planning projects
- Gave customers the opportunity to voice their opinions, comment on projects and ask questions
- Took the opportunity to demonstrate progress on our automation initiatives including our new planning and outage data exchange system (PODE)

The event successfully achieved its objective, facilitating good engagement with stakeholders. We specifically received comments praising our transparency and quality of information shared a key theme we were aiming to address. We took away feedback about providing more detail on plans between now and 2030 and will look to provide this at the next event.

We plan to continue hosting the GB wide OC2 forum on a yearly basis. We will use questions and guidance from these forums to supplement CSAT and SSAT comments to further develop these events.

Creating better solutions for our providers to access markets – The Stability Pathfinder Phase 3 focused on procuring services to better control inertia and short circuit level in the electricity system across England and Wales. Whilst planning this procurement exercise, we anticipated many new solutions would bid into the tender without already being connected to the network. We needed to make sure that bidders offering solutions in our Stability Pathfinders tender were not prevented from being successful because of challenges related to connecting to the network.

Feedback on the experience of stakeholders in the Phase 2 tender showed that:

- Long queues for connection applications formed in certain areas of the network where Stability Pathfinder solutions were required
- The waiting lists for connections also increased.
- There was an increased risk of delays of project delivery and increased costs to us, bidders, and network companies.

The Stability Pathfinder Phase 3 took the feedback from previous Pathfinders and, in collaboration with NGET and OFGEM, developed and launched the trial of bay reservation. This meant a handful of substation connection bays across the transmission network in England and Wales were pre-emptively reserved. This meant bidders didn't need to submit their own connection applications until the outcome of the tender was known but could still have access to a connection point.

Following the completion of the Stability Phase 3 tender, 10 of the bays that were reserved by us are being used by the successful bidders.

Collaborating with the Distribution Network Operators (DNOs) through the Distributed System Operator (DSO) transition – The journey to creating an energy system fit for the future wouldn't be possible without the close collaboration that's happening with industry partners. For example, we've been collaborating with our DNO partners during their work on creating DSOs to:

- Develop the DER Operational Visibility paper published in May 2022
- Develop a portfolio Regional Development Programmes (RDPs)
- Provide a leadership role across multiple Open Networks Forums and working groups
- Help them with the development of their RIIO-2 ED2 business plans.

As a result of this work, responses to the DER Operational Visibility paper have fed into the power responsive working group and will be addressed further as we ramp up our activity going into BP2. In collaborating across RDPs, we have put in place ground-breaking tri-partite service terms contracts to support the implementation the Mega Watt Dispatch service. We also delivered the Inter Control Room Communication Protocol (ICCP) links which are communication lines supporting cross organisation data transfers and future RDP and wider services.

C.3 Metric Performance for Role 3

There are no metrics for Role 3.

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 specific case studies for **Holistic Network Design**, and **Enhanced Services with Transmission Owners**, which were 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	We estimate the gross benefits to be £725 over the RIIO-2, and an NPV of £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 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
Summary	In terms of NPV, we now expect to deliver £728m (Commercial solutions in NOA and CMIS) over the RIIO-2 period which is more than the £663m set out in BP1. Over ten years we expect to deliver £2.24bn NPV, which is more the £1.3bn in BP1. As part of our transition to the Centralised Strategic Network Plan (CSNP), we have improved our NOA analysis to drive more consumer value. We have done this through the integration of the Holistic Network Design (HND) into our assessment, the development of a Hydrogen Electrolysis and Storage assessment, and the further refinement of our interconnector analysis. As agreed with Ofgem, some of our sensitivity factors have been deemed no longer valid, and as such, we do not expect to deliver the consumer benefit originally calculated, where it included those. NOA consumer value in RRE 3B is provided as part of the 2021-23 end of scheme report. We now expect to see £146.6m benefit from our Constraint Management Intertrip Service (CMIS) over the BP1 period. The CMIS does not include all of the commercial solutions assessed within the NOA, but it does capture a significant amount of the real-world benefit being delivered for consumers. **Constraint Management B6** We have concluded the Constraint management B6 tender and have published the results for the periods 2023/24 and 2024/25. We have included the costs from this tender in the NOA assessment and have updated the NOA methodology to reflect this. We've improved the plan and continue to review how to procure and run the CMIS more efficiently. This may effectively reduce the number of tender assessments we need to do in future for each Constraint Management Intertrip Service (CMIS) which allows us to focus on developing new CMIS markets to reduce constraint costs and deliver additional consumer value. In addition to these improvements, we have run two tenders for B6 for contract periods 2023/24 and 2024/25. **NOA recommendations consumer benefit** The total benefit reported of £429m across the RIIO2 period was based on NOA 2018/19 data. As each NOA analysis is conducted, the number of years that can be reported on within the RIIO-2 period decreases. This is because options being delivered in the year of the options assessment being unable to partake in the analysis. The NOA 2021-22 data shows a benefit of £394m, over the remaining RIIO-2 period, which is on track with our

2018/19 assessment. This is the benefit of the ESO options recommendations being followed for the three net zero scenarios.

Following the NOA 2021/22, we agreed a new strategic approach to the NOA. This means that options that are required in only a few years can have their NOA recommendation maintained without re-assessment, expediting option delivery. Therefore, the NOA Refresh must assess fewer years and by extension fewer options. With fewer options to assess, a smaller benefit can be reported from this strategic analysis. We believe that this approach to options assessment provides the greatest value for consumers by streamlining the delivery process for essential works to meet government targets. We undertake the NOA process each year which provides an updated set of investment recommendations, and this will be reviewed annually.

NOA Refresh

The NOA Refresh also provides recommendations for acceleration of some projects to a 2030 delivery. Acceleration in the context of this report refers to the NOA Refresh recommending specific options that were submitted with an earliest in-service date (EISD) later than 2030 to be delivered on a required in-service date (RISD) of 2030. We have calculated the potential constraint cost savings if this recommended acceleration is completed to be £1,214m. This was calculated by comparing the constraint cost of delivering these options with their EISD beyond 2030 being accelerated to be delivered in 2030. This saving is not part of the original CBA but is an additional figure for the ASTI works we recommended within NOA Refresh.

Calculation of monetary benefit to consumers

The £394m benefit is calculated as the ESO driven benefit from NOA recommendations, for the RIIO-2 period only. Greater benefit is driven over the lifetime of the recommended reinforcements. We expect consumer benefit from our effort to facilitate competition by embedding pathfinding projects into the NOA to be in line with our ambition.

As part of the Network Planning Reform, we will be conducting further work on extending the NOA approach to all connections wider works and to end of life asset replacement decisions, under the Centralised Strategic Network Plan (CSNP).

Our forecast for B6 CMIS of £60m in 2023/24 is based upon an extrapolation from October 2023 (of £40m) to the end of the fiscal year. Together with EC5 CMIS, this is calculated as £334m benefit over the RIIO-2 period.

Key RIIO-2 Deliverables and progress

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

Deliverable	Status of associated milestones
D8.1 New areas of need identified, and 3-6 tenders run.	100% complete

Activity A8.2 - Enhance tendering models

Deliverable	Status of associated milestones
D8.2 Improved tender approaches that enable more participants to enter the market.	100% complete

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

Deliverable	Status of associated milestones
D8.3 Frameworks based on competitive regime not monopoly regime.	100% complete

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

Deliverable	Status of associated milestones
D9.1 Developed and trialled connection wider works (CWW) processes with TOs.	100% milestones no longer valid

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

Deliverable	Status of associated milestones
D9.2 Completed and published connection wider works trials, in selected geographic regions, in NOA.	100% milestones no longer valid

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

Deliverable	Status of associated milestones
D9.3 Incremental expansion of the process (following trials) which results in making recommendations on all connections wider works in NOA 2026.	100% milestones no longer valid

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

Deliverable	Status of associated milestones
D9.4 Efficient planning process agreed with TOs	100% milestones no longer valid

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

Deliverable	Status of associated milestones
D10.1 NOA expertise shared with DNOs	100% complete

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

Deliverable	Status of associated milestones
D11.1 Improved identification of when is the most economical time to invest and the most efficient solution	75% complete 25% delayed – internal reasons

Activity A11.2 - Implement probabilistic modelling

Deliverable	Status of associated milestones
D11.2 Improved identification of network needs	100% complete

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

Deliverable	Status of associated milestones
D11.3 Improved assessment of voltage requirements, and ability to look across a range of network needs at the same time	100% complete

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

Deliverable	Status of associated milestones
D11.4 Improved assessment of stability requirements across the network.	100% complete

Forecasted benefits

Gross Benefits 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	-	-	29.5	29.5	59.0	118.0
Extend NOA approach to all connections wider works	-	37.0	37.0	37.0	37.0	148.0
Support decision making for investment at the distribution level	-	-	10.0	10.0	10.0	30.0
Total Gross Benefit	127.5	97.8	171.4	157.6	170.4	724.8

The total benefits for A8 - A11 NOA enhancements are between £521 million and £987 million, with a central case of £725 million over the RIIO-2 period.

End of Scheme NPV view of benefits:

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Consumer benefit of implementing commercial solutions	N/A	N/A	-	143	251	394
Extending NOA to end of life asset replacement decisions	No longer valid	No longer valid	No longer valid	No longer valid	No longer valid	No longer valid
Extend NOA approach to all connections wider works	No longer valid	No longer valid	No longer valid	No longer valid	No longer valid	No longer valid
Support decision making for investment at the distribution level	-	-	-	-	-	-
Constraint Management Intertrip Service consumer benefit	-	80	63.3	96.2	94.5	334
Total	-	80	63.3	239.2	345.5	728

Once the commercial solution has been given a recommendation in the NOA, the constraint management intertrip service (CMIS), formerly constraint management pathfinder (CMP), identifies a route to deliver the benefit. Presently, the B6 CMIS 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[38]. Once the infrastructure needed to deliver this service is built by the transmission owners, the savings can be realised. We expect these savings for B6 to be £210 up to 2024/25. In addition, £815.3m in savings could be realised through the CMIS for the EC5 boundary in the years up to and including 2030. Presently, the forecasted savings if all of the commercial solutions are delivered is estimated at £728m.

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	Year 1 (2021-22), 55% of all services procured through competitive means (meeting expectations) Year 2 (2022-23) 43% of all services procured through competitive means (below 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)	i) Saved balancing costs: £726m in the period 2021-26 from new operability measures. ii) Saved infrastructure costs: RDP avoided asset build estimated at £12.9m as per RIIO2 Business Plan iii) Monetised carbon reductions: Pathfinders: Estimated £5.2bn (2021-22 to 2025-26) RDPs: Estimated £260m (2023-24 to 2025-26).
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).	NOA consumer benefit: £212m (over RIIO-2 period), Consumer benefit from Large Onshore Transmission Investment (LOTI) CBA: £1.7bn (2021-22 to 2022-23) Consumer benefit from ad-hoc cost benefit analysis (CBAs): £1.6bn (2021-22 to 2022-23)

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

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	NOA: 136 asset-based solutions (including 22 new options) and 8 commercial solutions submitted to NOA 2021/22. 29 asset-based solutions (including 21 new options) and 8 commercial solutions submitted to NOA 2021/22 refresh in 2022-23. A wide range of solutions were considered in NOA pathfinders.

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.

BP1 Assumption	End of scheme 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 as a minimum. Additional consumer benefit is expected from the additional 0.7GW but we are unable to quantify that at this moment.
Extending NOA to end of life asset replacement decisions		
TOs provide asset replacement data	Milestone no longer valid, as agreed with Ofgem.	This NOA improvement is planned as part of the Electricity Transmission Network Planning Reform within BP2.
Greater information provision will help the decision-making process	Milestone no longer valid, as agreed with Ofgem.	This NOA improvement is planned as part of the Electricity Transmission Network Planning Reform within BP2
Extend NOA approach to all connections wider works		
TO will complete additional work through studying more boundaries and creating more options	Milestone no longer valid, as agreed with Ofgem.	This NOA improvement is planned as part of the Electricity Transmission Network Planning Reform within BP2
We will find issues on the newly-created boundaries. We may find no issues, resulting in no benefits	Milestone no longer valid, as agreed with Ofgem.	This NOA improvement is planned as part of the Electricity Transmission Network Planning Reform within BP2

because no actions would be needed		
Support decision making for investment at the distribution level		
Expected level of investment at the 132kV level is £40 million per year	The NOA currently focuses on Transmission level reinforcements which is where the highest volume of system constraints are experienced.	We conduct cost benefit analysis on behalf of the DNOs, which have been reported within our RRE 3B.
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

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
Summary	We now estimate gross benefits of £18m over RIIO-2, which is an increase of £9.9m on the original BP1 assumption of £8.1m. This gives a net present value (NPV) of £13.5m compared with the BP1 assumption of £2m. The following drivers / assumptions impacting this CBA have changed since BP1:

Significant increase in volume of connection applications	BP1 assumed an 8% annual increase in applications being managed by our Customer Connections Team, but we now estimate this to be 49% per year on average during RIIO-2.
Increase in complexity	We have seen further increase in the change to existing connection contracts to accommodate co-location / mix in technologies, along with the support to growth of number of Battery Storage and Offshore Wind Connections.
Increase in FTE	In response to the increased volume and complexity of connections we have increased FTE from the BP1 assumption of 49 to around 74 at the end of March 2023, and planned to reach 102 at the end of RIIO-2 (in line with BP2).
Customer service improvements	The new and enhanced A14 deliverables will mitigate the impact of the increased workload resulting from increased number of connections
Delay to launch of Connections Portal Phase 1	The Portal went live on 13 March 2023, 11 months later than assumed in BP1.

The impact of these changes on the costs and benefits are as follows:

Increased efficiency savings for customers	We believe the assumptions regarding efficiency savings for customers who use the connections process and the resulting reduction in FTE requirements, are still valid. These will now be observed across a greater

	number of connections, increasing the overall benefits delivered by £8.9m.
Improved CSAT due to customer service improvements	Estimated benefit of £1m in 2025-26. Our Customer Connections Team has a key role of engagement and providing a service to Customers across GB. Improvement to the service we provide via not only initiatives identified in BP1 but also BP2 highlights our commitment to ensure we perform against our CSAT Metrics. This performance has been captured as a Benefit that can be claimed against the Reward that may applied if Networks continues to perform to achieve a score of 4.
Increased cost of FTE	£3m increase in OPEX compared with BP1 assumptions. The OPEX increase has been included in the calculation to determine the revised benefits in the two rows above.
Delay to delivery of benefits	Benefits delayed by 11 months as a result of the delayed launch of the Portal

Detail:

The Customer Portal, now known as Connections Portal, consists of a series of delivery phases, of which Phase 1 culminated in the delivery of an MVP Platform on 13 March 2023, accessible to all Customers across GB.

A BETA release took place on the 2 December 2022, which enabled the Project Team to work with a selected group of Customers (85) to identify areas within the platform that didn’t work or required a small fix to be implemented, ahead of wider release to all industry in March to ensure the robustness of the platform upon release to hundreds of users.

The Phase 2 of the Connections Portal release still looks to:

- provide a product that would meet customers’ expectations
- enable a more complete experience as part of the application process
- deliver on out commitments to provide Customers with a more automated, self-service platform which improves customer experience as part of the connections application process

The assumptions originally made regarding the increase in customer connections applications have increased from an average growth of 8% to 67% in 2021-22 and 74% YTD in 2022-23. The growth in applications will impact the overall benefit if the growth observed thus far is maintained. There will be a need for continuous review of the volume of applications being processed over the next years to be able to confirm the overall benefit as the volume of application is market driven.

The increase in workload has been sustained all throughout this financial year and we have seen further increase in the change to existing connection contracts to accommodate co-location / mix in technologies, along with the support to growth of number of Battery Storage and Offshore Wind Connections. Our response to this sustained increase in volume and complexity was as follows:

- The Connections Team Structure has been changed and number of FTEs increased, and continues to increase up to 102 FTEs by end of RIIO T2 as per our BP2 submission. Currently growing up to 74 FTEs by end of March 2023, following onboarding of new FTES ahead of the start of the new Business Plan period.
- 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 our ability to meet licence conditions whilst ensuring that the quality of the connection customer offer is not compromised.

- Release of our 5 Point Plan to manage constraints on the system.
- The Connections Reform Project, which looks to develop the proposal for the Connections Process, is to be reformed to the deliver on the needs of a resilient and secure energy system that meets the Net Zero Targets.
- Focus placed on Customer and Stakeholder Engagement strategy, by finding new and updating existing ways of communicating and engaging that are relevant for our Customers and Stakeholders.

Calculation of monetary benefit to consumers

The table below shows the end of scheme view of benefits compared with those included in BP1.

We estimate gross benefits of £18m over RIIO-2, an increase of £9.9m on the original BP1 assumption of £8.1m.

Over the five year RIIO-2 period we estimate an NPV of £13.5m, an increase of £11.3m versus BP1. Sensitivity analysis suggests an NPV range of £9.4 million to £13.9 million over the RIIO-2 period.

Over ten years, we estimate an NPV of £24.6m, an increase of £9.5m versus BP1.

All figures in £m	RIIO-2 gross benefits	5 year NPV	10 year NPV
Original BP1 assumptions	8.1	2.2	15.1
End-of-scheme view	**18.0**	**13.5**	**24.6**
Difference	+9.9	+11.3	+9.5

Figures are rounded to the nearest £0.1m

The benefits are estimated based on efficiency savings, and customer service improvements, as follows:

Efficiency Savings

Assumption	BP1 / current	Justification
Growth in number of connection applications per year	BP1: 8%	BP1: Slowing from today's around 20% at the time of BP1, based on actual number of connections
	Current: 49% (on average)	Continued growth of connections applications of 64% overall in FY23
Cost saving resulting from roll out of our secure online management facility in April 2025	BP1 and BP2: 30% cost saving	Based on IT investment delivery timelines and the connections hub will provide an element of 'self-serve' for customers
Total number of FTEs	BP1: 49 FTE Current: 102 FTE	Based on IT investment delivery timelines

Efficiency Savings - Sensitivity analysis used for determination of the monetary benefit to Consumers	
Market factors	Repeated the analysis with the high and low cases number of connection applications
Delivery factors	Modelled a one-year delay in delivery for the low case, from 2022/23.

Number of applications	**2021/22**	**2022/23***	**2023/24**	**2024/25**	**2025/26**
Applications	1050	1160	1327	1488	1655

*We have already seen number of applications for FY23 exceed average projections, YTD 1539; However, we maintain numbers used for calculation of CBA as this steep increase can be limited to one year. If exponential increase continues to be observed BP2 CBA will be reviewed.

Customer Service Improvements (additional Benefit – change from BP1)	
Assumptions	Justification
Networks directorate maintains performance score of Low 4	The new deliverables will mitigate the impact of the increased workload due to the increased number of connections
The ECC Team contribute 25% of total Customer Service	This is likely an underestimate as the ECC team has some of the greatest exposure to customers and exposure is growing

Customer Service Improvements – Benefits Calculation	
Assumptions	Outcome
Assume a Level 4 CSAT is Maintained throughout the RIIO Period	Reward is equal to £4m*[1]
The ECC Team contribute 25% of total Customer Service	Total claimed in 2025/26 is equal to £1m*[2]

*[1] *Reward should be representative of the benefit the ESO has delivered to customers through maintaining Quality of Service and not allowing service levels to decline due to the number of connections increasing*

*[2] *25% of this benefit can be claimed in 2025/26 to account for ECC team specifically*

Calculation of benefits

The way benefits were calculated can be understood separating the calculation principles into to two benefits areas:

Efficiency Savings

- Benefits from efficiency savings are directly proportional to the total number of connection applications. At BP1 we used a figure of 400 connection applications per year while at time of submission BP2, and the current forecast, is an average of 1,381 connection applications per year. We are observing a rising and sustained number of connection applications and therefore any benefit associated with improving efficiency during grid connections will also increase.

- The saving calculation was achieved by understanding how much of the process will be automated thus removing the level of input from Team Members through the life of a connections - number of hours per connections allocated to FTEs is expected to be reduced by 30% by the end of RIIO T2, when all phases of Connections Portal have been released and new processes, automation and enablement of some online account management is BAU.

Customer Service Improvement

- This is a new benefits case to account for the material changes in A14.3. It represents £1m of benefit in the last year of the RIIO period.
- The calculation of this Benefit was done by identifying that 25% of the incentive payment to Role 3 would result of a contribution from the Electricity Customer Connections Team

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	100% complete

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	100% complete
D14.4.2 Phase 2 of the connections hub concluded	This is a BP2 Deliverable

Forecasted benefits

Forecasted in original CBA:

Benefits £m	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

End of Scheme view:

Benefits £m	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total	0	3.7	4.2	4.7	6.3	18

Delay to delivery on forecasted benefits:

The development and introduction of the Connections Portal Phase 1 went live on 13th of March. This is a delay of 11 months from the original timeline

The delay to the programme is driven by:

- Limited knowledge of the level of complexity associated with the development and build of the relevant functionalities across Salesforce and Portal Platforms at the time the scope and programme were developer
- Some of the tasks of development and build have taken up to 3 times longer than originally allowed for on the programme
- The need to align with our other IT Programmes such as DEP and DAP
- Resource availability (due to increase of scope as noted on the 1st bullet point, we had to increase specialist resource headcount which faced some challenges due to lack of availability of resources readily available with the right set of skills and knowledge in the open market)

Related metrics/ Regularly Reported Evidence

N/A

Sensitivity factors

The estimated consumer value stated in the original 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	**Present**	**Commentary**
The number of connection applications grows 8 per cent per year	We are still seeing a continual exponential increase in connection applications. YTD 64%, following a 67% increase in 21/22	The volume of applications is 180% overall higher in March 2023 than what it was in January 2021. Due to the changes of a micro (GB) and macro (GB) economic landscape and energy security we are seeing changes to the way the market is responding, making it very difficult to predict how customers and developers will behave with regards to new applications and progressing with their contracted connections.
Roll out of our secure online account management (Customer Portal) facility in April 2025 brings a 30% cost saving	Customer Portal Phase 1 completed on 13 March 2023.	Consumer benefit expected to be in line with original assumptions but delayed with regards to when benefits shall be observed due to the delay with release of the Portal from April 22 to March 23.

	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 finding fit for purpose data platforms that deliver on value, but which don’t attract an increase in expenditure with IS Project.

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

Note re redacted content in this CBA: As per Paragraph 5.3 of the ESORI Guidance document, the ESO "should redact any confidential or commercially sensitive information". For this reason we have redacted certain content within the following CBA.

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

Summary

RDPs remain on track to deliver the benefits originally set out, although [redacted] has been realigned to be delivered in parallel with [redacted]. There has been no driver to complete this work to the earlier timescale, and alignment of the [redacted] projects will reduce overall ESO delivery costs whilst ensuring that learnings from the [redacted] [redacted] and [redacted] can be fed back into the development process.

For the Whole system operability NOA type assessment, we have progressed Enhanced Frequency Control Capability (EFCC) project phase 1 and now concluded that other frequency management products developed during this regulatory period could cover the system needs up to 2025. In the meantime, we have developed and implemented many other operability solutions such as Dynamic Containment, Accelerated Loss of Main Protection Program, implementation of Frequency Risk and Control Report (FRCR) and Pathfinder projects. The detailed benefits are reported in RRE3A Future savings from Operability Solutions, the total benefits so far in BP1 are £726.5m.

Calculation of monetary benefit to consumers

RDP carbon savings – we have repeated the calculation undertaken in the original RIIO-2 CBA (table 147) [39]. Connected volumes of [redacted] and [redacted] have been used based on the latest [redacted] data from [redacted] and these volumes have been extrapolated for [redacted].

We have also assessed technology types to ensure we are assessing volumes of zero carbon generation, and we have used generic annual load factors for these generation types drawn from those published in the TNUoS charging methodology. Carbon intensity values are drawn from the FES22 consumer value figures.

RDP asset savings – this has been incorporated for [redacted] only and is the value of £12.9M used [redacted].

Key RIIO-2 Deliverables and progress

Activity A1.1 – Ongoing Activities

Deliverable	Status
D1.1.6 Assessment of future operability challenges communicated through the Operability Strategy Report	100% complete

Activity A4.6 - New services market development

Deliverable	Status
D4.6.1 Development of competitive approaches to procurement of stability	78% complete 22% delayed – external reasons
D4.6.2 Development of competitive approaches to procurement of reactive power	86% complete 14% delayed – external reasons

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% complete

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[39] ESO RIIO-2 Annex 2 – Cost-benefit analysis report (nationalgrideso.com)

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	100% complete

Activity A15.5 - Develop Regional Development Programmes (RDPs)

Deliverable	Status
D15.11.1 Forward Plan 2020-21 [redacted]	100% delayed – external reasons
D15.11.2 Forward Plan 2020-21 [redacted]	100% delayed – external reasons
D15.5.1 Start [redacted] of RIIO-2	75% complete 25% delayed – internal reasons
D15.5.2 Start [redacted] of RIIO-2	100% complete
D15.5.3 Start [redacted] of RIIO-2	33% complete 66% delayed - consumer benefits
D15.5.4 Start [redacted] of RIIO-2	75% complete 25% delayed – internal reasons
D15.5.5 Development of roadmap to deliver GB rollout of functionality (visibility & control of DER) developed through [redacted].	100% complete

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[40]	50% complete 50% no longer valid

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	100% complete

Forecasted benefits

Forecasted in original CBA: Whole system operability NOA-type assessment

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Operability savings	0	125.8	125.8	125.8	125.8	503.2

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[40] Note that the MCS project builds on the EFCC project referred to above. This is also linked to investment 500 ”Zero Carbon Operability”.

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

Forecasted in original CBA: Regional Development Programmes – carbon savings

Benefits £ millions	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Carbon Saving	No RDP	No RDP	2.0	2.0	2.1	6.1

End of Scheme view:

Benefits £ millions	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
RDP	12.9	19.4	76.6	88.7	113.9	311.5
Whole system operability NOA type assessment	27.2	699.3				726.5
Total	40.1	718.7	76.6	88.7	113.9	1,038

[redacted] benefits are due to both net efficiency savings of non-build vs traditional investment solution and earlier connection of zero carbon DER. Going forwards RDP benefits have been attributed to carbon savings due to earlier connection of zero carbon generation. We have realised these benefits at the point at which DER are able to connect and, in absence of underlying data, assumed already connected DER have not connected until [redacted]. For future RDPs ([redacted]) we have quoted anticipated benefits similar to those for [redacted].

[redacted]

With many Whole system operability developed and implemented, we have seen more consumer benefits realised through system balancing cost saving (details refer to RRE3A Future savings from Operability Solutions). We have a plan to develop further solutions in this area such as Stability Pathfinder phase 2 and 3 to explore more benefits during the transition into Zero Carbon Operation.

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.	Total balancing costs of £6.9bn vs benchmark of £3bn for the two-year BP1 period (below expectations).
RRE 1I Security of supply	Successfully addressing operability needs should enable us avoid voltage excursions, avoiding a deterioration in performance	Over the two-year BP1 period, there were zero frequency excursions, and four instances where the frequency was 0.3 – 0.5 Hz away from 50Hz for more than 60 seconds.

Metric 2A Competitive Procurement	Lead to increased competition for operability needs, which will lead to improvements in the long term	Year 1 (2021-22), 55% of all services procured through competitive means (meeting expectations) Year 2 (2022-23) 43% of all services procured through competitive means (below expectations)
RRE 2B Diversity of service providers	Where these activities lead to operability needs being provided by different technologies, this will lead to improvements	See RRE 2B in Demonstration of Plan Benefits section
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	i) Saved balancing costs: £726m in the period 2021-26 from new operability measures. ii) Saved infrastructure costs: RDP avoided asset build estimated at £12.9m as per RIIO2 Business Plan iii) Monetised carbon reductions: Pathfinders: Estimated £5.2bn (2021-22 to 2025-26) RDPs: Estimated £260m (2023-24 to 2025-26).
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	NOA: 136 asset-based solutions (including 22 new options) and 8 commercial solutions submitted to NOA 2021/22. 29 asset-based solutions (including 21 new options) and 8 commercial solutions submitted to NOA 2021/22 refresh in 2022-23. A wide range of solutions were considered in NOA pathfinders.

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.

Whole system operability NOA type assessment

Assumption	**Present**	**Commentary**
Forecast operability costs of £596 million per year	Current operability costs are lower than forecast £2.35billion for the period June 2021 – May 2022	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	This benefit category has been used solely for [redacted]. [redacted]
Additional renewable capacity unlocked by each RDP is [redacted]	RRE 3A assessment of [redacted] and [redacted] states the following DER capacities have been unlocked by each RDP: [redacted] [redacted] [redacted]	This suggests that each RDP unlocks on average [redacted], leading to a higher consumer benefit. The impact of this on overall benefits has been countered by a revised load factor estimate of 10% based on generic annual load factors for renewable technologies used in TNUoS charge calculations. The original business plan used a factor of 40%.
Carbon intensity assumption from FES 2019 Steady Progression	Updated with carbon intensity figures from FES 22 'Consumer Transformation'. This ranges through the assessment range from comparable to around 40g CO2/kWh higher.	This increases the estimated benefit by around 8% over the RIIO-2 period.
Six RDPs will be delivered over the RIIO-2 period	This is still our intention; [redacted] has been rephased to align with development of [redacted]. There was no operational driver to complete earlier, and project delivery will be more	Consumer benefit expected to be in line with original assumptions

	efficient with [redacted]	
BEIS short-term traded carbon values	Updated with values from BP2 CBA report.	This has significantly increased the benefits from RDPs by around a factor of 16.

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

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

Summary

We now estimate gross benefits of £367m over RIIO-2, which is an increase of £143m from the original BP1 assumptions.

The drivers of the increase in benefits are as follows:

1. Higher wholesale energy prices compared with BP1 assumption, resulting in £115m increase in constraint cost savings from activity 16.2 during the BP1 period.
2. High engagement from the TOs and the completion of low-risk/high-yield initiatives. This has led to approximately £29m increase in constraint cost savings from activity 16.2 during the BP1 period.

16.2:

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 BP1 period of £220m, which is an increase of £143m on BP1. This accounts for 100% of the overall estimated increase in benefits on this CBA. The savings are wholly made up of savings as a result of enhanced service provisions agreed between the ESO and Transmission Owner in the England and Wales region.

16.3 and 16.4:

The improvement of the activities around D16.4.1 coupled with the progress made with A16.3 are still expected to realise consumer saving consistent with the initially estimated £25m in total over the last two years of RIIO-2. The delivery of whole system notifications (A16.4) and Deeper Access Planning (A16.3) will not yield commercial results until 25/26 with the preceding BP1 and BP2 years still being dedicated to scoping and development activities. The deliverables forming 16.3 and 16.4 are currently on track and in line with what was expected in BP1. Whilst some of the milestones show below as delayed, it's been agreed with Ofgem that the original dates were showing as one or two years too early and this has now been corrected for BP2.

Calculation of monetary benefit to consumers

The calculations for activity A16.2 do consider the actual wholesales energy cost.

The process is as follows. For each initiative presented by a transmission owner or identified by the ESO there will be a forecast figure, an ex-ante figure and an ex-post figure.

The forecast figure is used to ‘trigger’ the decision. A calculation is made which makes comparison between the transmission owners’ costs of delivering the enhancement and the ESO calculated consumer savings. If the consumer savings outweigh the transmission owner costs, then a proceed decision is given. There is therefore some sensitivity in the assessment.

An ex-ante calculation is made once the enhancement has been delivered to ensure that the initiative is delivering savings as expected.

An ex-post calculation is made once the enhancement has been completed or the financial year has drawn to a close to calculate the actual savings using real energy costs. As this uses historic rather than forecast energy prices, we have a high degree of confidence in the reported figures.

An initiative, as referenced above, will typically be a service that the ESO has procured from a TO in order to increase the transfer capability across a transmission constraint boundary. The greater the transfer capability across a boundary, the less the ESO will have to spend on managing the boundary with commercial actions. The calculation therefore is the difference between the ESO spend with the initiative in place, versus the ESO costs incurred without the initiative in place.

For 2022/23 year the consumer savings were above the initial forecast. The main driver for this increase has been the high wholesale prices. We estimate that this accounts for about 80% of the uplift. The remaining 20% of the uplift has been due to the completion of low-risk/high-yield initiatives that were only identified as a result of the proactivity and engagement of the TOs during the BP1 period.

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 of associated milestones
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 of associated milestones
D16.2.1 GB wide NAP process goes live including extension of the existing SO-TO payment mechanism to the whole of GB.	100% complete

Activity A16.3 - Work more closely with DNOs and DER to facilitate network access

Deliverable	Status of associated milestones
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	100% complete
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	25% complete 75% delayed – external reasons
D16.3.4 Deeper access planning go-live	50% complete 50% delayed – external reasons

Activity A16.4 - TOGA / Whole system outage notification

Deliverable	Status of associated milestones
D16.4.1 Scoping exercise concluded for delivery of enhancements to outage notifications	25% complete 75% delayed – external reasons

Forecasted benefits

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	36	42	49	57	224

End of Scheme view:

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total	40	179	42	49	57	367
Variance vs original CBA	-	+143	-	-	-	+143

Our original CBA stated that benefits associated with activity A16 will start to be delivered from 2021/22. In the first three years, all of the benefit delivered comes from 16.2. In in the final two years, there will be benefits across 16.2, 16.3 and 16.4.

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.

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	Total balancing costs of £6.9bn vs benchmark of £3bn for the two-year BP1 period (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.	Estimated savings of £4.2bn in avoided constraints costs over the two-year BP1 period.

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.

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	Constraint costs in 22/23 have been substantially higher than expected due to the high wholesale cost of energy. As there is a lot of uncertainty around future gas prices, at this stage we assume no change from BP1 assumptions for future years.
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.	The GB wide NAP process including extension of the existing SO-TO payment mechanism is very well established. There is a high level of engagement and understanding of the processes across the TOs and the ESO.
DNOs and TOs engage with the new process	All DNO parties have been initially engaged with positive feedback,	DNO engagement continues while the DNOs themselves progress through consultations regarding their DSO

	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.	transition. Developments have been made to the products developed in conjunction with the trial partners. The planned approach is now to use the more mature RDP (regional development programmes) as case studies to allow us to understand the requirements for code modification and offline modelling changes. 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 has shown some positive results but draft code modifications are not due to take place until 2023-24. The TOs’ ongoing engagement with the enhancements to the Network Access Planning (NAP) policy was noted as a sensitivity but has been shown to be very positive to date.

Consumer benefit case study for Role 3 - Holistic Network Design

Activity

Holistic Network Design (HND)

The HND sets out the network requirements to facilitate the connection of 23 GW of in scope offshore wind projects. When combined with existing offshore wind projects and those already further advanced in their development, the HND should enable the connection of 50 GW of offshore wind in Great Britain by 2030.

The HND includes the offshore transmission network, the onshore works essential to facilitate each connection and the network needed to transport the electricity around the country. The design seeks to balance the needs of consumers, developers, communities, and the environment. The delivery of a coordinated offshore network will enable zero carbon generation to connect in an efficient way, supporting the government's 50 GW ambition whilst minimising the impact on consumers and communities.

The HND covers the following future offshore wind projects:

- A total of 8 GW of projects successful in The Crown Estate Offshore Wind Leasing Round 4
- A total of 11 GW of projects successful in the ScotWind leasing round,
- Assumptions on 1 GW of floating wind from the upcoming Celtic Sea leasing round
- 3 GW of other sites that are located near to Round 4 and ScotWind sites, to test whether there are opportunities for coordination

The diagram below shows the full set of major network requirements recommended by the HND.

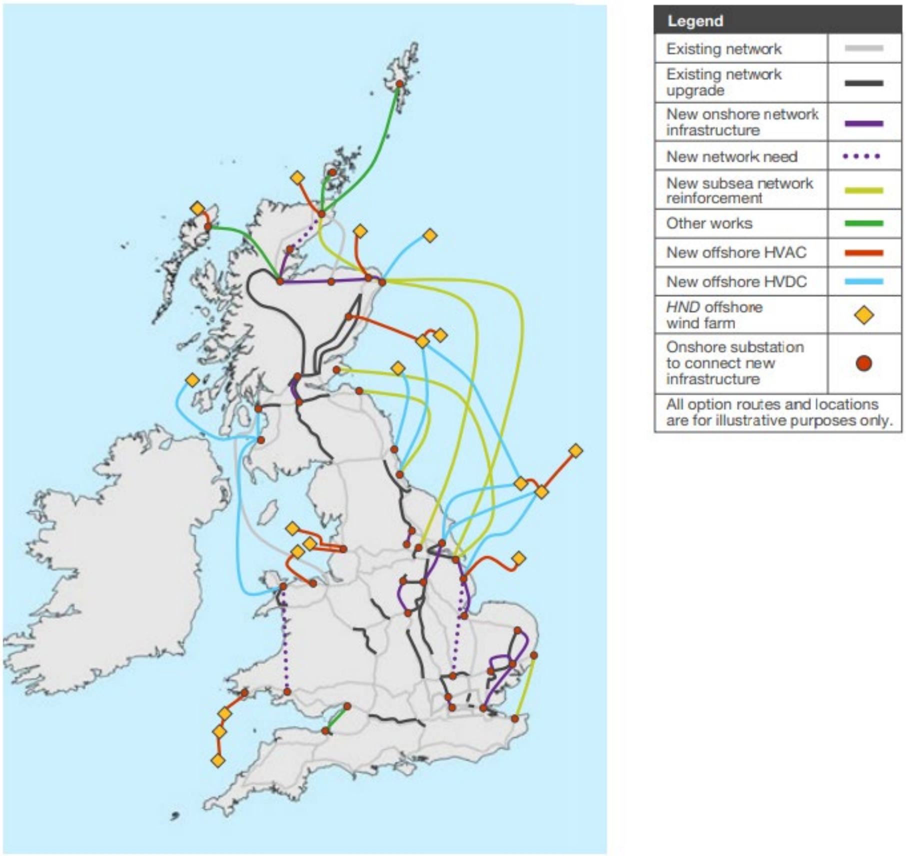

Figure 1 - Note that this diagram shows both the offshore and onshore networks

Role	Role 3
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050 • The Electricity System Operator (ESO) is a trusted partner
Key RIIO-2 Deliverables	Activity A15.10 relates to Offshore Coordination. The HND is part of the Offshore Coordination project, although was not included at the time of producing the BP1 delivery schedule as the scope of the Offshore Coordination project was not yet known.
Is the consumer benefit mainly this year or in future years?	Future years: the recommendations within the HND will facilitate the future connection of 23GW of offshore wind. The HND will deliver overall net consumer savings of approximately £5.5bn. These cost savings are calculated over a 40-year asset life period, starting in 2030. The HND balances four network design objectives as set out by the terms of reference: • Economic and efficient costs • Deliverability and operability • Environmental impact • Local community Impact
Calculation of monetary benefit to consumers	To determine the consumer benefit of the HND, it is necessary to consider how the in-scope wind farms would have been connected if the HND had not been carried out. We created an optimised radial design to enable us to evaluate the benefits of a coordinated design against a counterfactual. The optimised radial design consists of point-to-point connections between offshore wind farms and onshore interface points. The approach used takes into consideration all in scope wind generation, rather than considering each application individually under the previous process. This provides a credible counterfactual against which to compare our recommended design. Optimised radial design (shown below)- this diagram just shows the offshore infrastructure

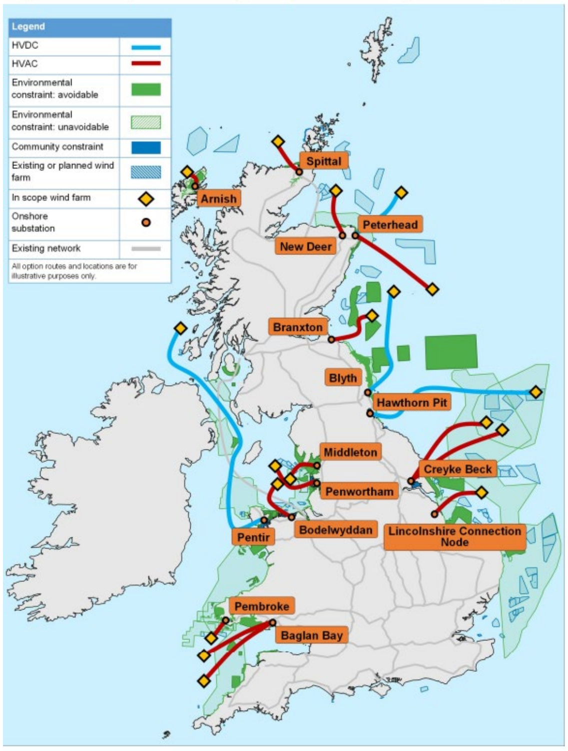

Figure 2 - Optimised Radial Design - Offshore Infrastructure Only

Recommended design (shown below)- this diagram just shows the offshore infrastructure

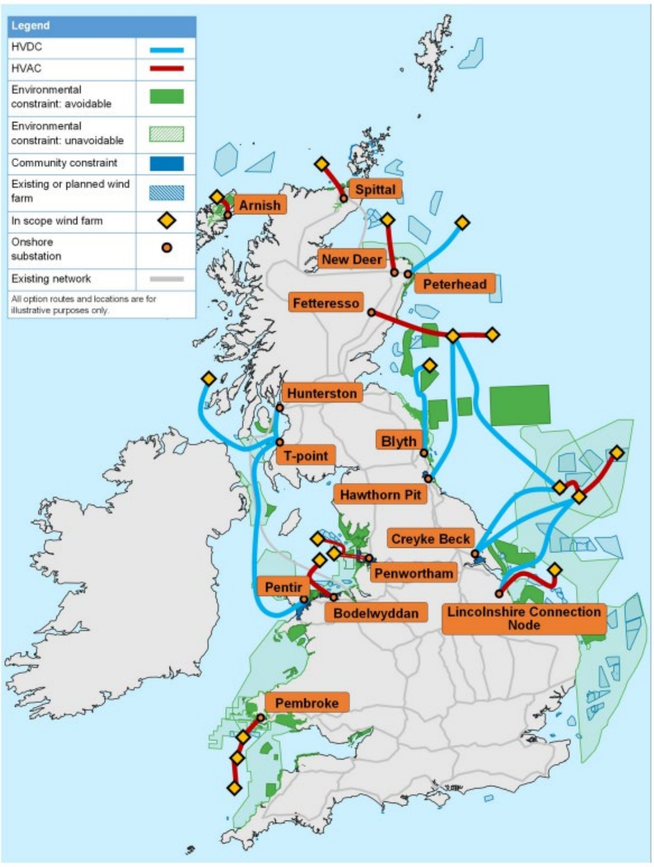

Figure 3 - Recommended Design - Offshore Infrastructure only

When the entirety of Great Britain is taken into account, the recommended design performs better than the optimised radial design from an economic perspective. Although the optimised radial design has lower capital costs (as less offshore infrastructure is needed), it leads to significantly higher constraint costs. The constraint costs for the recommended design are £13.bn lower than for the optimised radial design.

It is also worth noting that the coordinated parts of the recommended design provide redundancy compared to the radial design (which simply provides a minimum-sized connection for each wind farm). This redundancy translates into higher capital costs for the coordinated parts of the design. The economic optimiser used in the design process considers the cost of replacement energy if offshore wind power cannot get to shore.

Based on the assumptions used in our economic modelling, the costs of the offshore network infrastructure required in the recommended design would be around £32 billion. This compares to around £24.4 billion for the optimised radial design (giving the differential of £7.6 billion). These costs are based on high-level assumptions, and we would expect them to change during the Detailed Network Design stage as routing and technology choices are decided.

The economic comparison between the optimised radial design and the recommended design is shown in the table below:

Cost Type	Most economic option	Cost differential (£bn)
New offshore/onshore capital and operational costs	Optimised radial	£7.6bn
Onshore Boundary reinforcement costs	Equivalent	-
Constraint costs	Recommended	£13.1bn
Total costs	Recommended	£5.5bn [41]

The HND will therefore deliver significant benefits when compared to an optimised radial design, including overall net consumer savings of approximately £5.5 billion. The recommended design leads to an additional £7.6 billion of capital costs due to the additional offshore infrastructure, but this is outweighed by the £13.1 billion savings in constraint costs that are expected to result from the additional network capacity this infrastructure provides. This equates to a saving of £2.18 per year on the average customer electricity bill.

Assumptions made in calculating monetary benefit

New offshore/onshore capital and operational costs: The cost of constructing and operating all offshore assets to connect the generators to the system, plus any onshore works required to connect in a manner compliant with relevant standards that are not NOA works. The costs of new offshore transmission network infrastructure are based on component unit costs derived from data provided by equipment suppliers. The input cost assumptions have been provided to in scope developers and Offshore Transmission Network Review (OTNR) stakeholders.

Onshore Boundary reinforcement costs: The cost of constructing works that are required for the connection of the generators and/or boundary reinforcement, which have previously been included in a NOA assessment. These costs are broadly comparable between all options considered; however, it should be noted that there is

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[41] The £5.5bn figure is calculated by subtracting £7.6bn from £13.1bn.

	a limit to the amount of boundary reinforcement that can be delivered in the lead up to 2030. This is due to the time taken to deliver large scale infrastructure projects, as well as other factors including supply chain and network access. However, if these delivery constraints were removed and more network reinforcement options were available, the HND would reduce the requirement to invest in onshore infrastructure. This is demonstrated through the significant reductions in constraint costs it provides compared to the optimised radial design. Constraint costs are the cost of taking balancing actions to redispatch generation to prevent unacceptable network flows across parts of the network that have limited capacity. These consist of actions to decrease generation output in one part of the country, and actions to increase generation output in a different part of the country. The constraint costs we have modelled are consistent with those used in the ESO's other economic modelling, for example the Network Options Assessment (NOA). All cost savings are calculated over a 40-year asset life period, starting in 2030, using 2021/22 prices, unless otherwise stated.
How benefit is realised in the consumer bill	The higher offshore network costs associated with the HND's recommended design would translate into higher TNUoS costs, with an average increase of £1.44 per year. The lower constraint costs with the HND's recommended design would translate into lower BSUoS costs, with an average saving of £3.62 per year. This will lead to a net saving of £2.18 per year. These figures are in 2021/22 prices and are on individual household electricity bills. They are based on a set of assumptions which are standard across the ESO's consumer bill analysis.
Non-monetary benefits	The HND balances deliverability, economic, environmental and community impact criteria and will deliver significant benefits when compared to an optimised radial design, including: • A reduction in the impact on the environment with up to a third smaller footprint from offshore cables connecting to shore as a result of the increased use of high voltage direct current (HVDC) technology, reducing the impact on the seabed. • Increasing the availability of offshore wind on the system by 32 TWh over a ten-year period from 2030, equivalent to powering 10 million homes for an entire year. • Reducing cumulative CO_2 emissions from gas powered generation between 2030 and 2032 by 2 million tonnes of CO_2 – equivalent to grounding all UK domestic flights for a year – through transporting power produced by offshore wind to where it will be used more of the time, reducing the need for fossil fuel generation to be used in its place
Assumptions made in calculating non-monetary benefit	The 10 million homes figure is based on today's average household electricity consumption figures

Consumer benefit case study for Role 3 - Enhanced Services with Transmission Owners

Activity	The SO:TO Optimisation output delivery incentive (ODI) is a 2 year trial incentive, designed to encourage the Transmission Owners (TOs) to work collaboratively with the ESO to identify solutions to reduce constraint costs, using existing STCP11-4 procedures. The network access planning team in the ESO assesses the eligibility of the enhanced services, to ensure they deliver over and above business-as-usual activity. Building on the success of the trial, Ofgem have recently consulted on their proposal to continue to operate the ODI for the remaining years of the RIIO-2 price control.
Role	Role 3
ESO Ambitions	• the ESO is a trusted partner • a whole system strategy that supports net-zero by 2050
Key RIIO-2 Deliverables	A16.2 Enhance the Network Access Policy (NAP) process with TOs
Is the consumer benefit mainly this year or in future years?	The consumer benefit occurs mainly in the year that the enhanced service from the TO is delivered, although the benefits could be enduring if the enhanced service involved a physical upgrade to equipment which would remain for the lifetime of the physical asset. By enhancing the process with the TOs we are identifying more potential enhanced solutions for high cost outages. This is resulting in significant savings in constraint cost: in 21/22 we saved £42.5m and in 22/23 we have saved £293m in constraint costs.
Calculation of monetary benefit to consumers	The enhanced service aims to improve the constraint limit, which is the maximum amount of power that can flow out of an area to the wider transmission system (or flow into an area, from the wider transmission system). To ensure the flow of power does not breach the constraint limits, we have to take actions in the BM to change the generation output and this incurs a cost. If the constraint limit can be increased, we have to take fewer action on generation and the outturn cost is reduced. The saving is calculated as the constraint volume (MW) x cost (£/MWhr) x duration (hr). An outturn, ex-post saving is also calculated using the metered flows on the boundary circuits and the cost of constraints.
Assumptions made in calculating monetary benefit	The forecast saving calculation uses these forecast data sets: demand, generation running patterns, interconnector flow & direction and BM prices. Our forecasting tool uses a statistical output of wind output. The constraints limits are calculated from the power flow studies using the system topography that is expected at the time the enhanced service is used.
How benefit is realised in the consumer bill	The constraint costs incurred in managing the system are included in BSuOS. From April 2023 the BSuOS charge is paid for by end consumers in their electricity bills. Prior to that the BSuOS charge was paid 50% by the end consumer and 50% by generators. Any reduction in constraint cost, leads to a reduction in the BSuOS charge.
Non-monetary benefits	N/A
Assumptions made in calculating non-monetary benefit	N/A

Regularly Reported Evidence

Table: Summary of RREs for Role 3

Role 3 RREs don't have performance benchmarks.

RRE	Measure	BP1 outturn
3A Future savings from Operability Solutions	i) Saved balancing costs:	Savings of £726m in the period 2021-26 from new operability measures
	ii) Saved infrastructure costs:	RDP avoided asset build estimated at £12.9m as per RIIO2 Business Plan
	iii) Monetised carbon reductions:	Pathfinders: Estimated £5.2bn (2021-22 to 2025-26) RDPs: Estimated £260m (2023-24 to 2025-26).
3B Consumer Value from the NOA	NOA consumer benefit	£212m (over RIIO-2 period)
	Consumer benefit from Large Onshore Transmission Investment (LOTI) CBAs	£1.7bn (2021-22 to 2022-23)
	Consumer benefit from ad-hoc cost benefit analysis (CBAs)	£1.6bn (2021-22 to 2022-23)
3C Diversity of Technologies Considered in NOA	NOA	136 asset-based solutions (including 22 new options) and 8 commercial solutions submitted to NOA 2021/22. 29 asset-based solutions (including 21 new options) and 8 commercial solutions submitted to NOA 2021/22 refresh in 2022-23.
	NOA Pathfinders	A wide range of solutions were considered in NOA pathfinders.

RRE 3A Future savings from Operability Solutions

April 2021 to March 2023 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: Estimated saved balancing costs in the period 2021-26 from new operability measures

Operability Solution projects	a **Contract Cost** (£m)	b **Counterfactual Spend** (£m)	b – a **Savings** (£m)
Stability Pathfinder Phase 1	328.0	380.0	**52.0**
Stability Pathfinder Phase 2	283.0	413.0	**130.0**
Stability Pathfinder Phase 3	1,200	16,100	**14,900**
Mersey Voltage Pathfinder	3.9	54.4	**50.5**
Pennines Voltage Pathfinder	22.5	40	**17.5**
Loss of Mains programme	26.8	236.1	**209.3**
B6 Boundary Constraint Management Pathfinder	4.7	428.0	**383.3**
TOTAL	**308.7**	**1035.2**	**726.5**

Above we show the total savings for the RIIO-2 period, although the different projects are contracted for different periods, as follows:

- Stability Pathfinder Phase 1: April 2020 to March 2026
- Stability Pathfinder Phase 2: April 2024 to March 2034
- Stability Pathfinder Phase 3: April 2025 to March 2035
- Mersey Voltage Pathfinder: April 2022 to March 2031
- Pennines Voltage Pathfinder: August 2024 to March 2034
- Loss of Mains programme: enduring
- B6 Boundary Constraint Management Pathfinder: April 2022 to March 2026[42]

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[42] The B6 Boundary Constraint Management Pathfinder contracts will end in September 2026, but for the purposes of the cost and carbon savings, these have been calculated to March 2026.

Supporting information

Stability Pathfinder Phase 1

Stability Phase 1 contracts were awarded in April 2020 with six years contract length. All units are now operational and being used by ESO to support system inertia.

Stability Pathfinder Phase 2 and 3

In March 2022, 10 contracts were completed for Stability Pathfinder Phase 2 and a further 29 contracts were concluded in November 2022 under Phase 3. These will support system inertia, short circuit level and voltage out to 2035. The first of these units is due to commence from March 2024 and the benefits shown above are as estimated at the point of contract award.

Long-Term Mersey Pathfinder

Mersey Voltage contract was awarded in May 2020 with nine years contract length. Both units are now live and supporting voltage needs in the Mersey region.

Long-Term Pennines Pathfinder

In February 2022, 700 MVAr of reactive power capability was procured under the Pennine High Voltage Pathfinder for delivery between 2024 and 2034 in the North East of England and West Yorkshire regions. This will be delivered by Dogger Bank C wind farm’s onshore transmission asset alongside 3 reactors being built by NGET.

B6 Constraint Management Pathfinder

In February 2022, we concluded contracts for the B6 (English/Scottish boundary) Constraint Management Pathfinder with a start date of October 2023. However, as some of the contracted units were already connected to the intertripping scheme, we requested that these units commence their service from April 2022 bringing forward the cost and carbon savings. A subsequent tender round has awarded contracts for delivery between October 2024 and September 2025.

We expect all the Pathfinder contracts to continue to deliver significant amounts of balancing cost saving alongside reducing the carbon intensity of the electricity network.

Loss of Mains programme

The Accelerated Loss of Mains Change Programme (ALoMCP) has progressed well. Over 8,400 generation sites have completed protection changes with support from the programme, with a combined capacity of 13.2GW. With the addition of generators contacted and known to have achieved compliance, this takes the total engaged to 24.2GW, or 94% of the total generation capacity that is within scope. Progress in ALoMCP delivery has also been the primary driver in the Frequency Risk and Control Report (FRCR) recommendation to reduce the inertia holding level from 140GVA/s to 120GVA/s, which if adopted is forecasted to deliver more balancing cost saving from summer 2023.

This program, in conjunction with Dynamic Containment (DC) and Frequency Risk and Control Report (FRCR) launched during BP1 period, achieved a significant saving to the balancing cost in frequency management area (see Consumer benefit case study for Role 1: Frequency Strategy). The calculation here only considers the isolated impact from the change of loss of main protection; hence it is much smaller than the numbers quoted in the case study which considered the impact from all three combined. It is also worth to note the future years savings beyond 22/23 are estimated in this report, we will update savings based on the system conditions in the future years in next report.

Method of calculating benefits

For the above projects (Pathfinder projects and 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 solutions 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.

The exception to this is the Constraint Management Pathfinder where the counterfactual spend is based on the estimated cost of alternative actions in the Balancing Mechanism at current prices and comparing this to actual spend on the contracted units.

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[43]. This will vary depending on the scope of the RDP.

Supporting information

This data continues to be used to support the justification for RDP1. We are currently envisaging that new RDP solutions will primarily be focused on opportunities to connect DER on an interim non-firm basis ahead of transmission enabling works, and links to the Connections five point plan. Hence the bulk of the benefits will be attributed to carbon savings of early connection of DER and are reported later in this report.

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 around 8 -10 years to build. We undertook an enhanced operability assessment which identified the possibility of implementing an operational solution that can bring forward the connection dates of some customers on a non-firm basis ahead of the delivery of the enabling works.

The results of the assessment indicated that there is a certain volume of capacity that can be made available on the South East coast, prior to the construction of the enabling works. However, this would be subject to unpaid restrictions. These restrictions could be post-fault (where tripping occurs to avoid voltage stability issues), or pre-fault; the latter option is subject to discussion as to the practicalities of its implementation.

A secondary finding of this study indicated a potential opportunity for battery energy storage systems to assist with constraint management, depending on their behaviour in different scenarios. This approach will enable a flexible and efficient use of the available network capacity to be used by projects which are ready to connect without undue delays and further works are in progress to enable this to happen.

iii. Monetised carbon reductions

The carbon prices used in the tables below are taken from the BEIS publication 'valuing greenhouse gas emission in policy appraisal'[44]. These prices are also those used in our RIIO-2 Business Plan 2 Cost-Benefit Analysis – Annex 2[45].

However, for Short Term Mersey Pathfinder, we have used prices from the BEIS publication 'Updated short-term traded carbon values used for UK policy appraisal (2018)'[46]. This is due to the service concluding in March 2022, which was within the BP1 period.

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[43] https://www.nationalgrideso.com/document/158061/download

[44] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal

[45] https://www.nationalgrideso.com/document/266121/download

[46] https://www.gov.uk/government/publications/updated-short-term-traded-carbon-values-used-for-uk-policy-appraisal-2018

a) Pathfinders

Stability Pathfinder Phase 1	Unit	2022-23	2023-24	2024-25	2025-26	TOTAL
Avoided CCGT output in MW	MW	1,250	1,250	1,250	1,250	5,000
Avoided CCGT output in TWh (assuming **30%** availability during the year)	TWh	3.3	3.3	3.3	3.3	13.2
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	394	394	394	n/a
CO2 in tonnes	tCO2	1.3m	1.3m	1.3m	1.3m	5.2m
Carbon price (BP2)	£/tCO2e	248	252	256	256	n/a
Savings	**£m**	**321.0**	**326.2**	**331.3**	**336.5**	**1,315.0**

Stability Pathfinder Phase 2	Unit	2024-25	2025-26	TOTAL
Avoided Coal output in MW	MW	1200	1200	2400
Avoided Coal output in TWh (assuming **50%** availability during the year)	TWh	5.3	5.3	10.6
Carbon intensity for Coal from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	937	937	n/a
CO2 in tonnes	tCO2	4.9m	4.9m	9.8m
Carbon price (BP2)	£/tCO2e	256	260	n/a
Savings	**£m**	**1,2680.8**	**1,280.5**	**2,541.3**

Stability Pathfinder Phase 3	Unit	2025-26	TOTAL
Avoided CCGT output in MW	MW	1800	1800
Avoided CCGT output in TWh (assuming **50%** availability during the year)	TWh	7.9	7.9
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	n/a
CO2 in tonnes	tCO2	3.1m	3.1m
Carbon price (BP2)	£/tCO2e	260	n/a
Savings	**£m**	**807.6**	**807.6**

Short-Term Mersey Pathfinder	Unit	2021-22	TOTAL
CCGT generation output avoided in MW	MW	220	220
CCGT generation output avoided in GWh (220 nights at 8 hours per night)	GWh	387	387
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	n/a
CO2 in tonnes	tCO2	152,557	152,557
Carbon price (BP1)	£/tCO2e	14.7	n/a
Savings	**£m**	**2.2**	**2.2**

Savings do not extend beyond 2021-22 as these contracts have now ended. Savings for 2020-21 not included as they fall outside the BP1 period.

Long-Term Mersey Pathfinder	Unit	2022-23	2023-24	2024-25	2025-26	TOTAL
CCGT generation output avoided in MW	MW	220	220	220	220	880
CCGT generation output avoided in GWh	GWh	387	387	387	387	1,548
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	394	394	394	n/a
CO2 in tonnes	tCO2	152,557	152,557	152,557	152,557	610,228
Carbon price (BP2)	£/tCO2e	248	252	256	260	n/a
Savings	**£m**	**37.8**	**38.4**	**39.1**	**39.7**	**155.0**

Long-Term Pennines Pathfinder	Unit	2024-25	2025-26	TOTAL
CCGT generation output avoided in MW	MW	550	770	1320
CCGT generation output avoided in GWh	GWh	565	1,355	1,920
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	394	n/a
CO2 in tonnes	tCO2	222,479	533,949	756,427
Carbon price (BP2)	£/tCO2e	256	260	n/a
Savings	**£m**	**57**	**138.8**	**195.8**

Constraint Management Pathfinder B6	Unit	2022-23	2023-24	2024-25	2025-26	TOTAL
CCGT generation output avoided in GWh	GWh	423	423	423	423	1,692
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	394	394	394	n/a
CO2 in tonnes	tCO2	166,903	166,903	166,903	166,903	667,612
Carbon price (BP2)	£/tCO2e	248	252	256	260	n/a
Savings	**£m**	**41.4**	**42.1**	**42.7**	**43.4**	**169.6**

Supporting information

Stability Pathfinder Phase 1

In Stability Pathfinder Phase 1, we procured 12.5GVAs of inertia. If the Stability Pathfinder had not taken place, the most economic option for increasing system inertia would be 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 most of the time avoiding the need for any additional operational actions and therefore, we have assumed we would have had to buy on CCGTs 30% of the time.

We have used our Carbon Intensity Forecast methodology to convert the MWh of avoided CCGT generation into avoided tonnes of carbon. For the price of Carbon, the BEIS valuing greenhouse gas emission in policy appraisal prices for 2021/22 onwards have been used to convert this into monetised carbon savings. Therefore, across 2022-2026 this equates to an estimate of:

- Avoided generation from CCGTs: 13.2TWh
- Avoided CO2: 5.2m Tonnes
- **£ Savings: £1.315bn**

Stability Pathfinder Phase 2

In Stability Pathfinder Phase 2, we procured 8.4GVA of SCL and 6GVA.s of inertia, which is the equivalent amount provided by 4 coal units at 300MW each. In order to calculate the carbon reductions associated with the Stability Pathfinder, we assume that when the Pathfinder providers are supplying inertia and SCL, they displace these coal units. However, their services are not always needed as the market can provide sufficient SCL and inertia, though we have estimated that this would only be for 50% of the time.

We have used our Carbon Intensity Forecast methodology to convert the MWh of avoided Coal generation into avoided tonnes of carbon. For the price of Carbon, the BEIS valuing greenhouse gas emission in policy appraisal prices for 2021/22 onwards have been used to convert this into monetised carbon savings. Therefore, across 2022-2026 this equates to an estimate of:

- Avoided generation from Coal: 10.6TWh
- Avoided CO2: 9.8m Tonnes
- **£ Savings: £2.541bn**

Stability Pathfinder Phase 3

In Stability Pathfinder Phase 2, we procured 12.7GVA of effective SCL and 17.1GW.s of inertia, which is the equivalent amount provided by 6 CCGT units at 300MW each. In order to calculate the carbon reductions associated with the Stability Pathfinder, we assume that when the Pathfinder providers are supplying inertia and SCL, they displace these CCGT units, 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 SCL and inertia, though we have estimated that this would only be for 50% of the time.

We have used our Carbon Intensity Forecast methodology to convert the MWh of avoided CCGT generation into avoided tonnes of carbon. For the price of Carbon, the BEIS valuing greenhouse gas emission in policy appraisal prices for 2021/22 onwards have been used to convert this into monetised carbon savings. Therefore, across 2022-2026 this equates to an estimate of:

- Avoided generation from Coal: 7.9TWh
- Avoided CO2: 3.1m Tonnes

- **£ Savings: £0.807bn**

Short-Term Mersey Pathfinder

The Short-Term Mersey contracts was an arrangement between April 2020 and March 2022 where a contract with Inovyn avoided 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 was necessary to enact the Innovyn contract: we have assumed that this is an 8-hour period. We have calculated the MWh of CCGT generation avoided, and used our 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.

The estimated savings delivered from the short-term contract are:

- Avoided generation from CCGTs: 0.8TWh
- Avoided CO2: 305k Tonnes
- **£ Savings: £4.3m**

Long-Term Mersey Pathfinder

The Long-Term Mersey Pathfinder contracts are a contractual arrangement with a battery owned by Zenobe at Capenhurst alongside a reactor that is connected at Frodsham and operated by Mersey Reactive Power Limited. These assets similarly forego the need to bring on generation at Rocksavage Power. To calculate the monetised value of carbon savings, we have used the BEIS valuing greenhouse gas emission in policy appraisal prices for 2021/22 onwards.

Across the short and long term Mersey contracts, the savings across 2020 to 2026 equates:

- Avoided generation from CCGTs: 1.5TWh
- Avoided CO2: 610k Tonnes
- **£ Savings: £155m**

Long-Term Pennines Pathfinder

The Long-Term Pennines Pathfinder awarded a contract to Dogger Bank to provide voltage support from the wind farm’s onshore transmission asset. Additionally, 3 reactors submitted by NGET were selected to be built. The assets will forego the need to bring on generation from CCGT units. To calculate the monetised value of carbon savings, we have used the BEIS valuing greenhouse gas emission in policy appraisal prices for 2021/22 onwards.

Across the short and long term Mersey contracts, the savings across 2020 to 2026 equates:

- Avoided generation from CCGTs: 1.9TWh
- Avoided CO2: 756k Tonnes
- **£ Savings: £196m**

B6 Constraint Management Pathfinder

The Constraint Management Pathfinder B6 contracts are a contractual arrangement where generators in Scotland are contracted to provide an intertrip service to alleviate system constraints. This allows more renewable generation to be exported which would otherwise have been curtailed. The first set of contracts were due to start from October 2023, however as some of the contracted units were already connected to the intertripping scheme, we requested that these units commence their service from April 2022. To calculate the monetised value of carbon savings, we have used the BEIS valuing greenhouse gas emission in policy appraisal prices for 2021/22 onwards.

The constraint service is estimated to deliver savings of:

- Avoided generation from CCGTs: 1.7TWh
- Avoided CO2: 668k Tonnes
- **£ Savings: £169.6m**

a) RDPs

Table: Carbon savings calculation for RDP2 (UKPN south coast):

UKPN	Unit	Connected	2023-24	2024-25	2025-26	TOTAL
Additional capacity connecting per year	MW	48	653	21	0	722
Cumulative additional capacity	MW	48	701	722	722	722
Additional capacity in GWh (8760 hours / year and Load factor of 10%)	GWh	42	614	632	632	1921
Carbon intensity 'Consumer Transformation' (FES 22)	gCO2/kWh	142.7	169.2	150.6	127.5	N/A
CO2 in tonnes	tCO2	6,023	103,884	95,234	80,627	285,768
Carbon price (BP2 CBA)	£/tCO2e	248	252	256	260	N/A
Savings	£m	1.49	26.18	24.38	20.96	73.02

Table: Carbon savings calculation for RDP3 (UKPN East Anglia):

UKPN	Unit	Connected	2023-24	2024-25	2025-26	TOTAL
Additional capacity connecting per year	MW	0	202.3	202.3	202.3	606.9
Cumulative additional capacity	MW	0	202.3	404.6	606.9	606.9
Additional capacity in GWh (8760 hours / year and Load factor of 10%)	GWh	0	177	354	532	1063
Carbon intensity 'Consumer Transformation' (FES 22)	gCO2/kWh	169.2	150.6	127.5	123.8	N/A
CO2 in tonnes	tCO2	0	26,689	45,190	65,818	137,696
Carbon price (BP2 CBA)	£/tCO2e	248	252	256	260	N/A
Savings	£m	0	6.7	11.6	17.1	35.4

Note: data for generation connecting per annum was not available so we have spread connections across the next three years.

Table: Carbon savings calculation for RDP1 (NGED):

NGED	Unit	Connected	2023-24	2024-25	2025-26	TOTAL
Additional capacity connecting per year	MW	576	774	156	229	1,736
Cumulative additional capacity	MW	576	1,351	1,507	1,736	1,736
Additional capacity in GWh (8760 hours / year and Load factor of 40%)	GWh	505	1,183	1,320	1,521	4,529
Carbon intensity 'Consumer Transformation' (FES 22)	gCO2/kWh	142.7	169.2	150.6	127.5	N/A
CO2 in tonnes	tCO2	72,033	200,195	198,861	193,935	665,024
Carbon price (BP2 CBA)	£/tCO2e	248	252	256	260	N/A
Savings	£m	17.9	50.4	50.9	50.4	151.8

Supporting information

Updated connection data has been used as provided through the Appendix G process. We have also added connected generation volumes in the RIIO-2 period where this data is available.

Carbon prices have been updated to align with the Business Plan 2 CBA and we have updated the carbon intensity projections to align with the FES 2022 ‘Consumer Transformation’ scenario.

RDP1 and RDP2 values includes all DER connecting in these regions that are required to provide visibility and control to the ESO. This includes parties connecting as part of the N-3 intertripping projects as well as parties connecting through MW Dispatch constraint management service. We have provided an overall view of the volume of parties that have already connected under these terms and assumed a connection date midway through the BP1 period.

RDP3 has now been included as initial works have released additional capacity at two GSPs in East Anglia. The solution requires additional visibility and control systems in place to allow early connection of DER ahead of local transmission works. These visibility and control solutions are now being implemented. We do not yet have data to support revised connection dates for these projects so have assumed an equal split across the three remaining years of RIIO-2. Works continue with UKPN to explore wider opportunities to get DER connected in the region on a similar basis which are linked to our Connections five point plan.

RRE 3B Consumer Value from the NOA

April 2021 to March 2023 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 carry 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.

Table: Total forecast savings 2021-23 (£m)

	Time period	Unit	TOTAL
NOA	2021-22 to 2025-26	£m	**212**
Consumer benefit from Large Onshore Transmission Investment (LOTI) CBAs	2021-22 to 2022-23	£m	**1,719**
Consumer benefit from ad-hoc cost benefit analysis (CBAs)	2021-22 to 2022-23	£m	**1,588**
Total		£m	**2,722**

Below we set out how we have calculated the forecast benefits.

Supporting information

The NOA 2021/22 Refresh[47] data shows a gross benefit of £212m, over the RIIO-2 period. This is the average benefit of the ESO option recommendations being followed for the three net zero scenarios.

Transitional Centralised Strategic Network Plan (TCSNP2) options assessment Methodology improvements

During the last six months, we changed the 2023 methodology in the key areas outlined below. These changes will be applied in the TCSNP2 options assessment:

- We have undertaken extensive work to restructure the TCSNP2 options assessment Methodology to enable readers to understand our process more easily. We aim for this to demonstrate more transparency and accessibility to the options assessment, for all industry parties.
- We will be focusing the scope of the CBA onto options that are required after 2030. Options previously studied in the NOA 2021/22 which have been classed as required for 2030 are not going to be re-assed in the TCSNP options assessment and are assumed to be part of the network background that future options will built. We believe that this is the strategic decision to streamline the delivery of works that are essential for GB over the next seven years to meet the 50GW target by 2030.
- We have extended the chapter covering suitability for third party delivery and tendering assessment to include early competition assessments.

Interested Persons' Process Improvements

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 economic assessment process for transmission system reinforcements. This is designed to increase the diversity of options considered

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[47] The NOA 2021/22 Refresh replaces the previously published NOA 2021/22 and incorporates the recommended offshore network design set out in the Holistic Network Design (HND).

within the economic process through academic and industry participation. In continually improving our processes and for the enduring Centralised Strategic Network Plan (CSNP)[48], we are preparing a revised methodology for IP that aims to improve the process' transparency. We plan to retain the existing collaborative approach whereby IPs can approach us with options at any time while requiring them to be viable in time for annual economic assessment submission deadlines.

The Network Competition framework will provide a delivery mechanism for IP options. As our Early Competition work has progressed, we have identified common areas for processes such technological readiness and technical competency which we intend to use for the IP.

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. Over the last six months, we have undertaken significant studies for NGET, and SPEN, to support them delivering the network capacity needed to enable the low carbon transition.

Over the last 2 years, we have worked on 8 separate LOTI schemes, at Initial Needs Case, and Final Needs case level. Across these schemes we have analysed the most economically preferable options which has reduced consumer costs by approximately £1,719m.

Details of the previous three six months periods can be found in previous six-monthly reports. For the last six-months, we have calculated the consumer benefit of our analysis as £800m across 2 projects. Details of the specific schemes we have supported are:

East Anglia Green

- For NGET, we considered nine options to improve the ability to transfer electricity through the East Anglia section of the network. It was found that the optimum option included the construction of a new overhead line connecting Norwich to Bramford, Bramford to Tilbury, and Tilbury to Grain, as well as an offshore HVDC Link from Richborough to Sizewell. The optimal solution identified within the CBA provides £479m of additional value compared to other options.
- From sensitivities identified by OFGEM, the East Anglia Green analysis was developed further to assess whether an offshore scheme delivered in the same timescales could deliver equivalent savings to the consumer. This was assessed by the Economics Assessment team, and no savings were found (the offshore option was found to have an additional £2593m worst regrets)
- Further analysis was requested to assess whether the Five Estuaries and North Falls integrating with SeaLink could affect the net consumer benefit of EA Green (this integration would delay delivery of EA Green).
- We found that this could cause increased consumer costs ranging from £723m - £4.7bn

Southeast Scotland to Northwest England AC Onshore Reinforcement

- This reinforcement (CMNC) is required to provide uplift to the B6 boundary. SPEN will build a new 400kV OHL from Galashiels North to the Anglo-Scottish border via Teviot with NGET to connect from the border into a substation in England.
- The previous NOA gave a proceed and also notification that accelerating the scheme would be worth up to £1bn per year it was accelerated up to 2030 (from original target date of 2033). After HND the benefits of accelerating CMNC were diminished due to the inclusion of the offshore connections bypassing the B6 boundary
- We assessed the new benefit to the consumer of accelerating CMNC, using the new HND network, combined with the 4 FES scenarios, and found the optimal delivery date to revert back to 2033. This would provide an estimated £300m in CAPEX costs to accelerate the scheme, we have found this to provide consumer benefit of £321m (when adjusted into present value)

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[48] Ofgem have launched their Electricity Transmission Network Planning Review (ETNPR), aiming to enhance the network planning processes to implement enduring arrangements for the CSNP. The CSNP is envisaged to take a GB-wide holistic view to develop an optimised plan for taking forward network investment, a significant evolution of the NOA process.

Consumer benefit of Commercial Solutions

Commercial solutions drive consumer value by providing an alternative to asset-based solutions. Currently, these take the form of commercial intertrips (where we form an agreement with generation plant to alter their output if required) but in the future, there may be additional forms. Commercial solutions can be implemented sooner than an asset can be delivered, meaning they can help address the growth in constraint cost in the short-term. It is however important to note that these solutions do not provide network resilience or help towards compliance with the SQSS. Use of commercial solutions should continue to be explored for a specific range of network conditions and locations 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, the commercial solutions can be adapted to address them.

We forecast that the consumer benefit of the commercial solutions in NOA is 5.81% of the overall consumer benefit of the NOA 2021/22 Refresh [49] CBA. Due to the unique nature of the NOA Refresh, this consumer benefit is from the single scenario Leading the Way+ (LW+). Leading the Way+ is an adaptation of the FES Leading the Way scenario for use in the Holistic Network Design (HND) and NOA 2021/22 Refresh processes. The benefit was calculated using the 'Anti-regret' method but has been adjusted to options post-2030 only. This differs from historic NOAs and is the driver for the slightly reduced consumer benefit seen here compared to NOA 2021/22's benefit of 6.5%.

Potential benefit of acceleration of delivery of options

The NOA Refresh also provides recommendations for acceleration of some projects to a 2030 delivery. Acceleration in the context of this report refers to the NOA Refresh recommending specific options that were submitted with an EISD later than 2030 to be delivered on a required in-service date (RISD) of 2030. We have calculated the potential constraint cost savings if this recommended acceleration is completed to be £1,214m. This was calculated by comparing the constraint cost of delivering these options in 2030 and their EISD. This is an additional benefit, which was not expected at the start of RIIO-2 period.

Consumer benefit from ad-hoc cost benefit analysis (CBAs)

Summary of results

In the past 6 months, we conducted two ad-hoc CBAs, which has concluded. By carrying out these assessments on behalf of the TOs and other industry members, we aim to recommend options which are in the best interest of consumers. We estimate that the recommendations we have made across these projects have the potential to save consumers approximately £791.1m.

Below are the estimated consumer benefits from the ad-hoc cost benefit analysis we have conducted over the last six months. These have been calculated using the method detailed below in the illustrative example.

Ad-hoc CBA	Estimated Consumer Benefit (£m)
Beauly – Blackhillock 275kV Reprofiling	3.1
Port of Tyne	788
Total	791.1

Over the last two years, we have conducted nine bespoke CBAs, saving consumers £1.59 billion. The estimated consumer benefit breakdown for these can be found in the table below.

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[49] The NOA 2021/22 Refresh replaces the previously published NOA 2021/22 and incorporates the recommended offshore network design set out in the Holistic Network Design (HND).

Ad-hoc CBA	Estimated Consumer Benefit (£m)
North of Beauly	10
Burwell ANM and SGT assessment	140
Dinorwig to Pentir cable replacement programme	0.4
Necton circuit assessment	0.3
Bramford to Norwich circuit assessment	43
Harker and Penwortham assessment	14
Bramford SGT upgrade CBA	588.4
Beauly – Blackhillock 275kV Reprofiling	3.1
Port of Tyne	788
Total	1587.7

Illustrative example:

The following is a worked example using dummy data to illustrate our methodology for calculating the benefit of the ad-hoc CBAs. This example is the same one used in our previous RIIO-2 reports.

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**

RRE 3C Diversity of Technologies Considered in NOA

April 2021 to March 2023 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.

a) Solutions considered in NOA 2021/22 Refresh

The expression of interest process does not apply to the NOA so here we report on solutions submitted by participants.

The NOA 2021/22 Refresh, published in the Summer of 2022, replaces the previously published NOA 2021/22 and incorporates the recommended offshore network design set out in the Holistic Network Design (HND). The table below shows the number of options submitted by participants in the NOA 2021-22 Refresh, and of those, how many are new to the NOA this year. The 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. The NOA 2021-22 Refresh did not assess options that were found to be optimal pre-2030 as they inherited their recommendation from NOA 2021/22 or options that were classes as 'HND essential' through the connections' assessment process of the Holistic Network Design (HND).

We are in the preparatory phase of the (TCSNP) currently and will report on those outputs following their publication.

Table: Options submitted by participants in NOA 2021-22 Refresh

Technology Main Category	Total Number Submitted in NOA 21/22 Refresh	New options Submitted in NOA 21/22 Refresh
Circuit	28	20
Route modification	-	-
Transformers	-	-
Substation & switching	-	-
Flexible AC transmission system (FACTS)	1	1
New technology	-	-
Total asset-based solutions	29	21
Commercial solutions	8	-

b) NOA Pathfinders

Supporting Information

More detailed information on the NOA Stability, Voltage and Constraints pathfinder can be found in the Pathfinder section of RRE 3A.

Value for Money

All roles

Value for Money

Under the ESO incentive arrangements for RIIO-2, the ESO must report on its outturn 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. Final outturn costs were submitted for the 2021/22 reporting period in the RRP and submitted to Ofgem in July 2022. The final cost outturn for the BP1 period will be submitted in the next RRP cycle in July 2023.

The reported spend for the 2022/23 reporting year 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 RRP reporting. The ESO uses the methodology, as set out in the ESORI guidance, to allocate costs to each role.

The ESO's cost benchmark of £506.0m has not changed since the prior cost assessment published in October 2022.

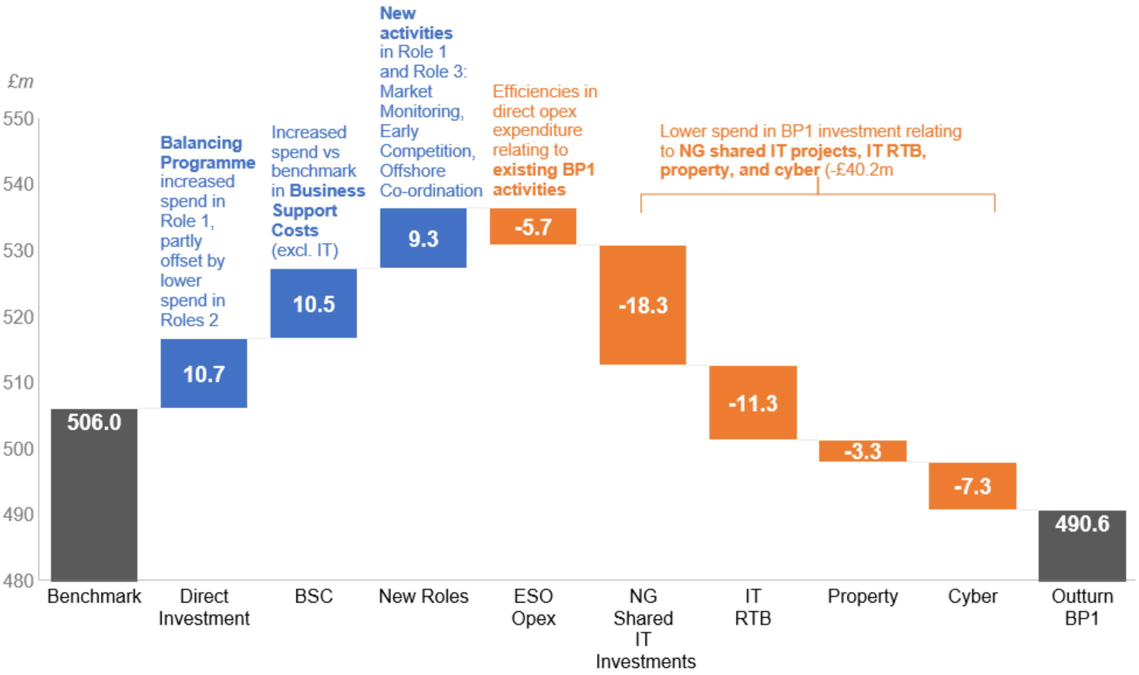
The following table sets out our overall spend in the RIIO-2 BP1 period, compared to the cost benchmark. For a more detailed breakdown please see the Cost Benchmark Summary Table on Page 270.

Total 2021-23 spend compared to BP1 benchmark

		Role 1	Role 2	Role 3	**Total**
Cost benchmark	(£m)	208.0	158.6	139.4	**506.0**
Spend for BP1 period	(£m)	226.0	143.5	121.2	**490.6**
£m deviation from cost benchmark	(£m)	18.0	(15.1)	(18.2)	**(15.4)**
% deviation from cost benchmark	(%)	8.6%	(9.5%)	(13.1%)	**(3.0%)**

Total spend across the BP1 period is £490.6m, £15.4m lower than the £506.0m benchmark. The following chart shows a high-level view of the main drivers contributing to the variances to benchmark costs. Further detail is provided on these drivers on a role-by-role basis within the remainder of this report.

Chart 1: TOTAL ESO EXPENDITURE £m



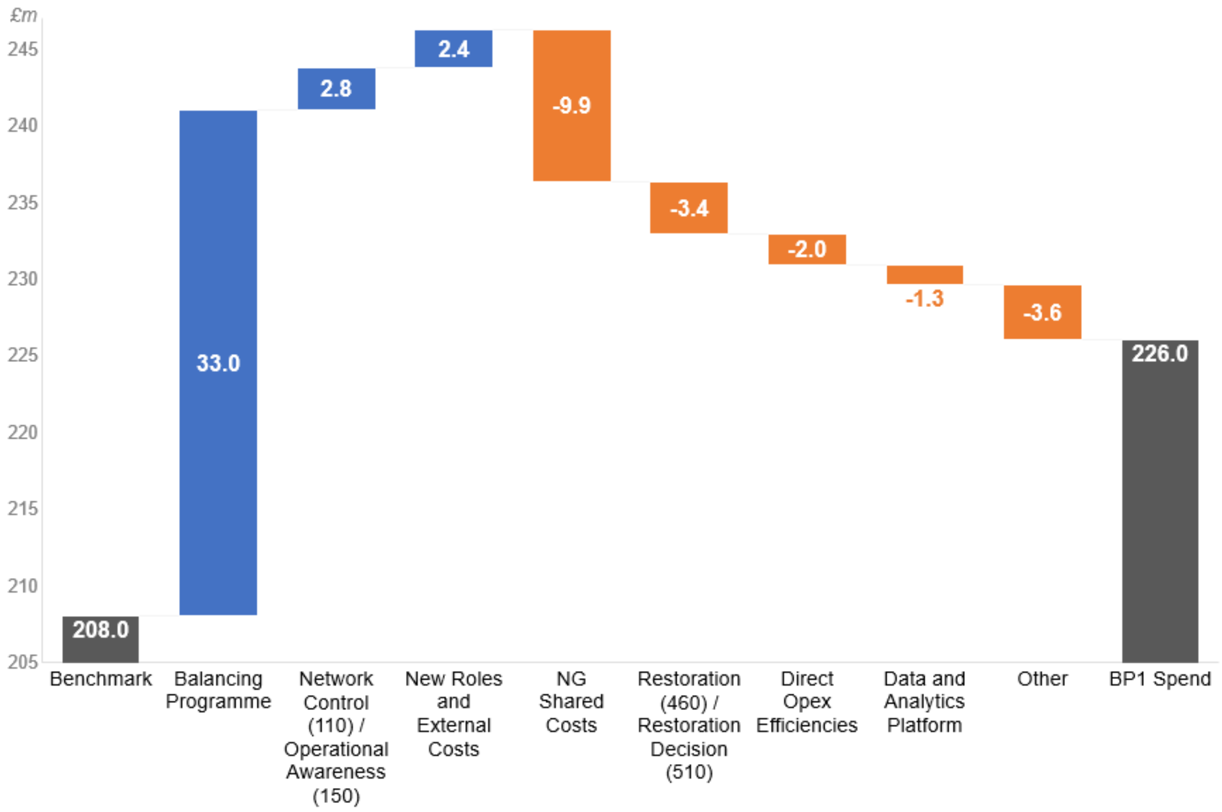
Role 1 (Control centre operations) expenditure

For Role 1, we have spent **£18.0m** more than the cost benchmark over the BP1 period delivering 95% of the milestones in our plan delivery schedule (excluding milestones that are no longer valid, delayed for reasons outside of our control, and delayed for consumer benefit).

	Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
Role 1	ESO Opex	61.6	30.4	31.6	62.0	0.3	0.5%
	Capex	63.5	47.1	48.6	95.8	32.2	50.7%
	BSC	12.0	1.2	6.5	7.7	(4.3)	(35.9%)
	Total Directly Attributable to Role 1	**137.2**	**78.7**	**86.7**	**165.4**	**28.2**	20.6%
	ESO Opex	5.2	2.4	2.4	4.8	(0.3)	(6.2%)
	Capex	14.4	6.9	3.5	10.3	(4.0)	(28.1%)
	BSC	42.1	19.0	19.7	38.7	(3.4)	(8.1%)
	Other Price Control Costs	9.2	3.4	3.3	6.7	(2.5)	(27.0%)
	Total Indirectly Attributable to Role 1	**70.8**	**31.7**	**28.9**	**60.6**	**(10.2)**	(14.5%)
	Total Attributable to Role 1	**208.0**	**110.3**	**115.6**	**226.0**	**18.0**	8.6%

Below we set out the high-level activities driving the variances across Role 1. The key driver of additional spend over the BP1 period has been the Balancing Programme, where we have developed a much greater understanding of the scale and complexity of transforming our balancing capability, which has resulted in the need for higher levels of investment. Higher than benchmark spend on the Balancing Programme has been partly offset by lower spend on other direct IT investments and a lower allocation for shared investments and business support costs. The lower allocation of shared costs is largely driven by lower IT support costs, re-phasing of investment across the shared infrastructure asset refresh programmes and lower costs to complete our cyber security deliverables.

Chart 2: ROLE 1 EXPENDITURE £m



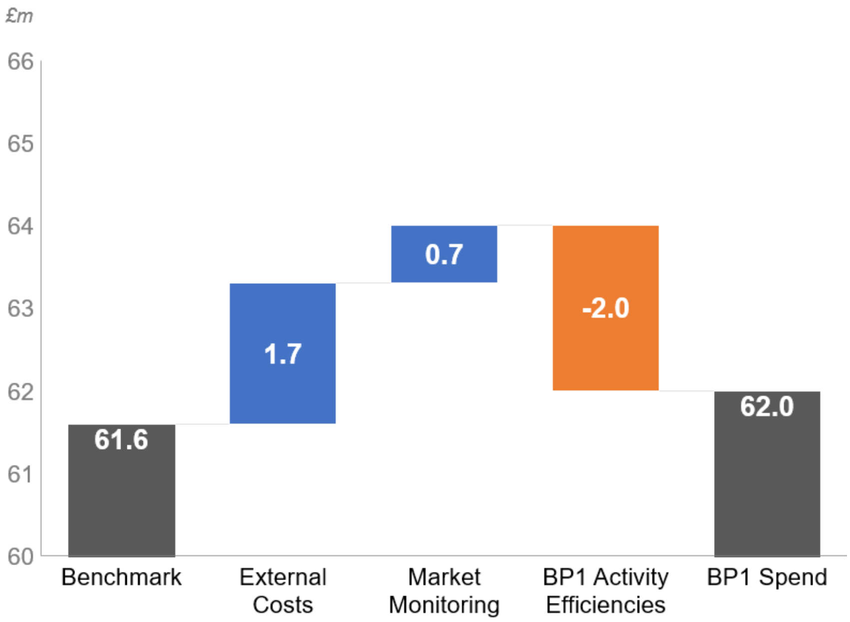
Directly Attributable ESO Opex

Directly attributable opex refers to the operating costs that the ESO incurs to deliver its outputs under its three roles.

Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
ESO Opex	61.6	30.4	31.6	62.0	0.3	0.5%

For Role 1 directly attributable ESO opex, we have spent £0.3m more than the benchmark of £61.6m over the BP1 period. During BP1 new initiatives and changes were introduced that were outside the scope of the original business plan. For example our response to the COVID-19 pandemic, managing through Winter 2022/23 and implementing a new market monitoring function. We have continually prioritised our projects to deliver the best value for consumers. The below chart illustrates the cost impact of these initiatives and changes relating to Role 1.

Chart 3: ROLE 1 DIRECT OPEX BREAKDOWN £m



External Costs (ENTSO-E and CORESO) +£1.7m

The benchmark value for Role 1 did not include any subscription costs for ENTSO-E as this was included in Role 2 as part of the roles in Europe activity. However following the UK's withdrawal from the EU the ESO remained a party to several ENTSO-E contracts some of which (Regional Security Coordination Centres and the European Awareness System) were funded within Role 1.

The BP1 benchmark included £5.5m of costs within Role 2 for ENTSO-E costs. Overall, across the ESO £3.5m was spent across the BP1 period. £2.8m of this was spent within Role 2 and £0.7m within Role 1. This has driven an increase in cost of £0.7m to Role 1, which is offset by an equal reduction in Role 2.

In addition, amounts paid to CORESO which were included in the Role 1 benchmark increased by £1.0m over the 2-year period, driven by CORESO's 5-year ambition to transform from a Regional Security Centre to a high performing Regional Coordination Centre. To achieve this ambition there has been investment in improving "enabling functions" such as finance, HR and IT, redeveloping the legacy services that are currently running in the co-ordination room, and implementing the Clean Energy Package requirements. This cost is approved by the CORESO board and the ESO pays for its share.

Market Monitoring +0.7m

In April 2021, Ofgem introduced a new licence obligation for the ESO to proactively monitor activity in the balancing services market. £0.7m has been spent on conducting this activity which was not originally included within the BP1 benchmark.

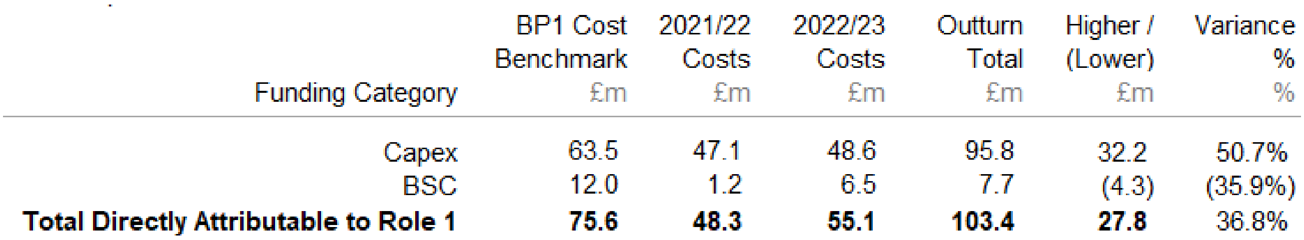
For further information on Market Monitoring please refer to page 5.

Winter 22/23 Preparedness

As referenced in page 4, we undertook an enormous effort to plan, train, communicate and deliver across all teams to ensure we were prepared to face the challenges of Winter 22/23. For Role 1 this included designing, procuring and implementing enhanced services into the Electricity Control Room to protect electricity margins over the winter peak periods. As the costs relating to this were absorbed by the relevant areas within the ESO it has been difficult to estimate the financial impact on Role 1. As a result, the costs attributed to these services have not been captured on the above illustration but is to be considered within the overall £62.0m BP1 spend.

Directly Attributable ESO Capex and BSC[50]

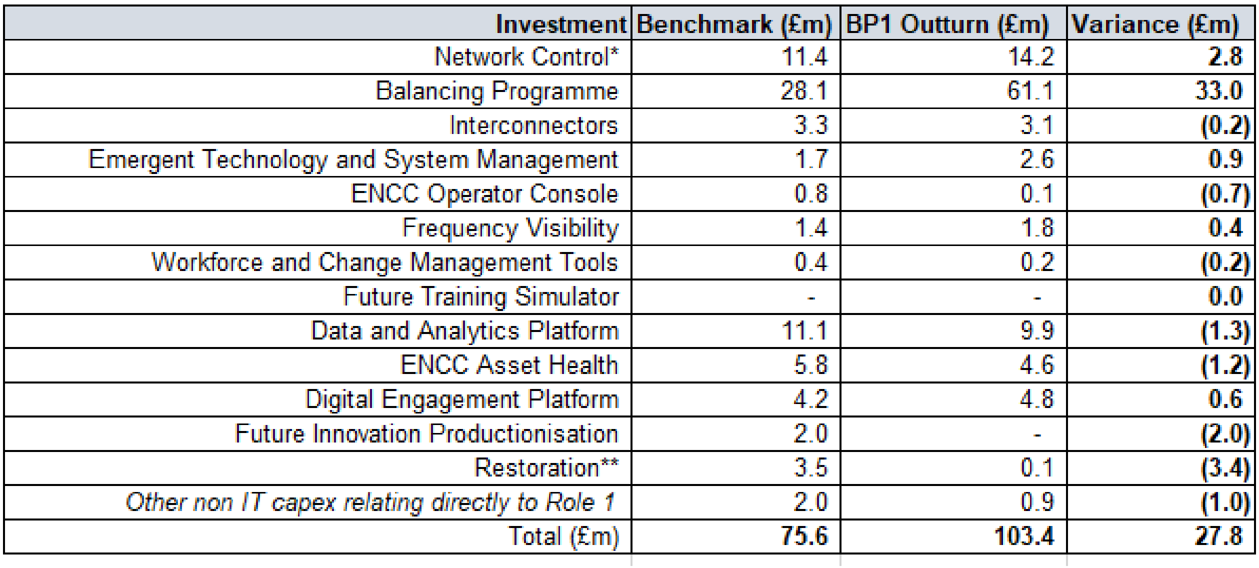
Directly attributable ESO capex and BSC expenditure refers to capex and opex costs relating to ESO investments that can be mapped to specific roles.



Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
Capex	63.5	47.1	48.6	95.8	32.2	50.7%
BSC	12.0	1.2	6.5	7.7	(4.3)	(35.9%)
Total Directly Attributable to Role 1	**75.6**	**48.3**	**55.1**	**103.4**	**27.8**	36.8%

For Role 1 directly attributable ESO capex and BSC, we have spent £27.8m more than the benchmark of £75.6m over the BP1 period.

Table 1: ROLE 1 INVESTMENT (£m)



Investment	**Benchmark (£m)**	**BP1 Outturn (£m)**	**Variance (£m)**
Network Control*	11.4	14.2	**2.8**
Balancing Programme	28.1	61.1	**33.0**
Interconnectors	3.3	3.1	**(0.2)**
Emergent Technology and System Management	1.7	2.6	**0.9**
ENCC Operator Console	0.8	0.1	**(0.7)**
Frequency Visibility	1.4	1.8	**0.4**
Workforce and Change Management Tools	0.4	0.2	**(0.2)**
Future Training Simulator	-	-	**0.0**
Data and Analytics Platform	11.1	9.9	**(1.3)**
ENCC Asset Health	5.8	4.6	**(1.2)**
Digital Engagement Platform	4.2	4.8	**0.6**
Future Innovation Productionisation	2.0	-	**(2.0)**
Restoration**	3.5	0.1	**(3.4)**
Other non IT capex relating directly to Role 1	2.0	0.9	**(1.0)**
Total (£m)	**75.6**	**103.4**	**27.8**

**includes investments 110 and 150*

***includes investments 460 and 510*

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[50] Business Support Costs – costs associated with activities delivered by National Grid shared services

The key driver of the overall increase in investment costs for BP1 remains to be the **Balancing Programme**, where we have spent £33.0m more than our BP1 benchmark. The programme incorporates investments in Balancing Asset Health and Forecast Enhancements as well as enhancing our balancing capability through the replacement of our current Energy Balancing System. The biggest driver of cost increase compared to benchmark is in transforming our balancing capability. The cost included in our RIIO-2 Business Plan, which was developed in 2019, was a high-level estimation underpinned by key market, operational and technology assumptions, some of which did not materialise. Since 2019 we also had to accommodate new scope, our plans and updated cost estimates for the delivery of this programme are reflective of that and fully outlined in our BP2 business plan. During BP1, through engagement with industry, we have developed a Roadmap to deliver a new Open balancing Platform (OBP) which will deliver our operational capability to support our zero carbon operability requirements.

Our **Network Control** investment will deliver real-time situational awareness capability providing control centre operators capability to manage the electricity network as we move to zero carbon grid operations. In the BP1 period we spent £2.8m more than our BP1 benchmark for this programme, though this included an additional £2.0m of hardware spend we chose to pull forward from FY24 to reduce delivery risk, given supply chain delivery uncertainties. There have been additional upward cost pressures on the programme due to the cost and complexity of leveraging the benefits of more modern compute and storage platforms and use of additional business resource to ensure successful delivery. We have combined the delivery of the Operational Awareness and Decision Support initiative into this programme which will drive efficiency using a single team to deliver all outcomes.

Our **Emergent Technology and System Management** programme is delivering the capability and tools for our control room users to manage challenges and risks highlighted in the operability strategy report[51]. We have spent £0.9m more than our benchmark in the BP1 period. The key driver for the additional spend was additional scope driven by the Pathfinder project which has already led to the delivery of significant financial and carbon reduction benefits.

Our **ENCC Operator Console** project will provide an open Desk Workspace for control room staff and was not mobilised until towards the end of the BP1 period. We expect to deliver the original scope of this project with no material change to the overall cost of delivery, but the spend has been re-phased to align with current planning. We therefore spent £0.7m less than the benchmark in the BP1 period.

The BP1 scope of our **Interconnectors** and **Data Analytics Platform (DAP)** projects were fully delivered in the BP1 period, both at lower cost than BP1 benchmark. Whilst some additional scope was delivered in the Interconnectors project, delivery through a single dedicated team helped to drive efficiencies with costs for the period being £0.2m below benchmark. The DAP project spent £1.3m less than benchmark where the adoption of an incremental delivery approach helped to drive efficiencies.

Our **ENCC asset health programme** delivers operational systems stability to our control room. During the BP1 period we spend £1.2m less than our BP1 benchmark. Whilst we delivered most of our planned scope, we delivered additional scope through the implementation of the technical component associated with the new Demand Flexibility Service (DFS).

The **Digital Engagement Platform** cost £0.6m more than the BP1 Benchmark. The project delivered its Foundational release in Q4 of FY23 which incorporated the new web platform making content on our website more accessible and discoverable for a wide range of stakeholders. When the BP1 submission was made, the user research had only been conducted at a high level and the FSO consultation had not been launched, both of which led to a re-visit of the architecture roadmap. This has led to additional cost and some work being deferred into the BP2 period.

Our **Restoration** project has spent £3.4m less than the BP1 Benchmark. The scope of the Restoration project was significantly decreased with the Distributed Restart Zonal Controller (DRZC) element being moved out of scope as it is now being delivered by the DNOs. Other deliverables have been rephased to deliver in the RIIO-2 period following a later than planned direction from the Secretary of State for the new Restoration Standard which now allows 5 years for implementation with a revised compliance date of 31 December 2026.

Our **Future Innovation Productionisation** project was not mobilised in BP2 due to focus on delivery of other key projects.

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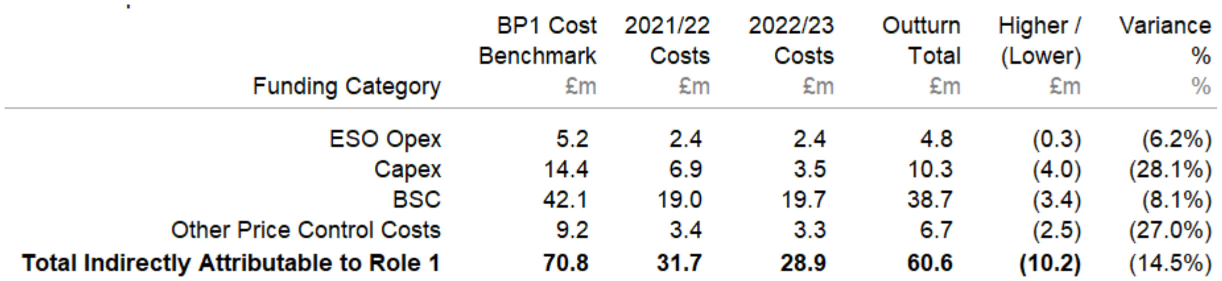
[51] https://www.nationalgrideso.com/news/operability-strategy-report-2023

Other non-IT capex in role 1 relates to upgrades and enhancements to the control room physical environment and the purchase of the physical assets associated with inertia monitoring.

Indirectly Attributable ESO Costs

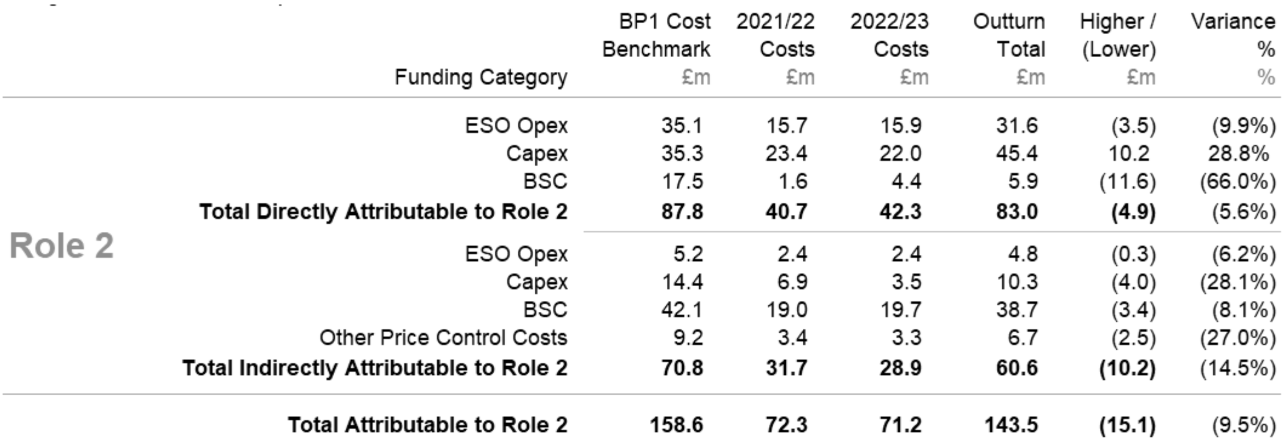
Indirectly attributable costs relate to costs for teams that work across the ESO business who support the activities within the three roles, and the costs for National Grid shared services. The costs for these supporting activities are shared 1/3 per role as they cannot be directly attributed to the activities performed within each role.



Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
ESO Opex	5.2	2.4	2.4	4.8	(0.3)	(6.2%)
Capex	14.4	6.9	3.5	10.3	(4.0)	(28.1%)
BSC	42.1	19.0	19.7	38.7	(3.4)	(8.1%)
Other Price Control Costs	9.2	3.4	3.3	6.7	(2.5)	(27.0%)
Total Indirectly Attributable to Role 1	**70.8**	**31.7**	**28.9**	**60.6**	**(10.2)**	(14.5%)

Role 2 (Market development and transactions) expenditure

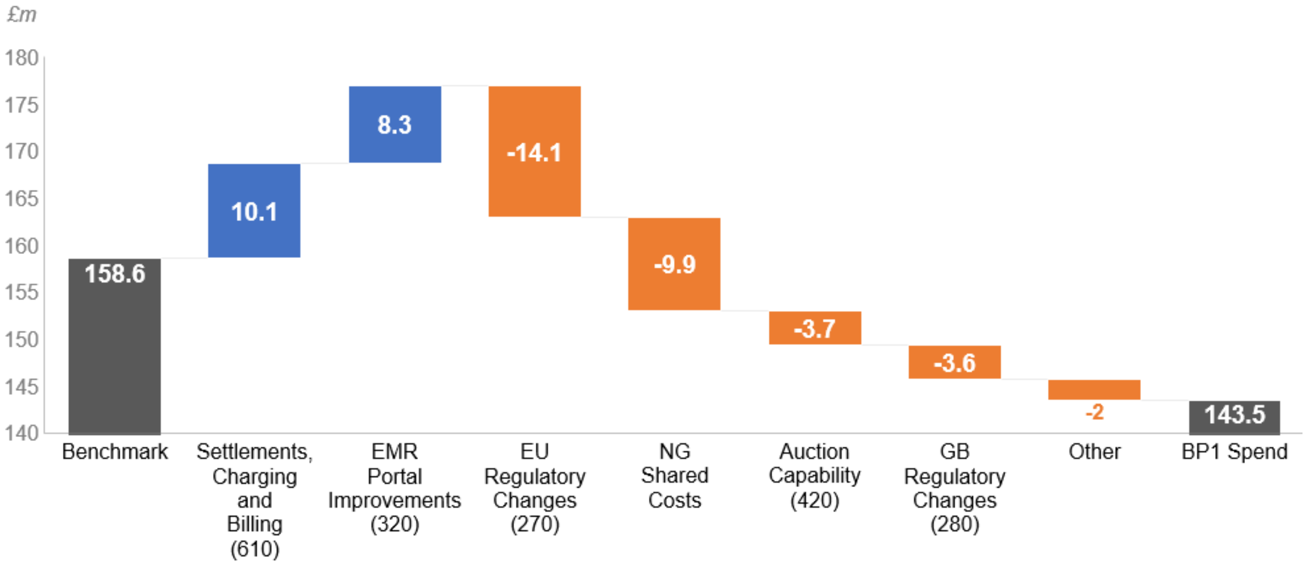
For Role 2, we have spent £15.1m less than the cost benchmark over the BP1 period delivering 83% of the milestones in our plan delivery schedule (excluding milestones that are no longer valid, delayed for reasons outside of our control, and delayed for consumer benefit).



	Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
Role 2	ESO Opex	35.1	15.7	15.9	31.6	(3.5)	(9.9%)
	Capex	35.3	23.4	22.0	45.4	10.2	28.8%
	BSC	17.5	1.6	4.4	5.9	(11.6)	(66.0%)
	Total Directly Attributable to Role 2	**87.8**	**40.7**	**42.3**	**83.0**	**(4.9)**	(5.6%)
	ESO Opex	5.2	2.4	2.4	4.8	(0.3)	(6.2%)
	Capex	14.4	6.9	3.5	10.3	(4.0)	(28.1%)
	BSC	42.1	19.0	19.7	38.7	(3.4)	(8.1%)
	Other Price Control Costs	9.2	3.4	3.3	6.7	(2.5)	(27.0%)
	Total Indirectly Attributable to Role 2	**70.8**	**31.7**	**28.9**	**60.6**	**(10.2)**	(14.5%)
	Total Attributable to Role 2	**158.6**	**72.3**	**71.2**	**143.5**	**(15.1)**	(9.5%)

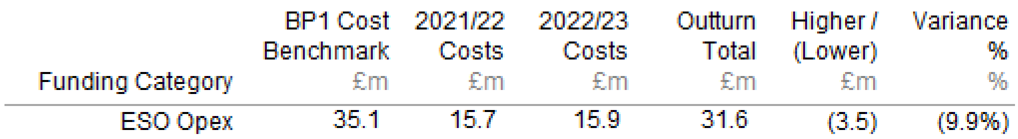
Below we set out the high-level activities driving the variances across Role 2. Two of our investment programmes, the Settlements, Charging and Billing and EMR portal programmes, were substantially rescoped during the BP1 period which has led to higher cost and longer delivery times. In both cases we anticipate programmes will still deliver significant benefits. Key drivers of lower cost were lower EU regulatory changes driven by our exit from the EU and lower allocated costs for shared investment and business support activities.

Chart 4: ROLE 2 EXPENDITURE



Directly Attributable ESO Opex

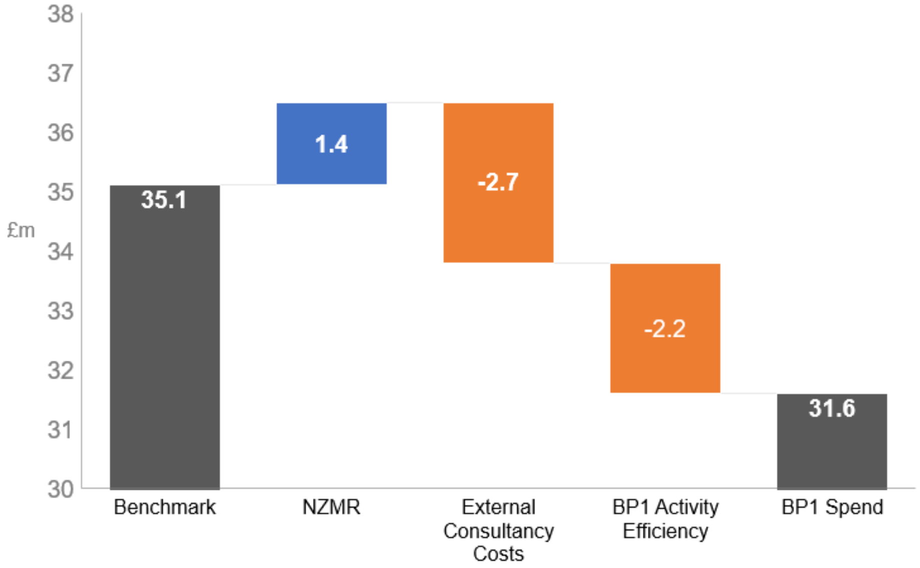
Directly attributable opex refers to the operating costs that the ESO incurs to deliver its outputs under its three Roles.



Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
ESO Opex	35.1	15.7	15.9	31.6	(3.5)	(9.9%)

For Role 2 directly attributable ESO opex, we have spent £3.5m less than the benchmark of £35.1m over the BP1 period. During BP1 new initiatives and changes were introduced that were outside the scope of the original business plan. We have continually prioritised our projects to deliver the best value for consumers. The below illustrates the cost impact of the initiatives relating to Role 2 directly attributable ESO opex.

Chart 5: ROLE 2 DIRECT OPEX BREAKDOWN



Net Zero Market Reform (NZMR) +£1.4m

Our Net Zero Market Reform (NZMR) programme was established in early 2021, to holistically examine the changes to GB electricity market design that would be required to achieve the power sector's 2035 decarbonisation targets cost-efficiently and securely, while laying the foundation for a net zero economy by 2050. £1.4m has been spent during the BP1 period delivering this programme that was not included within the BP1 benchmark.

For further information on our NZMR programme please refer to page 101.

External Consultancy Costs (ENTSO-E) -£2.7m

Following the UK's withdrawal from the EU the ESO ceased to be a member of ENTSO-E and as such the related fees that were included in the benchmark are no longer being paid. However, some specific contracts remained in place with associated costs of which Operational Planning and Data Environment and the Physical Communication Network were funded within Role 2. The BP1 benchmark included £5.5m of costs within Role 2 for this activity. Overall, across the ESO £3.5m was spent across the BP1 period. £2.8m of this was spent within Role 2 and £0.7m within Role 1.

£0.7m of the £2.7m reduction shown in Role 2 is offset with Role 1 as mentioned on page 247.

Winter 22/23 Preparedness

As referenced on page 99 we undertook an enormous effort to plan, train, communicate and deliver across all teams to ensure we were prepared to face the challenges of Winter 22/23. For Role 2 this included the introduction of Winter Contingency Contracts and the Demand Flexibility Service. As the costs relating to this were absorbed by the relevant areas within the ESO it has been difficult to estimate the financial impact on Role 2. As a result, the costs attributed to these services have not been captured on the above illustration but is to be considered within the overall £31.6m BP1 spend.

Directly Attributable ESO Capex and BSC

Directly attributable ESO capex and BSC expenditure refers to capex and opex costs relating to ESO investments that can be mapped to specific roles.

Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
Capex	35.3	23.4	22.0	45.4	10.2	28.8%
BSC	17.5	1.6	4.4	5.9	(11.6)	(66.0%)
Total Directly Attributable to Role 2	**52.8**	**25.0**	**26.4**	**51.4**	**(1.4)**	(2.7%)

For Role 2 directly attributable ESO capex and BSC, we have spent £1.4m less than the benchmark of £52.8m over the BP1 period.

Table 2: ROLE 2 INVESTMENT (£m)

Investment	**Benchmark (£m)**	**BP1 Outturn (£m)**	**Variance (£m)**
Settlements, Charging and Billing	8.9	18.9	**10.1**
EMR Portal Improvements	3.5	11.8	**8.3**
EU Regulation Changes	18.0	3.9	**(14.1)**
GB Regulatory Changes	6.0	2.4	**(3.6)**
Digitalised Code Management	-	0.1	**0.1**
Single Markets Platform	10.4	12.2	**1.8**
Auction Capability	6.0	2.3	**(3.7)**
Other non IT capex relating directly to Role 2	-	- 0.2	**(0.2)**
Total (£m)	**52.8**	**51.4**	**(1.4)**

During BP1 we spent £10.1m more than the BP1 benchmark on our **Settlements, Charging and Billing** systems. The key driver of additional cost is our decision to replace our existing billing system (CAB) rather than re-engineer it since our assessment of CAB's architecture and health deemed it as obsolete, not cost-effective and unfit for purpose to deliver against the long-term future requirements from a growing market. We are replacing the CAB system with our solution chosen for Settlements which will drive alignment of outcomes and requirements, and benefits from merging technology and programme delivery capability. A deeper understanding of the complexity of the solution has driven additional cost as well as the requirement to deliver a high number of regulatory changes to legacy systems as well as the new STAR platform. The STAR Platform is now in place with some settlement and billing processes transitioned to the new platform. This will deliver benefits through system flexibility and scalability to accommodate change more quickly, as well as driving process automation and improved customer experience via easier access to quality data.

Our investment in the EMR Portal will deliver a new platform for **Electricity Market Reform (EMR)** to enhance EMR customer experiences, enable increased market participation and deliver future regulatory change at pace and cost-effectively. During the BP1 period we have spent £8.3m more than the cost benchmark. Our original RIIO-2 Business Plan had assumed that the EMR portal improvements would largely be delivered by the end of RIIO-1 and that we would deliver a modest amount of regulatory change and continuous improvements during the RIIO-2 period. In practice there has been a substantial amount of regulatory change since October 2019 which has led us to rescope and reprofile our delivery plan for the EMR portal. Key drivers of increased cost have arisen from an enhanced understanding of the business requirement, the evolving complexity of the regulatory environment as well as higher than anticipated costs in configuring the chosen Salesforce solution to meet business requirements.

During BP1 we have spent below the benchmark for both **EU and GB regulatory changes**. The key driver of the £14.1m lower than benchmark spend for EU changes has been the change in relationship with our

European counterparts due to Brexit. This has led to the UK not being able to take part in TERRE or MARI, which were forecast to cost a considerable amount (c£4.5m) during the BP1 period. In addition to this several obligations under the Clean Energy Package, although retained under British law, have had derogations or similar agreed with Ofgem due to either lack of industry agreement on the way forward or due to a lack of benefit to British consumers, which has significantly decreased the scope of our work. Our lower spend on GB regulatory change has been largely due to the fluid nature of regulatory change with some of the original changes included in the benchmark number being withdrawn and others being delivered. Also, some of our changes have been delivered through programmes delivering new systems such as the Settlements, Charging and Billing programme. In addition, as the volume of regulatory change grew, a small, dedicated team was set up to manage pre-project analysis in this space; this led to efficiencies compared to the previous process, as the dedicated team can specialise in this activity, ensuring fewer resources are required to complete the analysis - the team was able to complete over 100 pieces of regulatory analysis during the BP1 period.

During BP1 the project activity was brought forward for Phase 1 (Discovery) for **Digital Code Management (DCM)** as it is considered as a no-regrets option that is independent of the outcome of the code consolidation workstream and ECR outcome. It will drive consumer benefit regardless of the code it is applied to, with the Grid Code being targeted initially. We now have a good high-level understanding of customer needs and the high-level solution design which will be taken forward into a detailed delivery plan.

Our **Single Markets Platform (SMP)** programme delivers access for all market participants into ESO market and energy services. The programme has gone through significant restructuring since the original RIIO-2 submission was published. The original RIIO-2 plan focused on the upstream steps for onboarding and enabling markets participants to participate in day ahead markets for delivery as soon as achievable. However, we have added additional scope to reflect the back-end changes required on platforms such as Procurement, Balancing and Settlements that underpin the introduction of new services (response and reserve), and their enhancements. Consequently, the Ancillary Services Reform (ASR) programme of work was added as new scope to this programme during BP1 and has been the main driver of the additional £1.8m spend compared to BP1 Benchmark.

Our **Auction Capability** project will deliver an enduring auction capability to unlock more efficient auction-based procurement activities and facilitate closer to real time procurement. During BP1 we spent £3.7m less than the BP1 Benchmark. This is due to a change in the deployment timescales due to compliance with the Utilities Contracts Regulation 2026 tendering process requiring a much more thorough multi-stage solution procurement process taking 13 months instead of the 4 month BP1 estimate. The discovery phase of the project also took longer than expected with the requirement to source consultants to support with expertise which we did not have in house.

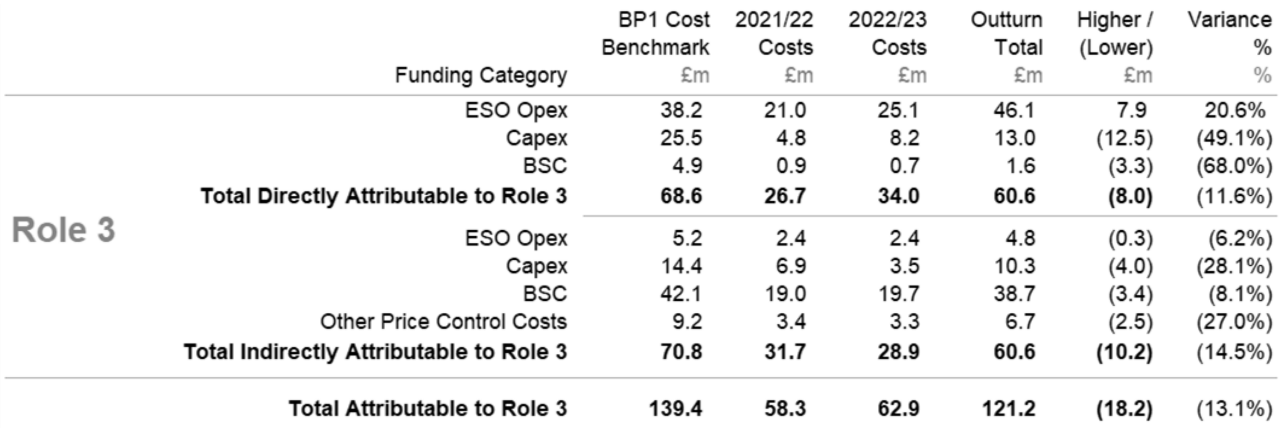
Indirectly Attributable ESO Costs

Indirectly attributable costs relate to costs for teams that work across the ESO business who support the activities within the three roles, and the costs for National Grid shared services. The costs for these supporting activities are shared 1/3 per role as they cannot be directly attributed to the activities performed within each role.

Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
ESO Opex	5.2	2.4	2.4	4.8	(0.3)	(6.2%)
Capex	14.4	6.9	3.5	10.3	(4.0)	(28.1%)
BSC	42.1	19.0	19.7	38.7	(3.4)	(8.1%)
Other Price Control Costs	9.2	3.4	3.3	6.7	(2.5)	(27.0%)
Total Indirectly Attributable to Role 2	**70.8**	**31.7**	**28.9**	**60.6**	**(10.2)**	(14.5%)

Role 3 (System insight, planning and network development) expenditure

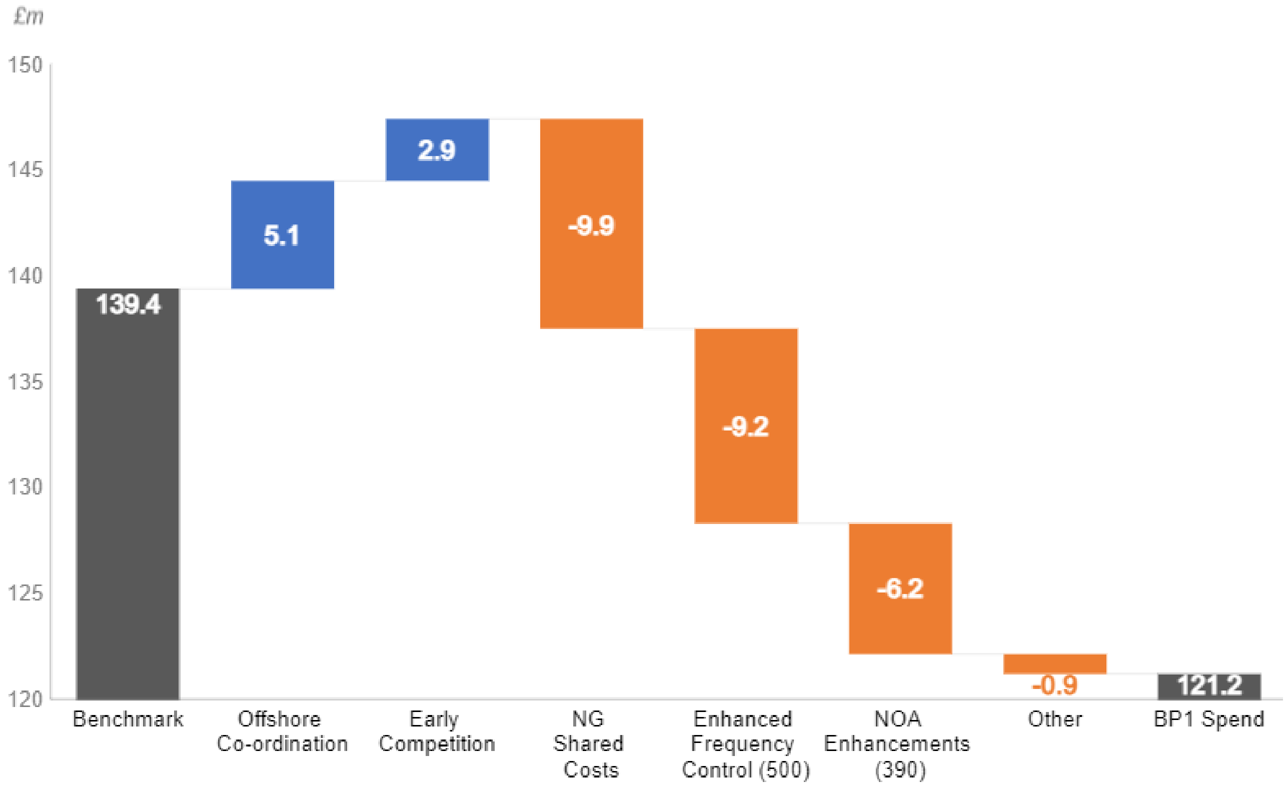
For Role 3, we have spent **£18.2m** less than the cost benchmark over the BP1 period delivering 96% of the milestones in our plan delivery schedule (excluding milestones that are no longer valid, delayed for reasons outside of our control, and delayed for consumer benefit).



	Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
Role 3	ESO Opex	38.2	21.0	25.1	46.1	7.9	20.6%
	Capex	25.5	4.8	8.2	13.0	(12.5)	(49.1%)
	BSC	4.9	0.9	0.7	1.6	(3.3)	(68.0%)
	Total Directly Attributable to Role 3	**68.6**	**26.7**	**34.0**	**60.6**	**(8.0)**	(11.6%)
	ESO Opex	5.2	2.4	2.4	4.8	(0.3)	(6.2%)
	Capex	14.4	6.9	3.5	10.3	(4.0)	(28.1%)
	BSC	42.1	19.0	19.7	38.7	(3.4)	(8.1%)
	Other Price Control Costs	9.2	3.4	3.3	6.7	(2.5)	(27.0%)
	Total Indirectly Attributable to Role 3	**70.8**	**31.7**	**28.9**	**60.6**	**(10.2)**	(14.5%)
	Total Attributable to Role 3	**139.4**	**58.3**	**62.9**	**121.2**	**(18.2)**	(13.1%)

Below we set out the high-level activities driving the variances across Role 3. Additional roles for Offshore Co-ordination and Early Competition were not included in the BP1 benchmark and drove an additional £8.0m of cost over the BP1 period. This was offset by lower investment in Enhanced Frequency Control where the benefits of this investment will be delivered through our Dynamic Containment initiative. Our NOA enhancements project delivered some efficiencies compared to benchmark cost but also has deferred some deliverables into future periods. Our allocated costs for shared IT investment and support functions costs were also well below benchmark with the main driver being lower IT support costs.

Chart 6: ROLE 3 EXPENDITURE



Directly Attributable ESO Opex

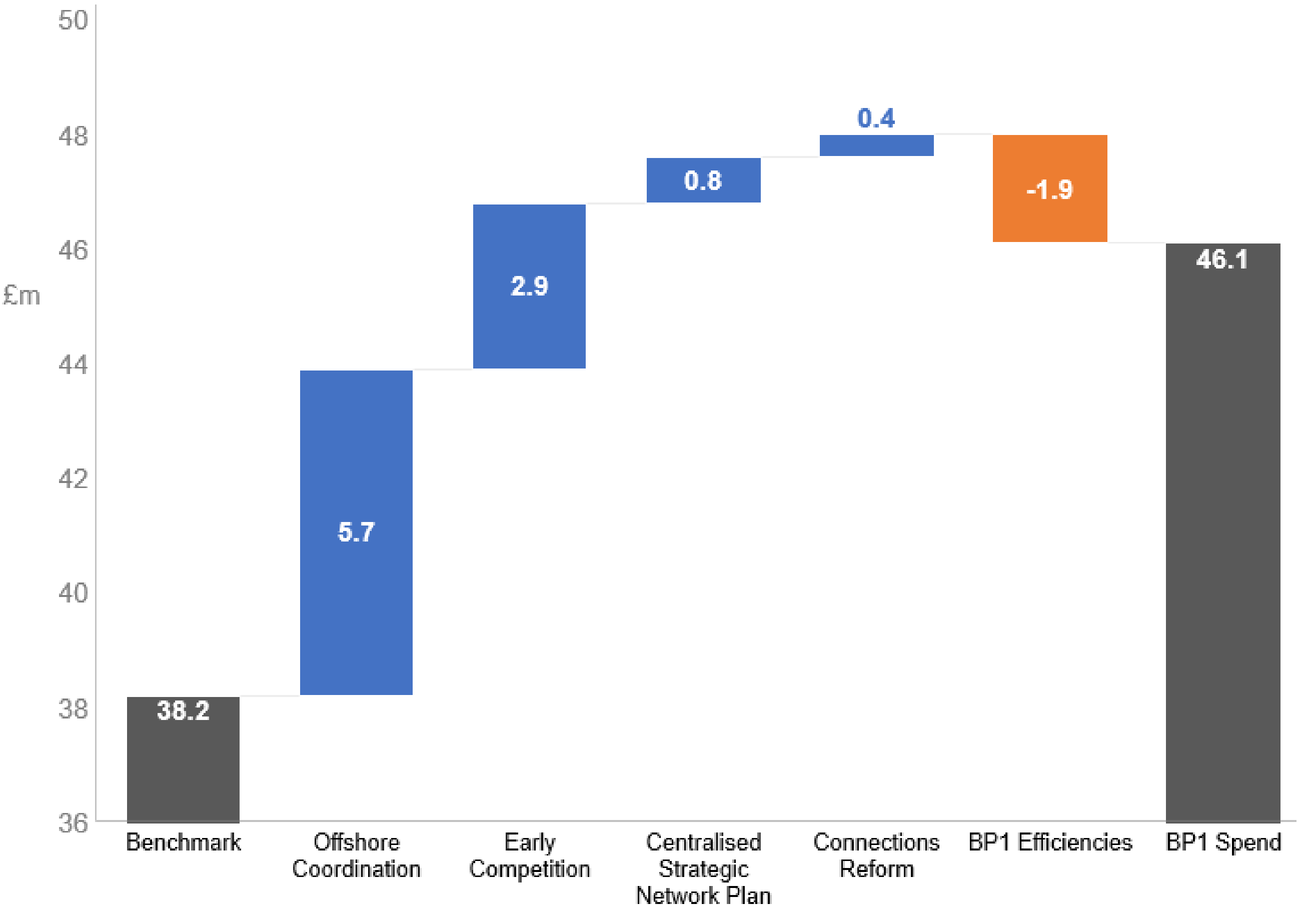
Directly attributable opex refers to the operating costs that the ESO incurs to deliver its outputs under its three Roles. These are predominantly staff and external contractor costs.

Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
ESO Opex	38.2	21.0	25.1	46.1	7.9	20.6%

For Role 3 directly attributable ESO opex, we have spent £7.9m more than the benchmark of £38.2m over the BP1 period. During BP1 new initiatives and changes were introduced that were outside the scope of the original business plan. The ESO has continually prioritised its projects to deliver the best value for consumers. The below illustrates the cost impact of the initiatives relating to Role 3 directly attributable ESO opex.

Excluding expenditure relating to the initiatives highlighted in this chart, the spend attributed to Role 3 for delivering against its BP1 plan is £36.3m. This is an underspend of £1.9m against the BP1 benchmark. The initiatives referenced in the chart are discussed in further detail below.

Chart 7: ROLE 3 DIRECT OPEX BREAKDOWN



Offshore Co-ordination +£5.7m

Our 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. During BP1 we were asked by Ofgem and BEIS, as it was known at the time, to carry out additional roles and activities across the Offshore Transmission Network Review workstreams. This has led to £5.7m extra cost incurred over the BP1 period that was not included within the BP1 benchmark.

For further information on Offshore Co-ordination please refer to page 167.

Early Competition +£2.9m

In April 2022 Ofgem approved our Early Competition Plan (ECP) proposal and directed us to implement it with the aim of having a tender solution available to be used in 2024. Early Competition was not originally included in the BP1 benchmark as insufficient work had been completed at the time of the RIIO-2 submission to understand the scope of work required. £2.9m has been spent on Early Competition in the BP1 period.

For further information on Early Competition please refer to page 172.

Centralised Strategic Network Plan +£0.8m

Building on the foundations of the Holistic Network Design the output of role 3 has increased through development of the Centralised Strategic Network Plan (CSNP) which has engaged a wide range of industry stakeholders to define a forward-looking strategic plan for electricity transmission infrastructure. £0.8m has been spent on developing the CSNP during the BP1 period.

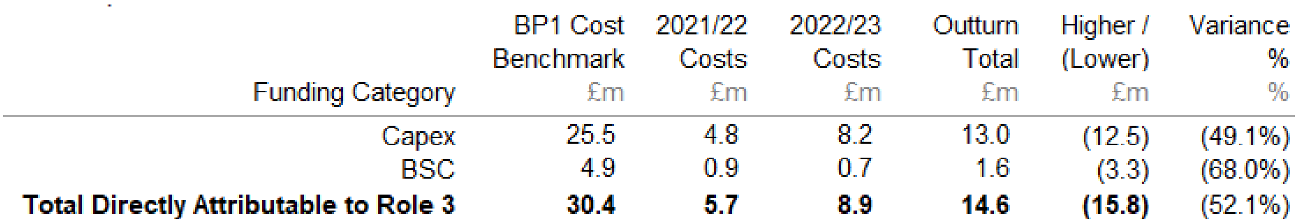
For further information on the CSNP please refer to page 168.

Acceleration of Connections Reform +0.4m

Connections Reform is a new activity we will be undertaking during BP2. As mentioned within our BP2 plan[52] this new activity aims to mitigate the impacts that we, and the wider industry are experiencing as the volume and complexity of connections is increasing and the capacity and capability of the existing process is stretched. To deliver connections reform we have split our programmes into several different phases. Due to the importance of and the urgent need for this reform, we have already begun Phase 1 activities within BP1. £0.4m has been spent on the Connections Reform activity in the BP1 period.

Directly Attributable ESO Capex and BSC

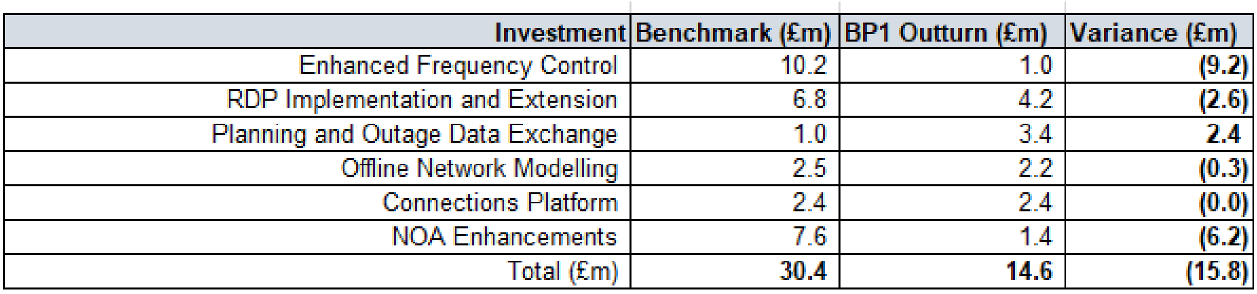
Directly attributable ESO capex and BSC expenditure refers to capex and opex costs relating to ESO investments that can be mapped to specific roles.



Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
Capex	25.5	4.8	8.2	13.0	(12.5)	(49.1%)
BSC	4.9	0.9	0.7	1.6	(3.3)	(68.0%)
Total Directly Attributable to Role 3	**30.4**	**5.7**	**8.9**	**14.6**	**(15.8)**	(52.1%)

For Role 3 directly attributable ESO capex and BSC, we have spent £15.8m less than the benchmark of £30.4m over the BP1 period.

Table 3: ROLE 3 INVESTMENT



Investment	Benchmark (£m)	BP1 Outturn (£m)	Variance (£m)
Enhanced Frequency Control	10.2	1.0	**(9.2)**
RDP Implementation and Extension	6.8	4.2	**(2.6)**
Planning and Outage Data Exchange	1.0	3.4	**2.4**
Offline Network Modelling	2.5	2.2	**(0.3)**
Connections Platform	2.4	2.4	**(0.0)**
NOA Enhancements	7.6	1.4	**(6.2)**
Total (£m)	**30.4**	**14.6**	**(15.8)**

Our **Enhanced Frequency Control (EFC)** project was established to implement a monitoring and control system (MCS) to provide fast and coordinated frequency response for low inertia zero carbon grid operation. We have reviewed the intended delivery of EFC as proposed in BP1, with our analysis highlighting that EFC's expected benefits are now attributable to another initiative – Dynamic Containment (DC), which launched successfully during BP1 and delivers a different solution to the same problem as EFC. Therefore, we have

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[52] https://www.nationalgrideso.com/what-we-do/our-strategy/our-riio-2-business-plan

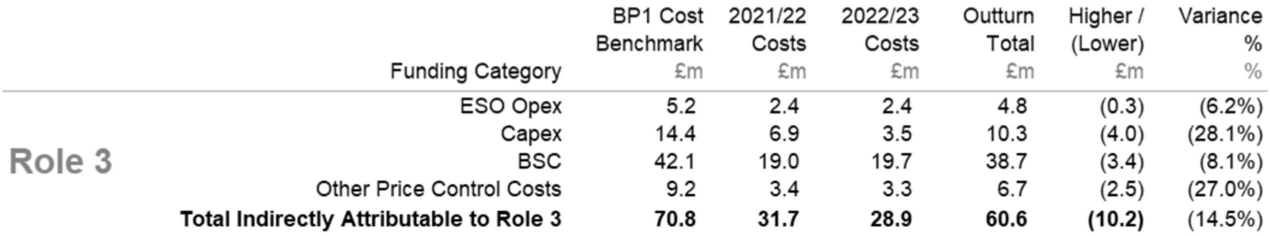
concluded that it would not be an economic use of consumer funding to continue EFC beyond its first phase. This has resulted in an underspend compared to BP1 benchmark of £9.2m.

The **Regional Development Programmes (RDP)** are delivering IT solutions that facilitate connections for Distributed Energy Resources (DER) more quickly and at lower cost for the consumer. The project has spent £2.6m less than BP1 benchmark due to the additional complexity of delivering the network connections for the N-3 ICCP link which has deferred spend into the BP2 period.

We spent £2.4m more than BP1 benchmark on our **Planning Outage and Data Exchange** project. This project was established to enhance our outage planning and data exchange services across transmission and distribution networks. The additional cost is largely driven by the Electricity Network Access Management System (eNAMS), and Electricity Generator Availability and Margin Analysis (eGAMA) capabilities being delivered in BP1 rather than in the RIIO-1 period. This was due to additional development work during end-to-end regression testing (before go-live) due to the need for access to eNAMS functionality by a wider external customer base. Also, there was a delay in data migration due to the complex nature of the legacy data structure and the need for additional data validation and testing.

Our **NOA Enhancements** project was established to deliver major improvements to how we model the electricity system and makes recommendations which optimises over £12 billion of investment every year. The project has spent £6.2m less than the BP1 benchmark. Some of this lower spend is due to efficiencies with savings in the development of the probabilistic modelling tool, achieved in negotiations with the supplier during best and final pricing for new tooling. Savings were also delivered through less resources used within the Economic Assessment Tool procurement. However, some of the lower spend is due to deliverables being re-phased to June 2023.

Indirectly Attributable ESO Costs



	Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
Role 3	ESO Opex	5.2	2.4	2.4	4.8	(0.3)	(6.2%)
	Capex	14.4	6.9	3.5	10.3	(4.0)	(28.1%)
	BSC	42.1	19.0	19.7	38.7	(3.4)	(8.1%)
	Other Price Control Costs	9.2	3.4	3.3	6.7	(2.5)	(27.0%)
	Total Indirectly Attributable to Role 3	**70.8**	**31.7**	**28.9**	**60.6**	**(10.2)**	(14.5%)

Indirectly attributable costs relate to teams that work across the ESO business who support the activities within the three roles, and the costs for National Grid shared services. The costs for these supporting activities are shared 1/3 per role as they cannot be directly attributed to the activities performed within each role.

Indirectly Attributable Costs (All roles)

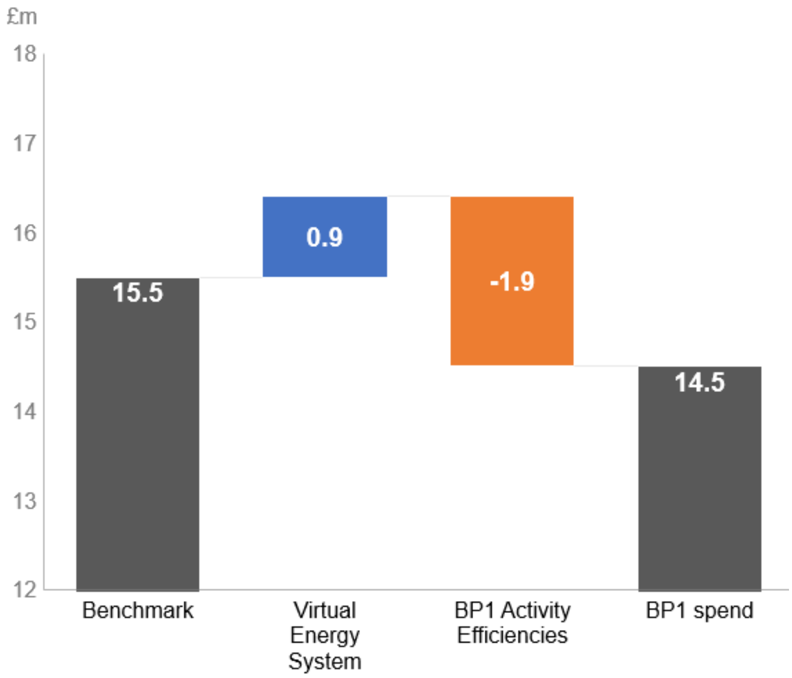
Our assessment for value for money is not only based on costs which are directly driven by activities within a particular role. Some activities support all roles equally and a summary of these costs and our spend against benchmark is given below.

	Activity	BP1 cost Benchmark £m	BP1 Spend £m	Variance £m	Variance %
	Supporting Operational Costs	15.5	14.6	(0.9)	(6.0%)
	Property Capex	6.6	3.3	(3.3)	(49.8%)
	IT & Telecoms and Other Capex	36.5	27.6	(8.8)	(24.2%)
	Total Business Support Costs	126.3	116.1	(10.2)	(8.1%)
Business Support sub-categories	*IT & telecoms-*	93.8	73.0	(20.8)	(23.2%)
	Property management-	11.4	14.3	2.8	24.9%
	HR & non-operational training-	4.8	5.6	0.7	14.7%
	Finance, audit & regulation -	6.4	10.4	4.0	62.3%
	Procurement	1.4	1.0	(0.4)	(27.7%)
	Insurance-	1.6	1.3	(0.3)	(20.2%)
	CEO & group management-	6.8	10.5	3.7	54.2%
	Other Price Control Costs	27.5	20.1	(7.4)	(27.0%)
	Total Indirectly Attributable Costs	**212.4**	**181.7**	**(30.7)**	**(14.4%)**

Supporting Operational Costs

BP1 Benchmark	Spend to Date	Variance
£15.5m	£14.6m	(£0.9m)

There are several teams that work across the ESO business rather than being dedicated to one of the Roles. They carry out activities that we refer to as “cross-cutting”. These teams are Business Change, Innovation, Assurance, and Regulation & Customer Stakeholder. Below details any new initiatives relating to these areas that were not within the scope of our BP1 plan, and the cost impact.



Virtual Energy System +£0.9m

The Virtual Energy System (VirtualES) programme is a new innovation activity that was initiated during BP1. The ambition of the VirtualES programme is to enable the creation of an ecosystem of connected digital twins of the entire energy system of Great Britain. As stated in Chapter 10 of our BP2 plan[53], we consider totex funding as the most appropriate funding model for the large amount of stakeholder engagement and facilitation needed as part of the programme. The £0.9m totex spend on this programme during BP1 was not included within the original benchmark. Future costs for this programme have been built into our BP2 plan.

Efficiency Savings -£1.9m

During BP1 our cross-cutting teams have successfully supported the delivery of our plan and achieved approximately £1.9m in cost efficiency savings against our BP1 benchmark.

Property Capex

Property capex relates to spend on ESO occupied properties. This is primarily spending on the Wokingham site but also covers enhancements for the contingency control centre and our share of capex required for the portion of National Grid UK’s Warwick head office that houses the ESO.

BP1 Benchmark	Spend to Date	Variance
£6.6m	£3.3m	(£3.3m)

Spend has been lower than benchmark largely due to £1.3m of planned spend on cooler units being deferred into the BP2 period, as well as the decision to defer some planned upgrades and enhancements at the Wokingham site to deliver within the Wokingham site refurbishment project planned in the BP2 period.

IT & Telecoms Capex

The indirectly attributable IT & Telecoms portfolio is made up of shared investments being delivered as a five-year plan for RIIO-2 across the NG Group businesses. Further detail on the progress of larger initiatives within this portfolio can be found below.

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[53] https://www.nationalgrideso.com/what-we-do/our-strategy/our-riio-2-business-plan

Hosting and Data Management/ Archiving-Tool/Licensing/Implementation

These investments are being delivered under a single Hosting initiative within National Grid Global IT as the capabilities and outcomes are closely aligned. This looks to deliver modernisation of Infrastructure, replacing end of service life assets in line with asset health policies. As well as upgrading on premise infrastructure including AIX, storage, and backup, and migrating all applications to new and refreshed hosting services as required.

BP1 Benchmark	Spend to Date	Variance
£16.9m	£6.1m	(£10.8m)

The underspend against BP1 benchmark is largely accounted for by a re-phasing of spend across the 5-year RIIO-2 period. We expect costs to be broadly in line with our RIIO-2 forecast across the full period.

WAN and LAN Infrastructure

Improvements to WAN infrastructure will provide a secure and reliable Wide Area Network to enable employees to be productive when working in National Grid offices. Consistent progress is being made focusing on reducing the technical debt that we began the period with and improving control over the network environment to increase performance and customer experience.

Improvements to LAN infrastructure will provide a reliable wired and wireless local area network transport with a goal to optimize performance, maximize uptime, and enable end user mobility requirements and improve experience in connecting to internal or external applications and services. Consistent progress is being made focusing on reducing the technical debt that we began the RIIO-2 period with and improving Wi-Fi capabilities at our sites.

BP1 Benchmark	Spend to Date	Variance
£5.6m	£0.7m	(£4.9m)

The underspend against BP1 benchmark is largely due to a re-phasing of spend across the 5-year RIIO-2 period. We expect to be broadly in line with our RIIO-2 plan across the full period though we will continue to prioritise our work across the LAN Infrastructure, WAN Infrastructure and CNI Infrastructure initiatives as we respond to current issues.

CNI Infrastructure Upgrades and Maintenance

CNI Infrastructure upgrades and maintenance will develop Continued reliability and availability of the UK Electricity CNI Networks, decreased probability of network disruption and to the applications that use it, lowered risk of a reduced standard of service and regulatory sanction and maintenance of security measures, by ensuring components are kept within manufacture support.

BP1 Benchmark	Spend to Date	Variance
£2.4m	£3.1m	+£0.7m

The overspend against benchmark is a result of a some CNI investments that began in RIIO-1 completing and closing during the first year of RIIO-2 BP1.

Digital IT Operations/Network Operations Centre (NOC)

Digital IT Operations/NOC leverages advances in automation, observability, performance monitoring and machine learning to create production environments which are more stable, more efficient and improves business agility. Investment in Digital IT Operations is building the technology foundations for us to stand up a full Network Operations Centre (NOC). Therefore, we have chosen to combine the two initiatives in our reporting.

BP1 Benchmark	Spend to Date	Variance
£3.0m	£1.2m	(£1.8m)

Although showing a combined underspend against benchmark, the Digital IT Operations proportion of the benchmark is over the BP1 benchmark due to an increased focus on building the Digital IT Operations foundation, before pivoting across to specific NOC investments in the latter half of the RIIO-2 period. We currently forecast to be broadly in line with our RIIO-2 forecast across the full period.

Service Now Upgrade and Capability Improvements

ServiceNow supports many key National Grid workflows, including but not limited to IT and Business Services processes. We will maintain and evolve our ServiceNow platform with the aim to keep the estate up to date and preserve the value of the investment already made.

BP1 Benchmark	Spend to Date	Variance
£1.0m	£0.1m	(£0.9m)

The underspend against BP1 is largely due to a re-phasing of spend across the 5-year RIIO-2 period as we prioritise other investments. We forecast to be broadly in line with our RIIO-2 forecast across the full period.

ERP (SAP S/4 HANA)

SAP is the digital core of National Grid's Finance systems. Scope includes Payroll, Procure to Pay, Invoice to Cash, and Accounting to Reporting (including for Inventory, Projects and Fixed Assets). Investment in our ERP systems supports a continuous programme of Asset Health work and Functional Change.

BP1 Benchmark	Spend to Date	Variance
£2.7m	£5.4m	+£2.7m

The first release of the ERP project in RIIO-1 enabled us to migrate from legacy SAP ECC system to S4 Hana and delivered a level of core capability. Release 2 in the BP1 period delivered further functionality such as project systems, fixed asset accounting, time reporting, HR integration and enhanced reporting capability. The new ERP system has delivered benefits such as delivery of more automated reporting, automation of financial controls and increased efficiency of finance processes. Much of the release 2 functionality was expected to be delivered in the RIIO-1 period, so ERP costs are higher than benchmark costs.

SuccessFactors

SuccessFactors is a cloud-based Human Capital Management (HCM) system which will be regularly refreshed and updated throughout RIIO-2. SuccessFactors is the core foundation upon which we will base future IT investments in HR.

BP1 Benchmark	Spend to Date	Variance
£0.5m	£0.9m	+£0.4m

We are currently delivering in line with the RIIO-2 plan.

Other Business Support Costs

Business Support Costs cover services that are shared across all the National Grid group businesses under a single function for several key support services. These include IT support, property management, human resources (HR), procurement, corporate affairs, legal and finance.

Each National Grid group business pays a fair share of the costs of these functions, through the unified cost allocation methodology (UCAM) approach agreed with Ofgem. These allocations are submitted to Ofgem every year as part of the regulatory reporting pack (RRP) process, which includes a description of and reasons for any allocation methodologies that have changed.

Below we provide detail on the main activities driving the variance for Business Support areas against BP1.

IT & telecoms

BP1 Benchmark	Spend to Date	Variance
£93.8m	£73.0m	(£20.8m)

IT and telecoms costs were £20.8m lower than the BP1 benchmark. £11.3m of this lower spend was in IT support costs where incremental costs from IT project delivery were lower than those in the BP1 plan. There were also £9.5m lower shared IT project opex costs which is due to the phasing of spend over the RIIO-2 period, where we expect the forecast over the full RIIO-2 period to be broadly in line with our RIIO-2 business plan.

Property Management

Our property function is responsible for making sure our offices and other properties are in good condition and safe for our people to work in, managing the services to run our buildings, such as security, cleaning and catering and providing recycling services and using sustainable materials and energy

BP1 Benchmark	Spend to Date	Variance
£11.4m	£14.3m	+£2.8m

The overspend against BP1 for property management is due to rising costs for utilities driven by market conditions that were not foreseen during the time of the BP1 submission.

HR & Non-Operational Training

HR & Non-Operational Training includes costs for graduates and trainees as well as our HR function.

BP1 Benchmark	Spend to Date	Variance
£4.8m	£5.6m	+£0.7m

One of the ways we are looking to drive our people growth agenda is through recruiting graduates and apprentices with related skills for further development. The overspend against BP1 benchmark is largely driven by the increasing focus on our new talent programmes, which have been developed and enhanced during BP1. Against a general backdrop of rising rates of attrition, we have sought to recruit more of our new talent through our graduate programmes, where we typically see much higher rates of retention. Given the growth and specialist skills requirement we see as we transition to FSO we believe that investing more now in our graduate programmes is a cost-effective way to prepare for our future challenges.

More information on this can be found in Chapter 11 of our BP2 plan [54].

Finance, Audit & Regulation and Procurement

BP1 Benchmark	Spend to Date	Variance
£6.4m	£10.4m	+£4.0m

The overspend against BP1 is due to increased FY22 audit fees and the costs of meeting ongoing business and external environment reporting demands.

CEO & Group Management

BP1 Benchmark	Spend to Date	Variance
£6.8m	£10.5m	+£3.7m

The overspend against BP1 is driven by a £1.0m increase in legal fees and £2.7m increased spend in our Corporate Affairs function.

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[54] https://www.nationalgrideso.com/what-we-do/our-strategy/our-riio-2-business-plan

During BP1, we had to build out and create capabilities for a Corporate Affairs function that is independent of National Grid Group. Today, we handle a large volume of national media enquiries and requests. Over the winter period we have dealt with enquiries that are at the top of the news agenda, from security of supply to our new Demand Flexibility Service to winter operations. We have also had to separate out our website from National Grid Group and create content that explains the role and purpose of the ESO. In order to become the FSO and provide the business with external advice and input, we have had to engage with and brief politicians and external stakeholders and use that insight to deliver a better service.

Other Price Control Costs

Other price control costs mainly relate to cyber security costs and are £7.4m lower than our BP1 benchmark. This portfolio is being delivered as a five-year plan across the National Grid Group businesses and progress is reported separately under the PCD obligations.

Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
Other Price Control Costs	27.5	10.2	9.9	20.1	(7.4)	(27.0%)

Amber Projects

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 our IT projects, which is set out in Appendix 4 of Final Determinations.

These projects are:

3. 110 – Network Control
4. 180 – Enhanced Balancing Capability
5. 220 – Data and Analytics Platform
6. 500 – Zero Carbon Operability

1. 110 – Network Control

BP1 Benchmark	Spend to Date	Variance
£11.4m*	£14.2m	£2.8m

**As agreed with Ofgem, investments 110 Network Control and 150 Operational Awareness and Decision Support were merged at the end of BP1.*

Background

This programme was established to deliver real-time situational awareness capability providing control centre operators capability to manage the electricity network as we move to zero carbon grid operations. Our priority for Network Control is to maintain an efficient, safe, and reliable electricity network.

The current Integrated Electricity Management System (IEMS) is shared with NGET, with access rules to ensure logical separation. The implementation of the Network Control Management System (NCMS) under investment 110 by the ESO, and the corresponding replacement by NGET will enable full separation of the systems. Following separation, the ESO will no longer use IEMS and will decommission the old platform.

There are strong synergies between investments 150 and 110 Network Control, and we will deliver these as a combined programme.

Since the original Business Plan was created, the Network Control Management System (NCMS) procurement event has been undertaken, resulting in the award to GE Digital. Analysis undertaken during this event and after it has identified significant cross over between the objectives/deliverables stated within the 150 Operational Awareness and Decision Support initiative and those that are delivered by the GE Digital commercial off the shelf (COTS) product being deployed for NCMS.

Due to this analysis, it was proposed and accepted that the 150 Operational Awareness and Decision Support initiative and budget be assimilated into 110 Network Control Programme as the delivery of these capabilities will all be undertaken by the existing NCMS programme team therefore it is inefficient to continue to report and manage them as independent items.

It should be noted that the deliverables specified and committed to within the Business Plan remain unchanged, all that would be changing is the mechanism for how the ESO would deliver them which would be via one singular team rather than two separate and distinct teams. This approach has been proposed and accepted by Ofgem.

In BP1 we worked with NGET to validate:

- What current capabilities can or should be shared
- Extended support of current system after 2023
- High-level ESO and NGET programme plans

In BP1 we have also defined the new capabilities that are required by the ESO which may differ from the current systems.

ESO with NGET have signed a new Managed Service Agreement with GE Digital for the existing IEMS thereby extending the support life of the current asset whilst the strategic replacement is delivered in parallel.

Explanation of variance against BP1 benchmark

As highlighted within our recent BP2 update, we have changed design approach so that we leverage the benefits associated with using modern compute and storage platforms, specifically, Blade and SAN Architecture. This allows us to utilise virtualisation technologies that run on top of this platform rather than individual servers and storage. This change in approach has resulted in our hardware expenditure being higher than previously forecasted within the original cost modelling. This will give the ESO the benefits of a much more flexible platform to develop further applications and services on top of and increase the speed of delivery, patching and maintenance by reducing our physical footprint. The benefits of employing these technologies now greatly outweigh the cost and will help to reduce the need for additional equipment in the future due to its flexibility. Equally, given the ongoing effects of COVID on supply chains, we have elected to pull forward procurement activity for hardware at no extra risk, to ensure that these are delivered by required dates to reduce potential future risk and impact.

Additionally, the number of business resources assigned to NCMS have increased to ensure successful delivery. We have consulted with our independent Technology Advisory Council (TAC) and external stakeholders who have provided insights into prioritising end user ownership and operational requirements during delivery. We have listened to their advice for “establishing product-like teams and technology teams who are close to operational teams" and "ensuring our teams understand the operational mindset".

The net impact of these has influenced the upward pressure on our BP1 outturn.

Our assumptions during BP1 have evolved as detailed planning activities have started to take place, this has seen a reduction and reprofiling of Opex and RtB for the period.

The delays with data centre readiness have also had an impact on the expected Opex spend for BP1, this underspend is not expected to impact future costs into BP2.

The earlier than planned procurement of IT hardware has had an impact on BP1 Capex spend, again this is not expected to impact future costs into BP2.

2. 180 – Enhanced Balancing Capability

BP1 Benchmark	Spend to Date	Variance
£20.3m	£38.3m	£18.1m

Background

As part of BP1 we have engaged extensively with market participants to agree a co-created roadmap and now have a priority list that is fully supported by industry.

During BP1, we have developed a much greater understanding of the scale and complexity of transforming our balancing capability. In this second Business Plan we have updated our plans and costs to facilitate a programme to deliver the new platform called Open Balancing Platform (OBP).

Our original plan was to enhance EBS (Electricity Balancing System) to consolidate the creation of our 4-hour ahead schedules for balancing. This scheduling capability was to be integrated with our new modular platform, to eventually replace BM (Balancing Mechanism) by 2023/24. Our Foundation and Blueprint phases determined that the changes required in EBS to enable this integration would be too complex, carry a substantial risk and would, along with a major infrastructure upgrade, lead to significant prohibitive costs. Furthermore, changes in control room requirements driven by market changes have helped us determine that our current and planned 4-hour scheduling capabilities would not meet operational needs in the future.

To date, the programme has completed six programme increments. Increments 3,4, 5 and 6 were functional developments. The programme is halfway through programme increment 7.

The primary outcome in development is release 1 of the OBP, planned for December 2023. This will provide the ENCC with the ability to dispatch many small zone units efficiently, significantly reducing small unit skips rates.

Explanation of variance against BP1 benchmark

Balancing Transformation efforts and costs have exceeded the original estimates made in BP1. Our original plan was a high-level estimation underpinned by key market, operational and technology assumptions, some of which did not materialise.

As we detailed in our final BP2 plan, the decision to build the Open Balancing Platform (OBP) was based on the need to move away from our legacy systems, we have pivoted away from enhancing our existing EBS system, to fully replacing it, to maintain our operational capability support our zero carbon operability requirements.

The roadmap for the OBP has been co-created with Industry and the costs are now aligned to our co-created Roadmap. We have revisited our original BP1 plan which was based upon high-level estimation and assumptions. As part of building resilience against cyber threats, we plan to deliver a tertiary site. We have been able to plan for CNI support and training more efficiently reducing the Opex spend as compared to the forecast in BP1. Due to an increased scope, the go-live of the new platform is delayed which has reduced the RTB spend associated with it in BP1.

The programme’s co-created Roadmap is costed, based on a capacity model required to deliver the capabilities and outcomes required to transition away from our legacy systems. We can track these costs down to an individual resource level using our detailed cost modelling and management.

Our roadmap continues to be reflective of Industry, market, consumer, and operational priorities. As such we are currently reprioritising capabilities within our roadmap for review with industry in June 2023.

3. 220 – Data and Analytics Platform

BP1 Benchmark	Spend to Date	Variance
£11.1m	£9.9m	(£1.3m)

Background

This investment delivers the capability for us to meet our Open Data commitments. The Data and Analytics Platform (DAP) will:

- Provide the technology underpinning the management of all our data, making it discoverable and accessible to internal and external stakeholders.
- Create a new architecture that allows new systems to be integrated seamlessly in a 'plug-and-play' or 'app-like' way. This allows our future system upgrades, to flex as needed and meet the challenges of facilitating the transition to net zero.
- Provide analytical capability to enable insights. This allows quicker, accurate operational decisions and give our customers value added information based on the insights.

Explanation of variance against BP1 benchmark

Delivery of the Data and Analytics project has changed to an incremental delivery method to achieve maximum value and realise benefits earlier rather than delivery of the full platform at once as was originally planned and costed.

The initial costs were related to building out all Azure capabilities under a one-off deployment, to hold all data, and integrate all data points to create all reports committed to in the BP1 plan. With a change in ways of working and adoption of an incremental delivery approach, the team created a roadmap to deliver an MVP leading to a route into BP2. This has led to lower costs in BP1 as the incremental delivery method has been applied.

On the above the biggest cost in BP1 besides resources would have been data storage in Azure as the initial plan was to pump data into Azure then use it as needed, with incremental delivery we only ingest the data needed for the outcome, which has reduced costs.

Throughout BP2 the operating model for data products will continue to evolve aligned to priorities for our teams and customers. We will develop data products using agile requirements discovery, capture and build where possible. Release management will be implemented in phases with sequential releases of capability to data consumers. Infrastructure release for major Azure product services and associated capability will follow a sequential release process.

A large amount of work on the Grey IT estate has moved us into a better control position in this area and has also had significant expenditure on it.

4. 500 – Enhanced Frequency Control (formerly Zero Carbon Operability)

BP1 Benchmark	Spend to Date	Variance
£10.2m	£1.0m	(£9.2m)

Background

This project was established to implement a monitoring and control system (MCS) to provide fast and coordinated frequency response for low inertia zero carbon grid operation

We have been reviewing the intended delivery of EFC as proposed in BP1, with our analysis highlighting that EFC's expected benefits are now attributable to another initiative – Dynamic Containment (DC), which launched successfully during BP1 and delivers a different solution to the same problem as EFC. Therefore, we have concluded that it would not be an economic use of consumer funding to continue EFC beyond Phase 1.

We have modified the scope of Phase 0, with the remaining roadmap and strategy work removed and the focus shifted to researching other areas of Wide Area Monitoring and Control (WAMC). We are progressing the commercial negotiations; these are currently ongoing and need to be completed to enable the start of building the prototype for the Phase 1 NIA funded non-operational demo in early FY24 to enable commencement of the demo in Q2 and completion of the demo in Q3.

Explanation of variances against BP1 benchmark

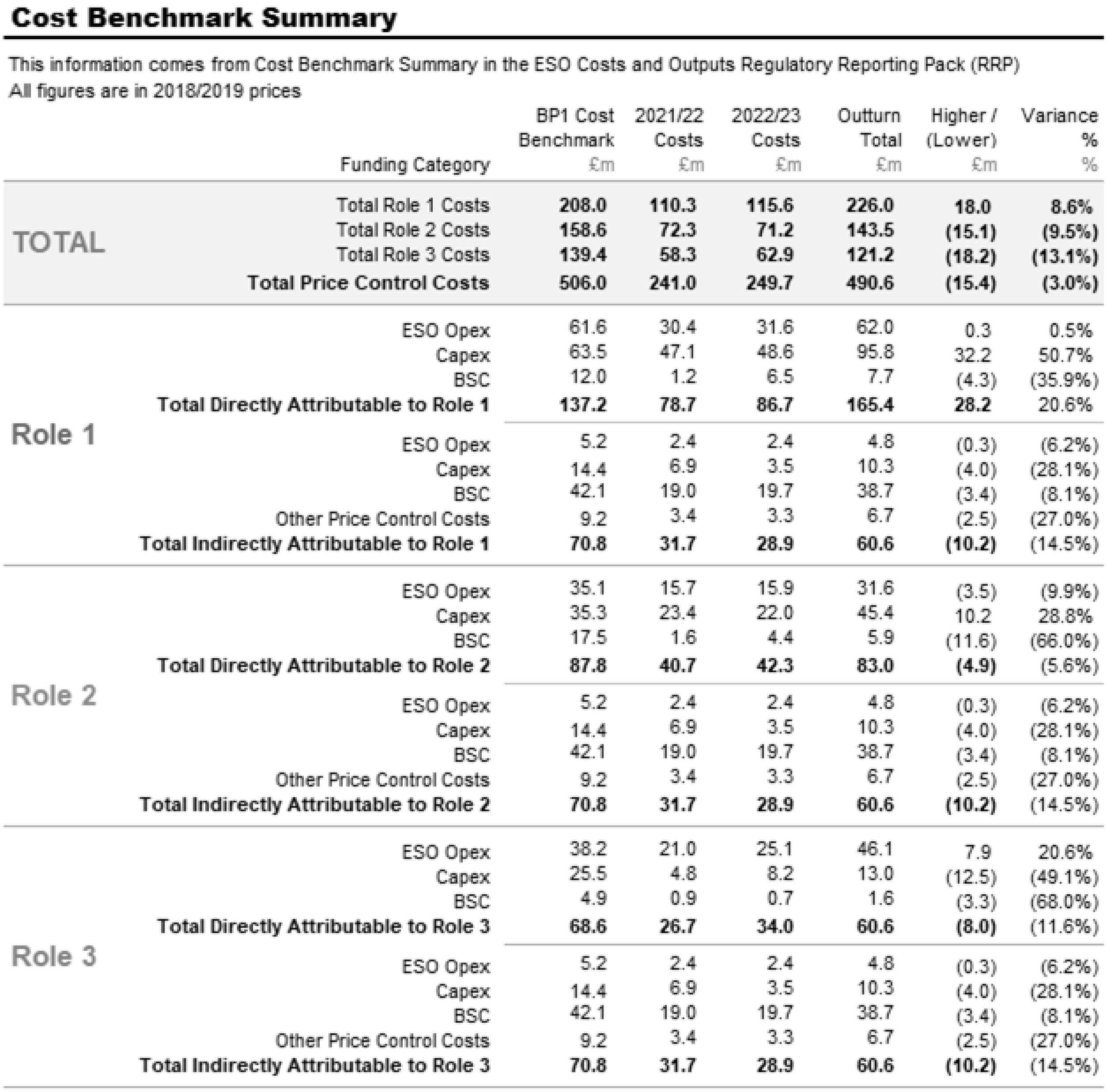
During the BP1 period, a new “Phase Zero” milestone was introduced, which was not in the original five-year plan. This provided a strategy and design blueprint for the programme and mobilised participants for the Phase One non-operational demonstration.

Through Phase 0, the project team evaluated the need case of EFC along with already existing post fault frequency services such as Dynamic Containment (DC). Due to these additional works, the Phase One non-operational demonstration was deferred, and is currently expected to be completed by Q3 FY24 in BP2.

The subsequent milestones of operational demonstration and roll-out of EFC (Phase Two to Phase five) were planned to be delivered during BP2 and have now been subsequently curtailed.

The proposed change of scope of work for this investment has been approved through our internal governance channels including the Design Authority and Portfolio Review Board. It has also been communicated to Ofgem in our response to the Draft Determinations.

Identifying this opportunity to streamline our focus has identified efficiencies to our activities and forecasted expenditure. Phases 0 and 1 will cost £1.2m to deliver, resulting in a net saving of £21m from not completing Phases 2-5.



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	2022/23 Costs £m	Outturn Total £m	Higher / (Lower) £m	Variance % %
TOTAL	Total Role 1 Costs	**208.0**	**110.3**	**115.6**	**226.0**	**18.0**	**8.6%**
	Total Role 2 Costs	**158.6**	**72.3**	**71.2**	**143.5**	**(15.1)**	**(9.5%)**
	Total Role 3 Costs	**139.4**	**58.3**	**62.9**	**121.2**	**(18.2)**	**(13.1%)**
	Total Price Control Costs	**506.0**	**241.0**	**249.7**	**490.6**	**(15.4)**	**(3.0%)**
Role 1	ESO Opex	61.6	30.4	31.6	62.0	0.3	0.5%
	Capex	63.5	47.1	48.6	95.8	32.2	50.7%
	BSC	12.0	1.2	6.5	7.7	(4.3)	(35.9%)
	Total Directly Attributable to Role 1	**137.2**	**78.7**	**86.7**	**165.4**	**28.2**	20.6%
	ESO Opex	5.2	2.4	2.4	4.8	(0.3)	(6.2%)
	Capex	14.4	6.9	3.5	10.3	(4.0)	(28.1%)
	BSC	42.1	19.0	19.7	38.7	(3.4)	(8.1%)
	Other Price Control Costs	9.2	3.4	3.3	6.7	(2.5)	(27.0%)
	Total Indirectly Attributable to Role 1	**70.8**	**31.7**	**28.9**	**60.6**	**(10.2)**	(14.5%)
Role 2	ESO Opex	35.1	15.7	15.9	31.6	(3.5)	(9.9%)
	Capex	35.3	23.4	22.0	45.4	10.2	28.8%
	BSC	17.5	1.6	4.4	5.9	(11.6)	(66.0%)
	Total Directly Attributable to Role 2	**87.8**	**40.7**	**42.3**	**83.0**	**(4.9)**	(5.6%)
	ESO Opex	5.2	2.4	2.4	4.8	(0.3)	(6.2%)
	Capex	14.4	6.9	3.5	10.3	(4.0)	(28.1%)
	BSC	42.1	19.0	19.7	38.7	(3.4)	(8.1%)
	Other Price Control Costs	9.2	3.4	3.3	6.7	(2.5)	(27.0%)
	Total Indirectly Attributable to Role 2	**70.8**	**31.7**	**28.9**	**60.6**	**(10.2)**	(14.5%)
Role 3	ESO Opex	38.2	21.0	25.1	46.1	7.9	20.6%
	Capex	25.5	4.8	8.2	13.0	(12.5)	(49.1%)
	BSC	4.9	0.9	0.7	1.6	(3.3)	(68.0%)
	Total Directly Attributable to Role 3	**68.6**	**26.7**	**34.0**	**60.6**	**(8.0)**	(11.6%)
	ESO Opex	5.2	2.4	2.4	4.8	(0.3)	(6.2%)
	Capex	14.4	6.9	3.5	10.3	(4.0)	(28.1%)
	BSC	42.1	19.0	19.7	38.7	(3.4)	(8.1%)
	Other Price Control Costs	9.2	3.4	3.3	6.7	(2.5)	(27.0%)
	Total Indirectly Attributable to Role 3	**70.8**	**31.7**	**28.9**	**60.6**	**(10.2)**	(14.5%)

ESO