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

1 October 2019

Contents

1. **Delivering consumer benefit**

1.1 Approach to cost-benefit analysis

To create a robust, well-justified Business Plan, it is essential that the Electricity System Operator's (ESO) decision-making process considers our commercial judgement, stakeholder views and economic assessments.

For the economic assessment in our October submission we have undertaken a cost-benefit analysis[1] (CBA) or break-even analysis on all our transformational activity proposals. We have worked with Ofgem to develop a CBA model based on the approach for other RIIO-regulated companies but tailored for the type of business we are. This approach follows best practice from HM Treasury's Green Book. It uses established procedures, recommended by Ofgem, for expenditure-related decisions.

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. The table below outlines how we have interpreted the guidance we have received:

Table 1:Ofgem CBA guidance

Ofgem guidance	How we have complied with the guidance
Be consistent with published guidance and recognised best practice, for example HM Treasury Green Book and Spackman discounting approach.	We have built this best practice into our thinking, working with HM Treasury Green Book and using the appropriate Spackman discounting in the CBA templates.
The ESO should undertake its CBA at an activity level, consistent with its Business Plan reporting.	Our CBA is aligned with the activities in our Business plan. Where appropriate we have combined activities and/or investments e.g. *NOA* enhancements.
A CBA is an essential part of the investment decision pack and will be prepared for any new or transformational investments or additional roles or responsibilities the ESO undertakes.	We have applied a CBA or breakeven analysis to all our transformational activities, some activities may be combined (see above).
Existing or ongoing activities should be justified through appropriate benchmarking.	For ongoing (non-transformational) activities, we have not performed a CBA. Instead we have justified these costs using historical and current costs as our benchmark, supported by stakeholder feedback and additional assumptions on efficiency.

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

Consistent with the HM Treasury Green Book, the ESO must clearly identify the range of options that were considered to meet its aim. This list should, where feasible, include an option that requires a minimal initial investment (the “do minimum option”) against which other options can be compared.	The number of options vary for each activity, with some being binary i.e. do the activity or not. As we are considering transformational activities there will always be a ‘do minimum’ option.
Benefits should be categorised as per the ESO *2019/21 Forward Plan* and Ofgem Forward Work Programme: • Lower bills for consumers • Ensuring system security and reliability • Reduced environmental damage • Better quality of service • Benefits for society.	We have used the same five areas to categorise RIIO consumer 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.	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. We also highlight when the CBA becomes positive.
We do not expect the ESO to consider CBAs at face value (i.e. 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.	We have undertaken further sensitivity analysis to add to our understanding of the activity. In addition, we have considered stakeholder feedback and our commercial and technical judgment (see next item).
The overall position, determined across the following three elements, will determine and substantiate the most appropriate solution: Commercial and Technical Justification paper; Stakeholder Engagement & Support; and the quantitative analysis (i.e. CBA).	We have balanced the CBA with our stakeholder feedback and own commercial and technical judgment, as detailed in the main Business Plan document.
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).*	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.

The ESO must clearly show the links between its CBA, Business Plan and associated data tables.	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 Annex 1D – Metrics 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.

1.2 What we appraise using CBA

Our Business Plan contains both our ongoing and transformational activities. In line with guidance, we are performing a CBA on our transformational activities rather than our ongoing activities. Again, in line with Ofgem guidance, our ongoing activities have their costs justified and benchmarked. For details on our overall benchmarking approach see section 3 of the main report plus additional information in chapters 11 and 13. In addition the theme chapters explain the detail of the activity (delivery, timelines etc.) and how individual costs are justified.

Many of our transformational activities combine to deliver a common benefit or share a common cost base. To ensure our CBA analysis is proportionate, we have combined some of these activates into 11 larger activity groups.

1.3 How we are analysing consumer benefit

As these are transformational activities, there is always a 'do minimum' option which the activity can be compared against. As the future energy landscape is uncertain, the benefits which each activity delivers may be different. So, where appropriate, we have used additional sensitivities to fully understand these benefits.

For our CBA, we have considered the costs and benefits over the RIIO-2 period. These figures are used to calculate the five-year Net Present Value (NPV). We have flatlined the final year (i.e. 2025/26) to calculate the ten-year NPV. To add further transparency, we will also highlight where activities become net positive, i.e. when benefits exceed costs.

1.3.1 Methodology for calculation Net Present Value (NPV)

For each transformational activity we:

1. Estimate the capex and opex costs for each year of the RIIO-2 period.
2. Calculate the financial value of each of the five consumer benefit areas for each year of the RIIO-2. We use a range of sources, including historic data, forecasts, published analysis and engineering/technical judgement. Our benefit assumptions are clearly justified.
3. The template then calculates the NPV by:
    a. Depreciating the capex expenditure over the capex depreciation period (see table below).
    b. Applying the cost of capital assumption to depreciated capex investments.
    c. Calculating net benefits by the difference between costs (opex and capex above) and the benefits.

   d. Discounting these net benefits by the discount rate and calculating net present values (NPV) 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.

Interactions between benefit areas

We are conscious that there are many overlaps and interdependencies between our activities which could lead to double counting of benefits. For example, Theme 1 and Theme 2 both claim lower response and reserve costs. Theme 3 and Theme 4 use forecast cost of constraints in the benefits calculation. For simplicity and transparency, we have considered each activity notionally, that is the benefits from one are not reflected in the other. For more detail see the relevant section. More generally to mitigate double counting we have adopted a conservative approach to benefits calculation where we have less certainty. Any potential double counting will also be accounted for in the relevant sensitivity analysis.

1.3.2 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 or not to proceed.

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

1. A market sensitivity for market factors outside our control.
2. A third-party sensitivity for third-party factors outside our control
3. A delivery sensitivity for factors we can control.

Examples of factors considered in these are in the table below. The exact inputs into specific sensitivity analysis can be found in appropriate place in the report. It should be noted that we may not conduct each type of sensitivity analysis for every benefit line.

Table 2: Sensitivity analysis factors

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

• Energy landscape assumptions	

1.3.3 Assumptions

We make several assumptions to calculate our central case:

Table 3: CBA modelling assumptions

Assumption	CBA model value
Capex depreciation period	Seven years
Cost of carbon £/tonneCO2e	BEIS short-term traded carbon values[2] (converted from calendar into financial year values) 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	3.5%
Price base	2018/19
Constraint costs £ million	2021/22: £600 million, 2022/23: £689 million, 2023/24: £809 million, 2024/25: £931 million, 2025/26: £909 million[3]
Response and reserve costs	We take the average cost of response and reserve over the past 12 years: Response: £193 million per year Reserve: £321 million per year[4]

The model calculates a net present value (NPV), rather than a net benefit. This is similar but accounts for financing, depreciation and discounting.

[2] 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.
[3] Average constraint costs across the *Future Energy Scenarios* as used in the modelling of the 2018/19 *NOA*
[4] This is the average response and reserve cost over the past 12 years

1.3.4 Risks and mitigations

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

Likelihood

Table 4: Risk likelihood scoring

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

Impact

Table 5: Risk impact scoring

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

1.4 Benefits calculations

In the following section, we explain how we have considered benefits. As each activity is unique, the method for calculating benefits is not set – the steps are listed with each benefit line. To structure our thinking, we have used a high-level framework which considers both the category and type of benefit.

1.4.1 Benefit categories

We use the five categories of consumer benefit (see above). This is also consistent with the *Forward Plan 2019/21*.

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.

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 explaining 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 impact and 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.
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% and 2.5%, respectively. It could also generate a 15% increase in global welfare and reduce negative health effects caused by local air pollution by 60%.

Figure 1: Benefit categories

When we calculate benefits, we assign them to one of these categories and provide descriptions.

1.4.2 Benefit type

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

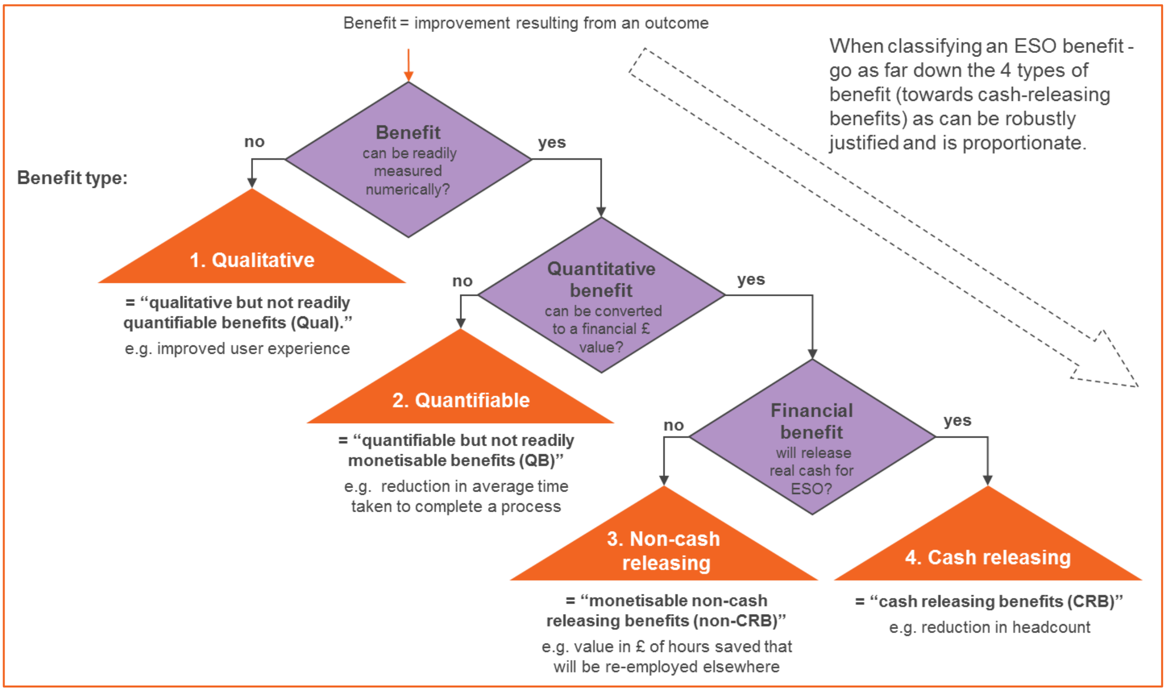


Figure 2: Benefit types

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 cost-benefit analysis (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 we pass on benefits to third parties, we assume the cost-saving is fully passed on to consumers. We highlight this in the appropriate sections.

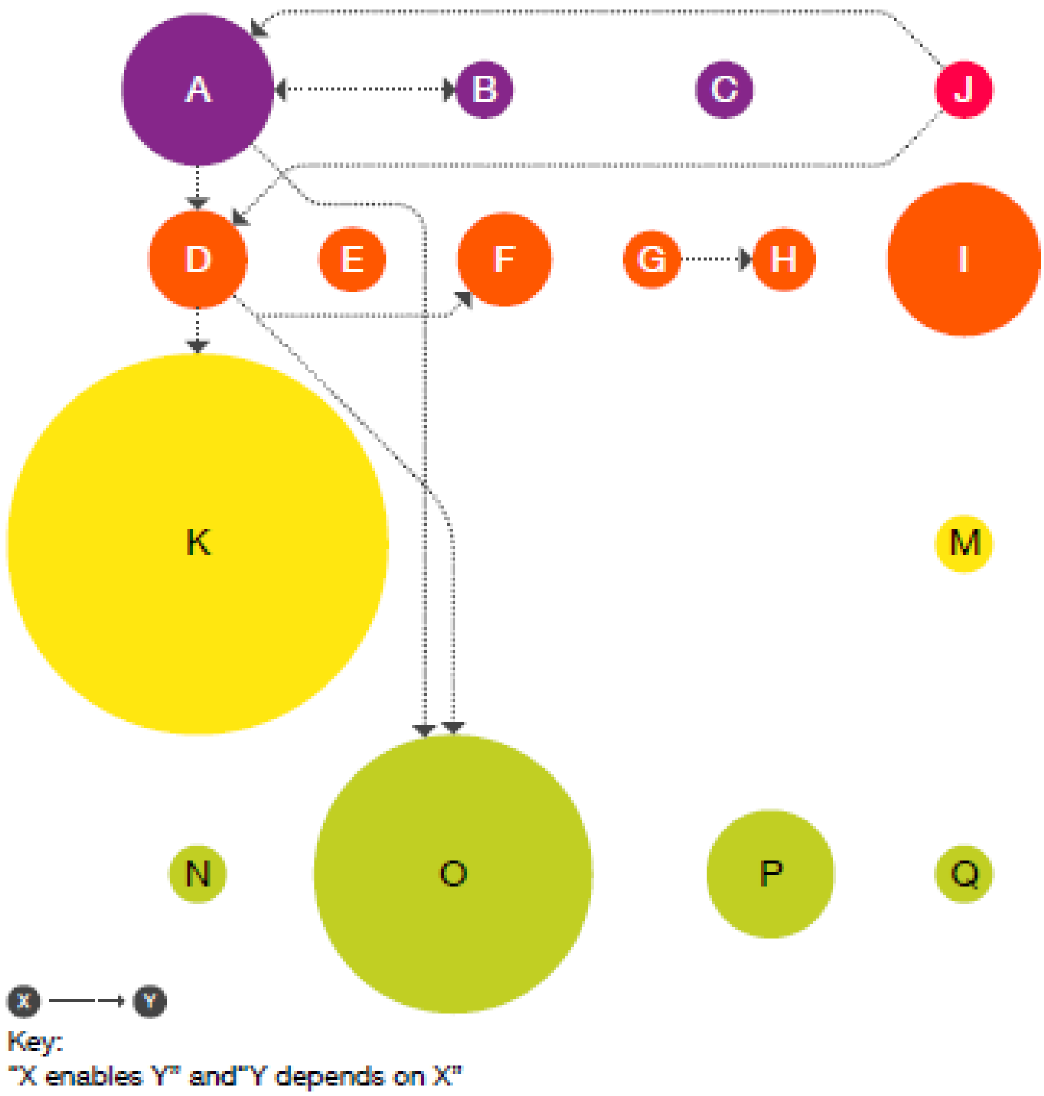
Table 6: Activities by Benefit type

Theme	Activity group	Analysis type	Activity reference[5]
Theme 1	Control centre architecture and systems	CBA	A
	Control centre training and simulation	CBA	B
	Restoration	CBA	C
Theme 2	Build the future balancing service and wholesale markets	CBA	D
	Designing the markets of the future	Break-even	E
	Transform access to the capacity market	CBA	F
	Transform the process to amend our codes	Break-even	G
	Work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025	CBA	H
	Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges	CBA	I
Theme 3	Enhance the *Network Options Assessment (NOA)*	CBA	K
	Review of the Security and Quality of Supply Standard (SQSS)	Break-even	M
Theme 4	Lead the debate	Break-even	Q
	Taking a whole electricity system approach to connections	CBA	N
	Taking a whole electricity system approach to promote zero-carbon operability	CBA	O
	A whole system approach to accessing networks	CBA	P
Open Data	Delivering consumer benefits from improved network access planning	Break-even	J

[5] Used in Figure 3 below

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

Figure 3: Activity dependencies (see activity reference in table 6)



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[6] sensitivity analysis.

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[6] If no sensitivity analysis has been undertaken a "–" is shown

Table 7: Summary benefits table

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
Control centre architecture and systems	242	565	374	140	476	69	-	-
Control centre training and simulation	20	45	26	14	35	0	-	-
Restoration	-8	-23	-	-	-	-	-	-
Theme 1 total	254	587	392	146	502	60	-	-
Build the future balancing service and wholesale markets	67	183	87	47	115	3	-	-
Transform access to the capacity market	62	129	83	42	94	22	65	60
Work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025	1	14	2	0	-	-3	4	-2
Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges	280	580	730	270	-	206	-	-
Theme 2 total	411	906	903	359	490	228	417	405
NOA enhancements	663	1,321	906	488	-	462	-	-
Theme 3 total	663	1,321	906	488	-	462	-	-
Taking a whole electricity system	2	15	3	1	-	-2	-	-

approach to connections								
Taking a whole electricity system approach to promote zero-carbon operability	469	949	608	366	-	333	488	450
Delivering consumer benefits from improved network access planning	205	420	310	138	286	98	-	-
Theme 4 total	676	1384	921	505	757	429	695	656
ESO total	**2,002**	**4,198**	**3,122**	**1,498**	**2,412**	**1,180**	**2,027**	**1,978**

2. Cost-benefit analysis: Theme 1

This section provides further context on the costs and quantifiable benefits of Theme 1's transformational activities:

Table 8: Theme 1 activities

Activity group	Analysis type
Control centre architecture and systems	CBA
Control centre training and simulation	CBA
Restoration	CBA

The NPV of Theme 1 is estimated at £254 million over the RIIO-2 period and £587 million over ten years. Sensitivity analysis suggests an NPV range of £60 million to £502 million over the RIIO-2 period.

2.1 Control centre architecture and systems

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

The net-present value of control centre architecture and systems proposals is £242 million over the RIIO-2 period, and £565 million over ten years. Sensitivity analysis suggests an NPV range of £69 million to £476 million over the RIIO-2 period

2.1.1 The counterfactual

If we did not undertake our transformational 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 the main document. 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 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 CO2 emissions

Table 9: Reduced CO2 emissions assumptions

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 is around 5% of national demand. So 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.

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% 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% of the maximum benefit to avoid double counting restoration benefits. This generates £52 million of consumer benefit over the RIIO-2 period.

Sensitivity analysis - Reduced CO2 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.

Table 10: Carbon prices 2021 to 2026

Calendar year	2021	2022	2023	2024	2025	2026
Carbon value (£/tCO2e, BEIS central estimate, 2018 real prices)	14.56	15.11	15.68	16.28	17.70	23.95

Table 11: Benefits calculation for reduced CO2 emissions

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 Total	Calculation
Carbon intensity Steady Progression (gCO2/kWh)	136.44	119.55	128.48	123.71	110.89		A
Carbon intensity Two Degrees gCO2/kWh	69.19	57.56	53.57	44.33	38.69		B
Reduction gCO2/kWh	67.25	61.99	74.91	79.38	72.21		C = A - B
Expected demand TWh (Two Degrees)	288.18	286.36	285.24	284.50	284.82		D
Carbon price t/CO2e (calendar year adjusted to financial year)	14.70	15.25	15.83	16.63	19.24		E

Saving (£ millions)	285	271	338	376	396		F = C x D x E
Attributable saving (£ millions)	14.2	13.6	16.9	18.8	19.8		G = 5% x F
Percentage of maximum annual benefit claimed	20%	40%	60%	80%	94%		H
Adjusted saving (£ millions)	2.8	5.4	10.1	15.0	18.6	52.0	= G x H

Table 12: Benefits for reduced CO2 emissions

Benefits £ millions	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Reduced CO2 emissions	2.8	5.4	10.2	15.0	18.6	52.0
Sensitivity – high market factors	5.7	10.8	20.3	30.1	36.1	103.0
Sensitivity – low market factors	0	0	0	0.5	2.3	2.8
Sensitivity – low delivery confidence	0	2.7	6.8	11.3	15.8	36.6

The above table shows the benefits associated with reduced CO2 emissions are between £2.8 million and £103 million, with a central case of £52 million.

2.1.2.2 Greater interconnection

Table 13: Greater interconnection assumptions

Assumptions	Justification
£11 billion of consumer benefits from interconnectors over next 25 years to 2042	Analysis[7] undertaken by National Grid Ventures.
ESO proposals unlock 2% of this benefit	ESO engineering judgement. Analysis of historic data comparing the volume of activity in balancing mechanism and trading activity as a proportion of national demand suggests we dispatch 5% of the market. So we control 5% of new interconnection. Allowing that some interconnector actions might be undertaken anyway with existing systems, we claim 2% of the total benefit.
Percentage of maximum annual benefit claimed	ESO engineering judgement, based on the cumulative benefits of interconnection as the number increases

Analysis indicates interconnection benefits of **£11 billion over the next 25 years** which averages at £440 million per year. The value of the benefit is the reduction in the total spend on electricity in GB because of interconnector imports. This is due to imported electricity being cheaper than electricity generated by carbon-intensive GB generators, especially fossil fuels such as gas.

A modest assumption is that our investments contribute to unlocking around 2% of these benefits through modelling these in our balancing and situational awareness tools. This gives an estimated consumer benefit of £35 million.

Sensitivity analysis - Greater interconnection

- Market factors: we have assumed interconnectors unlock 10% more benefit.
- Delivery factors: we have assumed our proposals unlock 1% and 3% of the benefits
- Third-party factors: we have not conducted a third-party sensitivity because we believe the portfolio of interconnectors over the RIIO-2 period is unlikely to vary.

Table 14: Benefit calculations for greater interconnection

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 total	Calculation
Benefit per year from greater interconnection (£ millions)	440	440	440	440	440	2,200	A

[7] National Grid: Connecting for a smarter future https://www.nationalgrid.com/document/118641/download

ESO attribute saving (£ millions)	8.8	8.8	8.8	8.8	8.8	44	B = 2% x A
Percentage of maximum annual benefit claimed	60%	70%	80%	90%	100%		C
Benefit (£ millions)	5.3	6.2	7.0	7.9	8.8	35.2	D = B x C

Table 15: Benefits for greater interconnection

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Greater interconnection	5.3	6.2	7.0	7.9	8.8	35.2
Sensitivity – high market factors	6.4	7.5	8.5	9.6	9.7	41.6
Sensitivity – high delivery confidence	7.9	9.2	10.6	11.9	13.2	52.8
Sensitivity – low delivery confidence	2.6	3.0	3.5	4.0	4.4	17.6

The above table shows the benefits from greater inteconnection are between £17.6 million and £52.8 million, with a central case of £35.2 million.

2.1.2.3 Utilising flexible technology

Table 16: Utilising flexible technology assumptions

Assumptions	Justification
£3.95 billion consumer savings per year to 2030 from new flexibility sources	Analysis[8] undertaken in a report to the Committee on Climate Change indicates there is potentially between £3.2 billion and £4.7 billion savings per year for a more flexible system. We have taken the average of £3.95 billion per year as the basis for our central case.
ESO proposals unlock 1% 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

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

	system benefits". Our assumption is based on this analysis and our engineering judgement. Analysis of historic data suggests we dispatch 5% of the market. This figure was reached comparing the volume of activity in balancing mechanism and trading activity as a proportion of national demand. So, we assume 5% of the new flexibility is within our control. Allowing that some flexibility actions might be undertaken anyway, we claim 1% of the total benefit.
Percentage of maximum annual benefit claimed	We believe our proposals ultimately unlock, at most, 1% 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.

According to a report from the Committee on Climate Change, **new sources of flexibility could provide up to £4.7 billion consumer savings per year to 2030.** The benefits are estimated between £3.2 billion and £4.7 billion per year in a system meeting a carbon emissions target of 100 gCO2/kWh in 2030. The value of the benefits includes:

- Reduced investment in low-carbon generation as renewable and nuclear generation can be used more efficiently. This enables the system to reach the carbon target with less low carbon generation capacity. Depending on the scenario, the total savings will be between 25% and 60%.
- Reduced system operation cost as reserve services are provided by new and cheaper flexibility sources rather than by conventional generation. This accounts for between 25% and 40% of savings, depending on the scenario.
- Reduced requirement for distribution network reinforcement and back-up capacity. This is between 10% and 20% of savings, depending on the scenario.

Based on our technical judgement, we assume our investments contribute to **unlocking 1% of these benefits**, leading to £103.7 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 are £3.2 billion and £4.7billion, as shown in the report.
- 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 0.5% and 1.5% of the benefits.

Table 17: Benefit calculation for utilising flexible technology

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 Total	Calculation
Benefit per year from flexible technology (£ millions)	4,700	4,700	4,700	4,700	4,700	23,500	A
ESO attributable saving	47	47	47	47	47	235	B = 1% x A
Percentage of maximum annual benefit claimed	12.5%	25%	50%	75%	100%		C
Benefit (£ millions)	4.9	9.9	19.8	29.6	39.5	103.7	D = B x C

Table 18: Benefits for utilising flexible technology

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Utilising flexible technology	4.9	9.9	19.8	29.6	39.5	103.7
Sensitivity – high market factors	5.9	11.8	23.5	35.3	47.0	123.4
Sensitivity – low market factors	4.0	8.0	16.0	24.0	32.0	84.0
Sensitivity – high delivery confidence	7.4	14.8	29.6	44.4	59.2	155.5
Sensitivity – low delivery confidence	0.0	2.5	4.9	9.9	14.8	32.1

The above table shows the benefits from using flexible technology are between £32.1 million and £155.5 million, with a central case of £103.7 million.

2.1.2.4 Better inertia forecasting and needs management

Table 19: Better inertia forecasting and needs management assumptions

Assumptions	Justification
Inertia issues to be resolved in May 2022	Compliance with the Distribution Code[9]

[9] Energy Networks Association: Accelerated Loss of Mains Protection http://www.energynetworks.org/electricity/engineering/loss-of-mains.html

Rate of Change of Frequency (RoCoF) spend will be £144 million per year	Current spend
10% i improvement in forecasting	Consistent with improvements in demand forecasting as per the 2018/19 *Forward Plan* End of Year Report evidence chapters[10] (12% improvement in demand forecasting and 3% improvement in wind generation forecasting).

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% 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% and 15% improvement in forecasting.

Table 20: Benefit calculation for better inertia forecasting and needs management

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

Table 21: Benefits for better inertia forecasting and needs management

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Better inertia forecasting and needs management	14.4	1.2				15.6

[10] National Grid Electricity System Operator: 2018-19 Forward Plan End of Year Report Evidence Chapters https://www.nationalgrideso.com/document/128421/download

Sensitivity – high delivery confidence	21.6	1.8	23.4
Sensitivity – low delivery confidence	7.2	0.6	7.8

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.

2.1.2.5 Improved situational awareness

Table 22: Improved situational awareness assumptions

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[11] that new tools could deliver a reduction of 3% to 12% in constraint spend.
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.

Improved situational awareness – the ability to monitor and understand network status and evolving operational limits - allows better management of transmission constraints, with more economic levels of response and reserve. **Across *control centre architecture and systems,* and *control centre training and simulation,* we take 5% improvement in constraint spend and 2% improvement in response and reserve spend.** This is based on a **recent NIA project**, and is tapered as new systems are delivered. We claim the benefits of reduced constraint spend, and the benefits of reduced response and reserve spend in the control centre training and simulation *section.* This delivers benefits of £126.7 million over RIIO-2.

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% savings for constraints; for the lower case we assume 3% savings and a one-year delay

[11] Energy Networks Association Smarter Networks Portal: Mathematics of Balancing Energy Networks Under Uncertainty https://www.smarternetworks.org/project/nia_nget0052

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.

Table 23: Benefit calculation for improved situational awareness

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	20%	40%	60%	80%	100%	132	C
Benefit (£ millions)	6.0	13.8	24.3	37.2	45.5	126.7	D = A x B x C

Table 24: Benefits for improved situational awareness

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Improved situational awareness	6.0	13.8	24.3	37.2	45.5	126.7
Sensitivity – high market factors	7.5	22.1	39.7	56.3	69.5	195.1
Sensitivity – low market factors	4.4	10.0	16.9	25.8	26.5	83.4
Sensitivity – high delivery confidence	14.4	33.1	58.2	89.4	109.1	304.2
Sensitivity – low delivery confidence	0.0	4.1	9.7	16.8	21.8	52.4

The above table shows the benefits associated with improved situational awareness are between £83.4 million and £304.2 million, with a central case of £126.7 million

2.1.2.6 Reduced Balancing Mechanism outage downtime

Table 25: Reduced Balancing Mechanism outage downtime assumptions

Assumptions	Justification
Cost of an outage is £700,000 per hour	Based on current service level agreement (SLA)

2 hours 23 minutes of unplanned outage per year	Recent average of balancing mechanism (BM) outages. Unplanned incidents since 2016: 1. 22 Jan 2016 - 2hrs 25min 2. 8 Feb 2019 - 4hrs 57min
Our proposals will reduce this to one hour per year	ESO engineering judgement

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**. This will deliver savings of just under £5 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.

Table 26: Benefits for reduced Balancing Mechanism outage downtime

Benefits £ million	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Reduced balancing mechanism outage downtime	1.0	1.0	1.0	1.0	1.0	4.8
Sensitivity – high delivery confidence	1.3	1.3	1.3	1.3	1.3	6.6
Sensitivity – low delivery confidence	0.6	0.6	0.6	0.6	0.6	3.1

The table above shows the benefits from reduced balancing mechanism outage downtime are between £3.1 million and £6.6 million, with a central case of £4.8 million.

The total benefits for control centre architecture systems are between £150 million and £595 million, with a central case of £338 million over the RIIO-2 period.

2.1.3 Activity costs

Delivery of our control centre architecture and systems activities will require additional capex and opex spend, summarised below:

Table 27: Incremental costs for control centre architecture and system

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	17.4	27.5	31.7	25.7	18.1	120.4
Opex	3.4	5.6	7.5	7.9	8.5	32.8
Total	20.8	33.1	39.2	33.6	26.6	153.3

The total costs for our *control centre architecture and systems* activities are £153.3 million.

2.1.4 Net Present Value

The net present value (NPV) of our *control centre architecture and systems* activities is estimated at £242 million over the RIIO-2 period and £565 million over ten years. Our *control centre architecture and systems* activities will start to deliver positive returns from 2021/22. Sensitivity analysis suggests an NPV range of:

- Market factors between £140 million and £374 million
- Delivery factors between £69 million and £476 million

2.1.5 Dependencies, enablers and whole energy system

This activity is dependent on the following transformational activities:

1. Control centre training and simulation (Theme 1) – Equipping the control centre with fully-trained staff to operate in a zero-carbon world.
2. 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

1. Taking a whole electricity system approach to promote zero-carbon operability (Theme 4)
2. Build the future balancing service and wholesale markets (Theme 2)
3. Control centre training and simulation (Theme 1) - Providing real world experience for training and simulations
4. 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 integrating their systems and data to our new tools. However, we believe new market participants would incur these costs anyway. 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.

Table 28: Risks for control centre architecture and systems

Risk	Mitigations	Likelihood	Impact
Unable to source vendors.	Starting our work as soon as possible, in particularly creating 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 re-designed.	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 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 authority, so market changes will be picked up quickly.	2	2
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

2.2 Control centre training and simulation

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

The net present value (NPV) of control centre training and simulation is £20 million over the RIIO-2 period, and £45 million over ten years. Sensitivity analysis suggests an NPV range of £0 million to £35 million over the RIIO-2 period.

2.2.1 The counterfactual

If we did not undertake our transformational control centre training and simulation activities, we would make enhancements to our legacy simulators and continue with our current training schemes, because 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

Table 29: Reduced resource costs assumptions

Assumptions	Justification
Cost saving	Based on past resource costs

Updated shift patterns, working arrangements and increased staff retention will enable a **reduction in resource costs**. We estimate £5 million savings over RIIO-2. We have not conducted a sensitivity analysis.

Table 30: Benefits for Reduced resource costs assumptions

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

2.2.2.2 Decreased training costs

Table 31: Decreased training costs assumptions

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 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.

The **increased knowledge of new starters will reduce training time**. Our internal analysis estimates this will be £3 million over the RIIO-2 period.

This assumes we can reduce training time by three months due to the increased knowledge of the new starter. This would save approximately £32,000 per candidate. We train on average more than 30 people per year. As new training and simulation systems will be delivered in a modular fashion 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 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.

Table 32: Benefit calculation for decreased training costs assumptions

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	20%	40%	60%	80%	100%		C
Benefit £ million	0.2	0.4	0.6	0.8	1	3	D = A x B x C

Table 33: Benefits for decreased training costs assumptions

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Lower training costs	0.2	0.4	0.6	0.8	1	3
Sensitivity – high delivery confidence	0.3	0.5	0.8	1.0	1.3	3.9
Sensitivity – low delivery confidence	0.1	0.3	0.4	0.5	0.6	1.9

The above table above shows the benefits from decreased training costs are between £1.9 million and £3.9 million, with a central case of £3 million.

2.2.2.3 Improved decision making

Table 34: Improved decision making assumptions

Assumption	Justification
Reserve and response cost estimates	Based on 12-year historic average
2% improvement in reserve and response spend	A network innovation allowance (NIA) project demonstrated[12] new tools could deliver a constraint spend reduction of between 3% and 12%.
Percentage of maximum annual benefit claimed	We believe our proposals ultimately deliver a 52 saving in reserve and response 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.

Improved situational awareness allows us to better manage transmission constraints and still retain economic levels of response and reserve products. Across control centre architecture and systems and control centre training and simulation we take 5% improvement in constraint spend and 2% improvement in response and reserve spend, based on the findings from a recent NIA project. As new systems will be delivered in a modular fashion we have considered the percentage of the maximum annual benefit we can claim. We claim the benefits of reduced reserve and response spend here, and of reduced constraint spend in the control centre architecture and systems section. This delivers benefits of £31 million over RIIO-2.

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 3% savings; for the lower case we assume 1% 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.

[12] Energy Networks Association Smarter Networks Portal: Mathematics of Balancing Energy Networks Under Uncertainty https://www.smarternetworks.org/project/nia_nget0052

Table 35:Benefit calculation for improved decision making

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	20%	40%	60%	80%	100%		C
Benefit £ million	2.1	4.1	6.2	8.2	10.3	30.8	D = A x B x C

Table 36: Benefits for improved decision making

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Improved decision making	2.1	4.1	6.2	8.2	10.3	30.8
Sensitivity – high market factors	2.5	5.0	7.4	9.9	12.4	37.2
Sensitivity – low market factors	1.6	3.2	4.9	6.5	8.2	24.5
Sensitivity – high delivery confidence	3.1	6.2	9.3	12.3	15.4	46.3
Sensitivity – low delivery confidence	0	1.0	2.1	3.1	4.1	10.3

The above table shows the benefits from improved decision-making are between £10.3 million and £46.3 million, with a central case of £30.8 million

The total benefits for control centre training and simulation are between £17 million and £55 million, with a central case of £38 million over the RIIO-2 period.

2.2.3 Activity costs

Delivery of control centre training and simulation will require additional capex and opex spend, summarised below.

Table 37: Incremental costs for control centre training and simulation activities

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0	0	1.2	2.3	2.3	5.8
Opex	1.8	2.3	3.2	4.0	4.7	16.0
Total	1.8	2.3	4.4	6.3	7.0	21.8

The total costs for our control centre training and simulation activities are £21.8 million.

2.2.4 Net Present Value

The net present value of these activities is estimated at £20 million over the RIIO-2 period and £45 million over 10 years. They will start to deliver positive returns from 2021/22. Sensitivity analysis suggests an NPV range of:

- Market factors between £26 million and £14 million
- Delivery factors between £35 million and £0 million

2.2.5 Dependencies, enablers and whole energy system

This activity is dependent on the following transformational activity:

1. Control centre architecture and systems (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:

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

Delivery of this activity could pass on benefits and costs to third parties. There may be a cost to DNOs and TOs for training their staff 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 co-ordination and collaboration of training will help the industry make better whole system decision, particularly in areas such as 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.

Table 38: Risks for control centre training and simulation

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 specify role 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

2.3 Restoration

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

The net-present value of our 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 restoration activities, we would make ongoing enhancements to our 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

Table 39: Benefits from the distributed Energy NIC project assumptions

Assumptions	Justification
£115 million NPV to 2050	Findings from Distributed Energy NIC Project[13]

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**.**

Table 40: Benefits distributed Energy NIC project assumptions

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Benefits from the Distributed Energy NIC project	0	0	0	0	4.6	4.6

2.3.2.2 Carbon savings

Table 41: Carbon savings assumptions

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

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 restoration service, leading to reduced carbon emissions from large generators needing to be available. We assume this is allocated evenly from 2025 when the project will start delivering benefits. With an average carbon price of £19.78 per t/CO_2e in 2025/26, this would deliver a benefit of £0.6 million over RIIO-2.

[13] 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

Table 42: Benefits for carbon saving

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Carbon savings	0	0	0	0	0.6	0.6

2.3.3 Benefits summary

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

2.3.4 Activity costs

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

Table 43: Incremental costs for restoration activities

Costs £ 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	1.6	2.6	3.4	8.6
Total	1.0	3.1	9.3	10.7	9.7	33.8

The total costs for our restoration activities are £33.8 million.

2.3.5 Net Present Value

The net present value (NPV) of our 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.

2.3.6 Dependencies, enablers and whole energy system

This activity is not a strong enabler for, or dependent on, any of our other activities. Our Distributed Energy NIC project does complement our work in Theme 2 to transform participation in balancing markets. The restoration decision support tool will complement other tools delivered by our 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 Distributed Energy Resource (DER) Network Innovation Competition (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.

2.3.7 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.

Table 44: Risks for Restoration

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 sub-standard or inappropriate restoration tool is implemented	Project scoping and resource to support this are included in our funding plans	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 large resources, limiting the involvement of smaller DERs	The DER NIC project will provide a working (albeit small-scale) solution for resilient telecommunications which can be scaled for GB-wide use	3	2
Unknown level of technical changes and how to implement those required on distribution networks. Risks of failure to change restoration speeds,	The risk will be identified through the DER NIC project	3	2

lack of investment in DER technology			
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

2.4 Cost summary

This table summarises the total costs of Theme 1.

Description	Business plan location	Type	RIIO-1	2021/22	2022/23	2023/24	2024/25	2025/26	2 year average	2 year total
Transformational Activity subject to CBA	Annex 2 - 2.1.3	OPEX	-	3.3	5.6	7.5	7.9	8.5	4.4	8.9
		CAPEX	-	17.4	27.5	31.7	25.7	18.1	22.4	44.8
Ongoing Activities		OPEX	19.6	21.3	21.3	21.3	19.9	19.6	21.3	42.6
		IS OPEX	-	1.4	1.6	1.4	1.5	2.3	1.5	3.0
		CAPEX	22.6	5.9	7.2	5.3	4.8	5.2	6.5	13.0
Total Control Centre Architecture and Systems Ref BP Theme 1 chapter	**4.2.1**	**OPEX**	**19.6**	**26.0**	**28.5**	**30.2**	**29.3**	**30.3**	**27.2**	**54.4**
		CAPEX	**22.6**	**23.2**	**34.6**	**37.0**	**30.5**	**23.2**	**28.9**	**57.9**
Ongoing Activities		OPEX	4.4	4.9	4.9	4.9	4.9	4.9	4.9	9.8
		IS OPEX	-	-	-	-	-	-	-	-
		CAPEX	-	-	-	-	-	-	-	-
Total Commercial Operations & Strategy Ref BP Theme 1 chapter	**4.2.1**	**OPEX**	**4.4**	**4.9**	**4.9**	**4.9**	**4.9**	**4.9**	**4.9**	**9.8**
		CAPEX	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transformational Activity subject to CBA	Annex 2 - 2.2.3	OPEX	-	1.8	2.3	3.2	4.0	4.7	2.1	4.1
		CAPEX	-	-	-	1.2	2.3	2.3	-	-
Ongoing Activities		OPEX	2.0	-	-	-	-	-	-	-
		IS OPEX	-	-	-	-	-	-	-	-
		CAPEX	-	-	-	-	-	-	-	-
Total Control Training and Simulation Ref BP Theme 1 chapter	**4.3.1**	**OPEX**	**2.0**	**1.8**	**2.3**	**3.2**	**4.0**	**4.7**	**2.1**	**4.1**
		CAPEX	**-**	**-**	**-**	**1.2**	**2.3**	**2.3**	**-**	**-**
Transformational Activity subject to CBA	Annex 2 - 2.3.4	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
Ongoing Activities		OPEX	0.7	0.6	0.6	0.6	0.6	0.6	0.6	1.3
		IS OPEX	-	-	-	-	-	-	-	-
		CAPEX	-	-	-	-	-	-	-	-
Total Restoration Ref BP Theme 1 chapter	**4.4.1**	**OPEX**	**0.7**	**0.7**	**1.4**	**2.3**	**3.3**	**4.1**	**1.1**	**2.2**
		CAPEX	**-**	**0.9**	**2.3**	**7.7**	**8.1**	**6.3**	**1.6**	**3.2**
Theme 1 Total On CBA	**Annex 1 - Table 2**	**Opex**	**-**	**5.2**	**8.6**	**12.3**	**14.6**	**16.6**	**6.9**	**13.8**
		Capex	**-**	**18.3**	**29.7**	**40.5**	**36.1**	**26.7**	**24.0**	**48.0**
Theme 1 Total Ongoing activites and transformational activities subject to breakeven analysis		**Opex**	**26.7**	**26.9**	**26.8**	**26.8**	**25.4**	**25.1**	**26.8**	**53.7**
		IS Opex	**-**	**1.4**	**1.6**	**1.4**	**1.5**	**2.3**	**1.5**	**3.0**
		Capex	**22.6**	**5.9**	**7.2**	**5.3**	**4.8**	**5.2**	**6.5**	**13.0**
Theme 1 Total	**4.1 - Fig. 16**	**Opex**	**26.7**	**33.4**	**37.1**	**40.6**	**41.5**	**44.0**	**35.3**	**70.5**
		Capex	**22.6**	**24.1**	**36.9**	**45.9**	**40.9**	**31.9**	**30.5**	**61.0**
		Totex	**49.3**	**57.6**	**74.0**	**86.4**	**82.4**	**75.9**	**65.8**	**131.5**

3. Cost-benefit analysis: Theme 2

This section provides further context on the costs and benefits of Theme 2's transformational activities:

Table 45: Theme 2 activities

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

The net present value of Theme 2 is £411 million over the RIIO-2 period and £906 million over ten years. Sensitivity analysis suggests an NPV range of £228 million to £903 million over the RIIO-2 period.

3.1 Build the future balancing service and wholesale markets

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

The net present value of 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 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

Table 46: More liquid response and reserve market assumptions

Assumptions	Justification
Value of the response and reserve market is £514 million per year.	See main assumptions section
Our actions deliver a five percent saving in the response and reserve markets	Evidence from early trials, as identified in the *Forward Plan*
Benefits delivered from year three of RIIO-2	This allows two years for implementation.

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 percent through this increased competition[14]. If we assume a **five percent 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% and 2.5% 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.

Table 47: Benefit calculation for more liquid response and reserve market

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

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

Table 48: Benefits 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	25.7	25.7	25.7	77.2
Sensitivity – high market	0	0	31.2	31.2	31.2	93.7
Sensitivity – low market	0	0	20.2	20.2	20.2	60.6
Sensitivity – high delivery	0	0	38.6	38.6	3.68	115.7
Sensitivity – low delivery	0	0	0	12.9	12.9	25.7

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.

3.1.2.2 Buying the optimal volume of response

Table 49: Buying the optimal volume of response assumptions

Assumptions	Justification
Value of the response market is £193 million per year.	See main assumptions section
Our actions deliver a five percent saving in the response market	Evidence from early trials, as identified in the *Forward Plan*
Benefits delivered from year three of RIIO-2	This allows two years for implementation.

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:

1. 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.
2. Operating a market closer to real-time means we can target more specific volume. Volumes set in advance carry ‘headroom’ against forecasting inaccuracies.
3. 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. Considering the daily variation and the decline in mandatory services means we buy considerably less volume than by doing nothing. In this analysis, based on our previous experience, we estimate a **5% 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 reserve and 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% and 2.5% 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 3.1.2.1. Any potential double counting is accounted for in the sensitivity analysis.

Table 50: Benefit calculation buying the optimal volume of response

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

Table 51: Benefits 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	9.7	9.7	9.7	29.0
Sensitivity – high market	0	0	11.5	11.5	11.5	34.6
Sensitivity – low market	0	0	7.8	7.8	7.8	23.3
Sensitivity – high delivery	0	0	14.5	14.5	14.5	43.4
Sensitivity – low delivery	0	0	0	4.8	4.8	9.7

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.

The total benefits for build the future balancing service and wholesale markets are between £35 million and £158 million, with a central case of £106 million over the RIIO-2 period.

3.1.3 Activity costs

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

Table 52: Incremental costs for build the future balancing service and wholesale markets

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	36.7

The total costs for build the future balancing service and wholesale markets are £36.7 million.

3.1.4 Net Present Value

The net present value of 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 £87 million and £47 million
- Delivery factors between £115 million and £3 million

3.1.5 Dependencies, enablers and whole energy system

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

1. Control centre architecture and systems (Theme 1) – Ensuing the control centre has the tools required to dispatch new players in the reserve and response markets.
2. 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:

1. Taking a whole electricity system approach to promote zero-carbon operability (Theme 4).
2. Transforming access to the capacity market (Theme 2).
3. *NOA* enhancements (Theme 3).

4. 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 summarise the key risks and how we propose to mitigate them.

Table 53: Risks for build the future balancing service and wholesale markets

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

3.2 Lead a review of wholesale, balancing and capacity markets

This sub-section provides further context on the breakeven analysis we have conducted on 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 lead a review of wholesale, balancing and capacity markets is we do not undertake a review.

3.2.3 Activity costs

Table 54: Incremental cost for lead a review of wholesale, balancing and capacity markets

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	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

In addition to the above 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:

Table 55: Risks for lead a review of wholesale, balancing and capacity markets

Risk	Mitigations	Likelihood	Impact
Industry does not engage with the process, leading to a sub-optimal market design. There will also be overlap potential which will need to be co-ordinated, 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
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

3.2.5 Benefits

The quantitative benefits of a targeted review of a 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 efficiently 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 decarbonisation and so reduced carbon 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 but 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 Transform access to the Capacity Market

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

The net present value of transform access to the Capacity Market is estimated at £62 million over the RIIO-2 period, and £129 million over ten years. Sensitivity analysis suggests an NPV range of £94 million to £22 million over the RIIO-2 period.

3.3.1 The counterfactual

If we did not undertake Transform access to the Capacity Market would leave us with only ongoing modelling capability and only incremental improvements in our capability.

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

Table 56: Enhanced modelling capability assumptions

Assumptions	Justification
Clearing price of the Capacity Market is £17.08 /kW per year.	Average of last four T-4 auctions
Our actions deliver a 1 GW saving in capacity purchased	This saving is equivalent to approximately two percent of the average volume purchased in the last four T-4 auctions, comparable with EMR demand forecasting incentives as a benchmark[15]
Benefits delivered from year two of RIIO-2	This allows a year for implementation, given auction timings.

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 give a more accurate balance. In turn, this will ensure security of supply at the most efficient cost.

Enhanced data and modelling capability will reduce sensitivities in the forecasting process. 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 reduction in required capacity will benefit the consumer by ensuring security of supply at the best possible cost

In our modelling, **we have assumed that we save consumers the equivalent purchase cost of 1 GW of capacity.** Any capacity saving is hard to accurately forecast, given the complexity of how the final auction price is arrived at. This saving is equivalent to approximately two percent of the average volume purchased in the last four T-4

[15] 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

auctions (see table below). This is comparable with EMR demand forecasting incentives as a benchmark.

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.
- 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.

Table 57: Capacity Market auction data

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	46.353	18,000,000
2018/19	19.4	49.258	19,400,000
Average	**17.075**	**49.613**	**17,075,000**

Table 58: Benefits for enhanced modelling capability

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Enhanced modelling capability	0	17.1	17.1	17.1	17.1	68.3
Sensitivity – high market	0	22.3	22.3	22.3	22.3	89.4
Sensitivity – low market	0	11.8	11.8	11.8	11.8	47.2
Sensitivity – high delivery	0	25.6	25.6	25.6	25.6	102.5
Sensitivity – low delivery	0	0	8.5	8.5	8.5	25.6

The above table table shows the benefits from enhanced modelling capability are between £47.2 million and £102.5 million, with a central case of £68.3 million over the RIIO-2 period.

3.3.2.2 Reduced barriers to entry and cost of participation

Table 59: Reduced barriers to entry and cost of participation assumptions

Assumptions	Justification
400 companies entering the Capacity Market auction.	Seen in the CM register
Our actions save two FTE weeks of time from each Capacity Market company	Mirroring ESO commitments
Benefits delivered from year two of RIIO-2	This allows a year for implementation, given auction timings.

We will remove 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 saving 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** (as seen in the CM register[16]) **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.

Table 60:Benefit calculation for educed barriers to entry and cost of participation

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

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

Table 61: Benefits for educed barriers to entry and cost of participation

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Enhanced modelling capability	0	1.5	1.5	1.5	1.5	6.2
Sensitivity – high market	0	1.9	1.9	1.9	1.9	7.7
Sensitivity – low market	0	1.2	1.2	1.2	1.2	4.6
Sensitivity – low delivery	0	0	1.5	1.5	1.5	4.6
Sensitivity – high third party	0	2.3	2.3	2.3	2.3	9.2
Sensitivity – low third party	0	0.8	0.8	0.8	0.8	3.1

The above table shows the benefits from this activity are between £9.7 million and £43.4 million, with a central case of £29.0 million over the RIIO-2 period.

The total benefits for transform access to the Capacity Market are between £29 million and £112 million, with a central case of £74 million over the RIIO-2 period

3.3.3 Activity costs

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

Table 62: Incremental costs for transform access to the Capacity Market

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	1.0	0.8	0.8	0.9	0.9	4.4
Total	2.3	1.7	1.7	1.7	1.8	9.1

The total costs for transform access to the Capacity Market are £9.1 million.

3.3.4 Net Present Value

The net present value of *Transform access to the Capacity Market* is estimated at £62 million over the RIIO-2 period and £129 million over ten years will start to deliver positive returns from 2022/23. Sensitivity analysis suggests an NPV range of:

- Market factors between £83 million and £42 million
- Delivery factors between £94 million and £22 million

- Third Party factors between £65 million and £60 million

3.3.5 Dependencies, enablers and whole energy system

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

1. Build the future balancing service and wholesale markets (Theme 2) – Sharing the single market platform.

Delivering this activity depends on full engagement with the new 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 summarise the key risks to delivering our activities and how we propose to mitigate them.

Table 63: Risks for transform access to the Capacity Market

Risk	Mitigations	Likelihood	Impact
The current ringfence around the EMR function limits the scope for efficiencies from increased co-ordination of rule development and data sharing across the ESO	Ofgem is already consulting 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, that removing the additional EMR ringfence will 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 implementation across Europe and to maintain availability of consistent data sources or modelling.	2	4

3.4 Transform the process to amend our codes

This sub-section provides further context on the break-even analysis we have conducted on 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 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

Table 64: Incremental costs for Transform the process to amend our codes

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	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

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

The key risks are:

Table 65: Risks for transform the process to amend our codes

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 a leadership 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 a leadership role in the Energy Codes Review. Engage Ofgem and BEIS to highlight the legislative changes required for our future role	3	4

3.4.5 Benefits

The quantitative benefits of a targeted review of ad a review of 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 which customers are involved in it and codes more generally with change with the most expected benefits being easily prioritised. Newer and smaller providers are now 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 and a better critical friend, etc.
- There will be minor consequential benefits to the environment as a result of these changes e.g. more efficient codes contribute to more efficient decarbonisation

3.4.6 Conclusion

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

- Overall process efficiency for ESO and Industry e.g. fewer meetings, more focused discussions etc., these efficiencies are likely to be realised year-on-year, by the average number of codes modifications which the ESO facilities a year[17]. 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 deliver one year earlier.

3.5 Work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025

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

The net present value of work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025is £1 million over the RIIO-2 period and £14 million over ten years. Sensitivity analysis suggests an NPV range of £4 million to negative £3 million over the RIIO-2 period.

3.5.1 The counterfactual

If we did not undertake work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025we 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 part experience.

3.5.2 The Benefits

Table 66: Work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025 assumptions

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

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

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

improvements will also aid new smaller entrants, as well as 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 500 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: 600 and 400 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.

Table 67: Benefit calculation work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025

Number of parties interacting with the whole system Grid Code		Annual cost of an FTE £s		One month		Annual saving £ million
500	x	100,000	÷	12	=	4.2

Table 68: Benefits for work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025

Benefits £ million	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Digitised Grid Code	0	0	0	2.1	4.2	6.3
Sensitivity – high market	0	0	0	2.5	5.0	7.5
Sensitivity – low market	0	0	0	1.7	3.3	5.0
Sensitivity – low delivery	0	0	0	0	2.1	2.1
Sensitivity – high third party	0	0	0	3.1	6.3	9.4

Sensitivity – low third party	0	0	0	1.0	2.1	3.1

The total benefits for work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025 are between £9.4 million and £3.1 million, with a central case of £6.3 million over the RIIO-2 period

3.5.3 Activity Costs

Delivery of work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025 will require additional capex and opex spend, summarised below:

Table 69: Incremental costs work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025

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

The total costs for work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025 are £6.1 million.

3.5.4 Net Present Value

The NPV of work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025is estimated at £1 million over the RIIO-2 period and £14 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 £0 million
- Delivery factors between £1 million and negative £3 million
- Third Party factors between £4 million and negative £2 million

3.5.5 Dependencies, enablers and whole energy system

Work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025 is dependent on the following transformational activity:

1. Transform the process to amend our codes (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 this 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 summarise the key risks and how we propose to mitigate them.

Table 70: Risks for work with all stakeholders to create a fully-digitised, whole-system Grid Code by 2025

Risk	Mitigations	Likelihood	Impact
Identifying the appropriate business capabilities and resource	Targeted use of consultants	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 a leadership role in the energy codes review. Engage Ofgem and BEIS to highlight the legislative changes required to enable our future role	3	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

3.6 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 Fully or partially fixing Balancing Services Use of System (BSUoS).

The net present value of look at fully or partially fixing one or more components of 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 £730 million to £206 million over the RIIO-2 period.

3.6.1 The counterfactual

If we did not undertake look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges the BSUoS arrangements will remain unchanged and the BSUoS price will continue to be set after the event, with only incremental improvements in our capability.

3.6.2 The Benefits

Table 71: Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges assumptions

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

The benefits of this activity are 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[18] 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.

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:

[18] 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

Table 72: Benefits for look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Fully or partially fixing BSUoS benefits	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

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

3.6.3 Activity costs

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 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 higher estimate of costs of £7.4 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 10

Table 73: Incremental costs for look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Other costs ESO funding arrangements estimates	0	4.8	4.8	4.8	4.8	19.2
Sensitivity – high market	0	2.2	2.2	2.2	2.2	8.8
Sensitivity – low market	0	7.4	7.4	7.4	7.4	29.6

The total costs for 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 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. Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges will start to deliver positive returns from 2022/23. Sensitivity analysis suggests an NPV range of:

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

Table 74. Risks for look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges

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 the defect and the proposal align with 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

3.7 Cost summary

This table summarises the total costs of Theme 2.

Description	Business plan location	Type	RIIO-1	2021/22	2022/23	2023/24	2024/25	2025/26	2 year average	2 year total
Transformational Activity subject to CBA	Annex 2 - 3.1.3	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 subject to breakeven analysis		OPEX	-	-	-	1.2	2.5	0.4	-	-
		CAPEX	-	-	-	-	-	-	-	-
Ongoing Activities		OPEX	3.0	3.8	3.8	3.8	3.7	3.6	3.8	7.5
		IS OPEX	-	1.5	0.3	0.4	0.4	0.4	0.9	1.9
		CAPEX	1.1	2.2	0.2	0.1	0.2	0.2	1.2	2.4
Build the future balancing service and wholesale markets Ref BP Theme 2 chapter	**5.2.1**	**OPEX**	**3.0**	**11.8**	**9.7**	**11.1**	**10.4**	**8.5**	**10.7**	**21.5**
		CAPEX	**1.1**	**5.3**	**3.3**	**2.3**	**1.4**	**1.5**	**4.3**	**8.6**
Transformational Activity subject to CBA	Annex 2 - 3.3.3	OPEX	-	1.0	0.8	0.8	0.9	0.9	0.9	1.8
		CAPEX	-	1.2	0.9	0.9	0.9	0.9	1.1	2.1
Ongoing Activities		OPEX	3.0	3.4	3.3	3.3	3.0	2.9	3.3	6.6
		IS OPEX	-	0.8	0.6	0.6	0.6	0.6	0.7	1.4
		CAPEX	4.6	-	-	-	-	-	-	-
Transform access to the Capacity Market Ref BP Theme 2 chapter	**5.3.1**	**OPEX**	**3.0**	**5.2**	**4.7**	**4.7**	**4.4**	**4.4**	**4.9**	**9.9**
		CAPEX	**4.6**	**1.2**	**0.9**	**0.9**	**0.9**	**0.9**	**1.1**	**2.1**
Transformational Activity subject to CBA	Annex 2 - 3.5.3	OPEX	-	-	1.1	1.3	1.7	0.4	0.6	1.1
		CAPEX	-	-	-	0.3	0.8	0.5	-	-
Transformational subject to breakeven analysis	Annex 2 - 3.4.3	OPEX	-	0.5	1.5	1.7	1.9	2.1	1.0	2.0
		CAPEX	-	-	-	-	-	-	-	-
Ongoing Activities		OPEX	7.1	8.5	8.5	8.6	8.6	8.6	8.5	17.1
		IS OPEX	-	5.4	2.6	2.9	3.2	5.6	4.0	8.0
		CAPEX	8.9	12.9	10.3	10.2	10.6	10.5	11.6	23.3
Develop code and charging arrangements that are fit for the future	**5.4.1**	**OPEX**	**7.1**	**14.5**	**13.7**	**14.6**	**15.4**	**16.7**	**14.1**	**28.2**
		CAPEX	**8.9**	**12.9**	**10.3**	**10.5**	**11.4**	**10.9**	**11.6**	**23.3**
Theme 2 Total On CBA	**Annex 1 - Table 2**	**Opex**	**-**	**7.5**	**7.5**	**7.9**	**6.4**	**5.4**	**7.5**	**15.0**
		Capex	**-**	**4.4**	**4.0**	**3.4**	**2.9**	**2.6**	**4.2**	**8.3**
Theme 2 Total Ongoing activites and transformational activities subject to breakeven analysis		**Opex**	**13.1**	**16.2**	**17.1**	**18.7**	**19.7**	**17.7**	**16.6**	**33.2**
		IS Opex	**-**	**7.8**	**3.5**	**3.8**	**4.1**	**6.5**	**5.7**	**11.3**
		Capex	**14.6**	**15.1**	**10.5**	**10.2**	**10.8**	**10.6**	**12.8**	**56.9**
Theme 2 Total	**5.1.4 - Fig. 23**	**Opex**	**13.1**	**31.5**	**28.1**	**30.3**	**30.2**	**29.7**	**29.8**	**59.5**
		Capex	**14.6**	**19.5**	**14.5**	**13.6**	**13.7**	**13.3**	**17.0**	**34.0**
		TOTEX	**27.7**	**51.0**	**42.5**	**43.9**	**43.9**	**42.9**	**46.8**	**93.5**

4. Cost-benefit analysis: Theme 3

This section provides further context on the costs and benefits of Theme 3's transformational activities:

Table 75: Theme 3 activities

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

The net present value of 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 £462 million to £906 million over the RIIO-2 period.

4.1 *Network Options Assessment* (*NOA*) enhancements

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

The net-present value of our *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 £462 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 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*

Table 76: Facilitate competition by embedding pathfinding projects into the NOA assumptions

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*

This activity takes learnings and processes from the ESO 2019/2021 *Forward Plan* and embed 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.

Table 77: Benefits for Facilitate competition by embedding pathfinding projects into the NOA

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Consumer benefit of implementing commercial solutions (£ million)	127.5	60.8	95.9	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	95.9	81.1	64.4	301.3

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

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

Table 78: Extending NOA to end of life asset replacement decisions assumptions

Assumption	Justification
TOs will provide asset replacement data	TOs already have appropriate funding and resourcing due to existing *NOA* commitments. Incentive framework should reward them for delivering more value
TOs would build asset	Reasonable assumption given such a process does not currently exist

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 there were 25%overhead line (OHL) related. Assets are only considered for replacement when their life expires in the next five years, based on TO risk factors. So only 12.5% (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 back-end 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.

Table 79: Benefits for extending NOA to end of life asset replacement decisions

Benefits £ millions	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Extending *NOA* to end of life asset replacement decisions	0	0	29.5	29.5	59	118
Sensitivity – high market factors	0	0	29.5	59	59	147.5
Sensitivity – low market factors	0	0	29.5	29.5	29.5	88.5
Sensitivity – low delivery confidence	0	0	0	29.5	59	88.5

The above table shows the benefits from extending the *NOA* to end-of-life asset replacement is between £88.5 million and £147.5 million, with a central case of £118 million.

4.1.2.3 Extend *NOA* approach to all connections wider works

Table 80: Extend NOA approach to all connections wider works assumptions

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
Issues on the newly-created boundaries. We may find no issues, resulting in no benefits because no actions would be needed	Historic data suggest such options do exist

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 ~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% 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% 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% 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% 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.

Table 81: Benefits for extend NOA approach to all connections wider works

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total

Extend *NOA* approach to all connections wider works (£ million)	0	37.0	37.0	37.0	37.0	148.0
Sensitivity – high market factors	0	53.4	53.4	53.4	53.4	213.6
Sensitivity – low delivery confidence	0	0	37	37	37	111.0

The above table shows the benefits of extending the *NOA* to connections wider works is between £111 million and £213.6 million, with a central case of £148 million.

4.1.2.4 Support decision making for investment at the distribution level

Table 82: Support decision making for investment at the distribution level assumptions

Assumption	Justification
Expected level of investment is £40 million per year	Based on historic data from the *2018/19 Forward Plan*[19]
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

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 it 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 ~60% of all options make it onto the optimal path and can be carried out for the next 12 months. (The 60% 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%in any given area. Applying the 60%to the

[19] https://www.nationalgrideso.com/about-us/business-plans/forward-plans-2021#targetText=It's%20an%20ambitious%20plan%2C%20outlining,for%20April%202018%20%E2%80%93%20March%202019.

£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.

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 line) 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.

Table 83: Benefits support decision making for investment at the distribution level

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Support decision making for investment at the distribution level	0	0	10.0	10.0	10.0	30.0
Sensitivity – high market factors	0	0	16.0	16.0	16.0	48.0
Sensitivity – low market factors	0	0	7.0	7.0	7.0	21.0
Sensitivity – low delivery confidence	0	0	0	10.0	10.0	20.0

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.

The total benefits for *NOA* enhancements are between £520 million and £987 million, with a central case of £724 million over the RIIO-2 period.

4.1.3 Activity Costs

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

Table 84: Incremental costs for NOA enhancements

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	1.0	1.3	1.5	1.2	1.1	6.1
Total	4.0	4.4	4.7	2.8	2.3	18.2

The total costs for our *NOA enhancements* activities are £18.2 million.

4.1.4 Net Present Value

The NPV of *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 £906 million and £488 million
- Delivery factors between £663 million and negative £462 million

4.1.5 Dependencies, enablers and whole energy system

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

1. Build the future balancing service and wholesale markets (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.

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

Table 85: Risks facilitate competition by embedding pathfinding projects into the NOA

Risk	Mitigations	Likelihood	Impact
Increasing constraints costs or compliance issues from delayed	We will develop streamlined processes that minimise delays. The cost of any unavoidable	4	3

network investment due to competition	delays will be factored into our final CBA		
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	4	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

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

Table 86: Risks 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

4.1.6.3 Support decision making for investment at the distribution level

Table 87: Risk 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	4	2

4.2 Undertake with industry a review of the 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

Table 88: Incremental cost for undertake with industry a review of the SQSS

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	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

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:

Table 89: Incremental cost for undertake with industry a review of the SQSS

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
TOs would resource as part of a joint team	Regulatory arrangements incentivise TOs to undertake work to deliver consumer benefit

Table 90: Risks for 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

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.

4.3 Cost summary

This table summarises the total costs of Theme 3.

Description	Business plan location	Type	RIIO-1	2021/22	2022/23	2023/24	2024/25	2025/26	2 year average	2 year total
Transformational Activity subject to CBA	Annex 2 - 4.1.3	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
Ongoing Activities		OPEX	1.7	2.4	2.4	2.4	2.4	2.4	2.4	4.9
		IS OPEX	-	-	-	-	-	-	-	-
		CAPEX	-	-	-	-	-	-	-	-
Network Development Ref BP Theme 3 chapter	**6.2.1**	**OPEX**	**1.7**	**3.3**	**3.7**	**3.9**	**3.7**	**3.5**	**3.5**	**7.0**
		CAPEX	**-**	**3.0**	**3.0**	**3.2**	**1.6**	**1.2**	**3.0**	**6.1**
Transformational subject to breakeven analysis	Annex 2 - 4.2.3	OPEX	-	0.2	0.3	0.3	0.2	0.1	0.2	0.4
		CAPEX	-	-	-	-	-	-	-	-
SQSS Ref BP Theme 3 chapter	**6.3.**	**OPEX**	**-**	**0.2**	**0.3**	**0.3**	**0.2**	**0.1**	**0.2**	**0.4**
		CAPEX	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transformational subject to breakeven analysis		OPEX	-	0.1	0.1	0.1	0.1	0.1	0.1	0.2
		CAPEX	-	-	-	-	-	-	-	-
Ongoing Activities		OPEX	-	-	-	-	-	-	-	-
		IS OPEX	-	0.0	0.0	0.0	0.0	0.0	0.0	0.1
		CAPEX	-	0.3	0.2	-	-	-	0.2	0.5
CATO Ref BP Theme 3 chapter		**OPEX**	**-**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**
		CAPEX	**-**	**0.3**	**0.2**	**-**	**-**	**-**	**0.2**	**0.5**
Theme 3 Total On CBA	**Annex 1 - Table 2**	**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**
Theme 3 Total Ongoing activites and transformational activities subject to breakeven analysis		**Opex**	**1.7**	**2.7**	**2.8**	**2.8**	**2.7**	**2.6**	**2.7**	**5.5**
		IS Opex	**-**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**
		Capex	**-**	**0.3**	**0.2**	**-**	**-**	**-**	**0.2**	**5.3**
Theme 3 Total	**6.1.2 - Fig. 27**	**Opex**	**1.7**	**3.6**	**4.1**	**4.2**	**3.9**	**3.7**	**3.9**	**7.7**
		Capex	**-**	**3.3**	**3.2**	**3.2**	**1.6**	**1.2**	**3.3**	**6.5**
		TOTEX	**1.7**	**6.9**	**7.3**	**7.4**	**5.5**	**4.9**	**7.1**	**14.3**

5. Cost-benefit analysis: Theme 4

This section provides further context on the costs and quantifiable benefits of Theme 4's transformational activities:

Table 91: Theme 4 activities

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

The net present value of Theme 4 is £676 million over the RIIO-2 period and £1.4 billion over ten years. Sensitivity analysis suggests an NPV range of £927 million to £429 million over the RIIO-2 period.

5.1 Lead the debate

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

5.1.1 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 because lead 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 Lead the debate is continuing with our current publications

5.1.3 Activity costs

Table 92: Incremental costs for lead the debate

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0	0	0	0	0	0
Opex	1.6	1.7	1.8	1.9	1.7	8.7
Total	1.6	1.7	1.8	1.9	1.7	8.7

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5.1.4 Assumptions, uncertainties and risks

The key risks have been identified:

Table 93: Risks for lead the debate

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 'lead the debate' area	2	2

5.1.5 Benefits

The qualitative benefits are:

- Enable more informed decision making by industry on key areas of GB'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 develop their regional *FES* type analysis
- Increase consumer engagement through sharing of information on the energy transition and the potential implications for them

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; set a clear direction and make policy recommendations to key decision and policy makers, that deliver the best outcomes for consumers.

5.2 Taking a whole electricity system approach to connections

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

The net present value of 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 £3 million to negative £2 million over the RIIO-2 period.

5.2.1 The counterfactual

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

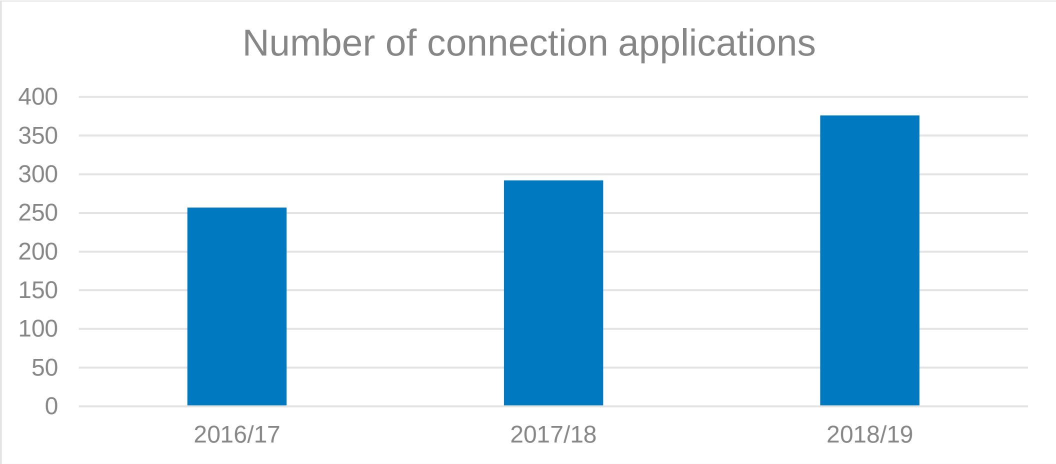
5.2.2 The benefits

Table 94: Taking a whole electricity system approach to connections assumptions

Assumptions	Justification
The number of connection applications grows 8 percent per year	Slowing from today's ~20 percent based on historic observations
Roll-out of our secure on-line account management facility in April 2025 brings a 30 percent saving	Based on IT investment delivery
Information across the transmission-distribution interface will reduce our direct resource requirements by 10 percent from 2022	Based on IT investment delivery

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% 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 and independent DNOs

Figure 4: Number of connection applications



Both 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 percent today to around 8 percent per year:**

Table 95: Forecast number of connection applications

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

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

We estimate a reduction in our direct resource requirements of five percent delivered from April 2022. An additional 5% will be delivered in April 2022 with capacity information across the transmission-distribution interface. Roll-out of our secure online account management facility in April 2025 will deliver an additional 30% 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 - 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 percent a year and 0 percent a year respectively.
- Delivery factors: we have also modelled a one-year delay in delivery for the low case, from 2022/23

Table 96: Benefits for Taking a whole electricity system approach to connections

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
ESO efficiency saving	0.2	0.2	0.3	0.6	2.3	3.5

Sensitivity – low delivery	0	0.2	0.2	0.3	0.6	1.2
Customer efficiency savings	0.4	0.5	0.8	0.8	2.1	4.6
Sensitivity – high market	0.4	0.5	0.9	1.0	2.8	5.6
Sensitivity – low market	0.4	0.4	0.7	0.6	1.5	3.7
Sensitivity – low delivery	0	0.4	0.5	0.8	0.8	2.5

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

5.2.3 Activity Costs

Delivery of Closer ways of working with other network organisations to streamline the connection process for smaller players will require additional capex and opex spend, summarised below:

Table 97: Incremental costs taking a whole electricity system approach to connections

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

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

5.2.4 Net Present Value

The net present value of 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 2023/24. Sensitivity analysis suggests an NPV range of:

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

5.2.5 Dependencies, enablers and whole energy system

To deliver 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 summarise the key risks and how we propose to mitigate them.

Table 98: Risks for taking a whole electricity system approach to connections

Risk	Mitigations	Likelihood	Impact
There are many industry initiatives to develop connections portals simultaneously and this is an inefficient and uncoordinated approach (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 providing feedback to TOs' 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)	2	1
There are many industry initiatives to develop connections portals simultaneously and this is an inefficient and uncoordinated approach (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 providing feedback to TOs' business plans	2	1

5.3 Taking a whole electricity system approach to promote zero-carbon operability

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

The net present value of taking a whole electricity system approach to promote zero-carbon operability for zero-carbon whole system operability is £469 million over the RIIO-2 period and £949 million over ten years. Sensitivity analysis suggests an NPV range of £608 million to £333 million over the RIIO-2 period.

5.3.1 The counterfactual

If we did not undertake taking a whole electricity system approach to promote zero-carbon operability for zero-carbon whole system operability we would not undertake additional regional development plans, 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 two areas:

- Whole system operability *NOA*-type assessment
- Regional Development Plans (RDP)

5.3.2.1 Whole system operability *NOA*-type assessment

Table 99: Whole system operability NOA-type assessment assumptions

Assumptions	Justification
Forecast operability costs of £596 million per year	*NOA* assessment of future operability challenges
Cost of a 0.2 Giga Volt Ampere (GVA) solution costs £25 million	Current build solution costs
Solutions last 40 years	Current build solution lifetimes

The benefits have been calculated by complete high-level power system analysis[20] to determine the network operability requirements. We 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:

Since July 2019 further, more detailed analysis gives us greater understanding of the size of the operability challenge.

This has shown that nine GVA of fault infeed would help to address operability issues in Scotland; this can be extrapolated to be 18 GVA to address issues in England & Wales.

We assume that a current build solution to address these 18 GVA needs costs £25 million for 0.2 GVA of fault infeed, giving a total cost of £2.25 billion. We envisage innovative, or short--term, solutions can provide this 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.

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
- It will alleviate the need to spend £596 million per year

[20] 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

The net cost of this works out as a £10.06 billion net positive benefit after discounting the costs over 40 years under HMT's Green Book guidance on discounting.

As the forecast benefit will be achieved over a 40-year period, but enabled throughout the RIIO 2 period, we divided the benefit by 40 to provide £251 million per year:

Table 100: Whole system operability NOA-type assessment annual benefit calculation

40-year net benefit £ billion		Savings per year		Annual net benefit £ million
10.06	÷	40	=	251

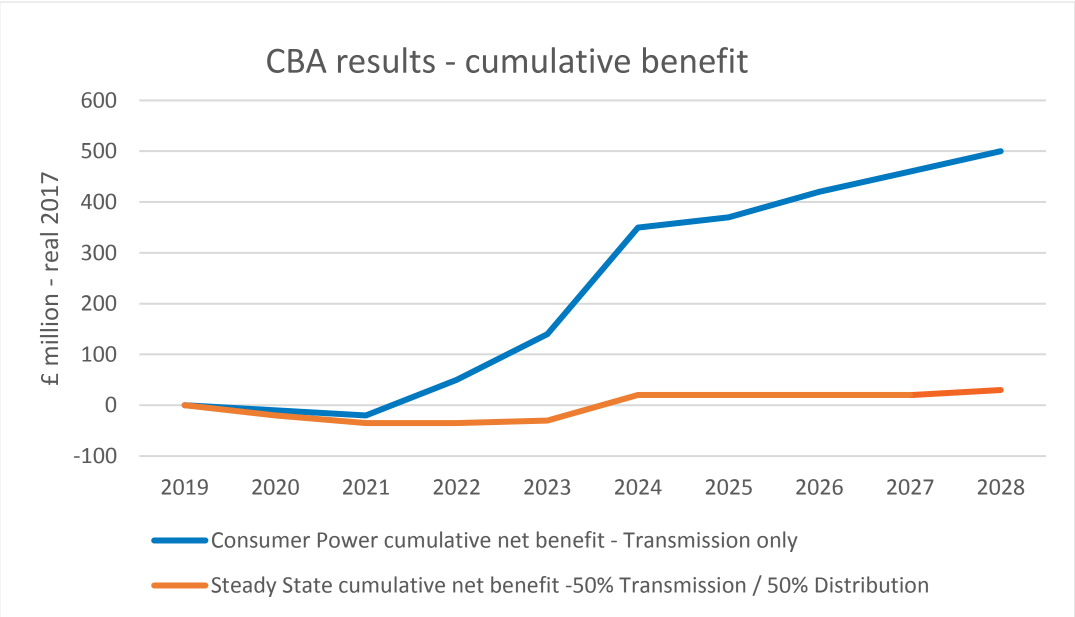
As forecasting operability costs is challenging and uncertain, we have built in a 50% contingency to achieve £125.5 million per year or £627.5 million over the RIIO 2 period

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.

As the benefits are large, we also benchmarked this by considering the EFCC innovation project[21] which forecast benefits of £420 million over the RIIO-2 period for improving a single aspect of system operability (see figure below):

Figure 5: EFCC innovation project example benchmarking



[21] https://www.nationalgrideso.com/document/142876/download

Table 101: Benefits for whole system operability NOA-type assessment market

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Operability savings	0	125.8	125.8	125.8	125.8	503
Sensitivity – high market	0	149.0	149.0	149.0	149.0	596
Sensitivity – low market	0	102.5	102.5	102.5	102.5	410
Sensitivity – low delivery	0	0	125.8	125.8	125.8	377
Sensitivity – high third party	0	120.5	120.5	120.5	120.5	482
Sensitivity – low third party	0	131.0	131.0	131.0	131.0	524

5.3.2.2 Benefits of Regional Development Plans (RDPs)

Table 102: Benefits of Regional Development Plans (RDPs) assumptions

Assumptions	Justification
Value of RDP avoided asset build £12.9 million	Based on previous RDP delivery
Additional renewable capacity of RDP 278 MW	Based on previous RDP delivery
Six RDP 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

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. **We assumed this value of £13 million along** with the value of our second completed RDP to forecast future RDP benefits[22].

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

[22] https://www.nationalgrideso.com/insights/whole-electricity-system/regional-development-programmes

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 GWh**[23] 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 Plans (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.

Table 103: RDP profile

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
sensitivity – low delivery - asset saving	0	0	0	1	1	2

Table 104:Carbon savings from RDP

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total

[23] 278MW of carbon free generation with an estimated load factor of 40%

Carbon intensity Two Degrees gCO2/kWh	146.72	143.63	148.28	137.06	130.75	
	x	x	x	x	x	
Carbon generation reduction GWh	974	974	974	974	974	
Carbon generation reduction GWh - Sensitivity – high market	1948	1948	1948	1948	1948	
Carbon generation reduction GWh - Sensitivity – low market	487	487	487	487	487	
	=	=	=	=	=	
Thousand tonnes of carbon saved	143	140	144	133	127	
Thousand tonnes of carbon saved - Sensitivity – high market	286	280	289	267	255	
Thousand tonnes of carbon saved - Sensitivity – low market	71	70	72	67	64	
	x	x	x	x	x	
Carbon price £/tCO2e	14.56	15.11	15.68	16.28	17.70	
Carbon price £/tCO2e GWh - Sensitivity – high market	29.38	30.50	31.66	33.26	37.35	
Carbon price £/tCO2e GWh - Sensitivity – low market	-	-	-	0.54	2.39	
	=	=	=	=	=	
Saving £ million	No RDP	No RDP	2.3	2.2	2.5	7.0
Saving £ million - Sensitivity – high market	No RDP	No RDP	9.1	8.9	9.5	27.5
Saving £ million - Sensitivity – low market	No RDP	No RDP	0	0.0	0.2	0.2

Saving £ million - Sensitivity – low Delivery	No RDP	No RDP	No RDP	2.2	2.5	4.3

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.

Table 105: Incremental benefits for RDPs

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

The total benefits taking a whole electricity system approach to promote zero-carbon operability are between £403 million and £673 million, with a central case of £549 million over the RIIO-2 period.

5.2.3 Activity Costs

Delivery of taking a whole electricity system approach to promote zero-carbon operability will require additional capex and opex spend, summarised below:

Table 106: Incremental costs for taking a whole electricity system approach to promote zero-carbon operability

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	1.6	2.6	4.4	6.2	7.5	22.3
Total	9.7	11.8	15.3	17.5	20.5	74.8

The total costs for taking a whole electricity system approach to promote zero-carbon operability for zero-carbon whole system operability are £74.8 million.

5.2.4 Net Present Value

The net present value of taking a whole electricity system approach to promote zero-carbon operability is estimated at £469 million over the RIIO-2 period and £949 million over ten years, which will start to deliver positive returns from 2023/24. Sensitivity analysis suggests an NPV range of:

- Market factors between £608 million and £366 million
- Delivery factors between £469 million and £333 million
- Third party factors between £488 million and £450 million

5.2.5 New Dependencies, enablers and whole energy system

Taking a whole electricity system approach to promote zero-carbon operability depends on two other transformational activities:

1. Build the future balancing service and wholesale markets (Theme 2) - ensuing the new markets have been developed to support zero-carbon system operation
2. Control centre architecture and systems (Theme 1) – ensuing the control has the tools to operate a zero-carbon system

Delivering this activity requires third parties to deliver solutions, either through investment in assets or commercial solutions

5.2.6 Uncertainties and risks

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

The table below summarise the key risks and how we propose to mitigate them.

Table 107: Risks for taking a whole electricity system approach to promote zero-carbon operability

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 2019/21 ESO *Forward Plan*	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

5.4 Delivering consumer benefits from improved network access planning

This sub-section provides further context on the costs and benefits of our activity delivering consumer benefits from improved network access planning.

The net present value of transforming participation in balancing and capacity markets is £205 million over the RIIO-2 period and £420 million over ten years. Sensitivity analysis suggests an NPV range of £310 million to £98 million over the RIIO-2 period.

5.4.1 The counterfactual

If we did not undertake delivering consumer benefits from improved network access planning, we would not roll out Network Access Policy (NAP) to England and Wales. Instead we would continue with our ongoing system access process, with only incremental improvements in our capability.

5.4.2 The benefits

Table 108: Delivering consumer benefits from improved network access planning assumptions

Assumptions	Justification
The same proportion (between 7 percent and 16 percent) of benefits could be realised in England & Wales as has been seen in Scotland	Observed result from Scotland and power system knowledge
England and Wales constraint costs (see table below)	From *NOA* model run

The benefits that will be delivered are through rolling out the NAP 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 percent and 16 percent reduction in costs. Our power system knowledge infers a 50:50 split in complexity for outage planning between England & Wales (E&W) and Scotland, so we have **assumed same proportion of benefits could be realised in England & Wales.** For rolling out the NAP to England & Wales we have assumed the mid-range estimate of 11.5 percent.

We have used the *NOA* process to forecast constraints costs based on the 18/19 outturn numbers.

Sensitivity analysis - 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 percent and 7 percent 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 section 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.

Table 109: England and Wales forecast constraint costs

Forecast constraint costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26
Estimated E&W 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 110: Benefit calculation for England and Wales forecast constraint costs NAP savings

	2021/22	2022/23	2023/24	2024/25	2025/26
Estimated E&W 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
7 percent 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

This has provided the following forecast benefit, which start being delivered from 2021/22:

Table 111:Benefits for delivering consumer benefits from improved network access planning

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Consumer savings based expanding the process into E&W with a 7% reduction.	40.4	36.3	41.7	49.2	56.7	224
Sensitivity – high market	50.7	58.4	68.3	74.4	86.6	338

Sensitivity – low market	29.3	26.3	29.0	34.0	33.0	152
Sensitivity – high delivery	56.2	50.6	58.1	68.5	78.9	312
Sensitivity – low delivery	0	22.1	25.4	30.0	34.5	112

The total benefits for delivering consumer benefits from improved network access are between £112 million and £339 million, with a central case of £224 million over the RIIO-2 period.

5.4.3 Activity Costs

Delivery of *A whole system approach to accessing networks* will require additional capex and opex spend, summarised below:

Table 112: Incremental costs for delivering consumer benefits from improved network access planning

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

The total costs for delivering consumer benefits from improved network access planning are £7.8 million.

5.4.4 Net Present Value

The net present value of delivering consumer benefits from improved network access planning is estimated at £205 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 £310 million and £138 million
- Delivery factors between £286 million and £98 million

5.4.5 Dependencies, enablers and whole energy system

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.

Table 113: Risks delivering consumer benefits from improved network access planning

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. Closer coordination with our IT developers and build in an agile way Deep understanding of stakeholder needs	2	1
Insufficient coordination to deliver efficient procurement of services from DER to meet the needs of both NGESO and DNOs	Ensure strong links with relevant activities under Theme 2 Close coordination through RDP partner DNOs Strong links with Open Networks to share learning Proportionate engagement with DER community	3	2

5.5 Cost summary

This table summarises the total costs of Theme 4.

Description	Business plan location	Type	RIIO-1	2021/22	2022/23	2023/24	2024/25	2025/26	2 year average	2 year total
Transformational subject to breakeven analysis	Annex 2 - 5.1.3	OPEX	-	1.6	1.7	1.8	1.9	1.7	1.7	3.3
		CAPEX	-	-	-	-	-	-	-	-
Ongoing Activities		OPEX	2.2	2.5	2.5	2.5	2.5	2.5	2.5	5.0
		IS OPEX	-	-	-	-	-	-	-	-
		CAPEX	-	-	-	-	-	-	-	-
Leading the debate Ref BP Theme 4 chapter	**7.2.1**	**OPEX**	**2.2**	**4.1**	**4.2**	**4.3**	**4.4**	**4.1**	**4.2**	**8.3**
		CAPEX	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Transformational Activity subject to CBA	Annex 2- 5.2.3	OPEX	-	1.0	1.0	0.8	0.9	0.9	1.0	2.0
		CAPEX	-	0.7	0.7	0.2	0.1	0.1	0.7	1.4
Ongoing Activities		OPEX	3.2	3.3	3.3	3.3	3.3	3.3	3.3	6.6
		IS OPEX	-	-	-	-	-	-	-	-
		CAPEX	-	-	-	-	-	-	-	-
Whole system approach to connections Ref BP Theme 4 chapter	**7.3.1**	**OPEX**	**3.2**	**4.3**	**4.3**	**4.1**	**4.2**	**4.2**	**4.3**	**8.7**
		CAPEX	**-**	**0.7**	**0.7**	**0.2**	**0.1**	**0.1**	**0.7**	**1.4**
Transformational Activity subject to CBA	Annex 2 - 5.2.3	OPEX	-	1.6	2.6	4.4	6.2	7.5	2.1	4.2
		CAPEX	-	8.1	9.1	11.0	11.3	13.0	8.6	17.2
Ongoing Activities		OPEX	3.4	3.3	3.3	3.3	3.3	3.2	3.3	6.7
		IS OPEX	-	-	-	-	-	-	-	-
		CAPEX	2.9	-	-	-	-	-	-	-
Whole electricity system approach to promote zero-carbon operability Ref BP Theme 4 chapter	**7.4.1**	**OPEX**	**3.4**	**4.9**	**6.0**	**7.6**	**9.5**	**10.7**	**5.5**	**10.9**
		CAPEX	**2.9**	**8.1**	**9.1**	**11.0**	**11.3**	**13.0**	**8.6**	**17.2**
Transformational Activity subject to CBA	Annex 2 - 5.4.3	OPEX	-	0.2	0.3	0.8	0.8	0.9	0.2	0.5
		CAPEX	-	0.4	0.4	1.2	1.4	1.4	0.4	0.8
Ongoing Activities		OPEX	4.3	4.5	4.5	4.5	4.5	4.5	4.5	8.9
		IS OPEX	-	0.1	0.1	0.0	0.1 -	0.0	0.1	0.2
		CAPEX	-	-	-	-	-	-	-	-
Delivering consumer benefits from improved network access Ref BP Theme 4 chapter	**7.5.1**	**OPEX**	**4.3**	**4.7**	**4.9**	**5.3**	**5.4**	**5.3**	**4.8**	**9.7**
		CAPEX	**-**	**0.4**	**0.4**	**1.2**	**1.4**	**1.4**	**0.4**	**0.8**
Theme 4 Total On CBA	**Annex 1 - Table 2**	**Opex**	**-**	**2.8**	**4.0**	**5.9**	**7.9**	**9.2**	**3.4**	**6.7**
		Capex	**-**	**9.2**	**10.3**	**12.4**	**12.8**	**14.4**	**9.7**	**19.5**
Theme 4 Total Ongoing activites and transformational activities subject to breakeven analysis		**Opex**	**13.1**	**15.3**	**15.3**	**15.3**	**15.4**	**15.1**	**15.3**	**22.3**
		IS Opex	**-**	**0.1**	**0.1**	**0.0**	**0.1 -**	**0.0**	**0.1**	**0.2**
		Capex	**2.9**	**-**	**-**	**-**	**-**	**-**	**-**	**22.3**
Theme 4 Total	**7.1.2 - Fig. 32**	**Opex**	**13.1**	**18.1**	**19.4**	**21.3**	**23.4**	**24.3**	**18.8**	**37.6**
		Capex	**2.9**	**9.2**	**10.3**	**12.4**	**12.8**	**14.4**	**9.7**	**19.5**
		TOTEX	**16.0**	**27.3**	**29.7**	**33.7**	**36.2**	**38.8**	**28.5**	**57.0**

6. Cost-benefit analysis: 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 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

Table 114: Incremental costs open data

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	1.3	1.3	1.1	0.6	0.0	4.3
Opex	1.8	1.9	1.8	1.6	1.2	8.3
Total	3.1	3.2	2.9	2.2	1.2	12.6

6.4 Assumptions, uncertainties and risks

The key assumptions, uncertainties and risks are:

Table 115: Open data assumptions

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 116: Risks for open data

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 re-designed.	2	3

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.

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 open data have been articulated by the research and

McKinsey Global Institute

Research by the McKinsey Global Institute. suggests that 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, 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 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 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 open data. This provides confidence around our view that the costs of this activity are far outweighed by the potential benefits.

experience shown in the call-out box above which references McKinsey Global Institute[24] and Transport for London (TfL)[25].

In addition, to capture the benefits outlined in the '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.

[24] https://www.mckinsey.com/business-functions/digital-mckinsey/our-insights/open-data-unlocking-innovation-and-performance-with-liquid-information
[25] http://content.tfl.gov.uk/deloitte-report-tfl-open-data.pdf