# ESO RIIO-2 Business Plan Annex 2 Cost-Benefit Analysis Report

27 January 2020

# Version history

| Version | Published | Notes |
|---|---|---|
| 1.1 | 27 January 2020 | A small number of minor errors in version 1.0 have been identified. These are corrected in version 1.1. |
| 1.0 | 9 December 2019 | Original version published. |

## Summary of changes in version 1.1

### 1.4 Overview of the benefits we deliver

- Table 8 - updates to the third party sensitivity totals for activity A1, Role 1 Theme 1 and the ESO total, based on the error identified in section 2.1 (see below). The high and low third party sensitivities respectively are:
    - £214 million and £208 million for activity A1 (not £221 million and £203 million)
    - £222 million and £215 million for Role 1, Theme 1 (not £229 million and £211 million)
    - £1,998 million and £1,939 million for the ESO total (not £2,006 million and £1,935 million)
- Table 8 – correction of a typographical error for the low delivery sensitivity for Activity A5. This is £21 million (not £22 million).

### 2.1 A1 Control centre architecture and systems

- Table 17 - correction of a methodological error in the calculation of the third party sensitivity for Greater interconnection (section 2.1.2.2). The low and high third party sensitivities are £9.3 million and £16.4 million respectively. The totals for each year are also updated.
- The overall third party sensitivity range for activity A1 in section 2.1.4 has also been updated. It is now £208 million to £214 million (not £221 million and £203 million).
- A typographical error in the "Measuring benefits and consumer bill impact" in section 2.1.2.2 has been corrected to £11.8 million (not £11.9 million).

### 3.3 A5 Transform access to the capacity market

- Correction of a typographical error in the net present value. The lower bound indicated by the sensitivity analysis is £21 million (not £22 million).
- Correction of a typographical error in the text under Table 70. The lower bound of the benefit range is £25.6 million (not £47.2 million).
- Correction of typographical errors in the total benefits case. The total benefits are between £30 million and £108 million (not £29 million to £112 million). The central case is unchanged (£74 million).

- Correction of a typographical error in section 3.3.4 “Net present value”. The lower bound for the delivery sensitivity is £21 million (not £22 million).

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

- Correction of a typographical error in the description of the low market factors sensitivity. This is based on 600 projects (not 500).

## 5. Cost-benefit analysis: Role 3, Theme 4

- The text under Table 126 has been corrected. The Theme 4 NPV is £673 million (not £674 million) and the sensitivity analysis range is £427 million to £916 million (not £428 million to £919 million).

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

- The lower bound for the NPV sensitivity is £603 million (not £607 million).
- Table 144 - the high and low third party sensitivity totals were the wrong way around. This has been corrected.
- There was a typographical error in the lower and upper bounds of the total benefits case. This is £407 million (not £497 million) and £698 million (not £697 million).

# Contents

# 1. Delivering consumer benefit

## 1.1. Approach to cost-benefit analysis

To create a robust, well-justified Business Plan, our decision-making process must consider economic assessments of our proposed options, alongside our commercial and technical judgement, and stakeholder views.

For the economic assessment in our submission we have undertaken either a cost-benefit analysis[1] (CBA) or a break-even analysis on all our transformational proposals. The principle of CBA is the determination of a project's financial and economic cashflow. This value, whether positive or negative, supports the appraisal of investment options and the final decision.

Our ongoing activities have not been subject to a CBA. Instead we have challenged their costs for efficiency, including through benchmarking. For details on our overall benchmarking approach see chapters 3, 10 and 12 of our Business Plan. In addition, the Theme chapters (chapters 4 to 7) explain the detail of the activities and should be used in conjunction with the report. References are also included for all the activities considered in this report.

We have worked with Ofgem to develop our CBA approach[2] based on that of the other RIIO-regulated companies but tailored for the type of business we are. This approach follows best practice from HM Treasury's Green Book[3] and uses established procedures, recommended by Ofgem, for expenditure-related decisions. Section 7 sets out how we have complied with Ofgem's CBA guidance.

## 1.2. How the ESO delivers consumer benefit

In the following section, we explain the different ways the ESO delivers consumer benefit. To structure our thinking, we have used a high-level framework which considers both the category and type of benefit.

### 1.2.1. Benefit categories

In line with Ofgem's guidance we use the following five categories of consumer benefit.

When we calculate benefits, we assign them to one of these categories and provide descriptions – the image can be used to identify the category.

**Improved safety and reliability**

The on demand provision of electricity is a fundamental part of our modern life which must be continuously attended to with the utmost importance by the Electricity National Control Centre (ENCC) and supporting functions. We will continue our focus on system balancing and security at optimum cost in line with the expectations that government, the regulator and the consumer have of us. We plan ahead, to ensure we can operate the system in the future, as it adapts to use more low carbon, intermittent, non-synchronous and distributed generation sources.

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[1] Please note these figures represent our proposed spending. The cost borne by consumers in any year will depend on the funding model chosen.

[2] Ofgem: RIIO-2 Cost Benefit Analysis Guidance https://www.ofgem.gov.uk/system/files/docs/2019/11/riio-2_eso_cba_guidance.pdf

[3] https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

**Improved quality of service**

Over recent years we have transformed our approach to engaging with our stakeholders. We listen to what they want from us and deliver on that where we can. Where we cannot we explain why. This stakeholder input has shaped how we do things and put much more of a focus for us on why and how we can improve our quality of service. Improved service quality ultimately benefits the consumer due to interactions in the value chains across the industry being more seamless, efficient and effective.

**Lower bills than otherwise the case**

We lower consumer bills by working to control, reduce, and optimise elements of the system charges which we can influence. These charges are the Balancing Services Use of System (BSUoS) and the Transmission Network Use of System charges (TNUoS). These charges are levied on suppliers and transmission-connected generators, and passed through to end consumers. We optimise across BSUoS and TNUoS by linking our balancing decisions with our *Network Options Assessments (NOA)* so that in the long-term the economic and efficient outcomes are being driven when planning, developing and investing in the network. Nearer to real time we manage BSUoS by focusing on controlling, reducing, and optimising our spend on balancing and operating the system. These charges flow through to the consumer bill from suppliers, therefore any reduction of this cost (approximately £1 billion of BSUoS and £3 billion of TNUoS per annum) will benefit the consumer.

**Reduced environmental damage**

Great Britain has committed to reducing its $CO_2$ emissions year on year with a commitment to achieve net zero emissions by 2050.

We are committed to supporting new providers and technologies to enter and compete fairly in the energy markets. One way we can do this is to base our purchasing decisions on the technical capabilities of providers, not on the fuel they use to generate power. We are committed to being ‘technology neutral’, as market participants already have environmental costs priced into their products and services, for example through carbon price levies.We also work innovatively to design novel solutions which ensure the system can operate safely and securely both now and in the future with large levels of intermittent and non-synchronous generation running.

**Benefits for society as a whole**

By 2050, energy system decarbonisation efforts could add 19 million jobs and $52 trillion of gross domestic product (GDP) to the global economy, increasing the GDP of Northern and Western Europe by 1.25 per cent and 2.5 per cent, respectively. It could also generate a 15 per cent increase in global welfare and reduce negative health effects caused by local air pollution by 60 per cent.

*Figure 1 Benefit categories*

### 1.2.2. Benefit type

We always try to attach a monetary value to benefits. Where this is not possible, we use the following logic to decide which type of benefit the activity will deliver:

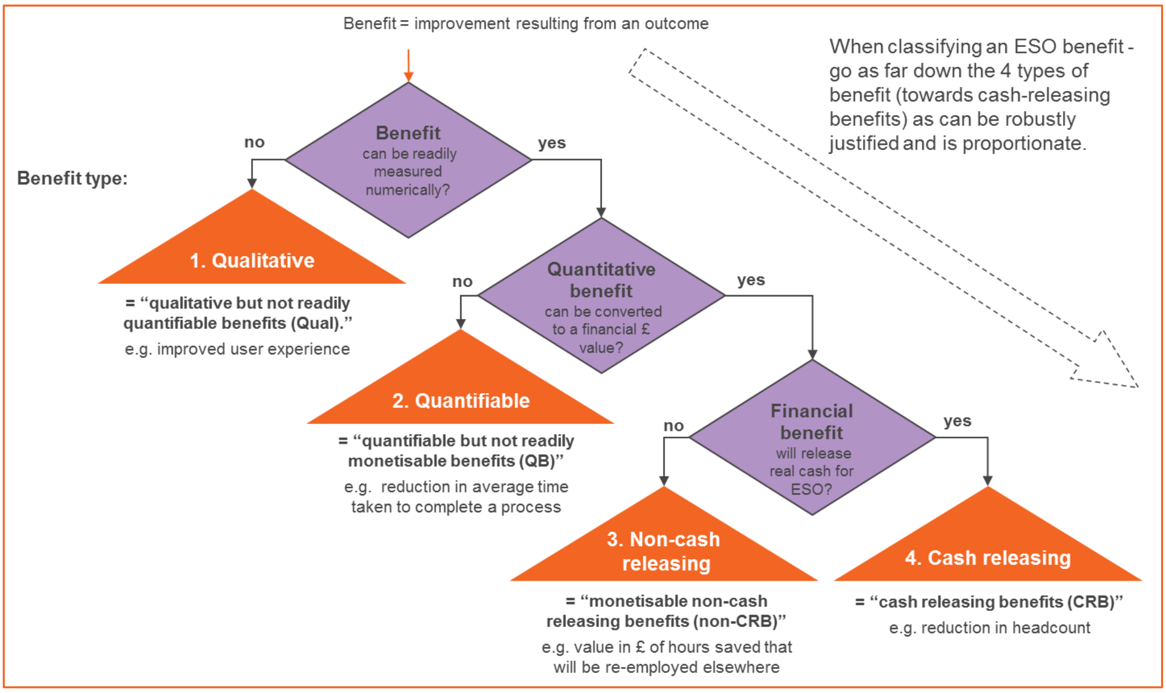


*Figure 2: Benefit types*

To keep the analysis proportionate we focus on the benefits that are easiest to define, quantify and attribute. This means the harder-to-analyse benefits are not quantified, so our CBA is likely to be more conservative.

If multiple activities are necessary to unlock some benefits to avoid double counting, we only attribute the benefit to one of them.

Where we are unable to attach a monetary value to the benefits, we will undertake a break-even analysis. That means we take the costs of the activity and decide the level of benefits required for it to cover its costs. In cases where the final consumer benefits are delivered through a third party, we assume the cost saving is fully passed on to consumers. We highlight this in the appropriate sections.

## 1.3. How we analyse consumer benefit

### 1.3.1. Assumptions

We make several assumptions[4] to calculate our best estimate of benefits, which we call the central case:

| Assumption | CBA model value |
|---|---|
| Capex depreciation period | Seven years |
| Cost of carbon £/tonne$CO_2$e | BEIS short-term traded carbon values[5] (converted from calendar into financial year values)<br>2021/22: 14.70, 2022/23: 15.25, 2023/24: 15.83, 2024/25: 16.63, 2025/26: 19.24 |
| Cost of capital | 2.64% (placeholder) |
| Discount rate | Social time preference rate of 3.5% |
| Price base | 2018/19 |
| Constraint costs £ million | 2021/22: £600m, 2022/23: £689m, 2023/24: £809m, 2024/25: £931m, 2025/26: £909m[6] |
| Response and reserve costs | We take the average cost of response and reserve over the past 12 years:<br>Response: £193m per year<br>Reserve: £321m per year[7] |

*Table 1: CBA modelling assumptions*

[4]Unless stated otherwise, assumption from Ofgem guidance document
[5] BEIS: Update short-term traded carbon values - used for modelling purposes (April 2019) https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/794188/2018-short-term-traded-carbon-values-for-modelling-purposes.pdf.
We have converted calendar years into financial years by taking 275/365 of one year and 90/365 of the next year.
[6] Average constraint costs across the *Future Energy Scenarios* as used in the modelling of the 2018/19 *NOA*
[7] This is the average response and reserve cost over the past 12 years – we have taken this time period, which is the full period available, to account for the volatility in the reserve and response market

### 1.3.2. How we have considered options

We have used the following process to consider options:

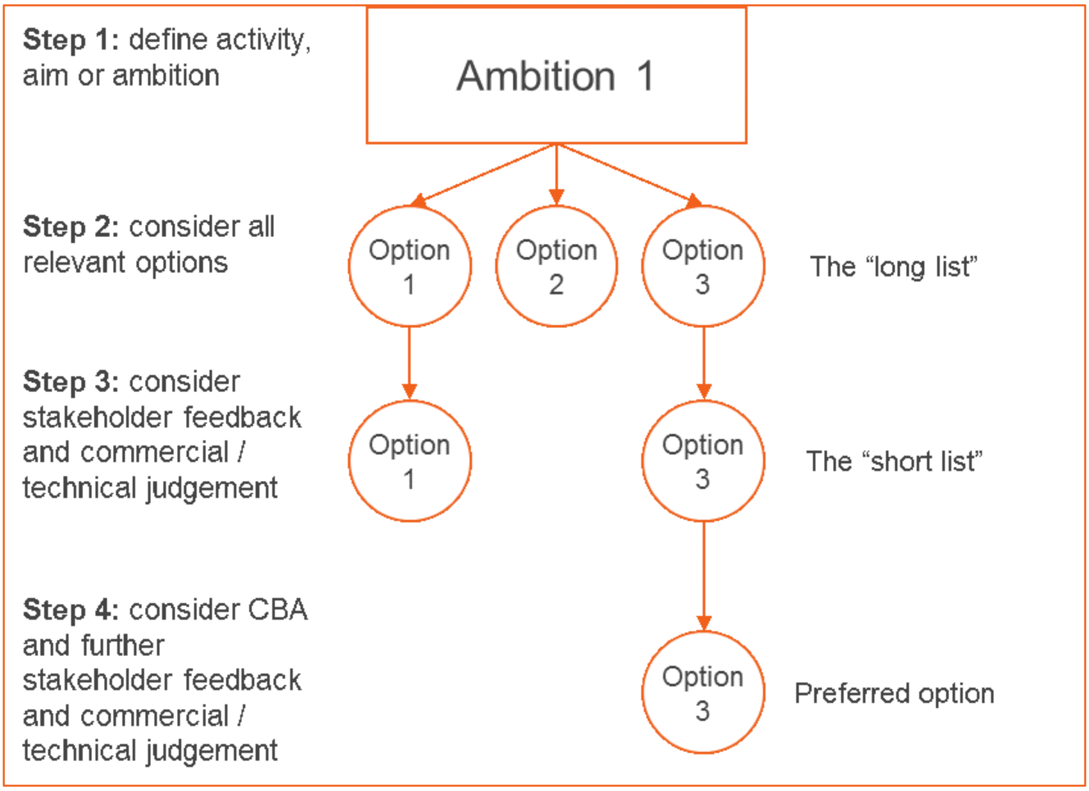


*Figure 3: Option consideration process*

1. We first defined our ambition, and the transformational activities needed to meet it.
2. From this, we considered the possible options that could reasonably meet it. We call this the "long list".
3. We engaged on these options with stakeholders and used our commercial and technical judgement to narrow down the number of options. We call this the "short list".
4. We undertake cost-benefit analysis of the options on the short list, using the methodology in section 1.2.3. We consider the result of this, along with any further stakeholder feedback and our commercial and technical judgement to arrive at a preferred option.

### 1.3.3. Methodology for calculating Net Present Value (NPV)

The model we use calculates an NPV, rather than a net benefit. This accounts for financing, depreciation and discounting.

For each transformational option we:

1. Estimate the capex and opex costs for each year of the RIIO-2 period.
2. Calculate the financial value, where appropriate, across the five consumer benefit areas (see section 1.3.1) for each year of RIIO-2. We use a range of sources,

including historic data, forecasts, published analysis and our commercial and technical judgement. Our benefit assumptions are stated and justified.

3. We calculate the NPV by:
    - Depreciating the capex expenditure over the capex depreciation period (see table 1);
    - Applying the cost of capital (see table 1) assumption to depreciated capex investments;
    - Calculating net benefits by the difference between costs (opex and capex above) and the benefits; and
    - Discounting these net benefits by the discount rate (see table 1) and calculating NPVs over five and ten years.
4. Consider the NPV, along with stakeholder feedback and our commercial and technical judgement (including risks to delivery), to decide which option (if any) to propose.
5. Where appropriate, perform additional sensitivity analysis to account for any uncertainties in the assumptions, using the process outlined in section 1.3.4.

### 1.3.4. Sensitivity analysis

The benefits in this report are our best estimates; we call them our central case. The actual benefit delivered will ultimately depend on a range of factors both within and outside our control. We have conducted a sensitivity analysis to determine a reasonable benefit range. In cases where our central estimate is marginal, a sensitivity analysis can help determine whether to proceed.

For each benefit area, we have conducted three sensitivity analyses:

1. **A market sensitivity** - for market factors outside our control. The ESO has some limited influence over markets, but most are dependent on market forces or international energy prices, which we perform sensitivity analysis on.
2. **A third-party sensitivity** - for third party factors outside our control. Some ESO activities require third parties to deliver benefits for consumers. We have highlighted who these parties are and performed sensitivity analysis on how the benefit is delivered.
3. **A delivery sensitivity** - for factors we can control. Here we perform sensitivity analysis on deliver time scales and output quality, that is the scale of the benefit delivered.

Examples of factors considered in our sensitivity analysis are in the table below. The exact inputs into specific sensitivity analysis can be found in the relevant sections in the report. It should be noted that we have not necessarily conducted each type of sensitivity analysis for every benefit line.

| Market factors | Third party factors | Delivery factors |
|---|---|---|
| • Constraint costs.<br>• Balancing and ancillary service costs.<br>• Carbon price.<br>• Energy landscape assumptions. | • Efficiency created by ESO activities i.e. customer time saved.<br>• Costs of solution e.g. operability solutions. | • Implementation i.e. do we deliver the activity on time.<br>• Quality of implementation i.e. does the activity deliver the benefit we anticipate. |

*Table 2: Sensitivity analysis factors*

### 1.3.5. Interactions between benefit areas

As highlighted by the dependencies map, in figure 5 in section 1.4.2 below, there are many overlaps and interdependencies between our activities. It is possible that this could lead to double counting of benefits, or that undertaking an activity alters the benefit case in another. For example, Role 1, Theme 1 and Role 2, Theme 2 both claim lower response and reserve costs. Role 3, Theme 3 and Role 3, Theme 4 use forecast cost of constraints in the benefits calculation, which proposals in Role 1, Theme 1 seek to reduce. We have highlighted in the relevant section where there is potential interaction.

To mitigate the risk of double counting we have considered each activity separately, that is, the benefits from one are not reflected in the other. This means that:

- The level of double counting is likely to be small. For example, Role 1, Theme 1 proposes a 2 per cent reduction in reserve and response prices and Role 2, Theme 2 claims a 5 per cent reduction. Any interaction should be minimal.
- We have generally adopted a conservative approach to benefit calculation, especially where we have less certainty.
- Any potential double counting will be accounted for in the relevant sensitivity analysis. For example, where Role 1, Theme 1 and Role 2, Theme 2 both claim to reduce response and reserve costs by a fixed percentage, they both also have a market sensitivity that runs applies the same percentage to a lower reserve and response cost, which could account for the effects of any interaction.

### 1.3.6. Risks and mitigations

For our preferred option, we score the risks to delivery using the following rules:

*Likelihood*

| Score | Description | Frequency of occurrence | Probability of occurrence |
|---|---|---|---|
| 1 | Remote | <Once in 20 years | <20% chance |
| 2 | Less likely | <Once in 15 years | >20% & <40% chance |
| 3 | Equally likely as unlikely | <Once in 10 years | >40% & <60% chance |
| 4 | More likely | <Once in 5 years | >60% & <80% chance |
| 5 | Almost certain | One or more a year | >80 & <100% chance |
| 6 | Certain | | 100% chance |

*Table 3: Risk likelihood scoring*

*Impact*

| Score | £ million |
|---|---|
| 1 | Less than 5 |
| 2 | Between 5 and 10 |
| 3 | Between 10 and 30 |
| 4 | Between 30 and 50 |
| 5 | Greater than 50 |

*Table 4: Risk impact scoring*

### 1.3.7. Measuring benefit realisation

Alongside the CBA for our proposed RIIO-2 transformational activities, we have also proposed a suite of metrics to measure our performance over the RIIO-2 period see Annex 7 – Metrics and measuring performance for details. There is natural alignment between the forecast consumer benefits and metrics, with over 80 per cent of consumer benefits covered by either:

- a metric which directly measures the consumer benefit e.g. consumer value savings from NOA; or
- a metric which measures the benefit driver, one step removed from the consumer benefit itself e.g. proportion of balancing services procured through competitive means.

For the consumer benefits which are not covered by a metric, there is the potential to track these as part of any regulatory reporting for RIIO-2, subject to being proportional and adding value. The table below shows the breakdown of consumer benefits across these categories.

| Metric / consumer benefit alignment | Consumer benefit | % of total consumer benefits |
| --- | --- | --- |
| Measure benefit | £1,428m | 60.4% |
| Measure benefit driver | £481m | 20.3% |
| No metric | £457m | 19.3% |
| Total | £2,366m | 100.0% |

*Table 5: Metric / benefit alignment*

For each benefit area we have highlighted the metric which either directly measures the benefits or the benefits driver. Again, for more details see Annex 7 – Metrics and measuring performance.

### 1.3.8. Impact of benefits on the consumer bill

The customer bill impact is calculated based on the transformational activities we have calculated benefit for. It does not consider the benefits from our ongoing activities. The consumer benefit figure is therefore likely to be understated.

The benefits from our transformational activities will feed through to consumer bills in one of three ways:

- **via a change to the BSUoS charge:** It is assumed that 50 per cent will be passed on to demand consumers and that this benefit will be realised across BSUoS volumes across the industry. BSUoS volumes have been calculated using the volume forecast for 2019/20 through the RIIO-2 period. A loss scaling factor of 9 per cent is assumed which remains constant through the RIIO-2 period, and a typical usage value of 3,100 kilowatt hours (kWh) has been used, in line with medium profile class 1 electricity usage[8].
- **via a change to the Transmission System Use of System (TNUoS) charge:** It is assumed that 85 per cent will be passed on to demand consumers and it is that this benefit will be realised across TNUoS volumes across the industry which have been calculated using the volume forecast for 2019/20 through the RIIO-2 period. A loss scaling factor of 9 per cent is assumed which remains constant through the RIIO-2 period, and a typical usage value of 3,100 kWh has been used, in line with medium profile class 1 electricity usage.
- **via a change to the supplier charge:** It is assumed that 100 per cent will be passed on to demand consumers. A loss scaling factor of 9 per cent is assumed which remains constant through the RIIO-2 period, and a typical usage value of 3,100 kWh has been used, in line with medium profile class 1 electricity usage.

We have assumed that any benefit that does not fit into one of these categories, e.g. $CO_2$ reduction savings, does not directly reduce the consumer bill.

[8] https://www.ofgem.gov.uk/gas/retail-market/monitoring-data-and-statistics/typical-domestic-consumption-values

Table 6 shows the breakdown of consumer benefits across these categories.

| Bill impact area | Consumer benefit | Per cent of total consumer benefits |
|---|---|---|
| BSUoS Charge | £1,167m | 49.3% |
| TNUoS Charge | £733m | 31.0% |
| Supplier Charge | £409m | 17.3% |
| No direct impact | £57m | 2.4% |
| Total | £2,366m | 100.0% |

*Table 6: Consumer bill impact*

For each benefit area discussed in the rest of this document, we have highlighted how it would affect the consumer bill.

## 1.4. Overview of the benefits we deliver

### 1.4.1. Activities subject to CBA and break-even analysis

We have conducted 11 CBAs and five break-even analyses, as outlined in the table below.

| Role and Theme | Activity group and reference | Analysis type |
|---|---|---|
| Role 1, Theme 1 | A1 Control centre architecture and systems | CBA |
| | A2 Control centre training and simulation | CBA |
| | A3 Restoration | CBA |
| Role 2, Theme 2 | A4 Build the future balancing service and wholesale markets | CBA |
| | A4 Designing the markets of the future | Break-even |
| | A5 Transform access to the capacity market | CBA |
| | A6.4 Transform the process to amend our codes | Break-even |
| | A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 | CBA |
| | A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges | CBA |
| Role 3, Theme 3 | A8 – A11 Enhance the *Network Options Assessment (NOA)* | CBA |
| | A12 Review of the Security and Quality of Supply Standard (SQSS) | Break-even |
| | A13 Leading the debate | Break-even |

| Role and Theme | Activity group and reference | Analysis type |
|---|---|---|
| Role 3, Theme 4 | A14 Taking a whole electricity system approach to connections | CBA |
| | A15 Taking a whole electricity system approach to promote zero carbon operability | CBA |
| | A16 Delivering consumer benefits from improved network access planning | CBA |
| | A17 Digitalisation and open data | Break-even |

*Table 7: Activities by Benefit type*

### 1.4.2. Dependencies between the CBA activities

The diagram below highlights the dependencies between the 11 CBA activities. For a dependency, we mean that an activity could not fully deliver its benefits without another activity:

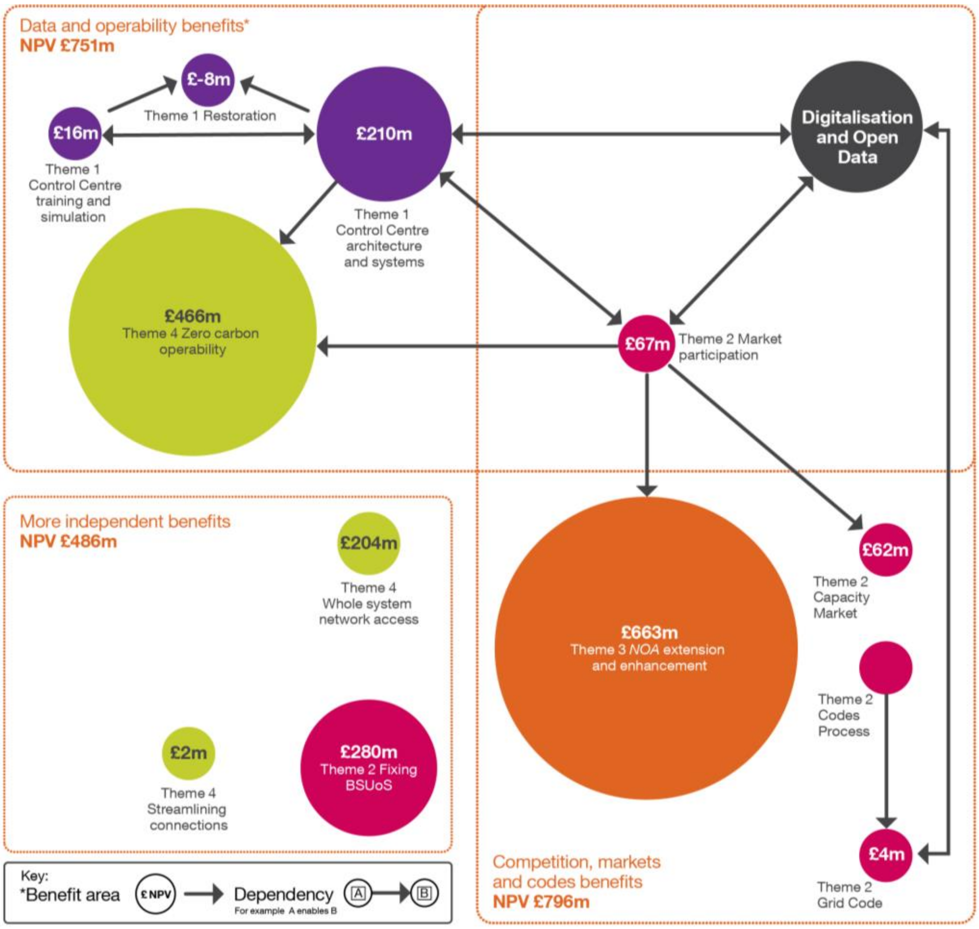


*Figure 4: Activity dependencies*

### 1.4.3. Summary of the benefits delivered

Our benefit assumptions, data (including costs) and calculations are in the following section. A summary is shown below for the preferred option of the activities for which we have undertaken a CBA, along with any[9] sensitivity analysis.

| ESO activities £ million | Five year NPV | Ten year NPV | Market factors High 5-year NPV | Market factors Low 5-year NPV | Delivery factors High 5-year NPV | Delivery factors Low 5-year NPV | Third Party factors High 5-year NPV | Third Party factors Low 5-year NPV |
|---|---|---|---|---|---|---|---|---|
| A1 | 210 | 526 | 385 | 86 | 404 | 57 | 214 | 208 |
| A2 | 16 | 42 | 21 | 11 | 42 | -2 | N/A | N/A |
| A3 | -8 | -23 | N/A | N/A | N/A | N/A | N/A | N/A |
| Role 1, Theme 1 total | 218 | 546 | 398 | 89 | 438 | 46 | 222 | 215 |
| A4 | 67 | 183 | 87 | 47 | 115 | 3 | N/A | N/A |
| A5 | 62 | 128 | 83 | 42 | 94 | 21 | 65 | 60 |
| A6.5 | 4 | 18 | 7 | 2 | N/A | -1 | 9 | 0 |
| A6.6 | 280 | 580 | 730 | 270 | N/A | 206 | N/A | N/A |
| Role 2, Theme 2 total | 414 | 909 | 908 | 362 | 493 | 229 | 421 | 407 |
| A8 – A11 | 663 | 1,321 | 906 | 488 | N/A | 463 | N/A | N/A |
| Role 3, Theme 3 total | 663 | 1,321 | 906 | 488 | N/A | 463 | N/A | N/A |
| A14 | 2 | 15 | 3 | 1 | N/A | -2 | N/A | N/A |
| A15 | 466 | 943 | 603 | 358 | N/A | 331 | 486 | 447 |
| A16 | 204 | 420 | 310 | 138 | 286 | 98 | N/A | N/A |
| Role 3, Theme 4 total | 673 | 1,378 | 916 | 497 | 755 | 427 | 692 | 654 |
| **ESO total** | **1,967** | **4,153** | **3,128** | **1,435** | **2,348** | **1,165** | **1,998** | **1,939** |

*Table 8: Summary benefits table*

[9] If no sensitivity analysis has been undertaken a "N/A" is shown

# 2. Cost-benefit analysis: Role 1, Theme 1

This section provides further context on the costs and quantifiable benefits of the transformational activities in Role 1, Theme 1:

| Activity group | Analysis type |
|---|---|
| A1 Control centre architecture and systems | CBA |
| A2 Control centre training and simulation | CBA |
| A3 Restoration | CBA |

*Table 9: Role 1, Theme 1 activities*

The NPV of Role 1, Theme 1 is estimated at £218 million over the RIIO-2 period and £546 million over ten years. Sensitivity analysis suggests an NPV range of £46 million to £438 million over the RIIO-2 period.

## 2.1 A1 Control centre architecture and systems

This sub-section provides further context on the costs and quantifiable benefits of our A1 Control centre architecture and systems activities.

The net present value of A1 Control centre architecture and systems proposals is £210 million over the RIIO-2 period, and £526 million over ten years. Sensitivity analysis suggests an NPV range of £57 million to £404 million over the RIIO-2 period

### 2.1.1 The counterfactual

If we did not undertake our transformational A1 Control centre architecture and systems activities, we would use existing balancing and network control tools. These are outlined in the ‘ongoing activities and enhancements during RIIO-2’ section of our Business Plan. This is because we will need to carry out this work, in parallel to building new systems, to maintain compliance with our licence obligations.

### 2.1.2 The benefits

Our A1 Control Centre architecture and systems activities deliver benefits in six areas, which we explain in the sections below. The six areas are:

- reduced CO2 emissions
- greater interconnection
- utilising flexible technology
- better inertia forecasting and needs management
- improved situational awareness
- reduced balancing mechanism outage downtime.

#### 2.1.2.1 Reduced $CO_2$ emissions

| Assumptions | Justification |
|---|---|
| 5% of power sector carbon emissions are influenced by ESO instructions | From analysis of historic data, we have calculated the volume of ESO activity in the balancing mechanism and trading is around 5% of national demand. As the balancing mechanism is reflective of the wider market, 5% of power sector emissions are influenced by the ESO's instructions |
| Use of Steady Progression and Two Degrees from *FES* 2019 as proxies | If the we do not upgrade our balancing and control capabilities, we will be a blocker to achieving the lower carbon intensities under the Two Degrees scenario. Based on the *FES* 2019 scenarios, our judgement is that Steady Progression acts as a reasonable proxy for tools not upgraded and Two Degrees for upgraded tools. |
| Levels of expected demand taken from Two Degrees from *FES* 2019 | There is little variation in expected annual demand over the five years of RIIO-2 across the *FES* scenarios. |
| Percentage of maximum annual benefit | ESO judgement on the plan timetable and the need to avoid double counting. |

*Table 10: Reduced $CO_2$ emissions assumptions*

Our proposals help unlock the benefits of the lower carbon intensity energy market of the future. Without investment in new balancing and control capability, the control room will not be able to maximise the use of low carbon technologies and still balance in a technology neutral manner. Under the assumption that 5 per cent of all power sector carbon emissions are influenced by ESO, we can calculate the carbon savings by comparing the carbon intensities of high and low decarbonisation.

We assume our proposals unlock the lower carbon intensities of our Two Degrees scenario compared with Steady Progression. To account for new systems being delivered in a modular fashion we have considered the percentage of the maximum annual benefit. In the final year, we claim only 94 per cent of the maximum benefit to avoid double counting A3 Restoration benefits. This generates £51 million of consumer benefit over the RIIO-2 period.

*Sensitivity analysis - Reduced $CO_2$ emissions*

- Market factors: we have repeated the analysis with the low and high cases of the BEIS short-term traded carbon values.
- Third party factors: we have not conducted a third-party sensitivity as the benefits case is not dependent on third parties. For example, there is little variation in expected demand in the RIIO-2 period across the *FES* scenarios.
- Delivery factors: we have modelled a one-year delay in the delivery of new systems. We have not modelled bringing forward delivery as we do not believe this is deliverable.

| **Financial year:** | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** | **RIIO-2 Total** | **Calculation** |
|---|---|---|---|---|---|---|---|
| Carbon intensity Steady Progression ($gCO_2/kWh$) | 136.44 | 119.55 | 128.48 | 123.71 | 110.89 | | A |
| Carbon intensity Two Degrees $gCO_2/kWh$ | 69.19 | 57.56 | 53.57 | 44.33 | 38.69 | | B |
| Reduction $gCO_2/kWh$ | 67.25 | 61.99 | 74.91 | 79.38 | 72.21 | | C = A - B |
| Expected demand terawatt hours (Two Degrees) | 305.43 | 304.23 | 303.50 | 304.10 | 303.87 | | D |
| Carbon price $t/CO_2e$ (calendar year adjusted to financial year) | 14.70 | 15.25 | 15.83 | 16.63 | 19.24 | | E |
| Saving (£ millions) | 302 | 288 | 360 | 401 | 422 | | F = C x D x E |
| Attributable saving (£ millions) | 15.1 | 14.4 | 18.0 | 20.1 | 21.1 | | G = 5% x F |
| Percentage of maximum annual benefit claimed | 5% | 25% | 60% | 80% | 94% | | H |
| Adjusted saving (£ millions) | 0.8 | 3.6 | 10.8 | 16.1 | 19.8 | 51.0 | I = G x H |

*Table 11: Benefits calculation for reduced $CO_2$ emissions*

| | Benefits £ millions | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|---|
| Reduced $CO_2$ emissions | | 0.8 | 3.6 | 10.8 | 16.1 | 19.8 | 51.0 |
| Sensitivity – high market factors | | 1.5 | 7.2 | 21.6 | 32.1 | 38.5 | 100.9 |
| Sensitivity – low market factors | | 0.0 | 0.0 | 0.0 | 0.5 | 2.5 | 3.0 |
| Sensitivity – low delivery confidence | | 0.0 | 0.7 | 4.5 | 12.0 | 16.9 | 34.2 |

*Table 12: Benefits for reduced $CO_2$ emissions*

The above table shows the benefits associated with reduced $CO_2$ emissions are between £3 million and £100.9 million, with a central case of £51 million.

*Measuring benefits and consumer bill impact*

The £51 million benefit could be tracked as part of any regulatory reporting for RIIO-2.

This benefit will not directly impact consumer bills.

### 2.1.2.2 Greater interconnection

| Assumptions | Justification |
|---|---|
| Consumer benefits delivered by interconnection | Analysis[10] undertaken by Poyry for Ofgem using the High (MA) GB consumer welfare impact, extrapolating from the three Window 2 projects. The MA (marginal additional) case provides a lower bound for benefits by assuming an interconnector is the last to be added, contrasted with FA (first additional) case that provides an upper bound by assuming an interconnector is the first to be added. We used the High (MA) case as it provides central consumer welfare impact benefit proxy out of the four published MA cases. |
| ESO proposals unlock 2% of this benefit | Analysis of historic data comparing the volume of activity in balancing mechanism and trading activity as a proportion of national demand suggests we reprofile 5% of the market, and thus have leverage over 5% of interconnection. Allowing for the fact that we are making ongoing improvements (IT investment reference 120 - interconnectors) and that the benefits will mainly come from our transformational |

[10] Poyry Management Consulting: Near-term interconnector cost-benefit analysis: independent report (cap and floor window 2)

| | |
|---|---|
| | investments in inertia forecasting, frequency visibility and situational awareness, we claim a conservative 2%. |
| Percentage of maximum annual benefit claimed | We believe our proposals ultimately unlock, at most, 2% of savings from greater interconnection. Given that we are developing new tools across the RIIO-2 period, we cannot claim the maximum benefit until the end, and so claim a reduced benefit in the preceding years. |
| Profile of interconnection capacity during RIIO-2 | The ENA Common Scenario output indicates between 15GW and 16.5GW of installed capacity to 2030. Community Renewables *FES* scenario is the best fit (16GW in 2030), so we have used this scenario to profile interconnector delivery. |

*Table 13: Greater interconnection assumptions*

We have reviewed published analysis undertaken by Poyry for Ofgem on the benefits of interconnection. Using conservative assumptions, this indicates there is around £1 billion of consumer benefits from greater interconnection over the RIIO-2 period. The value of the benefit is the reduction in the total spend on electricity in GB because of interconnector imports.

We are currently required to control interconnector flow (for example by trading back) for operability reasons. New balancing and control capabilities, in particular inertia monitoring, frequency visibility and situational awareness, would allow us to better understand the operating envelope across the day. This would help us use interconnectors more efficiently by factoring in smaller risk margins and being able to match the risk profile of operability concerns to the market profile throughout the day. Currently, we only consider the largest risk profile on a given day.

A modest assumption is that our investments contribute to unlocking around 2 per cent of these benefits given by greater interconnection. This gives an estimated consumer benefit of £11.8 million.

### *Sensitivity analysis - Greater interconnection*

- Market factors: for the high sensitivity we repeated the analysis with the Base (MA) case from Poyry's findings; for the low sensitivity we used the Low (MA) case[11]
- Delivery factors: for the high sensitivity we assume our proposals unlock 3 per cent of the benefits; for the low sensitivity we assume our proposals unlock 1 per cent of the benefits and are delivered one year later
- Third party factors: for the high sensitivity we have assumed an additional 16 GW of interconnection is delivered; for the low sensitivity was have assumed an additional 8 GW.

[11] When looking at consumer impact (as opposed to GB net welfare impact or total net welfare impact) the Base (MA) case provides higher consumer benefit than the High (MA) case

| Interconnector | Benefit per GW (2015 €m) |
|---|---|
| North Connect | 800 |
| Neu Connect | -200 |
| Grid Link | 1,200 |
| Average | 600 |

*Table 14: Interconnector consumer welfare impact*

| Item | Value | Calculation |
|---|---|---|
| Total benefit per GW (2015 €m) | 600 | |
| Total benefit per GW (2018 £m)[12] | 474.3 | A |
| Total value per GW per year (£m)[13] | 19.0 | B = A / 25 |

*Table 15: Benefit calculations for greater interconnection*

| Financial year: | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | RIIO-2 total | Calculation |
|---|---|---|---|---|---|---|---|
| Total value per GW per year (£m) | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 94.9 | B |
| Amount of interconnection (GW) | 8.4 | 8.4 | 10.3 | 11.7 | 13.1 | 13.1 | C |
| Total benefit from interconnection (£m) | 159.4 | 159.4 | 195.5 | 222.0 | 248.6 | 985.0 | D = B x C |
| Maximum benefit unlocked by ESO (£m) | 3.2 | 3.2 | 3.9 | 4.4 | 5.0 | 19.7 | E = 2% x D |
| Percentage of maximum annual benefit claimed | 5% | 25% | 60% | 80% | 100% | | F |
| Total benefit (£m) | 0.2 | 0.8 | 2.3 | 3.6 | 5.0 | 11.8 | G = E x F |

*Table 16: Benefit delivered by greater interconnection*

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[12] Adjusting for inflation and exchange rates. Exchange rate is average annual 2015 EUR-GBP rate from Bank of England. Inflation is from ONS RPI All items index.
[13] 25 years is the assumed project life

| Benefits £ millions | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Greater interconnection | 0.2 | 0.8 | 2.3 | 3.6 | 5.0 | 11.8 |
| Sensitivity – high market factors | 0.7 | 3.2 | 9.5 | 14.4 | 20.2 | 48.0 |
| Sensitivity – low market factors | 0.1 | 0.5 | 1.5 | 2.3 | 3.2 | 7.6 |
| Sensitivity – high delivery confidence | 0.2 | 1.2 | 3.5 | 5.3 | 7.5 | 17.7 |
| Sensitivity – low delivery confidence | 0.0 | 0.1 | 0.5 | 1.3 | 2.0 | 3.9 |
| Sensitivity – high third party benefits | 0.2 | 1.0 | 3.4 | 5.0 | 6.8 | 16.4 |
| Sensitivity – low third party benefits | 0.1 | 0.8 | 1.9 | 2.6 | 3.9 | 9.3 |

*Table 17: Benefits for greater interconnection*

The above table shows the benefits from greater interconnection are between £3.9 million and £48 million, with a central case of £11.8 million.

*Measuring benefits and consumer bill impact*

The driver of this £11.8 million benefit can, in part, be measured via Metric 1 - Balancing cost management. See Annex 7 - Metrics and measuring performance for more details.

This benefit will impact on consumer bills by unlocking lower BSUoS and TNUoS charges than would otherwise have been the case.

### 2.1.2.3 Utilising flexible technology

| Assumptions | Justification |
|---|---|
| £1.34 billion savings from reduced system operation costs delivered by accessing new sources of flexibility | Analysis[14] by Imperial College London suggests that there is between £0.8bn (25% of £3.2bn) and £1.88bn (40% of £4.7bn) consumer savings per year from reduced system operation costs achievable by accessing new sources of flexibility. Taking a midpoint of gives £1.34bn. |
| ESO proposals unlock 3% of this benefit | The report explains the enablers to unlock this benefit. In paragraph 2.6 one of the main requirements for future electricity systems will be “appropriate systems and interfaces to manage greater complexity in the system”. In paragraph 4.1.4 the report states that system operators should be incentivised to “access all flexibility resource and be prepared to handle additional complexity in the system, by making investments and operational decisions that maximise total system benefits”. We believe our transformational proposals help enable this and, consistent with our residual balancer role, unlock 3% of this, giving £40.2m savings per year. |
| Percentage of maximum annual benefit claimed | We believe our proposals ultimately unlock, at most, 3% of savings from greater flexibility. Given that we are developing new tools across the RIIO-2 period, we cannot claim the maximum benefit until the end, and so claim a reduced benefit in the preceding years. |

*Table 18: Utilising flexible technology assumptions*

Based on our technical judgement, we assume our investments contribute to unlocking 3% of benefits from reduced system operation costs, leading to £105.5 million of consumer benefits over RIIO-2. To account for new systems being delivered in a modular fashion, we have considered the percentage of the maximum annual benefit we can claim.

#### *Sensitivity analysis - Utilising flexible technology*

- Market factors: we assume the benefits of flexibility from reduced system operation costs are £0.8 billion and £1.88 billion, being the 25 per cent and 40 per cent cases respectively
- Third party factors: we have not conducted a third-party sensitivity because the benefit case is not dependent on third party actions not accounted for under the market factors sensitivity.
- Delivery factors: we have assumed our proposals unlock between 2 per cent and 4 per cent of the benefits.

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[14] Poyry and Imperial College London – Roadmap for Flexibility Services to 2030: A report to the Committee on Climate Change https://www.theccc.org.uk/wp-content/uploads/2017/06/Roadmap-for-flexibility-services-to-2030-Poyry-and-Imperial-College-London.pdf

| Financial year: | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | RIIO-2 Total | Calculation |
|---|---|---|---|---|---|---|---|
| Benefit per year from flexible technology (£ millions) | 1,340 | 1,340 | 1,340 | 1,340 | 1,340 | 6,700 | A |
| ESO attributable saving | 40.2 | 40.2 | 40.2 | 40.2 | 40.2 | 201 | B = 3% x A |
| Percentage of maximum annual benefit claimed | 5% | 25% | 60% | 80% | 100% | | C |
| Benefit (£ millions) | 2.0 | 10.1 | 24.1 | 32.2 | 40.2 | 108.5 | D = B x C |

*Table 19: Benefit calculation for utilising flexible technology*

| Benefits £ millions | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Utilising flexible technology | 2.0 | 10.1 | 24.1 | 32.2 | 40.2 | 108.5 |
| Sensitivity – high market factors | 2.8 | 14.1 | 33.8 | 45.1 | 56.4 | 152.3 |
| Sensitivity – low market factors | 1.2 | 6.0 | 14.4 | 19.2 | 24.0 | 64.8 |
| Sensitivity – high delivery confidence | 2.7 | 13.4 | 32.2 | 42.9 | 53.6 | 144.7 |
| Sensitivity – low delivery confidence | 0.0 | 1.3 | 6.7 | 16.1 | 21.4 | 45.6 |

*Table 20: Benefits for utilising flexible technology*

The above table shows the benefits from using flexible technology are between £45.6 million and £152.3 million, with a central case of £108.5 million.

### *Measuring benefits and consumer bill impact*

The driver of this £109 million benefit can, in part, be measured via Metric 1 - Balancing cost management. See Annex 7 – Metrics and measuring performance for more details.

This benefit will impact on consumer bills by unlocking lower BSUoS and TNUoS charges than would otherwise have been the case.

### 2.1.2.4 Better inertia forecasting and needs management

| Assumptions | Justification |
|---|---|
| Inertia issues to be resolved in May 2022 | Compliance with the Distribution Code[15] |
| Rate of Change of Frequency (RoCoF) spend will be £144 million per year | Current spend |
| 10% improvement in forecasting | Consistent with improvements in demand forecasting as per the 2018/19 *Forward Plan* End of Year Report evidence chapters[16] (12% improvement in demand forecasting and 3% improvement in wind generation forecasting). |

*Table 21: Better inertia forecasting and needs management assumptions*

Inertia forecasting and needs management improvements will give us a more accurate understanding of system inertia. This, in turn, will enable us to manage risk more efficiently, by being able to operate the system closer to the limits. This issue will be resolved in May 2022, so we assume benefits until then i.e. 13 months.

Our current spend on Rate of Change of Frequency (RoCoF) is £144 million per year. Assuming a 10 per cent improvement in accuracy, which is consistent with 2018/19, this delivers £15.6 million of benefit over RIIO-2.

*Sensitivity analysis - Better inertia forecasting and needs management*

- Market factors: we have not conducted a sensitivity analysis.
- Third party factors: we have not conducted a sensitivity analysis because we are assuming compliance with the Distribution Code.
- Delivery factors: we have modelled a 5 per cent and 15 per cent improvement in forecasting.

[15] Energy Networks Association: Accelerated Loss of Mains Protection http://www.energynetworks.org/electricity/engineering/loss-of-mains.html
[16] National Grid Electricity System Operator: 2018-19 Forward Plan End of Year Report Evidence Chapters https://www.nationalgrideso.com/document/128421/download

| Financial year: | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | RIIO-2 total | Calculation |
|---|---|---|---|---|---|---|---|
| RoCoF spend per year (£ millions) | 144 | 12 | N/A | N/A | N/A | 156 | A |
| ESO attribute saving | 10% | 10% | N/A | N/A | N/A | | B |
| Benefit (£ millions) | 14.4 | 1.2 | N/A | N/A | N/A | 15.6 | C = A x B |

*Table 22: Benefit calculation for better inertia forecasting and needs management*

| **Benefits**<br>**£ millions** | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** | **Total** |
|---|---|---|---|---|---|---|
| Better inertia forecasting and needs management | 14.4 | 1.2 | N/A | N/A | N/A | 15.6 |
| Sensitivity – high delivery confidence | 21.6 | 1.8 | N/A | N/A | N/A | 23.4 |
| Sensitivity – low delivery confidence | 7.2 | 0.6 | N/A | N/A | N/A | 7.8 |

*Table 23: Benefits for better inertia forecasting and needs management*

The above table shows the benefits from better inertia forecasting and needs management are between £7.8 million and £23.4 million, with a central case of £15.6 million.

### *Measuring benefits and consumer bill impact*

The driver of this £15.6 million benefit be measured via Metric 1 – Balancing cost management. See Annex 7 – Metrics and measuring performance for more details.

This benefit will impact on consumer bills through lower BSUoS charges than would otherwise have been the case.

### 2.1.2.5 Improved situational awareness

| Assumption | Justification |
|---|---|
| Constraint cost estimates | Based on modelling used in the *NOA* process |
| 5% improvement in constraint spend | A network innovation allowance (NIA) project demonstrated[17] that new tools could deliver a reduction of 3% to 12% in constraint spend. Based on this, we claim a conservative 5%. |
| Percentage of maximum annual benefit claimed | We believe our proposals ultimately deliver a 5% saving in constraint costs. Given that we are developing new tools across the RIIO-2 period, we cannot claim the maximum benefit until the end, and so claim a reduced benefit in the preceding years. |

*Table 24: Improved situational awareness assumptions*

Improved situational awareness – the ability to monitor and understand network status and evolving operational limits – allows better management of transmission. Based on the findings of a recent NIA project, we believe our new balancing and control capabilities could ultimately reduce constraint spend by 5 per cent per year. We taper these benefits to match the delivery of our new capabilities. This delivers benefits of £117 million over RIIO-2.

To avoid any potential double counting with the benefits in section 2.2.2.3 we have not considered a reduction in reserve and response spend. It is, however, important that our proposals in A1 Control Centre architecture and systems and A2 Control Centre training and simulation are considered as a package.

#### *Sensitivity analysis - Improved situational awareness*

- Market factors: we repeat our analysis with the lowest and highest constraint forecasts from the *FES* scenarios.
- Third party factors: we have not conducted a third-party sensitivity because the impact of actions by third parties is accounted for in the market factors sensitivity.
- Delivery factors: for the upper case we assume 12 per cent savings for constraints; for the lower case we assume 3 per cent savings and a one-year delay.

[17] Network Innovation Allowance Closedown Report – Transmission Network Topology Optimisation https://www.smarternetworks.org/cdn/pdf/closedown/48646d78-d4cd-e711-93f1-001517891cc5

*Interaction with other benefit areas*

The proposals in sections 4.1.2.1 and 5.4.2 claim to lower constraint costs. We have not accounted for these in the central benefit case here, but they would be accounted for in the market factors sensitivity analysis.

| Financial year: | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | RIIO-2 Total | Calculation |
|---|---|---|---|---|---|---|---|
| Constraint costs (£ millions) | 600 | 689 | 809 | 931 | 909 | 3,938 | A |
| Improvement | 5% | 5% | 5% | 5% | 5% | | B |
| Percentage of maximum annual benefit claimed | 5% | 25% | 60% | 80% | 100% | | C |
| Benefit (£ millions) | 1.5 | 8.6 | 24.3 | 37.2 | 45.5 | 117.1 | D = A x B x C |

*Table 25: Benefit calculation for improved situational awareness*

| Benefits £ millions | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Improved situational awareness | 1.5 | 8.6 | 24.3 | 37.2 | 45.5 | 117.1 |
| Sensitivity – high market factors | 1.9 | 13.8 | 39.7 | 56.3 | 69.5 | 181.2 |
| Sensitivity – low market factors | 1.1 | 6.2 | 16.9 | 25.8 | 26.5 | 76.4 |
| Sensitivity – high delivery confidence | 3.6 | 20.7 | 58.2 | 89.4 | 109.1 | 281.0 |
| Sensitivity – low delivery confidence | 0.0 | 1.0 | 6.1 | 16.8 | 21.8 | 45.7 |

*Table 26: Benefits for improved situational awareness*

The above table shows the benefits associated with improved situational awareness are between £45.7 million and £281 million, with a central case of £117 million.

*Measuring benefits and consumer bill impact*

The driver of this £117 million benefit can be measured via Metric 1 - Balancing cost management. See Annex 7 – Metrics and measuring performance for more details.

This benefit will impact on consumer bills through lower BSUoS charges than would otherwise have been the case.

### 2.1.2.6 Reduced Balancing Mechanism outage downtime

| Assumptions | Justification |
|---|---|
| Cost of an outage is £700,000 per hour | Based on current service level agreement (SLA) for Balancing Mechanism system |
| 2 hours 23 minutes of unplanned outage per year | Recent average of balancing mechanism (BM) outages. Unplanned incidents since 2016:<br>1. 22 Jan 2016 - 2hrs 25min<br>2. 8 Feb 2019 - 4hrs 57min |
| Our proposals will reduce this to one hour per year | ESO engineering judgement |

*Table 27: Reduced Balancing Mechanism outage downtime assumptions*

From recent events, we have calculated the cost of an unplanned outage as approximately £700,000 per hour. Since 2016 there have been on average 2 hours 23 minutes of unplanned outage per year, costing £1.67 million per year.

We assume our proposals will reduce unplanned outages to one hour per year. We only claim this benefit in 2025/216, when our new enhanced balancing tool is fully delivered. This will deliver savings of just under £1 million over RIIO-2

*Sensitivity analysis*

- Market factors: we have not conducted a sensitivity analysis based on market factors.
- Third party factors: we have not conducted a sensitivity analysis based on third party factors because our benefit case is not dependent on the actions of third parties.
- Delivery factors: we assume a reduction to 1.5 hours and 0.5 hours per year for the lower and upper cases respectively.

| **Benefits £ million** | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** | **Total** |
|---|---|---|---|---|---|---|
| Reduced balancing mechanism outage downtime | 0.0 | 0.0 | 0.0 | 0.0 | 1.0 | 1.0 |
| Sensitivity – high delivery confidence | 0.0 | 0.0 | 0.0 | 0.0 | 1.3 | 1.3 |
| Sensitivity – low delivery confidence | 0.0 | 0.0 | 0.0 | 0.0 | 0.6 | 0.6 |

*Table 28: Benefits for reduced Balancing Mechanism outage downtime*

The table above shows the benefits from reduced balancing mechanism outage downtime are between £0.6 million and £1.3 million, with a central case of £1 million.

*Measuring benefits and consumer bill impact*

The driver of this £1 million benefit can be measured via Metric 2 – Critical National Infrastructure (CNI) system reliability. See Annex 7 – Metrics and measuring performance for more details.

This benefit will impact on consumer bills through lower BSUoS charges than would otherwise have been the case.

*Total benefits case*

The total benefits for control centre architecture systems are between £138 million and £519 million, with a central case of £305 million over the RIIO-2 period.

### 2.1.3 Activity costs

Delivery of our A1 Control Centre architecture and systems activities will require additional capex and opex spend, summarised below:

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 17.4 | 27.5 | 31.7 | 25.7 | 18.1 | 120.3 |
| Opex | 3.4 | 5.6 | 7.5 | 7.9 | 8.5 | 32.8 |
| Total | 20.7 | 33.0 | 39.3 | 33.6 | 26.6 | 153.2 |

*Table 29: Incremental costs for control centre architecture and system*

The total costs for our A1 Control centre architecture and systems activities are £153.2 million.

### 2.1.4 Net Present Value

The net present value (NPV) of our A1 Control Centre architecture and systems activities is estimated at £210 million over the RIIO-2 period and £526 million over ten years. Our A1 Control centre architecture and systems activities will start to deliver positive returns from 2023/24. Sensitivity analysis suggests an NPV range of:

- market factors between £86 million and £385 million
- delivery factors between £57 million and £404 million
- third party factors between £208 million and £214 million.

### 2.1.5 Dependencies, enablers and whole energy system

This activity is dependent on the following transformational activities:

- A2 Control centre training and simulation (Role 1, Theme 1) – Equipping the control centre with fully trained staff to operate in a zero carbon world; and
- A17 Digitalisation and open data – Ensuring the data flow between the ESO and market participants allows them to understand system operability.

Through the most efficient operation of a complex decentralised and decarbonised electricity system this also delivers the following transformational activities:

- A2 Control centre training and simulation (Role 1, Theme 1) - Providing real world experience for training and simulations.
- A4 Build the future balancing service and wholesale markets (Role 2, Theme 2).
- A15 Taking a whole electricity system approach to promote zero-carbon operability (Role 3, Theme 4).
- A17 Digitalisation and open data - Providing additional data from real world system operation.

Delivery of this activity will pass on benefits and costs to other parties. There may be a cost to DNOs, TOs and market participants to integrate their systems and data to our new tools. New market participants would incur these types of costs today. In all cases, the benefit of moving towards standardised technology and data should outweigh any additional cost.

### 2.1.6 Uncertainties and risks

We have accounted for market, third party and deliverability uncertainties in our sensitivity analysis.

The table below summarise the key delivery risks and how we propose to mitigate them. Where appropriate, their impact on the consumer benefit delivered is included. Risks for the associated IT investments can be found in Annex 4 – Technology investment report.

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Unable to source vendors. | Starting our work as soon as possible, in particularly creating the proposed cross-sector design authority. We have established partners and have already started talking with them. The move to a modular build removes the risk of single source of failure. | 2 | 2 |
| Data platform cannot be delivered in a timely fashion, delaying delivery of other systems | Early engagement with framework supply partners and out of sector industries who have already gone through a transformation. A key impact would be that the roadmap would need to be significantly redesigned. | 2 | 3 |
| Unable to source skilled resource within ESO and market participants to deliver in required timescales. | Starting our work as soon as possible, in particularly creating the proposed cross-sector design authority. The people, culture and capability strategy will source the required capability - the skills we need are broader than traditional power system engineers. | 2 | 2 |
| Unforeseen market changes mean requirements change. | Developing capability in a modular fashion to ensure flexibility. The full end-to-end process is overseen by the design | 2 | 2 |

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| | authority, so market changes will be picked up quickly. | | |
| Market landscape does not evolve as expected. | Developing capability in a modular fashion to ensure flexibility. The full end-to-end process is overseen by the design authority, so market changes will be picked up quickly. | 2 | 2 |

*Table 30: Risks for A1 Control centre architecture and systems*

### 2.1.7 Other options considered

We considered four options for our A1 Control centre architecture and systems proposals. These form a two by two matrix based on whether we deliver transformational investment or simply maintain our current capabilities, and how we deliver it - either within the current architecture while the current control room is online, or offline with new architecture. The table below demonstrates this, with further information below.

| **Options for developing our balancing and control capabilities** | | **Investment** | |
|---|---|---|---|
| | | **Ongoing** | **Ongoing and transformational** |
| **Delivery method** | **Online within the current architecture** | Option 1 | Option 3 |
| | **Offline with new architecture** | Option 2 | Option 4 |

*Table 31: A1 Control centre architecture and systems options*

In all options, we will continue to operate the electricity transmission system safely, economically and efficiently, consistent with our licence obligations.

*Advantages and disadvantages*

#### 2.1.7.1 Ongoing: replace the current systems as needed, online and within the current architecture

This is the investment listed in section 4.2.2 of our Business Plan. Under this option, we would upgrade our core systems, so we remain compliant with our licence obligations, but not deliver new and transformational capabilities. This option forms the counterfactual for assessing the other options against.

| Advantages | Disadvantages |
|---|---|
| Lowest direct cost | Outdated architecture designed for a marketplace with a relatively small number of large centralised participants. It is not capable of being easily modified for a decentralised and decarbonised world<br>Unlikely to deliver the balancing and control capabilities we need and meaning that we cannot meet our commitment to operate a zero carbon system by 2025 |

*Table 32: A1 Control centre architecture and systems options Option 1 advantages and disadvantages*

#### 2.1.7.2 Replace the current systems as needed within a new architecture developed offline

This option would deliver a new architecture, designed and developed offline, but would only refresh systems as per option 1.

| Advantages | Disadvantages |
|---|---|
| Develops new architecture. Allows new capabilities to be developed quicker and upgraded in a "plug and play" or "app-like" manner | Unlikely to deliver the balancing and control capabilities we need. Would mean that we cannot meet the 2025 ambition |

*Table 33: A1 Control centre architecture and systems options Option 2 advantages and disadvantages:*

We do not see a justification for creating a new architecture if we are only going to replace our current systems on an ongoing basis. In line with Ofgem's guidance, we have not taken this option forward to the long list.

#### 2.1.7.3 Deliver new and upgraded balancing and control systems online within the current architecture

The transformational capabilities we have described would be built and installed into the existing control room while it is still online.

| Advantages | Disadvantages |
|---|---|
| Develops new balancing and control capabilities we need<br>Lower cost than Option 4, due to removal of some investments (e.g. data platform) | There is high complexity in amending large interdependent IT systems while they are live. This would lead to slower implementation times and increased operational and commercial risk, which may not meet the needs of market participants<br>Approach is similar to the way we have developed systems historically; this has not delivered the speed of change to that stakeholders want |

| Advantages | Disadvantages |
|---|---|
| | Proceeding with this option would make it significantly more challenging to meet the 2025 zero carbon ambition. This is because the current systems rely heavily on a point-to-point communication architecture. Thus, a change to one system will trigger multiple changes to other systems – this would restrict the flexibility we need to adapt quickly to the changing energy landscape |

*Table 34: A1 Control centre architecture and systems options Option 3 advantages and disadvantages*

Overall, we do not believe this option would allow us to deliver our ambition and provide the transparency that stakeholders need. In line with Ofgem's guidance, we have not taken this option forward to the long list.

#### 2.1.7.4 Preferred option

Deliver new and upgraded balancing and control architecture and systems, designed and developed offline in a modular fashion.

| Advantages | Disadvantages |
|---|---|
| Develops the new balancing and control capabilities we need.<br>Develops new architecture, allowing new capabilities to be developed quicker and upgraded in a "plug and play" or "app-like" manner. | Potential for disruption when new systems go live. |

*Table 35: A1 Control centre architecture and systems options Option 4 advantages and disadvantages*

*Summary*

We have decided to proceed with Option 4 because:

- our approach is supported by stakeholders
- the CBA indicates a positive NPV
- in our commercial and technical judgement, we need to invest in new balancing and control capabilities, and create a new control architecture, to be able to operate the electricity system of the future carbon free.

## 2.2 A2 Control centre training and simulation

This sub-section provides further context on the costs and quantifiable benefits of our A2 Control centre training and simulation activities.

The net present value (NPV) of A2 Control centre training and simulation is £16 million over the RIIO-2 period, and £42 million over ten years. Sensitivity analysis suggests an NPV range of negative £2 million to £42 million over the RIIO-2 period.

### 2.2.1 The counterfactual

If we did not undertake our transformational A2 Control centre training and simulation activities, we would make enhancements to our legacy simulators and continue with our current training schemes. Some of this work will be carried out whilst our transformational activities are in development.

### 2.2.2 The benefits

We have quantified benefits in three areas:

- Reduced resource costs.
- Decreased training costs.
- Improved decision making.

#### 2.2.2.1 Reduced resource costs

| Assumptions | Justification |
|---|---|
| Cost saving | Based on past resource costs |

*Table 36: Reduced resource costs assumptions*

Current inefficiencies in our workforce management tools are costing around £1m per year. New workforce and change management tools, updated shift patterns and working arrangements will create efficiencies and increase staff retention. We believe we can ultimately save around £1.3 million per year, by removing the spend on current inefficiencies and creating further efficiencies. To allow time for them to be embedded, we claim a reduced benefit in the first two years. This creates £5 million savings over RIIO-2.

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Reduced resource costs | 0.5 | 0.5 | 1.3 | 1.3 | 1.3 | 5 |

*Table 37: Benefits for Reduced resource costs assumptions*

*Measuring benefits and consumer bill impact*

The £5 million benefit could be tracked as part of any regulatory reporting for RIIO-2.

This benefit will impact on consumer bills through lower BSUoS charges than would otherwise have been the case.

### 2.2.2.2 Decreased training costs

| Assumptions | Justification |
|---|---|
| Reduction in training time | ESO judgement, based on proposed transformational activities reducing training time from seven months to four months (42%) |
| Training cost | Historic averages of £75,000 per candidate, with 30 candidates trained per year |
| Number of new starters trained | Based on historic data and forecast industry turnover |
| Percentage of maximum annual benefit claimed | We believe our proposals ultimately deliver a three-month reduction in training time. Given that we are implementing enhanced training and developing new tools gradually over the RIIO-2 period, we cannot claim the maximum benefit until the end, and so claim a reduced benefit in the preceding years. |

*Table 38: Decreased training costs assumptions*

Our enhanced training proposals and new training and simulator proposals will mean that new starters have more knowledge and we can train them quicker. We estimate this will lead to a saving of £2.2 million over the RIIO-2 period. This assumes we can reduce training time by three months, saving approximately £32,000 per candidate. We train on average more than 30 people per year. Given that we are implementing enhanced training and developing new tools gradually over the RIIO-2 we have considered the percentage of the maximum annual benefit we can claim.

*Sensitivity analysis*

- Market factors: we have not conducted a sensitivity analysis based on market factors.
- Third party factors: we have not conducted a sensitivity analysis based on third party factors because any the benefit case is not dependent on the actions of third parties.
- Delivery factors: we have modelled a reduced training time of three months and five months for the upper and lower cases respectively.

| Financial year: | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | RIIO-2 Total | Calculation |
|---|---|---|---|---|---|---|---|
| Training costs £ million | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 11.5 | A |
| Improvement | 42% | 42% | 42% | 42% | 42% | | B |
| Percentage of maximum annual benefit claimed | 5% | 15% | 35% | 80% | 100% | | C |
| Benefit £ million | 0.1 | 0.1 | 0.3 | 0.8 | 0.9 | 2.2 | D = A x B x C |

*Table 39: Benefit calculation for decreased training costs assumptions*

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Lower training costs | 0.1 | 0.1 | 0.3 | 0.8 | 0.9 | 2.2 |
| Sensitivity – high delivery confidence | 0.1 | 0.2 | 0.4 | 1.0 | 1.3 | 3.0 |
| Sensitivity – low delivery confidence | 0.0 | 0.1 | 0.2 | 0.5 | 0.7 | 1.5 |

*Table 40: Benefits for decreased training costs assumptions*

The above table above shows the benefits from decreased training costs are between £1.5 million and £3.0 million, with a central case of £2.2 million.

*Measuring benefits and consumer bill impact*

The £2.2 million benefit could be tracked as part of any regulatory reporting for RIIO-2.

This benefit will impact on consumer bills through lower BSUoS charges than would otherwise have been the case.

### 2.2.2.3 Improved decision making

| Assumption | Justification |
|---|---|
| Reserve and response cost estimates | Based on 12-year historic average |
| 2% improvement in reserve and response spend | Based on evidence from the ESO Distributed Energy Resource (DER) desk |
| Percentage of maximum annual benefit claimed | We believe our proposals for better training and simulation capability, combined with better tools, ultimately deliver a 2% saving in reserve and response costs.<br>Allowing for the time it will take training and simulation enhancements to translate to operational decision-making improvements, we cannot claim the maximum benefit until the end, and so claim a reduced benefit in the preceding years. |

*Table 41: Improved decision making assumptions*

The introduction of the DER desk in January 2019 allows us to control around 4 GW of distributed resource out a total of 65 GW of resource we typically utilise in the balancing mechanism. As a result of the DER desk we have seen a 65 per cent increase in bid and offer volume on units that were historically available, meaning around 2.7 GW of resource is better utilised. This gives a 2.7 GW / 65 GW = 4 per cent improvement.

We recognise that a range of factors can influence savings made to future spend, but the above provides evidence of how the introduction of new situational awareness with clear training has helped us to improve management of the power system overall. It is reasonable to assume similar gains for improving our tools and training, because the way our new tools and training are implemented will mirror that of the DER desk. To account for potential uncertainly, we believe our proposals will result in a 2 per cent reduction in response and reserve spend.

To avoid potential double counting with the benefits in section 2.1.2.5 we have not considered a reduction in constraint spend. It is, however, important that our proposals in A1 Control centre architecture and systems and A2 control centre training and simulation are considered as a package.

#### *Sensitivity analysis*

- Market factors: we repeat our analysis with the response and reserve costs adjusted by one standard deviation in either direction.
- Third party factors: we have not conducted a sensitivity analysis because the benefits case is not dependent on the actions of third parties.

- Delivery factors: for the upper case we assume 4 per cent savings, consistent with the above evidence; for the lower case we assume 1 per cent savings and a one-year delay.

*Interaction with other benefit areas*

Lower reserve and response costs are also claimed as benefits in sections 3.1.2.1 and 3.1.2.2. Any potential double counting is accounted for in the sensitivity analysis.

| **Financial year:** | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** | **RIIO-2 Total** | **Calculation** |
|---|---|---|---|---|---|---|---|
| Reserve and response costs £ million | 514 | 514 | 514 | 514 | 514 | 2,570 | A |
| Improvement | 2% | 2% | 2% | 2% | 2% | | B |
| Percentage of maximum annual benefit claimed | 5% | 25% | 60% | 80% | 100% | | C |
| Benefit £ million | 0.5 | 2.6 | 6.2 | 8.2 | 10.3 | 27.8 | D = A x B x C |

*Table 42:Benefit calculation for improved decision making*

| **Benefits £ million** | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** | **Total** |
|---|---|---|---|---|---|---|
| Improved decision making | 0.5 | 2.6 | 6.2 | 8.2 | 10.3 | 27.8 |
| Sensitivity – high market factors | 0.6 | 3.1 | 7.4 | 9.9 | 12.4 | 33.5 |
| Sensitivity – low market factors | 0.4 | 2.0 | 4.9 | 6.5 | 8.2 | 22.1 |
| Sensitivity – high delivery confidence | 1.0 | 5.1 | 12.3 | 16.4 | 20.6 | 55.5 |
| Sensitivity – low delivery confidence | 0.0 | 0.3 | 1.3 | 3.1 | 4.1 | 8.7 |

*Table 43: Benefits for improved decision making*

The above table shows the benefits from improved decision-making are between £8.7 million and £55.5 million, with a central case of £27.8 million

*Measuring benefits and consumer bill impact*

The driver of this £27.8 million benefit can be measured via Metric 1 - Balancing cost management. See Annex 7 - Metrics and measuring performance for more details.

This benefit will impact on consumer bills through lower BSUoS charges than would otherwise have been the case.

*Total benefits case*

The total benefits for A2 Control centre training and simulation are between £15 million and £64 million, with a central case of £35 million over the RIIO-2 period.

### 2.2.3 Activity costs

Delivery of A2 Control Centre training and simulation will require additional capex and opex spend, summarised below.

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 0.0 | 0.0 | 1.2 | 2.3 | 2.3 | 5.8 |
| Opex | 2.1 | 2.6 | 3.2 | 3.8 | 4.2 | 15.9 |
| Total | 2.1 | 2.6 | 4.4 | 6.1 | 6.6 | 21.7 |

*Table 44: Incremental costs for A2 Control centre training and simulation activities*

The total costs for our A2 Control centre training and simulation activities are £21.7 million.

### 2.2.4 Net Present Value

The net present value of these activities is estimated at £16 million over the RIIO-2 period and £42 million over 10 years. They will start to deliver positive returns from 2023/24. Sensitivity analysis suggests an NPV range of:

- Market factors between £11 million and £21 million.
- Delivery factors between negative £2 million and £42 million.

### 2.2.5 Dependencies, enablers and whole energy system

This activity is dependent on the following transformational activity:

- A1 Control centre architecture and systems (Role 1, Theme 1) – Allowing highly skilled engineers to use their training for zero carbon system operation.

A highly skilled workforce which can operate a complex decentralised and decarbonised electricity system also enables the following transformational activity:

- A1 Control centre architecture and systems (Role 1, Theme 1) - Providing real world experience for training and simulations.

Delivery of this activity could pass on benefits and costs to third parties. There may be a cost to DNOs and TOs for training their staff to use our systems. However, this would likely be offset by savings from not having to run some or all their own training programmes. They will benefit from having a greater pipeline of resource from our enhanced academic partnerships attracting talent to the industry. Greater coordination and collaboration of training will help the industry make better whole system decision, particularly in areas such as A3 Restoration and disaster recovery.

### 2.2.6 Uncertainties and risks

We have accounted for market, third party and deliverability uncertainties in our sensitivity analysis.

The table below summarise the key risks to delivering our activities and how we propose to mitigate them. Risks for the associated IT investments can be found in and measuring performance 4 – Technology Investment.

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Unable to source people with right skills and right competencies to deliver enhanced training | Create a suitable package to attract resource. Look for people and advertise roles well in advance. Build future capabilities internally | 2 | 1 |
| Reluctance from external stakeholders to develop a holistic resourcing approach. | Early engagement to understand individual business needs. | 3 | 1 |
| Reluctance from academia to create a bespoke course, meaning lack of recognised qualifications | Approach universities where relationships have already been established. Review appetite from refreshing existing courses and develop new modules before deciding whether to proceed | 4 | 1 |
| Simulator is not fit for future development or use. | Explore opportunities with current or alternative supplier for short-term upgrade ahead of development of enhanced simulator | 3 | 2 |
| Unable to acquire the necessary skill to produce the simulator of the future. | Early engagement with IT supply partners as part of development of new control centre tools | 3 | 2 |

*Table 45: Risks for A2 Control centre training and simulation*

### 2.2.7 Other options considered

| Options for delivering A2 Control Centre training and simulation | Investment |
|---|---|
| 1 - The proposed transformational activity, as set out in the Business Plan | Ongoing and Transformational |
| 2 - Ongoing activities and enhancements only | Ongoing |

*Advantages and disadvantages*

#### 2.2.7.1 Preferred option – proposed Control Centre training and simulation activities

| Advantages | Disadvantages |
|---|---|
| Develops new training and simulation tools in conjunction with our new balancing and control capabilities.<br>Enables our control centre engineers to be able to operate the carbon free system of the future, which we expect to be increasingly complex. | Higher cost than ongoing. |

#### 2,2.7.2 Ongoing activities and enhancements only

| Advantages | Disadvantages |
|---|---|
| Reduced investment cost and no implementation time. | Our workforce planning and resource profiles indicate we will be unable to effectively resource our activities without our transformational activities.<br>Our current training simulators are not fit for purpose and must be upgraded.<br>The training timescales and our staff attrition rate are similar, leading to an unsustainable business model without enhanced training. |

*Summary*

The proposed transformational activity is our preferred option because:

- the cost-benefit analysis indicates clear consumer benefit;
- our approach is supported by stakeholders; and
- in our commercial and technical judgement:
    - our workforce planning and resource profiles indicate we will be unable to effectively resource our activities without our transformational activities
    - our current training simulators are not fit for purpose and must be upgraded
    - the training timescales and our staff attrition rate are similar, leading to an unsustainable business model without enhanced training
    - we need skills in new areas, that only enhanced training will deliver.

## 2.3 A3 Restoration

This sub-section provides further context on the costs and benefits of our A3 Restoration activities.

The net present value of our A3 Restoration activities is negative £8 million over the RIIO-2 period and negative £23 million over ten years.

### 2.3.1 The counterfactual

If we did not undertake our transformational A3 Restoration activities, we would make ongoing enhancements to our A3 Restoration tools and would not implement the proof of concept findings from our Distributed Energy NIC project.

### 2.3.2 The benefits

We have quantified benefits in two areas:

- Benefits from the Distributed Energy NIC project.
- Carbon savings.

#### 2.3.2.1 Benefits from the Distributed Energy NIC project

| Assumptions | Justification |
|---|---|
| £115 million NPV to 2050 | Findings from Distributed Energy NIC Project[18] |

*Table 46: Benefits from the distributed Energy NIC project assumptions*

The net present value of implementing the Black Start from DER project is £115 million to 2050. This is due to increased competition and reduced costs from the use of some large generators. This would be passed on to consumers through reduced BSUoS charges. We assume this is allocated evenly from 2025, when the project will start delivering benefits. This delivers £4.6 million of benefit during RIIO-2 and £23 million to 2030**.**

*Sensitivity analysis*

We have not conducted sensitivity analysis here because the benefit case is based on benefit figures previously published by the ESO.

[18] National Grid Electricity System Operator: Black Start from Distributed Energy Resources https://www.ofgem.gov.uk/system/files/docs/2018/11/redacted_electricity_nic_submission_2018_esoen01_v03.pdf

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Benefits from the Distributed Energy NIC project | 0.0 | 0.0 | 0.0 | 0.0 | 4.6 | 4.6 |

*Table 47: Benefits distributed Energy NIC project assumptions*

*Measuring benefits and consumer bill impact*

The £4.6 million benefit could be tracked as part of any regulatory reporting for RIIO-2.

This benefit will impact on consumer bills through lower BSUoS charges than would otherwise have been the case.

#### 2.3.2.2 Carbon savings

| Assumptions | Justification |
|---|---|
| Reduction of 810,000 tonnes of $CO_2$ to 2050 | Findings from Distributed Energy NIC Project |

*Table 48: Carbon savings assumptions*

We estimate the Black Start from DER project will lead to a reduction of 810,000 tonnes of $CO_2$ by 2050. This is through low carbon DER taking part in A3 Restoration service, leading to reduced carbon emissions from large generators needing to be available. We assume this is allocated evenly from 2025/26 when the project will start delivering benefits. With an average carbon price of £19.78 per t/$CO_2$e in 2025/26, this would deliver a benefit of £0.6 million over RIIO-2.

It should be noted that the benefits after 2025/26 are calculated based on the carbon prices for that year, rather than being flatlined. This is in line with the Ofgem guidance.

*Sensitivity analysis*

We have not conducted sensitivity analysis here because the benefit case is based on benefit figures previously published by the ESO.

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Carbon savings | 0.0 | 0.0 | 0.0 | 0.0 | 0.6 | 0.6 |

*Table 49: Benefits for carbon saving*

*Measuring benefits and consumer bill impact*

The £0.6 million benefit could be tracked as part of any regulatory reporting for RIIO-2.

This benefit will not directly impact on consumer bills.

*Total benefits case*

The total benefits for A3 Restoration are a central case of £5 million over the RIIO-2 period.

### 2.3.3 Activity costs

Delivery of our A3 Restoration activities will require additional capex and opex spend. These are summarised below:

| Costs<br>£ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 0.9 | 2.3 | 7.7 | 8.1 | 6.3 | 25.2 |
| Opex | 0.1 | 0.8 | 1.7 | 2.6 | 3.4 | 8.6 |
| Total | 1.0 | 3.0 | 9.3 | 10.7 | 9.7 | 33.8 |

*Table 50: Incremental costs for A3 Restoration activities*

The total costs for our A3 Restoration activities are £33.8 million.

### 2.3.4 Net Present Value

The net present value (NPV) of our A3 Restoration activities is estimated at negative £8 million over the RIIO-2 period and negative £23 million over ten years. Given the £115m NPV of the Distributed Energy NIC project, we are confident our proposals will deliver net benefits out to 2050.

### 2.3.5 Dependencies, enablers and whole energy system

This activity is dependent on the following transformational activities:

- A1 Control centre architecture and systems (Role 1, Theme 1) – Allowing highly skilled engineers to use their training for zero carbon system operation.
- A2 Control centre training and simulation.

This is because in order for DER to provide restoration services, new tools will be needed to handle a greater number of participants and we will need to train our control centre engineers on new restoration procedures.

Our Distributed Energy NIC project complements our proposals in Role 2, Theme 2 to transform participation in balancing markets. The A3 Restoration decision support tool will complement other tools delivered by our A1 Control centre architecture and systems activities.

Our proposals may pass some costs onto third parties. DNOs, TOs and restoration service providers will need to invest to comply with the restoration standard for which we will be conducting the assurance process. DNOs and service providers may need to implement communication systems, depending on the proof of concept findings from the DER NIC project. We believe the benefits, including reduced restoration timelines, the ability of new technologies to provide restoration services and, for DNOs, the potential to control restoration in their own area, outweigh these costs.

### 2.3.6 Uncertainties and risks

We have accounted for market, third party and deliverability uncertainties in our sensitivity analysis.

The table below summarise the key risks to delivering our activities and how we propose to mitigate them. Risks for the associated IT investments can be found in Annex 4 – Technology investment report.

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| A restoration standard is not established, and implementation frameworks are not used | ESO can set target restoration timeframes through our current structure and justify our restoration strategy against this | 1 | 2 |
| A substandard or inappropriate restoration tool is implemented | Project scoping and resource to support this are included in our Business Plan | 2 | 2 |
| New roles and responsibilities between industry parties are currently unknown and may influence restoration options | Ongoing engagement with distribution system operation (DSO) model development and impact on restoration to ensure associated roles and responsibilities adapt as required | 3 | 2 |
| Stakeholders challenge proposed Grid Code changes | Maintain a dialogue with other parties involved in restoration, and champion relevant regulatory, legal, or code changes to enable full participation. Share code changes and timetables for implementation and maintaining industry awareness | 3 | 3 |
| Roles and skillset required for DER are challenging to resource | Mitigated through the training and simulation part of our Business Plan | 2 | 3 |
| Cost of sufficient resilience in telecommunications means focusing on a small number of | The DER NIC project will provide a working (albeit small scale) solution for resilient | 3 | 2 |

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| large resources, limiting the involvement of smaller DERs | telecommunications which can be scaled for Great Britain wide use | | |
| Unknown level of technical changes and how to implement those required on distribution networks. Risks of failure to change restoration speeds, lack of investment in DER technology | The risk will be identified through the DER NIC project | 3 | 2 |
| Despite new technologies and techniques, the restoration speed does not reduce | Implement an annual evaluation of restoration time against expectations. New technologies and products will feed into this evaluation. | 2 | 2 |
| Market mechanisms across different parties (ESO/DSO/DERs) are too complex and may be susceptible to distortion. | Market mechanisms are still being trialled for balancing services and will be developed with this risk in mind. | 2 | 1 |
| The high cost of retrofitting DER and distribution networks (including systems and telecommunications) and funding arrangements is unclear. | The DER NIC project will identify the specific requirement and associated costs. | 2 | 2 |

*Table 51: Risks for Restoration*

### 2.3.7 Other options considered

| Options for delivering A3 Restoration | Investment |
|---|---|
| 1 - The proposed transformational activity, as set out in the Business Plan | Ongoing and Transformational |
| 2 – Ongoing activities and enhancements only | Ongoing |

*Advantages and disadvantages*

#### 2.3.7.1 Preferred option – proposed restoration activities

| Advantages | Disadvantages |
|---|---|
| Looks to open restoration services distributed energy resources, allowing more technologies and services to participate | CBA indicates a negative NPV over RIIO-2 |
| Invests in new systems to ensure we can meet the GB restoration standard | |
| Would lead to quicker restoration timescale | |

#### 2.3.7.2 Ongoing activities and enhancements only

| Advantages | Disadvantages |
|---|---|
| Reduced investment cost and no implementation time | Does not allow us to take advantage of DER in providing restoration services |
| Current procurement activities to allow fully competitive restoration procurement would continue | Will lead to slower restoration timescales |

*Summary*

The proposed transformational activity is our preferred option because:

- Our approach is supported by stakeholders
- In our commercial and technical judgement, investment is needed to take advantage of new restoration services at the distribution level and invest in a new restoration decision support tool to ensure we meet the GB restoration standard
- The cost-benefit analysis indicates a low negative NPV over the RIIO-2 period compared to potential cost of a future black start event, and is likely to be positive out to 2050

## 2.4 Cost summary

This table summarises the total costs of Role 1, Theme 1.

| Ref | Type | RIIO-T1 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2 year average | 2 year total |
|---|---|---|---|---|---|---|---|---|---|
| Transformational Activity subject to CBA CBA Ref: NGESOT2001 | OPEX | - | 3.4 | 5.6 | 7.5 | 7.9 | 8.5 | 4.5 | 8.9 |
| | CAPEX | - | 17.4 | 27.5 | 31.7 | 25.7 | 18.1 | 22.4 | 44.8 |
| Transformational not subject to a CBA | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 16.7 | 21.6 | 21.3 | 21.1 | 19.5 | 19.0 | 21.4 | 42.9 |
| | IS OPEX | - | 1.4 | 1.6 | 1.4 | 1.5 | 2.3 | 1.5 | 3.0 |
| | CAPEX | 22.1 | 5.9 | 7.2 | 5.3 | 4.8 | 5.0 | 6.5 | 13.0 |
| **Total Control Centre Architecture and Systems Ref BP Theme 1 chapter** | **OPEX** | **16.7** | **26.3** | **28.5** | **30.0** | **28.9** | **29.8** | **27.4** | **54.8** |
| | **CAPEX** | **22.1** | **23.2** | **34.6** | **37.0** | **30.5** | **23.0** | **28.9** | **57.9** |
| Transformational Activity subject to CBA CBA Ref: N/A | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Transformational not subject to a CBA | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 4.0 | 5.4 | 5.3 | 5.2 | 5.2 | 5.1 | 5.3 | 10.6 |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| **Total Commercial Operations & Strategy Ref BP Theme 1 chapter** | **OPEX** | **4.0** | **5.4** | **5.3** | **5.2** | **5.2** | **5.1** | **5.3** | **10.6** |
| | **CAPEX** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| Transformational Activity subject to CBA CBA Ref: NGESOT2002 | OPEX | - | 2.1 | 2.6 | 3.2 | 3.8 | 4.2 | 2.4 | 4.7 |
| | CAPEX | - | - | - | 1.2 | 2.3 | 2.3 | - | - |
| Transformational not subject to a CBA | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 1.9 | - | - | - | - | - | - | - |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| **Total Control Traning and Simulation Ref BP Theme 1 chapter** | **OPEX** | **1.9** | **2.1** | **2.6** | **3.2** | **3.8** | **4.2** | **2.4** | **4.7** |
| | **CAPEX** | **-** | **-** | **-** | **1.2** | **2.3** | **2.3** | **-** | **-** |
| Transformational Activity subject to CBA CBA Ref: NGESOT2003 | OPEX | - | 0.1 | 0.8 | 1.6 | 2.6 | 3.4 | 0.4 | 0.9 |
| | CAPEX | - | 0.9 | 2.3 | 7.7 | 8.1 | 6.3 | 1.6 | 3.2 |
| Transformational not subject to a CBA | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 0.6 | 0.7 | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 | 1.3 |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| **Total Restoration Ref BP Theme 1 chapter** | **OPEX** | **0.6** | **0.8** | **1.4** | **2.3** | **3.3** | **4.0** | **1.1** | **2.2** |
| | **CAPEX** | **-** | **0.9** | **2.3** | **7.7** | **8.1** | **6.3** | **1.6** | **3.2** |
| **Theme 1 Total On CBA** | **Opex** | **-** | **5.5** | **9.0** | **12.4** | **14.3** | **16.1** | **7.2** | **14.5** |
| | **Capex** | **-** | **18.3** | **29.7** | **40.5** | **36.1** | **26.7** | **24.0** | **48.0** |
| **Theme 1 Total Ongoing activites and transformational activities not on a CBA** | **Opex** | **23.2** | **27.6** | **27.2** | **27.0** | **25.3** | **24.8** | **27.4** | **54.8** |
| | **IS Opex** | **-** | **1.4** | **1.6** | **1.4** | **1.5** | **2.3** | **1.5** | **3.0** |
| | **Capex** | **22.1** | **5.9** | **7.2** | **5.3** | **4.8** | **5.0** | **6.5** | **13.0** |
| **Theme 1 Total** | **Opex** | **23.2** | **34.5** | **37.8** | **40.8** | **41.1** | **43.2** | **36.1** | **72.3** |
| | **Capex** | **22.1** | **24.1** | **36.9** | **45.9** | **40.9** | **31.7** | **30.5** | **61.0** |
| | **Totex** | **45.3** | **58.6** | **74.7** | **86.6** | **82.0** | **74.8** | **66.7** | **133.3** |

# 3. Cost-benefit analysis: Role 2, Theme 2

This section provides further context on the costs and benefits of the transformational activities in Role 2, Theme 2:

| Activity group | Analysis type |
|---|---|
| A4 Build the future balancing service and wholesale markets | CBA |
| A4 Lead a review of wholesale, balancing and capacity markets | Break-even |
| A5 Transform access to the Capacity Market | CBA |
| A6.4 Transform the process to amend our codes. | Break-even |
| A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 | CBA |
| A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges | CBA |

*Table 52: Role 2, Theme 2 activities*

The net present value of Role 2, Theme 2 is £414 million over the RIIO-2 period and £909 million over ten years. Sensitivity analysis suggests an NPV range of £229 million to £908 million over the RIIO-2 period.

## 3.1 A4 Build the future balancing service and wholesale markets

This sub-section provides further context on the costs and benefits of our activity A4 Build the future balancing service and wholesale markets.

The net present value of A4 Build the future balancing service and wholesale markets is £67 million over the RIIO-2 period and £183 million over ten years. Sensitivity analysis suggests an NPV range of £3 million to £115 million over the RIIO-2 period.

### 3.1.1 The counterfactual

If we did not invest in A4 Build the future balancing service and wholesale markets, we would continue with existing participation in balancing and capacity markets without a single platform or reduced participant size to 1 MW. This would bring only incremental improvements in our capability.

### 3.1.2 The benefits

We have quantified benefits in two areas:

- More liquid response and reserve market.
- Buying the optimal volume of response.

### 3.1.2.1 More liquid response and reserve market

| Assumptions | Justification |
|---|---|
| Value of the response and reserve market is £514 million per year. | See main assumptions section. Note this is not a forecast of future response and reserve spend. This is the value of the response and response market today used for estimation of consumer benefits. |
| Our actions deliver a five % saving in the response and reserve markets | Evidence from early trials, as identified in the *Forward Plan*[19] |
| Benefits delivered from year three of RIIO-2 | This allows two years for implementation of the activity. |

*Table 53: More liquid response and reserve market assumptions*

The value of the response and reserve markets today is £514 million per year. Moving closer to real time increases the number of potential participants. Some early trials have shown this increased competition could reduce market prices by around five per cent. If we assume a five per cent saving in the response and reserve markets in 2023/24 and in each of the following two years of RIIO-2 this would result in an annual benefit of £25.7 million from increased liquidity. This allows two years for implementation.

*Sensitivity analysis*

- Market factors: we have repeated the analysis with the high and low cases for the reserve and response markets: £625 million a year and £404 million a year respectively.
- Delivery factors: we have repeated the analysis with the high and low cases for reserve and response markets savings: 7.5 per cent and 2.5 per cent respectively. We have also modelled a one-year delay in delivery for the low case, from 2024/25.

*Interaction with other benefit areas*

Lower reserve and response costs are also claimed as benefits in section 2.2.2.3 and 3.1.2.2. Any potential double counting is accounted for in the sensitivity analysis.

| Per cent price reduction | | Size of annual reserve and response markets £ million | | Annual saving |
|---|---|---|---|---|
| 5% | x | £514 million | = | £25.7 million |

[19] ESO 2019/21 Forward Plan, p.111, National Grid ESO, 28 March 2019.

*Table 54: Benefit calculation for more liquid response and reserve market*

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| More liquid response and reserve market | 0.0 | 0.0 | 25.7 | 25.7 | 25.7 | 77.2 |
| Sensitivity – high market | 0.0 | 0.0 | 31.2 | 31.2 | 31.2 | 93.7 |
| Sensitivity – low market | 0.0 | 0.0 | 20.2 | 20.2 | 20.2 | 60.6 |
| Sensitivity – high delivery | 0.0 | 0.0 | 38.6 | 38.6 | 38.6 | 115.7 |
| Sensitivity – low delivery | 0.0 | 0.0 | 0.0 | 12.9 | 12.9 | 25.7 |

*Table 55: Benefits for more liquid response and reserve market*

The above table shows the benefits of a more liquid response and reserve market are between £25.7 million and £115.7 million, with a central case of £77.2 million over the RIIO-2 period.

### *Measuring benefits and consumer bill impact*

The driver of this £77 million benefit can be measured via Metric 6 - Proportion of balancing services procured through competitive means. See Annex 7 - Metrics and measuring performance for more details.

This benefit will impact on consumer bills by reducing the BSUoS charge element, more than would otherwise be the case.

### 3.1.2.2 Buying the optimal volume of response

| Assumptions | Justification |
|---|---|
| Value of the response market is £193 million per year. | See main assumptions section. Note this is not a forecast of future response spend. This is the value of the response market today used for the estimation of consumer benefits. |
| Our actions deliver a 5% saving in the response market | Evidence from early trials, as identified in the *Forward Plan*[20] |
| Benefits delivered from year three of RIIO-2 | This allows two years for implementation of the activity |

[20] ESO 2019/21 Forward Plan, p.111, National Grid ESO, 28 March 2019.

*Table 56: Buying the optimal volume of response assumptions*

The volume of required response varies considerably from day-to-day. At the month ahead stage we tender for the minimum volume and manage the daily variation using mandatory response on thermal plant. Having markets which can operate in real time unlocks additional liquidity in three ways:

- Parties can choose between a short and longer-term product. This allow us to achieve a better price by offering greater choice to market participants.
- Operating a market closer to real-time means we can target more specific volume. Volumes set in advance carry 'headroom' against forecasting inaccuracies.
- Allowing market parties to bid in makes them more confident of their position. This will potentially unlock services from parties who otherwise were restricted by intermittent generation.

The annual cost of procuring response in the market is £193 million. Managing the daily variation closer to real time, while reducing use of mandatory services means we buy considerably less volume than by doing nothing. In this analysis, based on our previous experience, we estimate a 5 per cent reduction on purchased volume from 2023/24. This will result in an annual saving for consumers of £9.7 million.

### *Sensitivity analysis*

- Market factors: we have repeated the analysis with the high and low cases for the response markets; £231 million a year and £155 million a year respectively.
- Delivery factors: we have repeated the analysis with the high and low cases for response market savings; 7.5 per cent and 2.5 per cent respectively. We have also modelled a one-year delay in delivery for the low case, from 2024/25.

### *Interaction with other benefit areas*

Lower response costs are also claimed as benefits in section 2.2.2.3 and 3.1.2.1. Any potential double counting is accounted for in the sensitivity analysis.

| % price reduction | | Size of annual response markets £ million | | Annual saving £ million |
|---|---|---|---|---|
| 5% | x | 193 | = | 9.7 |

*Table 57: Benefit calculation* buying the optimal volume of response

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Buying the optimal volume of response | 0.0 | 0.0 | 9.7 | 9.7 | 9.7 | 29.0 |
| Sensitivity – high market | 0.0 | 0.0 | 11.5 | 11.5 | 11.5 | 34.6 |
| Sensitivity – low market | 0.0 | 0.0 | 7.8 | 7.8 | 7.8 | 23.3 |
| Sensitivity – high delivery | 0.0 | 0.0 | 14.5 | 14.5 | 14.5 | 43.4 |
| Sensitivity – low delivery | 0.0 | 0.0 | 0.0 | 4.8 | 4.8 | 9.7 |

*Table 58: Benefits buying the optimal volume of response*

The above table shows the benefits of buying the optimal volume of response are between £9.7 million and £43.4 million, with a central case of £29.0 million over the RIIO-2 period.

### *Measuring benefits and consumer bill impact*

The £29 million benefit could be tracked as part of any regulatory reporting for RIIO-2.

This benefit will impact on consumer bills by reducing the BSUoS charge element, by more than otherwise would have been the case.

### *Total activity benefits case*

The total benefits for A4 Build the future balancing service and wholesale markets are between £35 million and £159 million, with a central case of £106 million over the RIIO-2 period.

## 3.1.3 Activity costs

Delivery of *A4 Build the future balancing service and wholesale markets will require additional capex and opex spend, summarised below:*

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 3.1 | 3.1 | 2.2 | 1.2 | 1.3 | 11.0 |
| Opex | 6.5 | 5.6 | 5.7 | 3.9 | 4.1 | 25.8 |
| Total | 9.6 | 8.7 | 7.9 | 5.1 | 5.4 | 36.8 |

*Table 59: Incremental costs for A4 Build the future balancing service and wholesale markets*

The total costs for A4 Build the future balancing service and wholesale markets are £36.8 million.

### 3.1.4 Net Present Value

The net present value of A4 Build the future balancing service and wholesale markets is estimated at £67 million over the RIIO-2 period and £183 million over ten years, which will start to deliver positive returns from 2023/24.  Sensitivity analysis suggests an NPV range of:

- Market factors between £47 million and £87 million.
- Delivery factors between £3 million and £115 million.

### 3.1.5 Dependencies, enablers and whole energy system

A4 Build the future balancing service and wholesale markets is dependent on the following transformational activities:

- A1 Control centre architecture and systems (Role 1, Theme 1) – Ensuring the control centre has the tools required to dispatch new players in the reserve and response markets.
- A17 Digitalisation and open data – Ensuring the data flow between the ESO and participants is open, allowing participants to understand market requirements.

Delivering competitive flexible markets also allows the following transformational activities:

- A15 Taking a whole electricity system approach to promote zero-carbon operability (Role 3, Theme 4).
- A5 Transforming access to the capacity market (Role 2, Theme 2).
- A8 – A11 *NOA* enhancements (Role 3, Theme 3).
- A17 Digitalisation and open data - Providing additional data from competitive markets.

Delivering this activity relies on third party engagement with the new system and markets. There may be minor costs from adapting to these new arrangements, but we believe this are within the scope of third parties’ ongoing investments.

### 3.1.6 Uncertainties and risks

We have accounted for market, third party and deliverability uncertainties in our sensitivity analysis.

The table below summarises the key risks and how we propose to mitigate them. Risks for the associated IT investments can be found in Annex 4 – Technology investment report.

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Arrangements for procurement of balancing services at the distribution level are not yet defined. This may lead to market | Participation in Energy Networks Association (ENA) Open Networks Programme and ensuring platform design is aligned with current preferred option. Platform will be | 2 | 4 |

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| portal design not being aligned to future arrangements | designed for flexibility to work with emerging market designs | | |
| IT delivery risk for platform | Focus is on delivering a flexible and adaptable platform. Build on lessons from development of PAS; deliver in an agile manner beginning with a minimum viable product then delivering progressively greater complexity and functionality through targeted roll outs. Work closely with stakeholders | 3 | 4 |
| System change happens quicker than expected before new markets are in place. This results in higher costs to consumers | Work continuing through this regulatory period on market change. Focus on learning by doing and use of innovation or sandbox to accelerate learning | 3 | 4 |
| Not all trials will be successful | Accept that some regret spend is inevitable given the uncertainty faced by the ESO. Focus on taking well understood and justified risks | 3 | 1 |

*Table 60: Risks for A4 Build the future balancing service and wholesale markets*

### 3.1.7 Other options considered

We considered three options for A4 build the future balancing service and wholesale markets:

| Options for delivering A4 build the future balancing service and wholesale markets | Investment |
|---|---|
| 1 - A single, integrated platform for all ESO markets. The new integrated platform would support the ESO markets noted above, including the EMR Capacity Market. The details of this option in the sections above. | Ongoing and Transformational |
| 2 - A single, integrated platform for ESO markets not including the Capacity Market: The new integrated platform for would include the ESO market noted above, apart from the EMR Capacity Market, which will continue to develop its standalone platform. See section 3.3 below for details of this Capacity Market option. | Ongoing and Transformational (excluding EMR Capacity Market) |
| 3 - Ongoing activities and enhancements only to maintain current approach of monthly and quarterly tenders for balancing services with a separate system for the Capacity Market. | Ongoing |

*Table 61: A4 build the future balancing service and wholesale markets options*

*Advantages and disadvantages*

#### 3.1.7.1 Preferred option - A single, integrated platform for all ESO markets:

| Advantages | Disadvantages |
|---|---|
| Optimal approach for attracting additional flexibility to operate a zero carbon system at lowest cost to consumers.<br>Maximises participation in ESO markets.<br>Reduces industry overhead of participating in ESO markets.<br>Facilitates coordination and alignment of flexibility markets across transmission and distribution. | Industry participants will need to adapt to changing market and system arrangements. This is mitigated by the benefits to existing and potential service providers of lower barriers to participation. |

*Table 62: A4 build the future balancing service and wholesale markets option 1 advantages and disadvantages*

### 3.1.7.2 A single, integrated platform for ESO markets not including the Capacity Market:

| Advantages | Disadvantages |
|---|---|
| The same benefits would be delivered for balancing markets participants, at a lower cost – estimated at £1 million less for auction capacity and £100 thousand less a year for the single market platform. Giving an option NPV of £68 million, up from £67 million for the preferred option. | Benefits would not be delivered for Capacity Market participants, with addition costs of £5 million required for standalone Capacity Market capability (ongoing EMR costs would cover the existing platform architecture). Giving an option NPV of £52 million, down from £62 million for the preferred option. This option is not supported by stakeholders, who welcome having a single platform to access all ESO markets. |

*Table 63: A4 build the future balancing service and wholesale markets option 2 advantages and disadvantages*

For this option we undertook a CBA for both A4 build the future balancing and wholesale markets and A5 transform access to the capacity market (see section 3.3 below). The table below shows the change in assumptions from the preferred option CBA:

| **A4 Build the future balancing and wholesale markets**<br>**£ million** | **Preferred option** | **Short list option** | **Difference** |
|---|---|---|---|
| Capex | 11.0 | 10.5 | -0.5 |
| Opex | 25.8 | 24.8 | -1.0 |
| Total cost | 36.8 | 35.3 | -1.5 |
| Gross benefit | 106 | 106 | - |
| NPV | 67 | 68 | 1 |

| **A5 Transform access to the capacity market**<br>**£ million** | **Preferred option** | **Short list option** | **Difference** |
|---|---|---|---|
| Capex | 4.7 | 4.7 | - |
| Opex | 4.5 | 9.5 | 5 |
| Total cost | 9.2 | 14.2 | 5 |
| Gross benefit | 74 | 68 | -6 |
| NPV | 62 | 52 | -10 |

*Table 64: A4 build the future balancing service and wholesale markets option CBA*

Thus, given the inefficiency, with an NPV difference of £9 million, in developing two auction capabilities with some participants having to use two systems, we have decided not to take this option forward.

#### 3.1.7.3 Do minimum option: Ongoing activities only

| Advantages | Disadvantages |
|---|---|
| Reduced investment cost and no implementation time. | Would not allow us to attract the additional flexibility required to operate a zero carbon system. Would not deliver NPV consumer benefits of £67 million, would not meet our customer expectations and not deliver systems which are capable of managing more participants then today. |

*Table 65: A4 build the future balancing service and wholesale markets option 3 advantages and disadvantages*

Thus, given this option does not deliver consumer benefits, when compared to the preferred option, and is not supported by stakeholders, we have decided not to take this option forward.

*Summary*

In line with Ofgem's guidance, we have based our decision on cost-benefit analysis, stakeholder feedback and our own commercial and technical justification. Details of the CBA are contained in the narrative above, supported by the content of the stakeholder report.

Based on this we have decided to proceed with option 1 because:

- stakeholders support it
- in our commercial and technical judgement
- it delivers consumer benefit, as shown by the positive NPV.

Based on these, we have decided to proceed with option 1. This is also part of the options consider for A5 Transform access to the Capacity Market see section 3.3 below.

## 3.2 A4 Lead a review of wholesale, balancing and capacity markets

This sub-section provides further context on the breakeven analysis we have conducted on A4 Lead a review of wholesale, balancing and capacity markets.

### 3.2.1 Why we have undertaken a breakeven analysis

It provides details of the benefit that would need to be delivered to cover the costs of an activity.

We have undertaken this because this activity does not deliver consumer benefit by itself. It is the implementation of its recommendations that provide consumer benefit, and we cannot say at this stage what, if any, these are.

### 3.2.2 The counterfactual

The counterfactual to A4 Lead a review of wholesale, balancing and capacity markets is we do not undertake a review.

### 3.2.3 Activity costs

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Opex | 0.0 | 0.0 | 1.2 | 2.5 | 0.4 | 4.1 |
| Total | 0.0 | 0.0 | 1.2 | 2.5 | 0.4 | 4.1 |

*Table 66: Incremental cost for A4 Lead a review of wholesale, balancing and capacity markets*

In addition to the costs above, minor costs are likely to be incurred by the industry to take part in the stakeholder engagement process.

### 3.2.4 Assumptions, uncertainties and risks

The key risks have been identified:

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Industry does not engage with the process, leading to a suboptimal market design. There will also be overlap potential which will need to be coordinated, such as in relation to the clean energy package, European network codes or BSC developments | Use best practice engagement e.g. Power Responsive and Charging Futures – Learn/Ask/ Contribute. Ensure ESO is resourced, with access to consultant funds to undertake ‘heavy lifting’ on behalf of the industry with consultancy support | 2 | 2 |

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Risks to time, quality and cost in delivery of the project and managing its scope, etc. | Implement good project management and appropriate controls. Create industry oversight for input, challenge and review e.g. as with Power Responsive | 3 | 1 |
| Market design does not fully meet requirements. Benefits are not as expected i.e. do not outweigh costs. | Ensure appropriate cost stage gates throughout the design to monitor spend against delivery. In built project controls only undertaking first stage design activities. Any detailed design activities and subsequent implementation activities then follow. | 4 | 1 |

*Table 67: Risks for A4 Lead a review of wholesale, balancing and capacity markets*

### 3.2.5 Benefits

The quantitative benefits of a targeted review of wholesale, balancing and capacity markets:

- Proposal ensures that there is sufficient flexible energy to maintain security of supply in a low carbon world.
- The markets will be designed with the future needs of market participants in mind and not their past needs as is presently the case.
- The focus of this work is to contribute to delivering the savings forecast through attracting sufficient flexibility onto the system. This work on markets is necessary but not sufficient to deliver these savings. Some savings that can be attributed to this work include improved efficiency in both wholesale and balancing markets which in theory should result in reduced costs and prices in those markets.
- Markets designed with the future in mind will be more conducive to reduced and zero carbon operation and will therefore result in reduced environmental damage.

### 3.2.6 Conclusion

Based on the above information, we believe it is beneficial to proceed with this activity because:

- Although the monetary value of this work is difficult to quantify, it is anticipated that this work will result in improved efficiency in wholesale and balancing markets.
- Given the annual spend in these markets is around £35 billion, even a small improvement in efficiency would result in a large consumer benefit.

- It should be noted that a study into future market design would not, itself, deliver quantifiable benefits. Instead the costs can be viewed as an “option fee” to allow a change to be made in the future if the costs of implementation across the entire industry were outweighed by the benefits of more efficient markets. However, we are confident that this transformational activity will deliver significant benefits for consumers.

## 3.3 A5 Transform access to the Capacity Market

This sub-section provides further context on the costs and benefits of our activity A5 transform access to the Capacity Market.

The net present value of A5 Transform access to the Capacity Market is estimated at £62 million over the RIIO-2 period, and £128 million over ten years. Sensitivity analysis suggests an NPV range of £21 million to £94 million over the RIIO-2 period.

### 3.3.1 The counterfactual

If we did not undertake A5 transform access to the Capacity Market we would only undertake our ongoing modelling improvements and continue to use the EMR only platform for customers to access information, pre-qualification and auctions.

### 3.3.2 The benefits

We have quantified benefits in two areas:

- Enhanced modelling capability.
- Reduced barriers to entry and cost of participation.

#### 3.3.2.1 Enhanced modelling capability

| Assumptions | Justification |
|---|---|
| Clearing price of the Capacity Market is £17.08/kW per year. | Average of four T-4 auctions held to date |
| Our actions save consumers the equivalent of purchasing an additional 1 GW of capacity | This saving is equivalent to approximately 2% of the average volume purchased in the last four T-4 auctions, comparable with EMR demand forecasting incentives as a benchmark[21] |
| Benefits delivered from year two of RIIO-2 | This allows a year for implementation of this activity, given auction timings, when improved analysis will feed into recommendations to procure capacity |

[21] See Special Condition 4L. Financial incentives on EMR at https://epr.ofgem.gov.uk/Content/Documents/National%20Grid%20Electricity%20Transmission%20Plc%20-%20Special%20Conditions%20-%20Current%20Version.pdf

*Table 68: Enhanced modelling capability assumptions*

Better industry data and enhanced modelling and analysis capability will allow better forecasting. Much of the theory on which capacity calculations are built is based on systems with conventional generation. We need a new understanding of security of supply for a system with large volumes of renewable generation and distributed flexible assets.

There is a fine balance for consumers between overpaying for security of supply and ensuring the standard is met. Improved modelling of security of supply in a low carbon, high flexibility world, underpinned by improved asset information, will mean we can better quantify the potential risks and improve the robustness of our recommendations. In turn, this will ensure security of supply at the most efficient cost.

Enhanced data and modelling capability will help us ensure the correct sensitivities are used in our modelling and that they are better quantified. It will also allow us to further refine our recommendations to the Department for Business, Energy and Industrial Strategy (BEIS) on how much capacity should be secured in each Capacity Market auction. Any improvement in the robustness of recommendations will benefit consumers by ensuring security of supply at the best possible cost.

In our analysis we consider the two possible scenarios of reduced risk of our recommendations on the capacity to secure being too low or too high:

1. Reduced risk of recommendations being too low: Save consumers the equivalent of purchasing at T-4 an additional 1 GW[22] of capacity, instead of at T-1 or short-term balancing markets. Any consumer savings are hard to accurately forecast, given the small number of T-1 auctions held to date and the volatile nature of short-term balancing markets. Purchasing capacity at T-4 will reduce the uncertainty of purchasing at the T-1 or balancing market stage. There is also an inherent security of supply risk associated with under forecasting.
2. Reduced risk of recommendations being too high: Save consumers the equivalent purchase cost of 1 GW[27] of capacity at T-4. Any capacity saving is hard to accurately forecast, given the complexity of how the final auction price is arrived at. However, if we consider the average clearing price over the four T-4 auctioned held to date, £17.08/kW (see table below), and apply to the 1 GW this would save consumers £17 million per year.

Given the additional complexity, with limited data and more uncertainty, in determining scenario 1 benefits we have used scenario 2 benefits in our CBA calculation below.

### *Sensitivity analysis* - Enhanced modelling capability

- Market factors: we have repeated the analysis with the high and low cases for the clearing price of the Capacity Market: £22.34 /kW per year and £11.81 /kW per year respectively.

[22] This saving is equivalent to approximately two per cent of the average volume purchased in the last four T-4 auctions (see table 61). This percentage is comparable with EMR demand forecasting incentives as a benchmark

- Delivery factors: we have repeated the analysis with the high and low cases for capacity saved: 1.5 GW and 0.5 GW respectively. We have also modelled a one-year delay in delivery for the low case, from 2023/24.

| T-4 Auction (delivery year) | Clearing price (£/kW/year) | Capacity secured (GW) | Cost of 1GW (£ million) |
|---|---|---|---|
| 2021/22 | 8.4 | 50.415 | 8,400,000 |
| 2020/21 | 22.5 | 52.425 | 22,500,000 |
| 2019/20 | 18.0 | 46.353 | 18,000,000 |
| 2018/19 | 19.4 | 49.258 | 19,400,000 |
| Average | 17.1 | 49.613 | 17,075,000 |

*Table 69: Capacity Market auction data*

| Benefits £ millions | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Enhanced modelling capability | 0.0 | 17.1 | 17.1 | 17.1 | 17.1 | 68.3 |
| Sensitivity – high market | 0.0 | 22.3 | 22.3 | 22.3 | 22.3 | 89.4 |
| Sensitivity – low market | 0.0 | 11.8 | 11.8 | 11.8 | 11.8 | 47.2 |
| Sensitivity – high delivery | 0.0 | 25.6 | 25.6 | 25.6 | 25.6 | 102.5 |
| Sensitivity – low delivery | 0.0 | 0.0 | 8.5 | 8.5 | 8.5 | 25.6 |

*Table 70: Benefits for enhanced modelling capability*

The above table shows the benefits from enhanced modelling capability are between £25.6 million and £102.5 million, with a central case of £68.3 million over the RIIO-2 period.

### *Measuring benefits and consumer bill impact*

The driver of this £68 million benefit can be measured via Metric 8 – EMR demand forecast accuracy. See Annex 7 - Metrics and measuring performance for more details.

This benefit will impact on consumer bills by reducing the supplier charge element, by more than otherwise would have been the case.

### 3.3.2.2 Reduced barriers to entry and cost of participation

| Assumptions | Justification |
|---|---|
| 400 companies entering the Capacity Market auction. | The approximate number of companies in the CM register[23] |
| Our actions save two FTE weeks of time from each Capacity Market company | We have assumed that companies FTE commitment mirroring ESO commitments |
| Benefits delivered from year two of RIIO-2 | This allows a year for implementation of the activity, given auction timings. |

*Table 71: Reduced barriers to entry and cost of participation assumptions*

We will work to reduce barriers to entry for the Capacity Market. Our aim is to make the process as efficient as possible for applicants, reducing their participation costs. These savings can be passed to the consumer.

If each applicant company were to save the cost of two weeks of a full time employee (FTE) we estimate a total annual saving of £1.5 million. This is based on 400 companies saving two FTE weeks of time, with the FTE costing £100,000 per year.

*Sensitivity analysis - Reduced barriers to entry and cost of participation*

- Market factors: we have repeated the analysis with the high and low cases for the number of Capacity Market companies: 500 and 300 respectively.
- Delivery factors: We have modelled a one-year delay in delivery for the low case, from 2023/24.
- Third Party factors: we have repeated the analysis with the high and low cases for Capacity Market time saved: three weeks and one week respectively.

| Number of companies in CM register | | Annual cost of an FTE £s | | Two weeks | | Annual saving £ million |
|---|---|---|---|---|---|---|
| 400 | x | 100,000 | ÷ | 26 | = | 1.5 |

*Table 72:Benefit calculation for educed barriers to entry and cost of participation*

[23] https://www.emrdeliverybody.com/CM/Registers.aspx

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Reducing barriers to entry | 0.0 | 1.5 | 1.5 | 1.5 | 1.5 | 6.2 |
| Sensitivity – high market | 0.0 | 1.9 | 1.9 | 1.9 | 1.9 | 7.7 |
| Sensitivity – low market | 0.0 | 1.2 | 1.2 | 1.2 | 1.2 | 4.6 |
| Sensitivity – low delivery | 0.0 | 0.0 | 1.5 | 1.5 | 1.5 | 4.6 |
| Sensitivity – high third party | 0.0 | 2.3 | 2.3 | 2.3 | 2.3 | 9.2 |
| Sensitivity – low third party | 0.0 | 0.8 | 0.8 | 0.8 | 0.8 | 3.1 |

*Table 73: Benefits for reduced barriers to entry and cost of participation*

The above table shows the benefits from this activity are between £3.1 million and £9.2 million, with a central case of £6.2 million over the RIIO-2 period.

*Measuring benefits and consumer bill impact*

The £6 million benefit could be tracked indirectly as part of any regulatory reporting for RIIO-2.

This benefit will impact on consumer bills by reducing the supplier charge element, by more than otherwise would have been the case

*Total benefits case*

The total benefits for A5 Transform access to the Capacity Market are between £30 million and £108 million, with a central case of £74 million over the RIIO-2 period.

### 3.3.3 Activity costs

Delivery of A5 Transform access to the Capacity Market will require additional capex and opex spend, summarised below:

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 1.2 | 0.9 | 0.9 | 0.9 | 0.9 | 4.7 |
| Opex | 1.1 | 0.8 | 0.8 | 0.9 | 0.9 | 4.5 |
| Total | 2.3 | 1.7 | 1.7 | 1.7 | 1.8 | 9.2 |

*Table 74: Incremental costs for A5 Transform access to the Capacity Market*

The total costs for A5 Transform access to the Capacity Market are £9.2 million.

### 3.3.4 Net Present Value

The net present value of A5 transform access to the Capacity Market is estimated at £62 million over the RIIO-2 period and £128 million over ten years will start to deliver positive returns from 2022/23. Sensitivity analysis suggests an NPV range of:

- Market factors between £42 million and £83 million.
- Delivery factors between £21 million and £94 million.
- Third Party factors between £60 million and £65 million.

### 3.3.5 Dependencies, enablers and whole energy system

A5 Transform access to the Capacity Market depends on the following transformational activity:

- A4 Build the future balancing service and wholesale markets (Role 2, Theme 2) – Sharing the single market platform.

Delivering this activity depends on engagement with the new, easier to use, system by third parties. There may be minor costs associated with adapting to these new arrangements, but we believe this are within the scope of third parties' ongoing investments.

### 3.3.6 Uncertainties and risks

We have accounted for market, third party and deliverability uncertainties in our sensitivity analysis.

The table below summarises the key risks to delivering our activities and how we propose to mitigate them. Risks for the associated IT investments can be found in Annex 4 – Technology investment report.

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| The current ringfence around the EMR function limits the scope for efficiencies from increased coordination of rule development and data sharing across the ESO | Ofgem has already consulted on whether the EMR ringfence remains necessary considering the recent legal separation of the ESO. We can use this to demonstrate that we successfully manage sensitive information and potential conflicts of interest. Engage with BEIS, Ofgem and industry to explain the protections provided by the new ESO ringfence. Also, reviewing the l EMR ringfence could increase efficiencies and reduce the number of separate interactions for our customers | 3 | 1 |
| We may not get access to all the industry data needed to undertake enhanced modelling and analysis | Work with stakeholders, including the Government's Data Taskforce, to ensure the ESO has access to relevant data. Engage with other European System Operators to ensure consistent operating regimes and reliability standards are implemented across Europe and to maintain availability of consistent data sources or modelling. | 2 | 4 |

*Table 75: Risks for A5 Transform access to the Capacity Market*

### 3.3.7 Other options considered

We considered three options for A5 transform access to the capacity market:

| Options for delivering A5 transform access to the capacity market | Investment |
|---|---|
| 1 - A single, integrated platform for all ESO markets. The new integrated platform would include EMR Capacity Market. Enhanced modelling capability. The details of this option in the sections above: | Ongoing and transformational |
| 2 – Enhanced modelling capability and current standalone platform for EMR. This option would only look to enhance our modelling capability, while not integrating EMR with the single market platform detailed above. See section 3.1 above for details of this. | Ongoing for market platform and transformational for modelling enhancements |
| 3 - Ongoing activities and enhancements only to maintain current approach for managing auctions and modelling. | Ongoing |

*Table 76: A5 transform access to the capacity market options*

*Advantages and disadvantages*

#### 3.3.7.1 Preferred option - A single, integrated platform for all ESO markets and. enhanced modelling capability

| Advantages | Disadvantages |
|---|---|
| Access to all ESO markets in one platform for ease of use by customers, fully supported by stakeholders. Modelling capability will keep pace with the changing energy landscape, with increase distributed, renewable and interconnection, again supported by stakeholders. | Additional costs required to implement. |

*Table 77: A5 transform access to the capacity market option 1 advantages and disadvantages*

#### 3.3.7.2 Enhanced modelling capability only

| Advantages | Disadvantages |
|---|---|
| The same benefits would be delivered for enhanced modelling, and there would be a lower cost for the single market platform– estimated at £1 million less for auction capacity and £100k less a year for the single market platform. Giving an option NPV of £68 million, up from £67 million for that preferred option. | Benefits of the single market platform would not be delivered for Capacity Market participants, with addition costs of £5 million required for standalone Capacity Market capability (ongoing EMR costs would cover the existing platform architecture). Giving an option NPV of £52 million, down from £62 million for the preferred option. This option is not supported by stakeholders, who welcome having a single platform to access all ESO markets. |

*Table 78: A5 transform access to the capacity market option 2 advantages and disadvantages*

For this option we undertook a CBA for both A4 build the future balancing and wholesale markets and A5 transform access to the capacity market (see section 3.1 above). The table below shows the change in assumptions from the preferred option CBA:

| A4 build the future balancing and wholesale markets<br>£ million | Preferred option | Short list option | Difference |
|---|---|---|---|
| Capex | 11.0 | 10.5 | -0.5 |
| Opex | 25.8 | 24.8 | -1.0 |
| Total cost | 36.8 | 35.3 | -1.5 |
| Gross benefit | 106 | 106 | - |
| NPV | 67 | 68 | 1 |

| A5 transform access to the capacity market<br>£ million | Preferred option | Short list option | Difference |
|---|---|---|---|
| Capex | 4.7 | 4.7 | - |
| Opex | 4.5 | 9.5 | 5 |
| Total cost | 9.2 | 14.2 | 5 |
| Gross benefit | 74 | 68 | -6 |
| NPV | 62 | 52 | -10 |

*Table 79: A5 transform access to the capacity market option 2 CBA*

Thus, given the inefficiency of developing separate market platforms resulting in an NPV difference of £9 million and some participants having to use two systems, we have decided not to take this option forward.

### 3.3.7.3 Do minimum option: Ongoing activities only

| Advantages | Disadvantages |
|---|---|
| Reduced investment cost and no implementation time. | Would not deliver NPV consumer benefits of £67 million, would not meet our customer expectations and would not deliver systems which are capable of managing more participants than today.<br>Risk of forecasting accuracy deceasing, and therefore increasing costs to consumers, as forecasting complexity increases. |

*Table 80: A5 transform access to the capacity market option 3 advantages and disadvantages*

Thus, given this option does not deliver consumer benefits when compared to the preferred option, and is not supported by stakeholders, we have decided not to take this option forward.

*Summary*

Based on this we have decided to proceed with option 1 because:

- stakeholders support it
- in our commercial and technical judgement
- it delivers consumer benefit, as shown by the positive NPV.

Based on these, we have decided to proceed with option 1. This is also part of the options consider for A4 build the future balancing service and wholesale markets see section 3.2 above.

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

This sub-section provides further context on the break-even analysis we have conducted on A4.6 transform the process to amend our codes.

### 3.4.1 Why we have undertaken a breakeven analysis

A breakeven analysis provides details of the benefit that would need to be delivered to cover an activity's costs.

We have conducted this analysis because the activity depends on the benefits of any code modification from the new process. While we are confident high consumer benefit code modifications will be presented during the RIIO-2 period, we do not yet have visibility of these.

### 3.4.2 The counterfactual

The counterfactual to A6.4 Transform the process to amend our codes is the ESO does not move from code administration to code manager, with only incremental improvements in our capability.

### 3.4.3 Activity costs

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Opex | 0.5 | 1.5 | 1.7 | 1.9 | 2.1 | 7.8 |
| Total | 0.5 | 1.5 | 1.7 | 1.9 | 2.1 | 7.8 |

*Table 81: Incremental costs for A6.4 Transform the process to amend our codes*

In addition to the above costs, there is likely to be minor industry costs to adjust to new ways of working; these should be within the scope of third parties' ongoing investments.

### 3.4.4 Assumptions, uncertainties and risks

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| BEIS/Ofgem Joint Energy Codes Review does not align with our RIIO-2 ambition and/or complete during the ESO *Forward Plan* 2019/21 period | Continue to undertake our role in the Energy Codes Review. Subject to this, our Business Plans may require revision and should be subject to future amendment | 3 | 2 |
| Based on stakeholder feedback and Ofgem's proposals in the RIIO-2 sector specific methodology publication, we have assumed the ESO will remain the code administrator for Connection and Use of System Code (CUSC), System Operator – Transmission Owner Code (STC) and Grid Code, as well as being the de facto code administrator for the SQSS | Continue to engage with industry to demonstrate we are best placed to maximise consumer benefit through the codes we administer | 1 | 5 |
| We have assumed necessary legislation changes will happen at the start of the RIIO-2 period to give us the powers to transform code processes. This is a key dependency which unlocks further change over the remainder of the RIIO-2 period | Continue to undertake our role in the Energy Codes Review. Engage Ofgem and BEIS to highlight the legislative changes required for our future role | 3 | 4 |

*Table 82: Risks for A6.4 Transform the process to amend our codes*

### 3.4.5 Benefits

The quantitative benefits of a targeted review of the wholesale, balancing and capacity markets:

- Ensures codes remain appropriate for emerging markets and business models to contribute to safe and reliable operation of the system at all times in future.
- The modification process is more efficient and reduces the time that customers are required to be involved. Code changes would be prioritized with those that have the greatest expected benefit implemented first. Newer and smaller providers are better served by more tailored and suitable arrangements allowing for more players to enter a more competitive market.
- The primary focus of this work is to drive efficiency into the codes and code change process by reducing barriers to entry and increasing information provision. The result is to contribute to the creation of more efficient and competitive markets, reducing wholesale market costs, as well as BSUoS and TNUoS costs, depending on the code in question and against a counterfactual of no change to

the process. There are also internal efficiency savings for industry participants as there is a quicker and less resource intensive change process.

- There will be secondary benefits to the environment as a result of these changes as more efficient codes contribute to more efficient decarbonisation of the energy system.

### 3.4.6 Conclusion

Based on the above information, we believe it is beneficial to proceed with this activity because:

It will drive overall process efficiency for the ESO and industry, including fewer meetings and more focused discussions. These efficiencies are likely to be realised year-on-year, driven by the average number of codes modifications which the ESO facilities each year[24]. We have assumed these benefits are delivered over four years, given a one year start up for the process.

Realising the benefits of code modifications to the market quicker, in particular prioritising high value code modifications. This is likely to be realised over a single year from a high value modification being delivered one year earlier.

### 3.4.7 Other options considered

We considered four options for A6.4 Transform the process to amend our codes.

| Options for A6.4 Transform the process to amend our codes | Investment |
|---|---|
| 1 – Step up to code manager for the codes we currently administer, Grid Code, CUSC and STC. The details of this option in the sections above. | Ongoing and Transformational |
| 2 – Step up to code manager for the codes we currently administer, Grid Code, CUSC and STC and additional codes. This option would be similar to option 1, but with addition codes managed. | Ongoing and additional Transformational |
| 3 – Hand over responsibility for ESO code administration for the Grid Code, CUS and STC to third parties. | None |
| 4 - Ongoing activities and enhancements only to maintain current approach for code administration. | Ongoing |

*Table 83: A6.4 Transform the process to amend our codes options*

[24] For the CUSC there are on average 15 modifications a year.

*Advantages and disadvantages*

### 3.4.7.1 Preferred option - Step up to code manager

| Advantages | Disadvantages |
|---|---|
| Improves the codes process, as supported by stakeholders. | Investment required and changes to ESO license required to be able to step up to code manager role. |

*Table 84: A6.4 Transform the process to amend our codes option 1 advantages and disadvantages*

### 3.4.7.2 Step up to code manager for additional codes

| Advantages | Disadvantages |
|---|---|
| Expands the benefits of code management to additional codes.<br>Creates synergies in code management and reduces costs due to efficiencies on managing multiple codes. | This option was not supported by Ofgem[25] in feedback from the sector specific consultation regarding retaining current roles and also based on feedback from wider stakeholders. |

*Table 85: A6.4 Transform the process to amend our codes option 2 advantages and disadvantages*

Thus, given the stakeholder feedback, we have decided not to take this option forward.

### 3.4.7.3 Hand over responsibility for code administration to another party

| Advantages | Disadvantages |
|---|---|
| Reduced investment cost for the ESO.<br>Depending on the new party responsible for administration, could create synergies in code management and reduce costs due to efficiencies e.g. through managing multiple codes. | This option was not widely supported by feedback from stakeholders.<br>Ofgem's RIIO-2 sector specific methodology ESO annex[26] supports retaining code administrator roles as a function within the ESO, subject to the ongoing Energy Codes Review, highlighted in the main Business Plan. |

*Table 86: A6.4 Transform the process to amend our codes option 3 advantages and disadvantages*

Given the ongoing Energy Codes Review, we do not believe we should relinquish our code administration role.

[25] https://www.ofgem.gov.uk/system/files/docs/2019/05/riio-2_sector_specific_methodoloy_decision_-_eso.pdf see section 2.6
[26] https://www.ofgem.gov.uk/system/files/docs/2018/12/riio-2_eso_annex_0.pdf

#### 3.4.7.4 Do minimum option - Ongoing activities only

| Advantages | Disadvantages |
| --- | --- |
| Reduced investment cost and no implementation time | Our stakeholders have told us that the current code process is not fit for purpose. Without action, our codes will continue to be an increasing barrier to innovation, competition and consumer value. This view has been reinforced by the joint BEIS and Ofgem Energy Codes Review |

*Table 87: A6.4 Transform the process to amend our codes option 3 advantages and disadvantages*

Thus, given this option is not supported by stakeholders, when compared to the preferred option, we have decided not to take this option forward.

*Summary*

Based on this we have decided to proceed with option 1 because:

- stakeholders support it
- in our commercial and technical judgement
- as shown by the breakeven analysis, the costs are likely to be low compared to the potential benefits.

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

This sub-section provides further context on the costs and benefits of our activity A6.5 Work with all stakeholders to create a fully digitalised, whole-system Grid Code by 2025.

The net present value of A6.5 Work with all stakeholders to create a fully digitalised, whole-system Grid Code by 2025 is £4 million over the RIIO-2 period and £18 million over ten years. Sensitivity analysis suggests an NPV range of negative £1 million to £9 million over the RIIO-2 period.

### 3.5.1 The counterfactual

If we did not undertake A6.5 Work with all stakeholders to create a fully digitalised, whole-system Grid Code by 2025 we would leave access to the Grid Code remaining as it is today. It would not extend to consider the whole system, with only incremental improvements in the third-party experience.

### 3.5.2 The Benefits

| Assumptions | Justification |
|---|---|
| 800 projects interacting with the whole system Grid Code per year | Based on twice the applications for connections to the transmission system, to account for estimated distribution projects |
| Our actions save one FTE month of time from each project | Estimated effort required on each application process |
| Benefits delivered from year four of RIIO-2 | This allows a year for implementation of the activity, given that the project begins in year two of RIIO and full benefits achieved in year five |

*Table 88: A6.5 Work with all stakeholders to create a fully-digitalised, whole-system Grid Code by 2025 assumptions*

Digitalising the Grid Code provides a more user friendly and tailored experience for the diverse needs of our customers. A simpler whole system Grid Code will speed up how important decisions are taken throughout the connection journey. Crucially it will provide more targeted and customised information when our customers need it. These improvements will also aid new smaller entrants, as well as supporting innovation in the market. In the long term, new parties will deliver efficiencies and lower cost for consumers

We have considered use of the whole system Grid Code by parties connecting to the transmission and distribution systems. We have assumed that the improved digital service will remove one person month of effort from each application process providing a total annual saving of £4.2 million. To calculate this, we have assumed the total cost of an FTE is £100,000 per year and that 800 potential projects will need to interact with the whole Grid Code. For comparison, in 2018, there were 393 applications for connection to the transmission network alone.

*Sensitivity analysis*

- Market factors: we have repeated the analysis with the high and low cases for the number of projects: 1000 and 600 respectively.
- Delivery factors: we have modelled a one-year delay in delivery for the low case, from 2025/26.
- Third Party factors: we have repeated the analysis with the high and low cases for project time saved: 1.5 months and 0.5 months respectively.

| Number of parties interacting with the whole system Grid Code | | Annual cost of an FTE £s | | One month | | Annual saving £ million |
|---|---|---|---|---|---|---|
| 800 | x | 100,000 | ÷ | 12 | = | 6.7 |

*Table 89: Benefit calculation A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025*

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Reducing barriers to entry | 0.0 | 0.0 | 0.0 | 3.3 | 6.7 | 10.0 |
| Sensitivity – high market | 0.0 | 0.0 | 0.0 | 4.2 | 8.3 | 12.5 |
| Sensitivity – low market | 0.0 | 0.0 | 0.0 | 2.5 | 5.0 | 7.5 |
| Sensitivity – low delivery | 0.0 | 0.0 | 0.0 | 0.0 | 3.3 | 3.3 |
| Sensitivity – high third party | 0.0 | 0.0 | 0.0 | 5.0 | 10.0 | 15.0 |
| Sensitivity – low third party | 0.0 | 0.0 | 0.0 | 1.7 | 3.3 | 5.0 |

*Table 90: Benefits for A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025*

The total benefits for A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 are between £3.3 million and £15 million, with a central case of £10 million over the RIIO-2 period

*Measuring benefits and consumer bill impact*

The £10 million benefit could be tracked as part of any regulatory reporting for RIIO-2.

This benefit will impact on consumer bills by reducing the supplier charge element, by more than otherwise would have been the case.

## 3.5.3 Activity Costs

Delivery of A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 will require additional capex and opex spend, summarised below:

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 0.0 | 0.0 | 0.3 | 0.8 | 0.5 | 1.6 |
| Opex | 0.0 | 1.1 | 1.3 | 1.7 | 0.4 | 4.5 |
| Total | 0.0 | 1.1 | 1.6 | 2.4 | 0.9 | 6.1 |

*Table 91: Incremental costs A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025*

The total costs for A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 are £6.1 million.

### 3.5.4 Net Present Value

The NPV of A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 is estimated at £4 million over the RIIO-2 period and £18 million over ten years, which will start to deliver positive returns from 2025/26. Sensitivity analysis suggests an NPV range of:

- Market factors between £2 million and £7 million.
- Delivery factors between negative £1 million and £4 million.
- Third Party factors between £0 million and £9 million.

### 3.5.5 Dependencies, enablers and whole energy system

A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 is dependent on the following transformational activity:

- A6.4 Transform the process to amend our codes (Role 2, Theme 2) – Allowing the ESO to manage codes more efficiently, prioritising change across all ESO-managed codes.

This activity will require third parties, in particular the distribution networks operators (DNO) to work collaboratively with the ESO to create the whole system element, and for current and future whole system Grid Code users to fully participate in the process. There may be minor costs from adapting to these new arrangements, but we believe these are within the scope of third parties' ongoing investments.

### 3.5.6 Uncertainties and risks

We have accounted for market, third party and deliverability uncertainties in our sensitivity analysis.

The table below summarises the key risks and how we propose to mitigate them. Risks for the associated IT investments can be found in Annex 4 – Technology investment report.

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Identifying the appropriate business capabilities and resource | Targeted use of consultant resource | 2 | 2 |
| Lack of industry engagement impacting quality and delivery to timescales | Engage with Ofgem, BEIS and industry to explain the benefits of ESO being able to apply its expertise and drive benefits across markets | 3 | 2 |
| We have assumed that primary legislation changes will be made at the start of the RIIO-2 period to give the power to transform code processes. This is a key dependency which unlocks further transformative change over the remainder of the RIIO-2 period | Continue to undertake our role in the energy codes review. Engage Ofgem and BEIS to highlight the legislative changes required to enable our future role | 2 | 2 |
| Risks to time, quality and cost in delivery of the project and management of the project scope, etc. | Apply good project management and appropriate project controls standards | 3 | 2 |
| Based on stakeholder feedback and Ofgem's proposals in the RIIO-2 sector specific methodology publication we have assumed the ESO will remain the code administrator for CUSC, STC and Grid Code, as well as being the de facto code administrator for the SQSS. | Continue to engage with industry to demonstrate we are best placed to maximise consumer benefit it through the codes we administer. | 1 | 5 |

*Table 92: Risks for A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025*

### 3.5.7 Other options considered

We considered three options for A6.5 work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025:

| Options for A6.5 work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 | Investment |
|---|---|
| 1 – Work with stakeholders to create a fully digitalised, whole system Grid Code by 2025. Taking the current Grid Code, expanding to distribution and using the latest data technologies to support navigation of the codes, being tailored to each code user's individual needs. The details of this option in the sections above. | Ongoing and Transformational |
| 2 – Work with stakeholders to create a fully digitalised, Grid Code by 2025. Taking the current Grid Code and using the latest data technologies to support navigation of the codes, being tailored to each code user's individual needs. This option would only look to fully digitalised the Grid Code for transmission participants. | Ongoing and transformational for transmission Grid Code only |
| 3 - Ongoing activities and enhancements only to maintain current approach for Gird Code management. | Ongoing |

*Table 93: A6.5 work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025: options*

*Advantages and disadvantages*

#### 3.5.7.1 Preferred option - Fully-digitalised, whole system Grid Code by 2025.

| Advantages | Disadvantages |
|---|---|
| Improved access to the Grid code for transmission and distribution participants. Reducing barriers to entry and costs for participants. | Investment required for three-year project to implement improvements. Complex to merge transmission and distribution codes |

*Table 94: A6.5 work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 option 1 advantages and disadvantages*

#### 3.5.7.2 Transmission only option

| Advantages | Disadvantages |
| --- | --- |
| The benefits would be delivered for transmission participants, and there would be a lower cost for this smaller project - estimated at £3 million less, not merging the transmission and distribution codes and simpler digitalising. | Many of the benefits arise from the co-ordinated approach for distributed assets. A transmission only code would not deliver these benefits. Giving an option NPV of £2 million, down from £4 million for the preferred option. |

*Table 95: A6.5 work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 option 2 advantages and disadvantages*

For this option we undertook a CBA. The table below shows the change in assumptions from the preferred option CBA:

| £ million | Preferred option | Short list option | Difference |
| --- | --- | --- | --- |
| Capex | 1.6 | 1.2 | -0.4 |
| Opex | 4.5 | 2.5 | -2 |
| Total cost | 6.1 | 3.7 | -2.4 |
| Gross benefit | 10 | 5 | -5 |
| NPV | 4 | 2 | -2 |

*Table 96: A6.5 work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 option 2 CBA*

Thus, with an NPV difference of £2 million, we have decided not to take this option forward.

#### 3.5.7.3 Do minimum option - Ongoing activities only

| Advantages | Disadvantages |
| --- | --- |
| Reduced investment cost and no implementation time | Would not deliver NPV consumer benefits of £4 million, would not meet our customer's expectations that codes and code governance are fit for purpose |

*Table 97: A6.5 work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 option 3 advantages and disadvantages*

Thus, given this option does not deliver consumer benefits, when compared to the preferred option, and is not supported by stakeholders, we have decided not to take this option forward.

*Summary*

Based on this we have decided to proceed with option 1 because:

- stakeholders support it
- in our commercial and technical judgement
- it delivers consumer benefit, as shown by the positive NPV.

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

This sub-section provides further context on the costs and quantifiable benefits of our activity A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS).

The net present value of A6.6 Look at fully or partially fixing Balancing Services Use of System (BSUoS) charges is £280 million over the RIIO-2 period and £580 million over ten years. Sensitivity analysis suggests an NPV range of £206 million to £730 million over the RIIO-2 period.

### 3.6.1 The counterfactual

If we did not undertake A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges, the BSUoS arrangements would remain unchanged and the BSUoS price would continue to be set after the event.

### 3.6.2 The Benefits

| Assumptions | Justification |
|---|---|
| We have assumed benefits outlines in “Final Modification Report for CMP250” | Industry working group set up to consider this issue |
| ESO will finance any new arrangements | Taking on the additional cost of managing the risk premia will require financing for the ESO to manage this risk |
| Benefits delivered from year two of RIIO-2 | Estimated delivery data from industry analysis |

*Table 98: A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges assumptions*

The benefits of this activity are a reduction in the risk premia which BSUoS parties pay to manage uncertainty and volatility. The difference in ESO financing costs, and savings from reduced industry risk premia, is due to the number of parties that hold risk premia for BSUoS – and this now being managed solely through the ESO. We will work with Ofgem and industry to further refine the benefits.

Based on previous industry analysis undertaken by a Connection and Use of System Code (CUSC) work group[27] an illustrative annual saving to consumers of around £81 million to £201 million a year was recorded for one of the scenarios. We also considered the higher ESO financing costs to manage any new BSUoS arrangements – again to reflect the uncertainty – of around £4.8 million per year and between £2.2 million and £7.2 million a year.

[27] https://www.nationalgrideso.com/document/106876/download - Exploring fixing BSUoS with a notice period as demonstrated in the Final Modification Report for CMP250, stabilising BSUoS with at least a twelve month notification period, Section 2.163

*Sensitivity analysis*

- Market factors: we have repeated the analysis with the high and low cases for benefits and financing costs: £201 million benefit and £2.2 million financing cost and £81 million benefit and £7.4 million financing cost respectively.
- Delivery factors: We have also modelled a one-year delay in delivery for the low case, from 2023/24.
- Given the uncertain nature of this activity we have used the lower estimate of benefits of £81 million per a year. We expect these to start being delivered from 2022/23:

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Reduced industry risk premia | 0 | 81 | 81 | 81 | 81 | 324 |
| Sensitivity – high market | 0 | 201 | 201 | 201 | 201 | 804 |
| Sensitivity – low market | 0 | 81 | 81 | 81 | 81 | 324 |
| Sensitivity – low delivery | 0 | 0 | 81 | 81 | 81 | 243 |

*Table 99: Benefits for A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges*

The total benefits for A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges are between £243 million and £804 million, with a central case of £324 million over the RIIO-2 period

*Measuring benefits and consumer bill impact*

The £324 million benefit can be measured directly via the output of the code modification process required to change the BSUoS charging arrangements.

This benefit will impact on consumer bills by reducing the supplier charge element, by more than otherwise would have been the case.

### 3.6.3 Activity costs

A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges will not require incremental capex or opex, nor any additional FTEs. It may require opex and capex for implementation, but these costs are expected be accounted for through ongoing arrangements for the RIIO-2 period i.e. relating to periodic changes to the charging arrangements.

Based on previous internal analysis undertaken before ESO legal separation, the costs for the CBA are estimates of the additional cashflow associated with a move from ex-post to ex-ante charging arrangements for BSUoS. We assume there will be an additional £150 million per annum of under-recovery risk for ESO in each financial year if we were to fix BSUoS on an annual basis; this change would result in an additional cashflow risk for the ESO until those costs can be recovered. Please note, this analysis was carried out before legal separation.

These additional costs relate to new funding facility costs, such as a revolving credit facility with a commercial bank. These will ensure the ESO has access to the funds it needs to run the business in the event of under recovery of BSUoS. These do not include any costs from wider arrangements for the ESO, e.g. the weighted average cost of capital; but we do not expect these to materially affect the CBA.

So, based on previous internal analysis by ESO, the costs of new funding arrangements could be in the region of £2.2 million to £7.4 million per annum from implementation of the change. Again, given the uncertain nature of this activity, we have used the average costs of £4.8 million, and assumed this from 1 April 2022.

**Note: This is an early estimate and is not reflected in our analysis of overall ESO financing costs, which is detailed in chapter 9**

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Other costs ESO funding arrangements estimates | 0.0 | 4.8 | 4.8 | 4.8 | 4.8 | 19.2 |
| Sensitivity – high market | 0.0 | 2.2 | 2.2 | 2.2 | 2.2 | 8.8 |
| Sensitivity – low market | 0.0 | 7.4 | 7.4 | 7.4 | 7.4 | 29.6 |

*Table 100: Incremental costs for A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges*

The total costs for A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges are £19.2 million**.**

### 3.6.4 Net Present Value

The net present value of A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges is estimated at £280 million over the RIIO-2 period, and £580 million over ten years and It will start to deliver positive returns from 2022/23. Sensitivity analysis suggests an NPV range of:

- Market factors between £270 million and £730 million.
- Delivery factors between £206 million and £280 million.

### 3.6.5 Dependencies, enablers and whole energy system

Delivering this activity requires ongoing work to demonstrate that any changes to BSUoS bring a positive benefit to consumers. We also need BSUoS to be confirmed as cost recovery by Ofgem. Finally, that BSUoS payers pass on any reduced operational costs to consumers.

### 3.6.6 Uncertainties and risks

We have accounted for market, third-party and deliverability uncertainties in our sensitivity analysis.

The table below summarise the key risks and how we propose to mitigate them. Risks for the associated IT investments can be found in Annex 4 – Technology investment report.

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| If CBA assumptions (for the BSUoS analysis) are not robust or circumstances change, there is a risk that the costs associated with the new arrangements outweigh the savings. An added uncertainty is the challenge of understanding risk premia values due to commercial confidentiality concerns amongst third parties. | Review costs and benefits to ensure robust estimates. Engage with industry about potential benefits to sense-check assumptions. | 2 | 4 |
| The funding and regulatory arrangements and their associated costs for ESO remain uncertain. This is exacerbated by the recent separation of ESO within the National Grid Group. | As above, update the costs associated with the new arrangements to ensure robust estimates. | 3 | 2 |
| The changes to BSUoS would need to occur via a Code Modification process. This would provide uncertainty in the specifics of any change to be presented to the Authority for approval. | Engage with Ofgem to ensure the scope of this is understood and the proposal align with their expectations. | 2 | 3 |
| Uncertainties about the future direction of balancing services charges. These could impact the options within this paper prior to RIIO-2. | Keep proposals under review to ensure costs and benefits are reflective of the most recent position for BSUoS. | 4 | 2 |

*Table 101. Risks for A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges*

### 3.6.7 Other options considered

We considered two options for A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges:

| Options for A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges | Investment |
|---|---|
| 1 – Implement the recommendations to fix BSUoS, subject to positive CBA outcome from review. The details of this option in the sections above: | Ongoing and Transformational |
| 2 - Ongoing activities and enhancements only to maintain current approach for BSUoS charges | Ongoing |

*Table 102: A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges options*

*Advantages and disadvantages*

#### 3.6.7.1 Preferred option: Implement the recommendations to fix BSUoS

| Advantages | Disadvantages |
|---|---|
| Benefits for consumers, with an NPV of £280 million. Supported by stakeholders | Requires code modifications and passes risk premia onto the ESO, which will require financing. Outcome of review is uncertain and final recommendation is currently unknown |

*Table 103: A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges option 1 advantages and disadvantages*

#### 3.6.7.2 Ongoing activities and enhancements only to maintain current approach for BSUoS charges

| Advantages | Disadvantages |
|---|---|
| No implementation time | In the event a positive CBA is demonstrated for the change we do not believe this option is viable as it would not be in the interests of consumers<br>Keeping the current arrangements is not supported by stakeholder |

*Table 104: A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges option 2 advantages and disadvantages*

Thus, given this option does not deliver consumer benefits, when compared to the preferred option, and is not supported by stakeholders, we have decided not to take this option forward.

*Summary*

Based on this we have decided to proceed with option 1 because:

- stakeholders support it
- in our commercial and technical judgement
- it delivers consumer benefit, as shown by the positive NPV.

## 3.7 Cost summary

This table summarises the total costs of Role 2, Theme 2.

| Ref | Type | RIIO-T1 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2 year average | 2 year total |
|---|---|---|---|---|---|---|---|---|---|
| Transformational Activity subject to CBA CBA Ref: NGESOT2010 | OPEX | - | 6.5 | 5.6 | 5.7 | 3.9 | 4.1 | 6.0 | 12.0 |
| | CAPEX | - | 3.1 | 3.1 | 2.2 | 1.2 | 1.3 | 3.1 | 6.2 |
| Transformational not subject to a CBA | OPEX | - | - | - | 1.2 | 2.5 | 0.4 | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 2.7 | 3.8 | 3.8 | 3.7 | 3.6 | 3.5 | 3.8 | 7.6 |
| | IS OPEX | - | 1.5 | 0.3 | 0.4 | 0.4 | 0.4 | 0.9 | 1.9 |
| | CAPEX | 1.1 | 2.1 | 0.2 | 0.2 | 0.2 | 0.2 | 1.1 | 2.3 |
| **Build the future balancing service and wholesale markets** | **OPEX** | **2.7** | **11.8** | **9.7** | **11.1** | **10.3** | **8.4** | **10.7** | **21.5** |
| **Ref BP Theme 2 chapter** | **CAPEX** | **1.1** | **5.2** | **3.3** | **2.4** | **1.4** | **1.5** | **4.3** | **8.5** |
| Transformational Activity subject to CBA CBA Ref: NGESOT2000 | OPEX | - | 1.1 | 0.8 | 0.8 | 0.9 | 0.9 | 0.9 | 1.9 |
| | CAPEX | - | 1.2 | 0.9 | 0.9 | 0.9 | 0.9 | 1.1 | 2.1 |
| Transformational not subject to a CBA | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 2.7 | 3.2 | 3.1 | 3.1 | 2.7 | 2.7 | 3.1 | 6.3 |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | 4.6 | - | - | - | - | - | - | - |
| **Transform access to the Capacity Market** | **OPEX** | **2.7** | **4.2** | **3.9** | **3.9** | **3.6** | **3.6** | **4.1** | **8.2** |
| **Ref BP Theme 2 chapter** | **CAPEX** | **4.6** | **1.2** | **0.9** | **0.9** | **0.9** | **0.9** | **1.1** | **2.1** |
| Transformational Activity subject to CBA CBA Ref: NGESOT2006 | OPEX | - | - | 1.1 | 1.3 | 1.7 | 0.4 | 0.6 | 1.1 |
| | CAPEX | - | - | - | 0.3 | 0.8 | 0.5 | - | - |
| Transformational not subject to a CBA | OPEX | - | 0.5 | 1.5 | 1.7 | 1.9 | 2.1 | 1.0 | 2.0 |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 6.7 | 8.6 | 8.5 | 8.5 | 8.4 | 8.3 | 8.5 | 17.1 |
| | IS OPEX | - | 4.1 | 2.9 | 3.2 | 3.6 | 4.7 | 3.5 | 7.1 |
| | CAPEX | 8.6 | 15.5 | 10.8 | 10.6 | 11.1 | 12.2 | 13.1 | 26.3 |
| **Develop code and charging arrangements that are fit for the future** | **OPEX** | **6.7** | **13.2** | **14.0** | **14.8** | **15.6** | **15.6** | **13.6** | **27.3** |
| **Ref BP Theme 2 chapter** | **CAPEX** | **8.6** | **15.5** | **10.8** | **11.0** | **11.9** | **12.6** | **13.1** | **26.3** |
| **Theme 2 Total On CBA** | **Opex** | **-** | **7.5** | **7.5** | **7.9** | **6.4** | **5.4** | **7.5** | **15.0** |
| **Theme 2 Total Capex** | **Capex** | **-** | **4.4** | **4.0** | **3.4** | **2.9** | **2.6** | **4.2** | **8.3** |
| **Theme 2 Total Ongoing activites and** | **Opex** | **12.0** | **16.1** | **16.9** | **18.3** | **19.2** | **17.1** | **16.5** | **32.9** |
| **transformational activities not on a CBA** | **IS Opex** | **-** | **5.7** | **3.3** | **3.6** | **3.9** | **5.1** | **4.5** | **9.0** |
| **Theme 2 Total Capex** | **Capex** | **14.3** | **17.6** | **11.0** | **10.8** | **11.3** | **12.4** | **14.3** | **59.5** |
| **Theme 2 Total** | **Opex** | **12.0** | **29.3** | **27.6** | **29.8** | **29.5** | **27.6** | **28.5** | **56.9** |
| | **Capex** | **14.3** | **22.0** | **14.9** | **14.2** | **14.2** | **15.0** | **18.5** | **36.9** |
| | **TOTEX** | **26.3** | **51.2** | **42.6** | **43.9** | **43.7** | **42.6** | | |

# 4. Cost-benefit analysis: Role 3, Theme 3

This section provides further context on the costs and benefits of the transformational activities in Role 3, Theme 3:

| Activity group | Analysis type |
|---|---|
| A8 - A11 Network Options Assessment (*NOA*) enhancements | CBA |
| A12 Undertake with industry a review of the SQSS | Break-even |

*Table 105: Role 3, Theme 3 activities*

The net present value of Role 3, Theme 3 is estimated at £663 million over the RIIO-2 period and £1.3 billion over ten years.  Sensitivity analysis suggests an NPV range of £463 million to £906 million over the RIIO-2 period. Note for activities A8 to A11 we have combined them into one CBA, as they share a common cost base.

## 4.1 *A8 - A11 Network Options Assessment (NOA) enhancements*

This sub-section provides further context on the costs and quantifiable benefits of our *A8 - A11 NOA enhancements* activities.

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

### 4.1.1 The counterfactual

The counterfactual to our proposals is that we would continue with the current *NOA* process, as per our existing licence conditions.

### 4.1.2 The benefits

We have quantified benefits in four areas:

- Facilitate competition by embedding pathfinding projects into the *NOA.*
- Extending *NOA* to end of life asset replacement decisions.
- Extend *NOA* approach to all connections wider works.
- Support decision making for investment at the distribution level.

#### 4.1.2.1 Facilitate competition by embedding pathfinding projects into the *NOA*

| Assumptions | Justification |
|---|---|
| Generic intertrip solution cost | Commercially sensitive historic information from bilateral contracts |
| Commercial solutions provide 1000MW from FY24 onwards | Output from commercial solutions pathfinder project, as detailed in in the 2018/19 *NOA* |

*Table 106: Facilitate competition by embedding pathfinding projects into the NOA assumptions*

This activity takes learnings and processes from the ESO *Forward Plan 2019-21* and embeds them into network investments. The pathfinding projects cover a wide range of network challenges, including regional voltage challenges, constraint management, network stability and commercial solutions competing with traditional transmission assets. As the pathfinding projects adopt a learn-by-doing approach it is hard to accurately forecast savings. However, our *Forward Plan* shows this benefit will be realised throughout the RIIO-2 period.

The benefit for implementing commercial solutions is calculated by:

1. Completing the standard *NOA* process.
2. Adding a commercial solution to provide additional boundary capacity.
3. Use historic costs of commercial solutions as a benchmark for analysis.
4. Repeat the *NOA* process with this extra commercial option.
5. Calculate the difference between (1) and (4).

This delivers £429 million of consumer benefit during RIIO-2. The table below only shows value out to 2025/26; however, there is further value out until 2027/28, mainly from the availability of a more flexible commercial solution before an asset build.

*Sensitivity analysis - Facilitate competition by embedding pathfinding projects into the NOA*

- Market factors: we have repeated the analysis with the highest and lowest values of commercial solutions from the *FES* scenarios.
- Third-party factors: we have not conducted a third-party sensitivity because we believe the regulatory framework on network companies would incentivise them to carry out any recommendations.
- Delivery factors: we have modelled a one-year delay in delivery. We have not modelled bringing forward delivery as we do not believe this is achievable.

*Interaction with other benefit areas*

The proposals in sections 2.1.2.5 and 5.4.2 claim to lower constraint costs. We have not accounted for these in the central benefit case here, but they would be accounted for in the market factors sensitivity analysis.

| Benefits £ millions | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Consumer benefit of implementing commercial solutions (£ million) | 127.5 | 60.8 | 94.9 | 81.1 | 64.4 | 428.8 |
| Sensitivity – high market factors | 162.9 | 95.9 | 117.4 | 102.4 | 99.7 | 578.3 |
| Sensitivity – low market factors | 101.0 | 20.3 | 70.0 | 54.2 | 32.3 | 277.8 |
| Sensitivity – low delivery confidence | 0.0 | 60.8 | 94.9 | 81.1 | 64.4 | 301.3 |

*Table 107: Benefits for Facilitate competition by embedding pathfinding projects into the NOA*

The above table shows the benefits from implementing commercial solutions to the *NOA* process are between £277.8 million and £578.3 million, with a central case of £428.8 million.

*Measuring benefits and consumer bill impact*

The £428.8 million benefit can be measured via Metric 10 – Consumer value savings from NOA. See Annex 7 - Metrics and measuring performance for more details.

This benefit will impact on consumer bills through lower BSUoS and/or TNUoS charges than would otherwise have been the case.

### 4.1.2.2 Extending *NOA* to end of life asset replacement decisions

| Assumption | Justification |
|---|---|
| TOs provide asset replacement data | TOs have this information and frameworks exist for them to share |
| Greater information provision will help the decision-making process | Currently only the ESO holds operational data. Combining this with asset data, held by the TOs, should ensure optimal decisions are made |

*Table 108: Extending NOA to end of life asset replacement decisions assumptions*

We propose to expand our network planning processes to look at TO end-of-life asset replacement decisions. Currently, TOs consider the best way to replace these assets. However, they do not have access to the same level of operational data as the ESO. We believe that by reviewing decisions, the ESO would be able to recommend a different approach. Initially we will only consider assets that may impact on major network boundaries.

It is very difficult to forecast the exact benefit for this activity as the ESO does not hold asset price data or long-term asset replacement information. Part of this activity will require the TOs to include this extra data with their *NOA* submissions. Below we present a plausible scenario where this activity will generate consumer value.

### *Example scenario*

Suppose a life-expired asset is due to be replaced like-for-like in 2025 at a cost of £50 million. If *NOA* recommends the asset is upgraded in 2030 at a cost of £60 million, the current process would result in a cost of £50 million to replace the asset in 2025 and the another £60 million to upgrade it in 2030 for a total spend of £110 million. There is a clear benefit in bringing forward the asset upgrade to avoid the need to replace the asset like-for-like. Bringing forward the upgrade to 2025 may increase the capital cost from £60 million to £71 million in present value terms; but the need to replace the asset is removed. This results in a capital cost saving of £39 million. The asset life will be reduced to 2065 from 2070 but most of this value will erode with discounting and become immaterial.

### *Calculation of the forecast saving during the RIIO-2 period*

Of schemes submitted to *NOA 4*[28] there were 25 per cent overhead line (OHL) related (i.e. related to asset upgrades). Assets are only considered for replacement when their life expires in the next five years, based on TO risk factors. So only 12.5 per cent (5 years of out of 40 – the assessment period of *NOA*) of reinforcements will be considered as value created in RIIO-2. So, of the 36 options in *NOA* 4 to upgrade assets, five schemes can provide benefit during the RIIO-2 period. We have profiled these to the backend of the RIIO-2 period. The average cost of these 36 schemes is £29.5 million. If this activity can save four schemes over the RIIO-2 period it would deliver £118 million of consumer benefit, per the below profile, assuming we would run this process once in 2023/24 and 2024/25, and twice in 2025/26

### *Sensitivity analysis - Extending NOA to end of life asset replacement decisions*

- Market factors: we have modelled assessing one more and one fewer scheme, instead of modelling the number of options put forward.
- Third-party factors: we have not conducted a third-party sensitivity because we believe the regulatory framework on network companies would incentivise them to carry out any recommendations.
- Delivery factors: we have modelled a one-year delay in delivery. We have not modelled bringing forward delivery as we do not believe this is achievable.

[28] https://www.nationalgrideso.com/document/137321/download

| Benefits £ millions | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Extending *NOA* to end of life asset replacement decisions | 0.0 | 0.0 | 29.5 | 29.5 | 59.0 | 118.0 |
| Sensitivity – high market factors | 0.0 | 0.0 | 29.5 | 59.0 | 59.0 | 147.5 |
| Sensitivity – low market factors | 0.0 | 0.0 | 29.5 | 29.5 | 29.5 | 88.5 |
| Sensitivity – low delivery confidence | 0.0 | 0.0 | 0.0 | 29.5 | 59.0 | 88.5 |

*Table 109: Benefits for extending NOA to end of life asset replacement decisions*

The above table shows the benefits from extending the *NOA* to end-of-life asset replacement is between £89 million and £148 million, with a central case of £118 million.

### *Measuring benefits and consumer bill impact*

The £118 million benefit can be measured via Metric 10 – Consumer value savings from NOA. See Annex 7 - Metrics and measuring performance for more details.

This benefit will impact on consumers' bills through lower BSUoS and/or TNUoS charges than would otherwise have been the case.

### 4.1.2.3 Extend *NOA* approach to all connections wider works

| Assumption | Justification |
|---|---|
| TO will complete additional work through studying more boundaries and creating more options | TOs already have appropriate funding and resourcing due to existing *NOA* commitments. Incentive framework should reward them for delivering more value |
| We will find issues on the newly-created boundaries. We may find no issues, resulting in no benefits because no actions would be needed | Analysis of historic data suggests there are likely to be issues on the newly-created boundaries. |

*Table 110: Extend NOA approach to all connections wider works assumptions*

We propose to expand our network planning processes to look at connections wider works. These are more local issues and not necessarily bulk transfer requirements. The principle behind this CBA is that the *NOA* currently looks at approximately 30 boundaries and this provides value to the consumer. Doing nothing would maintain this approach and only look at the major boundaries versus investing to cover more of the network.

As we do not know what extra wider works will be required throughout the RIIO-2 period, we've taken a backward-looking approach based on the output of *NOA* 4 coupled with wider works not currently considered in the *NOA* document.

*NOA* 4 looked at 34 boundaries across GB, which presented 139 different reinforcement options. An initial search found 15 were in customer offers not considered in the *NOA*. This suggested expanding the *NOA* to consider these extra options would lead to around a 10 per cent increase in analysis of boundaries and options. Again, *NOA* 4 showed the value created by presenting an investment plan for the next 12 months was between £1.85 billion and £2.67 billion.

If the *NOA* were expanded to consider 10 per cent more boundaries and more of the smaller wider work schemes, it is reasonable to expect these savings to increase. However, the relationship between considering more boundaries and saving more money will not be linear and given the uncertain nature of options, it is very challenging to determine the extra value this would generate; however even a pessimistic saving of just 2 per cent more would provide the consumer between £37 million and £53.4 million. We present the lower case here.

*Sensitivity analysis - Extend NOA approach to all connections wider works*

- Market factors: for the upper range, we assume 2 per cent savings of £2.67 billion; the lower range is the same as our central case.
- Third-party factors: we have not conducted a third-party sensitivity because we believe the regulatory framework on network companies would incentivise them to carry out any recommendations.
- Delivery factors: we have modelled a one-year delay in delivery. We have not modelled bringing forward delivery as we do not believe this is achievable without significant extra work for the ESO and TOs.

| **Benefits £ millions** | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** | **Total** |
|---|---|---|---|---|---|---|
| Extend *NOA* approach to all connections wider works (£ million) | 0.0 | 37.0 | 37.0 | 37.0 | 37.0 | 148.0 |
| Sensitivity – high market factors | 0.0 | 53.4 | 53.4 | 53.4 | 53.4 | 213.6 |
| Sensitivity – low delivery confidence | 0.0 | 0.0 | 37 | 37 | 37 | 111.0 |

*Table 111: Benefits for extend NOA approach to all connections wider works*

The above table shows the benefits of extending the *NOA* to connections wider works is between £111 million and £214 million, with a central case of £148 million.

*Measuring benefits and consumer bill impact*

The £148 million benefit can be measured via Metric 10 – Consumer value savings from NOA. See Annex 7 - Metrics and measuring performance for more details.

This benefit will impact on consumers' bills through lower BSUoS and/or TNUoS charges than would otherwise have been the case.

#### 4.1.2.4 Support decision making for investment at the distribution level

| Assumption | Justification |
|---|---|
| Expected level of investment at the 132kV level is £40 million per year | Based on historic data from the *Forward Plan 2018/19* [29] |
| 60% of investment options would be on the optimal path | Based on *NOA* 4 |
| DNOs can take commercial actions against network costs | Today some DNOs have live flexibility services that are making these comparisons |

*Table 112: Support decision making for investment at the distribution level assumptions*

The ESO currently assesses investment decisions for transmission networks (which includes the 132kV networks in Scotland). We considered whether there would be value in expanding the ESO's role further to undertake a *NOA*-type process on the 132kV networks in England and Wales. To demonstrate the potential value in this activity, our CBA counterfactual is that we do not expand the *NOA* into the 132kV domain and we do not provide any support for DNOs.

We also consider if it is viable for the ESO to perform a *NOA*-type assessment on the 132kV network; this is discussed below, however the incremental costs assume a consultancy role.

The level of expected investment is around £40 million per year, as noted in our *2018/19 Forward Plan*. So, we believe there is value in the ESO supporting the DNOs rather than expanding into the 132kV networks.

The *NOA* balances operational costs vs investment costs and historically the *NOA* determines that approximately 60 per cent of all options make it onto the optimal path and can be carried out for the next 12 months. (The 60 per cent of options does not mean options are necessarily inefficient; the process is intentionally designed to be challenging). If we assume the same proportion when extending the *NOA* to lower voltage levels, the *NOA* could deliver value for the consumers via the DNO. The *NOA* does takes a national approach and may recommend more than 60 per cent in any given area. Applying the 60 per cent to the £40 million investment implies around £16 million could be recommended not to proceed for that 12-month period. Given the uncertainty, we have assumed that not all the £16 million savings would be realised, but a more conservative £10 million. Profiling this to when work in this area could start delivers £30 million of consumer benefit during RIIO-2.

We cannot say definitively this is a direct reduction in investment costs; however, this figure highlights that a *NOA*-type process may save investment costs.

We believe sharing our expertise could help the DNOs optimise their investment plans and generate savings of around £10 million a year for consumers over the RIIO-2 period.

[29] https://www.nationalgrideso.com/about-us/business-planning-riio/forward-plans-2021

## Sensitivity analysis - Support decision making for investment at the distribution level

- Market factors: we model a saving of £16 million per year (consistent with the estimates of projects not on the optimal path) and £7 million per year for the upper and lower ranges respectively.
- Third party factors: we have not conducted a third-party sensitivity because we believe the regulatory framework on network companies would incentivise them to carry out this work.
- Delivery factors: we have modelled a one-year delay in delivery. We have not modelled bringing forward delivery as we do not believe this is achievable.

| Benefits £ millions | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Support decision making for investment at the distribution level | 0.0 | 0.0 | 10.0 | 10.0 | 10.0 | 30.0 |
| Sensitivity – high market factors | 0.0 | 0.0 | 16.0 | 16.0 | 16.0 | 48.0 |
| Sensitivity – low market factors | 0.0 | 0.0 | 7.0 | 7.0 | 7.0 | 21.0 |
| Sensitivity – low delivery confidence | 0.0 | 0.0 | 0.0 | 10.0 | 10.0 | 20.0 |

*Table 113: Benefits support decision making for investment at the distribution level*

The above table shows the benefits from supporting decision-making at the distribution level is between £20 million and £48 million, with a central case of £30 million.

### *Measuring benefits and consumer bill impact*

The £30 million benefit could be tracked as part of any regulatory reporting for RIIO-2.

This benefit will not directly impact on consumer bills This benefit will impact on consumers' bills through lower BSUoS, TNUoS or DUoS charges than would otherwise have been the case.

### *Total benefits case*

The total benefits for A8 - A11 *NOA* enhancements are between £521 million and £987 million, with a central case of £725 million over the RIIO-2 period.

### 4.1.3 Activity Costs

Delivery of our enhanced *NOA activities will require additional capex and opex spend, summarised below:*

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 3.0 | 3.0 | 3.2 | 1.6 | 1.2 | 12.1 |
| Opex | 0.9 | 1.3 | 1.5 | 1.2 | 1.1 | 6.0 |
| Total | 4.0 | 4.3 | 4.7 | 2.8 | 2.3 | 18.1 |

*Table 114: Incremental costs for A8 - A11 NOA enhancements*

The total costs for our *A8 - A11 NOA enhancements* activities are £18.1 million.

### 4.1.4 Net Present Value

The NPV of *A8 - A11 NOA enhancements* is estimated at £663 million over the RIIO-2 period and £1,321 million over ten years will start to deliver positive returns from 2021/22. Sensitivity analysis suggests an NPV range of:

- Market factors between £488 million and £906 million.
- Delivery factors between £463 million and £663 million.

### 4.1.5 Dependencies, enablers and whole energy system

The activity *facilitates competition by embedding pathfinding projects into the NOA* is dependent on the following transformational activity:

- A4 Build the future balancing service and wholesale markets (Role 2, Theme 2) – Creating new markets for commercial solutions.

Delivery of our proposals may pass on benefits and costs to other parties. There is likely to be more work for TOs and DNOs in creating options and running new processes. However, we expect that the cost should be offset by potential benefits for network companies to carry out this work because of their regulatory and incentive frameworks.

### 4.1.6 Uncertainties and risks

We have accounted for market, third party and deliverability uncertainties in our sensitivity analysis.

The table below summarise the key risks and how we propose to mitigate them. Risks for the associated IT investments can be found in Annex 4 – Technology investment report.

#### 4.1.6.1 Facilitate competition by embedding pathfinding projects into the *NOA*

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Increasing constraints costs or compliance issues from delayed network investment due to competition | We will develop streamlined processes that minimise delays. The cost of any unavoidable delays will be factored into our final *NOA* CBA process | 5 | 3 |
| Increased services in network development adds another layer of complexity to the balancing services market, deterring potential bidders | The role of longer-term tenders will be considered alongside our development of other balancing services | 3 | 2 |
| Increased use of commercial services could increase operational complexity | Our planning and control room processes will manage this risk | 3 | 3 |
| Increased risk of non-delivery of solutions from using new providers and technologies | We will manage this through our tender processes | 5 | 2 |
| Risk that frameworks and funding arrangements hamper the roll out of competition. | We will work closely with Ofgem and other relevant stakeholders such as ENA to develop appropriate frameworks | 2 | 4 |

*Table 115: Risks to facilitate competition by embedding pathfinding projects into the NOA*

#### 4.1.6.2 Extending *NOA* to end of life asset replacement decisions and connections wider works

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Duplication of efforts between ESO and TOs and/or increased bureaucracy | We will work closely with TOs to ensure any activity we undertake adds value | 3 | 1 |
| ESO assessment could delay investment decisions, potentially increasing constraints costs and compliance issues | We will work closely with TOs to understand their processes and time constraints to ensure the ESO assessment complement this | 3 | 3 |
| The ESO may need to develop additional modelling capabilities to assess wider works. | Ensure efficient processes are in place | 2 | 3 |

*Table 116: Risks to extending NOA to end of life asset replacement decisions and connections wider works*

#### 4.1.6.3 Support decision making for investment at the distribution level

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Difficult to reach consensus due to different priorities of DNOs, potentially causing confusion for solution providers | Establish closer ways of working with DNOs | 5 | 2 |

*Table 117: Risk to support decision making for investment at the distribution level*

### 4.1.7 Other options considered

We considered the following options for activities A8-A11 *Network Options Assessment (NOA)* enhancements:

| Options for A8-11 Network Options Assessment (NOA) enhancements | Investment |
|---|---|
| 1 - Enable all solution types to compete. | Ongoing and Transformational |
| 2 - Extend NOA to end of life asset replacement decisions. | Ongoing and Transformational |
| 3 - Extend NOA to connections wider works. | Ongoing and Transformational |
| 4 - Support decision making at the 132kV level. | Ongoing and Transformational |
| 5 - Extend the NOA to the 132kV level. | Ongoing and Transformational |
| 6 - Continue with the NOA as is. | Ongoing and Transformational |

*Table 118: A8-A-11 Network Options Assessment (NOA) enhancements options*

As shown in figure 4, the transformational activities listed above are all proposed additions to the *NOA*: either expanding the scope of *NOA* or expanding the solutions that can be inputted. As such, any combination of them defines a suite of options, against a baseline of continuing with the current *NOA* process as is.

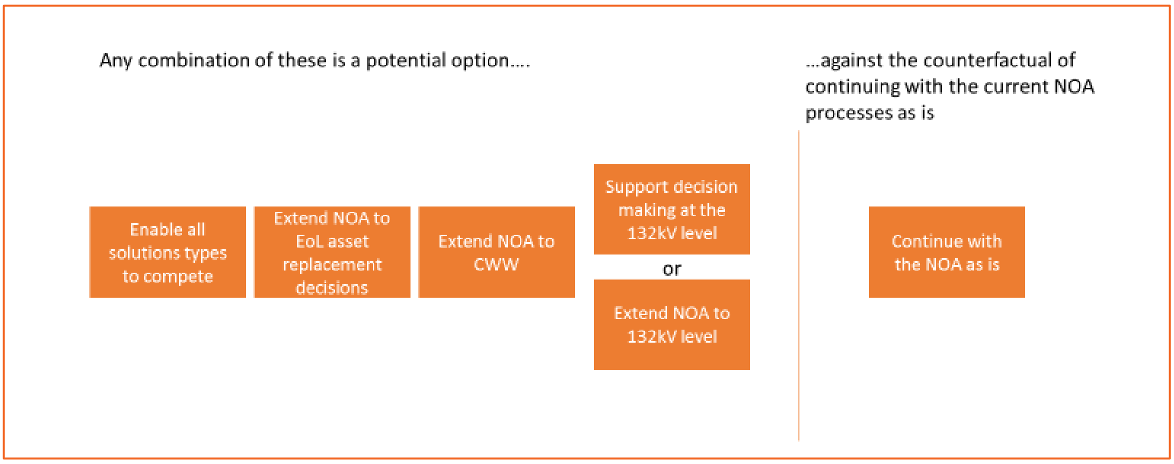


*Figure 5 Options considened for NOA enhacements*

#### 4.1.7.1 Option 5 - Extend *NOA* to the 132kV level

Within supporting decision making at the 132kV level, we also considered the following:

- We could look for the ESO to undertake a *NOA*-type analysis for each of the distribution network's 132kV network in England and Wales. This would involve the ESO undertaking the analysis, developing the modelling required and developing the skills and capabilities require for this type of network analysis.

This is an extension of option 4, which was to support the DNOs to do their own *NOA*-type analysis.

For this option 5 we undertook a high-level CBA. We consider that this option would still deliver the same £10m benefit, but at an additional cost to the ESO. Due to the significant differences between transmission and distribution networks, we would need to gain a thorough understanding of the distribution networks and develop the relevant modelling and analytical tools. This is likely to duplicate some of what the DNOs already have, causing unnecessary costs for consumers.

In addition, stakeholders have also told us the ESO is not best placed to undertake this analysis, given the how different the transmission and distribution networks are.

In summary, we have therefore decided not to proceed with this option because:

- it delivers a lower NPV
- stakeholders do not support it.
- in our commercial and technical judgement, we do not have the required expertise or modelling capability to carry out this activity without significant investment

*Summary*

Based on this we have decided to proceed with options 1 – 4 because:

- stakeholders support it
- in our commercial and technical judgement, we will be able to upgrade our analytical and modelling capabilities to support them
- it delivers consumer benefit, as shown by the positive NPV.

## 4.2 A12 Undertake with industry a review of the Security and Quality of Supply Standard (SQSS)

This sub-section provides further context on our breakeven analysis we have conducted on the SQSS review.

### 4.2.1 Why we have undertaken a breakeven analysis

A breakeven analysis provides details of the benefit that would need to be delivered to cover the costs of an activity.

We have conducted a break-even analysis because the SQSS review does not deliver consumer benefit by itself. It is the implementation of any review recommendations that provide consumer benefit, and we cannot say at this stage what these could be

### 4.2.2 The counterfactual

The counterfactual to our proposals is that an SQSS review would not take place, and any changes would be done through the existing process.

### 4.2.3 Activity costs

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Opex | 0.2 | 0.3 | 0.3 | 0.2 | 0.1 | 0.9 |
| Total | 0.2 | 0.3 | 0.3 | 0.2 | 0.1 | 0.9 |

*Table 119: Incremental cost for A12 Undertake with industry a review of the SQSS*

In addition to the above costs, there is likely to be a similar cost on TOs to resource the review.

### 4.2.4 Assumptions, uncertainties and risks

The key assumptions and uncertainties are:

| Assumption | Justification |
|---|---|
| Timeline for targeted review is four years | ESO judgement based on estimates of work |
| Cost of review is £1 million | New FTE needed for business lead and SMEs to help design solution, and additional FTE for customer relationship management and to manage tenders |
| Stakeholders, including TOs, would resource as part of a joint team | Regulatory arrangements incentivise TOs to undertake work to deliver consumer benefit |

*Table 120: Incremental cost for A12 Undertake with industry a review of the SQSS*

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| The review could deliver limited change | Focusing on specific areas rather than a generic review should ensure practical action | 3 | 1 |
| Review could delay changes | As above | 3 | 2 |

*Table 121: Risks for A12 Undertake with industry a review of the SQSS*

### 4.2.5 Benefits

The qualitative benefits are:

- Providing the opportunity to ensure industry codes and standards reflect the decarbonised energy systems. Updating the SQSS will ensure continued safety and reliability at least cost to consumers.
- The potential for improving the SQSS in focused areas, including its approach to deterministic standards, to ensure it reflects the *NOA*, and developing the offshore transmission section to reflect the growth of this sector. This will help ensure optimal investment decisions, minimising costs for consumers.

### 4.2.6 Conclusion

We believe it is beneficial to proceed with this activity because:

- the cost of conducting the review is low in comparison to the potential benefits
- there is stakeholder support.

### 4.2.7 Other options considered

We considered the following options for activity A12 Undertake with industry a review of the SQSS

| Options for A12 Undertake with industry a review of the SQSS | Investment |
|---|---|
| 1 – Undertaking a fundamental review of the SQSS | Ongoing and Transformational |
| 2 – Undertaking a focused, targeted review of the SQSS | Ongoing and Transformational |
| 3 – Ongoing – not undertaking a review | Ongoing |

*Table 122: A12 Undertake with industry a review of the SQSS options*

*Advantages and disadvantages*

#### 4.2.7.1 Undertaking a fundamental review of the SQSS

Under this option we would undertake a fundamental review of the whole of the SQSS

| Advantages | Disadvantages |
|---|---|
| Ensures all of the SQSS is fit for purpose for the future. | Takes longer than a targeted review, meaning priority changes may be delayed.<br>More expensive than a targeted review. |

*Table 123: A12 Undertake with industry a review of the SQSS option 1 advantages and disadvantages*

We did not proceed with this option because:

- it received mixed stakeholder feedback
- in our commercial and technical judgement, it would be better to conduct a focused review, and undertake a fundamental review if that review identifies the need for it.

#### 4.2.7.2 Undertaking a focused, targeted review of SQSS

Under this option we would undertake a focused review of the SQSS, addressing a targeted set of known concerns (to be agreed with Ofgem).

| Advantages | Disadvantages |
|---|---|
| Priority changes are undertaken quicker than with a fundamental review<br>Leaves open the option for a fundamental review should the need arise and/or stakeholders support it | Some elements of SQSS may not be updated, resulting in potentially suboptimal standards<br>More expensive than the ongoing |

*Table 124: A12 Undertake with industry a review of the SQSS option 2 advantages and disadvantages*

For the reasons listed above this is our preferred option because:

- it has broad stakeholder support
- the break-even analysis indicates substantial potential benefit relative to cost

- in our commercial and technical judgement, it would allow for priority changes to be expedited, and leaves open the potential for a more fundamental review later.

#### 4.2.7.3 Ongoing - not undertaking a review

Under this option we would not undertake a review.

| Advantages | Disadvantages |
|---|---|
| No cost.<br>Leaves open the option for a fundamental or targeted should the need arise and/or stakeholders support it. | Will result in suboptimal SQSS, with potential system security and reliability implications. |

*Table 125: A12 Undertake with industry a review of the SQSS option 3 advantages and disadvantages*

We did not proceed with this option because:

- stakeholders do not support it
- the break-even analysis indicates that there is likely to be benefit in conducting a review for a small cost
- in our commercial and technical judgement, the current SQSS is not fit for purpose for the future.

*Summary*

Based on this we have decided to proceed with option 2 because:

- stakeholders support it
- in our commercial and technical judgement, it would be better to conduct a focused review, and undertake a fundamental review if that review identifies the need for it.
- the break-even analysis indicates substantial potential benefit relative to cost

## 4.3 Cost summary

This table summarises the total costs of Role 3, Theme 3.

| Ref | Type | RIIO-T1 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2 year average | 2 year total |
|---|---|---|---|---|---|---|---|---|---|
| Transformational Activity subject to CBA<br>CBA Ref: NGESOT2004 | OPEX | - | 0.9 | 1.3 | 1.5 | 1.2 | 1.1 | 1.1 | 2.2 |
| | CAPEX | - | 3.0 | 3.0 | 3.2 | 1.6 | 1.2 | 3.0 | 6.1 |
| Transformational not subject to a CBA | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 1.5 | 2.5 | 2.4 | 2.4 | 2.4 | 2.3 | 2.4 | 4.9 |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| **Network Development<br>Ref BP Theme 3 chapter** | **OPEX** | **1.5** | **3.4** | **3.7** | **3.9** | **3.6** | **3.5** | **3.5** | **7.1** |
| | **CAPEX** | **-** | **3.0** | **3.0** | **3.2** | **1.6** | **1.2** | **3.0** | **6.1** |
| Transformational Activity subject to CBA<br>CBA Ref: N/A | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Transformational not subject to a CBA | OPEX | - | 0.2 | 0.3 | 0.3 | 0.2 | 0.1 | 0.2 | 0.4 |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | - | - | - | - | - | - | - | - |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| **SQSS<br>Ref BP Theme 3 chapter** | **OPEX** | **-** | **0.2** | **0.3** | **0.3** | **0.2** | **0.1** | **0.2** | **0.4** |
| | **CAPEX** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| Transformational Activity subject to CBA<br>CBA Ref: N/A | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Transformational not subject to a CBA | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | - | - | - | - | - | - | - | - |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| **CATO<br>Ref BP Theme 3 chapter** | **OPEX** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **CAPEX** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| **Theme 3 Total On CBA** | **Opex** | **-** | **0.9** | **1.3** | **1.5** | **1.2** | **1.1** | **1.1** | **2.2** |
| **Theme 3 Total Capex** | **Capex** | **-** | **3.0** | **3.0** | **3.2** | **1.6** | **1.2** | **3.0** | **6.1** |
| **Theme 3 Total Ongoing activites and transformational activities not on a CBA** | **Opex** | **1.5** | **2.6** | **2.7** | **2.7** | **2.5** | **2.4** | **2.7** | **5.3** |
| | **IS Opex** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| **Theme 3 Total Capex** | **Capex** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **4.9** |
| **Theme 3 Total** | **Opex** | **1.5** | **3.5** | **4.0** | **4.1** | **3.8** | **3.5** | **3.8** | **7.5** |
| | **Capex** | **-** | **3.0** | **3.0** | **3.2** | **1.6** | **1.2** | **3.0** | **6.1** |
| | **TOTEX** | **1.5** | **6.6** | **7.0** | **7.3** | **5.4** | **4.7** | | |

## 5. Cost-benefit analysis: Role 3, Theme 4

This section provides further context on the costs and quantifiable benefits of the transformational activities in Role 3, Theme 4:

| Activity group | Analysis type |
|---|---|
| A13 Lead the debate | Break-even |
| A14 Taking a whole electricity system approach to connections | CBA |
| A15 Taking a whole electricity system approach to promote zero carbon operability | CBA |
| A16 Delivering consumer benefits from improved network access planning | CBA |

*Table 126: Role 3, Theme 4 activities*

The net present value of Role 3, Theme 4 is £673 million over the RIIO-2 period and £1.4 billion over ten years. Sensitivity analysis suggests an NPV range of £427 million to £916 million over the RIIO-2 period.

## 5.1 A13 Leading the debate

This sub-section provides further context on the breakeven analysis we have conducted on A13 Leading the debate.

### 5.1.1 Why we have undertaken a break-even analysis

A breakeven analysis provides details of the benefit that would need to be delivered to cover the costs of an activity.

We have conducted a breakeven analysis because A13 Leading the debate does not in itself lead to direct benefits but helps inform others to be able to make more optimised decisions and allows all parties to be able to access high quality information to do this.

### 5.1.2 The counterfactual

The counterfactual to A13 Leading the debate is continuing with our current suite of publications.

### 5.1.3 Activity costs

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Opex | 1.2 | 1.3 | 1.4 | 1.4 | 1.2 | 6.5 |
| Total | 1.2 | 1.3 | 1.4 | 1.4 | 1.2 | 6.5 |

*Table 127: Incremental costs for A13 Leading the debate*

### 5.1.4 Assumptions, uncertainties and risks

The key risks have been identified:

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Industry stakeholders think that we are going beyond our remit by seeking to take a leading role in policy development based on our insights and data | Set clear parameters around what we will and won't do in the 'A13 Leading the debate' area | 2 | 2 |

*Table 128: Risks for A13 Leading the debate*

### 5.1.5 Benefits

The qualitative benefits are:

- Enable more informed decision making by industry on key areas of Great Britain’s energy transition to net zero, such as hydrogen, Carbon Capture Use and Storage (CCUS), storage and electric vehicles.
- Resolve critical issues and areas of uncertainty with industry to establish a clear direction to inform and influence key decision and policy makers.

- Establish links between system operability and policy focused on delivering the best outcomes for consumers.
- Align processes and data sharing to facilitate DNO's and TO's to develop their regional *FES* type analysis.

### 5.1.6 Conclusion

We believe it is beneficial to proceed with this activity because:

- The ESO is uniquely positioned to support the development of energy policy recommendations, informed by the valued insights we provide to a range of different audiences across and beyond the energy industry, through our *FES* and associated documents.
- We already work across the whole energy industry and our position will enable us to facilitate further constructive and structured conversations, covering the breadth of industry voices; identify and resolve the critical issues and areas of uncertainty; support policy development with our analysis and extended insights, delivering the best outcomes for consumers.

### 5.1.7 Other options considered

We considered the following options for our A13 Leading the debate activity:

| **Options for A13 Lead the debate** | **Investment** |
|---|---|
| 1 – Keeping *FES* as it is. | Ongoing |
| 2 – Bridging the gap to net zero. | Ongoing and Transformational |
| 3 – Making policy recommendations. | Ongoing and Transformational |
| 4 – FES: integrating with other networks. | Ongoing and Transformational |

*Table 129: A13 Leading the debate options*

*Advantages and disadvantages*

### 5.1.7.1 Ongoing – keeping *FES* at it is

Under this option, we would continue to develop, engage on and publish *FES* as we currently do

| Advantages | Disadvantages |
|---|---|
| Lowest cost. | Unlikely to take advantage of the ESO's analytical capabilities and energy expertise.<br>Some stakeholders from generation, supplier and gas DN sectors thought we should be going beyond our existing *FES* activities.<br>This is not an ambitious option and does not keep up with market or consumer expectations. |

*Table 130: A13 Leading the debate option 1 advantages and disadvantages*

We did not proceed with this option because:

- stakeholders did not support
- our break-even analysis on expanding *FES* to policy decisions highlighted benefits of doing more
- our judgement is that we can offer significant analysis and expertise above producing *FES* as is.

### 5.1.7.2 Policy – Bridging the gap to net zero

| Advantages | Disadvantages |
|---|---|
| Takes advantage of the ESO's analytical capabilities and energy expertise.<br>Provides input and challenge to policy decisions, which should improve them.<br>Keeps FES neutral.<br>Reflects current political drivers and therefore anticipated market changes. | Higher cost than the counterfactual.<br>If the ESO does not make firm recommendations, sub-optimal decisions may be taken by policymakers.<br>Requires assumptions from beyond our sphere of expertise that we will have to rely on external assumptions and inputs for. |

*Table 131: A13 Leading the debate option 2 advantages and disadvantages*

We decided to proceed with this option because:

- stakeholders support it
- our break-even analysis suggested significant benefit for the additional cost
- our judgement is that we can offer significant analysis and expertise in this area.

### 5.1.7.3 Policy – making policy recommendations

Under this option, the ESO would be proactive in making policy recommendations that arise from producing *FES*.

| Advantages | Disadvantages |
|---|---|
| Provides policy recommendations that, if implemented, should be optimal.<br>Takes advantage of the ESO's analytical capabilities and energy expertise. | Highest cost option.<br>Could undermine confidence in the neutrality of *FES.*<br>Not undertaken by ESO before. |

*Table 132: A13 Leading the debate option 3 advantages and disadvantages*

We did not proceed with this option because:

- stakeholder support was mixed
- in our commercial and technical judgement, we do not have the required expertise and it we do not believe we are the appropriate organisation to do this.

### 5.1.7.4 *FES*: Integrating with other networks

| Advantages | Disadvantages |
|---|---|
| Consistent with Energy Data Task Force recommendations.<br>Builds on internal analytical capabilities.<br>Allows more ease in comparing investment decisions between transmission and distribution. | Higher cost than the counterfactual.<br>Exact scope of role is not yet defined. |

*Table 133: A13 Leading the debate option 4 advantages and disadvantages*

We decided to proceed with this option because:

- stakeholders support it
- our break-even analysis suggested significant benefit for the additional cost
- our judgement is that we can offer significant analysis and expertise in this area.

*Summary*

Based on this we have decided to proceed with options 2 – 4 because:

- stakeholders support it
- in our commercial and technical judgement, they are the areas we can best put our expertise to good use
- the breakeven analysis suggest potential benefits will outweigh the costs.

## 5.2 A14 Taking a whole electricity system approach to connections

This sub-section provides further context on the costs and benefits of our activity A14 Taking a whole electricity system approach to connections.

The net present value of A14 Taking a whole electricity system approach to connections is £2 million over the RIIO-2 period and £15 million over ten years. Sensitivity analysis suggests an NPV range of negative £2 million to £3 million over the RIIO-2 period.

### 5.2.1 The counterfactual

If we did not undertake A14 Taking a whole electricity system approach to connections, we continue with our ongoing connections process with only incremental improvements in our capability

### 5.2.2 The benefits

| **Assumptions** | **Justification** |
|---|---|
| The number of connection applications grows 8 per cent per year | Slowing from today's around 20%, based on actual number of connections |
| Roll out of our secure online account management facility in April 2025 brings a 30% cost saving | Based on IT investment delivery timelines and the connections hub will provide an element of 'self-serve' for customers |
| Information across the transmission-distribution interface will reduce our direct resource requirements by 10% from 2022 | Based on IT investment delivery timelines |

*Table 134: A14 Taking a whole electricity system approach to connections assumptions*

The chart below shows the number of connection applications the ESO has received in each of the last three financial years. Additionally, in the last 12 months we have seen a 60 per cent increase in applications from new market participants, driven primarily by smaller generation units for battery storage and solar connections, new interconnectors and new demand points for data centres.

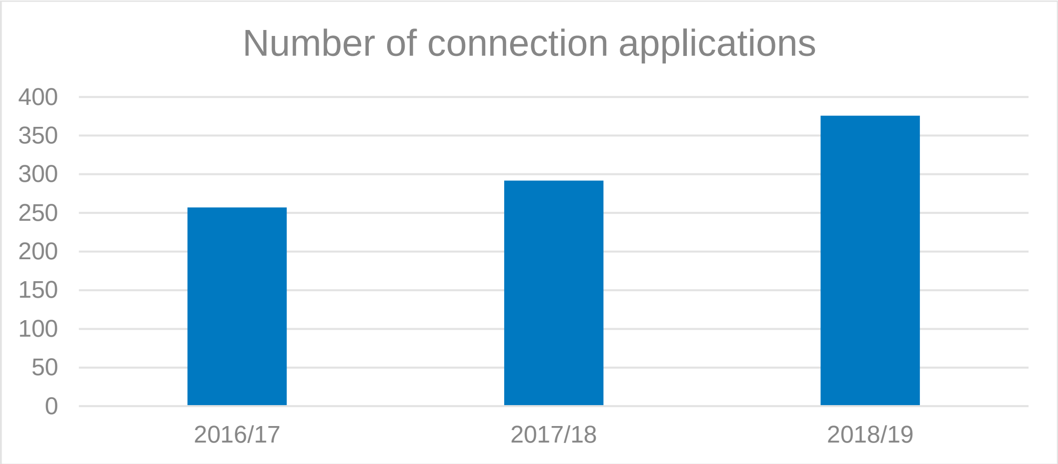


*Figure 6: Number of connection applications*

*Both of these drivers will result in a need for additional ESO resource in the RIIO-2 period to support customers through the connections process. It will be more efficient for us to provide initial support through our proposed connections hub. Our assumption is the future rate of increase in applications will slow from around 20 per cent today to around 8 per cent per year:*

| Number of applications | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 |
|---|---|---|---|---|---|
| Applications | 393 | 424 | 458 | 494 | 533 |

*Table 135: Forecast number of connection applications*

We have also assumed we will provide support to customers at similar levels to today, which is also likely to be an underestimate

We estimate a reduction in our direct resource requirements of five per cent delivered from April 2022. An additional 5 per cent will be delivered in April 2022 with capacity information across the transmission-distribution interface. Roll out of our complete secure online account management facility in April 2025 will deliver an additional 30 per cent saving. There will be efficiencies for customers in managing the connections process, including our extension of customer seminars and dedicated support staff. These are also estimated below.

### *Sensitivity analysis - A14 Taking a whole electricity system approach to connections*

- Market factors: we have repeated the analysis with the high and low cases number of connection applications: 16 per cent a year and 0 per cent a year respectively.
- Delivery factors: we have also modelled a one-year delay in delivery for the low case, from 2022/23.

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| ESO and customer efficiency saving | 0.6 | 0.7 | 1.0 | 1.4 | 4.4 | 8.1 |
| Sensitivity – high market | 0.6 | 0.7 | 1.1 | 1.6 | 5.1 | 9.2 |
| Sensitivity – low market | 0.6 | 0.7 | 0.9 | 1.2 | 3.8 | 7.2 |
| Sensitivity – low delivery | 0.0 | 0.6 | 0.7 | 1.0 | 1.4 | 3.7 |

*Table 136: Benefits for A14 Taking a whole electricity system approach to connections*

The total benefits for A14 Taking a whole electricity approach to connections are between £4 million and £9 million, with a central case of £8 million over the RIIO-2 period.

*Measuring benefits and consumer bill impact*

The £8 million benefit could be tracked as part of any regulatory reporting for RIIO-2.

This benefit will impact on consumer bills by reducing the TNUoS charge element, by more than otherwise would have been the case.

### 5.2.3 Activity Costs

Delivery of A14 Taking a whole electricity approach to connections will require additional capex and opex spend, summarised below:

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 0.7 | 0.7 | 0.2 | 0.1 | 0.1 | 1.8 |
| Opex | 1.0 | 1.0 | 0.8 | 0.9 | 0.9 | 4.6 |
| Total | 1.7 | 1.8 | 1.0 | 1.0 | 1.0 | 6.4 |

*Table 137: Incremental costs A14 Taking a whole electricity system approach to connections*

The total costs for A14 Taking a whole electricity system approach to connections are £6.4 million.

### 5.2.4 Net Present Value

The net present value of A14 Taking a whole electricity system approach to connections is estimated at £2 million over the RIIO-2 period and £15 million over ten years, which will start to deliver positive returns from 2025/26. Sensitivity analysis suggests an NPV range of:

- Market factors between £1 million and £3 million.
- Delivery factors between negative £2 million and £2 million.

### 5.2.5 Dependencies, enablers and whole energy system

To deliver A14 Taking a whole electricity system approach to connections requires customers to engage with the new hub and systems and connections customers to pass on any cost reductions to consumers.

### 5.2.6 Uncertainties and risks

We have accounted for market, third party and deliverability uncertainties in our sensitivity analysis.

The table below summarises the key risks and how we propose to mitigate them. Risks for the associated IT investments can be found in Annex 4 – Technology investment report.

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| There are many industry initiatives to develop connections portals simultaneously and there is a risk that parties do not take a coordinated approach to development (e.g. energy data task force, BEIS code governance reform review, BEIS/Ofgem work on smart systems and flexibility) | Continue to participate in these activities and coordinate with all relevant parties, including engaging with TOs' on the activities in their business plans | 3 | 1 |
| IT development process for the customer portal does not meet user requirements | Learn from previous similar IT projects (e.g. transmission outage and generator availability)<br><br>Closer coordination with our IT developers and build in an agile way<br><br>Deep understanding of stakeholder needs and test functionality with customers as it is developed | 2 | 1 |
| System changes for the customer portal follow a different timescale versus industry and regulatory readiness | Ensure the agile arrangements are developed with codified changes following as soon as practicable.<br><br>Facilitate the transition to RIIO-ED2 such that this price control is not seen to be a blocker to energy transition | 3 | 2 |

*Table 138: Risks for A14 Taking a whole electricity system approach to connections*

### 5.2.7 Other options considered

We considered the following options for our A14 Taking a whole electricity system approach to connections activity:

| Options for A14 Taking a whole electricity system approach to connections | Investment |
|---|---|
| 1 – Ongoing – do not develop a connections hub. | Ongoing |
| 2 – Develop a connections hub, with options to include some combination of additional support material, online access or alignment with TO initiatives. | Ongoing and Transformational |
| 3 – In addition to the above, develop a connections hub that provides whole system electricity guidance by working with DNOs and creating a national portal for distribution connections. | Ongoing and Transformational |

*Table 139: A14 Taking a whole electricity system approach to connections options*

*Advantages and disadvantages*

#### 5.2.7.1 Ongoing – do not develop a connections hub

Under this option we would not develop a connections hub and the connections process would continue as is

| Advantages | Disadvantages |
|---|---|
| No additional cost. | CBA indicates this would not deliver consumer benefit. |

*Table 140: A14 Taking a whole electricity system approach to connections option 1 advantages and disadvantages*

We did not proceed with this option because:

- stakeholders do not support it
- our CBA indicates there is likely to be consumer benefit in developing a connections hub
- in our commercial and technical judgement, we need to enhance the connections process to create an improved customer experience which facilitates the connection of new zero carbon generation.

### 5.2.7.2 Develop a connections hub, with options to include some combination of additional support material, online access or alignment with TO initiatives

| Options | Advantages | Disadvantages |
|---|---|---|
| Additional support material | CBA indicates that this is the most efficient option as it reduces additional resource to provide customer support.<br>Customer satisfaction increases as information more readily available. | We are aware that the TOs are proposing to provide additional support material online. We need to maintain consistency for customers and provide a seamless experience so not moving to an online process could reduce overall efficiency. |
| Online access | CBA indicates that this is the most efficient option as it reduces additional resource to provide customer support.<br>Our customers have told us that they would value information being more readily available and their connection applications being progressed more quickly and transparently. | A minority of stakeholders (a renewable energy customer) told us that their connection experience didn't necessarily need to be online to be positive. |
| Alignment with TO initiatives | Minimises duplication of effort by regulated entities and costs for consumers<br>Facilitates parties providing information that they are the gatekeeper for (for example TOs and project progression milestones) | Risk that end products lack consistency resulting in reduced customer satisfaction; need for close coordination to manage |

*Table 141: A14 Taking a whole electricity system approach to connections option 2 advantages and disadvantages*

We decided to proceed with this option because:

- stakeholders support it
- our CBA indicates that it would deliver net consumer benefit
- in our commercial and technical judgement, many new connections parties would value this information and it would help create a level playing field.

### 5.2.7.3 In addition to the above, develop a connections hub that provides whole system electricity guidance by working with DNOs and creating a national portal for distribution connections

| Options | Advantages | Disadvantages |
|---|---|---|
| Provide whole system electricity guidance by working with DNOs | Facilitates coordinated approach to connections across the whole GB electricity system. This can create efficiencies for parties which could consider both transmission and distribution connections. | Need for regular updating to ensure information remains relevant. |
| Create a national portal for distribution connections | National Grid as a pan-Great Britain entity could create a seamless process for connections nationwide. | Significant scale change to move into distribution connections.<br>Lack of expertise in distribution connections.<br>Not consistent with our approach to DSO. |

*Table 142: A14 Taking a whole electricity system approach to connections option 3 advantages and disadvantages*

We did not proceed with this option because:

- Stakeholders did not support it
- In our commercial and technical judgement, we do not believe this activity is consistent with our approach to DSO. Further we do not believe we have the appropriate skills and resource to undertake this role.

*Summary*

Based on this we have decided to proceed with option 2 because:

- Stakeholders support it
- Our CBA indicates it would deliver net consumer benefits
- In our commercial and technical judgement, many new connections parties would value this information and it would help create a level playing field.

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

This sub-section provides further context on the costs and quantifiable benefits of our activity A15 Taking a whole energy system approach to promote zero carbon operability.

The net present value of A15 Taking a whole energy system approach to promote zero-carbon operability is £466 million over the RIIO-2 period and £946 million over ten years. Sensitivity analysis suggests an NPV range of £603 million to £331 million over the RIIO-2 period.

### 5.3.1 The counterfactual

If we did not undertake A15 Taking a whole energy system approach to promote zero carbon operability we would not undertake additional Regional Development Programmes, embed enhanced frequency control capability, deliver potential innovations, nor efficiently identity future operability needs. This would deliver only incremental improvements in our current capability.

### 5.3.2 The benefits

We have quantified benefits in three areas:

- Whole system operability *NOA*-type assessment
- Regional Development Programmes (RDP)
- Development of a regime for an integrated offshore grid

#### 5.3.2.1 Whole system operability *NOA*-type assessment

| Assumptions | Justification |
|---|---|
| Forecast operability costs of £596 million per year | *NOA* assessment of future operability challenges |
| Cost of a 0.2 gigavolt ampere (GVA) solution is £25 million | Current build solution costs |
| Solutions last 40 years | Current build solution lifetimes |

*Table 143: Whole system operability NOA-type assessment assumptions*

The quantitative benefits in this area been calculated first by considering the Enhanced Frequency Control Capacity EFCC innovation project[30], which forecast benefits of £420 million over the RIIO-2 period for improving a single aspect of system operability (see figure below):

[30] https://www.nationalgrideso.com/document/142876/download

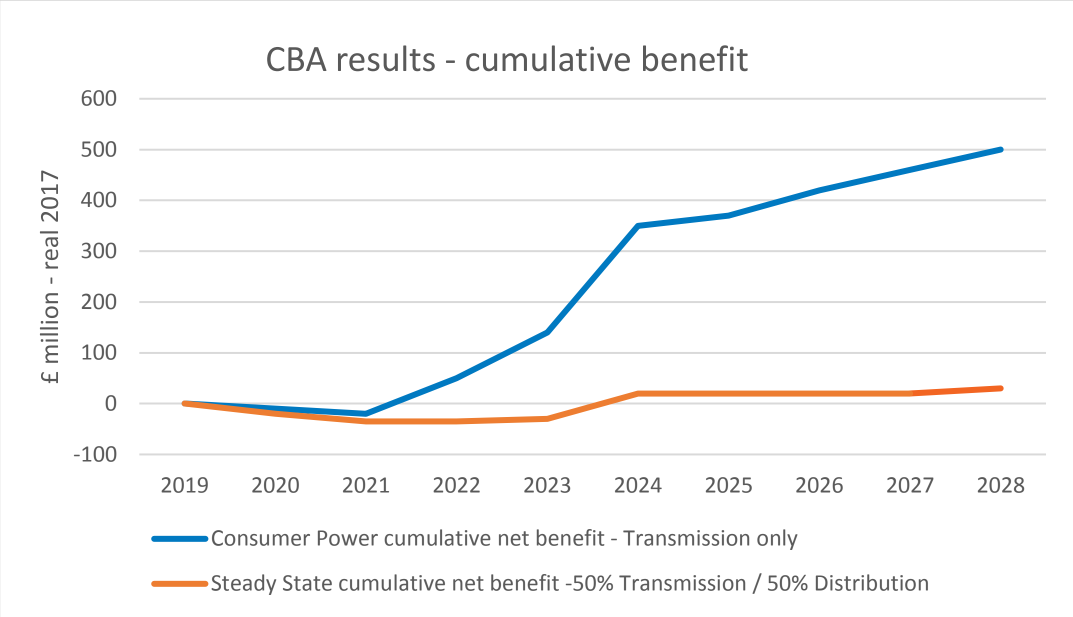


*Figure 7: EFCC innovation project example benchmarking*

This gives a good benchmark as to the scale of the benefits we could deliver in this area. To consider a more holistic look at the future operability challenges we completed a high-level power system analysis[31] to determine the network operability requirements.

We then used these to conduct a *NOA*-type assessment of operability constraints and calculated the cost to re-dispatch the network to address the system needs. This has forecast operability costs of £596 million per year during the RIIO 2 period.

More detailed analysis from our our recent stability pathfinder[32] gives us greater understanding of the size of the operability challenge. This has shown that 9 GVA of fault infeed would help to address operability issues in Scotland; this can be extrapolated to be 18 GVA to address operability issues in England and Wales.

We assume that a current build solution to address these 18 GVA needs costs £25 million for 0.2 GVA of fault infeed, or £125 million for 1 GVA, giving a total cost of £2.25 billion[33]. We envisage innovative, or short-term, solutions could be found for less, but to undertake a CBA we have used this example as we have reliable data. Note any cheaper solution will increase the benefits case. Thus, as there exists at least one solution which is cheaper than ongoing operability costs the *NOA*-type assessment is a valid approach to take.

To calculate the overall benefit, we have assumed:

- That the £596 million is a flat cost for the next 40 years;
- The £2.25 billion operability solution is implemented from 2025;
- The solution will last for 40 years; and

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[31] It's worth noting that operability requirements can be split into different linked categories, where one requirement can mask another, certain solutions can address one, two, or multiple requirements and where one solution may even make other requirements worse. Complex power system analysis is needed to ensure the right answer

[32] https://www.nationalgrideso.com/insights/network-options-assessment-noa/network-development-roadmap

33 Note – this solution is an example and does not reflect the ESO's view of what an optimal solution is.

- It will alleviate the need to spend £596 million per year.

The calculation is as follows

1. The Capex cost of the operability solution per year is £25 million per 0.2 GVA multiplied by the 18 GVA required, totaling £450 million per year.
2. We profile this over five years, starting in 2021/22. Discounting over the 40-year expected lifetime of the solution using the Spackmann approach gives a total cost of £1,841 million
3. The £596 million per year operability opex saving is discounted using the social time preference rate, as per the Green Book, over 40 years, starting in 2024/25, consistent with the delivery of the operability solution. This gives a total discounted saving of £11,903 million.
4. This gives a net benefit of around £10,060 million.
5. As the forecast benefit will be achieved over a 40-year period, but enabled throughout the RIIO 2 period, we divided the net benefit by 40 to provide £251 million per year.
6. As forecasting operability costs is challenging and uncertain, we have built in a 50 per cent contingency to achieve £125.8 million per year starting in 2022/23.
7. We start this benefit in 2022/23, giving £503 million over the RIIO 2 period. This is justified because we are not analysing the benefit of this particular solution, rather the benefit of this approach, which we assume would take the first year of RIIO-2 to implement.

*Sensitivity analysis - Whole system operability NOA-type assessment*

- Market factors: we have repeated the analysis with the high and low cases for the forecast operability costs: £696 million and £496 million respectively.
- Delivery factors: we have modelled a one-year delay in delivery for the low case, from 2025/26.
- Third Party factors: we have repeated the analysis with the high and low cases for cost of a 0.2 GVA solution: £15 million and £35 million respectively.

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Operability savings | 0.0 | 125.8 | 125.8 | 125.8 | 125.8 | 503.0 |
| Sensitivity – high market | 0.0 | 149.0 | 149.0 | 149.0 | 149.0 | 596.2 |
| Sensitivity – low market | 0.0 | 102.5 | 102.5 | 102.5 | 102.5 | 409.8 |
| Sensitivity – low delivery | 0.0 | 0.0 | 125.8 | 125.8 | 125.8 | 377.2 |
| Sensitivity – high third party | 0.0 | 120.5 | 120.5 | 120.5 | 120.5 | 524.0 |
| Sensitivity – low third party | 0.0 | 131.0 | 131.0 | 131.0 | 131.0 | 482.0 |

*Table 144: Benefits for whole system operability NOA-type assessment market*

The total benefits of this area are between £377 million and £596 million, with a central case of £503 million over the RIIO-2 period.

*Measuring benefits and consumer bill impact*

The £503 million benefit can be measured directly via Metric 12 - Future balancing costs saved by operability solutions and Metric 13 - Capacity saved through operability solutions. See Annex 7 - Metrics and measuring performance for more details.

This benefit will impact on consumer bills by reducing the BSUoS charge element, by more than otherwise would have been the case.

### 5.3.2.2 Benefits of Regional Development Programmes (RDPs)

| Assumptions | Justification |
|---|---|
| Value of RDP avoided asset build is £12.9 million | Based on previous RDP delivery, note this is a net value with costs accounted for |
| Additional renewable capacity unlocked by each RDP is 278 MW | Based on previous RDP delivery |
| Carbon intensity assumption from *FES 2019* Steady Progression | Business plan assumption |
| Six RDPs will be delivered over the RIIO-2 period | Estimated capacity to deliver three RDP as any given time, while ramping up capability |
| BEIS short-term traded carbon values | See main assumptions |

*Table 145: Benefits of Regional Development Programmes (RDPs) assumptions*

The RDPs are already delivering significant value for the end consumer with the first RDP delivering a net saving of £13 million through avoided asset build. As each RDP is a new bespoke piece of analysis for a specific situation, we have included these in our CBA. The increasing whole system focus of them will also increase the benefits they deliver to consumers. As such, the CBA presented is likely to be a low estimate of their true benefits. We assumed this value of £13 million along with the value of our second completed RDP to forecast future RDP benefits[34].

The two RDPs have provided different benefits:

- RDP 1 produced a saving of £13 million in required asset build.
- RDP 2 provided network access for renewable power ahead of the traditional connection process. It allowed an extra 278 MW of renewable generation across four grid supply points (GSPs). We have assumed this generation would connect in 2020 ahead of planned asset build in 2026. We have also assumed a carbon offset of 974 gigawatt hours (GWh)[35] of carbon free generation per year. We have assumed a similar carbon saving for future RDPs. Below is the carbon saving calculation. We have assumed one year to realise the benefits.

*Sensitivity analysis - Benefits of Regional Development Programmes (RDPs)*

- Market factors: we have repeated the analysis with the high and low cases RDP avoided asset build value: £25.8 million and £6.5 million respectively.
- Market factors: we have repeated the analysis with the high and low cases RDP additional renewable capacity; 556 MW and 139 MW respectively.
- Market factors: we have repeated the analysis with the high and low carbon prices; (see table below).
- Delivery factors: we have modelled four RDPs are delivered for the low case.

| RDP profile | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| RDPs completed | 0 | 1 | 1 | 2 | 2 | 6 |
| RDPs completed – sensitivity – low delivery | 0 | 0 | 0 | 2 | 2 | 4 |
| RDPs completed – carbon saving | 0 | 0 | 1 | 1 | 1 | 3 |
| RDPs completed – asset saving | 0 | 1 | 0 | 1 | 1 | 3 |
| RDPs completed – sensitivity – low delivery – carbon saving | 0 | 0 | 0 | 1 | 1 | 2 |

*Table 146: RDP profiles*

[34] https://www.nationalgrideso.com/insights/whole-electricity-system/regional-development-programmes
[35] 278MW of carbon free generation with an estimated load factor of 40%

*Regional Development Programmes – Carbon savings*

| **Benefits £ million** | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** | **Total** |
|---|---|---|---|---|---|---|
| Carbon intensity Steady Progression in grams of $CO_2$ per kilowatt hour ($gCO_2/kWh$) | 136 | 120 | 128 | 124 | 111 | |
| | x | x | x | x | x | |
| Carbon generation reduction GWh | 974 | 974 | 974 | 974 | 974 | |
| Carbon generation reduction GWh<br>Sensitivity – high market | 1948 | 1948 | 1948 | 1948 | 1948 | |
| Carbon generation reduction GWh<br>Sensitivity – low market | 487 | 487 | 487 | 487 | 487 | |
| | = | = | = | = | = | |
| Thousand tonnes of carbon saved | 133 | 116 | 125 | 120 | 108 | |
| Thousand tonnes of carbon saved<br>Sensitivity – high market | 266 | 233 | 250 | 241 | 216 | |
| Thousand tonnes of carbon saved<br>Sensitivity – low market | 66 | 58 | 63 | 60 | 54 | |
| | x | x | x | x | x | |
| Carbon price pounds per tonne of $CO_2$ equivalent ($£/tCO_2e$) | 14.70 | 15.25 | 15.83 | 16.63 | 19.24 | |
| Carbon price $£/tCO_2e$ GWh<br>Sensitivity – high market | 29.38 | 30.50 | 31.66 | 33.26 | 37.35 | |
| Carbon price $£/tCO_2e$ GWh | - | - | - | 0.54 | 2.39 | |

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Sensitivity – low market | | | | | | |
| | = | = | = | = | = | |
| Saving £ million | No RDP | No RDP | 2.0 | 2.0 | 2.1 | 6.1 |
| Saving £ million Sensitivity – high market | No RDP | No RDP | 7.9 | 8.0 | 8.1 | 24.0 |
| Saving £ million Sensitivity – low market | No RDP | No RDP | 0 | 0 | 0.1 | 0.1 |
| Saving £ million Sensitivity – low Delivery | No RDP | No RDP | No RDP | 2.0 | 2.1 | 4.1 |

*Table 147:Carbon savings from RDP*

The total benefits of this area are between £0.1 million and £24 million, with a central case of £6 million over the RIIO-2 period.

### *Measuring benefits and consumer bill impact*

The driver of this £6 million benefit can be measured via the ongoing RDP process.

This benefit will not directly impact on consumer bills

### *Regional Development Programmes – Asset savings*

To avoid double counting of asset and carbon saving, we have assumed each RDP will save either carbon or asset build in equal proportions.

We have committed to a minimum of three inflight RDPs annually during the RIIO-2 period, depending on system needs. Based on experience, these will take approximately two years to complete. So, RDP completions across the RIIO-2 period match this rate. The results of this assessment are shown in the table below.  The benefits may diminish over time as the most beneficial regions are investigated first and we have used a sliding scaling in our calculation to reflect this.

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Asset Saving | No RDP | 12.9 | No RDP | 12.9 | 12.9 | 38.7 |
| Sensitivity – high market | No RDP | 25.8 | No RDP | 25.8 | 25.8 | 77.4 |
| Sensitivity – low market | No RDP | 6.5 | No RDP | 6.5 | 6.5 | 19.4 |
| Sensitivity – low delivery | No RDP | No RDP | No RDP | 12.9 | 12.9 | 25.8 |

*Table 148: Incremental benefits for RDPs*

The total benefits of this area are between £19 million and £77 million, with a central case of £39 million over the RIIO-2 period.

#### *Measuring benefits and consumer bill impact*

The driver of this £39 million benefit can be measured via the ongoing RDP process.

This benefit will impact on consumer bills by reducing the BSUoS charge element, by more than otherwise would have been the case.

#### *Total benefits case*

The total benefits A15 Taking a whole electricity system approach to promote zero carbon operability are between £407 million and £698 million, with a central case of £548 million over the RIIO-2 period.

### 5.3.3 Activity Costs

Delivery of A15 Taking a whole electricity system approach to promote zero carbon operability will require additional capex and opex spend, summarised below:

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 8.1 | 9.1 | 11.0 | 11.3 | 13.0 | 52.5 |
| Opex | 1.8 | 3.0 | 4.7 | 6.6 | 7.9 | 24.1 |
| Total | 9.9 | 12.2 | 15.7 | 17.9 | 20.8 | 76.6 |

*Table 149: Incremental costs for A15 Taking a whole electricity system approach to promote zero carbon operability*

The total costs for A15 Taking a whole electricity system approach to promote zero carbon operability for zero-carbon whole system operability are £76.6 million.

### 5.3.4 Net Present Value

The net present value of A15 Taking a whole energy system approach to promote zero carbon operability is estimated at £466 million over the RIIO-2 period and £943 million over ten years, which will start to deliver positive returns from 2023/24. Sensitivity analysis suggests an NPV range of:

- Market factors between £358 million and £603 million
- Delivery factors between £331 million and £466 million
- Third party factors between £447 million and £486 million

### 5.3.5 Dependencies, enablers and whole energy system

A15 Taking a whole electricity system approach to promote zero carbon operability depends on two other transformational activities:

- A1 Control centre architecture and systems (Role 1, Theme 1) – ensuing the control has the tools to operate a zero carbon system.
- A4 Build the future balancing service and wholesale markets (Role 2, Theme 2) - ensuing the new markets have been developed to support zero carbon system operation.

Delivering this activity requires third parties to deliver solutions, either through investment in assets or commercial solutions

### 5.3.6 Uncertainties and risks

We have accounted for market, third party and deliverability uncertainties in our sensitivity analysis.

The table below summarise the key risks and how we propose to mitigate them. Risks for the associated IT investments can be found in Annex 4 – Technology investment report.

| **Risk** | **Mitigations** | **Likelihood** | **Impact** |
|---|---|---|---|
| Lack of DNO partners willing to enter into RDP arrangements | Ensure the benefits for end consumers are understood. Put into action the RDP identification process being developed as part of the Forward Plan 2019/21 | 2 | 1 |
| Solutions from RDPs or innovative activities stall through lack of funding | Discuss practical approach to delivering RDP participation through RIIO-ED2 conversations | 3 | 2 |
| Policy decisions on DSO affect the scope of our work | Take a least regrets approach consistent with Future Worlds 'World B'[36] | | |

[36] http://www.energynetworks.org/assets/files/14969_ENA_FutureWorlds_AW06_INT.pdf

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Early stage of whole energy system transition means potential opportunities and pathways are unclear | Use design by doing ethos initially through targeted innovation projects to inform transition and aid timely progression. | | |

*Table 150: Risks for A15 Taking a whole energy system approach to promote zero carbon operability*

### 5.3.7 Other options considered

We considered the following options for our A15 Taking a whole energy system approach to promote zero carbon operability activity:

| Options for A15 Taking a whole energy system approach to promote zero carbon operability | Investment |
|---|---|
| 1 – Transition to DSO. | Transformational |
| 2 – Facilitating zero carbon operability. | Transformational |

*Advantages and disadvantages*

#### 5.3.7.1 Transition to DSO

The transition to DSO has a significant bearing in our network operability activities as well as across other ESO functions. We have therefore considered how DSO will affect the ESO in RIIO-2 and developed our business plan accordingly.

Our options considered build on the ENA Open Networks Future Worlds work and also Ofgem's more recent work on DSO. Three options have been considered

- A DNO-led approach where the role of a DNO as a DSO is significant and our relationship with DNOs changes (Future Worlds; World A).
- A coordinated approach where we work with DNOs to develop consistent and transparent whole electricity system solutions (Future Worlds; World B)
- An ESO-led approach where the ESO takes up many DSO activities.  (Future Worlds; World D)

We have chosen the approach associated with Future Worlds World B because:

- It is consistent with stakeholder feedback to the accompanying ENA consultation[37].
- In our commercial and technical judgement, it is a least regrets approach and is also consistent with the Baringa impact assessment of the Future Worlds.
- We have therefore taken this approach to DSO and embedded within relevant activities across the Business Plan. For Network Operability this includes;

[37] http://www.energynetworks.org/electricity/futures/open-networks-project/workstream-products/ws3-dso-transition/future-worlds/future-worlds-impact-assessment.html

- Our capability in modelling and data management
- Our approach to RDPs
- Our technical support provision to DSO and whole electricity system alignment

#### 5.3.7.2 Facilitating zero carbon operability

We need to ensure we are considering options across the whole energy system to facilitate the transition to net zero and achieve our 2025 zero carbon operability ambition. To achieve this, we have considered five main areas:

- Facilitating the efficient and timely connection of zero carbon generation across the whole electricity system;
- At a transmission level we believe this can be achieved through the developed of an integrated offshore grid.
- At a distribution level we believe this can be discharged through increased data exchange and roll out of RDPs.
- Ensuring continued system operability leveraging;
- Learnings from recent innovation projects particularly EFCC. No options are provided as significant development work to inform the proposed monitoring and control system as already been undertaken in the EFCC innovation project.

Cross vector opportunities across the whole electricity system. This area is nascent at this time so rather than develop specific options we intend to progress through a combination of thought leadership (including industry initiatives) and design by doing through innovation.

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

This sub-section provides further context on the costs and benefits of our activity A16 Delivering consumer benefits from improved network access planning.

The net present value of this activity is £204 million over the RIIO-2 period and £420 million over ten years. Sensitivity analysis suggests an NPV range of £98 million to £310 million over the RIIO-2 period.

### 5.4.1 The counterfactual

If we did not undertake A16 Delivering consumer benefits from improved network access planning, we would continue with our ongoing network access process, with a focus on transmission rather than DER.

### 5.4.2 The benefits

| Assumptions | Justification |
|---|---|
| The same proportion (between 7% and 16%) of benefits could be realised in England and Wales as has been seen in Scotland | Observed result from Scotland and power system knowledge that system complexity is approximately the same between Scotland and England and Wales, allowing benefits to be extrapolated across from Scotland |
| England and Wales constraint costs (see table below) | From *NOA* model run |

*Table 151: A16 Delivering consumer benefits from improved network access planning assumptions*

Transmission and distribution connected parties will receive better notification of planned outages and their impacts on the networks. DNOs, meanwhile, will benefit from increased liaison, including greater procurement and coordination of flexibility services from Distributed Energy Resource (DER). This supports the quantifiable benefit delivered through rolling out the STC cost recovery mechanism process across all of GB. Consumer benefit for this approach has already yielded results in Scotland which in 2018/19 were forecast to be between £16 million and £36.7 million, equivalent to between a 7 per cent and 16 per cent reduction in costs. Our power system knowledge infers a 50:50 split in complexity for outage planning between England and Wales and Scotland, so we have assumed same proportion of benefits could be realised in England and Wales. For rolling out the STC cost recovery mechanism to England and Wales we have assumed the mid-range estimate of 11.5 per cent.

We have used the NOA process to forecast constraints costs based on the 2018/19 outturn numbers.

#### Sensitivity analysis - A16 Delivering consumer benefits from improved network access planning

- Market factors: we have repeated the analysis with the high and low cases for the England and Wales constraint costs; See table below.

- Delivery factors: we have repeated the analysis with the high and low cases for cost reduction: 16 per cent and 7 per cent respectively. We have also modelled a one-year delay in delivery for the low case, from 2022/23.

*Interaction with other benefit areas*

The proposals in sections 2.1.2.5 and 4.1.2.1 claim to lower constraint costs. We have not accounted for these in the central benefit case here, but they would be accounted for in market factors sensitivity analysis.

| **Forecast constraint costs £ million** | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** |
|---|---|---|---|---|---|
| Estimated England and Wales constraint costs based on *NOA* forecast. | 351 | 316 | 363 | 428 | 493 |
| Sensitivity – high market | 441 | 508 | 594 | 647 | 753 |
| Sensitivity – low market | 255 | 229 | 252 | 296 | 287 |

*Table 152: England and Wales forecast constraint costs*

| **Forecast constraint savings £ million** | **2021/22** | **2022/23** | **2023/24** | **2024/25** | **2025/26** |
|---|---|---|---|---|---|
| Estimated England and Wales constraint costs based on *NOA* forecast (£ million) | 351 | 316 | 363 | 428 | 493 |
| Sensitivity – high market | 441 | 508 | 594 | 647 | 753 |
| Sensitivity – low market | 255 | 229 | 252 | 296 | 287 |
| | x | x | x | x | x |
| 11.5% savings | 11.5% | 11.5% | 11.5% | 11.5% | 11.5% |
| | = | = | = | = | = |
| Annual savings (£ million) | 40.4 | 36.3 | 41.7 | 49.2 | 56.7 |
| Sensitivity – high market | 50.7 | 58.4 | 68.3 | 74.4 | 86.6 |
| Sensitivity – low market | 29.3 | 26.3 | 29.0 | 34.0 | 33.0 |

*Table 153: Benefit calculation for England and Wales forecast constraint costs savings*

This has provided the following forecast benefit, which start being delivered from 2021/22:

| Benefits £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Consumer savings based expanding the process into England and Wales with a 11.5% reduction. | 40.4 | 36.3 | 41.7 | 49.2 | 56.7 | 224.4 |
| Sensitivity – high market | 50.7 | 58.4 | 68.3 | 74.4 | 86.6 | 338.4 |
| Sensitivity – low market | 29.3 | 26.3 | 29.0 | 34.0 | 33.0 | 151.7 |
| Sensitivity – high delivery | 56.2 | 50.6 | 58.1 | 68.5 | 78.9 | 312.2 |
| Sensitivity – low delivery | 0 | 22.1 | 25.4 | 30.0 | 34.5 | 112.0 |

*Table 154:Benefits for A16 Delivering consumer benefits from improved network access planning*

The total benefits for delivering consumer benefits from improved network access are between £112 million and £338 million, with a central case of £224 million over the RIIO-2 period.

*Measuring benefits and consumer bill impact*

The £224 million benefit can be measured directly via Metric 14 – Capacity saved through our access planning actions and Metric 15 – Number of short notice changes to planned outages. See Annex 7 – Metrics and measuring performance for more details.

This benefit will impact on consumer bills by reducing the BSUoS charge element, by more than otherwise would have been the case.

### 5.4.3 Activity Cost

A16 Delivering consumer benefits from improved network access planning will require additional capex and opex spend, summarised below:

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 0.4 | 0.4 | 1.2 | 1.4 | 1.4 | 4.8 |
| Opex | 0.2 | 0.3 | 0.8 | 0.8 | 0.9 | 3.0 |
| Total | 0.6 | 0.7 | 2.0 | 2.2 | 2.3 | 7.8 |

*Table 155: Incremental costs for A16 Delivering consumer benefits from improved network access planning*

The total costs for A16 Delivering consumer benefits from improved network access planning are £7.8 million.

### 5.4.4 Net Present Value

The net present value of A16 Delivering consumer benefits from improved network access planning is estimated at £204 million over the RIIO-2 period and £420 million over ten years, which will start to deliver positive returns from 2021/22. Sensitivity analysis suggests an NPV range of:

- Market factors between £138 million and £310 million
- Delivery factors between £98 million and £286 million

### 5.4.5 Dependencies, enablers and whole energy system

A16 Delivering consumer benefits from improved network access planning requires code modifications and financial arrangements. We also require DNOs and TOs to participate in the new process.

### 5.4.6 Uncertainties and risks

We have accounted for market, third party and deliverability uncertainties in our sensitivity analysis.

The table below summarise the key risks and how we propose to mitigate them. Risks for the associated IT investments can be found in Annex 4 – Technology investment report.

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| IT development process for greater levels of outage data and information does not meet user requirements | Learn from previous similar IT projects.<br>Closer coordination with our IT developers and build in an agile way<br><br>Deep understanding of stakeholder needs | 2 | 1 |
| Insufficient coordination to deliver efficient procurement of services from DER to meet the needs of both ESO and DNOs | Ensure strong links with relevant activities under Role 2, Theme 2<br><br>Close coordination through RDP partner DNOs<br><br>Strong links with Open Networks to share learning<br><br>Proportionate engagement with DER community | 3 | 2 |

*Table 156: Risks A16 Delivering consumer benefits from improved network access planning*

### 5.4.7 Other options considered

We considered the following options for our A16 Delivering consumer benefits from improved network access planning activity:

| Options for A16 Delivering consumer benefits from improved network access planning | Investment |
|---|---|
| 1 - Extending the Scottish STC cost recovery mechanism to England and Wales. | Ongoing and Transformational |
| 2 – Extending the STC cost recovery mechanism to longer timescales (i.e. greater than current year). | Ongoing and Transformational |
| 3 – Incentivising TOs to promote SO-TO management of outages. | Ongoing and Transformational |
| 4 - Working more closely with DNOs to optimise system outages across the transmission and distribution interface. | Ongoing and Transformational |
| 5 – As it is. | Ongoing |

*Table 157: A16 Delivering consumer benefits from improved network access planning options*

*Advantages and disadvantages*

#### 5.4.7.1 Extending the Scottish STC cost recovery mechanism to England and Wales

Under this approach, we would not rollout the STC cost recovery mechanism across England and Wales

| Advantages | Disadvantages |
|---|---|
| CBA indicates that this is the most efficient approach delivering significant increased consumer value. | None identified |

*Table 158: A16 Delivering consumer benefits from improved network access planning option 1 advantages and disadvantages*

We decided to proceed with this approach because:

- stakeholders support it
- our CBA indicates in delivers net consumer benefit
- in our commercial and technical judgement, there are efficiencies to be realised from a single Great Britain-wide process.

#### 5.4.7.2 2 Extending the STC cost recovery mechanism to longer timescales (i.e. greater than current year)

Under this option we would work with TOs to develop this process to optimise delivery costs of major infrastructure projects.

| Advantages | Disadvantages |
|---|---|
| Significant consumer value can be realised through optimisation of major TO construction projects and associated ESO costs | Additional resource may be required |

*Table 159: A16 Delivering consumer benefits from improved network access planning option 2 advantages and disadvantages*

We decided to proceed with this option because:

- stakeholders support it
- our CBA indicates consumer net benefit
- in our commercial and technical judgement, given the long lead times of TO construction projects, there is likely to be benefit from a process looking over longer timescales.

#### 5.4.7.3 Incentivising TOs to promote SO-TO management of outages

Under this approach TOs would be incentivised to reduce the cost of system outages

| Advantages | Disadvantages |
|---|---|
| Potential additional savings through sharper incentivisation of TOs | Incentive options provided a risk of information asymmetry and therefore a potential for gaming<br>Mixed stakeholder feedback from TOs and other stakeholders on the use of incentives |

*Table 160: A16 Delivering consumer benefits from improved network access planning option 3 advantages and disadvantages*

We have not progressed this option at this time because:

- stakeholder feedback was mixed
- it was difficult to develop incentives that did not have a risk of gaming and needs to be designed carefully. We will continue to work with all TOs to develop their proposals in line with the comments above.

#### 5.4.7.4 Working more closely with DNOs to optimise system outages across the transmission-distribution interface

Under this approach we would work with DNOs and their developing flexibility markets to identify opportunities to harmonise SO costs.

| Advantages | Disadvantages |
|---|---|
| Consistent with our coordinated approach to DSO<br>Facilitates potential extension of the NAP process across the transmission-distribution systems (T-D) interface.<br>Facilitates development of coordinated flexibility markets across the T-D interface<br>Manages potential conflicts of flexibility services in a timely efficient manner | Additional resourcing required in both DNO and ESO organisations. |

*Table 161: A16 Delivering consumer benefits from improved network access planning option 4 advantages and disadvantages*

We decided to proceed with this option because:

- stakeholders support it
- in our commercial and technical judgement, it would allow for the development or coordinated markets, realising significant consumer benefit.

### *Summary*

Based on this we have decided to proceed with option 1, 2 and 4 because:

- stakeholders support them
- our CBA indicates it would deliver net consumer benefits
- in our commercial and technical judgement, there are likely to be significant benefits for parties across the system.

## 5.5 A15.7 Integrated offshore network

This sub-section provides further context on our breakeven analysis we have conducted on the A15.7 Integrated offshore network.

### 5.5.1 Why we have undertaken a breakeven analysis

A breakeven analysis provides details of the benefit that would need to be delivered to cover the costs of an activity.

We have conducted a breakeven analysis rather than a full cost-benefit analysis because this activity does not deliver quantitative consumer benefits itself. It is the establishment of the regime that will provide consumer benefits (if that is what our analysis and scoping recommends) such as realising efficiencies and minimising the costs of offshore connections by taking an integrated approach.

### 5.5.2 The counterfactual

The counterfactual to our proposals is that we would not undertake this activity.

### 5.5.3 Activity costs

The costs of this activity are part of A15 Taking a whole system approach to promote zero carbon operability.

### 5.5.4 Assumptions, uncertainties and risks

The key assumptions and uncertainties are:

| **Assumption** | **Justification** |
|---|---|
| Timeline | ESO judgement based on estimates of work |
| Cost | ESO estimates of new FTE required for analysis, scoping and stakeholder engagement |
| Industry supports the ESO conducting this activity | Initial stakeholder engagement shows support for the ESO conducting this work. |
| Levels of offshore wind are high enough to warrant creation of an integrated offshore network | Analysis[38] from the Integrated Offshore Transmission Project (East) project is that 17.2GW of offshore wind by 2030 would be needed to make an integrated offshore network beneficial.<br><br>In line with our Business Plan assumptions (see main Business Plan chapter 3 Assumptions underpinning our plan), we assume that we will be between 25.1GW and 29.1GW of offshore wind by 2020 |

*Table 162: assumptions for A15.7 integrated offshore network*

[38] Integrated Offshore Transmission Project (East) – Final Report and Recommendations https://www.nationalgrideso.com/document/125331/download

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Industry does not support the ESO conducting this work | Stakeholder engagement on why it is beneficial for the ESO to lead. If stakeholders were overwhelming against this then we would seek another party to lead | 2 | 1 |

*Table 163: Risks for A15.7 integrated offshore network*

### 5.5.5 Benefits

The benefits of the ESO undertaking this activity are:

- Utilising the ESO's position at the heart of the energy system to coordinate and facilitate multiple industry parties, including TOs, Offshore TOs, DNOs and generation providers.
- Availability of data and system operation experience necessary to conduct analysis and provide recommendations on the development of an integrated offshore network.
- Should our recommendations lead to the implementation of an integrated offshore network, we expect the qualitative benefits to be:
  - Timely delivery of an efficient, integrated offshore network that will support the UK's net zero target.
  - Optimised development of the limited number of suitable landing points for offshore networks, through adopting a coordinated approach, minimising cost and reducing disruption to local communities.
  - A consistent and efficient connections process aligned with whole energy thinking and followed by all network parties.

### 5.5.6 Conclusion

We believe it is beneficial to proceed with this activity because:

- The cost of conducting the review is low in comparison to the potential benefits
- There is stakeholder support for the ESO leading this work.

### 5.5.7 Other options considered

| Options for delivering A15.7 Integrated offshore network | Investment |
|---|---|
| 1 – The proposed transformational activity, as set out in the Business Plan | Ongoing and Transformational |
| 2 – Ongoing activities and enhancements only | Ongoing |

*Table 164: A15.7 Integrated offshore networks activity*

*Advantages and disadvantages*

### 5.5.7.1 Preferred option – proposed transformational activity

| Advantages | Disadvantages |
|---|---|
| Likely to be significant benefits, as described above | |

*Table 165: A15.7 Integrated offshore networks option 1 advantages and disadvantages*

### 5.5.7.2 Ongoing activities and enhancements only

| Advantages | Disadvantages |
|---|---|
| | Would not realise potential benefits described above |

*Table 166: A15.7 Integrated offshore networks option 2 advantages and disadvantages*

*Summary*

The proposed transformational activity is our preferred option because:

- stakeholders support it
- the breakeven analysis indicates significant potential benefit relative to the cost
- in our commercial and technical judgement, the ESO is well positioned to carry out this activity.

## 5.6 Cost summary

This table summarises the total costs of Role 3, Theme 4.

| Ref | Type | RIIO-T1 | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | 2 year average | 2 year total |
|---|---|---|---|---|---|---|---|---|---|
| Transformational Activity subject to CBA | OPEX | - | - | - | - | - | - | - | - |
| CBA Ref: N/A | CAPEX | - | - | - | - | - | - | - | - |
| Transformational not subject to a CBA | OPEX | - | 1.2 | 1.3 | 1.4 | 1.4 | 1.2 | 1.2 | 2.5 |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 2.1 | 2.5 | 2.5 | 2.5 | 2.4 | 2.4 | 2.5 | 5.0 |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| **Leading the debate** | **OPEX** | **2.1** | **3.7** | **3.8** | **3.8** | **3.9** | **3.6** | **3.7** | **7.4** |
| **Ref BP Theme 4 chapter** | **CAPEX** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| Transformational Activity subject to CBA | OPEX | - | 1.0 | 1.0 | 0.8 | 0.9 | 0.9 | 1.0 | 2.0 |
| CBA Ref: NGESOT2007 | CAPEX | - | 0.7 | 0.7 | 0.2 | 0.1 | 0.1 | 0.7 | 1.4 |
| Transformational not subject to a CBA | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 2.8 | 3.4 | 3.3 | 3.3 | 3.2 | 3.2 | 3.3 | 6.7 |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| **Whole system approach to connections** | **OPEX** | **2.8** | **4.4** | **4.4** | **4.1** | **4.1** | **4.1** | **4.4** | **8.7** |
| **Ref BP Theme 4 chapter** | **CAPEX** | **-** | **0.7** | **0.7** | **0.2** | **0.1** | **0.1** | **0.7** | **1.4** |
| Transformational Activity subject to CBA | OPEX | - | 1.8 | 3.0 | 4.7 | 6.6 | 7.9 | 2.4 | 4.9 |
| CBA Ref: NGESOT2009 | CAPEX | - | 8.1 | 9.1 | 11.0 | 11.3 | 13.0 | 8.6 | 17.2 |
| Transformational not subject to a CBA | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 3.1 | 3.4 | 3.3 | 3.2 | 3.2 | 3.1 | 3.4 | 6.7 |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | 3.3 | - | - | - | - | - | - | - |
| **Whole electricity system approach to promote zero-carbon operability** | **OPEX** | **3.1** | **5.2** | **6.3** | **8.0** | **9.8** | **10.9** | **5.8** | **11.6** |
| **Ref BP Theme 4 chapter** | **CAPEX** | **3.3** | **8.1** | **9.1** | **11.0** | **11.3** | **13.0** | **8.6** | **17.2** |
| Transformational Activity subject to CBA | OPEX | - | 0.2 | 0.3 | 0.8 | 0.8 | 0.9 | 0.2 | 0.5 |
| CBA Ref: NGESOT2008 | CAPEX | - | 0.4 | 0.4 | 1.2 | 1.4 | 1.4 | 0.4 | 0.8 |
| Transformational not subject to a CBA | OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| Ongoing Activities | OPEX | 3.8 | 4.5 | 4.5 | 4.4 | 4.4 | 4.3 | 4.5 | 9.0 |
| | IS OPEX | - | - | - | - | - | - | - | - |
| | CAPEX | - | - | - | - | - | - | - | - |
| **Delivering conusmer nemefits from improved network access** | **OPEX** | **3.8** | **4.7** | **4.8** | **5.2** | **5.2** | **5.2** | **4.7** | **9.5** |
| **Ref BP Theme 4 chapter** | **CAPEX** | **-** | **0.4** | **0.4** | **1.2** | **1.4** | **1.4** | **0.4** | **0.8** |
| **Theme 4 Total On CBA** | **Opex** | **-** | **3.0** | **4.4** | **6.3** | **8.3** | **9.6** | **3.7** | **7.4** |
| **Theme 4 Total Capex** | **Capex** | **-** | **9.2** | **10.3** | **12.4** | **12.8** | **14.4** | **9.7** | **19.5** |
| **Theme 4 Total Ongoing activites and transformational activities not on a CBA** | **Opex** | **11.7** | **14.9** | **14.9** | **14.8** | **14.7** | **14.2** | **14.9** | **22.4** |
| | **IS Opex** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| **Theme 4 Total Capex** | **Capex** | **3.3** | **-** | **-** | **-** | **-** | **-** | **-** | **22.4** |
| **Theme 4 Total** | **Opex** | **11.7** | **17.9** | **19.3** | **21.1** | **23.0** | **23.8** | **18.6** | **37.2** |
| | **Capex** | **3.3** | **9.2** | **10.3** | **12.4** | **12.8** | **14.4** | **9.7** | **19.5** |
| | **TOTEX** | **15.0** | **27.1** | **29.5** | **33.5** | **35.8** | **38.3** | | |

# 6. Cost-benefit analysis: A17 Digitalisation and open data

## 6.1 Why we have undertaken a breakeven analysis

This details the benefit that would need to be delivered to cover an activity's costs.

We have conducted a break-even analysis because our A17 Digitalisation and open data proposals do not directly deliver consumer benefits; they enable benefits in other areas, particularly in Themes 1 and 2.

## 6.2 The counterfactual

The counterfactual to our proposals is that we continue to share the data we currently do through existing channels.

## 6.3 Activity costs

| Costs £ million | 2021/22 | 2022/23 | 2023/24 | 2024/25 | 2025/26 | Total |
|---|---|---|---|---|---|---|
| Capex | 1.3 | 1.3 | 1.1 | 0.6 | 0.0 | 4.2 |
| Opex | 1.8 | 1.9 | 1.8 | 1.6 | 1.2 | 8.3 |
| Total | 3.0 | 3.1 | 2.9 | 2.2 | 1.2 | 12.5 |

*Table 167: Incremental costs A17 Digitalisation and open data*

## 6.4 Assumptions, uncertainties and risks

The key assumptions, uncertainties and risks are:

| Assumption | Justification |
|---|---|
| Stakeholders will make use of the data for investment and operational decisions to reduce costs. | This is backed up by stakeholder feedback and external evidence (see section below) |

*Table 168: A17 Digitalisation and open data assumptions*

| Risk | Mitigations | Likelihood | Impact |
|---|---|---|---|
| Data platform cannot be delivered on time, delaying delivery of other systems | Early engagement with framework supply partners and out of sector industries which have already undergone a transformation. A key impact would be if the roadmap needed to be significantly redesigned. | 2 | 3 |

*Table 169: Risks for A17 Digitalisation and open data*

## 6.5 Benefits

The data that we make available will provide greater clarity on our current and future needs. This will promote enhanced balancing of supply and demand by energy market participants, reducing the need for the ESO to take actions that we need to pay for.

Enhanced understanding of our needs by market participants will also lead to improved investment and commercial decision-making for the provision of balancing services. This means that the services we do require will be procured from more efficient solutions. This will directly drive lower Balancing Services Use of System (BSUoS) bills than would otherwise be the case.

In addition, the decisions that will be informed by our enhanced data and insight provision will also influence investment in assets that will participate in wholesale and capacity markets. This will drive more efficient costs in those markets, too.

Finally, by improving the standard of data we provide, and the channels through which it is consumed, we will lower transactional costs for stakeholders. Our portal will support automation and provide data in a standard format, which can remove the need for human interaction to retrieve our data. Similarly, costs of doing business with the ESO will be reduced over time through the single interface provided by our portal for ESO markets and services.

**McKinsey Global Institute**

Research by the McKinsey Global Institute. suggests that Digitalisation and open data can help create $3 trillion (£2.4 trillion) a year of value in seven areas of the global economy, with the potential to add between $340 billion (£276 billion) and $580 billion (£470 billion) of value annually across the electricity sector. By clarifying current inefficiencies and potential opportunities, Digitalisation and open data can help support the innovation and improvements needed to drive considerable efficiencies.

**Transport for London (TfL)**

Research conducted by Deloitte shows that by providing Digitalisation and open data to developers, TfL is improving journeys, saving people time, supporting innovation and creating jobs. This approach is also generating annual economic benefits and savings of up to £130 million a year.

TfL has adopted a strategy of making its Digitalisation and open data freely available to third parties and engaging with developers to deliver new products, apps and services for customers.

The provision of its data and APIs has driven innovation, by enabling thousands of developers to work on designing and building applications, services and tools, leading to the significant economic benefits and savings stated above.

There are many similarities in the transformation undertaken by TfL and our ambition for

The costs of the digital engagement platform that will deliver the capabilities required for the data portal – as well as meeting requirements for other external facing ESO systems such as the single market platform or connections portal – will be £12.6 million over five years. The wider benefits of A17 Digitalisation and open data have been articulated by the research and experience shown in the call out box above which references McKinsey Global Institute[39] and Transport for London (TfL)[40].

In addition, to capture the benefits outlined in the 'A4 Build the future balancing service and wholesale markets' section of this plan, market participants will need access to the data and insight detailed in this chapter.

## 6.6 Conclusion

Based on this, we believe it is beneficial to proceed with this activity because:

- The cost of our proposal is low in comparison to the potential benefits.
- There is stakeholder support for a greater transparency of our data.

[39] https://www.mckinsey.com/business-functions/digital-mckinsey/our-insights/open-data-unlocking-innovation-and-performance-with-liquid-information
[40] http://content.tfl.gov.uk/deloitte-report-tfl-open-data.pdf

# 7. How we have complied with Ofgem guidance

In this section, we summarise Ofgem's guidance and how we have interpreted it and applied it to our Business Plan.

## 7.1 Where we expect a CBA to be undertaken

### Ofgem guidance

CBA is an essential part of the decision-making process and should be undertaken for any new or transformational investments, or additional roles/responsibilities, that the ESO proposes in its business plan. The ESO should undertake CBA at an activity level. Existing or business as usual activities should be justified through appropriate benchmarking.

### How we have complied with the guidance

We have applied a CBA or breakeven analysis to all our transformational activities. Some activities may be combined, for example Role 3, Theme 3 activities A8 - A11 cover our *NOA* enhancements. Ongoing activities have been justified using historical and current costs and external benchmarking, supported by stakeholder feedback and additional assumptions on efficiency.

## 7.2 Identification of options

### Ofgem guidance

Consistent with HM Treasury's Green Book, the ESO should clearly list the range of options considered to meet its aim. This should include where feasible, an option that requires minimal investment (the "do minimum option") against which other options can be compared. The list should include options have been considered and rejected before full costing and a clear rationale for including/excluding options should be considered. For each investment, the ESO should explain what assumptions have been used and which regulations the minimum level of intervention relates to.

### How we have complied with the guidance

We outline our approach to considering options in section 1.2.2. Each benefit area lists the options considered for the activity, including a "do minimum" option and why certain options were not proceed with. Each benefit area has a table where we list the assumptions we have made and the justification for using it. The minimum level of intervention is always the activities (and associated costs), as described in the relevant "ongoing activities" section of our Business Plan and represents the level of investment required to maintain compliance with our licence obligations.

## 7.3 Valuing the costs and benefits of options

### Ofgem guidance

Benefits should be categorised as per the ESO *2019/21 Forward Plan* and Ofgem Forward Work Programme:

- Lower bills for consumers that would otherwise be the case
- Ensuring system security and reliability
- Reduced environmental damage
- Better quality of service
- Benefits for society.

The financial costs and benefits must be in 2018/19 prices, exclude real price effects (RPEs) and be net of expected productivity improvements, that is consistent with the data set out in the ESO Business Plan Data Template (BPDT). Where CBA outcomes are marginal, the ESO should run sensitivities analysis as detailed below.

### How we have complied with the guidance

We use the same five areas to categorises benefits, these are explained fully in section 1.3.1. We comply with the pricing guidance, as shown in section 1.2.1. Sensitivity analysis has been undertaken for most activities which have a CBA, providing greater transparency of the activities and a most robust assessment. Our approach to sensitivity analysis is outline in section 1.2.4.

## 7.4 Applying the Spackman approach to electricity transmission network investment

### Ofgem guidance

The following Spackman approach[41] should be used:

- Cost of capital (placeholder until a decision is made): 2.64 per cent
- Social time preference rate of 3.5 per cent (less than and equal to 30 years); 3 per cent (greater than 30 years) used to discount all costs and benefits

Costs and benefits should cover the period to 2030, which represents the useful economic life of our investments and is consistent with asset life assumptions in the ESO RIIO-2 finance model. Where possible the ESO should identify when investments will be recovered in shorter timeframes. Where costs and benefits have only been calculated for the RIIO-2 period, the ESO should average or flat-line the costs and benefits as appropriate.

[41] http://www.lse.ac.uk/GranthamInstitute/wp-content/uploads/2015/03/Working-Paper-182-Spackman.pdf

### How we have complied with the guidance

As set out in section 1.2.3 we have following the Spackman approach. For each activity, we have undertaken a CBA to the end of the RIIO-2 period in 2026 and for the ten-year period to 2031. Unless otherwise indicated, costs and benefits have been flatlined from 2025/26 onwards. We also highlight when the CBA becomes positive.

## 7.5 Society benefits and the treatment of non-marketed goods

### Ofgem guidance

The ESO should consider societal benefits and the avoided costs associated with each option. The ESO should also set out, within the wider investment appraisal, any non-marketed impacts or factors that cannot be monetised. For the benefits associated with preventing fatalities and injuries, we require the ESO to draw on guidance set out in HM Treasury Green Book and the HSE. In relation to carbon abatement values, we require the ESO to use the Department for Business, Energy and Industrial Strategy (BEIS) traded (central) carbon value

### How we have complied with the guidance

Many of our activities have wider societal and/or qualitative benefits, which we include in the relevant sections. Our proposals do not include any benefits associated with preventing fatalities our injuries. We have used the BEIS traded (central) carbon values, adjusting the prices to represent financial years; these can be found in section 1.2.1 below.

## 7.6 Decision rule

### Ofgem guidance

The purpose of the CBA template is to enable the ESO to demonstrate that the proposals included in their business plan provide the optimum solution which demonstrates best value for customers. We do not expect the ESO to consider CBAs at face value (that is including all schemes with positive NPV and excluding all those with negative NPV). Where a scheme has a marginally positive or negative NPV, the ESO should consider its inclusion or exclusion drawing on sensitivity analysis and the identification of non-financial benefits or costs. The overall position, determined across the following three elements, will determine and substantiate the most appropriate solution: commercial and technical justification paper, stakeholder feedback and the CBA.

### How we have complied with the guidance

In making our decisions, we have balanced the CBA with our stakeholder feedback and own commercial and technical judgment, as detailed in the relevant sections in the main Business Plan document. We have undertaken further sensitivity analysis to add to our understanding of the activity, as described in section 1.2.4.

## 7.7 Uncertainty and sensitivity analysis

### Ofgem guidance

We expect the ESO to undertake sensitivity analysis consistent with the HM Treasury Green Book guidance and consistent with their stakeholder approved process based on the 2019 *Future Energy Scenarios (FES).* The ESO should capture the risks associated with the chosen option. These risks should capture any material risk which may impact the cost and/or timing of the chosen investment. The risk impact should be quantified, and the likelihood of occurrence estimated. The relevant controls and risk mitigation should also be captured within this section

### How we have complied with the guidance

Our overall approach to sensitivity analysis is set out in section 1.2.4. Where appropriate we have used the *FES*, for example where an activity's benefits are dependent on the future energy landscape. Some activities will naturally be less sensitive under the *FES*, so their benefits will vary less. Here we may consider additional sensitivities. We have included a risks and mitigations section for each activity. Further risks and mitigations to each IT investment line and the overall IT portfolio can be found in Annex 4 – Technology investment report.

## 7.8 Links to business plan

### Ofgem guidance

The ESO must clearly show the links between its CBA, Business Plan and associated data tables. For example, the ESO should show how the workload and cost reductions underpinning the CBA and proposed asset investment plans feed through into the overall business plan proposals

### How we have complied with the guidance

We have been consistent in following activities from the Business Plan. The Business Plan will pull out and use the CBA as part of the narrative supporting the activity. In this report, and in the main Business Plan, we have shown the link between the transformational activities measured in our CBA and the metrics we propose to measure how we are delivering the outputs in our Business Plan.