# ESO RIIO-2 Business Plan 2 Supporting Information

## Annex 1

31 August 2022

## BP2 Supporting Information Annex

nationalgridESO

# Contents

# 1 Overview

This Annex accompanies our second RIIO-2 Business Plan (BP2) which covers the period 1 April 2023 to 31 March 2025. It contains several key areas to support the Plan.

## 1.1 Updates to our April Draft Plan

Our Draft Plan contained some areas which were still under development due to factors such as project maturity or matters pending legislative decisions. These areas were highlighted as such and have been updated as much as we can with the information we have today in our Final Business Plan. Similarly, updates have been made in response to stakeholder feedback and the Draft Plan consultation process which ran from 29 April to 10 Jun 2022.

Key updates are summarised for each Role, on a per-activity basis.

We also include tables[1] which outline changes to the structure and high-level content of the Final BP2 Business Plan.

## 1.2 Additional supporting information for activities and sub-activities

Information which is noted as additional to the content contained in the main Business Plan is included in this Annex. This information may provide further background, context or clarity to materially changed and new activities/sub-activities.

Activity financial and headcount tables with supporting narratives are also outlined activity this annex. We have also included roadmaps which summarise transformational deliverables at a high level and are a summarised version of the transformational deliverables in the full delivery schedule. Please note that continuous and ongoing deliverables are not included in the roadmaps.

## 1.3 Additional Supporting Information for Other Subject Areas

Further information supporting that of the main Business Plan is detailed relating to the following areas:

- ESO Innovation
- Our Regulatory Finance arrangements
- More information on the teams that support the delivery of BP2 (cross-cutting teams) financials and headcounts
- Key updates to the CBA Annex

## 1.4 Sub-activities not materially changed

Sub-activities with either minor or no change for BP2 when compared with the BP1 plans have been moved to this Annex. This is to facilitate a clearer focus on what's changing for BP2 in the full Plan. These sub-activities are outlined per role.

[1] Tables 1 and 2

# 2 How our five-year Business Plan has changed

## 2.1 Delivery Plan

Our Final BP2 submission has been restructured, and is set out in two main parts:

- Part A is the Summary Business Plan which sets out the high level context, intended outcomes, priorities, key focus areas, and expected costs and benefits of the Plan, and is designed to function as a standalone document.
- Part B is the Delivery Plan, following the regulatory Framework of Roles 1, 2 and 3 and providing the detail of the activities and milestones, as well as activities which cut across the full Plan.
- Further supporting information is then split into five Annexes.

The tables below give a high-level summary of how the structure and core content of our final BP2 submission has changed since our BP1 plan, and why we've made these changes.

### Role-Specific Chapters

| Chapter | Content/activity | Summary of Key Updates |
|---|---|---|
| **Cross-role Activities** | The Cross-role activities sub-chapters have been absorbed back into the Role sections for clarity. Related sections from the April Draft Plan are impacted as outlined below. | |
| | Net zero operations | Content absorbed within our updated Plan (Chapter 02c of Part A and Role 3 **A15.9**). |
| | Transparency, data and analytics | Content summarised to provide a clearer narrative and moved back to Role 1. |
| | Accelerating whole electricity flexibility | Due to its prominence and specific deliverables across roles, Accelerating Whole Electricity Flexibility (now renamed Facilitating Distributed Flexibility) has a "Spotlight" section at the end of Role 3 to make sure the links between roles are as clear as possible. The strategy has been updated following stakeholder feedback. |
| | Net Zero Market Reform (A20) and Role in Europe (A21) | No longer defined as ESO-wide activities and have moved back under Role 2. |
| **Chapter 6 – Role 1 Control Centre Operations** | Updates to new activities | **A18 Market Monitoring** – content summarised to provide a clearer narrative. |
| | Updates to materially changed activities | **A1 Control centre architecture and systems** – updated from our Draft Plan with new, detailed content for the Balancing Programme and Balancing Costs resulting in new sub-activity **A1.6**.<br><br>In April we proposed a new deliverable **D1.1.9 Upstream Technical Co-ordination.** This has now been removed because we concluded that this is an inherent part of our operations already.<br><br>**A2 Control Centre training and simulation** – narrative for one sub-activity has been updated to note a delayed deliverable.<br><br>**A3 Restoration** – narrative for one sub-activity has been updated to cover changes due to the Restoration Standard. |

| Chapter | Content/activity | Summary of Key Updates |
|---|---|---|
| **Chapter 7 – Role 2 Market development and transactions** | Updates to new activities | **A20 Net Zero Market Reform** – content summarised to provide a clearer narrative.<br>**A21 Role in Europe** – following feedback, content now also includes **A6.2** EU code change activities which has also been renamed. |
| | Updates to materially changed activities | **A4 Building the future balancing services and markets** – a number of new deliverables have been added<br>**A5 Transform access to the Capacity Market and Contracts for Difference** – new sub-activity has been added.<br>**A6 Develop code and charging arrangements that are fit for future** – a number of new deliverables and sub-activities have been added. **A6.2** has been moved and renamed under **A21**. The newly proposed **D6.4.1** has been removed because it overlapped too closely with the ambitions of **D6.8 Implementation of digital solutions**. |
| **Chapter 8 – Role 3 System insight, planning and network development** | Updates to new activities | **A22 Offshore coordination and network planning review** – content updated to include **A9** network development activities following stakeholder feedback that these should be considered alongside the Network Planning Review. Also added placeholder deliverables into the Delivery Schedule, to be updated once we know more on the policy direction of these areas. Therefore, no milestones will be put forward for BP2 due to the early maturity stage of the NPR in particular, and the interdependencies between both projects. |
| | Updates to materially changed activities | **A7 Network Development** – **A7.1** and **A7.2** are now materially changed; RIIO-2 year four milestones are removed and subsumed under sub-activity **A22.2 Network Planning Review.**<br>**A8 Enable all solution types to compete to meet transmission needs** – Pathfinder name has been updated to Network Services Procurement and new content is included for a new sub-activity under Early Competition. **A8.2** has been moved under **A8.1**.<br>**A9 Extend NOA approach to end-of-life asset replacement decisions and connections wider works** – content for this has been moved to **A22.1**. As a result, there is no Transformational Roadmap included for **A9**.<br>**A13 Leading the debate** – content added for new deliverables.<br>**A14 Take a whole electricity system approach to connections** – content updated to reflect an additional resource ask, delayed deliverable and a new sub-activity for Connections Reform **(A14.5)**.<br>**A15 Taking a whole energy system approach to promote zero carbon operability** – content updated to explain new deliverables, delayed deliverables, renamed sub-activities. Also we have moved **A15.10** Develop a regime for an integrated offshore grid to **A22**.<br>**A16 Delivering consumer benefits from improved Network Access Planning** – content added to explain a new sub-activity (**A16.5**) to look at automation of network access planning. |

Table 1: Key updates to role-specific activities since our Draft Plan

## Other Chapters

| Chapter | Summary of what has changed from our Draft Plan |
|---|---|
| **Chapter 9 – Digital, Data and Technology** | Chapter named has changed from “Technology Investment” and content summarised to provide a clearer narrative about our Digital, Data and Technology strategy and delivery. |
| **Chapter 10 – Innovation** | Content updated to provide a clearer narrative about our Innovation strategy, including detail of projects in progress or completed, prioritisation, justification of costs, and benefits. |
| **Chapter 11 – People, capability and culture** | Content summarised to provide a clearer narrative about our People, capability and culture strategy. |
| **Chapter 12 – Enabling activities** | Renamed from “Cross-cutting activities”, and content summarised to provide a clearer narrative. Our Consumer Strategy has been expanded into its own sub-section of the Customer, Stakeholder and Consumer section to emphasise the key focus areas for BP2. |
| **Chapter 13 – Deliverability of our BP2 plan** | New chapter added based on stakeholder feedback, detailing a deep-dive conducted on the deliverability of our BP2 plan. |
| **Chapter 14 – Performance Measures** | This chapter has been updated to provide our proposals for changes to our stakeholder survey metrics and also we outlineour current view on our existing metrics for future discussion with Ofgem.. |
| **Chapter 15 – Indicative plan to establish the Future System Operator** | Content added into our main plan, which details our indicative plan to establish the Future System Operator. This was originally in Annex 4 of our draft plan. |
| **Chapter 16 – Regulatory Finance** | Renamed from “Finance and DIWE”. Updated for our Final Business Plan, and with supporting information added to this Annex. |

Table 2: Key updates to other sections since our Draft Plan

# 3 Role 1 Updates and Supporting Information

## 3.1 Transformational Deliverables Roadmaps

The roadmaps below outline the transformational deliverables for Role 1 across BP2. Continuous deliverables are not shown.

### A1 - Control Centre architecture and systems

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 Q1 | RIIO-2 Year Three - 2023/24 Q2 | RIIO-2 Year Three - 2023/24 Q3 | RIIO-2 Year Three - 2023/24 Q4 | RIIO-2 Year Four - 2024/25 Q1 | RIIO-2 Year Four - 2024/25 Q2 | RIIO-2 Year Four - 2024/25 Q3 | RIIO-2 Year Four - 2024/25 Q4 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Milestones | | | | | | | |
| Enhanced Balancing Capability (A1.2) | Future of Balancing (D1.2.1) | Delivery of core Open Balancing Platform (OBP) into a cloud hosted data centre. The OBP delivery team will be over 50% through delivery of release 1 | Completed Programme Increment 8. Issued report on Earned Value and Progress | Completed Programme Increment 9 | Completed Programme Increment 10. Issued report on Earned Value and Progress | Completed Programme Increment 11 | Completed Programme Increment 12. Issued report on Earned Value and Progress | Completed Programme Increment 13 | Completed Programme Increment 14. Issued report on Earned Value and Progress | We will have completed Programme Increment 15 |
| | Develop inertia monitoring capabilities and other tools to address emerging technology and system management issues (as required) (D1.2.2) | First-of-their-kind inertia monitoring tools delivered and integrated with existing situational awareness tools<br>Implemented BP1 Pathfinders | | Integrate inertia data with Data and Analytics Platform | | | | | | Inertia monitoring tools integrated with new Network Control Tool<br>Inertia monitoring tools integrated with DAP and enhanced balancing capability |
| Transform Network Control (A1.3) | Develop and deliver new real-time situational awareness tool (D1.3.1) | Significantly enhanced existing situational awareness capabilities | | Look-ahead functionality running in development environments | Commence build of environments for Voltage Stability Analysis and Online Stability Assessment tools | Shadow Control Centre operational<br>Initial Data and Analytics Platform (DAP) integration | Look Ahead Iteration 1/ VSAT/ OSA hosted in new DCs | NGET receiving RTU Data<br>DAP & balancing integration | Serial RTU connections removed | Deliver integrated network control tool (inc VSAT & Look Ahead OSA), including its specific digital twin |
| | Enhanced network modelling capabilities (D1.3.2) | Proof of concept of look-ahead analysis functionality delivered | | | Common Information Model (CIM) integration requirements complete | Integrate with enhanced balancing tool | | | Common Information Model (CIM) integration complete | Integrate models with new Network Control Management |
| | Upgraded Control Centre video walls and operator consoles (D1.3.3) | Requirements scoped for ENCC Operator Console | Complete UI/UX requirements for ENCC Operator Console | Commence design phase | Commence build | Scope requirement and start design of video walls | Commence solution testing | | ENCC Operator Console build complete. Move to implementation and enhanced testing | Development and testing of user experience tools and video walls |
| Control Centre Architecture (A1.4) | Data and Analytics Platform (D1.4.1) | Data available and accessible to all parties via application programming interfaces<br>Digital Engagement Platform and Single Markets Platform integration<br>Data catalogue publication | | | Enhanced Balancing data discovery & ingestion | Integrate data platform with enhanced balancing tool | | | Network Control tool data discovery & data ingestion | Network Control integration |
| A1.5 Operational coordination with DER and DSO (A1.5) | Increased DER visibility in real-time operations (D1.5.1) | New deliverable | Initiate operational input into project scoping to enable operational visibility of DER (aligned with D15.8.2) | Provide operational input into technical standards (aligned with D15.8.2) | Provide operational input into IT discovery phase (aligned with D15.8.2) | | Provide operational input into requirements and design phase to enable operational visibility of DER (aligned with D15.8.2) | | | Provide operational input into delivery of DER data into the Control Centre |
| | Development of RDP and LCM functionality into real-time environment (D1.5.3) | New deliverable | Continue to provide operational input into LCM and RDPs | | | | Continue to provide operational input into LCM and RDPs | | | |
| Minimising Balancing Costs (A1.6) | Constraint boundary optimisation (D1.6.1) | New deliverable | | | Full coverage of additional constraint management role in Control Centre | | | | | |
| | An agile programme of strategic and tactical Balancing Cost improvement activities (D1.6.2) | New deliverable | Programme plan shared | | Updated programme plan shared | | Updated programme plan shared | | Updated programme plan shared | |
| | Stakeholder Engagement on Minimising Balancing Costs (D1.6.3) | New deliverable | | Regular sessions with stakeholders to discuss opportunities to minimise balancing cost | | | | | | Continuing stakeholder engagement forum on Balancing Cost minimisation |

Figure 1: A1 transformational deliverables roadmap

## A2 – Control Centre training and simulation

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 Q1 | RIIO-2 Year Three - 2023/24 Q2 | RIIO-2 Year Three - 2023/24 Q3 | RIIO-2 Year Three - 2023/24 Q4 | RIIO-2 Year Four - 2024/25 Q1 | RIIO-2 Year Four - 2024/25 Q2 | RIIO-2 Year Four - 2024/25 Q3 | RIIO-2 Year Four - 2024/25 Q4 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Milestones | | | | | | | |
| Enhanced training material (A2.2) | Development of new modules and (based on feedback) new qualifications in system operation (D2.2.1) | Trial delivered with two academic institutions for updated course modules and work-based placements | Deliver work-based placement years | Deliver reviewed modules and year 3 placement opportunities defined | Delivery of placement opportunities | Delivery of modules and receive feedback on placement opportunities | Review and update summer placements for 2024 | | Update placement opportunities for one year placements | Refresh and run existing courses |
| | Enhanced training and simulation with DNOs and wider industry (D2.2.2) | Requirements for possible training collaboration explored with industry | Further develop cross-industry secondments | | | Develop requirements for connectivity of training simulators | | Engage with selected DNOs on simulator training options | | Trial training DNO staff on ESO simulators |
| Training simulation and technology (A2.3) | Developing new training simulation capability (D2.3.1) | Network Control Management System (NCMS) Training Simulator requirements complete<br><br>Requirements scoped for joint network control and balancing training simulator | | Initial new Network Control training simulator stood up | | Requirements completed for joint training simulator | | Commence development and training phases of joint training simulator | | Move to implementation of joint training simulator |
| | New training methods and platforms (D2.3.2) | New platforms for training include e-learning options | Initial suite of e-learning packages built | Learning packages tried and tested on trainees | | 24/7 access to learning packages established | Comprehensive suite of learning packages available | | | Simulation training can be accessed remotely 24/7 |
| Workforce and change management tools (A2.4) | Personalised updates and automated shift login (D2.4.1) | Repository created for all data relating to shift authorisation, development and training | Delivery of automated system and mobile application | | | Develop document management and rota improvements | Users can register for training and receive training when it suits them | | | Document management and rota improvements implemented |
| | Training plans designed, developed and delivered (D2.4.2) | Capabilities for roles are regularly assessed and updated where necessary | Annual review of training plans | Ad hoc review of training plans | | Personalised training plans in place with continued gap analysis | Created automation of training plans | User testing of automation of training plans | | Roll-out of automated plans for operational training |

Figure 2: A2 transformational deliverables roadmap

## A3 – Restoration

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 Q1 | RIIO-2 Year Three - 2023/24 Q2 | RIIO-2 Year Three - 2023/24 Q3 | RIIO-2 Year Three - 2023/24 Q4 | RIIO-2 Year Four - 2024/25 Q1 | RIIO-2 Year Four - 2024/25 Q2 | RIIO-2 Year Four - 2024/25 Q3 | RIIO-2 Year Four - 2024/25 Q4 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Milestones | | | | | | | |
| Restoration standard (A3.2) | Facilitate and compile the annual assurance framework for Electricity System Restoration (D3.2.1) | The first restoration assurance framework was published in April 2022 | Review, update (if required) and submit for Ofgem's approval the annual Assurance Framework | | | | Review, update (if required) and submit for Ofgem's approval the annual Assurance Framework | | | |
| | Maintain obligations and requirements against the new standard for restoration capability provision (D3.2.3) | Concluded industry engagement to develop regulatory solutions | Update regulatory framework following Ofgem's approval of regulatory changes | | Engagement with industry during tender process to secure restoration service providers | | | Engagement with industry to ensure progress with network changes | Engagement with industry for training and upskilling | |
| | Restoration decision support tool (D3.2.4) | The development of the tool is significantly progressed, incorporating requirements from across industry | | | | Tool available for integration with Network Control tools | | | | Tool testing in progress |
| Innovation (NIC) project in restoration (A3.3) | Subject to industry adoption, implement Distributed ReStart findings (D3.3.2) | Distributed ReStart project is complete and the roadmap for productionising the recommendations of the project is published | Fully understand project recommendations and their implications | | Decide which recommendations will be implemented in future (subject to industry adoption) | | | | | |

Figure 3: A3 transformational deliverables roadmap

## A17 Open Data and Transparency, A8 Market Monitoring, and A19 Data and Analytics Operating Model

The deliverables for A17, A18 and A19 are continuous, and so no roadmaps are provided.

## 3.2 Role 1 Activities and Sub-activities

The following section contains:

- Transformational deliverable roadmaps per activity, which outline the timelines only for deliverables which are not continuous/ongoing
- Narrative which provides additional detail or context to the main BP2 plan content where appropriate
- Financials and headcount tables and updates per activity
- Sub-activities which are either unchanged, or which have non-material changes from BP1

The table below clarifies the nature of the included content for each sub-activity in this Annex. Any sub-activities not listed will be those which are new or materially changed for BP2, but which have no additional supporting information provided in this Annex.

| Content | No or minimal change – Sub-activity BP2 content covered in this Annex only | New or materially changed for BP2 – Further information included here | New or materially changed for BP2 - Content in main plan only |
|---|---|---|---|
| A1.1 Ongoing Activities | | ✓ | |
| A1.2 Enhanced Balancing Capability | | ✓ | |
| A1.3 Transform Network Control | | | ✓ |
| A1.4 Control Centre architecture | ✓ | | |
| A1.5 Operational Coordination with DER and DSO | | | ✓ |
| A1.6 Minimising Balancing Costs | | | ✓ |
| A2.1 Ongoing activities | ✓ | | |
| A2.2 Enhanced training material | ✓ | | |
| A2.3 Training simulation and technology | ✓ | | |
| A2.4 Workforce and change management tools | | | ✓ |
| A3.1 Ongoing activities | ✓ | | |
| A3.2 Restoration standard | | | ✓ |
| A3.3 Innovation project in restoration | ✓ | | |
| A17 Transparency and Open Data | | ✓ | |
| A18 Market Monitoring | | ✓ | |
| A19 Data and analytics operating model | | ✓ | |

Table 3: Role 1 supporting information context

## 3.3 A1 Control Centre Architecture and Systems

### 3.3.1 A1.1 Ongoing Activities

While this sub-activity is materially changed, the main Plan details only those deliverables which are themselves materially changed for BP2.

There are no changes to:

- **D1.1.1 Balance Great Britain's (GB) demand for energy with supply from generators around the clock.**
- **D1.1.2 Maintain security of supply in real time and the ability to restart the system in the event of a partial or total loss of power**

- **D1.1.3 Maintain the integrity of the transmission network, while managing the economical operation of the system**

Additional information is however provided as follows for **D1.1.4 European Operations:**

- Since the BP1 delivery schedule was published in October 2020, the Trade and Cooperation Agreement (TCA) has been finalised, defining the extent to which the UK can participate in European projects and initiatives. Therefore, the ESO is no longer a member of the European Network of Transmission System Operators for Electricity (ENTSO-E). However, we will support development of new methodologies for interconnector capacity calculations under the TCA, and continue to support European cooperation, including with ENTSO-E, based on the outcome of the Memorandum of Understanding with ENTSO.
- Our membership of Coreso (Coordination of Electricity System Operators) continues, based on agreement with EU National Regulatory Authorities, and we value the provision of daily security analysis to our Control Centre.
- Following the publication of the Memorandum of Understanding, we will continue to participate in key projects and services relating to cross border capacity calculations, security analysis and situational awareness, along with associated reporting. We are continuing the business-as-usual activities of submitting individual grid models for the Common Grid Model project and Coreso security studies. Activities for intra-day capacity calculations and management of interconnector ramp rates are at the discussion stage with stakeholders. For more information about our role in European electricity transmission activities, see the activity **A21** Role in Europe in the main Business Plan and in this Annex..

Operability Strategy Report (**D1.1.6**)

- The Operability Strategy Report (OSR) has been refocused to cover the operational requirements and our future system needs. This makes a clear difference between this report and the Markets Roadmap, which explains how our markets are evolving to meet these future needs in the most efficient way. The reference to Control Centre management plans has been dropped from the **D1.1.6** deliverable description as the focus is on system needs and our operability requirements as set out in our five security workstreams.
- The OSR will continue to evolve according to the needs of stakeholders. For example, we anticipate its scope will expand to consider constraints at the transmission-distribution interface, to ensure a whole electricity system view is taken to lowering the constraint costs that impact consumer bills.
- In line with sub-activity **A15.9** Net-Zero Operability, we plan to expand the scope of the Operability Strategy Report to bring in two new areas (flexibility and capacity adequacy) which will set out requirements to further enable decarbonisation. The definition of flexibility will align with the Smart Systems and Flexibility Plan6 developed by the government and Ofgem to include storage, interconnection, and smart systems.

### 3.3.2 A1.2 Enhanced Balancing Capability

**Balancing Programme Activities and Decisions in BP1**

When we wrote our first RIIO-2 Business Plan, our future balancing capability plan was to enhance an existing system called the Electricity Balancing System (EBS) to consolidate the creation of four-hour ahead schedules for balancing. This scheduling capability was to be integrated with a new modular platform, replacing another existing system called the Balancing Mechanism (BM) by 2024.

At the start of BP1,we undertook a Foundation phase in which we established a requirement for a new, hybrid cloud platform and made other key technology selection decisions. These decisions were based on our newly developed understanding of the strategic importance of shifting capability requirements away from scheduling and further towards near real-time optimisation of dispatching decisions. This capability shift better aligns to meet our strategic goals and objectives, and is further supported by the following:

- Recent market changes have facilitated large hourly swings in some interconnector flows, which have significantly reduced the value of a four-hour ahead schedule, since each interconnector can change flow by up to 2000MW up to four times after the schedule is created.

- It was not possible to deliver the four-hour scheduling capability in EBS as expected with inflexibility holding back most enhancements. Its architecture will be unable to support the expected increases in BMUs without significant additional investment.

The Balancing Programme has also completed the Blueprint phase in which we detailed how a new highly scalable and flexible balancing system called the Open Balancing Platform (OBP) will work, enabling its development to start. In the Blueprint phase we:

- Defined the data architecture, including the principle of service harmonisation (i.e. that we will treat all units in the same way) and service configurability.
- Defined high-level modular architecture and aligned it to a storyboard for bulk dispatch.
- Defined the operational model for the hybrid cloud platform, inclusive of DevOps and environment management.
- Established an initial roadmap and product backlog for the Core phase which will deliver the skeleton service.

In April 2022 we began building an internal optimisation and modelling capability which will work closely with industry and academia to solve strategic optimisation problems. These optimisation capabilities will be developed in parallel and integrated into the OBP.

We deploy the Core release of the OBP into our Azure test platform in July 2022, with the first production release into the Control Centre following in September 2023.

By April 2023, we will complete the deployment of the Modern Dispatch Advisor (MDA), a modernised version of our existing Dispatch Advisor, within investment **180** Enhanced Balancing Capability. It has been necessary to invest in the MDA to make sure that we maintain resilience of dispatch advice to the Control Centre. We expect to integrate the MDA into the OBP as part of the 'National Optimiser' component of the platform.

**Balancing Programme Cost Changes since BP1**

The RIIO-2 cost forecasts for the Balancing Programme IT investments have increased significantly since BP1, from £63m to £173m (including capex, opex and running costs). These increases in costs have resulted from obtaining a full understanding of the technology requirements of our Balancing transformation (which we did not have at BP1) and from market changes during BP1 which have necessitated a change in the scope of our future balancing capabilities.

In our BP1 plan, we expected to build a new modular, flexible dispatch platform from foundation to completion in three years, between 2021 and 2024. This platform was anticipated to be tightly integrated with the Electricity Balancing System (EBS) four-hour ahead scheduling system. The associated costs were estimated through a methodology which considered their size, complexity, hosting and delivery types and compared them with other National Grid Group projects. At the time, we were unable to include high-level requirements, roadmaps, technology choices, delivery methods, supplier or team sizes in our cost estimates because full scoping activities had yet to take place.

In the BP1 period we delivered the Foundation phase for the new dispatch platform which scoped the high-level requirements from across the ESO. The conclusion of this phase was that we needed to deploy a modular balancing system, the OBP, which could be modified and deployed easily in secure Critical National Infrastructure (CNI) environments and was highly adaptable to future market and regulatory changes. The OBP will not be integrated with the EBS four-hour ahead schedule because the value of a four-hour ahead schedule has decreased significantly in BP1 for several reasons, including the introduction of hourly gates on most of the interconnectors. The costs of maintaining EBS now outweighs the value it provides. The focus of the OBP capabilities will be on near real-time optimisation of dispatching decisions.

The OBP is a significantly larger undertaking than was initially envisaged at BP1, with higher costs. We carried out a strategic review of our Balancing Programme plans, to validate requirements and to ensure that our plans for the OBP were supported by industry. Our latest cost estimates for the Balancing Programme IT investments are based on a sizing exercise on the OBP roadmap features. This sizing exercise gives us an understanding of the development team sizes (i.e. the capacity) required to deliver the roadmap. These team sizes, along with the costs of hardware, supporting business resources and existing system change capability costs, have been combined to provide new bottom-up cost estimates for BP2.

We recognise that the scale and pace of change in the energy sector will continue to increase and therefore we have to be able to respond. Responding to change may include changing the scope of our Balancing Programme investments again and therefore their associated costs. We have designed a quarterly planning and sanctioning process to ensure that our plans flex and adapt to future change and we will engage with industry on a quarterly basis to help them understand and provide input to future evolutions of our plans and costs.

The variances between our latest cost forecasts and those provided at BP1 for the RIIO-2 period are presented in the table below. Further breakdowns of the costs of our IT investments can be found in **Annex 4 – Digital, Data and Technology**.

| IT investment | RIIO-2 deliverable | Variance in capex | Variance in opex | Variance of cumulative incremental RtB | Commentary |
|---|---|---|---|---|---|
| **180 Enhanced Balancing Capability** | **D1.2.1** Future of Balancing | £59m | -£1m | £6m | Following delivery of the Blueprint and Foundation Phases, we have a greater understanding of the complexity and scale of the transition between existing and future balancing systems. Our revised costs also reflect an increase in scope to accommodate the system flexibility needed to satisfy the requirements from other RIIO-2 initiatives such as RDPs, Pathfinders and new market services. |
| **480 Ancillary Services Dispatch** | | £1m | £2m | -£1m | We have delivered our ancillary service dispatch capability through ASDP during BP1. Our updated plans require a development capability during 2023-24 and these costs are opex since Ancillary Services Dispatch Platform (ASDP) is expected to be replaced by OBP. |
| **210 Balancing Asset Health** | **D1.1.5** Maintenance and upgrades to existing systems | £13m | £10m | -£1m | We need to maintain change capability teams for the BM during BP2, which we underestimated at BP1. We expect to retain a minimum viable change capability during all of BP2, which will be treated as opex from April 2024, as we prepare to decommission the BM. |
| **260 Forecasting Enhancements** | **D1.1.7** Forecasting for demand and generation | £11m | -£1m | £2m | The increased importance of forecasting, especially in relation to increases in balancing costs, has led to an expansion in the scope of this investment. The consumer benefit delivered by **260** is estimated at around £1 billion over the RIIO-2 period. |
| **670 Real-time predictions** | | Costs are not provided in our BP2 submission because requirements are not fully understood yet | | | This is a new IT investment, necessary to realise the full potential benefits of the OBP. |
| **Total** | | £84m | £10m | £6m | |

Table 4: Balancing Program RIIO-2 cost forecast variances

**What will we deliver in BP2 for inertia forecasting, emergent technology and system management (D1.2.2)?**

We will develop new tools during RIIO-2 to address emerging technology and system management issues, as highlighted in future Operability Strategy Reports. New milestones for the deliverable **D1.2.2** will likely arise as issues are identified and solutions proposed from the reports. The requirements of this deliverable are also driven by industry provisions, for example services offered under the Pathfinder consultations, and evolving technologies. So our plans must remain flexible and adaptable to these external influences. See **A8 Enable all solution types to compete to meet transmission needs** for more details on the roll-out of Networks Services Procurement (Pathfinders).

### 3.3.3 A1.4 Control Centre architecture

#### What is this sub-activity and why is it important?

This sub-activity covers architecture, capabilities and governance to make changes to our Control Centre systems quicker and smarter.

#### What will we deliver in BP2?

**Data and Analytics Platform (D1.4.1)**

The scope and milestones for this IT investment in the BP2 period are unchanged. Our ambitions, strategy and capability plan for data and analytics are now described in **A19 Data and Analytics Operating Model** to give clarity and focus on the important role these will play in transforming our whole business.

**Technology Advisory Council (TAC) (D1.4.2)**

The TAC is a valuable engagement route for many of our RIIO-2 deliverables, allowing us to obtain stakeholder input into the design, development, and testing phases of IT solutions. The BP2 milestones for TAC engagement have been removed from the delivery schedules of other RIIO-2 deliverables to ensure that we can take an agile approach to using the TAC. Instead of prescribing an engagement schedule months or years in advance, the agendas for TAC meetings will flex with the progress of the transformational activities, the changing role of the ESO and the evolving needs of stakeholders.

#### What do we need to deliver this sub-activity?

This sub-activity is aligned to IT investment line **220** Data and Analytics Platform. The TAC is also expected to give significant feedback and direction to **180** Enhanced Balancing Capability, **110** Network Control, **220** Data and Analytics Platform, **250** Digital Engagement Platform, **400** Single Markets Platform and **500** Zero Carbon Operability.

We committed to work with stakeholders regularly as we transform balancing capability and so we rely on their ongoing participation as we deliver. The detail behind these investments can be found in **Annex 4 – Digital, Data and Technology**.

### 3.3.4 A1 Financials and Headcount

| A1 - Control Centre Architecture and Systems | | BP1 Actuals 2021/22 | BP1 Forecast 2022/23 | BP2 Forecast 2023/24 | BP2 Forecast 2024/25 | BP3 Forecast 2025/26 | TOTAL |
|---|---|---|---|---|---|---|---|
| Capex (£m) | BP2 | 48 | 59 | 61 | 58 | 40 | **266** |
| | BP1 | 23 | 35 | 37 | 31 | 23 | **148** |
| | **Variance** | **25** | **24** | **24** | **28** | **17** | **117** |
| Opex (£m) | BP2 | 31 | 36 | 46 | 50 | 49 | **212** |
| | BP1 | 32 | 34 | 35 | 34 | 35 | **170** |
| | **Variance** | **(1)** | **2** | **11** | **15** | **14** | **42** |
| **Totex (£m)** | **BP2** | **79** | **95** | **107** | **108** | **88** | **478** |
| | **BP1** | **55** | **68** | **72** | **65** | **58** | **318** |
| | **Variance** | **24** | **27** | **35** | **43** | **31** | **159** |
| FTE | BP2 | 263 | 310 | 335 | 337 | 337 | |
| | BP1 | 251 | 262 | 267 | 265 | 261 | |
| | **Variance** | **12** | **48** | **68** | **72** | **76** | |

*Table 5: RIIO-2 costs and FTE for A1. Numbers may not add exactly due to rounding.*

The forecasts for the opex, capex and FTEs needed to support **A1** activities in BP2 have all significantly increased since our first Business Plan submission. Most of these increases will occur ahead of BP2, as we plan and support changes to the Control Centre introduced by IT investments, market reform products and the requirement for whole system operation.

An additional 68 FTEs in FY24, increasing by four to 72 FTEs in FY25, are required compared to BP1. These are to support the increased IT investment and additional operational deliverables described in this chapter. The main drivers of the increase are:

- £52m capex, £7m project opex and 28 FTEs (FY25) for IT investments. The increase in capex is mainly driven by the IT investments:
  - **210 Balancing Asset Health** and **180 Enhanced Balancing Capability** – £13m and £59m additional capex as per **Annex 4 – Digital, Data and Technology** for the BP1 period
  - **110 Network Control** - £12m additional capex is due to evolving cyber security requirements, an improved delivery approach and adoption of an enhanced IT architecture, as described in sub-activity **A1.3 Transform network control** of the main BP2 Plan.
  - The costs of the additional 26 FTEs are accounted for in the increase to capex and are to support those capex projects.
  - The additional £7m opex is driven by increases in IT project opex and 'run the business' expenditure. Further information about our **A1** IT investments and their costs, including the remaining capex variances, can be found in **Annex 4 – Digital, Data and Technology**.
- £7m opex and 46 FTEs (FY25) for operational deliverables including:
  - 6 FTEs to support the greater use of automation, ML and AI through the work of the ESO Labs, described in the **Innovation** chapter.
  - 6 FTEs for our market requirements team, to improve our demand and BSUoS costs forecasting capabilities and due to an internal restructure in Role 2, as described in sub-activities **A1.1 Ongoing activities** and **A4.1 Manage balancing services and markets**.
  - 15 FTEs for the Control Centre and its supporting teams in their work described by sub-activity **A1.1 Ongoing activities**.
  - 5 FTEs to cover evolving cyber requirements, enhanced IT architecture and improved delivery approach in sub-activity **A1.3 Transform network control** as described the main BP2 Plan.

- 5 FTEs for the new transformational sub-activity **A1.5 Operational coordination with DSO and DER**.
- 9 FTEs were moved from **A2** to **A1** due to an internal restructure in Role 1. This restructure reallocated resources to the maintenance and upgrades of our legacy Control Centre systems described by deliverable **D1.1.5** in **A1.1 Ongoing activities**. Therefore, these cost increases are offset by corresponding decreases in FTEs and opex for the BP2 period in **A2**.
- The additional £7m opex is driven by the increase in FTEs explained in the preceding bullets.

## 3.4 A2 Control Centre Training and Simulation

### 3.4.1 A2.1 Ongoing activities

**What is this sub-activity and why is it important?**

This sub-activity covers ongoing work in resourcing the control centre, monitoring its performance, investigating incidents, and ensuring operational policy is adopted.

**What will we deliver in BP2?**

**Control Centre strategic resource planning, scheduling, and training (D2.1.1)**

The strategic workforce plan continues to be reviewed and updated to reflect current knowledge of our Control Centre workforce requirements given industry and market factors, process and technology change, process complexity and transaction volumes. Our approach remains adaptable and flexible, however we still need significant lead times for recruitment.

**Incident analysis and investigation of abnormal events (D2.1.2)**

To fulfil our commitment to being more proactive in sharing lessons learnt, we have been sharing details of system events and reviews through the Operational Transparency Forum and the Grid Code Review Panel. Whilst broader engagement and communications does add to the complexity of incident investigations, it also allows us to fully deliver on our commitment for proactive sharing of system event outcomes.

We have seen an increase in the complexity and number of incidents, driven by emerging power transmission technologies such as wind farms' and batteries' controllers, new Flexible Alternating Current Transmission System (FACTS) devices and High Voltage Direct Current (HVDC) links interacting with the transmission network. These new connections, which include "non-standard" connections, increase the volume and technical complexity of system or asset incidents and the resulting investigation process. Weather-related investigations and incidents have also increased. We are not forecasting higher FTE numbers for this additional workload; it will be absorbed by existing teams.

We aim to be more proactive in sharing learnings across the industry. This will enable us to highlight any potential operational risks and lead on new operational policy development and implementation.

**Monitor and report on system performance to regulatory bodies (D2.1.3)**

The EU System Operation Guideline became UK law in January 2021. As a result, we are directly responsible for the Operational Security Indicators and the annual load-frequency control reporting requirements. The ENTSO-E report compares Great Britain's TSO performance against other EU countries.  Post Brexit, Great Britain is not part of ENTSO-E and some of the content of the report becomes invalid without this comparison analysis.

During BP1 we also committed to additional reporting, including an annual report on Clean Energy Package Article 13 re-dispatching, relaunching the GC0105 System Incident Report in response to industry demand and reporting to comply with GC0151: Grid Code Compliance with Fault Ride Through Requirements. The GC0151 modification has needed monthly meetings with the Transmission Owners (TOs) to coordinate data collection for faults information, increasing the workload of our reporting team. To address this increased workload and increasing numbers of system incidents, our system monitoring solutions and tools may need investment in the RIIO-2 period, which would be carried out under IT investment references **240** ENCC Asset Health or **170** Frequency Visibility.

**Guidance on operational policies for use in the control centre produced (D2.1.4)**

This ongoing deliverable is unchanged for BP2.

**What do we need to deliver this sub-activity?**

Effective future system monitoring and reporting of system performance relies on the IT investments in **240** ENCC Asset Health and **170** Frequency Visibility.

Future direction may also be influenced by updated system performance requirements (set by Ofgem and/or changes to the Grid Code), and the impact of emerging power transmission technologies (such as long-duration storage) which are driving complexity in incident minimisation.

### 3.4.2 A2.2 Enhanced training material

**What is this sub-activity and why is it important?**

This sub-activity covers investment in training materials for universities and industry to ensure we have access to a pool of talented people. Our aim is to encourage more students to join us though a better understanding of what we do and how we contribute to society.

We experienced some initial delays during the first year of BP1 due to COVID-19 restrictions, however we still expect to deliver the benefits stated within BP1. Otherwise, the scope, costs and timescales of the sub-activity are unchanged from our BP1 plans.

**What will we deliver in BP2?**

We have partnered with two universities to influence course content (**D2.2.1**), to include an understanding of the role of the System Operator now and in the future. We will continue to work with several other engineering and technology universities to influence the talent pipeline. Future training material may include understanding the role of the DSOs and how the data supplied to us is used to make informed decisions.

Our ambition is to train ESO and DNO staff on whole system operation (**D2.2.2**); however, this needs to be agreed as the correct solution with DNOs and broader stakeholders.

**What do we need to deliver this sub-activity?**

Excellent simulation tools, as proposed in **A2.3**, are key to the successful delivery of this sub-activity. We have assumed that we will have resource available to support building relationships with universities and that other educational facilities that will champion us as a favoured employer.

We have also assumed DNOs will develop their own simulation capability through their RIIO-2 ED2 plans.

### 3.4.3 A2.3 Training Simulation and Technology

**What is this sub-activity and why is it important?**

This sub-activity covers the investment in simulation and e-learning technologies needed to provide training for Control Centre engineers that accurately reflects the changing energy landscape. This includes use of Digital Twin technology.

In our first RIIO-2 Business Plan, we set out our ambitions for using Digital Twin technology to create offline replicas of our Control Centre IT estate fed by real-time data to simulate both markets and the operation of the transmission system. Our ambitions were guided by the recommendations of the National Infrastructure Commission (NIC) and the Energy Data Taskforce for effective management of infrastructure using Digital Twin concepts.

Our first use-case for a Digital Twin in Role 1 is the development of a new training simulator (**D2.3.1**) to accurately reflect the changing energy landscape. This will be used to train Control Centre engineers on a range of scenarios, including using real-time and recent system scenario data as opposed to the ‘snapshot’ data we use today.

The key benefit is to enable training on new systems, using real-time or recent data, in a safe offline environment. Presently, offline training can only use snapshot data and live training is done via shadowing. The new simulation capability will also allow us to train staff under varying operational scenarios and could allow testing hypotheses about the effectiveness of new balancing processes or services.

Currently, training for Control Centre engineers is delivered on two disparate systems; our ambition is to link these to deliver a true end-to-end training experience. Beyond the RIIO-2 period, we can explore opportunities to enhance our new simulation capability through interactions with the Virtual Energy System (VirtualES) programme, led by our Innovation team. Through the VirtualES programme, we could investigate the benefits of introducing external live data feeds into our training simulator, explore the trade-offs with more layers of data collection, and design new use-cases for our Digital Twin technology (for example, supporting planning at the transmission-distribution interface).

#### What will we deliver in BP2?

Upgrades to the current simulators will be minor and only made to extend their life until the new simulation capabilities are ready. Simulation capabilities are being developed as part of the **D1.2.1 Future of Balancing** and **D1.3.1 Transform Network Control** deliverables and will be brought together in this sub-activity (**D2.3.1**). This is a large undertaking as we will need to coordinate scenarios, processes and data between systems.

In our first Business Plan, we indicated that our external engagement on simulation technology would be based on collaboration with DNOs. We are extending that scope to include the wider industry, to help further our understanding of whole system simulation. To date, most of our external engagement has been with TOs and we can see potential in collaborating with aggregators and generators too. Engagement with DNOs on simulators supports our whole system operation aims and we will discuss using their SCADA tools and technologies in the year preceding BP2.

The new balancing and network control tools must be sufficiently mature before we roll out additional training options (**D2.3.2**) to our Control Centre engineers. The RIIO-2 milestones for enhanced e-training delivery that are not linked to the balancing and network control investments are unchanged.

#### What do we need to deliver this sub-activity?

Development of the new simulator depends upon the delivery of sub-activities **A1.2 Enhanced Balancing Capability** and **A1.3 Transform Network Control** as outlined in the main BP2 Plan. The new simulation capability will be delivered by the IT investment **200** Future Training Simulator and Tools. Further information can be found in **Annex 4 – Digital, Data and Technology**.

Successful engagement with DNOs, TOs and wider industry on simulation ambitions and approaches will be an important influence on the success of this sub-activity.

### 3.4.4 A2 Financials and Headcount

| | | BP1 | BP2 | | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A2 - Control Training and Simulation | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | 0 | 0 | 1 | 2 | 2 | **6** |
| | BP1 | - | - | 1 | 2 | 2 | **6** |
| | **Variance** | **0** | **0** | **-** | **-** | **-** | **0** |
| Opex (£m) | BP2 | 2 | 2 | 2 | 3 | 4 | **12** |
| | BP1 | 2 | 3 | 3 | 4 | 4 | **16** |
| | **Variance** | **(0)** | **(1)** | **(1)** | **(1)** | **(1)** | **(4)** |
| **Totex (£m)** | **BP2** | **2** | **2** | **3** | **5** | **6** | **18** |
| | **BP1** | **2** | **3** | **4** | **6** | **7** | **22** |
| | **Variance** | **(0)** | **(1)** | **(1)** | **(1)** | **(1)** | **(4)** |
| FTE | BP2 | 18 | 18 | 16 | 16 | 16 | |
| | BP1 | 25 | 26 | 27 | 25 | 24 | |
| | **Variance** | **(7)** | **(8)** | **(11)** | **(9)** | **(9)** | |

Table 6: RIIO-2 costs and FTE for A2. Numbers may not add exactly due to rounding.

The forecast for the opex and FTEs needed to support **A2** activities in BP2 has decreased since our first Business Plan submission, whilst capex remains flat. The reduction in FTEs and opex is due to an internal restructure which reallocated resources to the maintenance and upgrades of our legacy Control Centre systems described by deliverable **D1.1.5** in **A1.1 Ongoing activities**. Therefore, these cost decreases are offset by corresponding increases in FTEs and opex for the BP2 period in **A1**.

## 3.5 A3 Restoration

### 3.5.1 A3.1 Ongoing activities

#### What is this sub-activity and why is it important?

This sub-activity covers the ongoing activities ensuring we have the right procedures to economically restore the system within acceptable timescales.

During BP1, we have implemented business continuity plans to mitigate risk and ensure appropriate resourcing levels during the COVID-19 pandemic. We have also delivered multiple incident management and disaster recovery exercises annually. Restoration plans have been reviewed and updated and the Black Start Strategy and Procurement Methodology 2021/22 was published on 10 May 2021.[2] Finally, the new Assurance Framework document was consulted on in late 2021, submitted to Ofgem and we await their direction.

#### What will we deliver in BP2?

Our Business Continuity team ensures that business continuity plans are agreed for the Electricity National Control Centre and teams within National Control. They also develop exercises with internal and external stakeholders to test our incident management and disaster recovery processes. We intend to expand the remit of this team to include oversight and coordination of business continuity plans across our whole business.

We will work with the relevant DNOs and industry stakeholders to incorporate recommendations from the Distributed ReStart project into our Restoration tenders in 2022 for the South-East and Northern regions. This will allow distribution-level connected generation to participate, increasing competition and enabling compliance with the Electricity System Restoration Standard (ESRS) by 2026.

Our Business Continuity team will share its knowledge and experience across our business to introduce best practice in all departments. This, combined with the increasing need for co-ordinated approaches with both internal and external stakeholders, drives the need for additional headcount to be brought forward to BP1.

This will provide:

- Business continuity expertise and a coordinated approach across our business rather than just for National Control
- Improved alignment and coordination of business continuity and emergency plans with external stakeholders

Following on and as a result of the Distributed ReStart recommendations,the South-East tender for restoration services is expected to involve more stakeholder engagement earlier. Additional work is needed to understand the interaction of generation and demand at both transmission and distribution level as well as revision of the restoration approach

This will include working closely with UK Power Networks (UKPN) and prospective restoration service providers connected to their distribution network. We had anticipated a need for additional resource to support implementation of recommendations of Distributed ReStart in 2023/24 but we can incorporate the project’s findings into our restoration tenders in 2022, which will support compliance with the ESRS in these regions by the end of 2026.

#### What do we need to deliver this sub-activity?

We have assumed that DNOs will support the feasibility assessments required to enable the inclusion of distribution-level connected generation into restoration. Also, the connecton of distribution-level generation into ESO IT systems will be made through investment **460 Restoration.** The detail behind this investment can be found in **Annex 4 – Digital, Data and Technology**

[2] https://www.nationalgrideso.com/document/191636/download

### 3.5.2 A3.3 Innovation project in restoration

#### What is this sub-activity and why is it important?

This sub-activity covers potential investments to implement the findings of the Network Innovation Competition project 'Distributed ReStart', which will conclude by the end of 2022 (**D3.3.1**).

#### What will we deliver in BP2?

The scope of **D3.3.2 Implement Distributed ReStart findings** is unchanged, but we have now defined milestones for BP2 now the Distributed ReStart project is in its final stages.

Most of the automation and control systems recommendations are for DNOs. However, we may need visibility of the information they hold, and new communications infrastructure is proposed to feed data from the new DNO control systems to the ENCC. Only one DNO is currently linked in this way.

The Distributed ReStart project recommendations are in pre-publication and stakeholders may decide against adopting them. Therefore, we need to retain flexibility in our plans and we will modify the milestones and IT investment for this deliverable as necessary to meet the needs of stakeholders.

#### What do we need to deliver this sub-activity?

If the ESO adopts recommendations of the Distributed ReStart project, any associated IT investments will be made via **460 Restoration.** The detail behind this investment can be found in **Annex 4 – Digital, Data and Technology**.

### 3.5.3 Financials and Headcount

| | | BP1 | BP2 | | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A3 - Restoration | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | - | 0 | 8 | 8 | 6 | **22** |
| | BP1 | 1 | 2 | 8 | 8 | 6 | **25** |
| | **Variance** | **(1)** | **(2)** | **-** | **-** | **-** | **(3)** |
| Opex (£m) | BP2 | 1 | 2 | 2 | 3 | 4 | **12** |
| | BP1 | 1 | 1 | 2 | 3 | 4 | **12** |
| | **Variance** | **(0)** | **1** | **(0)** | **(0)** | **(0)** | **(0)** |
| **Totex (£m)** | **BP2** | **1** | **3** | **10** | **11** | **10** | **34** |
| | **BP1** | **2** | **4** | **10** | **11** | **10** | **37** |
| | **Variance** | **(1)** | **(1)** | **(0)** | **(0)** | **(0)** | **(3)** |
| FTE | BP2 | 6 | 28 | 18 | 18 | 18 | |
| | BP1 | 9 | 14 | 19 | 19 | 18 | |
| | **Variance** | **(3)** | **14** | **(1)** | **(1)** | **0** | |

Table 7: RIIO-2 costs and FTE for A3. Numbers may not add exactly due to rounding.

The forecast for the opex and FTEs needed to support **A3** activities in BP2 remains broadly flat. We have however brought forward planned resource increases to FY23 to meet the revised scope of the Electricity System Restoration Standard. This will enable us to deliver code changes earlier than expected and to implement the recommendations of the Distributed ReStart project in 2022 restoration tenders.

# 3.6 A17 Open Data and Transparency & A19 Data and Analytics Operating Model

## 3.6.1 A17 Transparency and Open Data

**Target BP2 Outcomes and Capabilities for Digital Engagement Platform**

We have carried out user research since our first Business Plan submission which has provided insight to inform our target digital customer experience for publication of content and data. Key target outcomes for BP2 include providing:

- A variety of digital content including infographics, video and data visualisations
- Advanced and filterable search options across both data and content
- Publication of open data with access via an application programming interface (API) and other formats
- Subscription to datasets and notifications of data updates and new datasets
- Content and analysis presented alongside the data that underpins it and the narrative that brings it to life

At the beginning of the BP2 period, the Digital Engagement Platform Minimum Viable Product (MVP) will be operational. We are introducing the new continuous deliverable **D17.8 Digital Engagement Platform (DEP) continued phased deployment** to BP2 to describe how we will further evolve the DEP capabilities with phased deployment including:

- Design System and Customer Identify and Access Management (CIAM) solutions applied to further use cases across the ESO digital estate
- Integrated query management
- Co-ordinated interactive ESO calendar, and newsletters
- Alerts and notifications for key developments
- Account dashboard integrated with other ESO systems such as the Single Markets Platform and Connections Portal
- Personalised AI assisted navigation
- Content and analysis integrated with supporting data
- "Digital concierge" functionality linking elements of the digital customer journey, providing visibility and guidance on the end-to-end process of doing business with the ESO as well as progress status and actions linked to dashboard and notifications.

An enduring DEP Product Team will develop further capabilities to improve the digital customer experience.

## 3.6.2 A19 Data and Analytics Operating Model

**Characteristics of Data and Analytics Target Operating Model**

The activities delivered through the Hub and Spoke model are illustrated in the diagram below.

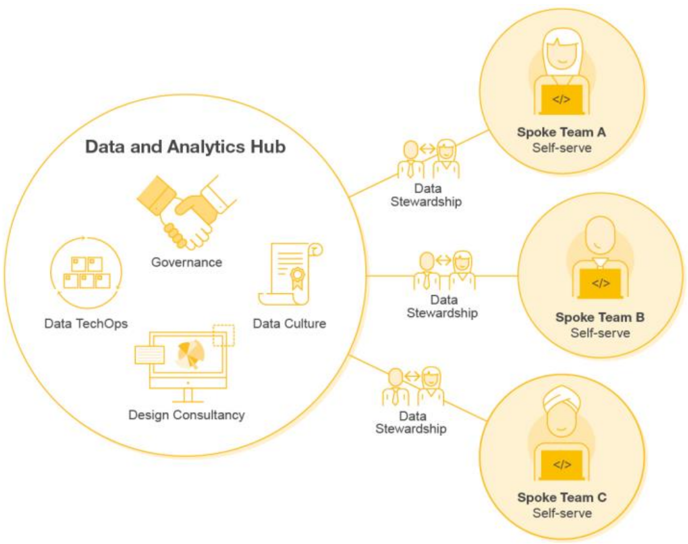


Figure 4: Data and Analytics operating model

The characteristics of our target Data and Analytics operating model, serving both internal and external stakeholders, are set out below:

- **Federated Data Governance:** An ESO Data Governance body implements data quality standards and data privacy policies, controls data access management, and has central visibility of data ownership to ensure consistent and compliant use of data across the ESO. Data Custodians3 (previously referred to as "Data Owners") are supported by a team of embedded Data Stewards who make sure internal standards are met and regulations are complied with. They will also run the Open Data Triage process and provide a forward view of the data needs of our organisation. The Data Governance body makes recommendations to, and takes direction from, the ESO's Portfolio Review Board with respect to data initiatives. Further information on the importance of our Data Custodians is outlined in the section below.
- **Self-serve Data & Analytics:** The "data as a product" approach is underpinned by our self-serve Data and Analytics Platform (DAP). The DAP platform will remove technical complexity for users and allow them to focus on the value they can create from data for their business domains. A common data management layer enables consistent governance and control and promotes data accessibility to internal and external stakeholders through a centrally maintained data catalogue.
- **Data TechOps:** The application of TechOps to the development and operation of data products draws on:
  - Best practice from agile, DevOps and manufacturing approaches, to deliver timely, trusted, analytics-ready data to the point of use.
  - Best practice from software application deployment, to automate releases of ML/analytics data products.
  - In conjunction with the DAP platform, the Data TechOps capability will enable efficient, robust and repeatable productionisation of ML/analytics applications, freeing up data science resources to focus on innovation and the continuous improvement of their models.
- **Embedded Data Culture**: To embed a data and information culture within the ESO, we are refreshing our Data and Analytics Training Curriculum and certifications, establishing Data Communities of Practice to drive collaboration and knowledge sharing, defining data related career paths to attract and retain the best talent to support delivery of our mission.
- **Design Consultancy**: In the early stages of adoption of the platform and new ways of working, a Design Consultancy capability within the Hub will work with business teams to advise and guide the development and embedding of data products.

**Further Information on Data Custodians**

Data Custodians play a critical role in delivering our data strategy. As subject matter experts in their domains, their input is vital in providing the contextual knowledge that will allow data to be used effectively and efficiently by internal and external stakeholders. As data is brought under management on DAP, Data Custodians will work with Data Stewards in a number of areas, for example:

- Classifying and categorising data
- Defining data quality rules and associated workflows
- Developing data dictionaries to enable interpretation and understanding of data
- Providing expert  with respect to the Open Data Triage process and the management of risks relating to inadvertent over-sharing.

It is anticipated that as the volume of data increases, so too will the involvement of Data Custodians in data life-cycle management. We will continuously monitor resource demands with respect to Data Custodian

[3] Data Custodians are ESO staff in operational roles that provide data and support to Open Data and Transparency deliverables. It is important to ensure that these staff have the capacity to provide this support as their subject matter expertise is essential to effective data governance and external stakeholder engagement.

activities, and should additional resources be required, we will fund these as they emerge via the passthrough mechanism.

### 3.6.3 A17 and A19 Financials and Headcount

| | | BP1 | BP2 | | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A17 & A19 - Transparency data and analytics | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | 1 | 4 | 2 | 1 | 1 | **10** |
| | BP1 | 1 | 1 | 1 | 1 | - | **4** |
| | **Variance** | **(0)** | **3** | **1** | **1** | **1** | **5** |
| Opex (£m) | BP2 | 0 | 0 | 2 | 2 | 2 | **6** |
| | BP1 | 2 | 2 | 2 | 2 | 1 | **8** |
| | **Variance** | **(1)** | **(1)** | **(0)** | **0** | **1** | **(2)** |
| **Totex (£m)** | **BP2** | **1** | **5** | **3** | **3** | **3** | **16** |
| | **BP1** | **3** | **3** | **3** | **2** | **1** | **13** |
| | **Variance** | **(2)** | **2** | **1** | **1** | **2** | **3** |
| FTE | BP2 | - | - | 9 | 8 | 7 | |
| | BP1 | 9 | 9 | 9 | 8 | 7 | |
| | **Variance** | **(9)** | **(9)** | **(1)** | **(0)** | **(0)** | |

Table 8: RIIO-2 cost and FTE for A17 and A19. Numbers may not add exactly due to rounding.

The table above includes costs for both activities **A17** and **A19**. The overall FTE headcount remains broadly the same compared to BP1. Seven of the FTEs in each year from 2023/24 are for roles in the Data and Analytics Hub, described in **A19**. The £2m increased capex (including two FTE) over the two years of BP2 relates to the **250** Digital Engagement Platform IT investment.

## 3.7 A18 Market Monitoring

### 3.7.1 Financials and Headcount

| | | BP1 | BP2 | | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A18 - Market Monitoring | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | - | - | - | - | - | **-** |
| | BP1 | - | - | - | - | - | **-** |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | - | 1 | 1 | 1 | 1 | **3** |
| | BP1 | - | - | - | - | - | **-** |
| | **Variance** | **-** | **1** | **1** | **1** | **1** | **3** |
| **Totex (£m)** | **BP2** | **-** | **1** | **1** | **1** | **1** | **3** |
| | **BP1** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Variance** | **-** | **1** | **1** | **1** | **1** | **3** |
| FTE | BP2 | - | - | 7 | 7 | 7 | |
| | BP1 | - | - | - | - | - | |
| | **Variance** | **-** | **-** | **7** | **7** | **7** | |

Table 9: RIIO-2 costs and FTE for A18. Numbers may not add exactly due to rounding.

This new activity requires 7 FTE and £2m opex over the BP2 period to deliver the new market monitoring deliverables, which are already in progress today.

# 4 Role 2 Updates and Supporting Information

## 4.1 Transformational Deliverables Roadmaps

The roadmaps below outline the transformational deliverables for Role 1 across BP2. Continuous deliverables are not shown.

### A4 - Building the future balancing service markets

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 | | | | RIIO-2 Year Four - 2024/25 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| | | | Milestones | | | | | | | |
| **Deliver a single, integrated platform for ESO markets (A4.4)** | A platform enabling market players to participate in balancing market (D4.4.1) | Market participants able to participate in auctions through interface of Single Markets Platform | | Initial integration with Enduring Auction Capability | Query Management process aligned with wider ESO digital process | Integration with Settlements system | | Enhance the wider BM registration process | | All balancing services procured through SMP |

Figure 5: A4 transformational deliverables roadmap

### A5 - Transform access to the Capacity Market and Contracts for Difference

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 | | | | RIIO-2 Year Four - 2024/25 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| | | | Milestones | | | | | | | |
| **Electricity Market Reform (EMR) Delivery Body (A5.1)** | Continuation of Electricity Market Reform (EMR) Delivery Body obligations - prequalification and auction processes for Capacity Market and qualification and allocation processes for Contracts for Difference (CfD). Deliver management obligations for the CM. (D5.1.1) | Delivered the annual Capacity Market auctions, together with agreement management activities, and ran CfD Allocation Round 4. Delivered several improvements to systems and processes, including increased co-creation of guidance with industry. We have also actively worked with customers to seek feedback and implement improvements, including to our query management process | Publish co-created guidance covering any rule changes and system and operational improvements, in collaboration with Ofgem, BEIS and industry, within 4 weeks of rules being set | Commence the pre-qualification process, with customers benefitting from enhanced guidance | Conclude the pre-qualification and disputes processes and prepare for the auctions | Deliver the auctions and post-auction activities, including capturing key learning points with industry | Publish co-created guidance covering any rule changes and system and operational improvements, in collaboration with Ofgem, BEIS and industry, within 4 weeks of rules being set | Commence the pre-qualification process, with customers benefitting from enhanced guidance | Conclude the pre-qualification and disputes processes and prepare for the auctions | Deliver the auctions and post-auction activities, including capturing key learning points with industry |
| | Continuation of Electricity Market Reform (EMR) Delivery Body obligations - identify, assess and implement policy, rule and process changes to further develop the Capacity Market and CfD mechanisms (D5.1.2) | We will have worked with BEIS and industry to identify key learnings from CfD Allocation Round 4 for the design and delivery of future CfD rounds | Develop a clear process for capturing and assessing policy, rule and process improvements. Feed this into CMAG and other relevant BEIS and Ofgem processes | Once established, we will run the improvement process on an ongoing basis, with key outputs timed to meet BEIS, Ofgem and CMAG timelines | | | Undertake informal review of the improvement process with industry, BEIS and Ofgem to identify ways to refine the approach | Implement process refinements and run refined improvement process from Q2 onwards | | |
| **Developing the EMR platform (A5.2)** | IT system to allow all participants in ESO markets (including CM and CfD) a single point of access for services and data (D5.2) | Delivered mandatory regulatory changes on the existing EMR portal. First elements of new EMR portal delivered for CM registration and pre-qualification in 2022/23 | | Additional improvements to EMR portal delivered & regulatory changes implemented for annual processes | | Use portal and data to increase automation of ESO processes | | Additional improvements to EMR portal delivered & regulatory changes implemented for annual processes | | Deliver planned integration of EMR within the Digital Engagement Platform, considerate of any licenced business separation requirements |
| **Improve our security of supply modelling capability (A5.3)** | Use of enhanced modelling and more granular data sets to improve security of supply modelling (D5.3) | Delivery of the Electricity Capacity Report (ECR) and associated modelling enhancements | Production of 2023 ECR | Develop further enhancements to security of supply modelling | | | Production of 2024 ECR | Develop further enhancements to security of supply modelling | | |
| **Long-term capacity adequacy (A5.4)** | Building our long-term security of supply modelling capability (D5.4) | Published the initial study in summer 2022 | Stakeholder engagement and modelling enhancements following first study published in 2022 | | | | Production of capacity adequacy study | | Stakeholder engagement and modelling enhancements | |

Figure 6: A5 transformational deliverables roadmap

## A6 - Develop code and charging arrangements that are fit for the future

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 | | | | RIIO-2 Year Four - 2024/25 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| | | | Milestones | | | | | | | |
| Code management/ market development and change (A6.1) | Enable major net zero programmes - Offshore Coordination (D6.1.1) | Technical and Commercial Code changes have been identified | | | | Delivery of code modifications associated with implementation of the offshore project | | | | |
| | Enable major net zero programmes - Onshore Competition (D6.1.2) | Technical and Commercial Code changes have been identified | | | | Delivery of code modifications associated with implementation of the onshore project | | | | |
| | Enable zero carbon operation - System Restoration (D6.1.3) | Requirement is to complete code mods by end of 2023; trying to beat this to maximise stakeholder leadtimes | Delivery of code modifications to set equipment specifications | Completion of code changes | | | | | | Code changes implemented for ESRS to facilitate licence compliance which is required by Dec 2026 |
| | Enable zero carbon operation - Stability (D6.1.4) | Initial specification approved through completion and approval of GC0137 Grid Code modification | GC0137 'Grid Forming' Grid Code modification - guidance document | | | | | | | |
| | Lead charging reform (D6.1.5) | Subject to the outcomes of the TNUoS Taskforces but we expect to be in a position to recommend changes for progression with industry | | | | Identify required code changes | Raise TNUoS modifications to facilitate charging reform | | | |
| | Support Market Wide Half Hourly Settlement (D6.1.6) | Identified the areas where code change is needed | | Produce required CUSC legal text and modifications raised | | | Code modifications concluded | | | |
| European Union (EU) code change (A6.2) | Continued facilitation of EU driven code changes into Great Britain market (D6.2) | Moved under A21 | | | | | | | | |
| | Implementation of the TCA and maintenance of European relationships (D6.2.1) | Moved under A21 | | | | | | | | |
| Industry revenue management (A6.3) | Market half-hourly Settlement (D6.3.1) | New deliverable | | High Level Discovery | Impact Assessment & Agree Approach | Design, test and implement | Design, test and implement | | | |
| | TNUoS Reform (D6.3.2) | New deliverable | High Level Discovery | Impact Assessment & Agree Approach | Design, test and implement | | Design, test and implement | | | |
| Work with all stakeholders to create a fully digitalised Whole System Technical Code by 2025 (A6.5) | Develop a single technical code for distribution and transmission that is focused on providing minimum standards to allow safe and secure operation of the electricity systems (D6.5) | Defined scope and objectives on the 2 workstreams, led by project team and steering group | Identify, prioritise and raise the modifications required | | | | Progress modifications | | | |
| Digitalisation of Codes (A6.8) | Implementation of digital solutions (D6.8) | New deliverable | | | | Implementation has commenced | | | | Implementation is complete |
| Whole electricity system framework reform (A6.9) | Whole electricity system framework assessment (D6.9) | New deliverable | | | Establish team to deliver assessment of frameworks | Detailed workplan and stakeholder engagement | | Full assessment of delivery areas | | Identify and raise or recommend changes |

Figure 7: A6 transformational deliverables roadmap

## A20 - Net Zero Market Reform

The deliverables for A20 are continuous, and so no roadmap is provided.

### A21 - Role in Europe

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 | | | | RIIO-2 Year Four - 2024/25 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| | | | Milestones | | | | | | | |
| **Setting the net zero cross border landscape (A21.1)** | Cross-border strategy development (D21.1) | First phases of the project focused on the analysis of available data will have been delivered | | First phase of implementation fully initiated | | | | | | Conclusions and recommendations reviewed to ensure relevance |
| **Enhancing cross border frameworks and markets (A21.2)** | Continued facilitation of EU driven code changes into Great Britain market. (D21.2.1) | Submission of data files for Short Term Adequacy (STA). Changes for Short Term Operating Reserve (STOR) ready for new auctions. Grid code and BSC change for Emergency and Restoration. Full compliance with Article 6 of the Clean Energy Package | Draft Interconnector Framework shared with industry | Ramping solution is SOGL compliant | Interconnector framework consulted upon | Long-term ramping solutions are investigated | | | | Interconnector Framework implementation plan agreed<br>Long-term ramping solution implementation started |
| | Implementation of the TCA (D21.2.2) | Developing Technical Procedure for Cross Border Balancing and other time frame Capacity Calculation; developing a technical procedure for Day Ahead Capacity Calculation; developing a plan for implementing harmonised Redispatching and Countertrading as per the TCA | Agreed UK Position on Day ahead; agreed Interim solution to cross border balancing; increased engagement with EU TSOs.<br>Agreed Interim solution to cross border balancing; increased engagement with EU TSOs. | | Draft UK Position on Intraday and Long Term. Continued development of Day Ahead arrangements | UK position on enduring balancing options agreed with all relevant parties | Interim solution being implemented pending recommendation from specialised committee on energy | Noticeable step change in ESO to EU TSO relationships | | Technical UK position agreed and negotiating with EU TSOs Enduring solution agreed at UK Level, ongoing negotiations with EU |

Figure 8: A21 transformational deliverables roadmap

## 4.2 Role 2 Activities and Sub-activities

The following section contains:

- Transformational deliverable roadmaps per activity, which outline the timelines only for deliverables which are not continuous/ongoing
- Narrative which provides additional detail or context to the main BP2 plan content where appropriate
- Financials and headcount tables and updates per activity
- Sub-activities which are either unchanged, or which have non-material changes from BP1

The table below clarifies the nature of the included content for each sub-activity in this Annex. Any sub-activities not listed will be those which are new or materially changed for BP2, but which have no additional supporting information provided in this Annex.

| Content | No or minimal change – Sub-activity BP2 content covered in this Annex only | New or materially changed for BP2 – Further information included here | New or materially changed for BP2 - Content in main plan only |
|---|---|---|---|
| A4.1 Manage existing balancing services and markets | | | ✓ |
| A4.2 Power Responsive | ✓ | | |
| A4.3 Delivering an efficient frequency market | ✓ | | |
| A4.4 Deliver a single, integrated platform for ESO Markets | ✓ | | |
| A4.5 Facilitate whole electricity system market access for distributed energy resources | | | ✓ |
| A4.6 Balancing and ancillary services market reform | | | ✓ |
| A5.1 Electricity Market Reform (EMR) Delivery Body | ✓ | | |
| A5.2 Deliver an enhanced platform for EMR | ✓ | | |
| A5.3 Improve our security of supply modelling capability | ✓ | | |

| Content | No or minimal change – Sub-activity BP2 content covered in this Annex only | New or materially changed for BP2 – Further information included here | New or materially changed for BP2 - Content in main plan only |
|---|---|---|---|
| A5.4 Long-term capacity adequacy | | | ✓ |
| A6.1 Code management / market development and change | | | ✓ |
| A6.2 European Union (EU) code change | | ✓ | |
| A6.3 Industy revenue management | | | ✓ |
| A6.4 Transform the process to amend our codes | ✓ | | |
| A6.5 Work with all stakeholders to create a fully digitalised Whole System Technical Code by 2025 | ✓ | | |
| A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges | ✓ | | |
| A6.7 Fixed BSUoS tariff setting | | | ✓ |
| A6.8 Digitalisation of codes | | | ✓ |
| A6.9 Whole electricity system framework reform | | | ✓ |
| A20.1 Net Zero Market Reform | | ✓ | |
| A21.1 Setting the net zero cross border landscape | | ✓ | |
| A21.2 Enhancing cross border frameworks and markets | | ✓ | |

Table 10: Role 2 supporting information context

## 4.3 A4 Build the Future Balancing service markets

### 4.3.1 A4.2 Power Responsive

#### What is this sub-activity and why is it important?

Power Responsive will continue to play an important role in developing demand side flexibility and its provision of balancing services. In BP2, we will continue to deliver an annual report every April, building on the work delivered under our continuous deliverable **D4.2.1**. This looks at publishing regular and specific metrics for flexibility markets, including DSO markets, through the Power Responsive Annual Report.

In BP1 we delivered a guide to ESO markets for Demand Side Response (DSR) providers in conjunction with the Major Energy Users Council (MEUC). In 2020 we published a new-look Annual Report with our partners, Everoze, which included greater coverage of DNO markets and insights from industry experts.

The Power Responsive Steering Group has met on a regular basis, with topics ranging from the delivery of net zero and carbon intensity in ESO markets, to upcoming code modifications and proposals for new balancing services. Also, we continued to support innovation projects such as e4futures and the BEIS FleX competition winners.

#### What will we deliver in BP2?

We will undertake engagement activities such as surveys and focus groups with the demand side community to identify the outstanding barriers to participation **(D4.2.2)**. We will focus particularly on industrial and commercial parties who may have participated in balancing services in the past, to learn and implement reforms based on their feedback.

We will also work more closely with Open Networks so the voice of the demand side community is heard in the development of DNO markets, specifically around Regional Development Programmes (RDPs), standardisation of contracts and market arrangements and service stacking.

We will support access for smaller scale flexibility including EVs and domestic consumers. We will focus on DSR projects, which could include removal of barriers or bringing in new participants.

One of the biggest blockers to DSR entering our markets is that our metering requirements were designed for big power generators, not demand-side flexibility. We want to encourage supplier aggregation in the Balancing Mechanism (BM) and have committed to reforming our operational metering requirements to unlock these new forms of flexibility. Using probabilistic analysis and techniques, such as asynchronous polling, we think that suppliers will be able to provide appropriate aggregated real time signals to the ESO and meet regulatory requirements. This will enable suppliers to innovate and bring their customers into the market.

Where appropriate, we will continue to form Working Groups under Power Responsive to address specific issues and barriers to entry that are impacting DSR providers.

#### What do we need to deliver this sub-activity?

To enable suppliers and aggregators to innovate and bring their customers into the market we want to encourage supplier aggregation in the Balancing Mechanism (BM) and have committed to reforming our operational metering requirements to unlock these new forms of flexibility. Using probabilistic analysis and techniques, such as asynchronous polling, we think that suppliers will be able to provide appropriate aggregated real time signals to the ESO and meet regulatory requirements.

### 4.3.2 A4.3 Deliver an efficient frequency market

#### What is this sub-activity and why is it important?

The name of this sub-activity has been changed from “Deliver a single-day-ahead response and reserve market” to better reflect that as we go through the process of optimising the response and reserve service, we might find better solutions that are wider in scope than the original title.

Enhancing our procurement process for our reformed ancillary services markets is crucial to unlocking maximum value for ourselves and the end consumer. In BP1 we introduced two platforms to improve the procurement experience of parties participating in our markets, moving these closer to real time by procuring STOR on cloud-based Salesforce software and new frequency response services; Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR) on the EPEX platform. Procuring these services much closer to real time, and operating supporting business activities at day-ahead via auctions, has provided greater flexibility for participants and allowed us to be more dynamic in our procurement strategies. We have gained valuable information from this to support activities for both the procurement of our new reserve services and the enduring auction tender work.

We started developing the Single Markets Platform (SMP) (refer to **A4.4** for greater detail) in the first year of BP1. The first release went live during Q4 2021/22 in support of the onboarding process for day-ahead Frequency Response Markets, DC, DM and DR.

We are also running a procurement event to select a partner for our Enduring Auction Capability (EAC). Whilst work to implement EAC is being taken forward, we will continue to procure our new services via day ahead auctions and make improvements to continue to realise the benefits of closer to real time procurement.

#### What will we deliver in BP2?

**D4.3.3 New reserve products development and introduction of a new suite of products to provide reserve to the Control Room**

The design and delivery of new services is of significant interest to customers as revenue is impacted by changes to services. As we move past implementation, our focus will move onto improving and refining services. Engaging with stakeholders on future changes will ensure we continue to improve them.

Implementing a structure around our ‘day 2’[4] activities will allow issues to be identified, provide visibility on progression and set out a timetable on delivery. We will have delivered provisional service designs for quick and slow reserve services by the end of BP1. In BP2, we will deliver these new services, integrated on SMP EAC with a prioritised product backlog for future development.

**D4.3.4 Delivering an efficient frequency market**

We are exploring solutions to deliver an efficient frequency market. Part of this is creating a longer-term procurement strategy which spans response and reserve, looking at how the products interact operationally

[4] Day 2 refers to the features of a new service that are not included when this is launched but will be added to the service in the next planned update/release.

and commercially, and with the wider market. For example, in BP2 we will be looking at the order in which we buy services through auction. Deciphering how these services interact, and how the market rules/algorithms ensure maximum co-optimisation will be a key output. This work will be delivered via the EAC project, removing barriers for reserve and response and SMP facilitating access to distributed assets.

**D4.3.5 Auction Capability**

The auction project will move into the delivery stage in BP2. This will be a phased approach and see the transition of new services from BP1 onto the platform.

These benefits will include improved user experience, enhanced automation and system integration with the SMP and allow us to procure services more flexibly, either through enhanced granularity, requirement setting or a streamlined route to market for future designed services.

ESO has recently signed with our selected vendor for enduring auction capability following a competitive procurement event. Following this we will be firming up milestones for delivery of this project and shaping engagement plans to determine how we share and co-create the projects delivery plans.

Whilst the ESO also runs auctions in EMR (Contracts for Difference (CfD)/Capacity Market (CM)), we consider these to be sufficiently different and stand-alone to not include them in our IT development of EAC.

**(New) D4.3.6 - Future developments to frequency response services**

This is a new deliverable that we have identified as part of our continuous improvement work within market reform. After successfully delivering the new suite of frequency response products (DC, DM and DR) and procuring frequency response in day-ahead timescales in BP1, BP2 will focus on improving the user experience and maximising participation. We will create a product backlog with suggestions for new features and changes to parameters of the product, IT systems and service design proposal. These changes will be impact-assessed and the list of developments, and the order in which they will be delivered, will be shared with our stakeholders.

We will implement a standardised consultation process with engagement throughout the year. Feedback on changes will be fed into the product backlog. Also, IT upgrades will improve visibility and control of response volume in the Control Room (see **A1.4 Control Centre architecture, A4.4 Single Market Platform and D4.3.5 Auction Capability**) and streamline processes from prequalification through to procurement. This will reduce the volume of manual work for stakeholders for auction and data transfer and improve the experience for response providers.

**What do we need to deliver this sub-activity?**

Key dependencies include RDPs **(A15.5)**, market participation and volume **(A4.5)**, primacy rules[5] **(A15.8)** (which sit within the Accelerating Whole Electricity Flexibility strategy) and the balancing transformation under Role 1 **(A1.1 and A1.2)**.

This sub-activity is aligned to IT investment line **400** Single Markets Platform and **420** Auction Capability and **610** Settlements, Charging and Billing. The detail behind these investments can be found in **Annex 4 – Technology investment**.

### 4.3.3 A4.4 Deliver a single, integrated platform for ESO markets

**What is this sub-activity and why is it important?**

As part of this sub-activity we will deliver the digital Single Markets Platform (SMP) which will be an important enabler of decarbonisation. It will provide frictionless access to our markets and is part of a wider strategy to digitise the way we work (further details can be found in **Annex 4 – Digital, Data and Technology** "**400** Single Markets Platform" investment line) and make it easier to do business with us. The SMP will also seek to align and interact with wider DSO/flexibility markets, and allow us to enact change more quickly, as well as adapt to new markets (**D4.4.2**).

During February 2022, the SMP team launched the foundational functionality to facilitate the onboarding of day ahead frequency response products (DC, DR and DM). This followed a strategic definition project that set the ambitions for the platform before moving into the initial design and development of the foundational release.

[5] Primacy rules are intended to provide transparent tools for the avoidance, and where applicable, resolution of conflicts to maintain system and network integrity as well as avoiding unnecessary system costs and carbon impacts.

We engaged with interested participants through our 'Show and Listen' industry working group events (as detailed in **Annex 3 - Stakeholder Engagement**) to ensure we were always focused on delivering the most value from the platform. This approach will continue as we further develop the SMP in line with the agile product development model, to enhance user functionality, integrate with upstream and downstream systems, and apply to further ancillary services.

### What will we deliver in BP2?

**D4.4.1 A platform enabling market players to participate in balancing markets.**

As we move through RIIO-2, we will develop the SMP in the following areas:

- Extend SMP interaction downstream of the onboarding process. For ancillary services this includes interaction with the auction capability, performance reporting and settlement data.
- Integrate with the upstream Connections Platform (investment **380** Connections Platform) to promote the seamless transition of a user from connections into ancillary services. The data will be available in the SMP system once an asset is connected, visible and active on SMP for the user to assign it to a unit and specific service.
- Deliver enhanced functionality to improve the user experience.
- Integrate the design system being developed within the '250 Digital Engagement Platform' project to all our systems.
- Apply SMP to cover other ancillary services.
- Support the ongoing development and evolution of Distribution System Operator (DSO)/Flexibility markets (**D4.4.2**).

This work will continue throughout BP2 in line with the move to a 'product model', where the SMP will be developed with regular releases of additional functionality. This allows us flexibility and the freedom to modify our approach in response to any change in the background or feedback from the industry.

We will continue to engage with our users and stakeholders to identify development priorities. This may result in a different delivery timetable than initially proposed.

We were looking to integrate more closely with the Electricity Market Reform (EMR) Portal however we have refined our plans and now we have a more detailed understanding of both SMP and Digital Engagement Platform (DEP). EMR will be integrated into DEP in the first instance. We still believe that integration into SMP in the future would drive benefit to market users, however the Capacity Market (CM) and Contracts for Difference (CfD) processes and data are currently substantially different from other markets in terms of detail, nomenclature and taxonomy. Integration between SMP and the EMR Portal will rely on standardisation of the CM and CfD data structures with other market services and products (e.g., common nomenclatures instead of the current distinction between Balancing Mechanism Units (BMUs) and Capacity Market Units (CMUs). In future, if the necessary regulatory changes are taken forward, it may be possible to fully integrate to SMP - however, we do not foresee those changes taking place in BP2 timescales.

A 23/24 Q1 milestone from our draft plan 'Initial Integration with Enduring Auction Capability' has moved out to Q2, however we remain confident that the existing final delivery date will not be impacted as this change is minimal.

**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.**

While the current focus is on optimising the foundational functionality across our markets, greater interaction with wider DSO markets through RIIO-2 will require a convergence in distribution and transmission market requirements. Industry platforms will integrate more closely to ensure visibility across ESO and DSO/flexibility markets to facilitate real time transparency of what assets are participating in which markets.

### What do we need to deliver this sub-activity?

We need to work through what integration of Flexibility markets look like, which could result in an impact to scope and costs to the SMP programme.

This sub-activity is aligned to IT investment line **400 Single Markets Platform**. The detail behind this investment can be found in **Annex 4 – Digital, Data and Technology**.

### 4.3.4 Financials and Headcount

| | | BP1 | | BP2 | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A4 – Build the Future Balancing service markets | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | 10 | 11 | 7 | 7 | 6 | **41** |
| | BP1 | 5 | 3 | 2 | 1 | 1 | **14** |
| | **Variance** | **5** | **8** | **4** | **5** | **5** | **27** |
| Opex (£m) | BP2 | 5 | 9 | 13 | 12 | 12 | **51** |
| | BP1 | 12 | 10 | 11 | 10 | 8 | **51** |
| | **Variance** | **(7)** | **(1)** | **2** | **2** | **3** | **(1)** |
| **Totex (£m)** | **BP2** | **15** | **19** | **20** | **19** | **18** | **91** |
| | **BP1** | **17** | **13** | **13** | **12** | **10** | **65** |
| | **Variance** | **(2)** | **6** | **7** | **7** | **8** | **26** |
| FTE | BP2 | 50 | 53 | 65 | 65 | 65 | |
| | BP1 | 56 | 54 | 56 | 57 | 56 | |
| | **Variance** | **(5)** | **(1)** | **10** | **8** | **9** | |

Table 11: RIIO-2 cost and FTE for A4. Numbers may not add exactly due to rounding.

The forecasts for the opex, capex and FTEs needed to support **A4** activities in BP2 have increased since our first Business Plan submission. The main drivers of the increase over the two years are:

- £9m increase to capex predominantly driven by increases in IT investment **400 Single Markets Platform**
- £4m opex increase and eight FTEs increase in FY25, to support a number of areas across the activity including:
- Six FTEs to support DSO flexibility markets. More information can be found in our Accelerating Whole Electricity Flexibility section.
- Three FTEs to support Network Services Procurement (formerly Pathfinders) projects and enabling our frequency management strategy to look further ahead and to expand the time horizon that the modelling considers.
    - This FTE increase has been offset by a decrease in consultancy support.

## 4.4 A5 Transform access to the Capacity Market and Contracts for Difference

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

**What is this sub-activity and why is it important?**

We will continue to act on behalf of Government as the Delivery Body for the Capacity Market and Contracts for Difference (CfD). Through this we play a key role in promoting security of electricity supply and driving the transition to net zero. Following BEIS's announcement in February 2022, we now expect to run CfD auctions annually (instead of approximately every two years) and support an even broader range of technologies and customers to enter these auctions. In addition to this, we will run annual Capacity Market prequalification and auction processes and support customers during the agreement management process.

We will also continue to play a critical role in supporting the development of policy and rules for the Capacity Market and CfDs and deliver key inputs into Ofgem's new Capacity Market Advisory Group (CMAG) to be established later in 2022. We will continually enhance our new EMR portal which will improve functionality and user experience for our customers and delivery partners.

#### What will we deliver in BP2?

**D5.1.1 and D5.1.2 Continuation of EMR delivery body obligations**

We will continue to deliver Capacity Market auctions in annual cycles and support customers in achieving agreement milestones. We are working closely with BEIS to move to annual CfD auctions and will continue to support customers in the pre-qualification process to maximise the number of participants that enter the Capacity Market and CfD auctions. We will continue to enhance the agreement management and delivery assurance processes, in terms of operational performance as well as policy and rule development. We will develop a clear process for initiating, capturing and assessing policy, rule and process improvements which will draw on our operational experience and customer feedback as well as the ESO's wider work on market strategy and design.

#### What do we need to deliver this sub-activity?

This sub-activity is aligned to IT investment line **320** EMR and CfD Improvements. The detail behind this investment can be found in **Annex 4 – Digital, Data and Technology.**

### 4.4.2 A5.2 Deliver an enhanced platform for EMR

#### What is this sub-activity and why is it important?

The EMR portal is the single point of access to our Capacity Market and CfD processes. During the BP1 period we have been developing a new portal to provide a more flexible and adaptable solution that will also significantly improve the user experience. We are also ensuring that our EMR portal remains compliant with changes in the regulations and rules governing the Capacity Market and CfDs.

The replacement of the EMR portal was moved from RIIO-1 into the RIIO-2 period. As we moved the portal replacement (and associated spend) into RIIO-2 and firmed up our forecast based on the selected solution, our cost forecast for BP1 has increased (see **Annex 4 – Digital, Data and Technology**, IT investment line **320** EMR and CfD Improvements for more information). This reflects a better understanding of the requirements for the new portal expressed by our customers (Refer to the **A5** stakeholder engagement section for further information).

#### What will we deliver in BP2?

**D5.2 Developing the EMR platform**

During the BP2 period we will continue to enhance the EMR portal and add functionality in response to user feedback and implement policy and rule changes, as well as deliver continuous improvements to the associated Capacity Market and CfD processes. We will work towards the integration of the EMR platform into our Digital Engagement Platform and harmonise processes to find greater efficiencies across our markets. We will also implement a new reporting tool, using Power BI, to give greater analytics capability for external users to self-service and generating insightful reports to better inform business decisions and the operation of EMR processes.

#### What do we need to deliver this sub-activity?

This sub-activity is aligned to IT investment line **320** EMR and CfD Improvements and **250** Digital Engagement Platform. The detail behind this investment can be found in **Annex 4 – Digital, Data and Technology**.

### 4.4.3 A5.3 Improve our security of supply modelling capability

#### What is this sub-activity and why is it important?

In a world of rapidly evolving energy systems, we need to employ the latest modelling techniques so that we can keep pace with these changes. In BP1 we proposed to improve our security of supply modelling that underpins our Capacity Market recommendations in the Electricity Capacity Report. These improvements are agreed with BEIS, Ofgem and BEIS's Panel of Technical Experts (PTE). The projects harness new data sources and/or improve the modelling methodologies. The work is scrutinised by BEIS's PTE, which produce an annual report.

We delivered the 2021 Electricity Capacity Report to BEIS by 1 June 2021 and published it in July 2021. We have since agreed and carried out a set of development projects in 2021/22 that will be reported in the 2022 Electricity Capacity Report in line with the established process.

### What will we deliver in BP2?

**D5.3 Use of enhanced modelling and more granular data sets to improve security of supply modelling**

We will continue to develop new data sets, so our modelling approach better reflects the evolving power system. We expect improvements in modelling on intermittent sources, duration-limited technologies and pan-European modelling for interconnectors.

It is also likely we'll need to improve modelling on reduced dependency of thermal generation as we transition to net zero, embedded generation and supporting BEIS's Ten-Year Review of the Capacity Market, which is due by 2024. It is difficult, at this stage, to specify which modelling enhancements will be taken forward in BP2. These are agreed annually through an established prioritisation process with BEIS, Ofgem and BEIS's PTE. Details of our modelling improvements, including the prioritisation process, are reported in the Electricity Capacity Report each year.

We now expect to deliver enhanced modelling quicker than set out in BP1 as the net zero transition gathers pace. We also need to improve our modelling on delivery assurance that wasn't previously included. This is particularly important during the mid-late 2020s, when large thermal plant is expected to be replaced by new capacity.

### What do we need to deliver this sub-activity?

We need to expand our team to deliver modelling enhancements sooner and improve modelling on delivery assurance.

The modelling enhancements we take forward in BP2 will need to be agreed through an established annual prioritisation process with BEIS, Ofgem and BEIS' PTE and therefore at present, it is difficult to specify what modelling enhancements we will deliver in BP2.

## 4.4.4 Financials and Headcount

| | | BP1 | BP2 | | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A5 - Transform access to the Capacity Market | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | 6 | 5 | 4 | 3 | 3 | **21** |
| | BP1 | 1 | 1 | 1 | 1 | 1 | **5** |
| | **Variance** | **5** | **4** | **3** | **2** | **2** | **17** |
| Opex (£m) | BP2 | 4 | 5 | 4 | 5 | 5 | **24** |
| | BP1 | 4 | 4 | 4 | 4 | 4 | **19** |
| | **Variance** | **(0)** | **1** | **0** | **2** | **1** | **4** |
| **Totex (£m)** | **BP2** | **10** | **10** | **8** | **8** | **8** | **45** |
| | **BP1** | **5** | **5** | **5** | **4** | **4** | **24** |
| | **Variance** | **4** | **6** | **4** | **4** | **4** | **21** |
| FTE | BP2 | 47 | 58 | 52 | 51 | 50 | |
| | BP1 | 37 | 35 | 35 | 32 | 32 | |
| | **Variance** | **11** | **23** | **17** | **19** | **18** | |

Table 12: RIIO-2 cost and FTE for A5. Numbers may not add exactly due to rounding.

The forecasts for the opex, capex and FTEs needed to support **A5** activities in BP2 have increased since our first Business Plan submission. The main drivers of the increase over the two years are:

- £5m increase to capex has been driven by increases in IT investment **320** EMR and CfD Improvements largely due to the following factors:
  - The original investment forecast was an initial estimate, and we have since selected the platforms for the replacement portal (Salesforce) and reporting solution and developed the roadmap for the EMR portal which enabled us to firm up the cost.
  - We now have a better understanding of integration requirements and costs with downstream systems, particularly IT investments **250** Digital Engagement Platform and **220** Data and Analytics Platform.

- The cost has also been significantly affected by fluctuating resourcing market rates, with Salesforce identified as a product impacted by global resource shortages/demand.
- £3m opex and 19 FTEs in FY25 will support a number of areas:
  - 13 FTEs to support the delivery of EMR auctions, delivering regulatory change and to cover the revised implementation date of the EMR portal and process automation (**A5.1**).
  - One additional FTE to support the 2030's modelling capability which includes delivery of modelling enhancements earlier and to improve modelling on delivery assurance (**A5.3**).
  - Five FTEs to support the new sub-activity **A5.4**, to build our capability studies under, deliver incremental modelling improvements and potentially undertake shorter follow-up studies.

## 4.5 A6 Develop code and charging arrangements that are fit for the future

### 4.5.1 A6.2 European Union (EU) Code Change (moved to A21.2 Enhancing cross border frameworks and markets)

In response to Ofgem feedback, we moved the two deliverables under A6.2 activity to sit under activity **A21 Role in Europe** due to the high level of dependency between the deliverables in these two areas.

Deliverables **D6.2** and **D6.2.1** have moved under new sub-activity **A21.2 Enhancing cross border frameworks and markets** as **D21.2.1** and **D21.2.2.**

### 4.5.2 A6.4 Transform the process to amend our codes

**What is this sub-activity and why is it important?**

In response to stakeholder feedback, we are transforming the process to amend our codes, so they are an enabler of change, rather than a barrier to change. By 2025 the codes we administer[6] will be accessible and relevant to all market participants. We are creating a no-regrets action plan to set ourselves up to become a Code Manager, addressing the changes identified in the Government's response to the consultation on Energy Code Reform (ECR) published in April 2022. We will also work with industry to make sure commercial, technical and regulatory arrangements are coordinated across transmission and distribution.

We've made good progress in this area in BP1, making improvements to the Critical Friend Process[7] and securing dedicated legal resource for our codes.

**What will we deliver in BP2?**

The deliverables under this sub-activity are dependent on the ECR and we will focus on making progress in this area now we have the consultation outcome. Ofgem have stated that an open letter on the ECR (including the arrangements for Code Manager appointment, Stakeholder Advisory Forums, implementation and transition arrangements) is being produced and will be released in late summer 2022. This will also include an update on code consolidation ambitions.

In our draft BP2 submission, we included a separate item **D6.4.1** which referenced Implement no regret actions from the ECR – within which the wording referenced Digitalisation of the Grid Code. **D6.4.1** has been removed as a deliverable under sub-activity A6.4 due to its similarities with **D6.8** Implementation of Digital Solutions. **D6.8** will be the driver for any changes to the Digital platform.

The removal of this deliverable has resulted in **A6.4** no longer being classed as "materially changed."

To set ourselves up be a Code Manager of the future (**D6.4**), we will continue to consult our stakeholders and make appropriate changes. Likely actions include continued evidence demonstrating Code Manager capability including providing insight into cross code impacts, building expertise within the team, finding ways to enable smaller parties to contribute to code change and supporting BEIS and Ofgem with larger scale reform.

We will also set out a clear plan for delivering large-scale reforms that provide confidence to Ofgem and industry that we can make these changes within the timescales provided in the ECR.

6 We are administrators for the Connection and Use of System Code (CUSC), the Grid Code (GC), the System Operator – Transmission Owner Code (STC), and the Security & Quality of Supply Standard (SQSS).
7 The Code Administrator provides assistance to parties with an interest code modifications. This is provided for in the Code Administration Code of Practice which includes assistance with drafting proposals and helping parties to understand the code modification process.

#### What do we need to deliver this sub-activity?

Fundamental reform is needed across industry and our plan will need to reflect any interactions with other codes. We will need to work within the timescales of our stakeholders and Government.

We are awaiting further guidance from the open letter due in summer 2022, where we can reassess our BP2 milestones. We will work with Ofgem/BEIS to ensure that any new milestones are realistic and stretching.

Another dependency is the Future System Operator, and we are working to understand how FSO plans impact our role as Code Administrator. We aim to become a Code Manager and will continue to work on these deliverables to ensure we are set up best for that role.

### 4.5.3 A6.5 Work with all stakeholders to create a fully digitalised, Whole System Technical Code by 2025 (Whole System Technical Code side)

#### What is this sub-activity and why is it important?

Our main focus in BP1 was engagement on the scope of this deliverable and particularly the format of a Whole System Technical code, as we envisioned this would be the first approach for digitalisation. Further work around a code consolidation solution is required, so a new sub-activity **A6.8 Digitalisation of codes** has been created to look more specifically at digital solutions.

In the second year of BP1 the project team, in conjunction with the steering group, will continue to progress both areas. Since its instigation, an industry steering group that the ESO has set up has validated 'go /no go' decisions for several workstreams within the project as their scope has been defined. This is a deviation from our original plan to determine a definitive way forward on all parts of the scope by 31 March 2022. The project team has engaged extensively with stakeholders to seek their views on scope, objectives, and approach, which formed the basis of the consultation issued in September 2021 and has updated industry regularly through the Grid and Distribution Code Panels and the Grid Code Development Forum. See **Annex 3 - Stakeholder Feedback Annex** for further information.

#### What will we deliver in BP2?

**D6.5 Develop a single technical code for distribution and transmission that is focused on providing minimum standards to allow safe and secure operation of the electricity systems**.

In BP2, we will continue to inform technical code consolidation in line with any proposed ECR or other reforms mandated by Ofgem. While digitalisation of the Grid Code continues, we have de-prioritised the consolidation element at the end of the first year of the BP1 period due to significant stakeholder feedback on the potential for interactions with ECR.

We agree with the Whole System Technical Code (WSTC) Steering Group that awaiting further detail from the outcome of the ECR will result in a more successful process. We will consider this further during BP2, when these interactions will be more clearly understood, noting that Ofgem have stated that their open letter on the ECR (expected in late summer 2022) will include an update on code consolidation ambitions. With the input of the WSTC Steering Group we would then consider what the most appropriate action is for this workstream. We are very open to working with Ofgem's ECR team on the best way to approach this within their programme and where synergies or learning from each piece of work can be applied.

#### What do we need to deliver this sub-activity?

Stakeholders are reluctant to make resource commitments for this activity, where the results could be dependent on the outcome of the ECR. Our proposal to mitigate this concern has been to define the scope of work in BP1 and delay delivery in BP2 until we fully understand the ECR outcome.

We assume industry can resource subject matter experts (SMEs) for the required workgroups to code modifications. However, due to the great deal of change currently ongoing in the industry, there is a risk that suitable resources may not be freely available.

See sub-activity **A6.8** for more detail on digitalisation.

### 4.5.4 A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges

We have worked with industry to deliver a programme of BSUoS reform which will result in code modifications and a change to our licence. This activity will be completed before the BP2 period.

A new sub-activity **A6.7** has now been created to look at the long-term delivery of the recommendation from the BSUoS taskforce.

### 4.5.5 Financials and Headcount

| A6 - Develop code and charging arrangements that are fit for the future | | BP1 Actuals 2021/22 | BP2 Forecast 2022/23 | BP2 Forecast 2023/24 | BP2 Forecast 2024/25 | BP3 Forecast 2025/26 | TOTAL |
|---|---|---|---|---|---|---|---|
| Capex (£m) | BP2 | 7 | 10 | 10 | 13 | 15 | **55** |
| | BP1 | 16 | 11 | 11 | 12 | 13 | **62** |
| | **Variance** | **(8)** | **(1)** | **(1)** | **1** | **2** | **(6)** |
| Opex (£m) | BP2 | 10 | 12 | 15 | 16 | 16 | **69** |
| | BP1 | 13 | 14 | 15 | 16 | 16 | **73** |
| | **Variance** | **(4)** | **(2)** | **0** | **0** | **1** | **(4)** |
| **Totex (£m)** | **BP2** | **17** | **22** | **25** | **29** | **31** | **124** |
| | **BP1** | **29** | **25** | **26** | **28** | **28** | **135** |
| | **Variance** | **(12)** | **(2)** | **(1)** | **2** | **3** | **(11)** |
| FTE | BP2 | 77 | 95 | 85 | 85 | 85 | |
| | BP1 | 72 | 75 | 77 | 81 | 80 | |
| | **Variance** | **5** | **20** | **9** | **5** | **5** | |

Table 13: RIIO-2 cost and FTE for A6. Numbers may not add exactly due to rounding.

The forecasts for the opex, capex have stayed relatively in line with our BP2 forecasts. FTEs needed to support **A6** activities in BP2 have increased since our BP1 submission. These changes are driven by:

- No overall increase to capex as the changes on the investments net off with each other.
- Four FTEs recruited during BP1 to enable a dedicated focus on implementation of the TCA under **A6.2** (please note this sub-activity has moved under **A21**).
- £1m increase to opex supported by an additional nine FTEs in FY24 reducing to five FTEs in FY25.The decrease between FY24 and FY25 is due to us remaining flat at a total of 85 FTE across both years BP2 compared to BP1. The main drivers of the increase in FTE from BP1 are:
  - Three FTEs to enable the Offshore Coordination programme by implementing code and standard changes to enable offshore networks (**A6.1**)
  - Two FTEs deliver the recommendations of the BSUoS taskforce, enhancing our ability to forecast and set BSUoS tariffs (**A6.7**)
  - Four FTEs to develop a holistic view of electricity frameworks and how they need to adapt (**A6.9**)

## 4.6 A20 Net Zero Market Reform

### 4.6.1 A20.1 Net Zero Market Reform

Supporting information BP1 deliverables only:

The net zero market reform (NZMR) programme kicked off in January 2021 and has completed three phases of work:

**Phase one: Scoping and stakeholder landscape**

We undertook a high-level analysis of the market landscape; developed case studies of international markets that have adopted innovative market designs (including Texas, California and Australia); interviewed 25 markets stakeholders and experts; and defined the scope of the next two phases.

**Phase two: Defining the case for change and developing the options assessment framework**

For the case for change, we looked at the challenges facing electricity markets, and the impact of not reforming them. This involved an extensive modelling exercise, where we modelled the three net zero compliant scenarios from our FES and identified what the system would look like if the existing market arrangements remained in place. We also conducted engagement across the industry including small and large-scale workshops

Also we developed 'The 'Market Design Options Assessment Framework' which covers the criteria we used to judge which options to take forward for further consideration in phase three.

**Phase three**: **Assessment of shortlisted options**

We assessed the shortlisted market design options against the criteria developed in phase two. Our analysis in Phase 3 focused predominantly on the operational (location and dispatch) market design elements. We found that locational wholesale pricing signals, through a nodal wholesale market with central dispatch, would be the most enduring and effective solution to build a holistic package of reforms for net zero.

### 4.6.2 Financials and Headcount

| | | BP1 | BP2 | | BP3 | |
|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | |
| A20 - Net Zero Market reform | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | - | - | 0 | 0 | 0 | **1** |
| | BP1 | - | - | - | - | - | **-** |
| | **Variance** | **-** | **-** | **0** | **0** | **0** | **1** |
| **Totex (£m)** | **BP2** | **-** | **-** | **0** | **0** | **0** | **1** |
| | **BP1** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Variance** | **-** | **-** | **0** | **0** | **0** | **1** |
| | | | | | | | |
| FTE | BP2 | - | - | 6 | 6 | 6 | |
| | BP1 | - | - | - | - | - | |
| | **Variance** | **-** | **-** | **6** | **6** | **6** | |

Table 14: RIIO-2 cost and FTE for A20. Numbers may not add exactly due to rounding.

This new activity will be carried out by six FTEs which make up the NZMR team. This team started in April 2021 and were not part of our original BP1 requirements. The costs of the additional headcount are being managed through efficiencies elsewhere in Role 2, and we are not asking for additional funding for these in BP2. There are no figures reflected in our BP1 columns within the table to show that this is a new activity for BP2. The six FTEs referenced will not be additional but a continuation of the team that started in April 2021. We are maintaining the same cost baseline in BP2.

## 4.7 A21 Role in Europe

### 4.7.1 A21.1 Setting the net zero cross border landscape

In creating the ambitions for this sub-acivity, it is assumed that these activities relating to Interconnectors in Roles 1 and 3 are completed or on track:

Role 1 activities:

- Expand the scope of the Operability Strategy Report to bring in two new key areas, capacity adequacy and flexibility, in line with sub activity **A15.9 Net-zero operability**
- Increase automation of trading processes and move to an auction platform to ensure we can continue to trade reliably, economically, and efficiently as GB's interconnection with Europe increases (see sub-activity **D1.18** Trading Solutions)

Role 3 activities:

- Continue the development of publications such as the 'Future Energy Scenarios' (FES) and 'Network Options Assessment' (NOA), providing an insight into future cross-border flows and their impact in the wider energy system
- Conduct long-term operability and adequacy analysis and modelling by expanding the scope of the operability strategy report (**D1.1.6**) and undertaking capacity adequacy studies in line with **D5.4 Building our long-term security of supply modelling capability**
- Contribute to Ofgem's Strategic Network Planning for interconnection
- Produce a report for Ofgem on system operability impacts of hypothetical combinations of interconnectors between GB and our neighbours
- Finalise Centralised Strategic Network Planning (CSNP); Ofgem envisages a central scenario sufficiently robust to support network planning, both onshore and offshore.

### 4.7.2 A21.2 Enhancing cross border frameworks and markets (formally A6.2)

**Supporting information for D21.2.2 Implementation of the TCA**

TCA technical elements to be delivered include:

Developing and delivering with other UK TSOs (interconnectors), the TCA technical procedures in the areas below; we will also have to strike agreements with other EU TSOs on all these technical procedures:

- Cross-border Balancing interim and enduring solution
- Capacity calculation for Day-ahead, Intra-day and Long-term
- Coordinated process for remedial actions including redispatch and countertrading (RDCT)
- Defining new TCA-related publications; monitoring and preparing the new operational reporting required
- Continue to encourage and drive European engagement in both formal and informal settings
- Assessing TCA recommendations presented by the Specialised Committee on Energy (SCE)
- Developing our relationship with EU stakeholders via TCA workgroups and governance forums

We foresee elevated levels of uncertainty around the TCA implementation to Role 1 activities (under deliverable **D1.1.4**) leading to the following:

- Supporting the development of new methodologies for interconnector capacity calculations under the TCA
- Continuing to participate in key projects relating to cross border capacity calculations, security analysis and situational awareness
- Continuing business-as-usual activities of submitting individual grid models for the Common Grid Model project and Coreso security studies

### 4.7.3 Financials and Headcount

The increased need to manage European and cross border issues was confirmed after the Trade and Cooperation Agreement was finalised, when we began additional recruitment into the Cross Border and EU team. This team was created in March 2020 and consisted of three FTEs; however, BP1 funding allowed the recruitment of three additional FTE in October 2021.

| | | BP1 | | BP2 | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A21 - Roles In Europe | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | - | - | 0 | 0 | 0 | 1 |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **0** | **0** | **0** | **1** |
| **Totex (£m)** | **BP2** | **-** | **-** | **0** | **0** | **0** | **1** |
| | **BP1** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Variance** | **-** | **-** | **0** | **0** | **0** | **1** |
| FTE | BP2 | - | - | 6 | 6 | 6 | |
| | BP1 | - | - | - | - | - | |
| | **Variance** | **-** | **-** | **6** | **6** | **6** | |

Table 15: RIIO-2 cost and FTE for A21. Numbers may not add exactly due to rounding.

We propose the same headcount in BP2 as in BP1 (six FTEs) to manage our European interactions. This headcount originally sat in the **A6 financials and headcount** table (for the April Draft submission). Please note that A6.2 has been moved to this activity.

# 5 Role 3 Updates and Supporting Information

## 5.1 Transformational Deliverables Roadmaps

The roadmaps below outline the transformational deliverables for Role 1 across BP2. Continuous deliverables are not shown.

### A7 Network Development

The deliverables for **A7** are continuous, and so no roadmap is provided.

### A8 Enable all solution types to compete to meet transmission needs

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 | | | | RIIO-2 Year Four - 2024/25 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| | | | Milestones | | | | | | | |
| Rollout of Network Services Procurement (formerly Pathfinders) approach and optimise assessment and communication of future needs (A8.1) | If needs case is met, relevant tenders are run | Substantial progress made towards our aim of running 3-6 tenders during RIIO-2 | | | EC5 tender run<br>Constraint Management Pathfinder B6 year 3 tender | | | | Constraint Management Pathfinder B6 year 2 service start date | |
| Enhance tendering models (A8.2) | Improved tender approaches that enable more participants to enter the market (D8.2) | Moved under A8.1 | | | | | | | | |
| Support Ofgem to establish enabling regulatory and funding frameworks (A8.3) | Frameworks based on competitive regime not monopoly regime (D8.3) | Sub-activity complete: Worked with Ofgem to develop solutions to current limitations with current regulatory arrangements | Sub-activity completed in BP1 | | | | | | | |
| Early Competition (A8.4) | Implementation of the Early Competition Model (D8.4) | Substantial implementation progress | Majority of commercial model elements delivered to Ofgem for approval (TRS, PPWCA) | First generic tender documents and processes delivered to Ofgem to be approved | Early Competition contract completed and aligned with relevant licence obligations | Implementation complete. Project identified for first competition | | | | Launch the first Early Competition tender |

Figure 9: A8 transformational deliverables roadmap

### A9 – Extend NOA approach to end of life asset replacement decisions and connections wider works

As this Activity has moved for BP2, there is no Transformational Deliverables Roadmap for A9.

### A10 Support decision making for investment at distribution level

As this Activity has complete during BP1, there is no Transformational Deliverables Roadmap for A10.

### A11 Enhance Analytical Capabilities

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 | | | | RIIO-2 Year Four - 2024/25 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| | | | Milestones | | | | | | | |
| Refresh and integrate economic assessment tools to support future network modelling needs (A11.1) | Improved identification of when is the most economical time to invest and the most efficient solution (D11.1) | Implementation of updated economic tool | | | Integration with our network assessment tools | | | | | Full integration with Data and analytics platform complete |
| Implement probabilistic modelling (A11.2) | Improved identification of network needs (D11.2) | Proof of concept for year-round thermal assessment of circuit constraints and integration into a NOA process | | | | Developed and implemented digital experience platform | | | | Full integration with Data and analytics platform complete |
| Build voltage assessment techniques into an optimisation tool (A11.3) | Improved assessment of voltage requirements, and ability to look across a range of network needs at the same time (D11.3) | Proof of concept for voltage optimisation tool | | | | Implemented VO tool and identified further enhancements | | | | Full integration with Data and analytics platform complete |
| Build stability assessment techniques into an optimisation tool (A11.4) | Improved assessment of stability requirements across the network. (D11.4) | Innovation project identified learnings and development needed on our data and models | | | | Proof of concept for a stability screening tool | | | | Implement stability screening tool |

Figure 10: A11 transformational deliverables roadmap

## A12 SQSS Review

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 | | | | RIIO-2 Year Four - 2024/25 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| | | | Milestones | | | | | | | |
| **Scope project, building on the BEIS recommendations (A12.1)** | Review fully scoped and target issues agreed (D12.1) | Sub-activity complete: A targeted NETS SQSS review was proposed to ensure standard is updated to enable decarbonisation of the electricity system | Sub-activity completed in BP1 | | | | | | | |
| **Identify solutions (A12.2)** | Potential solutions identified and direction established (D12.2) | Potential solutions identified for quick win topics | Changes initiated for the high-priority areas, and potential solutions developed | | | | | | Changes initiated for the low-priority areas, and potential solutions developed | |
| **Implement changes to the SQSS (A12.3)** | Key changes to SQSS made or in progress (D12.3) | Potential solutions made or in progress | | | Changes are made or in progress for the high-priority items | | | | | Changes are made or in progress for the low-priority items |

Figure 11: A12 transformational deliverables roadmap

## A13 Leading the Debate

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 | | | | RIIO-2 Year Four - 2024/25 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| | | | Milestones | | | | | | | |
| **Conduct mathematical modelling and market research on local and wider geographic demand information (A13.2)** | Provide whole system regional insights (D13.2.1) | New deliverable | Starting to work with Local Authorities to understand the feedback loop between FES / Distribution scenarios / Local Area Energy Plans<br>Starting to work with gas networks to agree the granular breakdown of FES scenarios (Natural Gas and Hydrogen) | Whole system regional data and insights provided<br>Regional data and visualisations added to Website<br>User-configurable FES view available for Electricity supply and demand | | | | Whole system regional data and insights provided<br>Regional data and visualisations added to Website<br>User configurable FES view available for Electricity / Gas / Hydrogen supply and demand | | |

Figure 12: A13 transformational deliverables roadmap

## A14 Take a whole electricity system approach to connections

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 | | | | RIIO-2 Year Four - 2024/25 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| | | | Milestones | | | | | | | |
| Further enhance the customer connection experience, including broader support for smaller parties (A14.3) | Establish dedicated Distributed Energy Resource (DER) account management function (D14.3.1) | Commencement delayed to BP2 | Run Connections process-focused meetings with DNOs and TOs | | Request feedback from Customers and DNOs | | Continuously deliver on the use of DER, learn lessons and implement improvements | | | |
| | Improving Systems and Data (D14.3.4) | New deliverable | Submit IT investment paper and obtain approval of scope and expenditure | Further develop new register, platform and connection with other systems; liaise with stakeholders to verify requirements | Further development and testing - engage with focus groups | Implementation of updates to ESO Portal | Obtain feedback on the new platform from internal and external stakeholders | Continuous review, maintenance and updates to the platform | | |
| Facilitate development of the customer connections portal (A14.4) | Implement first phase of the ESO connections portal (D14.4.1) | Initial delivery of phase 1 of ESO connections portal (last phase of minimum viable product) | Changes based on customer feedback | | | | | | | |
| | Phase 2 of the connections portal concluded (D14.4.2) | | Submit revised IT investment paper through internal governance process and obtain approval of scope and expenditure | Further develop concept of phase 2 deliverables and identify different stages of deliverables along with key stakeholders to work with | Development of concept designs | | Review and UAT for scheduled deliverables in Q3 & Q4 | Continuous development of further elements for later delivery | Delivery of elements of the phase 2; Continuous development of further elements for later delivery | Successful delivery of some elements of Phase 2 |
| Connections Reform (A14.5) | Connections Reform Phase 1 (D14.5.1) | We have already started to engage with OFGEM, BEIS, TOs, DNOs and wider customer and stakeholder community regarding the reform; Initial Problem statement paper already issued to OFGEM | Final iteration of problem statement and proposal paper to Ofgem<br><br>Produce a connections reform roadmap | Deliver TEC Amnesty and Queue Management Process, CPA review and modelling of storage review | | | | | | |
| | Connections Reform Phase 2 (D14.5.2) | N/A - BP2 Start | Start the connections reform Phase 2 as per roadmap - workgroups stage for definition of the problem and what good looks like | Continue to enable workgroups for discussion and definition of the problems; Touchpoints with ERSG, OFGEM, BEIS and wider stakeholder group | Complete Phase 2 - obtain a clear mapping of the problems to be addressed as part of the reform, focus areas for Phase 3 and summary of what good looks like | | | | | |
| | Connections Reform Phase 3 (D14.5.3) | N/A - BP2 Start | | | Initiate phase 3 of the reform by establishing working groups | Continue to enable workgroups for discussion and definition of the problems; Touchpoints with ERSG, OFGEM, BEIS and wider stakeholder group | Produce initial implementation programme and scope for review. Decision point on whether to progress with current set of solutions. Code and regulation changes framework to enable all relevant changes ahead of implementation | New process(es) defined and agreed on by all relevant impacted organisations<br><br>Implementation programme to be reviewed and agreed by all relevant stakeholders and organisations | | |
| | Connections Reform Phase 4 (D14.5.4) | N/A - BP2 Start | | | | | | | Initiate implementation programme | Review and update of programme, with report on findings from review and requirement to work on proposed changes to be further developed during the implementation phase; proposed to last up to 24 months |
| | Connections Reform Phase 5 (D14.5.5) | N/A - BP3 Start | BP3 deliverable - highlighted only as high-level context in BP2 plan | | | | | | | |

Figure 13: A14 transformational deliverables roadmap

## A15 Taking a whole energy system approach to promote zero carbon operability

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 | | | | RIIO-2 Year Four - 2024/25 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| | | | Milestones | | | | | | | |
| Manage operational data and modelling requirements for the ESO (A15.4) | Automation of data exchange mechanism and preparation for CIM implementation (D15.4.3) | New deliverable | | | | Initiative identified to automate data exchange<br>Commence preparation for data exchange enhancements | | | | Implementation of data exchange automation<br>Prepared for data exchange enhancements with network |
| Regional Development Programmes (RDPs) (A15.5) | Forward Plan 2020-21 RDP - Generation Export Management Scheme (GEMS) (D.15.11.2) | Energisation of pilot sites by April 2023 to commission first GEMS boundaries | Testing and commissioning of first GEMS pilot boundaries | | | Expansion of functionality to further boundaries on a system needs basis | | Design and integration of GEMS functionality with SPD ANM scheme | | Commissioning of first DER onto combined GEMS and SPD ANM functionality |
| | RDP2 of RIIO-2 (MW dispatch, South East, UKPN) (D15.5.2) | New service design developed for thermal constraint management | | IT implementation phase complete | | | | | | |
| | RDP3 of RIIO-2 (wider rollout & enhancements, WPD) (D15.5.3)<br>RDP4 of RIIO-2 (wider roll out & enhancements UKPN) (D15.5.4) | Commercial development complete including market viability and service design to resolve operability need. IT Requirements and Design phase commenced | Undertake IT requirements and design for new operability functionality with DNOs | Complete IT requirements and design | | | Complete IT development and testing; ongoing implementation of solution | Assess enhancements to new service in accordance with operability needs and customer feedback | | Complete enhancements to new service and final implementation |
| | Deliver GB rollout of functionality developed through initial RDPs (D15.5.5) | Development of roadmap to deliver GB rollout of functionality developed through initial RDPs | | Establish enduring process to determine needs at GSPs | | Rollout process and seek feedback from stakeholders | | Test application of process at one or more sites | | Implement enduring ongoing process |
| | RDP5 of RIIO-2 (D15.5.6)<br>RDP6 of RIIO-2 (D15.5.7) | New deliverable<br>New deliverable | Go / No go decision to progress RDP implementation; If yes, commence detailed RDP development | | Complete detailed RDP development ahead of IT build | | | Complete IT requirements and design | | Commence IT implementation in order to test new service solution |
| Transform our capability in modelling and data management (A15.6) | Further Grid Code modification implementation (D15.6.2) | Process for of identification for non-build solutions for connections developed in accordance with the roadmap and in alignment with activities ongoing in the Open Networks project | | | | Grid Code mods progressed or submitted for approval | Provide ongoing technical support and input to the code development process | | | |
| | Deliver major upgrades to our offline modelling tools (D15.6.6) | Hardware and software upgrade for OLTA offline analysis tool carried out. Offline modelling roadmap developed | | | | | | Further upgrade to offline modelling tool software / service pack | | Integration of offline modelling tools with Data and Analytics Platform |
| | Deeper Outage Planning go live in Offline Network Modelling (D15.6.7) | OLTA hardware refresh completed | | | | Feed findings from deliverable A16.3.2 and any Grid Code modifications into modelling scoping and development | | | | Feed findings from deeper access work into offline network modelling development |
| | Development & ongoing maintenance of EMT Capabilities (D15.6.8) | New deliverable | Learning from NIA projects to define requirements for EMT modelling work | Engage with wider industry and produce a roadmap to develop and maintain EMT models | | Identify the data requirements and develop process to collect required data and build initial EMT model | To carry out initial EMT simulations for the GB network | Define requirements for EMT simulation using learning from NIA projects (D15.6.9) | | Developed capability to carry out EMT simulations<br>Developed plan for ongoing maintenance of EMT model(s) |
| | Co-simulation analysis innovation project (D15.6.9) | New deliverable | Engage with wider industry to start the potential innovation project for co-simulation works | | | Evaluate the feasibility of co-simulation modelling between OLTA (PowerFactory) and PSCAD | | | | |
| Deliver Enhanced Frequency control by 2025 (A15.7) | Commence System State Targeted Monitoring and Control System (MCS) stage roll out (D15.7.1) | 2022/23 milestones pushed out to 2023/24 due to addition of a "Phase zero" | Phase 2 (develop operational demonstration) Development and Testing | | Phase 4 first stage rollout start-up | Phase 3 (Operational Demonstration) Implementation<br>Phase 4 first Stage Roll-out requirements and design | | Phase 4 First Stage Roll-out Developments | | Phase 4 First Stage roll-out implementation |
| | Commence System State Targeted Monitoring and Control System (MCS) second stage roll out. (D15.7.2) | New deliverable | | | | | | | | Phase 5 Second Stage Roll-out Startup requirements |
| Facilitate distributed flexibility and whole electricity system alignment (A15.8) | Enabling whole electricity flexibility service provision through operational visibility (D15.8.2) | Roadmap for greater operational visibility in progress and delivering<br>BM operational metering standards designed for residential flex | Initiate project scoping with external stakeholders to enable operational visibility of DER | Complete project scoping with external stakeholders to enable operational visibility of DER | Initiate IT discovery phase | Complete IT discovery phase and identify costs of implementation | Requirements and design phase to enable operational visibility of DER begins | | | Building the storage and transfer capability to utilise bigger volumes of data |
| | Enabling whole electricity system operational service co-ordination (D15.8.3) | Conclusion of ESO led work in Open Networks to develop initial set of primacy rules | Initiate IT discovery phase for primacy implementation | Complete IT discovery phase and identify costs of implementation | Requirements and design phase begins | | | | First wave of systems developed for operational co-ordination based on outputs of delivery phase | |
| Develop a regime for an integrated offshore grid (A15.10) | Initial scoping report published (D15.10.1) | Moved under A22 | | | | | | | | |

Figure 14: A15 transformational deliverables roadmap

## A16 Delivering consumer benefits from improved network access planning

| Sub-activity | Deliverable | BP1 End Point | RIIO-2 Year Three - 2023/24 Q1 | Q2 | Q3 | Q4 | RIIO-2 Year Four - 2024/25 Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Milestones | | | | | | | |
| **Scope a Whole Electricity System decision making policy (A16.2)** | GB-wide NAP process (D16.2.1) | Training delivered to England & Wales outage planning teams to demonstrate use of NAP process. NAP process integrated across all current-year teams | Stakeholder mapping activities commenced | Stakeholder mapping activities continued and context communicated to stakeholders | Organisation of cross industry forum with OC2 attendees to present and hear thoughts | CBA and summary paper for presentation to industry & ESO senior management | Develop framework to facilitate decision making | | | Agree framework to facilitate decision making |
| **Work more closely with DNOs and DER to facilitate network access (A16.3)** | Finalise new processes in readiness for approval of code modifications to facilitate closer working relationships and data exchange/ modelling. (D16.3.3) | Able to feed the findings from discussions, workshops and projects with trial partners into BP2 activities. High level of potential code modifications identified | | | | Proposals for draft code modifications completed | | | | Code modifications finalised for approval |
| | Deeper access planning go-live – frameworks, processes and models are in place to facilitate deeper access planning with network parties (D16.3.4) | Able to feed the findings from discussions, workshops and projects with trial partners into BP2 activities. High level of potential modifications required for models, frameworks and processes established | | | | Proposals for frameworks, models and processes completed | | | | Frameworks, models and processes completed to facilitate deeper access planning |
| **Whole system outage notification (A16.4)** | Scoping exercise for delivery of enhancements to outage notifications (D16.4.1) | A16.4 will follow on from A16.3 as a dependency | Dependent on outcomes out A16.3 deliverables | | | Scoping complete | Dependent on outcomes of A16.3 deliverables | | | |
| | Delivery of enhancements to outage notifications (D16.4.2) | | Dependent on outcomes of A16.3 deliverables | | | | Dependent on outcomes out A16.3 deliverables | | | Whole System Outage Notifications in use |
| **Network Access Planning Automation (A16.5)** | Agree future platform for any automation and create sandbox environment for application development (D16.5.1) | New deliverable | Continued use and development of sandbox environments<br>Platforms for development of automation tools known and agreed by Q4 | | | | Continued use of sandbox environments for A16.5.2 developments | | | |
| | Scope future automation development (D16.5.2) | New deliverable | Project delivery timelines and full project plan identified for delivery of contingency analysis automation & multiple cardinal demand point analysis | Proof of concept for agreed automation commenced | Proof of concept for automation completed | Training programme for teams in NAP developed and delivery schedule planned | Training of NAP staff on all tools underway | Training of NAP staff on all tools Complete and systems in use | | |

Figure 15: A16 transformational deliverables roadmap

## A22 Network Planning Review / Offshore Coordination

Due to the early stage maturity of these projects, there are no milestones set out within this activity's deliverables for BP2 at this time and therefore no transformational roadmap is provided.

# 5.2 Role 3 Activities and Sub-activities

The following section contains:

- Transformational deliverable roadmaps per activity, which outline the timelines only for deliverables which are not continuous/ongoing
- Narrative which provides additional detail or context to the main BP2 plan content where appropriate
- Financials and headcount tables and updates per activity
- Sub-activities which are either unchanged, or which have non-material changes from BP1

The table below clarifies the nature of the included content for each sub-activity in this Annex. Any sub-activities not listed will be those which are new or materially changed for BP2, but which have no additional supporting information provided in this Annex.

| Content | No or minimal change – Sub-activity BP2 content covered in this Annex only | New or materially changed for BP2 – Further information included here | New or materially changed for BP2 - Content in main plan only |
|---|---|---|---|
| A7.1 Analyse and communicate future network needs | | | ✓ |
| A7.2 Advise on economically efficient ways to address networks needs | | | ✓ |
| A7.3 Undertake ad hoc analysis in response to external requests | ✓ | | |
| A8.1 Rollout of Network Services Procurement (formerly Pathfinders) approach and optimise assessment and communication of future needs | | | ✓ |
| A8.2 Enhance tendering models | | | ✓ |
| A8.3 Support Ofgem to establish enabling regulatory and funding frameworks | ✓ | | |
| A8.4 Early Comptition | | | ✓ |
| A9 Extend NOA approach to end of life asset replacement decisions and connections wider works (*all sub-activities*) | | ✓ | |
| A11.1 Enhance Analytical Capabilities (*all sub-activities)* | ✓ | | |
| A12.1 Scope project, building on the BEIS recommendations | | | ✓ |
| A12.2 Identify solutions | ✓ | | |
| A12.3 Implement changes to the SQSS | ✓ | | |
| A13.1 Carry out analysis and scenario modelling on future energy demand and supply | ✓ | | |
| A13.2 Conduct mathematical modelling and market research on local and wider geographic demand information | | | ✓ |
| A13.3 Maintain external communication channels with consumers and stakeholders | ✓ | | |
| A13.4 *FES*: Bridging the gap to net zero | | | ✓ |
| A13.5 *FES*: Integrating with other networks and supporting DNOs to develop their own DFES processes | | | ✓ |
| A14.1 Provide contractual expertise and management of connection contracts including provision of connection offers to customers | | | ✓ |
| A14.2 Ensure Grid Code compliance of new connections | ✓ | | |
| A14.3 Further enhance the customer connection experience, including broader support for smaller parties | | | ✓ |
| A14.4 Facilitate development of the customer connections portal | | | ✓ |
| A14.5 Connections Reform | | ✓ | |

| Content | No or minimal change – Sub-activity BP2 content covered in this Annex only | New or materially changed for BP2 – Further information included here | New or materially changed for BP2 - Content in main plan only |
|---|---|---|---|
| A15.1 Develop the System Operability Framework (SOF) and provide solutions up to real time of network related operability issues | ✓ | | |
| A15.2 Provide technical support to the connections process | ✓ | | |
| A15.3 Assess the technical implications of framework developments and implement changes into business procedures and systems | ✓ | | |
| A15.4 Manage our operational data and modelling requirements | | | ✓ |
| A15.5 Develop Regional Development Programmes (RDPs) | | ✓ | |
| A15.6 Transform our capability in modelling and data management | | | ✓ |
| A15.7 Deliver enhanced frequency control by 2025 | | | ✓ |
| A15.8 Facilitate distributed flexibility and whole electricity system alignment | | | ✓ |
| A15.9 Net zero operability | | | ✓ |
| 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 | ✓ | | |
| A16.2 Scope a whole electricity system decision-making policy | ✓ | | |
| A16.3 Work more closely with DNOs and DER to facilitate network access | ✓ | | |
| A16.4 Whole system outage notification | ✓ | | |
| A16.5 Network Access Planning automation | | | ✓ |
| A22 Offshore Coordination and Network Planning Review (*all sub-activities)* | | ✓ | |

Table 16: Role 3 supporting information context

## 5.3 A7 Network Development

### 5.3.1 A7.3 Undertake ad hoc analysis in response to external requests

**What is this sub-activity and why is it important?**

Three key areas are broadly covered in this sub-activity, and these are:

- Strategic Wider Works (SWW) projects (now the Large Onshore Transmission Investments, or LOTI process)
- Boundary studies for the Connections and Infrastructure Options Note (CION) process covering offshore connections
- Cost-benefit analysis for small schemes (ad hoc assessments for localised network issues)

In BP1 we have undertaken analysis for LOTI projects and several CBAs for small schemes to support TO decision-making .The SWW re-opener process was replaced in RIIO-T2 by the LOTI re-opener process, which provides TOs with a route to apply for funding for large network investments that were not funded at the time of setting the price control due to insufficient certainty. We undertake analysis in line with Ofgem's LOTI

Reopener Guidance[8]. The threshold for LOTI projects is £100m, compared to £500m for SWW projects, so significantly more projects are requiring LOTI assessment than in RIIO-1. We have not undertaken any work for the CION process covering offshore connections, due to this being temporarily subsumed into the Offshore Coordination Project[9], but we will continue to provide insight and expertise.

#### What will we deliver in BP2?

The volume of projects requiring our analysis as part of the LOTI process had to be estimated at the time of writing BP1. The TO price controls have subsequently been finalised, and the workload for LOTI projects is at least double that required for SWW projects due to the change in threshold. Each LOTI project requires cost benefit analysis for both the initial and final needs cases. In FY22, we have completed five assessments for TOs. We are currently working on two more and expect at least a further seven in FY23. The NOA 2021/22 identified a further 14 projects requiring LOTIs (meaning 28 CBAs) in the coming years. We also expect further TO schemes requiring LOTIs, with the analyses undertaken by us.

#### What do we need to deliver this sub-activity?

The medium sized investment project (MSIP) reopener in the TO price control framework can require the ESO to undertake analyses, but our prior experience is that so far, no additional analysis has been required on standalone load-related (thermal constraints) investments. We assume this stays the same in the BP2 period, however this could change.

Once implemented, this sub-activity will benefit from improvements resulting from IT investments for **390** NOA enhancements.

### 5.3.2 Financials and Headcount

Financials and Headcount data for **A7** is contained within the combined table for **A7-A11** (paragraph 5.7.5).

## 5.4 A8 Enable all solution types to compete to meet transmission needs

### 5.4.1 A8.3 Support Ofgem to establish regulatory and funding frameworks

This sub-activity's deliverables will be completed within BP1, and do not extend into BP2.

### 5.4.2 Financials and Headcount

The table below covers **A8.4** only. Financials and Headcount data for activities **A8.1-A8.3** are contained within the combined table for **A7-A11** (paragraph 5.7.5).

| | | BP1 | | BP2 | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A8.4 - Early Competition | | Actuals | Forecast | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | 2 | 3 | 2 | 1 | 1 | **9** |
| | BP1 | - | - | - | - | - | **-** |
| | **Variance** | **2** | **3** | **2** | **1** | **1** | **9** |
| **Totex (£m)** | **BP2** | **2** | **3** | **2** | **1** | **1** | **9** |
| | **BP1** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Variance** | **2** | **3** | **2** | **1** | **1** | **9** |
| FTE | BP2 | 4 | 18 | 11 | 3 | 3 | |
| | BP1 | - | - | - | - | - | |
| | **Variance** | **4** | **18** | **11** | **3** | **3** | |

Table 17: RIIO-2 costs and FTE for A8.4

[8] https://www.ofgem.gov.uk/sites/default/files/docs/2021/03/large_onshore_transmission_investements_loti_re-opener_guidance_-_clean_0.pdf
[9] https://www.nationalgrideso.com/future-energy/projects/offshore-coordination-project

Financials and headcount data for this sub-activity **A8.4** is included separately as it is a new activity and part of the broader network planning ambitions. Resource peaks during the planning and implementation stage (second year of BP1, 18 FTEs) are forecast to reduce to three FTEs during BP2 to manage the Network Planning Body and Contract Counterparty roles.

This will include developing the detailed tender processes, supporting legislative and framework changes, and engaging the market and other stakeholders. This will continue until Q3 2023/24. Consultancy support will cover major infrastructure procurement skills gaps in our business.

Specific resource requirements for running Early Competition are subject to revision as the detail and split of responsibilities becomes clearer. However, currently we expect that between Q3 2023/24 and Q3 2024/25, we will require three FTEs to perform the Network Planning and Contract counterparty roles.

## 5.5 A9 Extend NOA Approach to end-of-life asset replacement decisions and connections wider works

As detailed in the Final BP2 Plan, the deliverables and ambitions for this activity have been moved under **A22.1 – Network Planning Review (NPR)**. FTEs associated with specific A9 deliverables have remained within **A7-A11** however their activities now sit under **A22**.

## 5.6 A10 Support decision making for investment at distribution level

This sub-activity's deliverables will be completed within BP1, and do not extend into BP2.

## 5.7 A11 Enhance analytical capabilities

Our modelling capabilities underpin what we intend to deliver in Role 3, enabling us to unlock significant benefits and maintain a secure and operable network. We need to be able to manage the rising number of scenarios and increased modelling complexity driven by the growing interaction between different network needs, such as voltage and stability. The better we understand likely needs, the better we can identify where and when to efficiently invest.

Our current analytical tools focus on thermal needs and some voltage issues and need to be expanded to cover all energy-related network issues. The innovative techniques being explored will need to be implemented during the remaining RIIO-2 period and we expect further consumer benefits as we build on these techniques. For example, greater integration between the different modelling tools will allow us to better understand the interactions between different network needs and optimise our economic decision-making.

### 5.7.1 A11.1 Refresh and integrate economic assessment tools to support future network modelling needs

**What is this sub-activity and why is it important?**

We have been using an economic assessment tool, BID3, since 2016 and committed to reviewing its use against other options in the market and the expansion of requirements that we now have. We have successfully completed the tender exercise and are implementing the winning solution (PLEXOS) with a go-live of March 2023.

**What will we deliver in BP2?**

We will look to fully integrate new tools with existing network assessment tools and further integrate with Data and Analytics Platform (investment **220**) through BP2.

**What do we need to deliver this sub-activity?**

Network Development is working with internal user groups: Energy Insights (the FES team) and EMR Modelling. The Data and Analytics Platform (DAP) project is a key dependency as it will need to integrate with our tool.

This sub-activity is aligned to IT investment line **390** NOA Enhancements and **220** Data and Analytics Platform.

### 5.7.2 A11.2 Implement probabilistic modelling

**What is this sub-activity and why is it important?**

A model which is capable of year-round thermal analysis and other system conditions is needed. This has progressed through BP1 and has aided planning to consider how often and under what conditions circuit overloads are expected. This is especially important for assessing low probability events or those events that will not occur under winter-peak conditions as currently studied.

**What will we deliver in BP2?**

There are no material changes to the ambitions of this sub-activity for BP2, but we will need to evolve how we store and access network data alongside providing high-quality versions for use within POUYA (power system simulation software) and/or other tools. We will work more closely with the TOs to share network data, for example new schemes studied for the NOA. More effective sharing between the ESO and the TOs would elevate the value.

**What do we need to deliver this sub-activity?**

This sub-activity is aligned to IT investment line **390** NOA Enhancements and **220** Data and Analytics Platform. Proof of concept of the in-house POUYA tool requires integration into existing NOA processes followed by integration with Data and Analytics Platform **(A1.4)**.

### 5.7.3 A11.3 Build voltage assessment techniques into an optimisation tool

**What is this sub-activity and why is it important?**

In collaboration with the University of Strathclyde, we committed to undertaking an innovation project to establish modelling techniques for enhanced voltage-optimisation. If successful, we will produce a full proof-of-concept and integrate with our other year-round modelling tools to have a production tool ready by the end of 2023/24.

Scaling up of the NIA project for proof-of-concept of enhanced voltage-assessment is required followed by testing on full GB models as part of the wider ETYS processes.

**What will we deliver in BP2?**

There are no material changes to the ambitions of this sub-activity for BP2.

**What do we need to deliver this sub-activity?**

This sub-activity is aligned to IT investment line **390** NOA Enhancements and **220** Data and Analytics Platform.

### 5.7.4 A11.4 Build stability assessment techniques into an optimisation tool

**What is this sub-activity and why is it important?**

We committed to completing an NIA project with energy consultants TNEI to investigate the potential to use screening techniques to label unstable network conditions for further analysis. This project would then be used to identify the need for more complete (e.g. year-round) stability assessments before building further tools.

In Spring 2022, the NIA project to build a machine learning (ML) tool for labelling stable and unstable conditions concluded. This innovation project has demonstrated the capability for such a tool to be built but has highlighted the following difficulties in implementing it with our current models, data and systems:

- Challenges in establishing solutions for the ETYS network model with year-round conditions
- Challenges with data quality relating to dynamic characteristics of generators

This has prevented the project from completing its aims of training a tool to run on the full GB system and investigation of how to implement such a tool into our current processes. We will be working to evolve our plans on this stability workstream in the coming months, which will set our detailed ambitions as part of BP2. To use cutting edge techniques, our data needs to be available and fully functioning.

**What will we deliver in BP2?**

We will continue to review how to enhance our stability modelling for long-term planning. This project needs more research and development, including enhancing our modelling data for our software (PowerFactory) and network solution assessment. We've been unable to implement the NIA project's conceptual model, due in part to our models being developed for winter peak studies on SQSS backgrounds meaning we lack some of the required data. As a result of this outcome, in BP2 our team will need to focus on the the next iteration of this workstream and bring any new techniques into working tools that can be implemented in business processes.

We will also need to develop our data to allow for more scenarios to be studied within PowerFactory to be able to baseline any innovative tools. This will include data pipelines being developed, providing our tools with the necessary detailed network information which currently is only provided for winter peak ETYS models.

**What do we need to deliver this sub-activity?**

The main dependency is the enhanced Power Factory models. This sub-activity is aligned to IT investment line **390** NOA Enhancements and **220** Data and Analytics Platform.

### 5.7.5 Financials and Headcount

| | | BP1 | | BP2 | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| **A7 - A11 (Minus A8.4) - Network Development** | | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** | **TOTAL** |
| Capex (£m) | BP2 | (0) | 2 | 3 | 2 | 1 | **8** |
| | BP1 | 3 | 3 | 3 | 2 | 1 | **12** |
| | **Variance** | **(3)** | **(1)** | **0** | **0** | **0** | **(4)** |
| Opex (£m) | BP2 | 3 | 3 | 4 | 4 | 4 | **19** |
| | BP1 | 3 | 4 | 4 | 4 | 4 | **18** |
| | **Variance** | **(0)** | **(0)** | **0** | **0** | **0** | **0** |
| **Totex (£m)** | **BP2** | **3** | **5** | **7** | **6** | **5** | **26** |
| | **BP1** | **6** | **7** | **7** | **5** | **5** | **30** |
| | **Variance** | **(3)** | **(2)** | **0** | **0** | **0** | **(4)** |
| FTE | BP2 | 36 | 39 | 40 | 40 | 40 | |
| | BP1 | 33 | 37 | 37 | 36 | 34 | |
| | **Variance** | **3** | **3** | **3** | **4** | **6** | |

Table 18: RIIO-2 costs and FTE for A7-11 (excluding A8.4). Numbers may not add exactly due to rounding.

This table contains the financial and resource data for all network development activities across activities **A7-A11**, except for **A8.4** (Early Competition) which can be found earlier in this section. This table covers multiple activities as they all represent our on-going activities and to keep consistency with BP1.

Our resourcing remains largely as outlined in our five-year plan, with minor uplift of four FTEs by FY25. They will support the following activities:

- Two FTEs to support expansion of ETYS scope (A7.1)
- Two FTEs to undertake the expanded role covering system operability impacts of combinations of further interconnection (A7.2)
- A9 activities have moved to A22 but FTEs remain within this finance table.

## 5.8 A12 SQSS Review

The National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) sets the standards that TOs must apply to develop and maintain their transmission system, and that we must apply to operate that system. The electricity industry has changed significantly since the NETS SQSS was first introduced. As we move towards a net zero energy system, the relevant codes and standards must adapt to this significant change which results in increased levels of complexity.

### 5.8.1 A12.1-A12.3

Due to the structure of the sub-activities in **A12**, this is a combined narrative for **A12.1** – Scope project, building on the BEIS recommendations; **A12.2** – Identify solutions; **A12.3** – Implement changes to the NETS SQSS.

**What are these sub-activities and why are they important?**

We have been engaging with industry on a wide range of issues within the NETS SQSS. These include the review of the offshore transmission section, aligning NETS SQSS chapter 3 with distribution network planning standard P2/7 and assessment of the linkage between NOA and NETS SQSS Chapter 4. Stakeholders have validated that our proposed topics are in line with the interests of the industry and the delivery of the changes will shape the NETS SQSS to reflect the current energy landscape.

**What will we deliver in BP2?**

We will engage with industry and implement required changes where our plans are currently on track. Based on the scoping work undertaken within **A12.1 Scope project, building on the BEIS recommendations (completed)**, greater levels of complexity have been identified than originally expected, particularly in areas like treatment of storage, NOA and Chapter 4 of the NETS SQSS review (design of the main interconnected transmission system).

**What do we need to deliver these sub-activities?**

To facilitate the implementation of the required changes, the resource profile will grow in BP2 to manage the added complexity of the findings. Additionally, after we conclude the industry consultation in 2022/23, stakeholder feedback may identify the need for further development and research to ensure any change needs identified in NETS SQSS are fully verified.

### 5.8.2 Financials and Headcount

| | | BP1 | | BP2 | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A12 - SQSS Review | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | 0 | 0 | 0 | 0 | 0 | **2** |
| | BP1 | 0 | 0 | 0 | 0 | 0 | **1** |
| | **Variance** | **0** | **(0)** | **0** | **0** | **0** | **1** |
| **Totex (£m)** | **BP2** | **0** | **0** | **0** | **0** | **0** | **2** |
| | **BP1** | **0** | **0** | **0** | **0** | **0** | **1** |
| | **Variance** | **0** | **(0)** | **0** | **0** | **0** | **1** |
| FTE | BP2 | 2 | 3 | 4 | 4 | 4 | |
| | BP1 | 2 | 3 | 3 | 2 | 1 | |
| | **Variance** | **0** | **0** | **1** | **2** | **3** | |

Table 19: RIIO-2 costs and FTE for A12

The forecast for opex for **A12** remains broadly in line with BP1. There is a small increase of 2 FTEs (FY25) during BP2. This resource will lead the SQSS change, engage industry and use industry working group to develop the specific proposal for those changes, then go through a SQSS change governance process.

## 5.9 A13 Leading the debate

### 5.9.1 A13.1 Carry out analysis and scenario modelling on future energy demand and supply

**What is this sub-activity and why is it important?**

We are committed to publishing the FES, Winter Outlook, Winter Review and Consultation, Summer Outlook and other reports detailing our future demand analyses and scenario modelling. This process includes engaging closely with stakeholders to understand key focus areas and needs, such as the implications of emerging technologies.

Following the introduction of net zero policies, we have expanded our scenarios over the BP1 period to include other non-energy sectors. We have improved visibility of assumptions and accessibility of our data by using the Data Portal.

We have introduced further European scenario modelling to help us understand the impact on interconnector flows, such as key times we rely on imported energy, and when we might need to curtail other generation.

We have also improved data sharing and coordination across the scenarios between the different network companies. This helps us to target our analysis in the areas with the greatest impact.

#### What will we deliver in BP2?

There are no material changes to the ambitions of this sub-activity for BP2.

#### What do we need to deliver this sub-activity?

This sub-activity is aligned to IT investment line **220 Data and Analytics Platform**. The detail behind this investment can be found in **Annex 4 – Digital, Data and Technology**. The Data and Analytics Platform (DAP) **(D1.4.1)** will provide a pathway to use additional cloud computing resources for advanced analytics and the application of ML, external data sharing, and opportunities for enhanced data visualisation (such as heat maps) and exploration tools. However, we are developing our data analysis resources in parallel to its development, so our ambitions are not wholly dependent on its delivery. Should it not be delivered as planned we would look at alternative ways of providing enhanced data storage and processing capabilities on a per-project basis. Gaining access to the additional data to facilitate our analysis may also require additional licencing costs, where we may use other people's models or purchase their data or for new models to enhance our scenario analysis.

### 5.9.2 A13.3 Maintain external communication channels with consumers and stakeholders

#### What is this sub-activity and why is it important?

Each year our FES team reviews changes to Government policy and engages with stakeholders to ensure FES reflects the latest developments in the energy sector. Stakeholder engagement has increased significantly - from 2012 when over 150 stakeholders were consulted, to 2021 where we received feedback from over 1200 different stakeholders. We have continued to engage with our external stakeholders over BP1 virtually. We also made it easier for stakeholders to read and absorb the content on our website.

As a result of these improvements, we have seen a significant increase in the number of stakeholder visits. We will continue this for 2022, improving the navigation, data visualisation and accessibility – for example, with configurable data tables. We have also added FES data to our portal, which is a dedicated platform for customers and stakeholders to access information.

#### What will we deliver in BP2?

There are no material changes to the ambitions of this sub-activity for BP2.

#### What do we need to deliver this sub-activity?

Improvements to the website will allow more FES insights to be delivered directly to stakeholders. Annual delivery of FES and related publications will include a much-enhanced regional focus which will feed into downstream publications such as the distributed future energy scenarios (DFES). Successful delivery will be dependent on IT investment **250** – Digital Enhancement Platform. No additional FTE will be required but maintaining the high levels of stakeholder feedback will inherently lead to success.

### 5.9.3 Financials and Headcount

| | | BP1 | | BP2 | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A13 - Leading the debate | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | 3 | 4 | 4 | 4 | 4 | **19** |
| | BP1 | 4 | 4 | 4 | 4 | 4 | **19** |
| | **Variance** | **(0)** | **0** | **(0)** | **0** | **0** | **0** |
| **Totex (£m)** | **BP2** | **3** | **4** | **4** | **4** | **4** | **19** |
| | **BP1** | **4** | **4** | **4** | **4** | **4** | **19** |
| | **Variance** | **(0)** | **0** | **(0)** | **0** | **0** | **0** |
| FTE | BP2 | 37 | 46 | 43 | 44 | 41 | |
| | BP1 | 31 | 33 | 34 | 35 | 32 | |
| | **Variance** | **5** | **13** | **9** | **9** | **9** | |

Table 20: RIIO-2 cost and FTE for A13. Numbers may not add exactly due to rounding.

The forecast for opex remains on track for BP2. The FTEs needed to support **A13** activities has changed over the BP1 period and is forecast to change further for BP2. The main drivers for these changes are:

- During the two years of BP1, the split from undertaking joint SO activities with National Grid Gas Transmission resulted in the requirement for four additional FTEs to support gas specific activities.
- Nine FTEs in response to increased support for strategic projects, increased volume and complexity and modelling.

This gives a total of 13 FTEs for the end of BP1. However, the start of BP2 shows a reduction of four FTEs (13 FTEs to nine FTEs) from BP1, which is due to recognition that with a growth of headcount across the whole ESO there will be opportunities to flex resource as required.

## 5.10 A14 Take a whole electricity system approach to connections

### 5.10.1 A14.2 Ensure Grid Code compliance of new connections

#### What is this sub-activity and why is it important?

We must understand the compliance requirement of new technologies in order to provide sufficient support to our customers and ensure Grid Code compliance. The solution to new challenges being presented by new configurations and new technologies must be designed into the processes. We must work more closely with stakeholders such as developers and manufacturers to understand the engineering challenges of new technologies, we should be making this knowledge public, engaging with industry and standardising/improving training and development. This will reduce or remove instances of non-compliance seen after connection.

#### What will we deliver in BP2?

For the remainder of the RIIO-2 period, we will continue to assess the compliance of connection offers, which have increased in volume and complexity.

We will carry on with the deliverable **D14.2.1 Compliance monitoring of new connections in accordance with Grid Code provisions**, which is a continuous activity started in BP1. However, due to the increases in volume of connections projects and complexity of new connections, we will need additional resource beyond the numbers set out in our original RIIO-2 plans for 2023/24.

#### What do we need to deliver this sub-activity?

There are Grid Code modifications in progress which have the potential to impact whet we need to deliver this activity.

- GC0141 proposes a periodic review of the compliance process for existing users and if approved would increase the frequency and complexity of compliance assessments.
- GC0117 is a proposal to re-define the threshold for which generators are considered large or small

To deliver this activity we need to know the outcome of these code changes.

### 5.10.2 A14.5 Connections Reform

As outlined in the main BP2 Plan in section 8.9.5.4 a key milestone of our new deliverable Connections Reform Phase 1 **(D14.5.1)** will require us to deliver the following by Q2 of 2023/24:

- A Transmission Entry Capacity amnesty event
- A Queue Management Process
- Reviews of Construction Planning Assumptions and how we model storage connections

Further detail on the requirements needed to meet this phase in full is covered in this section.

**Introduction of Queue Management and running Transmission Entry Capacity Amnesty Event**

We will lead a TEC Amnesty event by working with Ofgem and TOs. This amnesty will allow customers with contracted connections projects that are no longer viable to terminate the contract and release locked transmission capacity that can be allocated to other parties in the queue. This is in response to our customers' needs and the UK Government's drive for net zero and will be accompanied by the completion of the effective queue management process. The majority of this work will have been completed in BP1.

**What do we need to deliver these aims?**

To successfully deliver the TEC Amnesty event in Q2 of 2023/2024 we need continued support from Ofgem and the TOs on the terms of the amnesty and a positive response from customers who want to terminate or change their contracted TEC for a connection.

To successfully complete the introduction of Queue Management to Transmission Contracts in Q2 of 2023/2024 we will need CUSC modifications to be approved by the working group and will then need Ofgem's determination on the proposed code modifications.To make sure code modifications are sympathetic to the views of customers and stakeholders we will seek feedback via continued and regular engagement. We will need to make changes to the STC after working closely with the TOs to develop processes that enable better engagement and implementation of Queue Management.

**Review of the Construction Planning Assumptions**

We are focused on the ambition to enable earlier connections without compromising SQSS standards, so we have identified the need to review the Construction Planning Assumptions (CPAs). CPAs are used by TOs to study new generation connections to the National Electricity Transmission Systems (NETS). The requirement for a review is driven by a change in the generation and demand mix, a new and diverse range of technologies emerging and an increase in contracted generation and volume of applications. It is also driven by a need to ensure that Network Options Assessment, the Offshore Transmission Network Review[10] and the Electricity Transmission Network Planning Review[11] principles are adhered to.

Through the Construction Planning Assumptions work, we are aiming to enable a review of connection offers to clarify how much capacity can be unlocked, connection of some customers in the TEC queue who are dependent on wider reinforcements and periodic, regular review of key inputs to the CPA which are supported by terms of reference and documentation. The CPA guidelines will be agreed with the TOs, shared with the DNOs and we intend to host workshops and webinars with customers and stakeholders.

**Review of Modelling of Storage**

A workgroup will be established with TOs to carry out a review of the principles used for modelling of storage to ensure new technologies can play an important role as an enabler of renewable energy generation. We are seeing growth of storage projects triggering significant reinforcements because it is assumed they will be importing/exporting at the worst times for the system, exacerbating system constraints. Reviewing how storage is modelled should lead to more effective assessment of potential impacts and enable energy storage systems to achieve earlier connection dates.

[10] https://www.gov.uk/government/groups/offshore-transmission-network-review
[11] https://www.ofgem.gov.uk/publications/consultation-initial-findings-our-electricity-transmission-network-planning-review

**What do we need to deliver these aims?**

**CPA** - The ESO Connections Team as lead of the workstream will be dependent primarily on internal resource to develop a set of CPA assumptions to be presented to the TO. Feedback on these proposals will then be required and working closely with the TOs will be fundamental to success.

**Modelling of storage** - We will also need support from TOs as part of the review and decision process to adopt new approaches to CPA and storage modelling. The TOs are key to ensuring that these approaches are applied to new connections studies, They are also a key enabler for connection dates to be brought forward and contribute to a reduction in transmission constraints.

### 5.10.3 Financials and Headcount

| | | BP1 | BP2 | | BP3 | |
|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | |
| A14 - Whole system approach to connections | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | 1 | 1 | 1 | 1 | 1 | 6 |
| | BP1 | 1 | 1 | 0 | 0 | 0 | 2 |
| | **Variance** | **0** | **1** | **1** | **1** | **1** | **5** |
| Opex (£m) | BP2 | 3 | 3 | 6 | 6 | 5 | 22 |
| | BP1 | 4 | 4 | 4 | 4 | 4 | 21 |
| | **Variance** | **(2)** | **(1)** | **1** | **2** | **1** | **1** |
| **Totex (£m)** | **BP2** | **3** | **4** | **7** | **7** | **6** | **29** |
| | **BP1** | **5** | **5** | **4** | **4** | **4** | **23** |
| | **Variance** | **(2)** | **(1)** | **3** | **3** | **2** | **6** |
| FTE | BP2 | 49 | 56 | 102 | 107 | 107 | |
| | BP1 | 48 | 48 | 49 | 51 | 51 | |
| | **Variance** | **1** | **8** | **53** | **56** | **56** | |

Table 21: RIIO-2 cost and FTE for A14. Numbers may not add exactly due to rounding.

The forecast for capex is largely unchanged (£2m increase), and opex has increased by £3m. The FTEs needed to support **A14** activities in BP2 has increased by 56 (FY25) since our first Business Plan submission. The main drivers of the increase are:

- Nine FTEs (FY25) to support enhancements to the customer connections experience, managing the increasing volume of connection offers and the resulting contracts for the connection agreements.
- Nine FTEs (FY25) for compliance monitoring and assessment of compliance connection offers, which have grown in volume and complexity due in part to new technologies.
- Four additional FTEs (FY25) to contribute to Pathfinder projects, to support connection and network planning reviews, for the creation of a new internal connections process and for driving necessary code change.
- Five FTEs (FY25) will form the new Policy and Change Management Team.
- Additional 29 FTEs due to the higher level of customer connections we are processing. Some of these costs are recharged to applicants.
- There is a slight opex decrease in BP1 relating to a rise in recharges to connection applicants., The rise in volume of new applications has driven a parallel rise in team cost recharges to applicants, for which we not apply to cost pass-through mechanism.

## 5.11 A15 Taking a whole energy system approach to promote zero carbon operability

### 5.11.1 A15.1 Develop the system operability framework (SOF) and provide solutions up to real time of network-related operability issues

**What is this sub-activity and why is it important?**

We regularly publish the system operability framework (SOF) which identifies system operability requirements to accommodate the changing energy landscape. In BP1, the SOF commitment is to identify and quantify operability needs in both long and short-term planning timescales, encouraging market-based solutions wherever possible. This will be presented within SOF documentation (**D15.1.1**) and may include the use of external innovation funding, such as the NIA (**D15.1.2**).

Through extensive industry interaction, we have identified several key SOF topic areas in power quality, short circuit level management strategy and new technology impacts on operability. We have published the operability strategy report, national trends and insights and short circuit level data to outline the operability challenges and how we will work with industry to address those challenges.

**What will we deliver in BP2?**

The operability needs for a zero carbon system are expected to be significantly different to those of today. The ongoing shift from fossil fuels to renewable generation sources will present new challenges in operating the grid safely and securely, such as how to measure system strength, and how the standard could be defined and implemented. We will continue working in line with our RIIO-2 five-year plan to ensure the new operability needs are identified and addressed.

**What do we need to deliver this sub-activity?**

We will need to maintain high levels of industry stakeholder engagement to offer further improvements in the way in we identify topics for inclusion in the SOF. We will ultimately need positive feedback on the clarity of the content and to know that the industry is reassured that we are addressing operability strategy concerns in the short and long term. We must identify and initiate new innovation projects to address emerging challenges. There are no IT project dependencies and there are no additional FTE requirements.

### 5.11.2 A15.2 Provide technical support to the connections process

**What is this sub-activity and why is it important?**

We provide vital technical input into the connection process. This includes setting appropriate planning assumptions, identifying future operability requirements for each connection, and ensuring designs from TOs meet future operational needs. We will provide updates to customer offers and agreements, offering technical support and assessing connection offers to determine future operability needs.

Failure to deliver consistently and effectively could risk the safe and secure operation of the network and could delay new connections from coming online.

**What will we deliver in BP2?**

Providing additional technical policy support and ensuring the correct technical requirements are captured in users' connection agreements is key. The ever-evolving nature of connecting technologies means we must ensure flexibility and remain agile.

**What do we need to deliver this sub-activity?**

We have experienced a significant increase in the number of connection applications in recent years (49% in FY22 alone) and are expecting continuous growth throughout the BP2 period and beyond.

With connection applications becoming increasingly varied in terms of technology and complexity - such as zero megawatt connections which provide only reactive power, grid forming technologies and innovative offshore connections with integrated solutions there could be the need to access further resource during the BP2 period. Consequently, to be able to continue to support the connection application process and the commissioning of new connections, our team has grown by one FTE in BP1 and may grow further in BP2.

### 5.11.3 A15.3 Assess the technical implications of framework developments and implement changes into business procedures and systems

#### What is this sub-activity and why is it important?

We provide technical input into codes and standards development which includes assessing the technical implications of framework developments, providing technical expertise and implementing changes into business procedures and systems to ensure the new technical requirements are compliant. (**D15.3.1**).

#### What will we deliver in BP2?

The current commitments will continue through BP2, carrying out regular operability needs assessments to ensure we can safely achieve zero carbon operation. This includes the continuous support to ongoing Grid Code modifications GC0141 and GC0155 in the key operability areas of fault ride through, and stability control interaction studies. We will also lead the development of industry best practice on grid forming technology.

#### What do we need to deliver this sub-activity?

The loss of mains protection setting programme will be complete in BP1 (**D15.3.2**). To deliver **D15.3.1** however we will be required to implement efficient new processes to allow us to offer technical expertise to the industry on changes to technical codes and standards. We are not reliant on any IT investments to deliver on this activity, nor do we require additional FTE. We will use already allocated headcount in a flexible way accommodate the variable workload.

### 5.11.4 A15.5 Regional development programmes (RDPs) (Materially changed)

**Supporting information** - Over the course of BP1, we have made significant progress in the delivery of RDP projects with our partners, key achievements include:

- Under our MW dispatch project (covering RDPs 1 & 2) we have co-created a new transmission constraint management service and gathered feedback from DER via webinars and associated updates. We have held workshops with partner DNOs to capture and refine project requirements throughout the delivery process.
- The delivery of the agreed MW dispatch minimum viable product (MVP) functionality is progressing through development with our internal IT teams, and we have now captured a list of potential enhancements, prioritised for delivery through further engagement events with DER.
- We have also shifted our overall project delivery philosophy towards an agile approach, defining a roadmap for the implementation of a MVP, followed by customer-focused enhancements with WPD and are agreeing a similar MVP scope with UKPN.
- In addition, we have produced a detailed technical specification for the GEMS project, which has been taken forward into the SPT procurement activity.
- We have shared project updates and learnings with all GB DNOs through the new Whole Electricity System Joint Forum monthly meeting to ensure consistent approaches across GB.
- We have formed an RDP Strategy team for new non-network solutions for system needs at the transmission – distribution interface working with DNOs on five potential new regional projects.

During the remainder of the BP1 period, the RDP Strategy team will also be developing a roadmap for a broader roll-out of RDP functionality and learnings. Part of this work will then be progressed through new activities on DER visibility and primacy rules in BP2, as outlined in **A15.8**. We anticipate this will highlight the need for a proactive process in BP2 that will allow us to identify future local needs for non-network solutions. This will then allow the RDP development programme to transition to a full BAU process.

### 5.11.5 Financials and Headcount

| | | BP1 | | BP2 | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| A15 - Whole electricity system approach to promote zero-carbon operability | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | 2 | 7 | 14 | 12 | 8 | 42 |
| | BP1 | 8 | 9 | 11 | 11 | 13 | 52 |
| | **Variance** | **(6)** | **(2)** | **3** | **1** | **(5)** | **(10)** |
| Opex (£m) | BP2 | 5 | 7 | 10 | 11 | 12 | 43 |
| | BP1 | 5 | 6 | 8 | 10 | 11 | 40 |
| | **Variance** | **(1)** | **0** | **2** | **1** | **1** | **3** |
| **Totex (£m)** | **BP2** | **7** | **13** | **23** | **23** | **20** | **85** |
| | **BP1** | **13** | **15** | **19** | **21** | **24** | **93** |
| | **Variance** | **(7)** | **(2)** | **4** | **2** | **(4)** | **(7)** |
| FTE | BP2 | 48 | 66 | 93 | 95 | 93 | |
| | BP1 | 48 | 52 | 56 | 62 | 67 | |
| | **Variance** | **1** | **14** | **37** | **33** | **26** | |

Table 22: RIIO-2 cost and FTE for A15. Numbers may not add exactly due to rounding.

The forecast for the opex, capex and FTEs needed to **A15** activities in BP2 has increased since our first Business Plan submission. The main drivers of the support increase are:

- Capex increases by around £4m by FY25 (over BP2 period) due to our IT investment **500** Enhanced frequency control.
- Opex increases by £3m over the BP2 period and this is driven by:
  - One FTE (FY25) to support the growth in complexity of new connection types and continue to support the connection application process and the commissioning of new connections (**A15.2**).
  - Two FTEs (FY25) will be required as we improve the quality of system data and models used to analyse future network needs and operability solutions by moving to an automated approach of data and model maintenance **(A15.4)**.
  - Four FTEs (FY25) will be needed, as the number of RDPs in delivery increases, to drive changes to RDP BAU processes and systems, and collaborative work with partner DNOs (**A15.5**).
  - Six FTEs (FY25) will be added in **A15.6** to develop and maintain EMT models and to carry out EMT and power quality analysis.
  - The enhancements to the ambitions within **A15.8**, as detailed in the **Spotlight: Accelerating Whole Electricity Flexibility** section, will require 6 FTEs (FY25) for delivery throughout the BP2 period.
  - Four additional FTEs (FY25) will be needed to deliver our new zero carbon operation team, which will focus on engaging with stakeholders on implementation of technologies for effective zero carbon operation **(A15.9)**.

## 5.12 A16 Delivering consumer benefits from improved network access planning

### 5.12.1 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

**What is this sub-activity and why is it important?**

Our first RIIO-2 Business Plan set out to build on our automation techniques to optimise access planning solutions, taking full advantage of the greater availability of data and modelling. A sandbox environment for automation was tested and this will be used throughout BP2 as we enhance automation capability.

This constraint forecasting capability developed by our new Constraint Forecasting and Optimisation team will be maintained and used to capture the value being created within the Network Access Planning (NAP) team and to assist with the development of new long-term processes to support the NOA in a coordinated manner.

**What will we deliver in BP2?**

We will create a dedicated team to consider our long-term network access planning requirements, and create efficiencies in the existing structure, processes and systems to support it. This will enable greater focus on the operational needs of the future transmission system as well as assessing the impacts on the approach to net zero. This will ensure that future risks are identified and mitigated for much earlier in our processes, helping to strategically plan the path towards 2035 and consider the impact of an increasingly complex transmission system on our customers and stakeholders.

Through BP2 we will enhance our automation capability, develop enhanced communication tools and grow our team to address the challenges of increasing complexity and enable us to work more effectively with an emerging whole system methodology.

**What do we need to deliver this sub-activity?**

Further reform of our constraint forecasting and our outage costing methodologies will be required to deliver on this activity. Under the new activity A16.5 we will be developing tools to more expediently assess the commercial and technical impact of outages taken by Transmission Owners. This sub-activity recognises that to keep pace with improvements to offline modelling tools, we will also need to improve the processes by which we make the cost assessment in short, medium, and long-term timescales. As we expand our remit to offer an enhanced focus on longer term planning and costing, we recognise that the costing tools (such as Plexos, POUYA and BID3) that we currently use must keep pace. Agreements on this will be need to sought with the Network Access Policy group, this group consists of the three onshore TOs, ourselves and Ofgem. There is no direct dependency on IT projects to delivery initial improvements, but the full and final solutions will depend upon IT investment **350** (PODE) to link in with deeper access planning and on delivery of **A16.5** to link in with automation improvements. Outage plans developed with network owners will be optimised as will outage plans delivered to control rooms.

### 5.12.2 A16.2 (Name changed) Scope a whole electricity system decision-making policy

**What is this sub-activity and why is it important?**

This sub-activity’s ambitions are focused on unlocking consumer benefits by transforming our approach to system access. The cost recovery mechanisms (STCP 11-3 and STCP 11-4) have already been expanded in BP1 from Scottish TOs to include the TOs in England and Wales. This has allowed the Network Access Policy to guide a robust decision-making process through increased system analysis and cost assessments and has allowed us to make the right trade-offs between spending to progress, defer or cancel outages.

The decision-making process is currently solely bilateral between us and the respective TO. It is recognised that through BP2 and in conjunction with **A16.3**, we should be developing frameworks to allow whole system decision making which would require a broader range of information from a wider group of customers and stakeholders.

#### What will we deliver in BP2?

In conjunction with deliverables in **A16.3**, and the development of tools to coordinate deeper access planning throughout the BP2 period, we will work with our stakeholders to explore incorporating whole electricity system planning into the NAP process. Deeper access tools and visibility will enable us to make a more holistic commercial assessment of an outage request.

Change is necessary as Accelerating Whole Electricity Flexibility will lead to a need for us to factor in more information when assessing outage requests.

We need to remain flexible, as the outcomes of the push for all DNOs to create DSO functions is still in progress. As DNO and DER services become better understood (further to the work in **A16.3**) and joint operating procedures are put into place, whole system decisions around network access planning will become easier. The formal scoping work, which will form most of the early stages of this deliverable, will depend on the progress in the Whole Electricity System Joint Forum, between ourselves and the DNOs, and led by groups who have ownership of the **A15** activities.

#### What do we need to deliver this sub-activity?

The development, acceptance and embedding of joint operating procedures with trial partners in WPD and UKPN may determine how fast any additional wider scoping can occur.

The speed of progress on developments to the Planning and Outage Data Exchange (PODE) platform will determine the best time to perform scoping in this sub-activity. It is expected that frameworks to facilitate whole system decision making will be agreed by Q4 of 24/25 with 23/24 being reserved for stakeholder communications and mapping.

### 5.12.3 A16.3 Work more closely with DNOs and DER to facilitate network access

#### What is this sub-activity and why is it important?

We need to work more closely with DNOs to coordinate requirements for network access and ensure we are collectively optimising flows across the network, helping to lower system operation costs. This is driven by distribution networks becoming more active as greater volumes of DER connect. DNOs are developing system operation capabilities and provision of flexibility services is increasing.

We have been working closely with DNO partners to trial data transfer processes, offline model testing and drafting of high level joint operating procedures. Results will be shared with all DNO partners.

#### What will we deliver in BP2?

Our approach will remain flexible since the DNO to DSO transition is taking place at different rates across the 14 DNO regions, and some have progressed further than others through the RDPs. Through BP2 we will be proposing and agreeing code modifications, frameworks and models to facilitate this activity.

We estimate that, upon completion in Q4 of 2024/2025, work could realise savings between £10m and £40m per annum from service coordination activities related to NAP across the transmission and distribution interface.

#### What do we need to deliver this sub-activity?

The outcomes of Grid Code modification GC0139, which will require delivery of complex systems changes for all DNOs. This sub-activity is also directly linked to how network access planning processes intersect with developments on the whole electricity system planning activities set out in **A15**, particularly **A15.5** Regional Development Programmes. The direction of NAP deliverables may be shaped further in early 2022 by whole electricity system deliverables in **A15.5** and **A15.8**.

This sub-activity is aligned to IT investment lines **350** Planning and outage data exchange, **360** offline network modelling and **220** data and analytics platform.

### 5.12.4 A16.4 Whole system outage notification

**What is this sub-activity and why is it important?**

This activity extends our advanced outage notification system (eNAMS) to cover a wider range of stakeholders and it makes it more interactive. The eNAMS system was successfully delivered in BP1 (with a slight delay) and so the BP2 work, in conjunction with **A16.3**, will enhance its scope to facilitate notifications of outages to a wider range of stakeholders and customers. All three workstreams of the PODE platform will be integral to successful delivery of **A16.4** as the PODE platform will be capturing outage coordination and service coordination requirements across transmission and distribution networks.

**What will we deliver in BP2?**

BP2 will see the completion of the scoping activities for the entire 2023/2024 period followed by delivery of the whole system notifications by Q4 of 2024/2025.

**What do we need to deliver this sub-activity?**

Progress on milestones in **A16.3** are key to the successful delivery of this sub activity as are adequate levels of industry engagement during the PODE IT developments. The progress of IT investments **350** Planning and outage data exchange, **360** offline network modelling and **220** data and analytics platform are prerequisite to delivery.

### 5.12.5 Financials and Headcount

| | | BP1 | | BP2 | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| **A16 - Delivering consumer benefits from improved network access** | | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** | **TOTAL** |
| Capex (£m) | BP2 | 2 | 1 | 1 | 1 | 1 | **7** |
| | BP1 | 0 | 0 | 1 | 1 | 1 | **5** |
| | **Variance** | **2** | **1** | **0** | **(0)** | **(0)** | **2** |
| Opex (£m) | BP2 | 5 | 6 | 6 | 6 | 6 | **29** |
| | BP1 | 5 | 5 | 5 | 5 | 5 | **25** |
| | **Variance** | **1** | **1** | **1** | **1** | **1** | **4** |
| **Totex (£m)** | **BP2** | **7** | **7** | **7** | **7** | **7** | **37** |
| | **BP1** | **5** | **5** | **6** | **7** | **7** | **30** |
| | **Variance** | **2** | **2** | **1** | **1** | **1** | **7** |
| FTE | BP2 | 64 | 72 | 77 | 77 | 77 | |
| | BP1 | 62 | 63 | 68 | 67 | 67 | |
| | **Variance** | **2** | **8** | **9** | **10** | **10** | |

Table 23: RIIO-2 cost and FTE for A16. Numbers may not add exactly due to rounding.

The forecast capex for BP2 has remained in line with our BP2 forecast. The FTEs and opex required to support **A16** has increased since BP1. The main drivers of the opex increase are the growing complexity of network planning requirements and support our new Automation deliverables. The increase of headcount to 10 FTEs in FY25 is driven by:

- Four FTEs to deliver our long-term network access planning requirements and create efficiencies in existing processes
- Two FTEs to support the development of tools to coordinate deep access planning, which will enable us to make more holistic commercial assessments of outages, throughout BP2
- Four FTEs to lead on the Network Access Planning automation deliverables in **A16.5**, which will create efficiencies in our modelling processes

## 5.13 A22 Offshore coordination and network planning review

### 5.13.1 Current best view of enduring requirements to deliver a holistic approach to planning the onshore and offshore transmission network on a strategic basis

Both the Offshore Coordination (OC) and Network Planning Review (NPR) projects are expected to have a positive impact on our Network Planning capabilities, with the potential to be significant in a number of areas. The concept of a Centralised Strategic Network Plan (CSNP) cuts across the entirety of the existing network planning process, and the enduring approach to delivering an integrated offshore network is an essential element of this, introducing new activities for us to undertake.

Due to the early stage of maturity and ongoing uncertainty of both projects, a clearer view will emerge through 2022/23 and so no milestones are being set out within the deliverables for this activity at this stage. For BP2 we are setting out our current best view of the likely impact on our network planning activities and our view of the expected new requirements in terms of FTEs, opex and IT and modelling capabilities/capex; see Financials and Headcount (5.14.3) for the summary overview. To do this, we consider likely impacts at key stages of the network development process as follows:

### 5.13.2 Model supply and demand

The ESO currently undertakes significant activity to develop the Future Energy Scenarios (*FES*). Ofgem envisages a central scenario that can support onshore and offshore strategic network planning. We will look at what would be required in addition to the current *FES*, or as an evolution to it, that satisfies this requirement. It is our intention that the OC project's holistic network design (HND), in conjunction with the outcomes of the 2022 Network Options Assessment (*NOA*), form a transitional CSNP acting as a bridge with whatever enduring CSNP processes are established in future. This is likely to mean that an enhanced scenario framework will need developing early in the BP2 period to support that enduring CSNP approach.

The exact interplay between scenarios or estimates and associated sensitivities to support CSNP, and what scenarios are required to support other key users for planning purposes, will be one of the key elements that needs to be considered. We do not anticipate a 'one size fits all' approach to be feasible, and we anticipate that the specific needs and potential for different preparation and review timescales will place additional resource requirements on our Energy Insights team.

### 5.13.3 Potential FTE impact

Our initial view is that we will require an extra two FTEs for electricity generation modelling, two FTEs for demand modelling (which will include whole system considerations) and two FTEs for modelling development - in addition to the current team. We also anticipate requiring a further two FTEs to manage the impact of the development and implementation of a strategic seabed leasing plan - this is expected to include modelling resources to support the development and to understand and manage how the output of that plan interacts with the development of the scenarios.

### 5.13.4 Potential IT/capex impact

We need to ensure our systems can model sensitivities effectively. Disparate, new (and existing) data sources will need to be managed/converted so that they are compatible with existing and new systems. There are links here to existing RIIO-2 deliverables such as the Data and Analytics Platform, which is expected to be required to support efficient running of multiple scenario sensitivities.

### 5.13.5 Identify system needs

The Electricity Ten Year Statement (ETYS) is focused on major thermal transmission boundaries, with assessment of voltage and stability requirements made using a less systematic, more manual approach. For CSNP the expectation is that we will need to consider the full range of capability and operability requirements in a systematic way out to at least 2050, and to present those requirements in a way that can best support sourcing and delivery of solutions.

We also expect that there will need to be some level feedback and iteration of scenarios, based on their impact on the network. It is anticipated that this will help with optimising and refining the scenarios.

The potential impact of this on the current ETYS process could be significant, depending on the approach taken. To consider all capability and operability needs on a fully systematic basis will be challenging without the development of new tools and models as the current approach is manually intensive. We will need to carefully consider the options and timescales over which this could be achieved and agree how best to progress.

### 5.13.6 Potential FTE impact

Enhanced provision of network insights and requirements across a broader range of operability needs will require additional modelling tools and resource uplift to conduct the assessments. We expect increased, targeted assessment of voltage and stability needs to require at least four additional FTEs, with a further two FTEs to develop our modelling approach, for example to allow greater automation and use of machine learning techniques. Scaling this approach up would require significantly more power system engineers to evaluate complex system studies to determine optimal solutions – hence we anticipate that a truly systematic approach to understanding the full range of operability challenges will require a new approach to modelling the impact of future scenarios on the network. The FTE and capex implications of this would need to be worked through in detail before a robust estimate of BP2 requirements could be provided.

### 5.13.7 Potential IT/capex impact

Adopting a more systematic approach to the identification of system needs is expected to require new ways of assessing the impact of scenarios on the network. The exact needs will be worked through in detail as the projects progress.

### 5.13.8 Identify system options

This will be an entirely new activity us, from an asset perspective. TOs currently provide options to meet system needs through the 'System Requirements Form' process – CSNP will require ESO to provide high-level strategic options, with appropriate industry collaboration, covering both the onshore and offshore transmission network.

New teams with new capabilities will be required for us to be able to undertake high-level design activities for identification and development of strategic investment options, and to engage with stakeholders for expert input. These are expected to consist of power system engineers, economists, environmental constraint experts and land & marine planning experts, and we expect to require expertise in construction and project delivery to understand delivery timescales. Engagement with TOs and other 3rd parties is expected to be required to support these activities.

There is also an opportunity here to consider how the process of connecting to the transmission system can benefit from a more strategic approach to its development. This is already being considered in an offshore context via the development of the HND, with the connections requirements and strategic investments being considered together. It is anticipated this more integrated approach to planning offshore connections will replace the current Connections and Infrastructure Options Note (CION) process. More broadly we expect that the existence of strategic investments will create certainty of transmission capacity that could then be harnessed for connections in a more coordinated way.

### 5.13.9 Potential FTE impact

To ensure appropriate coverage of new network design and connection activities we anticipate requiring at least 10 FTEs for detailed design of strategic options and a further six FTEs for high-level design activities across Great Britain. The connection FTEs would work closely with the existing connections teams to ensure a consistent and coherent customer experience.

### 5.13.10 Potential IT/capex impact

New tools will be needed to enable these new design activities. This are expected to include (but not be limited to) software to assist with onshore and offshore route planning for high-level strategic investment options, and to manage visual amenity. Existing tools will also need to be augmented or supplemented to enable these activities to be delivered. Further resources may be identified as necessary to manage whole system interactions, including electricity distribution and, in future, across other energy vectors.

### 5.13.11 Options Appraisal Process

The assessments currently undertaken as part of the *NOA* process will be impacted by the development of strategic network investment options and the need to assess them in accordance with whatever process is determined to be appropriate. Based on current expectations of what is envisaged for CSNP, this is expected to include strategic options assessed on a longer-term cycle (such as three years), and other 'non-strategic' options that might need assessing on a more regular basis (for example annually, as now).

It is also anticipated that the nature of the assessment of costs and benefits will need to go beyond a pure analytical cost-benefit assessment, to include more qualitative assessment techniques, for example to consider environmental and social aspects of proposed strategic investments, which may require different skills and expertise depending on whether options relate to the onshore or offshore network.

This suggests the options appraisal process will need to be informed by robust analytical techniques, but with additional intellectual debate, stakeholder engagement, consultation, and decision-making. At this stage it is too early to say what the exact impact on the existing *NOA* process might be, however it is reasonable to assume that it will need to transform to reflect the additional needs of CSNP. We anticipate this transformation will affect the scope of work, and also the volume of activity required to be undertaken.

### 5.13.12 Potential FTE impact

We envisage at least four FTEs to manage this increase in workload, which includes one additional FTE to increase our ability to assess the suitability of options for delivery via competitive, rather than regulatory, mechanisms. Whilst from an enduring perspective we would expect to make use of existing expert *NOA* resource to undertake significant elements of the new activities, additional specialist resource will be required for the changed options assessment and environmental and social assessments, although this may only be needed at certain key points in the process, and hence might be something that we can contract out. This will be investigated as the NPR and OC projects progress.

### 5.13.13 Potential IT/capex impact

Existing tools may need to evolve to be able to deal with the consequences of a revised options appraisal process that incorporates both strategic and non-strategic developments in a suitable way.

### 5.13.14 Finalising the CSNP

This would represent the bringing-together of all the above, to create a strategic view of the network out to 2035/2050. Our initial view is that this activity will be an amalgamation of aspects of all the above functions, as well as collaboration with the wider industry, in a similar manner to the way the *NOA* report is prepared at the moment. Whilst we would expect to make best use of existing resource for this, we anticipate one additional FTE will be required to support planning, preparation and delivery of the finalised CSNP report.

### 5.13.15 Summary

In total, our initial view is that at least a further 35 FTEs will likely be required to deliver CSNP capability. This is subject to further work through 2022, however for the purposes of this BP2 we prefer to give an indication of likely requirements, rather than waiting for further detail to become apparent post-publication.

## 5.14 Enduring Offshore Regime – Additional Supporting Information

### 5.14.1 Strategic seabed leasing plan – additional information


Figure 16: Assumed timescales for development of strategic seabed leasing plan

The figure above sets out our assumptions on the timescales for the development of the strategic seabed leasing plan. This suggests the first version of the strategic seabed leasing plan could be available to the ESO for network planning purposes between October 2023 and April 2024. This could also be used to inform future leasing rounds beyond those currently planned and in related connection and network planning processes.

Based on our views on what a strategic seabed leasing plan should be in the context of the OTNR, we think that the ESO is unlikely to be best placed to own it. However, we will be integral to the development and implementation irrespective of the accountable party or parties.

### 5.14.2 How early competition is applied to the offshore network – additional information

If any strategic network planning related to future leasing rounds does not commence until some point between October 2023 and April 2024, we can assume that the high-level network design associated with the relevant leasing round capacity would not be available until sometime between April 2024 and October 2024. If there is a plan to compete some or all of that high-level design or the underlying network need via an offshore early competition, there is a need to assess and amend how the proposals for the onshore network needs to be adapted for the offshore network. The different licensing arrangements mean that the onshore regime cannot be transferred directly to the offshore network and resources would be required for activities such as adapting frameworks, tailoring contracts and evaluation criteria specifically to offshore and also engaging specifically with offshore stakeholders.

We anticipate the responsible party would need up to 12 months to design and launch the early competition, with preparatory work needing to commence in FY25. We therefore assume that an early competition related to offshore transmission associated with future leasing rounds is unlikely to commence in the BP2 period.

### 5.14.3 Financials and Headcount

| A22 - Offshore coordination / Network planning review | | BP1 Actuals 2021/22 | BP2 Forecast 2022/23 | BP2 Forecast 2023/24 | BP2 Forecast 2024/25 | BP3 Forecast 2025/26 | TOTAL |
|---|---|---|---|---|---|---|---|
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | 2 | 3 | 3 | 3 | 3 | **15** |
| | BP1 | - | - | - | - | - | **-** |
| | **Variance** | **2** | **3** | **3** | **3** | **3** | **15** |
| **Totex (£m)** | **BP2** | **2** | **3** | **3** | **3** | **3** | **15** |
| | **BP1** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Variance** | **2** | **3** | **3** | **3** | **3** | **15** |
| FTE | BP2 | 21 | 38 | 48 | 47 | 50 | |
| | BP1 | - | - | - | - | - | |
| | **Variance** | **21** | **38** | **48** | **47** | **50** | |

Table 24: RIIO-2 cost and FTE for A22. Numbers may not add exactly due to rounding.

The NPR project is currently assumed to close at the end of FY23, with project-related activities moving into the enduring CSNP activity from FY24 onwards. We currently expect the OC project to continue with the transitional activities set out into FY24 and FY25.

CSNP FTEs are the incremental resources required to undertake a transformed strategic network planning process, from development of scenarios through to the delivery of a plan. These have been optimised across the NPR, OC and EC projects and incremental BP2 resource for both FES and BAU network development activities – again to ensure no duplication of requirements.

FTE numbers in Table 24 are based on a best view of potential business impacts, noting that further work is planned for 2022 to investigate the requirements in more detail. Decisions taken by BEIS and Ofgem during the year will also have an impact. We expect these numbers to be refined as that work progresses.

This new activity will see 47 FTEs actively engaged in FY25, of which 35 are already in the business and working on Offshore Coordination. This resource is applied to the different areas of overall network development activity as follows:

Five FTEs for Offshore Coordination, will be working on the strategic seabed leasing plan, and in support of developing multi-purpose interconnector strategy. They will also support initial work on assessing the application of the onshore Early Competition regime to offshore networks.

42 FTEs for NPR, and to deliver CSNP (Centralised Strategic Network Plan) capability, including:

- Six FTEs for electricity generation and demand modelling and model development
- Two FTEs to manage the impact of development and implementation of the strategic seabed leasing plan
- Six FTEs to contribute to identifying and modelling system operability needs
- 16 FTEs for the detailed design of strategic options and design activities
- At least four FTEs for the options appraisal process
- Five FTEs focused on stakeholder engagement, working closely with TOs and developers to contribute to the CSNP and methodology
- Three FTEs committed to project managing the implementation of CSNP to ensure timely and quality delivery

Opex is applicable entirely to resource costs.

The table above does not include resources attributable to Early Competition, as this is covered within the table under its sub-activity, **A8.4**.

# 6 Other Sections Supporting Information and Updates

## 6.1 Benefits

There have been some updates to **Annex 2 – Cost Benefit Analysis** since our Draft Plan.

- The addition of **A1 Control Centre architecture and systems** CBA
- **A5 Transform Access to the Capacity Market** has updates to the methodology of the Reduced Barriers to Entry benefits case.

Please seen **Annex 2 – Cost Benefit Analysis** for more detailed information on all of our CBAs.

## 6.2 ESO Innovation – Investing more to solve emerging new challenges in BP2

### 6.2.1 Updates from our April Draft Plan

The Innovation chapter has been re-written since our Draft Plan, reflecting engagement with Ofgem and feedback from our consultation. Key feedback included a need for clarity or further detail in focus areas such as:

- Detail on projects in progress or completed (including funding)
- Prioritisation
- Justification of increased costs compared to forecasts
- Justifying chosen funding mechanisms
- Benefits tracking
- Increased resource requested for BP2

Much of the background information and supporting data is located below.

## 6.3 Additional Supporting Information

### 6.3.1 Overview of Innovation Process

We have developed and continue to refine a robust process to make sure that funds are only used where appropriate. Our end-to-end process requires an Innovation Business Partner per Role to be responsible for each project all the way through its delivery:

- We begin by refreshing our Innovation priorities every year through extensive stakeholder engagement. All project proposals must demonstrate that they address one or more of the priorities.
- We then assess each proposal's Technology Readiness Level (TRL). We only allow higher risk activities or those with uncertain or less understood solutions to access Innovation funding.
- We ensure projects have a clear path to delivery and benefit realisation by engaging directly with the relevant executives and getting their commitment. Proposals are placed on hold until this condition is met.
- Subsequent pitches at increasing levels of proposal maturity allow us to identify further risks and ensure mitigations are put in place for them. For example:
    - Longer and more complex projects run the risk of non-delivery or of becoming obsolete. To address this risk we have developed contracts with clear milestones and exit clauses that

ensure projects can "fail fast" and be quickly shut down to allow funding to be reallocated where appropriate.

- Innovation implementation activities are at risk of being deprioritised vs BAU activities. We work with our Business Change team and our three Roles to ensure the timely availability of resource needed to implement the outcomes of innovation into BAU.
- All projects must capture their 'lessons-learned' as a minimum requirement of the funding. This informs future innovation projects and any improvements that are needed to our process.

### 6.3.2 Stakeholder Engagement

We ask stakeholders for feedback on our projects and innovation process. This is carried out via regular surveying of our suppliers, partners and other stakeholders, usually through publications such as the NIA Annual Summary or our Innovation Strategy document[12], as well as through our CSAT and SSAT surveys. Our VirtualES programme will be built around comprehensive stakeholder engagement, please see the VirtualES section below for more information.

We are constantly looking to improve how we communicate to potential applicants what type of proposals we are looking for (e.g. through our publications, events, videos, website, etc.):

- The priorities in our Innovation Strategy highlight what challenges we are looking for new projects to help solve.
- How to submit new ideas, and how we can collaborate to develop them, is explained on our dedicated website[13] and in our recently updated 'How we work' document' (Innovating with the Electricity System Operator report[14].
- Case studies of current projects are included in our Innovation Strategy and Annual NIA Innovation Summary publications each year. We also use forums, conferences and other opportunities to share our projects.

The Innovation team practices Open Innovation. This means we co-create and co-develop each project with partners. This is especially clear during our Open Innovation Events, which serve as an opportunity for third parties to work closely with our subject matter experts over two days, to better understand how our organisation works, the specifics of the challenges we face and how successful projects can be developed to solve these.

**Open Innovation Event 2022**

This year's call for ideas resulted in over 60 project proposals from 33 different organisations, of which five were selected to be taken forward during the event, where they were collaboratively developed into successful project plans. Many of the other ideas we received (>30) will still be assessed as part of our regular innovation process.

Stakeholder feedback has resulted in important revisions of our process and continues to drive change in the way we work:

- ***Project participants have expressed some concerns with access to data*.** Though this issue is not yet fully solved, we now set aside time to better understand full data requirements when assessing new proposals and engage early on how to share data with project participants and implement new data inputs once a project has completed.
- ***Project partners have expressed frustration with delays in our contractual negotiations***. To address this, we are sharing contract positions (i.e. NIA conditions around intellectual property) early to identify any issues. We have also secured specialised resource within procurement to support our high volume of contracts.
- ***Stakeholders have asked for simplified proposal submission processes***. We have since improved how we collect new proposals for assessment, using an online form (alongside existing options) for third parties to submit innovation project ideas more easily. We have also secured specialised resource within procurement to support our high volume of contracts.

[12] https://www.nationalgrideso.com/future-energy/innovation/strategy/report
[13] https://www.nationalgrideso.com/future-energy/innovation
[14] https://www.nationalgrideso.com/document/155196/download

Below are statistics for our stakeholder engagement activities and project partnerships over the first year of RIIO-2 (2021/22). These are featured in our Annual NIA Innovation Summary[15] (published in July 2022).

## NIA Collaboration 2021/22

### Openness to external ideas and recognition of benefits

We received over 100 innovation ideas in 2021/22, just over 60% of these were submitted by third parties. Of the NIA projects we registered, 50% of these were from third party proposals. 51 'Big Ideas' (initial proposals) were approved in 2021/22.

### NIA Project Partnerships

We have expanded our partnerships, 41% of NIA suppliers were Small to Medium Enterprises (SMEs).

| Academia | GB Networks | Private sector (small) | Private sector (medium) | Private sector (large) | Non-profit | Total |
|---|---|---|---|---|---|---|
| 3 | 2 | 5 | 2 | 4 | 1 | **17** |
| 18% | 12% | 29% | 12% | 24% | 6% | **100%** |

Table 25: NIA project partnerships breakdown

## All Innovation Collaboration 21/22 (incl. NIA, NIC and SIF projects)

### Partners and Third Parties

In 2021/22 we worked with 53 different partners on innovation projects across the industry. For the newly introduced Strategic Innovation Fund (SIF) - we worked with 34 partners on Discovery-phase projects, 23 of which were suppliers we hadn't worked with before.

| Type of Partner | % |
|---|---|
| **Academia** | 15 |
| **GB Networks** | 26 |
| **Private sector (small)** | 17 |
| **Private sector (medium)** | 9 |
| **Private sector (large)** | 25 |
| **Non-profit** | 8 |

Table 26: Project partnerships breakdown

### Improvements

- Suppliers can now submit a 'Big Idea' directly to the Innovation Team using a short online form to capture their idea and the benefits it could deliver.
- Our recently updated 'Innovating with the Electricity System Operator'[16] report explains our process in detail and what you can expect when innovating with us.
- We are introducing a new short survey at project closure to capture feedback from our suppliers about their experience working with us. We are hoping this will identify any barriers to more successful innovation and highlight opportunities to refine our innovation process further.

[15] https://www.nationalgrideso.com/future-energy/projects/nia-annual-summary-report
[16] https://www.nationalgrideso.com/future-energy/innovation/get-involved/innovating-electricity-system-operator-report

**Engagement / Events**

We worked with Electricity Innovation Managers and Gas Innovation Governance Group, alongside the Energy Networks Association (ENA), on a number of key projects. Highlights include the publication of our third joint Electricity Networks Innovation Strategy, published in March 2022 alongside the Gas Network Innovation Strategy.

The Energy Networks Innovation Conference (ENIC) in October 2021 featured 409 speakers, the highest number of speakers to date at this annual conference. Over 3,000 people registered for the event from 116 countries

We held our annual Open Innovation Event in July, bringing together over 60 attendees, including suppliers and experts from the ESO and wider industry, to collaboratively develop new proposals over a rapid 2 day workshop. Proposals were aimed at solving some of our priority innovation challenges. Over 60 proposals were submitted, which we shortlisted to 5 teams, who developed their projects alongside ESO experts, and then pitched to a panel of industry judges on the second day. Stakeholder feedback has been very positive, many keen to know when the next event will be held.

**Other Highlights**

- Sharing our perspectives at the Ministerial Roundtable on AI assurance services.
- Delivering presentations at the Energy Innovation Forum.
- Speaking at the highest attended Utility Week Live session on 'Smart Homes, Smart Cars and Smart Energy'.
- Launching the Virtual Energy System programme at COP26 and holding a virtual conference to share the ambition and gather initial input from stakeholders.
- Exhibiting our innovation projects and Virtual Energy System programme at the House of Commons, to showcase the Digitalisation of Energy.
- Presented Virtual Energy System at the CIGRE UK Data Analytics Event.

### 6.3.3 NIA-funded innovation in BP1

Ofgem published the RIIO-2 NIA governance document in March 2021, almost at the very start of RIIO-2. We then had to implement the changes to the governance process and contracting arrangements, which has led to a six-month delay between funding being approved and new projects commencing. This slow start to RIIO-2 can be seen in Figure 17 below. Although approval of NIA projects has been increasing rapidly since April 2021, the corresponding new project registrations (which had to wait for the formal contractual arrangements to be put in place) did not catch up until Q3 FY 21/22.

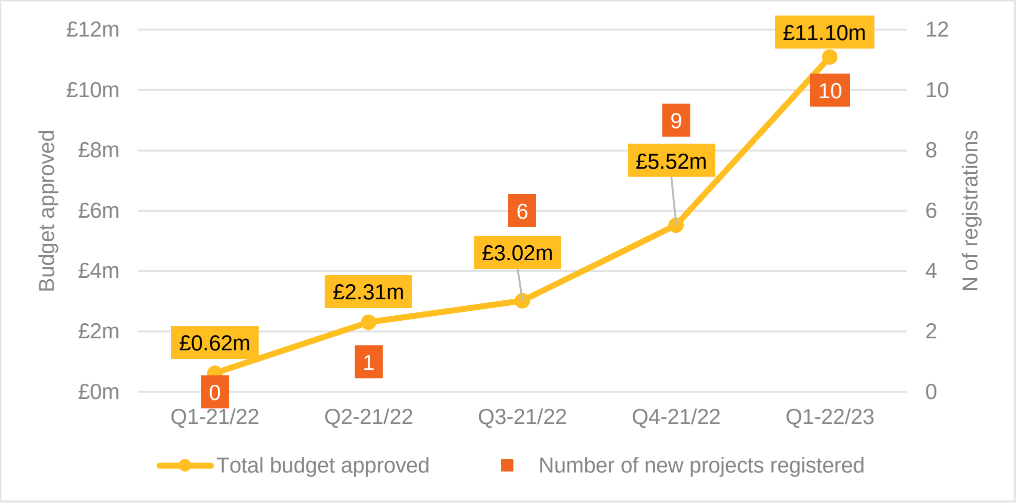


Figure 17: Budget for new projects approved since the start of RIIO-2

As shown on Figure 18 below, over the first year of BP1 (FY21/22) the ESO invested a total of £4m in RIIO-2 NIA projects. Of this, about £3.5m was spent outside the ESO (86.5% external spend), which is testimony to our successful Open Innovation and collaboration policies. Forecast NIA spend for the second year of BP1 (FY22/23) is currently estimated to be c.£8m, based on our existing pipeline (as of June 2022), however the final NIA investment will likely be higher as new project ideas continue to be received and assessed. The current forecast spend for the first two years of RIIO-2 (c.£12.6m) is already significantly higher than the annual allowance of c.£4.6m implied by the initial NIA award[17].

Projects in 'Delivery' have been officially registered and are currently in progress. Project proposals currently in 'Development' stage (i.e. the initial/early-stage idea has been approved but the project is still being designed before being pitched for funding), include estimated investment needed for these projects (e.g. the most current expected costs, duration and start date for each proposal based on quotes and experience of similar projects). The 'Forecast' amount includes very early-stage proposals which are still in the process of being assessed, prior to an initial approval decision and awaiting further feedback/development.

Cost estimates for live projects (in 'delivery') do occasionally change (part of the uncertain nature of innovation activities), either because the project has changed direction based on initial results, or because of unforeseen rising costs typical of innovation activities. Any project changes are managed through a tried and true change control process, to ensure costs remain proportional to the expected benefits from a project, and to ensure deliverables remain achievable and timely.

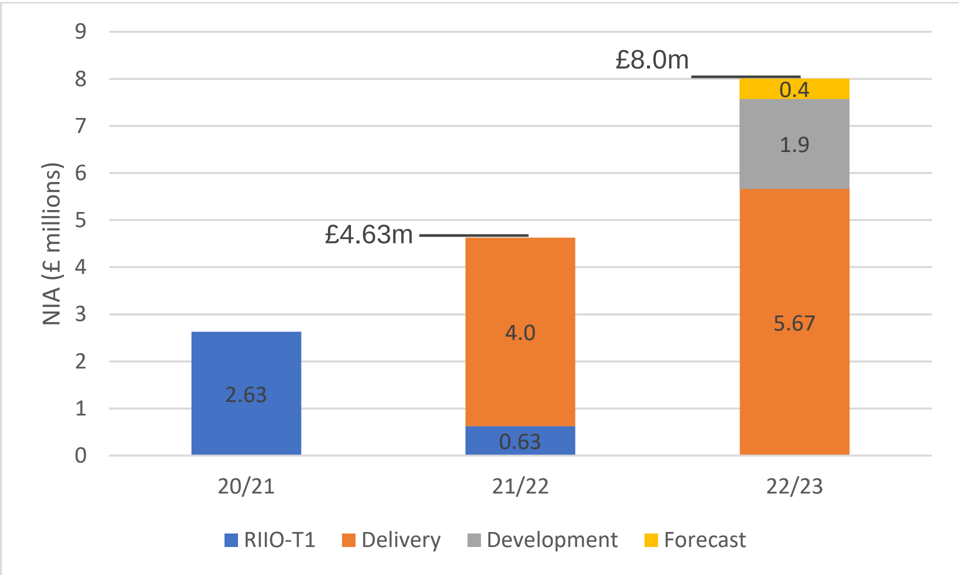


Figure 18: Actual and Forecast NIA annual budget in BP1: spend profile with the current £23m allowance for RIIO-2

Our internal controls are such that we only commit existing and approved NIA budget for RIIO-2. We won't approve new projects once all this funding has been allocated. Based on our current forecasts, and our existing pipeline of proposals in development and projects in delivery, we predict that current NIA funding will run out in 2023. Without additional funding we will not be able to fund higher TRL phases of existing workstreams, or progress new project ideas (both internal and external) beyond this point.

All of our innovation projects are currently funded through either NIA or SIF. Of the over 100 proposals we received for new NIA projects last year (2021/22), only 50% of these passed the initial approval stage, and only 14 were subsequently registered as live projects during the year. As of June 2022, there are 23 live NIA projects in the ESO innovation portfolio and another 14 in later-stage development (i.e. being finalised for final approval ahead of project registration). Following our recent Open Innovation Event (21st & 22nd July) we received over 60 proposals for additional projects, of which 5 are now in development and a further 30 are being assessed as initial proposals for NIA funding. All live, in delivery, and completed projects along with their expected benefits can be viewed on the ENA Smarter Networks Portal.[18]

[17] Whereby Ofgem initially allowed a total NIA of £23m, i.e. an average of c.£4.6m annually – but also clarified that this award was only based on the year 1 – year 2 plans, until year 3-5 plans have more visibility.
[18] https://smarter.energynetworks.org/

### 6.3.4 Typical innovation project length and cost

Projects typically start at research/feasibility stage. If successful, there is often a follow-on development project and then a demonstration project. The table below summarises the typical duration and cost for each project type:

| Project Type | Avg Project Length | Avg. Project Cost |
|---|---|---|
| Research | 0.5 year | £200k |
| Development | 1 year | £0.5m |
| Demonstration | 2 years | £1m |

Table 27: Typical project length and cost by project type

### 6.3.5 NIA-funded innovation planned for BP2

#### Role 1 - Control Centre Operations

**Current Status**

| Live NIA projects | Total NIA spend (Apr-21 – Mar-22) | NIA proposals in development | Legacy NIC projects | Total NIC spend (Apr-21 – Jul-22) |
|---|---|---|---|---|
| 3 | £1.2m | 8* | 1 | £10.3m |

Table 28: Role 1 NIA-funded Innovation for planned for BP2

*The investment in NIA projects in Role 1 is expected to increase significantly as our newly appointed Role 1 Innovation Business Partner sources and develops new ideas and addresses a backlog of initial proposals.

**In BP2, we expect that:**

- **We will continue to investigate advanced Machine Learning techniques and automation to help prepare our Control Centre for the energy system transition.** This includes forecasting increasingly uncertain supply and demand patterns and re-thinking how we continue to operate and maintain a secure, reliable system, at lowest cost and environmental impact. A dramatic increase in the amount of data informing our Control Centre decisions has created opportunities for better optimisation and further intelligence in our operations. We need to find ways to co-optimise new response and reserve services in our dispatch decisions and we are also exploring optimising dispatch based on marginal carbon emissions, in view of future potential government climate strategies.
- **VirtualES will form a key component of innovation in Role 1.** It will consolidate new and existing data into cohesive and better designed human-machine interfaces, bridging complex models and data from across the energy system, to enable better operational decisions and new strategic insights for planning. In BP2, new projects under the VirtualES will build on the Advanced Dispatch Optimisation project with Google X to begin testing of new tools and advanced techniques to help the Control Centre balance the future electricity system.
- **It will be important to understand the influence of weather on system operation.** Modelling the relationship between climate and weather parameters to power system response will help us ensure future scenarios and projections are aligned to emerging weather trends (e.g. heat waves, and droughts).

#### Role 2 - Market Development and Transactions

**Current Status**

| Live NIA projects | Total NIA spend (Apr-21 – Mar-22) | NIA proposals in development | Legacy NIC projects | Total NIC spend (Apr-21 – Jul-22) |
|---|---|---|---|---|
| 5 | £1.8m | 7 | - | - |

Table 29: Role 2 NIA-funded Innovation for planned for BP2

**In BP2, we expect that:**

- **We will investigate how future markets will facilitate increasing levels of competition and a greater variety of participants on the energy system.** The Future of Reactive Power trial will follow the initial NIA project delivered in BP1, which investigated the potential for a market-based solution to procure reactive power. In BP2, we will also finalise the design for a stability market, building on the initial BP1 innovation project.
- **The rise of the Consumer role within our markets will be an important theme with the associated development of Demand Response products.** We have commenced an important piece of work in this space (Crowdflex projects), looking to explore with external partners the true potential in GB for demand response services, and the opportunity to unlock energy and financial savings for the whole system.
- **We will create market sandboxes that allow us to acquire and test new products and services (in limited quantities) from non-traditional resources, informing future product decisions.** This, combined with our developing market simulations, will allow us to properly test and vet each service in a likely real-world scenario to better tweak the product parameters, while identifying the risks for gaming and market disruption.
- **Our Market Simulators will support Market Reform.** Allowing us to explore zonal pricing scenarios to ensure the most up-to-date projections and benefits.
- **Research will support the development of a 2045 cross-border strategy.** This will be a 'north star' for all future cross-border arrangements and will likely generate further NIA projects.
- **New methods will assess the risk and impact to consumers from service interruptions.** We will also develop better tools to calculate a more complete value of avoiding an outage event, including measures of societal costs, impact on vulnerable consumers, etc.

### Role 3 - System Insight, Planning and Network Development

**Current Status**

| Live NIA projects | Total NIA spend (Apr-21 – Mar-22) | NIA proposals in development | Legacy NIC projects | Total NIC spend (Apr-21 – Jul-22) |
|---|---|---|---|---|
| 9 | £1m | 22 | - | - |

Table 30: Role 2 NIA-funded Innovation for planned for BP2

**In BP2, we expect that:**

- **We will continue to play a central role in innovation across networks. Including** across the electricity transmission-distribution interface and in the interaction between electricity and gas networks (for example, through hydrogen). Extensive studies are being requested to cover DSO, whole energy system challenges, interconnectors, and achieving net zero.
- **Machine learning techniques and new data will be used to power our models.** New elements are being added to our scenario building and forecasts for all our relevant publications.
- **We will explore ways to achieve comprehensive system analysis that allows for whole-system simulations close to real-time.** This would increase our confidence in the security of the system and reduce our dependency on reserves. We may be able to better engineer our modelling work to allow for the more complex and computationally heavy tools (e.g. Transient calculations) to be broken down into different components capable of running in parallel.
- **Constraint management will continue to be an important focus for innovation**. This includes better ways to forecast, plan for and solve constrained network boundaries using no-build options.

### 6.3.6 Benefits expected from NIA-funded innovation

A summarised list of the benefits expected from Innovation under each of the ESO roles is provided below, this is based on positive engagements with Ofgem ("possible or probable future benefits from the innovation").

| Business Area | Activities | Potential benefits (over the RIIO-2 period) |
|---|---|---|
| **Role 1:** Control Centre Operations | Operating the system (monitoring and dispatch)<br>Coordinating with network operators on short-term operational decisions and outages changes<br>Short term energy and forecasting<br>Managing and sharing system data and information<br>Restoration and emergency response | Reduced CO2 emissions<br>Greater interconnection<br>Utilising flexible technology<br>Better inertia forecasting and needs management<br>Improved situational awareness<br>Reduced balancing mechanism outage downtime.<br>Improved decision making<br>Reduced resource costs |
| **Role 2:** Market development and transactions | Balancing and ancillary service market design<br>Service procurement and settlement<br>Revenue Collection<br>Policy advice and delivery of market framework changes<br>Code administrator<br>EMR Delivery Body | More liquid response and reserve market<br>Buying the optimal volume of response<br>Enhanced modelling capability<br>Reduced barriers to entry and cost of participation |
| **Role 3:** System insight, planning and network development | Long term forecasting, energy scenarios and identification of networks needs<br>Network Options Assessment<br>Delivering competitive system solutions and early network competition<br>Managing connections and access to the networks<br>Whole system process development | Support decision making for investment<br>Facilitate competition<br>Greater network operability<br>Improved decision making<br>Enhanced modelling capability |

Table 31: Expected NIA-funded Innovation benefits per role

In addition, the expected benefits from solving each of the Priority Challenges in our ESO Innovation Strategy document[19] are captured below, taken from the "opportunities" section under each Priority in the strategy document.

[19] https://www.nationalgrideso.com/future-energy/innovation/strategy

| 2022/23 Priority | Expected Outcomes |
|---|---|
| Zero Carbon Transition | Learn how best to assess, track and predict carbon intensity to understand what improvements are needed to network infrastructure and ESO operations to continue minimising this in future.<br><br>Predict how much reserve capacity is required to ensure security of supply from renewable sources and understand how long-duration storage can help support intermittent generators to allow the system to run with a higher penetration of renewables.<br><br>Create new market mechanisms that account for carbon intensity of participants to optimise our future system, e.g. for lowest cost and least carbon intensity.<br><br>Understand the long-term effects of climate change on the GB energy system and how to prepare – including how the transition to renewable generation and the electrification of transport and heat will change the energy landscape for all stakeholders.<br><br>Learn to operate the system by using newer zero carbon resources |
| Digital & Data Transformation | Help industry build a network of individual digital twins, of both the power system, as well as markets. We call this the Virtual Energy System.<br><br>Give teams access to better quality data and models to produce useful insights about the system as its characteristics continue to get increasingly complex.<br><br>Work towards faster decision-making to match our more complex, faster-moving electricity system using AI and machine learning.<br><br>Understand how these techniques can process the large amounts of data required to make the most economic, efficient and effective decisions, in sufficient time – from long-term network planning, to running new markets, to real-time operations in the Control Centre. |
| Future Markets | Learn how to remove barriers to new and existing markets for smaller participants and new technology types.<br><br>Identify the potential impact of locational marginal pricing on the network, market, and consumers.<br><br>Investigate how highly distributed, smaller assets can participate in our markets and how we can support this.<br><br>Develop more effective market modelling tools and capabilities which we can use to assess future market designs and interactions.<br><br>Understand potential new consumer markets, their technical characteristics and their entry requirements. |
| Constraint Management | Research long-term energy storage (electrochemical, thermal, or mechanical) and how it could help reduce year-round constraints.<br><br>Investigate whether low-carbon hydrogen production could be sited at advantageous locations to reduce constraints.<br><br>Understand how we can use data and new technologies to increase transfer or provide a fast acting, automated response to a system condition, to increase boundary capacity. |

| 2022/23 Priority | Expected Outcomes |
|---|---|
| System Stability and Resilience | Find better ways to model stability in an increasingly non-synchronous system.<br><br>Identify what tools can be developed to support the system in a decarbonised network. Develop new ways to speed up our processes, or automate them, to keep up with a lower inertia system.<br><br>Investigate what kinds of data or metadata could further support system operation and improve how we manage stability into the future. |
| Whole Energy System | Improve how we model the whole energy system (across all sectors) and incorporate this into our work with FES, NOA, and Early Competition.<br><br>Support further impact assessments and feasibility studies.<br><br>Investigate hydrogen's impact and see how Hydrogen electrolysers could benefit the system.<br><br>Identify and explore flexibility services that could be created for the electricity network – as other sectors, like transport and heating, decarbonise. |
| Whole Electricity System | Solve issues that affect both transmission and distribution networks and unlock additional network capacity through joint innovation projects.<br><br>Develop methods for how we build more complex, whole system models, which use data from both ESO and DSO. |

Table 32: Expected Innovation benefits linked to our priorities

### 6.3.7 Summary of general Innovation risks and mitigations

| Innovation Risk | Mitigation |
|---|---|
| Complexity of existing initiatives, standards, and regulation | Stakeholder engagement with related initiatives ensuring scope and interfaces are defined and understood. |
| Technical viability | Develop a demonstrator of a well-defined use case to prove capability early in the programme (by end of 22/23) |
| Data licensing | Identify example strategies with related initiatives and Ofgem's published Data Best Practice |
| Data security | Explore requirements of security standards and methods of triaging, anonymising or aggregating and securing data |
| Governance | Collaboration with other initiatives and programmes to avoid duplication. Introduction of Advisory groups and continued stakeholder engagement to ensure this becomes industry lead. |

Table 33: Innovation risks and mitigation

### 6.3.8 Virtual Energy System

The ambition of the Virtual Energy System programme is to enable the creation of an ecosystem of connected digital twins of the entire energy system of Great Britain. It will operate in synchronisation to the physical system. It will include representations of electricity and gas assets and link up to other sectors.

Stakeholder Engagement Workstream

**Case Study: Launch Conference**

We held an online conference on 1 December 2021 to set out the ambition of the programme. Over 500 individuals registered and over 250 were present on the day. Recordings were shared online after the event for those that couldn't attend live. Our full day agenda included panel sessions with industry leaders in digitalisation, regulation and innovation. We also shared the VirtualES vision and opened initial discussions with the wider audience, who were also invited to complete a survey to guide our programme.

Over the next period of the programme we will launch Advisory Groups which will be bring together experts from across the energy industry and beyond to define the priorities, requirements and specifications. These Advisory Groups and any associated Working Groups will meet regularly. They will deliver solutions to the challenges of digitalisation and data exchange. We will manage these groups bringing forward topics for discussion and organisational logistics. In all our stakeholder engagement we will collaborate with other ESO programmes and business planning processes to avoid duplication. Where there is any overlap with related programmes either internal or external the discussions and outcomes will be shared.

Use Cases Workstream

The Virtual Energy System will be a replica of the entire GB energy system. We will agree with stakeholders which use cases to build and how to prioritise them to deliver whole system value. While the programme develops in maturity, the ESO is leading by example with three initial use case projects. These projects build out high-value areas of the Virtual Energy System and generate learnings for future use case projects.

Alongside delivering the first wave of use case projects, to facilitate a second wave of use case projects Workstream Stream 3 activities aim to identify priority VirtualES areas and determine an appropriate form for a use case innovation call. As part of the prioritisation and planning of use cases each will go through a cost benefit analysis and risk assessment.

We will form a Use Case Advisory Group to consider the benefits case, long-term use case incentive mechanisms and dissemination of use cases. There will be a need for fixed or rolling use case innovation calls and more ESO and industry wide use case projects will need to be delivered. Depending on maturity of the proposal these will either form NIA or SIF innovation projects or link into future IT programmes as requirements.

**Role 1 National Control: Advanced Dispatch Optimiser – ESO, Alphabet X**

- This project aims to benchmark global best practice and recommend options for digital twin capabilities to support dispatch optimisation. The NIA project kicked off in November 2021 and included ESO subject matter expert interviews, data analysis and benchmarking research. The project has proposed a pipeline of digital twin projects to deliver the dispatch optimiser of the future grid. We are collaborating closely with the Balancing Transformation programme to ensure that learning is shared with our ongoing programmes.

**Role 2 Markets: Crowdflex – ESO, Octopus Energy, Ohme, WPD, SSEN Distribution**

- This project aims to characterise domestic flexibility for grid system operation and recommend statistical modelling approaches for digital twin capabilities. Expected benefits include improved modelling of domestic demand to simulate responses to future demand side services and energy price incentives. Through this SIF project a large-scale trial would be used to gather operational evidence and approaches to modelling domestic flexibility which will be developed using statistical techniques, including consideration of data exchanges required between flexibility providers and system operators .
- We are working with Octopus Energy, Ohme, Element Energy, Centre for Net Zero, Western Power Distribution (WPD) and Scottish and Southern Electricity Networks (SSEN) Distribution. Collaboration on this project has spanned multiple teams in ESO including Future Energy Scenarios, Customer and Stakeholder, and Markets Strategy

**Role 3 Networks: EN-Twin-E – SPEN, ESO**

- This project aims to develop a digital twin of a distribution network section to simulate impacts of dispatching assets for system balancing. Network maps will be the backbone of the VirtualES; this project begins building those key components. Expected benefits of an accurate, detailed map of distribution assets and networks include being able to operate the system more securely and drive value from distributed energy resources. We partnered on a Strategic Innovation Fund (SIF) Discovery round project which proposed designs for developing a digital twin of the distribution network. Collaboration on this project has spanned multiple teams in ESO including Network Access Planning and the Regional Development Programme teams.
- We have also partnered with other SIF projects investigating digital twins including Gas Network Interoperable Digital Twin with National Grid Gas Transmission and SGN's project investigating the potential for digital twins in future Hydrogen systems.

Common Framework Workstream

The scope of the framework has been defined by a number of key factors, of which six have been identified as priorities to demonstrate and implement. Figure 19 below shows these key factors aligned to People, Process, Data and Technology categories. The principles and standards behind these will be developed through the demonstrator NIA project in collaboration with the programme stakeholder engagement and other programmes.

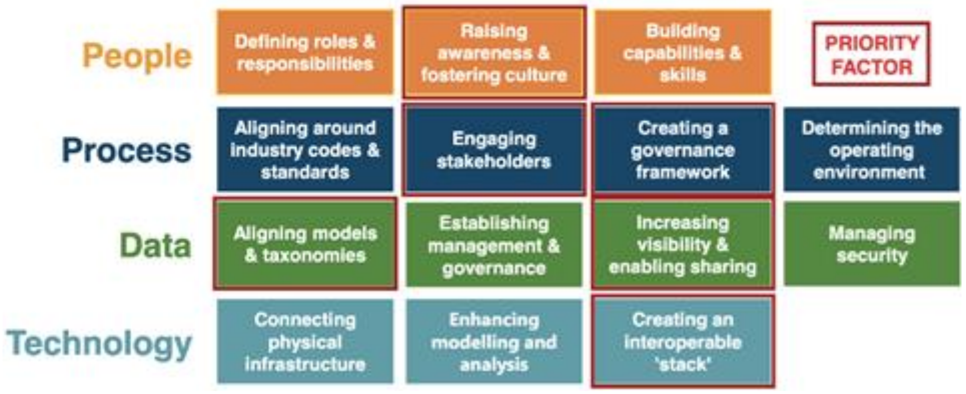


Figure 19: Common Framework priorities

Our next phase in developing the Common Framework is to begin a demonstrator. This will start small with a limited set of partners and begin to set out the initial priority requirements. The principles and standards that make up the Common Framework will be documented and published with references to sources for additional information and examples. This will be linked into agile governance processes to develop and evolve the standards over time.

Our SIF Alpha application for the Virtual Energy System was specifically for the development of the common framework. The project was declined for funding on the basis that the deliverables did not have a clearly articulated route to production and would benefit from smaller trials. We intend to act on this feedback and have developed a refined demonstrator project that continues at pace and has clear deliverables. This is currently being considered for NIA funding. During the delivery of this project we will ensure that value is clear and that next steps are identified for implementation.

## 6.4 Regulatory Finance

Ofgem's RIIO-2 Final Determinations (FDs) established our finance framework, setting the funding components, methodologies and parameter values for the RIIO-2 period. Some of these values were set only for the first two years, with the intent to review them again as part of the BP2 submission.

We agree with Ofgem's FD arrangements and methodologies and propose the same funding package components and methodologies are maintained for the BP2 period for the same activities. Arrangements should also be put in place to discuss potential additional funding to cover changes in our risks, such as those from BSUoS reform and any new roles we may be asked to undertake.

**Snapshot of BP2 funding proposals**

With our current roles and BSUoS arrangements at the time of this final BP2 submission, we do not see a need to change financial parameters around the additional funding already set in BP1 for the revenue collection role (including the costs of maintaining the Working Capital Facility, or WCF) and the risk asymmetry (including the DIWE cap level):

Only a short period of experience has been accumulated with the new framework to merit changing parameters; and

Despite the increase in some regulatory cash timing risks and a reduction in others, our overall estimates of capital required in BP2 to fund the revenue collection role remain within the original CEPA range that Ofgem's FDs used when calculating the additional funding parameters for BP1.

When approved, the BSUoS reform may significantly increase the risks borne by us under our revenue collection role. In this draft, we present our current assumptions on the increase in required capital and the resulting increase in additional funding for the equity employed following the methodology used by Ofgem in the BP1.

Some of the new roles we take on, for example, relating to Early Competition and Offshore Coordination, may cause a material change in the risk we bear, meriting consideration for additional funding.

### 6.4.1 Overview of our RIIO-2 Business Plan funding arrangements

Ofgem's FDs[20] arranged a funding framework taking into consideration our roles in the energy industry and our unique asset light nature:

- A total expenditure (totex) approach, where 'fast money' will be passed through in the year incurred; and 'slow money' added to the regulatory asset value (RAV) and a return received for the weighted average cost of capital (WACC) as well as depreciation over a 7-year period
- Additional funding to cover activities with no or little RAV, or for risks that remain unremunerated
- The outcome (reward or penalty) of the overall incentive scheme, and
- Absence of a 'totex incentive mechanism' (applicable to networks), creating a framework where all efficiently incurred costs of the ESO are passed through to consumers.

The funding model is summarised in Figure 20 below. It illustrates the totex components, which recover our costs and deliver a return on investments funded through the regulatory asset base (RAV*WACC and depreciation). It also shows the non-RAV layers of funding, namely the additional funding, and the outcome of the incentives scheme (a reward or a penalty).

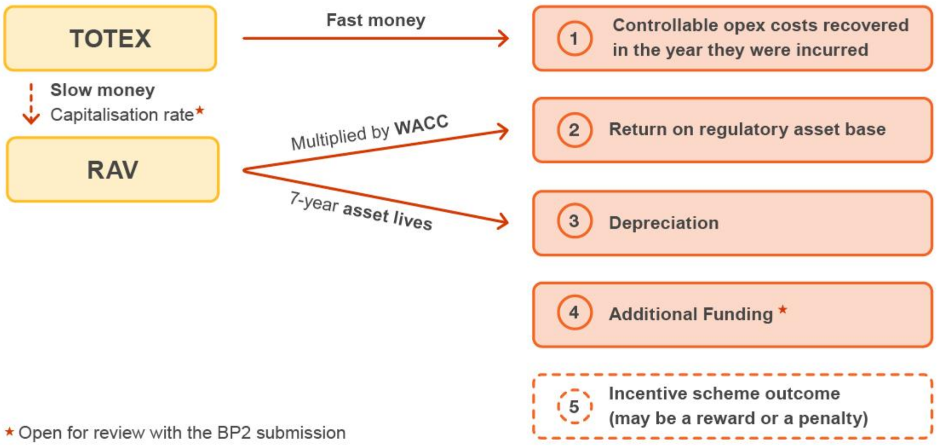


Figure 20: Illustration of RIIO-2 funding framework for ESO.

[20] RIIO-2 Final Determinations (Revised 3 February 2021) – Electricity System Operator Annex. Summary of all financial parameters forming the RAV*WACC plus Additional Funding package is on Table 10 (p.65).

All financial parameters, except for **additional funding** and **capitalisation rates,** were set for the full RIIO-2 period (in summary tables with the applicable timeframes in Section 5 of the Annex of the Ofgem FDs).

We provide an overview below of the RIIO-2 FD arrangements for the additional funding and capitalisation rate, which we are revisiting as part of our BP2 submission. As we review the additional funding for risk asymmetry, we will also cover the **Disallowance of Demonstrably Inefficient and wasteful expenditure ('DIWE') cap**, which is also open for revision in BP2[21].

### 6.4.2 Additional funding

Ofgem's FDs agreed that one of the critical roles we undertake on behalf of the energy industry, i.e., the revenue collection role, carries risks and costs not reflected in the RAV. Linked to this role, we rely on a WCF to manage potential cash shortfalls. Procuring and maintaining the WCF has associated fixed fees. Lastly, the cost disallowance mechanism creates a realistic investor perception of risk asymmetry. The FDs acknowledged these three sources of risks and costs are not remunerated through the totex fast/slow money model (RAV*WACC), and thus allocated 'additional funding' in our funding model.

### 6.4.3 Revenue collection and WCF fees[22]

Ofgem decided to follow a 'return on capital employed' approach to remunerate the risks and costs associated with the revenue collection role, including the costs of procuring and maintaining the WCF to manage the cash flow risk.[23]

Funding was based on the following assumptions (£m values are nominal annual forecasts):

- As per CEPA's estimate, the role requires capital of £165m (low scenario) to £260m (high scenario)
- The capital split would be 10% equity-90% debt in the low scenario vs 20% equity-80% debt in the high scenario
- Equity employed (£16.5m in low and £52m in high scenario) attracts a return based on our inflation-adjusted equity return of 9.72%. This results in a return of £1.6m in the low and £5.1m in the high scenario. Ofgem picked the midpoint of these, i.e., £3.3m
- Debt capital (£148.5m in low and £208m in high scenario) is remunerated based on the WCF costs of 0.45%, and results in a range of £0.7m to £0.9m. Ofgem estimated the pass-through of observable and efficient WCF costs will be the midpoint of these, i.e., £0.8m.

### 6.4.4 DIWE cap and compensation for perceived net risk asymmetry

Ofgem's FDs included an annual cost disallowance ('Demonstrably Inefficient and wasteful expenditure, DIWE') exposure capped at 2.5% of RAV. This means that, while Ofgem want us to be proactive and innovative to reach and exceed our ambitions and take on new activities in line with these goals, we can at best recover our costs and at worst be subject to cost disallowance.

Ofgem's FDs recognised that although they 'designed the RIIO-2 price control to focus more on the delivery of outputs' and they 'see disallowance of DIWE as a backstop measure', investors may reasonably evaluate the risk of DIWE disallowance as higher than Ofgem do. More specifically, 2.5% of RAV assumed at £312m creates a -£8m maximum downside risk due to cost disallowance. The upside asymmetry in the incentive scheme (reward cap minus the penalty cap) is +£9m. However, Ofgem acknowledges 'there may be a realistic perception on behalf of investors that the -£8m is more probable than the +£9m'.[24]

Assuming a 20% likelihood (high scenario) of £8m loss and considering small rewards for other asymmetry claims such as non-RAV systemic risk and contingent capital, Ofgem decided on £1.5m of funding under the title of asymmetry and other risk claims[25].

The additional funding of £1.5m, which Ofgem refers to as in the 'high end' of the estimated range, has been awarded mostly due to the realistic perception of risks by investors:

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[21] In RIIO-2 Final Determinations, DIWE was originally discussed under 'Internal Costs'. Our BP2 plan does not have such a separate section, and hence we will present our DIWE cap proposal in this section when discussing additional funding for risk asymmetry.
[22] Final Determinations – ESO Annex, Table 13, Table 14, and paragraph 5.36 with associated footnotes.
[23] ESO's response to Draft Determinations had recommended the alternative approach of margin-on-revenues collected/transferred, following the CMA's SONI precedent. Ofgem has considered that this approach has a disadvantage, mainly the assumption of a constant relationship between the amount of revenues collected and the underlying costs and risks. Ofgem has decided that a constant return on capital employed to manage these costs and risks was more appropriate. Final Determinations – ESO Annex, paragraph 5.37.
[24] Final Determinations – ESO Annex, para. 5.38.
[25] Final Determinations – ESO Annex, para. 5.35 and 5.38.

*"… we recognise that the price control framework is new and the lack of a totex incentive is untested. We therefore accept that it is possible investors may have a different perception of disallowance risk than we do, and it may take time and experience for this perception to change."*[26]

| BP 1 Additional Funding for: | £m nominal, annual |
|---|---|
| Return on equity capital employed for the revenue collection role | 3.3 |
| Estimated pass-through costs of fixed fees of the WCF | 0.8 |
| Asymmetry and other risk claims | 1.5 |
| **Total additional funding forecast** | **5.6** |

Table 34: Ofgem's additional funding decision applicable for the BP1 period

### 6.4.5 Capitalisation rates

Capitalisation rates determine the proportion of costs added to the RAV ('slow money') to be recovered through return on RAV and depreciation. Accurate rates ensure charges are fair and reflect annual and economic investment. Ofgem's FDs set annual capitalisation rates of 37% in 2021/22 and 34% in 2022/23, with rates for subsequent years to be confirmed alongside BP2 decisions.

### 6.4.6 What changes have there been since the start of BP1?

### 6.4.7 Revenue collection role

CEPA estimated the capital required by the revenue collection role as between £165m to £260m per annum. Although our committed facilities have exceeded the estimates in BP1, we forecast our required capital for the BP2 period to be within CEPA's range, specifically at £250m.

Our committed facilities in BP1 exceeded the size estimated by CEPA due to:

- CEPA's estimate not recognising the capital associated with the transition to the new TNUoS revenue collection risk arrangements, as well as £60m of pass-through costs incurred in RIIO-1 which will not be recovered until the end of 2022/23.
- Our commitment to fund deferral of balancing costs related to two industry code modifications in the BP1 period:
- In 2021/22, we committed to fund £100m of higher balancing costs resulting from the COVID-19 pandemic, under CMP345 and CMP350, and
- In January 2022, we committed to fund up to £200m of the exceptionally high balancing costs seen in the market to protect against further energy market company failures.

Our forecast for the revenue collection role capital requirements in the BP2 period is £250m, as shown in the last column of table 35 below, which remains in line with CEPA's original estimates. This is because some of the costs and risks (supported by the WCF) have reduced and some have increased since submission of BP1. We present these in table 35 and in detail below:

- **TNUoS recovery, billing, and collection, reduced**: Following Ofgem's decision to re-allocate TNUoS revenue collection risks to the onshore TOs, there is no longer a requirement for us to fund these risks.
- **Other transmission billing increased**: We rely on the WCF to cover the cash flow risks associated with the revenue collection role, namely the risk of under-forecasting pass-through costs for collection, and timing risks (advance payments versus collections made in 12 monthly instalments). However, there will be an additional source of cash flow risk in the BP2 period: our WCF will also make provision for a new risk around the funding of the new strategic innovation funding (SIF) arrangements[27]. This requires us to collect cash based on a forecast of which projects may be approved by Ofgem, with lump sum payments regardless of the timing of revenue collection. The SIF programme is expected to be far more ambitious than the Network Innovation Competition (NIC) in

[26] Final Determinations – ESO Annex, para. 5.39.
[27] https://www.ofgem.gov.uk/sites/default/files/2021-08/SIF%20Governance%20Document.pdf

RIIO-1, and we estimate up to 73 projects being approved in 2024/25 and an expected award of £77m. We estimate that £20m of our WCF would be ringfenced to support this cashflow risk.

- **Major Customer Failure reduced**: Our view of the amount of capital required to support a large supplier failure has reduced, given our recent experience of the special administration regime (SAR) which is used for large energy supplier failures. We have reduced our provision to cover a shortfall of three weeks' billing only, rather than two months'.
- **Regulatory obligations risk increased**: Since the preparation of our original RIIO-2 Business Plan in December 2019, an unprecedented amount of turbulence has impacted the energy market, driven by the COVID-19 pandemic, exceptionally high gas prices driven by the conflict in Ukraine. Charging reforms have also begun and discussions are under way about how a new Future System Operator could accelerate the transition to net zero. Though we cannot predict with certainty what risks will emerge we provide examples below of risks we have recently supported and some additional risks that could emerge:
    - We committed up to £200m to support industry to defer balancing costs through three separate code modifications
    - Due to unforeseen market conditions, we incurred higher-than-expected bad debt costs in the first year of RIIO-2 to only be recovered in future periods
    - We continued to fund TNUoS recovery and billing risk until the System Operator Transmission Owner Code (STC) changes could be implemented in July 2021
    - BSUoS reform could create significant tax cash flow timing risks with any profits associated with over recovery being chargeable to tax in the year incurred and offsetting losses generated through future recovery only being monetised through offset against future profits, and
    - There is a potential future risk of starting Future System Operator activities in 2022/23 with no cost recovery until 2023/24.

We consider it prudent to ringfence a proportion of our WCF to cover these types of potential risks.

| Capital requirement for the revenue collection role | | £m nominal annual forecast | |
|---|---|---|---|
| **Risk area** | **Detail** | **BP (2019) estimates** | **BP2 period estimates** |
| **TNUoS recovery** | Under-collection risk with a two-year lag. Sized 2x historic peak. | 140 | 0 |
| **TNUoS billing & collection** | Customers pay us based on their own forecasts. Sized on 5% under-collection. | 150 | 0 |
| **Other transmission billing** | Timing of true-up of pass-through costs and other site-specific charges. | 32 | 48 |
| **Terminations** | Mismatch between amounts paid to TO and termination sums. Sized based on possible significant mismatch from historic data modelling. | 67 | 67 |
| **Major customer failure** | Based on the average monthly billing of a top six customer with a 2-month exposure (revised to three weeks for BP2). | 100 | 40 |
| **Regulatory risk** | Unknown risks largely arising from the industry code modification process | 0 | 45 |

| | | | |
|---|---|---|---|
| **Other** | Smaller unexpected customer failure, BSUoS final settlement billing, BSUoS trade settlements, AAHEDC, spend prior to agreement of funding arrangements, income adjusting events. | 61 | 50 |
| **Total** | | **550** | **250** |

Table 35: Estimates of funding required for costs and risks associated with the revenue collection role.

### 6.4.8 Planned BSUoS reforms

In BP1, we committed to looking at partially or fully fixing BSUoS charges to provide greater certainty to our customers. In December 2020, following the publication of the report of the second BSUoS taskforce, Ofgem confirmed that setting BSUoS charges on a flat volumetric basis can have benefits. A code modification was subsequently raised in line with the taskforce recommendations.

Implementation of fixed BSUoS charges would materially increase our risk.

- **Liquidity risk -** Compared to the current situation, where the ESO recovers most balancing costs within 23 days, fixed volumetric BSUoS charges will increase the payment recovery timeline up to 2 years (depending on the solution alternative). All potential solutions involve us funding at least a proportion of the cash flow (liquidity) risk, and would require additional credit facilities to manage the liquidity risk. Taking on additional cash flow risk would be seen as credit negative and increases the risk of a standalone ESO not being able to meet it's licence obligation to maintain an investment grade credit rating.
- **Reputational risk –** BSUoS tariffs will be fixed on the basis of a forecast of future balancing costs which are highly volatile. This could lead to tariffs being re-set during a charging period with associated reputational damage for the ESO.
- **Legal/Regulatory risk –** The implementation of a new charging regime requires significant process and systems change as well as changes to treatment of direct and indirect taxation and International Financial Reporting Standards (IFRS) revenue recognition. Failure to comply with new licence conditions, or other regulatory requirements, perhaps due to errors, process failure, late delivery, or operational requirements could result in financial penalties or fines.
- **Profit volatility risk -** In the event of under-recovery for two consecutive years, we might not have enough retained earnings to make dividend distribution possible in not only year 1 but also year 2. Then, in a year of significant over-recovery, if we suffer a tax charge as a result and we do not make an equal and opposite loss to offset in the following year, there would be adverse corporation tax cash flow issues potentially leading to a long-term cash shortfall.
- Once BSUoS reforms are approved and put into place, there should be a re-evaluation of our risk metrics and proportionate increases to our additional funding for the revenue collection role.

### 6.4.9 What is our proposal for BP2?

| Area | Amount (£m) | |
|---|---|---|
| | **Current BSUoS arrangement** | **If fixed BSUoS charging reform is approved** |
| **Capital required for the revenue collection role** | *250* | *550 (£250m + additional £300m to support increased cash flow risk, based on current available headroom in existing facilities)* |
| **Return on equity capital employed for revenue collection role** | 3.3 | 7.7 |

| | | |
|---|---|---|
| **Return on debt capital employed for revenue collection role (pass-through of observable, efficient costs of the WCF)** | 0.8 | 0.8 |
| **Asymmetry and other risk claims, assuming a continued annual DIWE cap of 2.5% of RAV** | 1.5 | 1.5 |
| **Total additional funding** | **5.6** | **10.0** |

Table 36: Comparison of current versus proposed BSUoS charging arrangements and potential financial impact

### 6.4.10 Revenue collection role

We estimate an annual capital requirement of £250m to support revenue collection activities during BP2. This sits within the CEPA range of £165 - £260m, which Ofgem had used to arrive at the £3.3m midpoint estimate for the annual return on equity capital estimate. We consider the same £3.3m would be an appropriate annual return on equity employed for the revenue collection role in BP2, provided that the ESO activities remain the same as in BP1 (i.e. the same BSUoS arrangements and no new roles).

However, if proposals to fix annual BSUoS tariffs are implemented in BP2, increased additional funding may be necessary. Ofgem acknowledged this in the Final Determinations as follows:

*"BSUoS reforms: Industry has proposed changes to charging arrangements that potentially increase cashflow risk on the ESO. This could also lead to the consideration of new arrangements that could move cash flow risk from the ESO to another body. As a result, funding may need to be increased or decreased."*[28]

Current solution alternatives from the code modification workgroup all lead to increased cashflow risk for the ESO. In this case, we propose the same remuneration approach as above (return on capital employed) is applied after adjusting for the increase in capital needed to cover the increased liquidity risk. We consider this would provide a proportionate and flexible way to fund the additional risk. Assuming that we would make £300m available to manage the cash flow risk created by fixing BSUoS tariffs[29] the equity part of this additional capital employed would be £2.9m in the low-equity and £5.8m in the high-equity scenario. The midpoint would be £4.4m, which, added to the £3.3m return on equity employed for the revenue collection role without the BSUoS reform, would result in an overall funding of £7.7m for the equity component of the revenue collection role after the BSUoS reform.

Since the risks we are mitigating are highly unpredictable and we cannot forecast how facilities would be drawn during any given period, we cannot accurately predict the fixed costs of the WCF. So, we consider that pass-through of observable and efficient costs continues to be the most appropriate way to provide for WCF costs in the BP2 period. In the FDs, Ofgem based the additional funding for revenue collection role – debt component on the estimated fixed costs of a £550m facility, deciding on £0.8m per annum. As the actual size of our facility has not changed for BP2, we still estimate the fixed costs associated with the WCF to be £0.8m per annum.

### 6.4.11 DIWE cap and Additional Funding for Asymmetric Risk

Ofgem acknowledged in the RIIO-2 Final Determinations that the disallowance of DIWE mechanism, even when capped at 2.5% of RAV and when considered together with the net upside asymmetry of the ESO Incentive Scheme, creates a "realistic investor perception" of a higher likelihood of a loss. Ofgem stated that this 'realistic investor perception' was linked to the new and untested nature of the price control, including the new Incentive Scheme and the lack of a Totex Incentive Mechanism, and that "it may take time and experience for this perception to change".

Given that only one full year of the RIIO-2 price control period has passed, and we have not yet completed a full regulatory reporting cycle, we do not believe that there has been sufficient opportunity to test the new framework. Ofgem's 20% probability of disallowance assumption (employed in the FDs when evaluating DIWE net downside against incentive scheme net upside) equates to a one-in-five-year event and so we do not believe the new framework could be considered fully tested until the end of the five-year RIIO-2 period.

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[28] RIIO-2 Final Determinations – Electricity System Operator Table 15, page 86
https://www.ofgem.gov.uk/sites/default/files/docs/2021/02/final_determinations_-_eso_annex_revised.pdf

[29] Based on current available headroom in existing facilities. Current proposed code modifications require that the amount of support available would be reviewed and agreed with Ofgem to reflect changes in ESO liquidity risks and amount of overall credit facilities available to the ESO.

Therefore, we see no rationale at this stage to change the level of the DIWE disallowance cap from 2.5% and the risk asymmetry funding from £1.5m per annum.

We propose the funding of £1.5m per annum and the DIWE cap of 2.5% on RAV should be retained across the full RIIO-2 period.

### 6.4.12 Capitalisation rates

As planned in the Ofgem FDs, we agree that updating the annual capitalisation rates in line with the totex spend plans in BP2, reflecting the split between capex and opex expenditure, is appropriate.

### 6.4.13 Regulatory Finance Additional considerations for BP2

In our Business Plan submission, we expressed concerns there was no reward for us in taking on any new activity where there was a minimal addition to the RAV, which could drive a risk averse culture and fail to deliver consumer benefits. We disagree with Ofgem's FDs suggestion that new roles such as those relating to the **Early Competition Plan** or **Offshore Coordination** are not likely to materially change our risk profile nor merit consideration for additional funding.

Now that we have further developed plans for Early Competition, we are aware that certain roles such as the Procurement Body and Contract Counterparty could, due to their scale and complexity, present significant additional risks. We do not believe any commercial organisation would take on such additional activities with the prospect of, at best, recovering costs and, at worst, incurring fines, penalties, legal challenge, and reputational damage. As new roles develop relating to the Early Competition regime and Offshore coordination, we would welcome discussions with Ofgem around additional risks, possible mitigations, and additional funding.

### 6.4.14 Regulatory Finance Conclusion

Much of the RIIO-2 funding framework was set for the full RIIO-2 period, with additional funding, capitalisation rates, and DIWE cap to be reviewed in our BP2 submission.

Regarding our current set of activities and roles, we currently do not see a justification for changing the financial parameters set for BP1, due to no material changes in the overall netted out risks and a relatively short period of experience in the new ESO regulatory framework.

We do see emerging risks around BSUoS reform if it is implemented. We propose to extend Ofgem's return on capital methodology to provide a fair and flexible way to remunerate additional risks if BSUoS reform is implemented.

Some of the new roles we take on, such as those relating to Early Competition or Offshore coordination, may create material increases in risks and costs. When we receive clarity on potential new roles, we propose to review with Ofgem the changes in risks and costs that merit additional funding.

## 6.5 Enabling activities teams' financials and headcounts

The main BP2 plan contains a single combined table and key updates for the updated RIIO-2 financials and headcounts applicable to the cross-cutting teams. The individual breakdowns and additional supporting narrative are outlined below.

Note that numbers may not add exactly due to rounding.

### 6.5.1 Customer and Stakeholder

| | | BP1 | BP2 | | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| Customer and stakeholder | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | 1 | 2 | 1 | 1 | 1 | **7** |
| | BP1 | 2 | 2 | 2 | 2 | 2 | **8** |
| | **Variance** | **(0)** | **(0)** | **(0)** | **(0)** | **(0)** | **(1)** |
| **Totex (£m)** | **BP2** | **1** | **2** | **1** | **1** | **1** | **7** |
| | **BP1** | **2** | **2** | **2** | **2** | **2** | **8** |
| | **Variance** | **(0)** | **(0)** | **(0)** | **(0)** | **(0)** | **(1)** |
| FTE | BP2 | 11 | 13 | 12 | 12 | 12 | |
| | BP1 | 13 | 14 | 14 | 14 | 13 | |
| | **Variance** | **(2)** | **(1)** | **(2)** | **(2)** | **(1)** | |

Table 37: RIIO-2 cost and FTE for Customer and Stakeholder team. Numbers may not add exactly due to rounding

There is no material change to our costs or resourcing since our BP1 submission.

### 6.5.2 People, capability and culture

These FTEs are included in the Business Change table below.

### 6.5.3 Business change

| | | BP1 | BP2 | | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| Business change | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | 2 | 2 | 1 | 1 | 1 | **8** |
| | BP1 | 3 | 1 | 1 | 1 | 1 | **7** |
| | **Variance** | **(0)** | **1** | **1** | **1** | **1** | **2** |
| **Totex (£m)** | **BP2** | **2** | **2** | **1** | **1** | **1** | **8** |
| | **BP1** | **3** | **1** | **1** | **1** | **1** | **7** |
| | **Variance** | **(0)** | **1** | **1** | **1** | **1** | **2** |
| FTE | BP2 | 25 | 48 | 31 | 31 | 31 | |
| | BP1 | 8 | 8 | 8 | 8 | 8 | |
| | **Variance** | **17** | **40** | **23** | **23** | **23** | |

Table 38: RIIO-2 cost and FTE for Business Change team. Numbers may not add exactly due to rounding

The headcount for Business Change in BP2 is higher than in the original RIIO-2 Business Plan due to changes in the wider National Grid Group structure made in April 2021. Our original plan described a 'hub and spoke' model where a small change team of eight FTEs was supported by a central UK Change function providing services including change framework development, programme assurance and access to a flexible pool of resources.

This model was amended in April 2021, resulting in the establishment of a standalone Business Change function. The increase of 23 FTEs for FY25 is broken down as follows:

- Five FTEs (FY25) for the core team

- 17 FTEs (FY25) for a flexible resource pool, with resource costs charged directly to individual project and programme budgets. The changes were cost-neutral because they included removal of the cost allocation from National Grid Group to fund the UK Change function.
- This table also includes three FTEs (FY25) for our People and Capability team in BP2.

There are significant benefits to the revised structure, as delivery support services provided by the Business Change team can be fully tailored to our needs in the BP2 period. For example, recruitment for the flexible resource pool will focus on individuals with experience directly relevant to our activities.

The structure changes also mean the team can develop and refine the centralised Change Delivery Frameworks to accurately meet our requirements. This work will drive standardisation of methods and will include a training programme and associated guidance documents to help build change delivery capability in all business areas.

Lastly, in FY23 there are increased costs and headcount relating to the Future System Operator programme team. Post FY24 Future System Operator programme costs will be part of the Future System Operator project and are included Annex 5 - Future System Operator.

### 6.5.4 Business assurance

| | | BP1 | | BP2 | | BP3 | |
|---|---|---|---|---|---|---|---|
| | | Actuals | Forecast | | | | |
| Assurance | | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | TOTAL |
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | 2 | 2 | 2 | 2 | 2 | **8** |
| | BP1 | 1 | 1 | 1 | 1 | 1 | **6** |
| | **Variance** | **0** | **0** | **0** | **0** | **0** | **2** |
| **Totex (£m)** | **BP2** | **2** | **2** | **2** | **2** | **2** | **8** |
| | **BP1** | **1** | **1** | **1** | **1** | **1** | **6** |
| | **Variance** | **0** | **0** | **0** | **0** | **0** | **2** |
| FTE | BP2 | 18 | 20 | 18 | 18 | 18 | |
| | BP1 | 14 | 14 | 14 | 14 | 14 | |
| | **Variance** | **5** | **6** | **4** | **4** | **4** | |

Table 39: RIIO-2 cost and FTE for Business Assurance team. Numbers may not add exactly due to rounding

The insight and independence ESO Assurance brings is an invaluable safeguard across our complex and changing operating environment. To deliver the vision for this team we need to increase our resource by four FTE (FY25) to make sure we can provide engineering assurance and audit support which can continue to identify, test and validate key engineering risks.

### 6.5.5 Innovation team

| Innovation | | BP1 Actuals 2021/22 | BP1 Forecast 2022/23 | BP2 Forecast 2023/24 | BP2 Forecast 2024/25 | BP3 Forecast 2025/26 | TOTAL |
|---|---|---|---|---|---|---|---|
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | 1 | 1 | 2 | 2 | 2 | **8** |
| | BP1 | 1 | 1 | 1 | 1 | 1 | **4** |
| | **Variance** | **0** | **0** | **1** | **1** | **1** | **4** |
| **Totex (£m)** | **BP2** | **1** | **1** | **2** | **2** | **2** | **8** |
| | **BP1** | **1** | **1** | **1** | **1** | **1** | **4** |
| | **Variance** | **0** | **0** | **1** | **1** | **1** | **4** |
| FTE | BP2 | 9 | 13 | 23 | 23 | 23 | |
| | BP1 | 9 | 9 | 9 | 9 | 9 | |
| | **Variance** | **0** | **4** | **14** | **14** | **14** | |

Table 40: RIIO-2 cost and FTE for Innovation team. Numbers may not add exactly due to rounding

Compared to BP1, we require an additional £3m opex over the FY24 and FY25, as well as 14 more FTEs.

- 12 of these FTEs are to support the delivery of the Virtual Energy System programme, including FTEs to support across the workstreams, project management resource and a director to lead the programme.
- The other two FTEs will be to support the increased resource requirements driven by the SIF scheme applications.
- These additional FTEs are being included during BP1.

### 6.5.6 ESO Regulation

| Regulation | | BP1 Actuals 2021/22 | BP1 Forecast 2022/23 | BP2 Forecast 2023/24 | BP2 Forecast 2024/25 | BP3 Forecast 2025/26 | TOTAL |
|---|---|---|---|---|---|---|---|
| Capex (£m) | BP2 | - | - | - | - | - | - |
| | BP1 | - | - | - | - | - | - |
| | **Variance** | **-** | **-** | **-** | **-** | **-** | **-** |
| Opex (£m) | BP2 | 2 | 2 | 2 | 2 | 2 | **8** |
| | BP1 | 2 | 2 | 2 | 2 | 2 | **10** |
| | **Variance** | **(1)** | **(0)** | **(0)** | **(0)** | **(0)** | **(2)** |
| **Totex (£m)** | **BP2** | **2** | **2** | **2** | **2** | **2** | **8** |
| | **BP1** | **2** | **2** | **2** | **2** | **2** | **10** |
| | **Variance** | **(1)** | **(0)** | **(0)** | **(0)** | **(0)** | **(2)** |
| FTE | BP2 | 14 | 19 | 19 | 19 | 19 | |
| | BP1 | 19 | 19 | 19 | 19 | 19 | |
| | **Variance** | **(5)** | **(0)** | **(0)** | **(0)** | **-** | |

Table 41: RIIO-2 cost and FTE for the ESO Regulation team. Numbers may not add exactly due to rounding

Based on our assumptions, ESO Regulation team cost and FTEs remain in line with our original RIIO-2 submission. Therefore, our BP2 plans have not materially changed from BP1.

# 7 List of Activities and Sub-activities

The following table contains the full list of activities and sub-activities by role.

- Red represents new activities and sub-activities
- Strikethrough represents those which have moved under other sub-activities
- Greyed-out sub-activities will be completed by the end of BP1 with no further deliverables into BP2

| Activity # | Activity name | Sub-activity # | Sub-activity name |
|---|---|---|---|
| A1 | Control Centre architecture and systems | A1.1 | Ongoing activities |
| | | A1.2 | Enhanced Balancing Capability |
| | | A1.3 | Transform Network Control |
| | | A1.4 | Control centre architecture |
| | | A1.5 | Operational coordination with DER and DSO |
| | | A1.6 | Minimising Balancing Costs |
| A2 | Control Centre training and simulation | A2.1 | Ongoing activities |
| | | A2.2 | Enhanced training material |
| | | A2.3 | Training simulation and technology |
| | | A2.4 | Workforce and change management tools |
| A3 | Restoration | A3.1 | Ongoing activities |
| | | A3.2 | Restoration standard |
| | | A3.3 | Innovation project in restoration |
| A17 | Transparency and open data | A17 | Ongoing activities |
| A18 | Market monitoring | A18.1 | Ongoing activities |
| A19 | Data and analytics operating model | A19.1 | Ongoing activities |
| A4 | Building the future balancing service markets | A4.1 | Manage existing balancing services and markets |
| | | A4.2 | Power Responsive |
| | | A4.3 | Deliver an efficient frequency market |
| | | A4.4 | Deliver a single, integrated platform for ESO Markets |
| | | A4.5 | Facilitate whole electricity system market access for distributed energy resources |
| | | A4.6 | Balancing and ancillary services market reform |
| A5 | Transform access to the Capacity Market and Contracts for Difference | A5.1 | Electricity Market Reform (EMR) Delivery Body |
| | | A5.2 | Deliver an enhanced platform for EMR |
| | | A5.3 | Improve our security of supply modelling capability |
| | | A5.4 | Long-term capacity adequacy |
| A6 | Develop code and charging arrangements that are fit for the future | A6.1 | Code management / market development and change |
| | | ~~A6.2~~ | ~~European Union (EU) code change~~ |
| | | A6.3 | Industry revenue management |
| | | A6.4 | Transform the process to amend our codes |
| | | A6.5 | Work with all stakeholders to create a fully digitalised Whole System Technical Code by 2025 |
| | | A6.6 | Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges |
| | | A6.7 | Fixed BSUoS tariff setting |
| | | A6.8 | Digitalisation of codes |
| | | A6.9 | Whole electricity system framework reform |
| A20 | Net Zero Market Reform | A20.1 | Net zero market reform programme |
| A21 | Role in Europe | A21.1 | Setting the net zero cross border landscape |
| | | A21.2 | Enhancing cross border frameworks and markets |

| Activity # | Activity name | Sub-activity # | Sub-activity name |
|---|---|---|---|
| A7 | Network Development | A7.1 | Analyse and communicate future network needs |
| | | A7.2 | Advise on economically efficient ways to address networks needs |
| | | A7.3 | Undertake ad hoc analysis in response to external requests |
| A8 | Enable all solution types to compete to meet transmission needs | A8.1 | Rollout of Network Services Procurement (formerly Pathfinders) approach and optimise assessment and communication of future needs |
| | | ~~A8.2~~ | ~~Enhance tendering models~~ |
| | | A8.3 | Support Ofgem to establish enabling regulatory and funding frameworks |
| | | A8.4 | Early Competition |
| ~~A9~~ | ~~Extend NOA approach to end of life asset replacement decisions and connections wider works~~ | ~~A9.1~~ | ~~Expand network planning processes to enable more connections wider works to be assessed~~ |
| | | ~~A9.2~~ | ~~Trial assessment of all connection wider works in one region~~ |
| | | ~~A9.3~~ | ~~Expand to all Connections Wider Works (CWW)~~ |
| | | ~~A9.4~~ | ~~Develop process with TOs to input into ESO analysis of end of life asset replacement decisions~~ |
| A10 | Support decision making for investment at distribution level | A10.1 | Support DNOs to develop NOA type assessment processes |
| A11 | Enhance analytical capabilities | A11.1 | Refresh and integrate economic assessment tools to support future network modelling needs |
| | | A11.2 | Implement probabilistic modelling |
| | | A11.3 | Build voltage assessment techniques into an optimisation tool |
| | | A11.4 | Build stability assessment techniques into an optimisation tool |
| A12 | SQSS Review | A12.1 | Scope project, building on the BEIS recommendations |
| | | A12.2 | Identify solutions |
| | | A12.3 | Implement changes to the SQSS |
| A13 | Leading the Debate | A13.1 | Carry out analysis and scenario modelling on future energy demand and supply |
| | | A13.2 | Conduct mathematical modelling and market research on local and wider geographic demand information |
| | | A13.3 | Maintain external communication channels with consumers and stakeholders |
| | | A13.4 | FES: Bridging the gap to net zero |
| | | A13.5 | *FES:* Integrating with other networks and supporting DNOs to develop their own DFES processes |
| A14 | Take a whole electricity system approach to connections | A14.1 | Provide contractual expertise and management of connection contracts including provision of connection offers to customers |
| | | A14.2 | Ensure Grid Code compliance of new connections |
| | | A14.3 | Further enhance the customer connection experience, including broader support for smaller parties |
| | | A14.4 | Facilitate development of the customer connections portal |
| | | A14.5 | Connections Reform |
| A15 | Taking a whole energy system approach to promote zero carbon operability | A15.1 | Develop the *System Operability Framework (SOF)* and provide solutions up to real time of network related operability issues |
| | | A15.2 | Provide technical support to the connections process |
| | | A15.3 | Assess the technical implications of framework developments and implement changes into business procedures and systems |
| | | A15.4 | Manage our operational data and modelling requirements |
| | | A15.5 | Develop Regional Development Programmes (RDPs) |

| Activity # | Activity name | Sub-activity # | Sub-activity name |
|---|---|---|---|
| | | A15.6 | Transform our capability in modelling and data management |
| | | A15.7 | Deliver enhanced frequency control by 2025 |
| | | A15.8 | Facilitate distributed flexibility and whole electricity system alignment |
| | | A15.9 | Net zero operability |
| | | ~~A15.10~~ | ~~Develop a regime for an integrated offshore grid~~ |
| A16 | Delivering consumer benefits from improved network access planning | 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 |
| | | A16.2 | Scope a whole electricity system decision-making policy |
| | | A16.3 | Work more closely with DNOs and DER to facilitate network access |
| | | A16.4 | Whole system outage notification |
| | | A16.5 | Network access planning automation |
| A22 | Network Planning Review / Offshore Coordination | A22.1 | Network Planning Review |
| | | A22.2 | Offshore Coordination |

Table 42: BP2 Activities and sub-activities by role