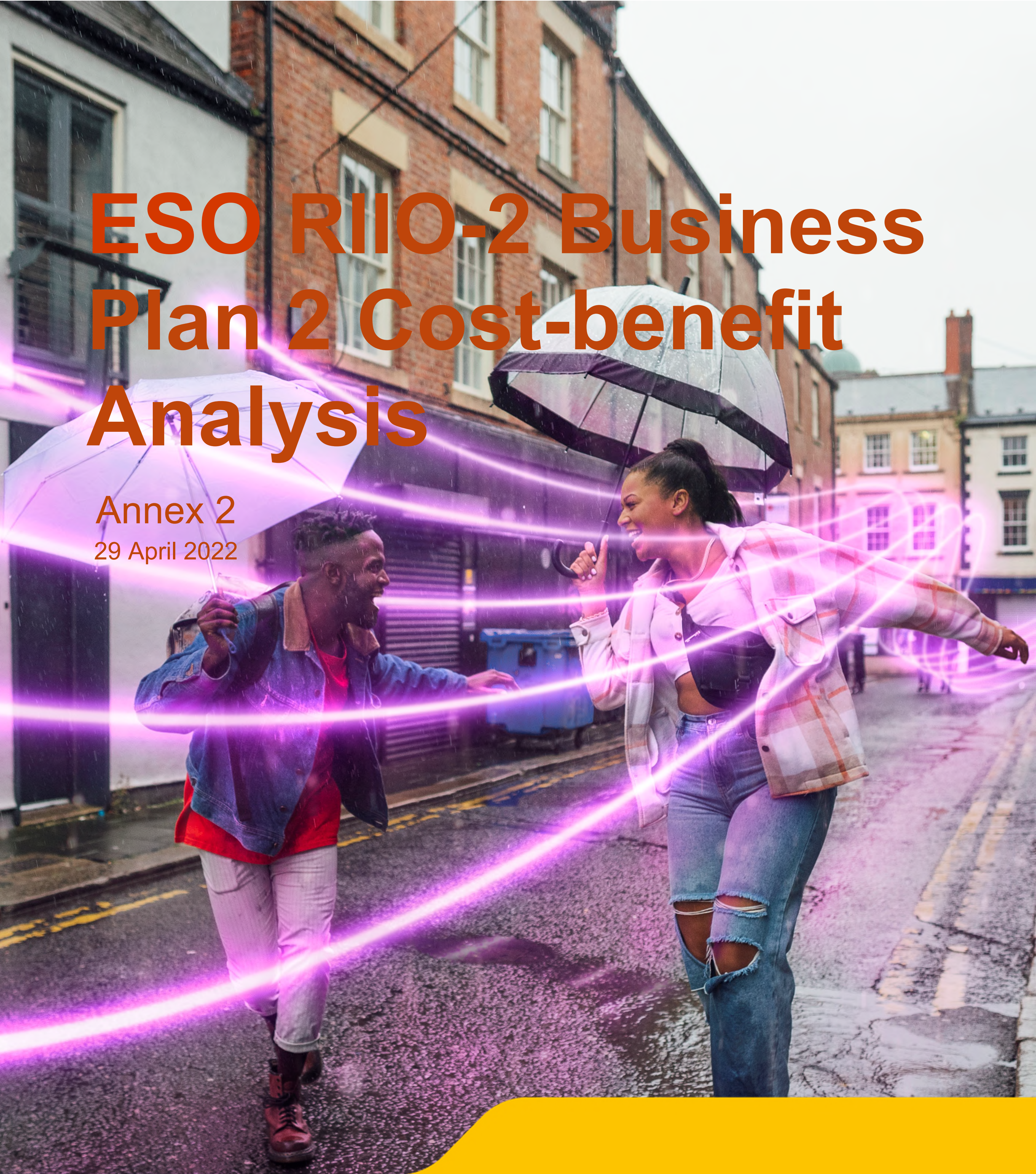
ESO RIIO-2 Business Plan 2 Cost-benefit Analysis

Annex 2

29 April 2022



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Contents

1. Executive summary

This cost-benefit analysis (CBA) annex accompanies our draft second RIIO-2 Business Plan (BP2) which covers the period April 2023 to March 2025.

Our original RIIO-2 CBA annex, submitted alongside our first RIIO-2 Business Plan (BP1) in 2019, set out the consumer benefit we expected our activities to deliver over the period April 2021 to March 2026. In BP1 we set out ambitious goals for the RIIO-2 period, focused on how to meet the challenges of the changing energy landscape and maximise benefits of the energy transition for consumers.

The RIIO-2 framework was designed to help us be flexible and agile in a changing external environment. In light of this, BP1 is now due to be updated. We've added some new activity to our BP2 plan and we've also updated (materially changed) activity across a number of areas.

Our Mission is to drive the transformation to a fully decarbonised electricity system by 2035 which is reliable, affordable and fair for all. We believe that the activities outlined in our plan support this Mission and deliver value for customers and consumers, providing net benefits of around £2.6 billion.

1.1. Updates to our RIIO-2 CBAs for BP2

In this CBA annex, we update the CBAs in the areas of material change to our RIIO-2 activities, in line with Ofgem's guidance for our second RIIO-2 business plan.

In total:

- 10 CBAs have been updated to reflect material changes
- 2 break-even analyses have been updated to reflect material changes
- 4 new break-even analyses have been undertaken for new activities or sub-activities

In most cases, only the underlying assumptions have been updated in the CBAs and just four CBAs have significant changes to their benefits methodologies since BP1. Appendix B provides a summarised list of the methodology changes. The text provided at BP1 to explain each benefits case has been included in this annex for completeness.

Total NPV Changes

BP1 Total 5-year NPV (£m)	BP2 Total 5-year NPV (£m)	Change (£m)
1,754*	2,581	+827

*This total excludes the BP1 A1 CBA

The updated estimate for the net present value (NPV) of the RIIO-2 activities across all roles is £2.6bn over the 5-year RIIO-2 period (April 2021 – March 2026) and £7.6bn over 10 years (April 2021 – March 2031). All RIIO-2 activities, subject to a CBA, now have a positive 5-year NPV. The total change in 5-year NPV from BP1 is +£827m. This positive increase has three main drivers:

1. **Increase to our cost of carbon assumption** – the financial benefits relating to activities which limit carbon emissions and reduce environmental damage have increased. Our updated cost of carbon assumption is based on the marginal abatement cost, rather than on the short-term traded value of carbon used in the BP1 CBAs. This update is recommended by BEIS[1].
2. **Increase to our constraint costs forecasts** – the benefits linked to proportional reductions in constraint costs have increased because forecasts for constraint costs have increased by £721m over the RIIO-2 period, since BP1.
3. **New deliverables providing greater consumer benefit** – by doing more and going further than in our first business plan we will unlock more value and provide greater benefits for consumers.

[1] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal

Role 1

BP1 Role 1 5-year NPV (£m)	BP2 Role 1 5-year NPV (£m)	Change (£m)
8*	19	+11

*This total excludes the BP1 A1 CBA

The £11m increase in NPV for Role 1 is due to increased benefit for the activity **A3 Restoration**. This increase in benefit is associated with low carbon distributed energy resources playing a greater part in restoration services, leading to reduced carbon emissions from large generators. The increase in our cost of carbon assumption has therefore driven the increase in the Role 1 NPV.

Please note that the NPV totals for Role 1 currently exclude the NPV for activity **A1 Control Centre architecture and systems**. The A1 CBA has not been updated for this draft business plan submission due to the ongoing Balancing Capability Strategic Review (described in the Role 1 chapter of the main business plan), but it will be updated for our final business plan submission in August 2022. The A1 NPV is expected to be in the range of £200-£650m.

Role 2

BP1 Role 2 5-year NPV (£m)	BP2 Role 2 5-year NPV (£m)	Change (£m)
411	227	-184

The £184m decrease in total 5-year NPV for Role 2 is mainly driven by the reduction in estimated NPV for the sub-activities A6.6 and A6.7 related to fixing Balancing Services Use of System (BSUoS) tariffs. This reduction is due to:

- Starting BSUoS reform in 2023 – this start date is aligned with the outcomes of the BSUoS Task Force, but it is one year later than was set out in our BP1 CBA.
- The use of an improved benefits methodology for BP2 - our BP1 CBA was created in 2019, well before the final report of the Second Balancing Services Task Force was published in September 2020 and therefore before the proposed changes to BSUoS were known.

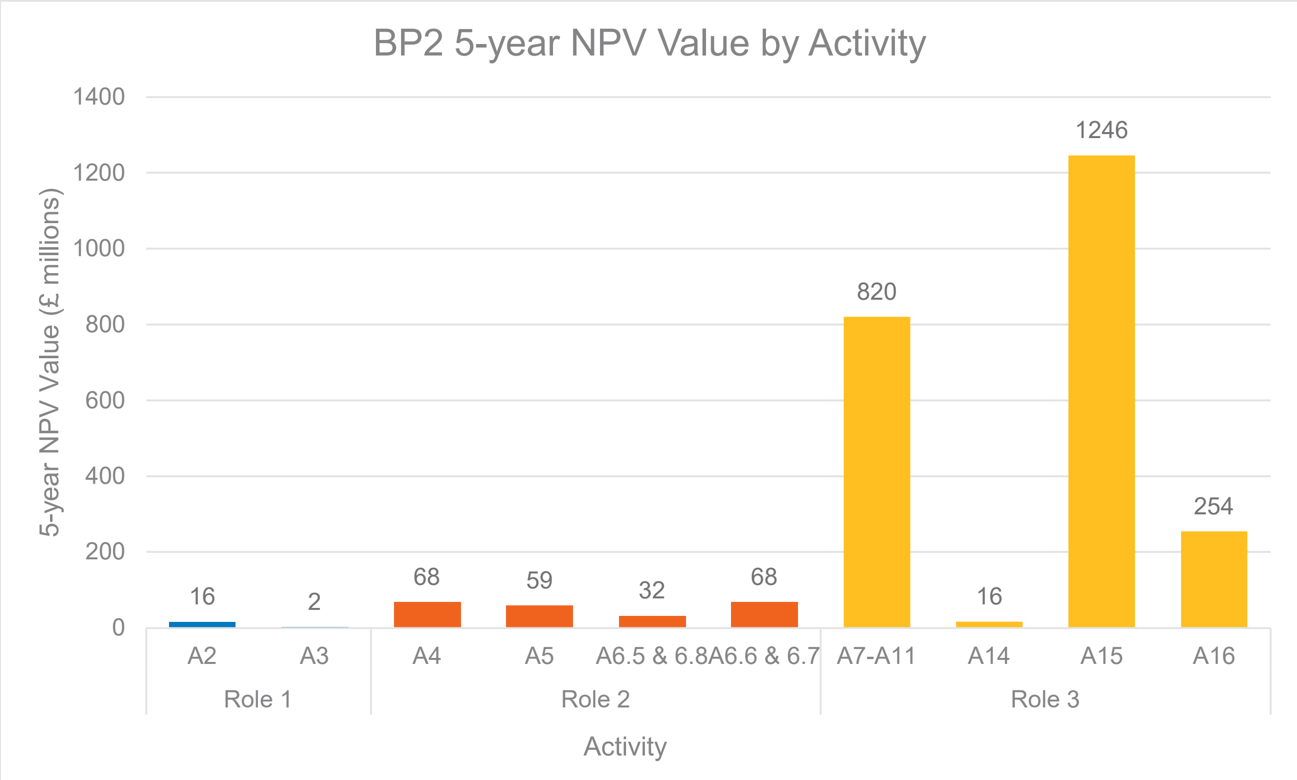
Role 3

BP1 Role 3 5-year NPV (£m)	BP2 Role 3 5-year NPV (£m)	Change (£m)
1,335	2,336	+1,001

The total 5-year NPV for Role 3 has increased significantly since BP1. All CBAs in this role have increased benefits, but by far the largest contributor to this increase is the activity **A15 Taking a whole energy approach to promote zero-carbon operability**. The 5-year NPV for A15 has increased by £820m mostly due to an increased estimate for constraint cost savings relating to whole-system operability assessments.

1.2. Updated RIIO-2 activities

The graph below presents the updated 5-year NPV values for each of the activities with a CBA. As shown below, all the activities have a positive 5-year NPV.



The table below lists the changes in NPV since BP1 for each updated CBA and the key drivers for those changes.

Activity	Name	BP1 5-year NPV (£m)	BP2 5-year NPV (£m)	5-year NPV change (£m)	Key drivers of change
A2	Control Centre training and simulation	16	16	-	N/A
A3	Restoration	-8	2	+10	Cost of carbon assumption
A4	Build the future balancing service markets	67	68	+1	Phasing of benefits
A5	Transform access to the Capacity Market	62	59	-3	IT investment costs
A6.5	Work with all stakeholders to create a fully digitalised, Whole System Technical Code by 2025	4	32	+28	Total number of connection applications
A6.8	Digitalisation of Codes				
A6.6	Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS)	278	68	-210	Improved benefits methodology
A6.7	Fixed BSUoS tariff setting				

Activity	Name	BP1 5-year NPV (£m)	BP2 5-year NPV (£m)	5-year NPV change (£m)	Key drivers of change
A7	Network Development	663	820	+157	Benefits for A7 have been included Latest commercial solutions assumption from the Future Energy Scenarios (*FES)*
A8	Enable all solution types to compete to meet transmission needs				
A9	Extend *NOA* approach to end-of-life asset replacement decisions and connections wider works				
A10	Support decision making for investment at distribution level				
A11	Enhance analytical capabilities				
A14	Take a whole electricity system approach to connections	2	16	+14	Total number of connection applications
A15	Delivering consumer benefits from improved network access planning	466	1246	+780	New deliverables providing greater consumer benefit Constraint costs forecasts Cost of carbon assumption
A16	Delivering consumer benefits from improved network access planning	204	254	+50	Constraint costs forecasts
Total		**1,754**	**2,581**	**+827**	

1.3. New RIIO-2 activities

Our BP2 plan sets out a number of new activities we will undertake over the period. For those new activities with transformational aspects, we have included analyses in this CBA annex, in line with Ofgem's guidance. All new RIIO-2 activities requiring a CBA have been subject to break-even analyses, where direct financial benefits are not defined. This is because all the new activities that require a CBA are either:

- 5-10 years away from the first benefits being delivered; or
- do not have direct consumer benefits themselves (they enable existing or future activities that deliver the direct consumer benefits).

Attempting, today, to put a direct financial benefit to consumers on these activities would be inappropriate given their scope and the timescales involved. The benefits cases will be reviewed at BP3 and, where appropriate, full CBAs will be undertaken then.

2. Approach to cost-benefit analysis for BP2

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

For the economic assessment in our submission, we have undertaken either a CBA or a break-even analysis on all our transformational proposals. Central to CBA is the determination of a project's financial and economic cashflow and their net present value (NPV). This value, whether positive or negative, supports the appraisal of investment options and the final decision. Our detailed methodology for the RIIO-2 CBAs is in appendix A of this annex.

In our BP2 submission, we have updated or completed new analyses for:

- Activities which are materially changed or are new
- Sub-activities which are materially changed or are new
- Deliverables which are materially changed or are new

Our high-level rules of thumb for identifying change as material are described in the next subsection.

For each existing CBA we have updated the contents of the analysis in accordance with the following table:

Section	Subsection	Description	Changes since BP1
NPV drivers		A summary of the key drivers of the change in NPV since BP1	New
Changes since BP1		An explanation of the changes since BP1	New
Counterfactual		Base case vs which other options are considered	No change
Benefits	Assumptions, justifications and methodology	Method for estimating consumer benefit with supporting assumptions and justification	Updated
	Sensitivity analysis	Sensitivities related to benefits to understand changes in internal and/or external factors	Updated where appropriate to account for new sensitivities (the underlying assumptions are updated even if the approach is not)
	Measuring benefits and consumer bill impact	Description of how we will track the benefits of the activity	Removed – new metrics will be determined following consultation with Ofgem as part of draft determinations
	Benefits tables and total benefits	Findings of benefits estimation	Updated
Costs		Costs relating to the activity	Updated
NPV		A financial evaluation of the costs and benefits of the activity	Updated
Dependencies, enablers and whole energy system		An evaluation of how this activity interacts with other benefits cases, defining where appropriate which benefits are mutually exclusive	Updated

Section	Subsection	Description	Changes since BP1
Uncertainties and risks		Provides an understanding of Risk which is accounted for in the benefits calculation of the activity	Updated
Other options considered		Other options considered during option process	This section has been removed for activities which have already started

The following graphic highlights new CBA sections in orange, updated sections in yellow and removed sections removed in blue.

2.1. Rules of thumb for material change

We have updated the BP1 CBAs in the areas of material change to our RIIO-2 delivery plan. An activity, sub-activity or deliverable is said to be materially changed if it meets any of the following criteria:

	Scope	Timescales	Costs
Activities	• New sub-activity • More than 25% of the sub-activities have materially changed	• More than 25% of the sub-activities have changed timescales	• Costs are 10% larger than at BP1 • Costs have increased by £25m
Sub-activity	• More than 25% of the deliverables have materially changed	• More than 25% of the deliverables have changed timescales	• Costs are 10% larger than at BP1 • Costs have increased by £10m
Deliverables	• Scope has reduced or expanded so considerably that the benefits case has clearly changed	• A BP1 milestone impacting stakeholders has slipped into BP2 • A BP2 milestone impacting stakeholders has slipped into BP3 • A key milestone for realising benefits has been delayed by more than 6 months	• Costs are 10% larger than at BP1 • Costs have increased by £2m

These rules of thumb were introduced to create a consistent approach to the CBA updates across all RIIO-2 activities. We also used our judgement to identify changes as material where they are likely to draw significant interest from stakeholders, customers, and consumers.

In total:

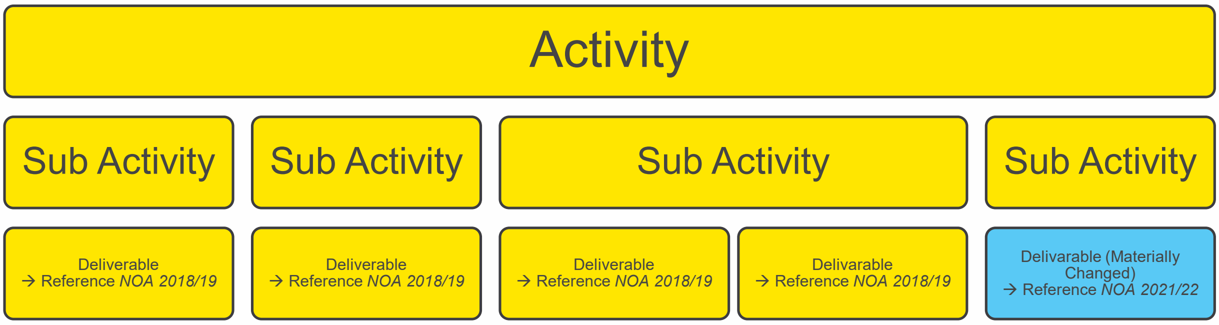
- 10 CBAs have been updated to reflect material changes
- 2 break-even analyses have been updated to reflect material changes
- 4 new break-even analyses have been undertaken for new activities or sub-activities

2.2. Updates to references

References in CBAs have been updated where there are new appropriate sources. Where references have not been updated it can be assumed that they still present the most current view.

We have updated CBAs where the associated RIIO-2 activities, sub-activities and deliverables have materially changed. If an activity has multiple sub-activities and deliverables, but only one deliverable has materially changed, we have only updated the analysis to reflect the changes for this one deliverable. Therefore, the same activity may reference two different sources, for example *NOA 2018/19* and *NOA 2021/22*, where the benefits case related to the updated sub-activities or deliverables will reference *NOA 2021/22* while the material which is not updated from BP1 will reference *NOA 2018/19*.

Please see the diagram below for clarity:



2.3. Updates to assumptions

All underlying assumptions of the CBAs have been determined by following Ofgem or BEIS guidance, industry best practice or previously published material. Where assumptions have been updated the same methodology as at BP1 has been used.

Four of our seven central assumptions for the CBAs have changed since BP1. The cost of carbon and constraint costs assumptions have changed significantly.

Cost of carbon:

- At BP1 we took carbon values from the BEIS publication *Updated short-term traded carbon values used for UK policy appraisal (2018)*
- For BP2 we have taken carbon values from the BEIS publication *Valuing greenhouse gas emissions in policy appraisal*
- The figures at BP2 are based on the Marginal Abatement Cost which involves setting the value of carbon at the level that is consistent with the level of marginal abatement costs required to reach the targets that the UK has adopted
- The figures at BP2 are approximately 15 times larger than at BP1

For benefits cases which have a positive impact on the environment and reduce carbon emissions the benefits will be approximately 15 times larger solely through this update of the cost of carbon assumption. The figures used are as advised by Ofgem.

Constraint costs:

- Total forecast constraint costs over the RIIO-2 period have increased by £721m since BP1
- In particular, forecast constraint costs for 2021/22 and 2025/26 have significantly increased from BP1

Several activities use a reduction in constraint costs as a way of demonstrating the benefits they generate. For most of these activities, we see the greatest benefits claimed in 2025/26 as the activity is either complete or close to completion. Therefore, we will expect to see a large change in benefits in these activities as constraint costs in 2025/26 are forecast to increase by 60%. It is therefore not surprising to see benefits increase by up to 60% for the activities where a reduction of constraint costs is a claimed benefit.

The below table sets out the assumptions we have used for the BP2 CBA and how this compares to our original BP1 assumptions:

Assumption	BP1 values	BP2 values	Impact of changes
Capex depreciation period	Seven years	Seven years	No change
Cost of carbon £/tonneCO2e	BEIS short-term traded carbon values[2] 2021/22: 14.70 2022/23: 15.25 2023/24: 15.83 2024/25: 16.63 2025/26: 19.24	BEIS valuing greenhouse gas emission in policy appraisal[3] 2021/22: 245 2022/23: 248 2023/24: 252 2024/25: 256 2025/26: 260	The cost of carbon is almost 15 times larger. The impact is significant with benefits cases involving carbon offset increasing greatly.
Weighted average cost of capital	2.64% (placeholder)	3.36%	Minimal impact on NPVs

[2] https://www.gov.uk/government/publications/updated-short-term-traded-carbon-values-used-for-uk-policy-appraisal-2018
[3] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal

Assumption	BP1 values	BP2 values	Impact of changes
Discount rate	Social time preference rate of 3.5%	Social time preference rate of 3.5%	No change
Price base	2018/19	2018/19	No change
Constraint costs[4] £ million	2021/22: £600m 2022/23: £689m 2023/24: £809m 2024/25: £931m 2025/26: £909m	2021/22: £947m 2022/23: £746m 2023/24: £660m 2024/25: £848m 2025/26: £1457m	Constraint costs have increased by approximately £721m. The impact is significant with benefits involving constraint costs increasing greatly.
Response and reserve costs[5]	We take the average cost of response and reserve over the past 12 years: Response: £193m per year Reserve: £321m per year	We take the average cost of response and reserve over the past 12 years: Response: £178m per year Reserve: £300m per year	Response and reserve costs have reduced slightly. Benefits cases involving response and reserve costs will decrease.

2.4. New break-even analyses

All new activities which require a CBA, because they have transformational aspects, have had a break-even analysis undertaken. In these analyses, benefits are quantified but direct financial benefits are not defined.

The new activities for which break-even analyses have been undertaken are:

- **A6.9 Whole systems codes reform**
- **A20 Net zero market reform**
- **A21 Role in Europe**
- **A22 Offshore coordination / Network Planning Review**

All these activities have timescales of 5-10 years before the first benefits are delivered, act to enable the ESO to deliver other activities, or form part of wider commitments towards a net zero energy system. Attempting, today, to put a direct financial benefit to consumers on these activities would be inappropriate given their scope and the timescales involved, leading to benefits cases with broad assumptions open to significant scrutiny. As such we have quantified the benefits for these new activities, but not undertaken financial analysis.

For example, there will be no benefit in attempting to describe the financial benefit of **A20 Net zero market reform** when part of the purpose of this activity is to define the benefits of net zero market reform.

The benefits cases will be reviewed at BP3 and, where appropriate, a full CBA will be undertaken.

[4] Average constraint costs across the *Future Energy Scenarios* as used in the modelling of the 2021 *NOA*
[5] This is the average response and reserve cost over the past 12 years – we have taken this time period, which is the full period available, to account for the volatility in the reserve and response market

3. BP2 cost-benefit analysis findings

Activity NPV Changes

Activity	Name	BP1 5-year NPV (£m)	BP2 5-year NPV (£m)	5-year NPV change (£m)
A1	Control Centre architecture and systems	Under strategic review		
A2	Control Centre training and simulation	16	16	-
A3	Restoration	-8	2	+10
A18	Market monitoring	Not subject to CBA		
A17	Transparency and open data	Break-even*		
A19	Data and analytics hub	Not subject to CBA		
A4	Build the future balancing service markets	67	68	+1
A5	Transform access to the Capacity Market	62	59	-3
A6.4	Transform the process to amend our codes	Break-even		
A6.5	Work with all stakeholders to create a fully digitalised, Whole System Technical Code by 2025	4	32	+28
A6.8	Digitalisation of Codes			
A6.6	Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS)	278	68	-210
A6.7	Fixed BSUoS tariff setting			
A6.9	Whole system codes reform	Break-even		
A20	Net zero market reform	Break-even		
A21	Role in Europe	Break-even		
A7	Network Development	663	820	+157
A8	Enable all solution types to compete to meet transmission needs			
A9	Extend *NOA* approach to end-of-life asset replacement decisions and connections wider works			
A10	Support decision making for investment at distribution level			
A11	Enhance analytical capabilities			
A12	SQSS review	Break-even*		
A13	Leading the debate	Break-even*		

Activity	Name	BP1 5-year NPV (£m)	BP2 5-year NPV (£m)	5-year NPV change (£m)
A14	Take a whole electricity system approach to connections	2	16	+14
A15	Delivering consumer benefits from improved network access planning	466	1,246	+780
A16	Delivering consumer benefits from improved network access planning	204	254	+50
A22	Offshore coordination / Network planning review		Break-even	
Total		**1,754**	**2,581**	**+827**

*Not updated

3.1. Summary of the benefits delivered

A summary of the findings of our sensitivity analyses is shown in the table below. The figures presented are for our preferred option for each activity.

	5-year NPV (£m)	10-year NPV (£m)	Market factors low 5-year NPV (£m)	Market factors high 5-year NPV (£m)	Delivery factors low 5- year NPV (£m)	Delivery factors high 5-year NPV (£m)	Third-party factors low 5- year NPV (£m)	Third-party factors high 5-year NPV (£m)
A1				Undergoing Strategic Review				
A2	16.44	40.85	11.28	21.60	-0.05	40.27	16.44	16.44
A3	2.25	24.78	-0.91	6.54	2.25	2.25	2.25	2.25
A17				Break-even analysis				
A18				Not subject to CBA				
A19				Not subject to CBA				
Role 1	**18.69**	**65.62**	**10.37**	**28.14**	**2.20**	**42.52**	**18.69**	**18.69**
A4	67.89	159.20	43.52	82.59	8.05	112.39	67.89	67.89
A4				Break-even analysis				
A5	58.99	116.81	43.52	76.91	17.37	90.29	55.03	62.73
A6.4				Break-even analysis				
A6.5 & 6.8	32.05	138.09	27.35	36.73	8.84	32.05	14.44	49.66
A6.6 & 6.7	67.97	166.77	67.97	67.97	67.97	67.97	67.97	67.97

	5-year NPV (£m)	10-year NPV (£m)	Market factors low 5-year NPV (£m)	Market factors high 5-year NPV (£m)	Delivery factors low 5- year NPV (£m)	Delivery factors high 5-year NPV (£m)	Third-party factors low 5- year NPV (£m)	Third-party factors high 5-year NPV (£m)
A6.9	Break-even analysis							
A20	Break-even analysis							
A21	Break-even analysis							
Role 2	**226.90**	**580.87**	**179.91**	**264.20**	**102.23**	**302.70**	**205.33**	**248.25**
A7 A8 A9 A10 A11	820.43	2,191.25	496.25	1,153.29	715.79	884.45	820.43	820.43
A12	Break-even analysis							
A13	Break-even analysis							
A14	16.18	35.94	13.78	18.59	10.86	16.40	16.18	16.18
A15	1,246.12	4,046.29	1,214.21	1,379.30	601.56	1,279.21	980.40	1,246.12
A16	254.15	639.80	188.83	319.48	127.34	356.40	254.15	154.15
A22	Break-even analysis							
Role 3	**2,336.88**	**6,913.28**	**1,913.47**	**2,870.66**	**1,455.55**	**2,536.46**	**2,071.16**	**2,336.88**
Total	**2,582.47**	**7,559.77**	**2,103.75**	**3,163.00**	**1,559.98**	**2,881.68**	**2,295.18**	**2,603.82**

3.2. Costs

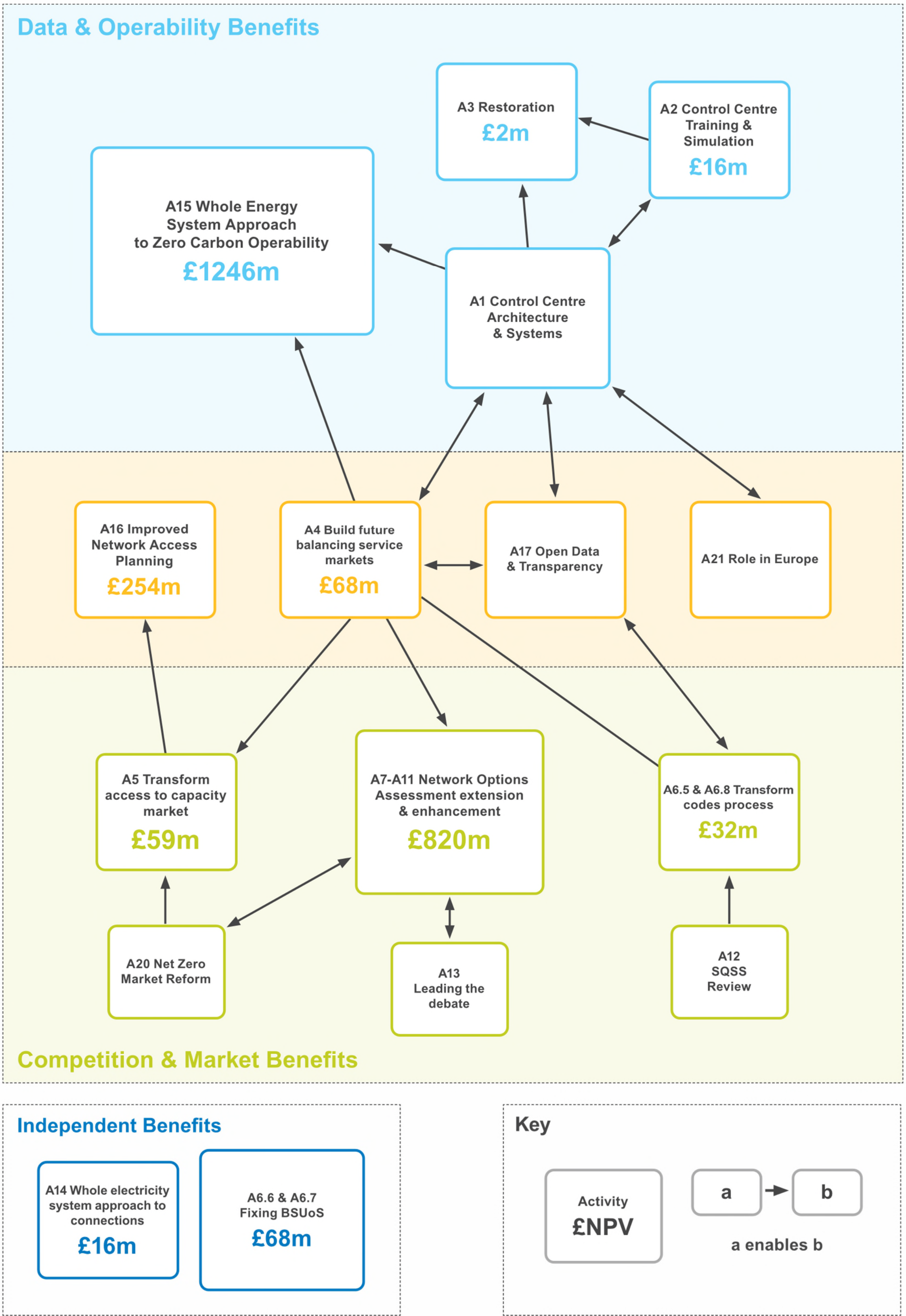
We have updated costs for all activities, sub-activities, and deliverables. We have not provided a discussion of changes to costs within this annex. A description of cost changes can be found in either the IT Annex or within the main business plan.

To ensure a useful comparison can be made with the BP1 CBAs, we have, wherever possible, used the same mapping of business and IT costs to CBAs as was used in BP1. The BP2 IT submission maps IT costs to RIIO-2 activities in much more detail within the Technology Business Management (TBM) taxonomy data model. We have chosen not to split the CBA costs in accordance with the TBM data model, since this will create misalignment between the BP1 and BP2 CBAs and prevent a meaningful comparison of NPVs.

For example, consider an imaginary IT investment line Z – at BP1 it was associated with the A1 CBA, but the TBM data model now has it split 80% to A1, 15% to A2 and 5% to A3. In the updated CBA for BP2, we will not split the costs between activities, and we leave them all in the A1 CBA.

3.3. Dependencies between the activities

We have updated our understanding of the dependencies between our RIIO-2 activities for this BP2 submission. The diagram below highlights the dependencies between the activities. By a dependency we mean that an activity could not fully deliver its benefits without another activity.



3.4. Impact of benefits on the consumer bill

We have updated our analysis for the impact of our RIIO-2 plans on the consumer bill. Our results for consumer bill impact are calculated based on the transformational activities we have calculated benefits for. It does not consider the benefits from our ongoing activities and therefore it is likely to be conservative.

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

- via a change to the Balancing Services Use of System (BSUoS) charge
- via a change to the Transmission System Use of System (TNUoS) charge
- via a change to the supplier charge

The cost of our activities in RIIO-2 is around £2.10 on a consumer's annual energy bill; however, our proposed outputs will save consumers around £5.50 per year, resulting in a net reduction of around £3.50 on the consumer bill. This is an increase in savings for the consumer of approximately £0.40, in comparison with our BP1 analysis.

Bill impact area	Consumer benefit	Percentage of total consumer benefits	Annual Bill Impact
BSUoS charge	£1,856m	63%	-£2.68
TNUoS charge	£929m	31%	-£2.28
Supplier charge	£176m	6%	-£0.51
Totals	**£2,960m**		**-£5.47**

4. Role 1

Within Role 1 we have updated the existing CBAs for A2 and A3. The A1 CBA has not been updated for this draft business plan submission due to the ongoing Balancing Capability Strategic Review (described in the Role 1 chapter of the main business plan document), but this CBA will be updated for our final business plan submission in August 2022.

The existing break-even analysis for A17 has not been updated because the activities it describes have not materially changed since BP1, please refer to the BP1 CBA annex to find the existing analysis. The new RIIO-2 activity A19 has been introduced to provide clarity on our operating model for data and analytics and to give it prominence in the business plan. The scope of A19 was part of A17 in BP1 and therefore an additional analysis is not required.

We have also not undertaken an analysis for A18, which covers ongoing activities that have already begun. This activity is neither new nor transformational and therefore not subject to analysis.

Activity	Activity name	Material changes in activity since BP1	Analysis status	Changes in analysis since BP1
A1	Control Centre architecture and systems	• New deliverables • Scope • Costs	Not updated due to Balancing Capability Strategic Review	
A2	Control Centre training and simulation	• Timescales	Updated: CBA	• Minimal change
A3	Restoration	• Scope • Timescales • Costs	Updated: CBA	• Underlying assumption 'Carbon Price' has changed
A18	Market monitoring	• New activity	None	
A17	Transparency and open data	• None	As BP1	
A19	Data and analytics operating model	• None	None	

4.1. A1 Control Centre architecture and systems

The ESO's plans for enhancing its balancing capability within the A1 RIIO-2 activity are currently under strategic review and as such, the main business plan contains only limited information about our transformational balancing activities.

Benefits have been calculated at the activity level for most activities and only separated where there is a clear delineation within the activity. The transformational balancing deliverables contribute significantly to the overall benefit case for A1, by both delivering benefits themselves and unlocking benefits in other deliverables across A1. Due to the interdependencies between A1 deliverables, it is not possible to separate out the benefits of an enhanced balancing capability from A1 without a complete change to the CBA benefits cases and calculation methodology.

Due to the ongoing Balancing Capability Strategic Review, interdependencies between A1 deliverables and the need to present accurate figures relating to both costs and benefit we have not included a CBA for A1 in this draft business plan submission. An updated A1 CBA will be provided in the final business plan submission in August 2022.

We can state that as per BP1**, A1 Control Centre architecture and systems activities** deliver benefits in six areas, but currently we cannot state the volume of the benefits or the costs of the activity:

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

Reduced CO2 emissions

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 Centre will not be able to maximise the use of low carbon technologies and still balance in a technology neutral manner.

Greater interconnection

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

Utilising flexible technology

We will be able to reduce system operation costs by using flexible technology.

Better inertia forecasting and needs management

Inertia forecasting and needs management improvements will give us a more accurate understanding of system inertia. This, in turn, will help us to manage risk more efficiently, by being able to operate the system closer to the limits.

Improved situational awareness

Improved situational awareness (i.e. the ability to monitor and understand network status and evolving operational limits) allows better management of transmission.

Reduced balancing mechanism outage downtime

We have calculated the cost of an unplanned outage as approximately £700,000 per hour. By reducing the time of unplanned outages, we can reduce costs for consumers.

4.2. A2 Control Centre training and simulation

This subsection contains the costs and quantifiable benefits of our **A2 Control Centre training and simulation** activity.

The net present value (NPV) of A2 is £16.44 million over the RIIO-2 period, and £40.84 million over ten years. Sensitivity analysis suggests an NPV range of -£0.05 million to £40.84 million over the RIIO-2 period.

4.2.1. NPV drivers

The NPV has not changed significantly since BP1. There is a negligible increase of £0.16m.

Costs have decreased overall by approximately £3m with most of the cost reduction in the last three years of the RIIO-2 period. We do not see significant movement with total benefits, but phasing is slightly altered with an increase in benefits in years one and two and a decrease in years three, four and five. Combining these factors leads to a negligible change in NPV.

We have not altered the benefits methodology from BP1 for this CBA. Only the underlying assumptions have been updated in accordance with the methodology for these assumptions at BP1.

4.2.2. Changes from BP1

Benefits case	Changes	Description
Decreased Training Costs	Delay to benefits	There is a delay of approximately 12 months to delivery of the associated RIIO-2 deliverable.
Improved Decision Making	Response and reserve costs	Latest response and reserve costs have been used.

Benefits associated with the sub-activity A2.4 Workforce and change management may be subject to further change due to supplier challenges. The potential delay due to supply chain is modelled in the sensitivity analysis for this CBA to account for worst case delivery.

4.2.3. The counterfactual

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

4.2.4. The benefits

We have quantified benefits in three areas:

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

4.2.4.1. Reduced Resource Costs

Assumptions	Justification
Cost saving	Based on past resource costs

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

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Reduced Resource Costs (central case)	0.5	0.5	1.3	1.3	1.3	**5**

4.2.4.2. Decreased Training Costs

Assumptions	Justification
Reduction in training time	ESO judgement, based on proposed transformational activities reducing training time from seven months to four months (42%)
Training cost	Historic averages of £75,000 per candidate, with 30 candidates trained per year

Number of new starters trained	Based on historic data and forecast industry turnover
Percentage of maximum annual benefit claimed	We believe our proposals ultimately deliver a three-month reduction in training time. Given that we are implementing enhanced training and developing new tools gradually over the RIIO-2 period, we cannot claim the maximum benefit until the end. So, we claim a reduced benefit in the preceding years.

Our enhanced training and simulator proposals mean that new starters will have more knowledge and can be trained quicker. We estimate this will lead to a saving of £1.2 million over the RIIO-2 period. This assumes we can reduce training time by three months, saving approximately £32,000 per candidate. We train on average more than 30 people per year. Given that we are implementing enhanced training and developing new tools gradually over the RIIO-2 we have considered the percentage of the maximum annual benefit we can claim in each year.

Sensitivity analysis

- **Market factors:** we have not conducted a sensitivity analysis based on market factors.
- **Third-party factors:** we have modelled a one-year delay in benefits to account for supplier challenges.
- **Delivery factors:** we have modelled a reduced training time of three months and five months for the upper and lower cases respectively.

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 Total	Calculation
Training costs (£ million)	2.3	2.3	2.3	2.3	2.3	11.5	A
Improvement	42%	42%	42%	42%	42%		B
Percentage of maximum annual benefit claimed	0%	5%	15%	35%	80%		C
Benefit (central case) (£ million)	0	0.05	0.14	0.33	0.76	1.2	D = A x B x C

Note: As in all tables in this document, numbers are rounded (for example, the rounded 'D' shown in this table may not exactly equal the product of rounded 'A', 'B', 'C' values shown)

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Decreased Training Costs (central case)	0	0.05	0.14	0.33	0.76	**1.2**
Sensitivity – high delivery	0	0.06	0.19	0.45	1.03	**1.7**
Sensitivity – low delivery	0	0.03	0.10	0.23	0.52	**0.9**
Sensitivity – low third-party	0	0	0.05	0.14	0.33	**0.5**

The above table above shows the benefits from decreased training costs are between £0.5 million and £1.7 million, with a central case of £1.2 million.

4.2.4.3. Improved Decision Making

Assumption	Justification

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

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

We recognise that a range of factors can influence savings made to future spend. The introduction of new situational awareness with clear training has helped us to improve management of the power system overall. It is reasonable to assume similar gains for improving our tools and training, because the way our new tools and training are implemented will mirror that of the DER desk. Nonetheless, to account for potential uncertainty, we halve the 4% benefit expected based on the DER desk case study, and we claim that our proposals will result in a 2% reduction in response and reserve spend.

To avoid potential double counting with A1 we have not considered a reduction in constraint spend. It is, however, important that our proposals in A1 and A2 are considered as a package.

Sensitivity analysis

- **Market factors:** we repeat our analysis with the response and reserve costs adjusted by one standard deviation in either direction.
- **Third-party factors:** we have not conducted a sensitivity analysis because the benefits case is not dependent on the actions of third parties.
- **Delivery factors:** for the upper case we assume 4% savings, consistent with the above evidence; 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 the A4 CBA. Any potential double counting is accounted for in the sensitivity analysis.

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 Total	Calculation
Reserve and response costs (£ million)	479	479	479	479	479	2,395	A
Improvement	2%	2%	2%	2%	2%		B
Percentage of maximum annual benefit claimed	5%	25%	60%	80%	100%		C
Benefit (central case) (£ million)	0.5	2.4	5.7	7.7	9.6	25.9	D = A x B x C

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Improved Decision Making (central case)	0.5	2.4	5.7	7.7	9.6	**25.9**
Sensitivity – high market	0.6	2.9	7.0	9.4	11.7	**31.5**
Sensitivity – low market	0.4	1.9	4.5	6.0	7.5	**20.2**
Sensitivity – high delivery	1.0	4.8	11.5	15.3	19.1	**51.7**
Sensitivity – low delivery	0	0.2	1.2	2.9	3.8	**8.1**

The above table of sensitivity analysis results shows the benefits from improved decision-making are between £8.1 million and £51.7 million, with a central case of £25.9 million.

4.2.4.4. Total benefits case

The total benefits for A2 are between £14 million and £58 million, with a central case of £32 million over the RIIO-2 period.

4.2.5. Activity costs

Delivery of A2 will require Capex and Opex spend, as summarised below.

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0.02	0.17	1.16	2.33	2.33	**6.01**
Opex	1.64	1.71	2.48	3.24	3.68	**12.75**
Total	**1.66**	**1.88**	**3.64**	**5.57**	**6.01**	**18.76**

The total cost for our A2 activities is £18.76 million.

4.2.6. Net present value

The net present value of these activities is estimated at £16.44 million over the RIIO-2 period and £40.84 million over 10 years. They will start to deliver positive returns from 2023/24. Sensitivity analysis suggests an NPV range of:

- Considering market scenarios, between £11.28 million and £21.60 million.
- Considering delivery scenarios, between -£0.05 million and £40.27 million.

4.2.7. Dependencies, enablers, and whole energy system

This activity is dependent on the following transformational activity:

- **A1 Control Centre architecture and systems** (Role 1) – this activity will allow highly skilled engineers to use their training for zero carbon system operation.

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

- **A1 Control Centre architecture and systems** (Role 1) – this activity will provide real world experience for training and simulation.

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 will likely be offset by savings from not having to run some or all their own training programmes. DNOs and TOs will also benefit from having a greater pipeline of resource from our enhanced academic partnerships attracting talent to the industry. Greater coordination and collaboration of training will help the industry to make better whole system decisions, particularly in areas such as restoration and disaster recovery.

4.2.8. Uncertainties and risks

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

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

4.3. A3 Restoration

This subsection contains the costs and benefits of our **A3 Restoration** activity. The net present value of our A3 activities is £2.25 million over the RIIO-2 period and £24.78 million over ten years.

4.3.1. NPV drivers

The increase in total NPV compared with BP1 of +£10.66 million is driven by one factor: the increase in our Cost of Carbon assumption. As a result, the overall NPV for this activity is now positive, demonstrating that it is a positive investment even without considering the other benefits this activity unlocks to 2050.

We have not altered the benefits methodology from BP1, we have only updated the underlying assumptions in accordance with the methodology used at BP1.

4.3.2. Changes from BP1

Benefits case	Changes	Description
Carbon Savings	Carbon price	Latest carbon prices from BEIS used. High/low sensitivities are now also included.

The sub-activity A3.2 Restoration standard has materially changed timescales. However, the benefits for this case are only applicable in the last year of the RIIO-2 period and therefore the delays to implementing the Electricity System Restoration Standard (ESRS) have had no impact on A3 benefits.

New or materially changed sub-activity	Benefits impact
A3.2 Restoration Standard	The changes have no impact on benefits. The associated benefits case is only applicable in the last year of RIIO-2 period and work is being undertaken to ensure delivery is on track as expected.

4.3.3. The counterfactual

If we did not undertake our transformational **A3 Restoration** activities, we would make ongoing enhancements to our restoration tools and we would not implement the proof-of-concept findings from our Distributed ReStart Network Innovation Competition (NIC) project.

4.3.4. The benefits

We have quantified benefits in two areas:

- Benefits from Distributed ReStart NIC project
- Carbon savings

4.3.4.1. Distributed ReStart NIC project

Assumptions	Justification
£115 million NPV to 2050	Findings from Distributed ReStart NIC Project[6]

The net present value of implementing the recommendations of the Distributed ReStart NIC project is £115 million to 2050. This is due to increased competition and reduced costs from the use of some large generators.

Cost savings will be passed on to consumers through reduced BSUoS charges. We assume this saving is allocated evenly from 2025, when the implementation of the project recommendations will start delivering benefits. This delivers £4.6 million of benefit during RIIO-2 and £23 million to 2030**.**

Sensitivity analysis

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

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Benefits from Distributed ReStart NIC project (central case)	0.0	0.0	0.0	0.0	4.6	**4.6**

4.3.4.2. Carbon Savings

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

[6] National Grid Electricity System Operator: Distributed ReStart NIC project https://www.ofgem.gov.uk/system/files/docs/2018/11/redacted_electricity_nic_submission_2018_esoen01_v03.pdf

We estimate the Distributed ReStart NIC 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 services, leading to reduced carbon emissions from large generators. We assume this reduction is allocated evenly from 2025/26 when the implementation of the project recommendations will start delivering benefits. With an average carbon price of £264 per t/CO_2e in 2025/26, this will deliver a benefit of £8.5 million over RIIO-2.

Sensitivity analysis

We have updated the benefits case to account for market high and low sensitivities, to reflect changing carbon prices.

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Carbon Savings (central case)	0.0	0.0	0.0	0.0	8.5	**8.5**
Sensitivity – market high	0.0	0.0	0.0	0.0	12.8	**12.8**
Sensitivity – market low	0.0	0.0	0.0	0.0	4.2	**4.2**

4.3.4.3. Total benefits case

The total benefits for A3 are a central case of £13.1 million over the RIIO-2 period, with a range of £8.8m to £15.4m.

4.3.5. Activity costs

Delivery of our A3 activities will require Capex and Opex spend, as summarised below:

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0	2.29	7.65	8.10	6.30	**24.34**
Opex	0	0.59	0.97	1.67	1.47	**4.70**
Total	**0**	**2.87**	**8.62**	**9.77**	**7.77**	**29.03**

The total cost for our **A3 Restoration** activities is £29.03 million.

4.3.6. Net present value

The net present value (NPV) of A3 is estimated at £2.25 million over the RIIO-2 period and £24.78 million over ten years. With a range of:

- Considering market scenarios, between -£0.91m and £6.54m

Given the £115m NPV of the Distributed ReStart NIC project to 2050, we are confident our proposals will deliver long-term net benefit.

4.3.7. Dependencies, enablers, and whole energy system

This activity is dependent on the following transformational activities:

- **A1 Control Centre architecture and systems** (Role 1) – this activity will allow highly-skilled engineers to use their training for zero carbon system operation.
- **A2 Control Centre training and simulation** (Role 1) – this activity will help to ensure a future supply of highly-skilled Control Centre engineers.

For DER to provide restoration services, new tools will be needed to handle a greater number of participants and we will need to train our Control Centre engineers on new restoration procedures. Hence the dependency of A3 benefits on activities A1 and A2.

Our Distributed ReStart NIC project complements our proposals in Role 2, to transform participation in balancing markets. The restoration decision support tool proposed in sub-activity A3.2 will complement the other tools delivered in A1.

Our proposals may pass some costs onto third parties. DNOs, TOs and restoration service providers will need to invest to comply with the restoration standard, for which we will be conducting the assurance process. DNOs and service providers may need to implement communication systems, depending on the proof-of-concept findings from the DER NIC project.

We believe the benefits, including reduced restoration timelines, the ability of new technologies to provide restoration services and, for DNOs, the potential to control restoration in their own areas of operation, outweigh these costs.

4.3.8. Uncertainties and risks

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

Risk	Mitigations	Likelihood	Impact
A restoration standard is not established, and implementation frameworks are not used	ESO can set target restoration timeframes through our current structure and justify our restoration strategy against this	1	2
A substandard or inappropriate restoration tool is implemented	Project scoping and resource to support this are included in our Business Plan	2	2
New roles and responsibilities between industry parties are currently unknown and may influence restoration options	Ongoing engagement with distribution system operation (DSO) model development and impact on restoration to ensure associated roles and responsibilities adapt as required	3	2
Stakeholders challenge proposed Grid Code changes	Maintain a dialogue with other parties involved in restoration, and champion relevant regulatory, legal, or code changes to enable full participation. Share code changes and timetables for implementation and maintaining industry awareness	3	3
Roles and skillset required for DER are challenging to resource	Mitigated through the training and simulation part of our Business Plan	2	3
Cost of sufficient resilience in telecommunications means focusing on a small number of large resources, limiting the involvement of smaller DERs	The Distributed ReStart NIC project will provide a working (albeit small scale) solution for resilient telecommunications which can be scaled for Great Britain 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, lack of investment in DER technology	The risk will be identified through the Distributed ReStart NIC project	3	2
Despite new technologies and techniques, the restoration speed does not reduce	Implement an annual evaluation of restoration time against expectations. New technologies and products will feed into this evaluation.	2	2

Risk	Mitigations	Likelihood	Impact
Market mechanisms across different parties (ESO/DSO/DERs) are too complex and may be susceptible to distortion.	Market mechanisms are still being trialed 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 unclear funding arrangements.	The Distributed ReStart NIC project will identify the specific requirement and associated costs.	2	2

4.4. Role 1 NPV Summary

	5-year NPV (£m)	10-year NPV (£m)	Market factors Low 5-year NPV (£m)	Market factors High 5-year NPV (£m)	Delivery factors Low 5-year NPV (£m)	Delivery factors High 5-year NPV (£m)	Third-party factors Low 5-year NPV(£m)	Third-party factors High 5-year NPV (£m)
A1	Undergoing Balancing Capability Strategic Review (CBA to be provided in final BP2 submission)							
A2	16.44	40.84	11.28	21.60	-0.05	40.27	16.44	16.44
A3	2.25	24.78	-0.91	6.54	2.25	225	2.25	2.25
A18	Not subject to CBA							
A17	Break-even analysis in BP1 CBA annex							
A19	Not subject to CBA							
Role 1	**18.69**	**65.62**	**10.37**	**28.14**	**2.20**	**42.52**	**18.69**	**18.69**

4.5. Role 1 Cost Summary

			2021/22 (£m)	2022/23 (£m)	2023/24 (£m)	2024/25 (£m)	2025/26 (£m)	Total (£m)
A1	Control Centre architecture and systems	Awaiting outcome of strategic review						
A2	Control Centre training and simulation	Capex	0.02	0.17	1.16	2.33	2.33	**6.01**
		Opex	1.64	1.71	2.48	3.24	3.68	**12.75**
		Total	1.66	1.88	3.64	5.57	6.01	**18.76**
A3	Restoration	Capex	0	2.29	7.65	8.10	6.30	**24.34**
		Opex	0	0.59	0.97	1.67	1.47	**4.70**
		Total	0	2.87	8.62	9.77	7.77	**29.03**
A18	Market monitoring	Not subject to revised analysis						

		2021/22 (£m)	2022/23 (£m)	2023/24 (£m)	2024/25 (£m)	2025/26 (£m)	Total (£m)
A17 Transparency and open data							
A19 Data and analytics hub							
Role 1	**Capex**	**0.02**	**2.46**	**8.81**	**10.43**	**8.63**	**30.35**
	Opex	**1.64**	**2.30**	**3.45**	**4.91**	**5.15**	**17.45**
	Total	**1.66**	**4.76**	**12.26**	**15.34**	**13.78**	**47.80**

5. Role 2

Within Role 2 we have updated the existing CBAs for A4, A5 and A6. We have also undertaken new break-even analyses for A20 and A21.

For A4 two separate pieces of analysis have been undertaken due to the different nature of its sub-activities. Likewise, for A6 we present four separate pieces of analysis which is consistent with our approach in BP1.

Activity	Activity name	Material changes in activity since BP1	Analysis status	Changes in analysis since BP1
A4	Build the future balancing service markets	Scope	Updated: CBA	Minimal change
A4	Lead a review of wholesale, balancing and capacity markets	New deliverables	Updated: Break-even	Minimal change (break-even analysis)
A5	Transform access to the Capacity Market	New deliverables	Updated: CBA	‘Companies on CM Register’ assumption has changed Cost increase
A6.4	Transform the process to amend our codes	Scope	Updated: Break-even	Minimal change (break-even analysis)
A6.5 & 6.8	Work with all stakeholders to create a fully digitalised, Whole System Technical Code by 2025	New sub-activity Costs	Updated: CBA	‘Connection applications’ assumption has changed
A6.6 & 6.7	Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS)	New sub-activity	Updated: CBA	5-year NPV estimates taken from Ofgem analysis
A6.9	Whole system codes reform	New sub-activity	New: Break-even	
A20	Net zero market reform	New activity	New: Break-even	
A21	Role in Europe	New activity	New: Break-even	

5.1. A4 Build the future balancing service markets

This subsection contains the costs and benefits for **A4 Build the future balancing service and wholesale markets** which comprises of the RIIO-2 sub-activities A4.3, A4.4 and A4.6.

The net present value of these activities is £67.89 million over the RIIO-2 period and £159.20 million over ten years. Sensitivity analysis suggests an NPV range of £8.05million to £112.39 million over the RIIO-2 period.

5.1.1. NPV drivers

The overall NPV of the A4 CBA has not changed significantly since BP1, we observe an increase of £0.61m for the RIIO-2 period.

In our BP2 CBA, cost forecasts have increased overall by approximately £10m with a decrease in costs in the first year of the RIIO-2 period but an increase in the last 4 years. Similarly, while total benefits are not significantly changed, we see an increase in the first two years of the RIIO-2 period but decrease in the last three years when compared with the BP1 CBA.

Our BP2 CBA also has a £23m reduction in 10-year NPV which is directly linked to an increase in costs and a reduction in benefits in the latter years of the RIIO-2 period.

We have not altered the benefits methodology of this CBA from BP1. We have only updated the underlying assumptions in accordance with the BP1 methodology.

5.1.2. Changes from BP1

Benefits case	Changes	Description
More liquid response and reserve market	Response and reserve costs	Latest response and reserve costs used
Buying the optimal volume of response	Response and reserve costs	Latest response and reserve costs used

The sub-activities A4.3 Deliver a single day-ahead response and reserve market and A4.4 Deliver a single integrated platform for ESO markets are both materially changed since BP1 due to delays in delivery. The sub-activity A4.6 Balancing and ancillary services market reform is materially changed due to new deliverables. These changes do not impact the benefits cases of the A4 CBA, but the new or changed costs are included in the CBA.

New or materially changed sub-activity	Benefits impact
A4.3 Deliver a single day-ahead response and reserve market	The delivery delays are short (3-6 months) and have no impact on the benefits timeline.
A4.4 Deliver a single integrated platform for ESO markets	The changes made to the deliverables do not impact the benefits case for A4. Likewise, the delays to delivery timescales are small and do not impact benefits.
A4.6 Balancing and ancillary services market reform	The new deliverables do not create additional financial benefits within A4 and existing benefits cases cover the benefits created by this sub-activity.

5.1.3. The counterfactual

If we did not invest in sub-activities A4.3, A4.4 and A4.6, we would continue to have only the existing participation in balancing and capacity markets; i.e. we would be unable to facilitate the single market platform or enable participants of 1 MW size. We could only expect incremental improvements in our capability and we would therefore be unable to deliver many of the benefits we set out in our original RIIO-2 plans.

5.1.4. The benefits

We have quantified benefits in two areas:

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

5.1.4.1. More Liquid Response and Reserve Market

Assumptions	Justification
Value of the response and reserve market is £479 million per year	See main assumptions section. Note this is not a forecast of future response and reserve spend, this is the value of the response and response market today used for estimation of consumer benefits.

Assumptions	Justification
Our actions deliver a 5% saving in the response and reserve markets	Evidence from early trials (as identified in the *2019-21 Forward Plan*[7]) and from subsequent market changes.
Benefits delivered from year three of RIIO-2	This allows two years for implementation of the activity.

The value of the response and reserve markets today is £479 million per year. Moving closer to real time markets increases the number of potential participants. If we assume a 5% 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 £23.9 million from increased liquidity. These timescales allow two years for implementation.

At BP1 our evidence for the 5% saving was based on early trials. Since then, we have found additional evidence to support this assumption. During the first 12 months of operation of the weekly Auction Trial from December 2019 to November 2020, the average monthly price of the Dynamic Low High frequency product (the dynamic auction product) was £7.08/MWh, while during the same period the average monthly price of tendered dynamic Firm Frequency Response (FFR), including monthly and longer-term tenders, was £8.17/MWh.

In the six months preceding the introduction of the weekly Auction Trial, namely the period from June to November 2019 inclusive, the average monthly price of tendered dynamic FFR was £11.35/MWh. This data shows that procurement in the weekly Auction Trial was cheaper than the monthly tender, and that the introduction of the Auction Trial also put downward pressure on tender prices.

Improvements to the Dynamic Containment (DC) service, such as the move from requiring a daily commitment from providers to procurement by Electricity Forward Agreement (EFA) block, also improved liquidity and resulted in a decrease in procurement costs for DC. This initiative seems to have had a beneficial impact on procurement costs, largely in line with the 5% decrease that was estimated at BP1 in this CBA.

Within the BP1 period, Dynamic Moderation (DM) and Dynamic Regulation (DR) products will launch in March and April 2022 respectively. While requirements will initially be in addition to the FFR requirements, before the BP2 period we plan to lift the volume cap, increase procurement of DM and DR and progress with the phase out of monthly FFR tenders. Features such as unbundling will also allow more participants to enter the market and increase liquidity.

Looking forward to the BP2 period, there are several planned initiatives that target further increases in market liquidity. Among these are:

- Co-optimisation of DC, DM, and DR (unlocked by the Enduring Auction Capability) – this will result in more efficient clearing of the various frequency response services and consequently better use of frequency response capacity.
- Stacking of the DC, DM, and DR services – this will allow more flexible and efficient use of assets, especially batteries (e.g. by making it easier to manage cycling rates within warranties, and to control state of charge management).

Sensitivity analysis

- **Market factors:** we have repeated the analysis with the high and low cases for the reserve and response market sizes: £549 million a year and £374 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 the A2 CBA. Any potential double counting is accounted for in the sensitivity analysis.

[7] ESO 2019-21 Forward Plan, p.111, https://www.nationalgrideso.com/document/140736/download

Central case calculation

Percentage price reduction		Size of annual reserve and response markets £ million		Annual saving
5%	x	£479 million	=	£23.9 million

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
More liquid response and reserve market (central case)	0.0	0.0	24	24	24	**72**
Sensitivity – high market	0.0	0.0	27	27	27	**81**
Sensitivity – low market	0.0	0.0	19	19	19	**57**
Sensitivity – high delivery	0.0	0.0	36	36	36	**108**
Sensitivity – low delivery	0.0	0.0	0	12	12	**24**

The above table shows the benefits of a more liquid response and reserve market are between £24 million and £108 million, with a central case of £72 million over the RIIO-2 period.

5.1.4.2. Buying the optimal volume of response

Assumptions	Justification
Value of the response market is £179 million per year	See main assumptions section. Note this is not a forecast of future response spend, this is the value of the response market today used for the estimation of consumer benefits.
Our actions deliver a 5% saving in the response market	Evidence from early trials (as identified in the *2019-21 Forward Plan*[8]) and from subsequent market changes.
Benefits delivered from year three of RIIO-2	This allows two years for implementation of the activity.

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

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

The annual cost of procuring response in the market is £179 million. Managing the daily variation closer to real time, while reducing use of mandatory services means we will 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 £8.9 million.

[8] ESO 2019-21 Forward Plan, p.111, https://www.nationalgrideso.com/document/140736/download

Sensitivity analysis

- **Market factors:** we have repeated the analysis with the high and low cases for the response markets; £216 million a year and £141 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 response costs are also claimed as benefits in the A2 CBA. Any potential double counting is accounted for in the sensitivity analysis.

% price reduction		Size of annual response markets £ million		Annual saving £ million
5%	x	178	=	8.9

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Buying the optimal volume of response (central case)	0.0	0.0	8.9	8.9	8.9	**26.8**
Sensitivity – high market	0.0	0.0	10.8	10.8	10.8	**32.4**
Sensitivity – low market	0.0	0.0	7.0	7.0	7.0	**21.1**
Sensitivity – high delivery	0.0	0.0	13.4	13.4	13.4	**40.2**
Sensitivity – low delivery	0.0	0.0	0	4.5	4.5	**8.9**

The above table shows the benefits of buying the optimal volume of response are between £8.9 million and £40.2 million, with a central case of £26.8 million over the RIIO-2 period.

5.1.4.3. Total benefits case

The total benefits in the A4 CBA are between £33 million and £148 million, with a central case of £99 million over the RIIO-2 period.

5.1.5. Activity costs

Delivery of these activities will require Capex and Opex spend as summarised below:

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	4.68	8.87	8.10	7.54	7.41	**36.60**
Opex	1.70	1.87	3.17	2.10	1.92	**10.76**
Total	**6.38**	**10.74**	**11.26**	**9.64**	**9.33**	**47.36**

The total costs for **A4 Build the future balancing service and wholesale markets** are £47.36 million.

5.1.6. Net present value

The net present value of **A4 Build the future balancing service and wholesale markets** is estimated at £67.89 million over the RIIO-2 period and £159.20 million over ten years, and these activities will start to deliver positive returns from 2023/24. Sensitivity analysis suggests an NPV range of:

- Considering market scenarios, between £43.52 million and £82.59 million.
- Considering delivery factors, between £8.05 million and £112.39 million.

5.1.7. Dependencies, enablers and whole energy system

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

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

Delivering competitive flexible markets also allows the following transformational activities:

- **A15 Taking a whole electricity system approach to promote zero-carbon operability** (Role 3)
- **A5 Transform access to the Capacity Market** (Role 2)
- **A7 – A11 *NOA* enhancements** (Role 3)
- **A17 Digitalisation and open data** (Role 1) – by providing additional data from competitive markets

Delivering this activity also 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.

5.1.8. Uncertainties and risks

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

The table below summarises the key risks and how we propose to mitigate them. Risks for the associated IT investments can be found in the IT annex.

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 ensuring platform design is aligned with current preferred option. Platform will be designed 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 previous development; 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	Some regret spend is inevitable given the uncertainty faced by the ESO. Focus on taking well understood and justified risks and identify lessons-learnt from all trials.	3	1

5.2. A4 Lead a review of wholesale, balancing and capacity markets

This subsection contains the break-even analysis 'Lead a review of wholesale, balancing and capacity markets', which comprises of the RIIO-2 sub-activities A4.1, A4.2 and A4.5.

5.2.1. Changes from BP1

One new deliverable has been added, this is D4.3.6 Future Developments to Frequency Response Services. The new deliverable builds on existing ones and does not have material impact on the overall benefits.

5.2.2. Why have we undertaken break-even analysis?

This analysis provides details of the benefit that would need to be delivered to cover the costs of the sub-activities involved.

We have undertaken a break-even analysis because these sub-activities do not deliver consumer benefits by themselves. It is the implementation of their recommendations that provide consumer benefit, and we cannot say at this stage what, if any, these are.

5.2.3. The counterfactual

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

5.2.4. Activity costs

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0	0	0	0	0	**0**
Opex	0	0	0.67	0.67	0.67	**2.01**
Total	**0**	**0**	**0.67**	**0.67**	**0.67**	**2.01**

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

5.2.5. Assumptions, justifications and risks

The following key risks have been identified:

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

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

5.2.6. The benefits

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

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

5.2.7. Conclusion

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

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

5.3. A5 Transform access to the Capacity Market

This subsection contains the costs and benefits of our activity **A5 Transform access to the Capacity Market**.

The net present value of A5 is estimated at £58.99 million over the RIIO-2 period, and £116.81 million over ten years. Sensitivity analysis suggests an NPV range of £17.37 million to £90.29 million over the RIIO-2 period.

5.3.1. NPV drivers

We have seen a £3m and £11m reduction in the 5-year and 10-year NPV for A5. This reduction in NPV is driven by an increase in costs from BP1 of £14m. Benefits remain relatively similar and have little overall bearing on the change in NPV.

We have updated the benefits methodology from BP1 to better reflect the number of companies interacting with the Capacity Market, the impact of this change is small at less than £1m per annum increase in benefits. All other methodology is the same as at BP1 and we have only updated the underlying assumptions, in accordance with the methodology for these assumptions at BP1.

5.3.2. Changes from BP1

Benefits case	Changes	Description
Enhanced Modelling Capability	T-4 Auction Clearing Prices	Updated to include latest clearing prices
Barriers to Entry	Number of companies on CM Register	Updated to latest figures
Barriers to Entry	% Of Companies interacting with the Capacity Market	New Factor included to account for participation by registrants

A5.4 Long-term capacity adequacy is a new sub-activity that does not generate tangible benefits within A5, however, its costs are included in the A5 CBA.

New or materially changed sub-Activity	Benefits impact
A5.4 Long-term capacity adequacy	A5.4 considers a much longer-term horizon than A5.3 Improving our security of supply modelling capability and should help industry while supporting policy, by building our capability studies However, the outcomes of A5.4 will not be used to inform decision making for the purchase of capacity as part of the Capacity Market mechanism. As such no benefits will be accounted for it in this cost-benefit analysis. A5.4 acts to support deliverables such as Net Zero Market Reform and to ensure the findings can be integrated into the real-time operational environment.

5.3.3. The counterfactual

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

5.3.4. The benefits

We have quantified benefits in two areas:

- Enhanced Modelling Capability.
- Reduced Barriers to Entry and Cost of Participation.

5.3.4.1. Enhanced Modelling Capability

Assumptions	Justification
Clearing price of the Capacity Market is £17.05/kW per year.	Average of six T-4 auctions held to date
Our actions save consumers the equivalent of purchasing an additional 1 GW of capacity	This saving is equivalent to approximately 2% of the average volume purchased in the last four T-4 auctions, comparable with EMR demand forecasting incentives as a benchmark[9]
Benefits delivered from year two of RIIO-2	This allows a year for implementation of this activity, given auction timings, when improved analysis will feed into recommendations to procure capacity

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

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

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

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

1. Reduced risk of recommendations being too low: Save consumers the equivalent of purchasing at T-4 an additional 1 GW[10] of capacity, instead of at T-1 or short-term balancing markets. Any consumer savings are hard to accurately forecast, given the small number of T-1 auctions held to date and the volatile nature of short-term balancing markets. Purchasing capacity at T-4 will reduce the uncertainty of purchasing at the T-1 or balancing market stage. There is also an inherent security of supply risk associated with under forecasting.
2. Reduced risk of recommendations being too high: Save consumers the equivalent purchase cost of 1 GW[27] of capacity at T-4. Any capacity saving is hard to accurately forecast, given the complexity of how the final auction price is arrived at. However, if we consider the average clearing price over the four T-4 auctioned held to date, £17.05/kW (see table below), and apply to the 1 GW this would save consumers £17 million per year.

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

Sensitivity analysis

- **Market factors:** we have repeated the analysis with the high and low cases for the clearing price of the Capacity Market: £21.39 /kW per year and £12.70 /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.

[9] 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
[10] This saving is equivalent to approximately 2% of the average volume purchased in the last four T-4 auctions (see table 61). This percentage is comparable with EMR demand forecasting incentives as a benchmark

T-4 Auction (delivery year)	Clearing price (£/kW/year)	Capacity secured (GW)	Cost of 1GW (£)
2023/24	18.00	40.820	18,000,000
2022/23	16.0	43.749	16,000,000
2021/22	8.4	50.415	8,400,000
2020/21	22.5	52.425	22,500,000
2019/20	18.0	46.353	18,000,000
2018/19	19.4	49.258	19,400,000
Average	17.1	49.613	17,075,000

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Enhanced Modelling Capability (central case)	0.0	17.0	17.0	17.0	17.0	**68.2**
Sensitivity – high market	0.0	21.4	21.4	21.4	21.4	**85.5**
Sensitivity – low market	0.0	12.7	12.7	12.7	12.7	**50.8**
Sensitivity – high delivery	0.0	25.6	25.6	25.6	25.6	**102.2**
Sensitivity – low delivery	0.0	0.0	8.5	8.5	8.5	**25.6**

The above table shows the benefits from enhanced modelling capability are between £25.6 million and £102.2 million, with a central case of £68.2 million over the RIIO-2 period.

5.3.4.2. Reduced Barriers to Entry and Cost of Participation

Assumptions	Justification
1122 companies registered on EMR portal	The approximate number of companies' registered on the EMR portal
Our actions save two FTE weeks of time from each Capacity Market company	We have assumed that companies FTE commitment mirroring ESO commitments
Benefits delivered from year two of RIIO-2	This allows a year for implementation of the activity, given auction timings.
50% of registered companies interact with the Capacity Market	We have assumed that around 50% of registered companies are active at either T1 or T4 auctions, based on historical observations.

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

If 50% of the registered companies interact with the Capacity Market and each of those were to save the cost of two weeks of a FTE we estimate a total annual saving of £2.2 million. This is based on 1122 companies saving two FTE weeks of time, with the FTE costing £100,000 per year.

We have updated the methodology at BP2 to better account for the total costs associated with participating in the Capacity Market Auction:

Change	Justification
Company number is now taken from companies registered on EMR portal rather than the number of companies entering the Capacity Market Auction.	Companies can choose to participate or not participate at the auction. Companies choosing to not participate at the auction will also incur costs which this activity seeks to reduce.
A new factor of 50% of registered companies interact with the Capacity Market is applied to the total number of companies registered	We observe historically that around 30-60% of registered companies participate in the auction. We have assumed 50% to account for the number of companies who incur costs who do not participate in the auction.

Sensitivity analysis

- **Market factors:** we have repeated the analysis with the high and low cases for the number of Capacity Market companies: +25% / -25%
- **Delivery factors:** we have modelled a one-year delay in delivery for the low case, from 2023/24.
- **Third-party factors:** we have repeated the analysis with the high and low cases for Capacity Market time saved: three weeks and one week respectively.

Number of companies registered on EMR Portal	% Interacting	Annual cost of an FTE £s	Two weeks		Annual saving £ million
1122	x 50%	x 100,000	÷26	=	2.2

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Reducing Barriers to Entry (central case)	0.0	2.2	2.2	2.2	2.2	**8.8**
Sensitivity – high market	0.0	2.7	2.7	2.7	2.7	**10.8**
Sensitivity – low market	0.0	1.6	1.6	1.6	1.6	**6.4**
Sensitivity – low delivery	0.0	0.0	2.2	2.2	2.2	**6.6**
Sensitivity – high third-party	0.0	3.2	3.2	3.2	3.2	**12.8**
Sensitivity – low third-party	0.0	1.1	1.1	1.1	1.1	**4.4**

The above table shows the benefits from this activity are between £4.4 million and £12.8 million, with a central case of £8.8 million over the RIIO-2 period.

5.3.4.3. Total benefits case

The total benefits for A5 are between £31 million and £115 million, with a central case of £77 million over the RIIO-2 period.

5.3.5. Activity costs

Delivery of A5 will require Capex and Opex spend, as summarised below:

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	5.38	5.46	4.08	3.07	3.07	**21.07**
Opex	0.69	0.95	0.85	0.83	0.65	**3.97**
Total*	**6.07**	**6.42**	**4.93**	**3.91**	**3.72**	**25.05**

**Totals may appear incorrect due to rounding*

The total cost for A5 is £25.05 million.

5.3.6. Net present value

The net present value of A5 is estimated at £58.99 million over the RIIO-2 period and £116.89 million over ten years will start to deliver positive returns from 2022/23. Sensitivity analysis suggests an NPV range of:

- Considering market factors, between £41.07 million and £76.91 million.
- Considering delivery factors, between £17.37 million and £90.29 million.
- Considering third-party factors, between £55.03 million and £62.73 million.

5.3.7. Dependencies, enablers and whole energy system

A5 is dependent on the following transformational activities:

- **A4 Build the future balancing service and wholesale markets** (Role 2) – this activity delivers the single market platform.
- **A20 Net zero market reform** (Role 2) – successful delivery of A5.4 is dependent on the outcomes of A20.

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

5.3.8. Uncertainties and risks

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

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

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

5.4. A6.4 Transform the process to amend our codes

This subsection contains the break-even analysis for **A6.4 Transform the process to amend our codes.**

5.4.1. Changes from BP1

One new deliverable has been added, this is **D6.4.1 Implement no regret actions from the Energy Codes Review**. The Energy Codes Review has only recently been published and therefore the scope and timescales for **D6.4.1** are not yet fully understood. We will consider whether any updates are needed to this analysis to account for D6.4.1 ahead for our final Business Plan submission in August 2022.

5.4.2. Why have we undertaken break-even analysis?

A break-even analysis provides details of the benefit that will 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.

5.4.3. The counterfactual

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

5.4.4. Activity costs

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0	0	0	0	0	**0**
Opex	0	0	0.28	0.28	0.28	**0.85**
Total	**0**	**0**	**0.28**	**0.28**	**0.28**	**0.85**

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.

5.4.5. Assumptions, justifications and risks

Risk	Mitigations	Likelihood	Impact
BEIS/Ofgem Joint Energy Codes Review does not align with our RIIO-2 ambition and/or complete during the ESO *Forward Plan* 2020/21 period	Continue to undertake our role in the Energy Codes Review. Subject to this, our Business Plans may require revision and should be subject to future amendment	3	2
Based on stakeholder feedback and Ofgem's proposals in the RIIO-2 sector specific methodology publication, we have assumed the ESO will remain the code administrator for Connection and Use of System Code (CUSC), System Operator – Transmission Owner Code (STC) and Grid Code, as well as being the de facto code administrator for the SQSS	Continue to engage with industry to demonstrate we are best placed to maximise consumer benefit through the codes we administer	1	5
We have assumed necessary legislation changes will happen at the start of the RIIO-2 period to give us the powers to transform code processes. This is a key dependency which unlocks further change over the remainder of the RIIO-2 period	Continue to undertake our role in the Energy Codes Review. Engage Ofgem and BEIS to highlight the legislative changes required for our future role	3	4

5.4.6. The benefits

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

- Ensures codes remain appropriate for emerging markets and business models to always contribute to safe and reliable operation of the system in future.
- The modification process is more efficient and reduces the time that customers are required to be involved. Code changes will be prioritised with those that have the greatest expected benefit implemented first. Newer and smaller providers are better served by more tailored and suitable arrangements allowing for more players to enter a more competitive market.
- The primary focus of this work is to drive efficiency into the codes and code change process by reducing barriers to entry and increasing information provision. The result is to contribute to the creation of more efficient and competitive markets, reducing wholesale market costs, as well as BSUoS and TNUoS costs, depending on the code in question and against a counterfactual of no change to the process. There are also internal efficiency savings for industry participants as there is a quicker and less resource intensive change process.
- There will be secondary benefits to the environment because of these changes as more efficient codes contribute to more efficient decarbonisation of the energy system.

5.4.7. Conclusion

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

- It will drive overall process efficiency for the ESO and industry, including fewer meetings and more focused discussions. These efficiencies are likely to be realised year-on-year, driven by the average number of codes modifications which the ESO facilities each year[11]. 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, prioritising high value code modifications. This is likely to be realised over a single year from a high value modification being delivered one year earlier.

5.5. A6.5 Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 & A6.8 Digitalisation of codes

This subsection contains the costs and benefits of our sub-activities **A6.5 Work with all stakeholders to create a fully digitalised, whole-system Grid Code by 2025** and **A6.8 Digitalisation of codes.**

The NPV of A6.5 and A6.8 is estimated at £32.05 million over the RIIO-2 period and £138.09 million over ten years, which will start to deliver positive returns from 2025/26.

5.5.1. NPV drivers

The 5 and 10-year NPV has increased by £28m and £120m respectively since BP1.

The reason for this large change is due to the increase in total benefits. Benefits for this case are directly proportional to the total number of connection applications. At BP1 we used a figure of 400 connection applications per year while at BP2 we are forecasting an average of 1,381 connection applications per year. We are observing a rising and sustained number of connection applications and therefore any benefit associated with improving efficiency during grid connections will also increase.

We have not altered the benefits methodology from BP1. Only the underlying assumptions have been updated, in accordance with the methodology for these assumptions at BP1.

5.5.2. Changes from BP1

Changes	Description
Number of Connection Applications	Updated to latest number and now includes detailed sensitivities

A6.8 is a new sub-activity; however, it does not generate new tangible benefits, the benefits were already accounted for at BP1. The original A6.5 sub-activity has now been split into two sub-activities A6.5 and A6.8 where A6.5 is focused on consolidation of code and A6.8 on digitalisation of codes. Splitting the original sub-activity improves governance and control of the project to deliver best value for consumers. The expected split of benefits is 80% Digitalisation and 20% Consolidation.

New or materially changed sub-activity	Benefits impact
A6.8 Digitalisation of codes	A6.8 has been created after splitting the original A6.5 Sub-Activity, it accounts for approximately 80% of the total benefits case. For simplicity, their remains a single benefits case, Reduced Barriers to Entry.

5.5.3. The counterfactual

If we did not undertake this activity, we would leave access to the Grid Code remaining as it is today. It would not extend to consider the whole system, with only incremental improvements in the third-party experience.

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

5.5.4. The benefits

Assumptions	Justification
Average 2762 projects interacting with the whole system Grid Code per year in RIIO-2 Period	Based on twice the applications for connections to the transmission system, to account for estimated distribution projects. Forecast connection numbers taken from A14 benefits case.
Our actions save one FTE month of time from each project	Estimated effort required on each application process
Benefits delivered from year four of RIIO-2	This allows a year for implementation of the activity, given that the project begins in year two of RIIO-2 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. It will provide more targeted and customised information when our customers need it. These improvements will also aid new smaller entrants, as well as supporting innovation in the market. In the long term, new parties will deliver efficiencies and lower cost for consumers

We have considered use of the whole system Grid Code by parties connecting to the transmission and distribution systems. We have assumed that the improved digital service will remove one person month of effort from each application process providing a total annual saving of £40 million. To calculate this, we have assumed the total cost of an FTE is £100,000 per year and that 2762 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 while in 2021 there were 1050 applications for connection. The numbers are continuing to increase with 2022 connection applications forecast to be well in excess of the 2021 numbers.

We claim half the maximum benefit in 2024/25 due to the implementation timescales.

Central case benefits calculations

Number of parties forecast to interact with the whole system Grid Code (2024/25)		Annual cost of an FTE £s		One month		Half of maximum benefit claimed		Annual saving £ million
2976	x	100,000	÷	12	÷	2	=	12.4

Number of parties forecast to interact with the whole system Grid Code (2025/26)		Annual cost of an FTE £s		One month		Annual saving £ million
3310	x	100,000	÷	12	=	27.6

Sensitivity analysis

- **Market factors:** we have repeated the analysis with the high and low cases for the number of projects.
- **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.

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Reducing Barriers to Entry (central case)	0.0	0.0	0.0	12.4	27.6	**40.0**
Sensitivity – high market	0.0	0.0	0.0	14.1	31.2	**45.3**
Sensitivity – low market	0.0	0.0	0.0	10.7	24.0	**34.7**
Sensitivity – low delivery	0.0	0.0	0.0	0.0	13.8	**13.8**
Sensitivity – high third-party	0.0	0.0	0.0	18.6	41.4	**60.0**
Sensitivity – low third-party	0.0	0.0	0.0	6.2	13.8	**20.0**

5.5.4.1. Total benefits case

The total benefit for A6.5 and A6.8 is between £13.8 million and £60.0 million, with a central case of £40.0 million over the RIIO-2 period

5.5.5. Activity costs

Delivery of A6.5 and A6.8 will require Capex and Opex spend, as summarised below:

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0.00	0.28	0.80	0.50	0.00	**1.58**
Opex	0.47	0.59	0.80	0.64	0.39	**2.89**
Total	**0.47**	**0.87**	**1.60**	**1.14**	**0.39**	**4.47**

The total cost for A6.5 and A6.8 is £4.47 million.

5.5.6. Net present value

The NPV of A6.5 and A6.8 is estimated at £32.05 million over the RIIO-2 period and £138.09 million over ten years, which will start to deliver positive returns from 2025/26. Sensitivity analysis suggests an NPV range of:

- Considering market factors, between £27.35 million and £36.73 million.
- Considering delivery factors, between £8.84 million and £32.05 million.
- Considering third-party factors, between £14.44 million and £49.66 million.

5.5.7. Dependencies, enablers and whole energy system

Delivery of A6.5 and A6.8 is dependent on the following transformational activities:

- **A6.4 Transform the process to amend our codes** (Role 2) – this sub-activity will allow the ESO to manage codes more efficiently, prioritising change across all ESO-managed codes.
- **A12 SQSS Review** (Role 3) – this activity will ensure alignment between recommended code changes.

A6.5 and A6.8 will require third parties, in particular the distribution networks operators (DNOs), to work collaboratively with the ESO to create the whole system element, and for current and future whole system Grid Code users to fully participate in the process. There may be minor costs from adapting to these new arrangements, but we believe these are within the scope of third parties' ongoing investments.

5.5.8. Uncertainties and risks

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

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

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

5.6. A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges and A6.7 Fixed BSUoS tariff setting

This subsection contains the NPV estimates for our activities **A6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS)** and **A6.7 Fixed BSUoS tariff setting**.

The NPV for A6.6 and A6.7 is estimated at £68 million over the 5-year RIIO-2 period. The 10-year NPV is estimated at £167 million.

5.6.1. NPV drivers and changes from BP1

Since BP1, the ESO has developed options for BSUoS reform through the code modification process, as recommend by the Balancing Services Charges Task Forces. These modifications are:

- CMP308 – Removal of BSUoS charges from generation and recovering all costs from final demand,

- CMP361 – Introduction of an ex-ante fixed BSUoS tariff.

The scope of BSUoS reform now includes removing charging arrangements from generators, as well as fixing tariffs. Therefore, the scope of our activities in A6.6 and A6.7 has expanded to include considerations for modification CMP308 and our updated CBA reflects the total benefits associated with this BSUoS reform.

Our estimate of the 5-year NPV for A6.6 and A6.7 has reduced significantly since BP1, by £210m. This is due to:

- The use of an improved benefits methodology for BP2 - our BP1 CBA was created in 2019, well before the final report of the Second Balancing Services Task Force was published in September 2020, and therefore before the proposed changes to BSUoS were known. The new methodology uses refined assumptions that were unavailable at the time of our original CBA estimate. In particular, the value assumed for the BSUoS industry risk premia has reduced significantly.
- Implementing BSUoS reform in April 2023 – this start date is aligned with the recommendations of the BSUoS Task Force and industry workgroup discussions. Our BP1 CBA assumed implementation in April 2022.

Changes from BP1	Description
Benefits methodology	Our 5-year NPV estimate is now based on analysis commissioned by Ofgem for CMP308
Change in implementation date for BSUoS reform	We assume benefits begin from April 2023

Since BP1 the sub-activity A6.6 has been completed and A6.7, a new sub-activity, can be viewed as the delivery of A6.6's recommendations. The benefits of A6.7 are already accounted for in the original A6.6 benefits case, so A6.7 has no additional financial benefits.

New or materially changed sub-activity	Benefits impact
A6.7 Fixed BSUoS Tariff Setting	No additional benefits, as benefits were already claimed against A6.6

5.6.2. The counterfactual

If we did not undertake A6.6 and A6.7, the BSUoS arrangements would remain unchanged and the BSUoS price would continue to be set after the event.

5.6.3. The benefits

Assumptions	Justification
We have assumed benefits as outlined in the minded-to decision and draft impact assessment for CMP308	Analysis commissioned by Ofgem
ESO will finance any new arrangements	Taking on the additional cost of managing the risk premia will require financing for the ESO to manage this risk
Benefits delivered from year three of RIIO-2	Estimated implementation date of BSUoS reform

Ofgem commissioned analysis by independent consultants, Frontier Economics and LCP to support their assessment of the above modifications. The analysis included an 18-year NPV for CMP308[12] and CMP361[13].

[12] https://www.ofgem.gov.uk/publications/cmp308-minded-decision-and-draft-impact-assessment (LCP/Frontier report - Wider System and Distributional Impacts of Recovering Balancing Services Costs from Demand)
[13] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp361-cmp362 (Annex 4 – Frontier Economics Report – CMP361 Analysis, CMP361 and CMP362 Code Administrator Consultation Annexes)

Unfortunately, different methodologies were used and hence it is not possible to easily combine the impacts to obtain a NPV of both modifications that reflects the total benefits of BSUoS reform. We have therefore chosen to focus on the CMP308 NPV using the Consumer Transformation *FES* as a basis, recognising that this gives a conservative estimate of the total NPV. To obtain an estimate of the NPV across the RIIO-2 period, we have annuitised the benefits from the analysis commissioned by Ofgem.

This gives an estimated NPV of £68 million over the 5-year RIIO-2 period and £167 million over 10-years. Therefore, our estimate of the 5-year NPV has reduced by £210m since BP1.

5.6.4. 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 and that BSUoS parties pass on any reduced operational costs to consumers.

5.6.5. Uncertainties and risks

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

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
If forecasted BSUoS costs are incorrect and the ESO's working capital facility (anticipated to be £300m) and any industry BSUoS fund are forecast to be exceeded, tariffs will need to be reset and this could result in energy suppliers continuing to hold a level of risk premia for such occasions.	Investment in BSUoS charges forecasting	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 will need to occur via a Code Modification process. This will provide uncertainty in the specifics of any change to be presented to the Authority for approval.	Engage with Ofgem to ensure the scope of this is understood and the proposal align with their expectations.	2	3
Uncertainties about the future direction of balancing services charges. These could impact the options within this paper prior to RIIO-2.	Keep proposals under review to ensure costs and benefits are reflective of the most recent position for BSUoS.	4	2

5.7. A6.9 Whole system codes reform

This subsection contains the break-even analysis for **A6.9 Whole system codes reform.**

5.7.1. Why have we undertaken break-even analysis?

A break-even analysis provides details of the benefit that will need to be delivered to cover an activity's costs.

We have conducted this analysis because the activity considers cross-cutting issues and will suggest solutions for:

- Changes to licenses, regulation, and codes
- Future non-network solutions on the electricity framework
- Changes to facilitate DSO and whole system outcomes between ESO and DNOs

This sub-activity will make recommendations on the appropriate structure of electricity market frameworks. This activity itself does not deliver a quantifiable financial benefit, the delivery of its recommendations will deliver the financial benefit, as such it is appropriate to undertake break-even analysis.

5.7.2. The counterfactual

The counterfactual to undertaking A6.9 is the ESO does not make recommendations on the structure of the codes to reach net zero, with only incremental improvements made. This would result in lost opportunities to optimise investment.

5.7.3. Activity costs

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0	0	0	0	0	**0**
Opex	0	0	0.4	0.4	0.4	**1.2**
Total	**0**	**0**	**0.4**	**0.4**	**0.4**	**1.2**

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.

5.7.4. Assumptions, justifications and risks

Risk	Mitigations	Likelihood	Impact
Other ESO initiatives do not deliver as expected to inform this activity e.g., Pathfinders, Onshore Competition, Pathfinders	Early alignment and engagement with other areas of the ESO. Look to pivot as markets continue to develop to ensure best value for consumers.	3	3
Framework design does not fully meet requirements. Benefits are not as expected i.e., do not outweigh costs.	Ensure engagement with all parties and look to trial findings in both live and test environments.	4	1
Industry does not engage with the process, leading to a suboptimal market design.	Use best practice engagement. Ensure ESO is resourced appropriately to undertake engagement.	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.	3	1

5.7.5. The benefits

The quantitative benefits of a targeted review of the Whole Electricity System Framework Reform are:

- The ESO will take a broader view and assess the likely impacts of changes in areas that would otherwise not be able to be fully considered leading to:
  - Improved market efficiency
  - Improved investment efficiency
  - Increased and new categories of market participants
  - Improved participation in the market by both existing and new categories of parties

5.7.6. Conclusion

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

- It will drive overall efficiency for the ESO, market and industry.
- It will consider the broader impacts of changes leading to significant risk mitigation.
- Even a small increase in efficiency or reduction in risk will result in a large benefit for consumers.

5.7.7. Other options considered

1. Industry/Market Participants lead on market reform:
   - Lack view of internal system, significant investment would be required to align all market participant from Generation through to Storage
   - Market Participants would have a vested interest in market design and lack impartiality the ESO provides
2. DNO leads on market reform at Distribution Level:
   - While market reform could be undertaken at the DNO level there would need to be significant investment to:
     - Align DNOs to create a single market
     - Upskill the DNOs to be able to manage markets in a similar manner to the ESO
3. Do nothing:
   - Continue with current markets
   - Investment will not be optimised
   - Risk will be larger

5.8. A20 Net zero market reform

This subsection contains the break-even analysis for **A20 Net zero market reform.**

5.8.1. Why have we undertaken break-even analysis?

It provides details of the benefit that will 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.

5.8.2. The counterfactual

The counterfactual to **A20 Net zero market reform** is we do not undertake a review into the current market.

5.8.3. Activity costs

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0	0	0	0	0	**0**
Opex	0	0	0.47	0.47	0.46	**1.40**
Total	**0**	**0**	**0.47**	**0.47**	**0.46**	**1.40**

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

5.8.4. Assumptions, justifications and risks

The key risks have been identified:

Risk	Mitigations	Likelihood	Impact
BEIS finds the recommendations do not align with current UK strategy. Leading to non-delivery of recommendations.	Engage early and continually with BEIS to ensure alignment. Ensure ESO is resourced, with access to consultant funds to undertake 'heavy lifting' on behalf of the BEIS.	2	2
Industry does not engage with the process, leading to a suboptimal market design.	Use best practice engagement. 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.	3	1
Market design does not fully meet requirements. Benefits are not as expected i.e., do not outweigh costs.	Ensure engagement with all parties and look to trial findings in both live and test environments.	4	1

5.8.5. The benefits

The quantitative benefits of a net zero market reform:

- Proposal provides recommendations to ensure the UK achieves net zero operation of the electricity system by 2035 in the most efficient manner.
- The recommendations will ensure investment is efficient and that the right types of assets are invested in
- The recommendations will ensure operational practices are efficient and that the market operates in the most efficient manner

5.8.6. Conclusion

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

- Although the monetary value of this work is difficult to quantify, it is anticipated that this work will result in improved efficiency across all UK current and future market participants and across the both the DNOs and TOs.
- Even a small improvement in efficiency would result in a large consumer benefit.
- It should be noted that a study into future market reform will not, itself, deliver quantifiable benefits. However, we are confident that this transformational activity will deliver significant benefits for consumers.

5.8.7. Other options considered

1. Industry/Market Participants lead on market reform:

- Lack view of internal system, significant investment would be required to align all market participant from Generation through to Storage
- Market Participants would have a vested interest in market design and lack impartiality the ESO provides

2. DNO leads on market reform at Distribution Level:

- While market reform could be undertaken at the DNO level there would need to be significant investment to:
  - Align DNOs to create a single market
  - Upskill the DNO' to be able to manage markets in a similar manner to the ESO

3. Do nothing:

- Continue with current markets
- Investment to ensure the UK achieves net zero operation of the electricity system by 2035

5.9. A21 Role in Europe

This subsection contains the break-even analysis for **A21 Role in Europe.**

5.9.1. Why have we undertaken break-even analysis?

It provides details of the benefit that will 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.

5.9.2. The counterfactual

The counterfactual to **A21 Role in Europe** is we do not engage effectively with Europe or interact coherently with our European counterparts leading to inefficient cross border markets.

5.9.3. Activity costs

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0	0	0	0	0	**0**
Opex	0	0	0.47	0.47	0.46	**1.40**
Total	**0**	**0**	**0.47**	**0.47**	**0.46**	**1.40**

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

5.9.4. Assumptions, justifications and risks

The key risks have been identified:

Risk	Mitigations	Likelihood	Impact
EU and UK relationships deteriorate leading to the EU not involving the UK in Energy centered conversations.	Engage early with Government to highlight the needs to appropriately manage European stakeholders. Engage early and continuously with our European counterparts.	3	3
Divergence of UK and EU energy policy	Engage with both Government and EU stakeholders to better manage cross border flow of policy and energy e.g., Interconnectors, Security of Supply (Gas)	3	3
Risks to time, quality, and cost in delivery of the project and managing its scope, etc.	Implement good project management and appropriate controls. Create oversight for input, challenge, and review.	3	1

5.9.5. The benefits

The quantitative benefits of a targeted improvements within the EU and UK energy relationship:

- Proposal ensures that the EU and UK energy relationship continues, it does not stagnate, and the UK has a lead on Energy Systems Operation in Europe
- Proposal ensures that information is shared between the EU and UK
- Proposal influences the EU to ensure developments in the EU are compatible with the UK and vice versa
- Proposal mitigates the risk of divergence between the EU and UK energy policy
- Proposal leads to goal congruence between the EU and UK, e.g., alignment of goals around net zero
- Additional benefits include:
  - Transparency with EU energy leads
  - Alignment of internal ESO Teams and a single voice interacting with the EU
  - Reduction of total resource required to manage relationship with the EU due to a single centralised team, rather than resource embedded within multiple different business units

5.9.6. Conclusion

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

- Although the monetary value of this work is difficult to quantify, it is anticipated that this work will result in reduced cost within the ESO through the centralising of this activity.
- Given the uncertainty in energy policy impacting the UK's interconnector capacity investment, it will be important to maintain relationships that ensure cross border flow.
- Alignment of internal and external stakeholders to ensure the ESO acts as one body on European challenges will ensure a consistent message to all stakeholders.
- Alignment between the UK and Europe on Energy challenges such as Security of Supply and Net Zero is a requirement to ensure a stable future energy system.

5.10. Role 2 NPV summary

	5-year NPV (£m)	10-year NPV (£m)	Market factors Low 5-year NPV (£m)	Market factors High 5-year NPV (£m)	Delivery factors Low 5-year NPV (£m)	Delivery factors High 5-year NPV (£m)	Third-party factors Low 5-year NPV (£m)	Third-party factors High 5-year NPV (£m)
A4	67.89	159.20	43.52	82.59	8.05	112.39	67.89	67.89
A4	Break-even analysis							
A5	58.99	116.81	41.07	76.91	17.37	90.29	55.03	62.73
A6.4	Break-even analysis							
A6.5 & 6.8	32.05	138.09	27.35	36.73	8.84	32.05	14.44	49.66
A6.6 & 6.7	67.97	166.77	67.97	67.97	67.97	67.97	67.97	67.97
A6.9	Break-even analysis							
A20	Break-even analysis							
A21	Break-even analysis							
Role 2	**226.90**	**580.87**	**179.91**	**264.20**	**102.23**	**302.70**	**205.33**	**248.25**

5.11. Role 2 Cost summary

			2021/22 (£m)	2022/23 (£m)	2023/24 (£m)	2024/25 (£m)	2025/26 (£m)	Total (£m)
A4	Lead a review of wholesale, balancing and capacity markets	Capex	0	0	0	0	0	**0**
		Opex	0	0	0.69	0.69	0.69	**2.06**
		Total	0	0	0.69	0.69	0.69	**2.06**
A4	Build the future balancing service markets	Capex	4.68	8.87	8.10	7.54	7.41	**36.60**
		Opex	1.70	1.87	3.17	2.10	1.92	**10.76**
		Total	6.38	10.74	11.26	9.64	9.33	**47.36**
A5	Transform access to the Capacity Market	Capex	5.38	5.46	4.08	3.07	3.07	**21.07**
		Opex	0.69	0.95	0.85	0.83	0.65	**3.97**
		Total	6.07	6.42	4.93	3.91	3.72	**25.05**
A6.4	Transform the process to amend our codes	Capex	0	0	0	0	0	**0**
		Opex	0	0	0.28	0.28	0.28	**0.85**
		Total	0	0	0.28	0.28	0.28	**0.85**
		Capex	0	0.28	0.80	0.50	0	**1.58**

			2021/22 (£m)	2022/23 (£m)	2023/24 (£m)	2024/25 (£m)	2025/26 (£m)	Total (£m)
A6.5 & 6.8	Develop code and charging arrangements that are fit for the future	Opex	0.47	0.59	0.80	0.64	0.39	**2.89**
		Total	0.47	0.87	1.60	1.14	0.39	**4.47**
A6.6 & 6.7	Look at fully or partially fixing one or more components of BSUoS charges	Capex	0	0	0	0	0	**0**
		Opex	0	0	0	0	0	**0**
		Total	0	0	0	0	0	**0**
A6.9	Whole system codes reform	Capex	0	0	0	0	0	**0**
		Opex	0	0	0.40	0.40	0.40	**1.20**
		Total	0	0	0.40	0.40	0.40	**1.20**
A20	Net zero Market Reform	Capex	0	0	0	0	0	**0**
		Opex	0	0	0.47	0.47	0.46	**1.40**
		Total	0	0	0.47	0.47	0.46	**1.40**
A21	Role in Europe	Capex	0	0	0	0	0	**0**
		Opex	0	0	0.47	0.47	0.46	**1.40**
		Total	0	0	0.47	0.47	0.46	**1.40**
Role 2		**Capex**	**10.06**	**14.61**	**12.98**	**11.11**	**10.48**	**59.25**
		Opex	**2.86**	**3.41**	**7.13**	**5.88**	**5.25**	**24.53**
		Total	**12.92**	**18.02**	**20.11**	**16.99**	**15.73**	**83.78**

6. Role 3

Role 3 was separated into two themes at BP1. We no longer report in themes, so all activities now sit within a single Role 3 view. We have updated all existing CBAs in Role 3 and we have created a break-even analysis for the new A22 activity.

Activities A7 - A11 are analysed together due to their interlinked and highly interdependent nature; this ensures we provide the best overall view of costs versus benefits for consumers, and do not double count or over-report benefits. A7 was not initially subject to a CBA but we recommended in our 2021-22 Mid-Year Report that A7 should be included in the existing A8-A11 CBA, for completeness.

The break-even analyses for A12 and A13 have not been updated. The activity A12 has not materially changed since BP1, and the changes to A13 do not materially impact its existing break-even analysis. Please refer to the BP1 CBA Annex for the existing analyses.

Activity	Activity name	Material changes in activity since BP1	Analysis status	Description of changes from BP1 in analysis
A7	Network Development	None	Updated: CBA	A7 has been included in the existing A8-A11 CBA
A8	Enable all solution types to compete to meet transmission needs	Scope Costs New deliverables		'Commercial Solutions' assumption has changed
A9	Extend *NOA* approach to end-of-life asset replacement decisions and connections wider works	None		Minimal change
A10	Support decision making for investment at distribution level	None		Minimal change
A11	Enhance analytical capabilities	Scope Timescales		Minimal change
A12	SQSS Review	None	As BP1	
A13	Leading the Debate	None	As BP1	
A14	Take a whole electricity system approach to connections	None	Updated: CBA	'Connection Applications' assumption has changed
A15	Taking a whole energy system approach to promote zero carbon operability	New sub-activities Scope Costs	Updated: CBA	New benefits case Changed benefits methodology 'Carbon Price' and 'Constraint Costs' assumptions have changed
A16	Delivering consumer benefits from improved network access planning	New deliverables	Updated: CBA	'Constraint Costs' assumption has changed

Activity	Activity name	Material changes in activity since BP1	Analysis status	Description of changes from BP1 in analysis
A22	Offshore Coordination / Network Planning Review	New activity	New: Break-even	

6.1. A7 - A11 Network Options Assessment (NOA) enhancements

This subsection contains the costs and benefits of our **A7 - A11 *NOA* enhancements** activities.

The net present value of our A7 - A11 activities is £820.43 million over the RIIO-2 period and £2,191.25 million over ten years. Sensitivity analysis suggests an NPV range of £496.65 million to £1,153.29 million over the RIIO-2 period.

6.1.1. NPV drivers

The NPV has increased by approximately £157m and £870m over 5 and 10 years respectively.

This is driven by an increase in benefits in two areas:

- **Annual NOA:** A new benefits case for undertaking a *NOA* every year with total benefits of £69m over the RIIO-2 period. This was not included at BP1 and now accounts for the benefits associated with A7.
- **Facilitate competition by embedding pathfinder projects into the NOA:** These benefits are delayed by two years but the total benefit is now approximately £130m larger than at BP1. This increase is driven by the latest commercial solution assumptions from the Future Energy Scenarios (*FES*).

With the exception of the new Annual *NOA* benefits case, we have not altered any other benefits methodology from BP1. Only the underlying assumptions have been updated, in accordance with the methodology for these assumptions at BP1.

6.1.2. Changes from BP1

Benefits case	Changes	Description
Annual *NOA*	New benefit case	Activity A7 is now included in this CBA
Facilitate Competition by Embedding Pathfinders into the *NOA*	Commercial solutions assumptions	Latest commercial solution assumptions from *FES* are included

As recommended in our *2021-22 Mid-Year Report,* A7 is now included within the *NOA* enhancements CBA for completeness.

New or materially changed sub-Activity	Benefits impact
A7 Network development	New benefits case: Annual *NOA*
A8 Enable all solution types to complete transmission needs	Underlying assumptions have been updated to reflect scope changes. Benefits for Early Competition have not been included in this CBA because the earliest expected date for benefits realisation is in late 2026, outside of the RIIO-2 period. If on review at BP3 the benefits realisation has been brought forward, we will update this CBA to include Early Competition. However, costs for Early Competition deliverables are included in this CBA.
A11 Enhance analytical capabilities	There are delays in the delivery of this activity, however they have no impact on expected benefits.

6.1.3. The counterfactual

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

6.1.4. The benefits

We have quantified benefits in five areas:

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

6.1.4.1. Annual NOA

Assumptions	Justification
NOA commitments go ahead as planned	TOs have appropriate funding and resources to deliver
Each *NOA* is responsible for 10% of total benefits	Other factors may drive the total benefits, so a 10% figure is used for the NOA's specific contribution

Each *NOA* updates and refines previously identified benefits relating to network investment recommendations and seeks to unlock further benefit. By undertaking a *NOA* annually it is possible to accelerate the identification and delivery of these benefits.

To calculate the benefits of an annual *NOA* we:

1. Take the capabilities for the optimal path from *NOA 2018/19* Two Degrees (the scenario with the highest investment costs) and put the capabilities for each boundary into the *NOA 2021/22* study.
2. For new boundaries, we use the *NOA 2021/22* capability.
3. Run BID3 (a power market dispatch model) with these new boundary capabilities for all four *FES* scenarios.
4. Take the average savings over the next 10 years and over the four *FES* scenarios as the saving for an incremental *NOA* process. The next 10 years is where the heaviest investment is made.
5. Divide this saving equally between the two *NOA*s.
6. Conservatively take 10% of the saving as directly attributable to the *NOA*. It is inappropriate to assume the *NOA* has identified all the benefits, since the ESO and wider industry use many other investment planning methods and benefits may be captured elsewhere. The 10% figure is a conservative figure where it is assumed the *NOA* process contributes a small amount to the total benefits.

	£ million
10-year average consumer benefit across *FES* scenarios	274
Consumer benefit associated with each *NOA*	137
10% of consumer benefit directly due to *NOA*	13.7

Therefore, we estimate than an annual *NOA* delivers £69 million of consumer benefit over the RIIO-2 period.

Sensitivity analysis

- **Market factors:** we have already taken the highest investment costs from *NOA 2018/19* therefore we have minimised the benefit and a sensitivity analysis is not needed

- **Third-party factors:** we have not conducted a third-party sensitivity analysis because we believe the regulatory framework for network companies will 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. We have also modelled for improved and poor delivery with a 20% and 5% claimed benefit.

Interaction with other benefit areas

The proposals in activities A1 and A16 also claim to lower constraint costs. By taking a conservative view of the benefits of an annual *NOA* (i.e. by taking the highest investment costs from *NOA* 2018/19 in our methodology), we believe that we have avoided double counting benefits.

Benefits £ million	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Consumer benefit of annual *NOA* (central case)	13.7	13.7	13.7	13.7	13.7	**69**
Sensitivity – high delivery	27.4	27.4	27.4	27.4	27.4	**137**
Sensitivity – low delivery	6.9	6.9	6.9	6.9	6.9	**35**

The table above shows the benefits from an annual *NOA* are between £35 million and £137 million, with a central case of £69 million.

6.1.4.2. Facilitate Competition by Embedding Pathfinders into the NOA

Assumptions	**Justification**
Generic intertrip solution cost	Commercially sensitive historic information from bilateral contracts
Commercial Solutions deliver value from FY24 onwards	We use the forecasts for value from Commercial Solutions provided in *NOA 2021/22*

This activity takes learnings and processes from our *2019-21 Forward Plan* and embeds them into network investments. The pathfinder 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 pathfinder projects adopt a learn-by-doing approach it is hard to accurately forecast savings. However, our *Forward Plan* showed that 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. Using historic costs of commercial solutions as a benchmark for analysis.
4. Repeating the *NOA* process with this extra commercial option.
5. Calculating the difference between (1) and (4).

This delivers £564 million of consumer benefit during RIIO-2. The table below only shows benefits up until 2025/26; however, we expect benefits to be delivered until 2027/28, mainly from the availability of a more flexible commercial solution before an asset build.

Sensitivity analysis

- **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 will 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 A1 and A16 also claim to lower constraint costs. We have not accounted for these in the central benefit case here, but they will be accounted for in the market factors sensitivity analysis.

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Consumer benefit of implementing commercial solutions (central case)	0	0	123	209	232	**564**
Sensitivity – high market	0	0	170	291	360	**821**
Sensitivity – low market	0	0	63	81	96	**240**
Sensitivity – low delivery	0	0	0	123	209	**332**

The above table shows the benefits from implementing commercial solutions to the *NOA* process are between £240 million and £821 million, with a central case of £564 million.

6.1.4.3. Extending NOA to End-of-Life Asset Replacement Decisions

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

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 TO decisions, the ESO will 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 will result in a cost of £50 million to replace the asset in 2025 and 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 2018/19*[14] only 25% were related to overhead lines (OHL) (i.e. related to asset upgrades). Assets are only considered for replacement when their life expires in the next five years, based on TO risk factors. So only 12.5% (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 2018/19* to upgrade assets, five schemes can provide benefit during the RIIO-2 period. We have profiled these to the backend of the RIIO-2 period. The average cost of these 36 schemes is £29.5 million. If this activity can save four schemes over the RIIO-2 period it will deliver £118 million of consumer benefit, as per the below profile, assuming we run this process once in 2023/24 and 2024/25, and twice in 2025/26

Sensitivity analysis

- **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 analysis because we believe the regulatory framework on network companies will 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.

Benefits £ million	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Extending *NOA* to end of life asset replacement decisions (central case)	0.0	0.0	29.5	29.5	59.0	**118.0**
Sensitivity – high market	0.0	0.0	29.5	59.0	59.0	**147.5**
Sensitivity – low market	0.0	0.0	29.5	29.5	29.5	**88.5**
Sensitivity – low delivery	0.0	0.0	0.0	29.5	59.0	**88.5**

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

6.1.4.4. Extend NOA approach to all connections wider works

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

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

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

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 2018/19* coupled with wider works not currently considered in the *NOA* document.

NOA 2018/19 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 suggests expanding the *NOA* to consider these extra options would lead to around a 10% increase in analysis of boundaries and options. Again, *NOA 2018/19* 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 will generate; however even a pessimistic saving of just 2% more will provide the consumer between £37 million and £53.4 million benefit. We present the lower case here.

Sensitivity analysis

- **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 will incentivise them to carry out any recommendations.
- **Delivery factors:** we have modelled a one-year delay in delivery. We have not modelled bringing forward delivery as we do not believe this is achievable without significant extra work for the ESO and TOs.

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Extend *NOA* approach to all connections wider works (central case)	0.0	37.0	37.0	37.0	37.0	**148.0**
Sensitivity – high market	0.0	53.4	53.4	53.4	53.4	**213.6**
Sensitivity – low delivery	0.0	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 £214 million, with a central case of £148 million.

6.1.4.5. Support decision making for investment at the distribution level

Assumption	Justification
Expected level of investment at the 132kV level is £40 million per year	Based on historic data from the *Forward Plan* for 2018/19 [15]
60% of investment options will be on the optimal path	Based on *NOA 2018/19*
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 have 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

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

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

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

The *NOA* balances operational costs vs investment costs and historically the *NOA* determines that approximately 60% of all options make it onto the optimal path and can be carried out for the next 12 months. The remaining 40% of options are not 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 take a national approach and may recommend more than 60% in any given area. Applying the 60% to the £40 million investment implies around £16 million could be recommended not to proceed for that 12-month period. Given the uncertainty, we have assumed that not all the £16 million savings will 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

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

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

6.1.4.6. Total benefits case

The total benefits for **A7 - A11 *NOA* enhancements** are between £566 million and £1297 million, with a central case of £929 million over the RIIO-2 period.

6.1.5. Activity costs

Delivery of our enhanced *NOA* activities will require Capex and Opex spend, as summarised below:

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

£ million						
Capex	-0.06	3.20	3.20	1.60	1.20	**9.15**
Opex	2.57	5.59	3.28	2.23	2.04	**15.71**
Total*	**2.51**	**8.79**	**6.48**	**3.83**	**3.24**	**24.86**

**Totals may appear incorrect due to rounding*

The total cost for our A7 - A11 activities is £24.86 million.

6.1.6. Net present value

The NPV of A7 - A11 is estimated at £820.43 million over the RIIO-2 period and £2,191.25 million over ten years and will start to deliver positive returns from 2021/22. Sensitivity analysis suggests an NPV range of:

- Considering market factors, between £496.65 million and £1153.29 million.
- Considering delivery factors, between £715.79 million and £884.45 million.

6.1.7. Dependencies, enablers and whole energy system

Facilitating competition by embedding Pathfinder projects into the *NOA* is dependent on the following transformational activity:

- **A4 Build the future balancing service and wholesale markets** (Role 2) – this activity will create new markets for commercial solutions.

There is also a dependency between activity **A13 Leading the debate** and the A7 - A11 activities. Due to the nature of the *FES* and the *NOA,* the link is both in the data, methodologies and resources required.

The Data and Analytics PAP Platform (DAP) is key to the delivery of several of the activities within A7 - A11, many of the required tools sit within the DAP platform and require integration with the DAP to achieve full benefits.

Furthermore, there is a dependency on **A20 Net zero market reform**, specifically in how competitive procurement should work. This will inform all deliverables across A7 - A11.

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. It is also expected that there will be an increased volume of data needing to be shared. However, we expect that these costs should be offset by the potential benefits for network companies to carry out this work, because of their regulatory and incentive frameworks.

6.1.8. Uncertainties and risks

We have accounted for market, third-party and delivery uncertainties in our sensitivity analysis. The table below summarises the key risks and how we propose to mitigate them. Risks for the associated IT investments can be found in the IT Annex.

Facilitate competition by embedding pathfinder projects into the NOA

Risk	Mitigations	Likelihood	Impact
Increasing constraints costs or compliance issues from delayed network investment due to competition	We will develop streamlined processes that minimise delays. The cost of any unavoidable delays will be factored into our final *NOA* CBA process	5	3
Increased services in network development adds another layer of complexity to the balancing services market, deterring potential bidders	The role of longer-term tenders will be considered alongside our development of other balancing services	3	2

Risk	Mitigations	Likelihood	Impact
Increased use of commercial services could increase operational complexity	Our planning and Control Centre processes will manage this risk	3	3
Increased risk of non-delivery of solutions from using new providers and technologies	We will manage this through our tender processes	5	2
Risk that frameworks and funding arrangements hamper the roll out of competition	We will work closely with Ofgem and other relevant stakeholders such as the ENA to develop appropriate frameworks	2	4

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

Support decision making for investment at the distribution level

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

6.2. A14 Take a whole electricity system approach to connections

This subsection contains the costs and benefits of our activity **A14 Taking a whole electricity system approach to connections**.

The net present value of A14 is £16.18 million over the RIIO-2 period and £35.94 million over ten years. Sensitivity analysis suggests an NPV range of £10.86 million to £18.59 million over the RIIO-2 period.

6.2.1. NPV drivers

For A14 there is a £14m and £21m increase in 5 and 10-year NPV since BP1.

This is driven by an increase in benefits in two areas:

- **Efficiency Savings:** Benefits from efficiency savings are directly proportional to the total number of connection applications. At BP1 we used a figure of 400 applications per year while at BP2 we are forecasting an average of 1,381 applications per year. We are observing a rising and sustained number of applications and therefore any benefit associated with improving efficiency during the grid connection process will also increase.
- **Customer Service Improvement:** A new benefits case to account for the material changes in sub-activity A14.3. It represents £1m of consumer benefit in the last year of the RIIO-2 period.

The costs for A14 have doubled since BP1, but due to the large increase in benefits from efficiency savings the 5-year NPV still increases by a factor of almost 7.

Excluding the new benefits case for Customer Service Improvement, we have not altered the benefits methodology from BP1. Only the underlying assumptions have been updated, in accordance with the methodology for these assumptions at BP1.

6.2.2. Changes from BP1

Benefits case	Changes	Description
Customer Service Improvement	New benefits case	Accounts for the material changes in sub-activity A14.3
Efficiency Savings	Number of connection applications	Updated to latest connection forecasts and now includes sensitivity analysis

Several new deliverables seek to improve customer experience and so we have included a new benefits case "Customer Service Improvement". Some deliverables are delayed; however, the delays are either insignificant (1-3 months), or do not impact the benefits case and therefore the benefits cases have not been adjusted for these delays.

6.2.3. The counterfactual

If we did not undertake A14, and if we continue with our ongoing connections process, the growing volume of connections would risk impacting the customer journey negatively due to potential efficiencies and improvements not being recognised.

6.2.4. The benefits

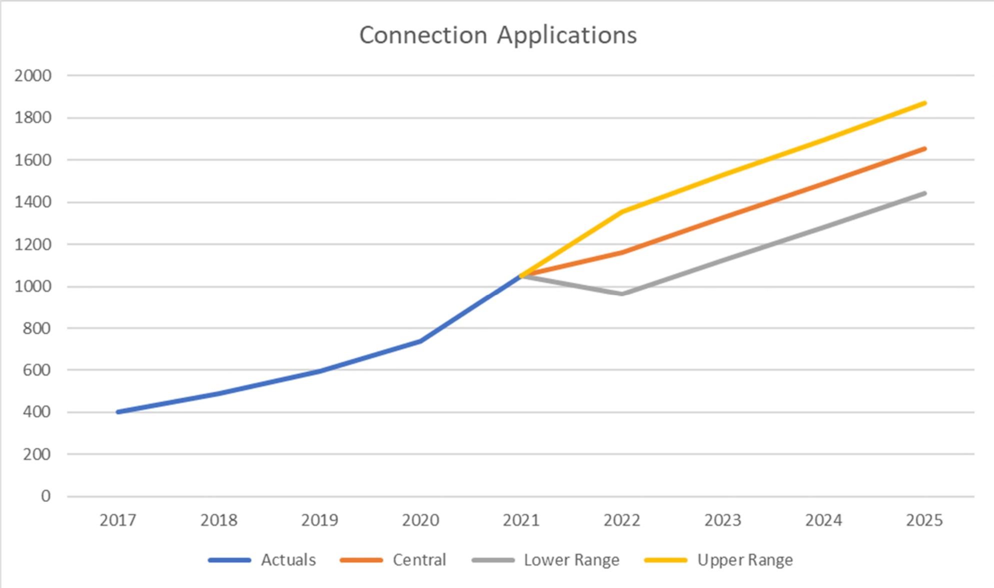
We have quantified benefits in three areas:

- Efficiency Savings
- Customer Service Improvement

6.2.4.1. Efficiency Savings

Assumptions	Justification
The number of connection applications grows 8% per year	Slowing from today's (around 20%), based on actual number of connections
Roll out of our secure online account management facility in April 2025 brings a 30% cost saving	Based on IT investment, delivery timelines and the connections hub, this will provide a user-friendly element of 'self-serve' for customers to take additional control of their connection journey (alongside ESO support)
Information shared across the transmission-distribution interface will reduce our direct resource requirements by 10% from 2022	Based on IT investment delivery timelines

The chart below shows the number of connection applications the ESO has received since 2017 plus central, lower and upper sensitivities. In the last 2 years we have seen an 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.



Number of applications	2021/22	2022/23	2023/24	2024/25	2025/26
Applications	1050	1160	1327	1488	1655

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

We estimate a reduction in our direct resource requirements of 5% delivered from April 2022. An additional 5% will be delivered from April 2022 with capacity information across the transmission-distribution interface. Roll out of our complete secure online account management facility in April 2025 will deliver an additional 30% 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

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

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Efficiency savings (central case)	3.3	3.7	4.2	4.7	5.3	**21.3**
Sensitivity – high market	3.3	4.3	4.9	5.4	6.0	**23.9**
Sensitivity – low market	3.3	3.1	3.6	4.1	4.6	**18.6**
Sensitivity – low delivery	0	3.3	3.7	4.2	4.7	**16.0**

The total benefits for **A14 Taking a whole electricity approach to connections** are between £16 million and £24 million, with a central case of £21 million over the RIIO-2 period.

6.2.4.2. Customer Service Improvement

Assumptions	Justification
Networks directorate maintains CSAT score of Low 4	The new A14 deliverables will mitigate the impact of the increased workload due to the increased number of connections
The Electricity Customer Connections (ECC) team contribute 25% of total Customer Service	This is likely an underestimate the ECC team has some of the greatest exposure to customers and exposure is growing

The new deliverables within A14 are to be delivered by the ECC Team. The ECC Team has significant exposure to customers within networks and are extremely focused on ensuring that we not only perform against BP1 deliverables, but that we recognise the need for these deliverables to evolve and grow with the expectation and needs of our customers.

A direct reflection of customer experience is the customer satisfaction (CSAT) score, the new deliverables and benefits continue to build on the work of the ECC team over the past 12 months including:

- Improving the level of engagement, response and support provided by Customer Contract Managers and Compliance Team
- Identifying issues within processes around the management of the Customer Journey from Application to Energisation, including platforms for supply, management of information, delivery, and management of change
- Increasing information available online via TEC Register plus improving quality to ensure accuracy and suitability to use by customers and Industry wide organisations
- Leading on engagement with customers to address changes to Codes, Regulation and Processes to enable understanding of what change means to customers
- Defining a better understanding of ESO role vs TOs

Poor performance on Customer Service and management of customer relationships would have a detrimental impact on the wider business. The way we evidence our customer service performance is mainly through CSAT surveys, with the final scores, feedback obtained, action plans and reports back to customers on actions taken to address their feedback.

The benefits calculation

- Assume a Level 4 CSAT score is at least maintained throughout the RIIO-2 period
- Reward is equal to £4m
  - Reward is representative of the benefit the ESO has delivered to customers through maintaining quality of service and not allowing service levels to decline due to the number of connections increasing
  - Maintaining service levels should be seen as a minimum and as such this represents an underestimate of benefits
  - 25% of this benefit can be claimed in 2025/26 to account for the ECC team specifically
  - Total claimed in 2025/26 is equal to £1m

Sensitivity analysis

- **Delivery factors:** we have modelled for high delivery and low delivery with a CSAT score of 5 and 3 respectively.

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
ESO and customer efficiency saving (central case)	0	0	0	0	1	**1**
Sensitivity – high delivery	0	0	0	0	1.25	**1.25**
Sensitivity – low delivery	0	0	0	0	0.75	**0.75**

The total benefits for A14 are between £0.75 million and £1.25 million, with a central case of £1 million over the RIIO-2 period.

6.2.4.3. Total benefits case

The total benefits for **A14 Taking a whole electricity approach to connections** are between £16.75 million and £25.25 million, with a central case of £22.30 million over the RIIO-2 period.

6.2.5. Activity costs

Delivery of A14 will require Capex and Opex spend, as summarised below:

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0.89	1.56	0.18	0.09	0.09	**2.81**
Opex	0.25	0.31	1	0.89	0.89	**3.34**
Total	**1.14**	**1.87**	**1.18**	**0.98**	**0.98**	**6.15**

The total costs for A14 to connections are £6.15 million.

6.2.6. Net present value

The net present value of A14 is estimated at £16.18 million over the RIIO-2 period and £35.94 million over ten years, which will start to deliver positive returns from 2025/26. Sensitivity analysis suggests an NPV range of:

- Considering market factors, between £13.78 million and £18.59 million.
- Considering delivery factors, between £10.86 million and £16.40 million.

6.2.7. Dependencies, enablers and whole energy system

Delivery of A14 requires customers to engage with the new hub and systems, and connections customers to pass on any cost reductions to consumers.

Customers remain the largest dependency; their engagement with the system and process requires significant ESO input to develop strong relationships and desired outputs.

There is also a large dependency on both IT systems and resources:

- File handling from both a system and use case perspective
- Sales platforms which store and manage customer journeys

Until these dependencies are resolved it is likely there will be an increased impact on resource and workload.

6.2.8. Uncertainties and risks

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

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

Risk	Mitigations	Likelihood	Impact
There are many industry initiatives to develop connections portals simultaneously and there is a risk associated with insufficient coordination during development (e.g., CUSC Mods and other licence changes, energy data task force, BEIS code governance reform review, BEIS/Ofgem work on smart systems and flexibility)	Continue to participate in these activities and coordinate with all relevant parties, including engaging with TOs on the activities in their business plans	3	1
IT development process for the customer portal does not meet user requirements	Learn from previous similar IT projects (e.g., transmission outage and generator availability) Close coordination with our IT developers and build in an agile way Maintain deep understanding of stakeholder needs and test functionality with customers as it is developed	2	1
Growth of customer connections outpaces IT developments and growth leading to inefficient ways of working	Early engagement and close coordination with our IT developers and build in an agile way Maintain deep understanding of stakeholder needs and test functionality with customers as it is developed	2	2
System changes for the customer portal follow a different timescale versus industry and regulatory readiness	Ensure the agile arrangements are developed with codified changes following as soon as practicable. Facilitate the transition to RIIO-ED2 such that this price control is not seen to be a blocker to energy transition	3	2
Changes to current connections process mean the internal IT developments are no longer fit for purpose	Continual engagement with key industry stakeholders and our IT developers to proactively manage changes	2	1

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

This subsection contains the costs and benefits of our activity **A15 Taking a whole energy system approach to promote zero carbon operability.**

The net present value of A15 is estimated at £1246.12 million over the RIIO-2 period and £4046.29 million over ten years. Sensitivity analysis suggests an NPV range of £601.56 million to £1379.30 million over the RIIO-2 period.

6.3.1. NPV drivers

The NPV for A15 has increased by approximately £780m and £3103m over 5 and 10 years respectively from BP1.

This is increase is driven primarily by two factors:

- A new benefits case for DER Visibility Savings
- An increase in the benefits of addressing whole-system operability challenges

A benefits case for DER Visibility Savings has been included to account for the benefits associated with new deliverables in sub-activity **A15.8 Facilitate transition to DSO and whole electricity system alignment**.[16] The delivery of these benefits is also supported by new deliverables in **A15.6 Transform our capability in modelling and data management**.[17] The benefits of these new deliverables total £73m; however, they are not the largest driver for the change of NPV.

The benefits case Whole System Operability *NOA*-type Assessment has the largest increase in benefits across the RIIO-2 period, with an increase of £800 million. The methodology for this benefits case has been updated for this CBA and the large increase in benefit is consistent with the large increase in constraint cost forecasts which A15 works to reduce. This benefits case is enabled by A15 deliverables which drive progress on the implementation of technologies required for effective zero carbon operation and coordinate with Pathfinder projects (described in A8) to identify system operability needs.

The methodology for the third benefits case, Regional Development Programmes, has not been altered since BP1. Only the underlying assumptions have been updated in accordance with the methodology for these assumptions at BP1.

6.3.2. Changes from BP1

Benefits case	Changes	Description
Regional Development Programmes – Carbon savings	Carbon intensity	Latest *FES* data used
Regional Development Programmes – Carbon savings	Carbon price	Latest BEIS figures used
Whole System Operability *NOA*-type Assessment	Methodology	Methodology changed to reflect the findings of Phase 1 and Phase 2 Stability Pathfinders
DER Visibility Savings	New benefits case	Benefit for new deliverables within A15.8

Sub-activities A15.6 and A15.9 both include new or materially change deliverables. Neither sub-activity generates tangible benefits within A15, but their costs are included in this CBA.

New or materially changed sub-activity	Benefits impact
A15.6 Transform our capability in modelling and data management	The new deliverable(s) do not create additional financial benefits within A15. They act to mitigate wider system changes. Existing benefits cases cover the benefits created from this sub-activity.

[16] D15.8.2 Operational Visibility; D15.8.3 Development of primacy rules for ESO-DSO coordination
[17] D15.6.8 Development and ongoing maintenance of EMT capabilities; D15.6.9 Co-simulation analysis innovation project

A15.8 Provide technical support to DSO and whole electricity system alignment	The new deliverable(s) have created additional financial benefits within A15. This is represented by the DER Visibility Savings benefits case.
A15.9 Net zero carbon operation	This new sub activity is too immature to attempt to associate tangible benefits. The potential benefits are large covering Security of Supply, Reduced Environmental Damage and Benefits for Society. Work will be completed over the next two years to refine these benefits as part of the wider A15.9 plan for 2025-2030. It is expected that initial financial benefits will be defined at BP3.

6.3.3. The counterfactual

If we did not undertake A15 we would not deliver additional Regional Development Programmes, embed enhanced frequency control capability, deliver necessary potential innovation projects, nor efficiently identity future operability needs. This would likely result in delivery of only incremental improvements in our current capability.

6.3.4. The benefits

We have quantified benefits in three areas:

- Whole system operability *NOA*-type assessment
- Regional Development Programmes (RDP)
- DER Visibility Savings

6.3.4.1. Whole System Operability NOA-type Assessment

Taking a whole system approach to reducing future operability costs will deliver significant benefits across the RIIO-2 period. We have updated the methodology for this associated benefits case. At BP1 we calculated benefits by estimating the difference between the costs of operability challenges over the next 40 years and a physical solution for those challenges. This information was aligned to the most recent stability Pathfinder at the time, which provided us with an understanding of the size and scale of the challenge.

Since BP1, analysis has been undertaken on additional stability Pathfinder projects, which better estimates the scale of the operability challenges and corresponding benefits of this work. We have therefore changed the methodology to represent the most recent findings and present the best available view for consumers. The updated methodology removes ambiguity and can be further updated with each additional Pathfinder project, ensuring consumers have the best and most up to date view of the benefits we are delivering.

As constraint cost forecasts have increased since our first CBA, we have seen a corresponding increase in the total benefits for this benefits case.

Assumptions	Justification
Benefits are equal to the cost of the balancing mechanism satisfying the Short Circuit Level	Costs are taken from: Phase 2 Stability Pathfinder Valuing the cost of the Counterfactual
50% of savings can be associated with pathfinders	Other factors may drive the total benefits, as such a conservative 50% figure is used for the whole system operability specific contribution

Stability is the ability of the system to withstand a network disturbance and continue to operate normally in line with our licence obligations. If the system becomes unstable, it could lead to a partial or total system shutdown, leading to the disconnection of consumers. We require stability services to manage inertia, dynamic voltage, and short circuit levels. Traditionally, synchronous plants (mainly gas and coal) have inherently provided system stability. However, as the generation mix evolves to include less of this type of generation, the ESO will incur significantly increased costs through either the curtailment of low carbon generation to manage constraints linked to inertia and short circuit levels, or synchronisation of generation to increase the stability. To overcome stability challenges and limit forecast costs we will need to secure new services or commercial solutions from new providers.

The ESO will procure commercial solutions based on the outcomes of whole system operability *NOA*-type assessment work. Therefore, the benefits are proportional to the benefits from overcoming the stability challenges.

For this CBA, we have considered the benefit of these commercial solutions to be equal to the cost of the Balancing Mechanism (BM) satisfying the Short Circuit Level (SCL) requirement:

- To overcome stability issues generation or load is turned on or off through the Balancing Mechanism.
- The cost of turning the generation or load on or off is equal to the benefits that will be delivered through the commercial solutions as generation will not need to be turned on or off.

Methodology

- Take the annual Cost of Curtailment of the Balancing Mechanism satisfying the SCL requirement from: *Phase 2 Stability Pathfinder Valuing the cost of the Counterfactual* (to be published)
- Conservatively attribute 50% of this benefit to the Whole system operability *NOA*-type assessment's contribution as other factors may drive the total benefits.

The table below shows the forecast annual cost (£m) of satisfying the SCL requirement[18].

Year	Number of curtailment options	Cost (£m)
2024	59	1,266
2025	61	1,339
2026	60	1,260
2027	58	1,350
2028	57	1,509
2029	54	1,619
2030	53	1,564
2031	51	1,512
2032	49	1,460
2033	47	1,411
Total	**548**	**14,291**

Sensitivity analysis

	High	Low
Market factors	No change	No change
Delivery factors	No change	One year programme delay
Third-party factors	No change	50% of curtailment options get delivered

[18] *Phase 2 Stability Pathfinder Valuing the cost of the Counterfactual* – to be published

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Operability savings (central case)	0	0	0	633	670	**1,303**
Sensitivity – low delivery	0	0	0	0	633	**633**
Sensitivity – low third-party	0	0	0	316	335	**651**

The total benefits of this area are between £633 million and £1,303 million, with a central case of £1,303 million over the RIIO-2 period.

6.3.4.2. Regional Development Programmes (RDP)

Assumptions	Justification
Value of RDP avoided asset build is £12.9 million	Based on previous RDP delivery, note this is a net value with costs accounted for
Additional renewable capacity unlocked by each RDP is 278 MW	Based on previous RDP delivery
Carbon intensity assumption from *FES 2021* Steady Progression scenario	Business plan assumption
Six RDPs will be delivered over the RIIO-2 period	Estimated capacity to deliver three RDP at any given time, while ramping up capability
BEIS Valuation of greenhouse gas emissions carbon values	See main assumptions

RDPs are already delivering significant value for the end consumer, with the first RDP delivering a net saving of £13 million through avoided asset build. As each new RDP is a bespoke piece of analysis for a specific situation, we have included two benefit methodologies in this CBA, one for carbon savings and one for asset savings, which are based on two RDPs we have delivered. We use the value of our completed RDPs to forecast future RDP benefits[19].

The two RDPs have provided different benefits:

- RDP 1 produced a saving of £13 million in required asset build.
- RDP 2 provided network access for renewable power ahead of the traditional connection process. It allowed an extra 278 MW of renewable generation across four grid supply points (GSPs). We have assumed a carbon offset of 974 gigawatt hours (GWh)[20] of carbon-free generation per year. We have assumed a similar carbon saving for future RDPs and one year to realise the benefits.

An increasing whole system focus will also drive benefits from RDPs to consumers. Therefore, this CBA is likely to present a conservative estimate of their benefits.

Sensitivity analysis

	High	Low
Market factors	Avoided asset build: £25.8m	Avoided asset build: £25.8m

[19] https://www.nationalgrideso.com/insights/whole-electricity-system/regional-development-programmes
[20] 278MW of carbon free generation with an estimated load factor of 40%

	High	Low
	Additional renewable capacity: 556 MW High carbon price MW	Additional renewable capacity: 556 MW Low carbon price
Delivery factors	No change	Four RDPs
Third-party factors	No change	No change

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**

Regional Development Programmes – Carbon savings

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Carbon intensity Steady Progression in grams of CO_2 per kilowatt hour (gCO_2/kWh)	112	88	89	88	85	
	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	109	86	86	86	83	

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Thousand tonnes of carbon saved Sensitivity – high market	218	172	174	172	167	
Thousand tonnes of carbon saved Sensitivity – low market	54	43	43	43	42	
	x	x	x	x	x	
Carbon price pounds per tonne of CO_2 equivalent (£/tCO_2e)	248	252	256	260	264	
Carbon price £/tCO_2e GWh Sensitivity – high market	373	378	384	390	396	
Carbon price £/tCO_2e GWh Sensitivity – low market	124	126	128	130	132	
	=	=	=	=	=	
Saving £ million	No RDP	No RDP	22	22	22	**66**
Saving £ million Sensitivity – high market	No RDP	No RDP	67	67	66	**200**
Saving £ million Sensitivity – low market	No RDP	No RDP	6	6	6	**18**
Saving £ million Sensitivity – low delivery	No RDP	No RDP	No RDP	4	5	**9**

The total benefits of this area are between £9 million and £200 million, with a central case of £66 million over the RIIO-2 period.

Regional Development Programmes – Asset savings

To avoid double counting of asset and carbon savings, 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. As such, 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; we have used a sliding scaling in our calculation to reflect this.

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Asset Saving (central case)	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 of this area are between £19 million and £77 million, with a central case of £39 million over the RIIO-2 period.

6.3.4.3. DER Visibility Savings

Assumptions	Justification
Forecast operability costs of £1,484 million per year	*NOA* assessment of future operability challenges
Reduction in constraint costs from DER Visibility	1% reduction in constraint costs from improved DER Visibility
Forecast reduction	10% forecasting benefit against *FES* backgrounds

A15 will deliver improved visibility of smaller distributed generation connections. Financial benefits are realised in two primary ways:

- Improved quality of forecasting, leading to lower operational costs.
- Improved market access for smaller distributed generation and therefore liquidity, increasing competition and lowering constraint costs.

The benefits are additive:

- **Improved forecasting:** From the *DER Visibility Benefits Assessment*[21] take the most conservative scenario as a view of forecasting benefits (Steady Progression Scenario)

plus

- **Increased liquidity and competition:** Estimate the reduction in constraint costs. We have assumed a conservative 1% improvement in constraint costs.

We do not expect the visibility savings to be realised until 2025/26.

There are other consumer benefits of DER Visibility which are difficult to quantify at this stage, therefore we expect this CBA to present a conservative view of its benefits.

Sensitivity analysis

	High	Low
Market factors	Commercial scenario changed to “Leading the Way”	No change
Delivery factors	Forecast reduction: 20%	Forecast reduction: 5% one year programme delay
Third-party factors	No change	No change

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

[21] *DER Visibility Benefits Assessment* - to be published

Operability savings (central case)	0	0	0	0	22	**22**
Sensitivity – high market	0	0	0	0	52	**52**
Sensitivity – high delivery	0	0	0	0	31	**31**
Sensitivity – low delivery	0	0	0	0	19	**19**

The total benefits of this area are between £19 million and £52 million, with a central case of £22 million over the RIIO-2 period.

6.3.4.4. Total benefits case

The total benefits of A15 carbon operability is between £779 million and £1631 million, with a central case of £1431 million over the RIIO-2 period.

6.3.5. Activity costs

Delivery of A15 will require Capex and Opex spend, as summarised below:

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	2.62	9.85	12.68	15.44	11.26	**51.85**
Opex	1.85	4.02	3.80	4.32	4.30	**18.30**
Total	**4.47**	**13.87**	**16.48**	**19.76**	**15.56**	**70.15**

This case does not include the costs associated with delivering the pathfinder solutions as discussed within Whole system operability *NOA*-type assessments as this section relates to assessments only.

The total costs for A15 are £70.15 million.

6.3.6. Net present value

The net present value of A15 is estimated at £1,246.12 million over the RIIO-2 period and £4,046.29 million over ten years, and it will start to deliver positive returns from 2023/24. Sensitivity analysis suggests an NPV range of:

	High (£m)	Low (£m)
Market factors	1,379.30	1,214.21
Delivery factors	1,279.21	601.56
Third-party factors	1,246.12	980.40
Range	**1,379.30**	**601.56**

6.3.7. Dependencies, enablers and whole energy system

Successful delivery of A15 depends on two other transformational activities:

- **A1 Control Centre architecture and systems** (Role 1) – this activity will ensure the Control Centre has the tools to operate a zero-carbon system.
- **A4 Build the future balancing service and wholesale markets** (Role 2) – this activity will ensure new markets have been developed to support zero carbon system operation.

Further dependencies exist associated with delivery of Pathfinder solutions (**A8 Implement and enhance competition to enable all solution types to compete to meet transmission needs**) as these provide visibility of key operability challenges for a net zero electricity network, and with sub-activity **A15.9 Net zero operations**, whose benefits will be realised from 2025-2030.

The Data and Analytics Platform (DAP) is key to the delivery of several of the activities within A15, many of the tools sit within the DAP or require integration with the DAP to achieve full benefits.

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

6.3.8. Uncertainties and risks

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

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

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 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
Policy decisions on DSO affect the scope of our work	Take a least regrets approach consistent with Future Worlds 'World B'[22]	2	2
Early stage of whole energy system transition means potential opportunities and pathways are unclear	Use design by doing ethos initially through targeted innovation projects to inform transition and aid timely progression.	1	1
Government Policy Surrounding Net Zero affecting scope of work	Early Engagement and continuous discussion with BEIS and Ofgem	2	1

6.4. A16 Delivering consumer benefits from improved network access planning

This subsection contains the costs and benefits of our activity **A16 Delivering consumer benefits from improved network access planning.**

The net present value of this activity is £254.15 million over the RIIO-2 period and £639.80 million over ten years. Sensitivity analysis suggests an NPV range of £127.34 million to £356.40 million over the RIIO-2 period.

[22] https://www.energynetworks.org/assets/images/Resource%20library/ON18-WS3-14969_ENA_FutureWorlds_AW06_INT%20(PUBLISHED).pdf

6.4.1. NPV drivers

The NPV has increased by approximately £50m and £221m over 5 and 10 years respectively. This increase in NPV is driven by the increase in forecast constraint costs since benefits in this CBA are directly proportional to them.

We have not altered the benefits methodology for this CBA from BP1, we have only updated the underlying assumptions in accordance with the methodology used at BP1.

6.4.2. Changes from BP1

Changes	Description
Constraint Costs	Latest constraint cost forecast used

A16.5 is a new sub activity that does not generate additional tangible benefits within A16, but its costs are included in this CBA.

New or materially changed sub-activity	Benefits impact
A16.5 Network Access Planning Automation	This sub-activity does not create additional financial benefit within A16. It mitigates the risks of wider system changes. Existing benefits cases cover the benefits created by this sub-activity.

6.4.3. The counterfactual

If we did not undertake A16, we would continue with our ongoing network access process, with a focus on transmission rather than DER.

6.4.4. The benefits

Assumptions	Justification
The same proportion (between 7% and 16%) of benefits could be realised in England and Wales as has been seen in Scotland	Observed result from Scotland and power system knowledge that system complexity is approximately the same between Scotland and England and Wales, allowing benefits to be extrapolated across from Scotland
England and Wales constraint costs	From *NOA* model run

Transmission and distribution connected parties will receive better notification of planned outages and their impacts on the networks. DNOs, meanwhile, will benefit from increased liaison, including greater procurement and coordination of flexibility services from Distributed Energy Resource (DER). This supports the quantifiable benefit delivered through rolling out the STC cost recovery mechanism process across all of GB. Consumer benefit for this approach has already yielded results in Scotland which in 2018/19 were forecast to be between £16 million and £36.7 million, equivalent to between a 7% and 16% reduction in costs.

Our power system knowledge infers a 50:50 split in complexity for outage planning between England and Wales and Scotland, so we have assumed same proportion of benefits could be realised in England and Wales. For rolling out the STC cost recovery mechanism to England and Wales we have assumed the mid-range estimate of an 11.5% reduction in costs.

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

Sensitivity analysis

	High	Low
Market factors	Increase of 25% in constraint costs	Reduction of 25% in constraint costs
Delivery factors	Reduction of 16% in constraint costs	Reduction of 7% in constraint costs One year delay
Third-party factors	No change	No change

Interaction with other benefit areas

The proposals in A1 and A7 - A11 also claim to lower constraint costs. We have not accounted for these in the central benefit case here, but they are accounted for in the market factors sensitivity analysis.

Forecast constraint costs £ million	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Estimated England and Wales constraint costs based on *NOA* forecast	351	463	322	453	876
Sensitivity – high market	439	580	403	566	1095
Sensitivity – low market	263	348	242	340	657

Forecast constraint savings £ million	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**
Estimated England and Wales constraint costs based on *NOA* forecast	351	463	322	453	876
Sensitivity – high market	439	580	403	566	1095
Sensitivity – low market	263	348	242	340	657
	x	x	x	x	x
11.5% savings	11.5%	11.5%	11.5%	11.5%	11.5%
	=	=	=	=	=
Annual savings (£ million)	40	53	37	52	101
Sensitivity – high market	50	67	46	65	126
Sensitivity – low market	30	40	28	39	76

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

Benefits £ million	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Consumer savings based expanding the process into	40	53	37	52	101	**284**

England and Wales with a 11.5% reduction (central case)						
Sensitivity – high market	50	67	46	65	126	**355**
Sensitivity – low market	30	40	28	39	76	**212**
Sensitivity – high delivery	56	74	52	72	140	**394**
Sensitivity – low delivery	0	32	23	32	61	**148**

The total benefits for delivering consumer benefits from improved network access are between £394million and £148million, with a central case of £284 million over the RIIO-2 period.

6.4.5. Activity costs

A16 will require Capex and Opex spend, as summarised below:

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	2.02	1.37	1.20	1.40	1.40	**7.40**
Opex	0.64	0.62	1.15	1.23	1.23	**4.86**
Total	**2.66**	**1.99**	**2.35**	**2.63**	**2.63**	**12.26**

The total costs for A16 are £12.26 million.

6.4.6. Net present value

The net present value of A16 is estimated at £254.15 million over the RIIO-2 period and £639.80 million over ten years and it will start to deliver positive returns from 2021/22. Sensitivity analysis suggests an NPV range of:

	High (£m)	Low (£m)
Market factors	319.48	188.83
Delivery factors	356.40	127.34
Range	**356.40**	**127.34**

6.4.7. Dependencies, enablers and whole energy system

A16 depends on the following transformational activities:

- **A5 Taking a whole energy system approach to promote zero carbon operability** (Role 2) - through the Regional Development Plans
- Code modifications and financial arrangements – we require DNOs and TOs to participate in the new process.

6.4.8. Uncertainties and risks

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

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

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 ESO and DNOs	Ensure strong links with relevant activities under Role 2 Close coordination through RDP partner DNOs Strong links with Open Networks to share learning Proportionate engagement with DER community	3	2

6.5. A22 Offshore coordination / Network Planning Review

This subsection contains the break-even analysis we have conducted **on A22 Offshore Coordination / Network Planning Review.**

6.5.1. Why have we undertaken break-even analysis?

This analysis provides details of the benefit that will need to be delivered to cover the costs of an activity.

We have undertaken a break-even analysis for A22 because this activity does not deliver forecast consumer benefit until 2025 and the benefit only becomes materially significant from 2030 onwards. At this stage it would be inappropriate to state the consumer benefit the project will deliver.

6.5.2. The counterfactual

If we did not undertake A22 we would continue with our current planning process which would continue to result in lost opportunities and increased waste due to less coordination and planning.

6.5.3. Activity costs

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0	0	0	0	0	**0**
Opex	2.76	4.16	3.22	3.42	3.42	**16.97**
Total	**2.76**	**4.16**	**3.22**	**3.42**	**3.42**	**16.97**

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

6.5.4. Assumptions, justifications and risks

The key risks have been identified:

Risk	Mitigations	Likelihood	Impact
Changes to governmental net zero policy	Close coordination with government stakeholders	1	3
Third-party timescales – due to the length of time required for many offshore projects it relies on third parties to invest resource and business capability over a long timescale	Closer coordination with third parties Deep understanding of stakeholder needs	2	2
Early stage of whole energy system transition means potential opportunities and pathways are unclear	Use design by doing ethos initially through targeted innovation projects to inform transition and aid timely progression.	1	1
Stakeholder buy in to planning processes are limited	Early stakeholder engagement Closer coordination with third parties	2	2
Increased use of commercial services could increase operational complexity	Our planning processes will manage this risk	3	3

6.5.5. The benefits

The benefits of Offshore Coordination:

- Forecast £6.6bn[23] in reduced Capital and Operational costs between 2030 and 20235.
  - Offshore projects as early as 2025 may benefit but, it is unlikely that any consumer benefits will be realised until 2030 due to the long planning process and timescales involved with offshore projects.
- Positive environmental impacts, social and local impacts by significantly reducing (more than 50%) the number of onshore landing points in sensitive areas and utilising less cables. Nevertheless, a significant amount of onshore space will be unavoidably required to accommodate the grid infrastructure, and it will still have social and environmental impacts.
- Through improved planning the security of electricity supply improves.

The benefits of Network Planning Review:

- The Network Planning Review will deliver:
  - End-to-end methodology to deliver a strategic approach to planning the network.
  - Assessment of the impact of the ESO acting as Central Planner to deliver centralised strategic network planning (CSNP).
  - Fit for purpose planning process to meet the needs of a net zero electricity system.
- The recommendations created by the Network Planning Review in the above areas will be focused on creating efficiencies in energy system investment and therefore on creating financial benefits for consumers.

6.5.6. Conclusion

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

- The forecast monetary saving from Offshore Coordination is large at £6.6bn. It is anticipated that the benefits will not be realised until 2025 and material benefits will only begin to be able to be evidenced from 2030 onwards. This work will result in improved investment efficiency across all UK current and future offshore players.

[23] https://www.nationalgrideso.com/uk/electricity-transmission/document/182936/download

- A fit for purpose planning system resulting from a Network Planning Review will ensure efficient investment across all parties interacting with the energy system.
- Even a small improvement in investment efficiency would result in a large consumer benefit.
- It should be noted that a study into offshore coordination and a network planning review would not, itself, deliver quantifiable benefits. However, we are confident that this transformational activity will deliver significant benefits for consumers.

6.5.7. Other options considered

1. Industry/Market Participants lead on offshore coordination and a network planning review:
    - Lack view of wider system, significant investment would be required to align all market participants from Generation through to Storage
    - Market Participants may have a vested interest and lack impartiality the ESO provides

2. DNO leads on offshore coordination and a network planning review at Distribution Level:

- While offshore coordination and network planning reviews could be undertaken at the DNO level there would need to be significant investment to:
    - Align DNO's to understand the wider system
    - Upskill the DNO's to be able to influence offshore coordination and network planning

3. Do nothing:

- Continue with current process
- Investment will not be optimised

6.6. Role 3 NPV summary

	5-year NPV (£m)	10-year NPV (£m)	Market factors Low 5-year NPV (£m)	Market factors High 5-year NPV (£m)	Delivery factors Low 5-year NPV (£m)	Delivery factors High 5-year NPV (£m)	Third-party factors Low 5-year NPV (£m)	Third-party factors High 5-year NPV (£m)
A7 A8 A9 A10 A11	820.43	2,191.25	496.65	1,153.29	715.79	884.45	820.43	820.43
A12	Break-even analysis							
A13	Break-even analysis							
A14	16.18	35.94	13.78	18.59	10.86	16.40	16.18	16.18
A15	1,246.12	4,046.29	1,214.21	1,379.30	601.56	1,279.21	980.40	1,246.12
A16	254.15	639.80	188.83	319.48	127.34	356.40	254.15	254.15
A22	Break-even analysis							
Role 3	**2,336.88**	**6,913.28**	**1,913.47**	**2,870.66**	**1,455.55**	**2,536.46**	**2,071.16**	**2,336.88**

6.7. Role 3 Cost summary

			2021/22 (£m)	2022/23 (£m)	2023/24 (£m)	2024/25 (£m)	2025/26 (£m)	Total
A7 - A11	*NOA* enhancements	Capex	-0.06	3.20	3.20	1.60	1.20	**9.14**
		Opex	2.57	5.59	3.28	2.23	2.04	**15.71**
		Total	2.51	8.79	6.48	3.83	3.24	**24.85**
A12	SQSS review	Not included in BP2 CBA annex						
A13	Leading the debate							
A14	Take a whole electricity system approach to connections	Capex	0.89	1.56	0.18	0.09	0.09	**2.81**
		Opex	0.25	0.31	1.00	0.89	0.89	**3.34**
		Total	1.14	1.87	1.18	0.98	0.98	**6.15**
A15	Taking a whole energy system approach to promote zero carbon operability	Capex	2.62	9.85	12.68	15.44	11.26	**51.85**
		Opex	1.85	4.02	3.80	4.32	4.30	**18.30**
		Total	4.47	13.87	16.48	19.76	15.56	**70.15**
A16	Delivering consumer benefits from improved network access planning	Capex	2.02	1.37	1.20	1.40	1.40	**7.40**
		Opex	0.64	0.62	1.15	1.23	1.23	**4.86**
		Total	2.66	1.99	2.35	2.63	2.63	**12.26**
A22	Offshore coordination / network planning review	Capex	0	0	0	0	0	**0**
		Opex	2.76	4.16	3.22	3.42	3.42	**16.98**
		Total	2.76	4.16	3.22	3.42	3.42	**16.98**
Role 3		**Capex**	**5.48**	**15.98**	**17.26**	**18.53**	**13.95**	**71.20**
		Opex	**8.06**	**14.72**	**12.48**	**12.12**	**11.91**	**59.29**
		Total	**13.54**	**30.69**	**29.74**	**30.66**	**25.86**	**130.49**

7. Appendix A: Approach to cost-benefit analysis for RIIO-2

7.1. How the ESO delivers consumer benefit

In this section, we explain the different ways the ESO delivers consumer benefit.

7.1.1. Benefit categories

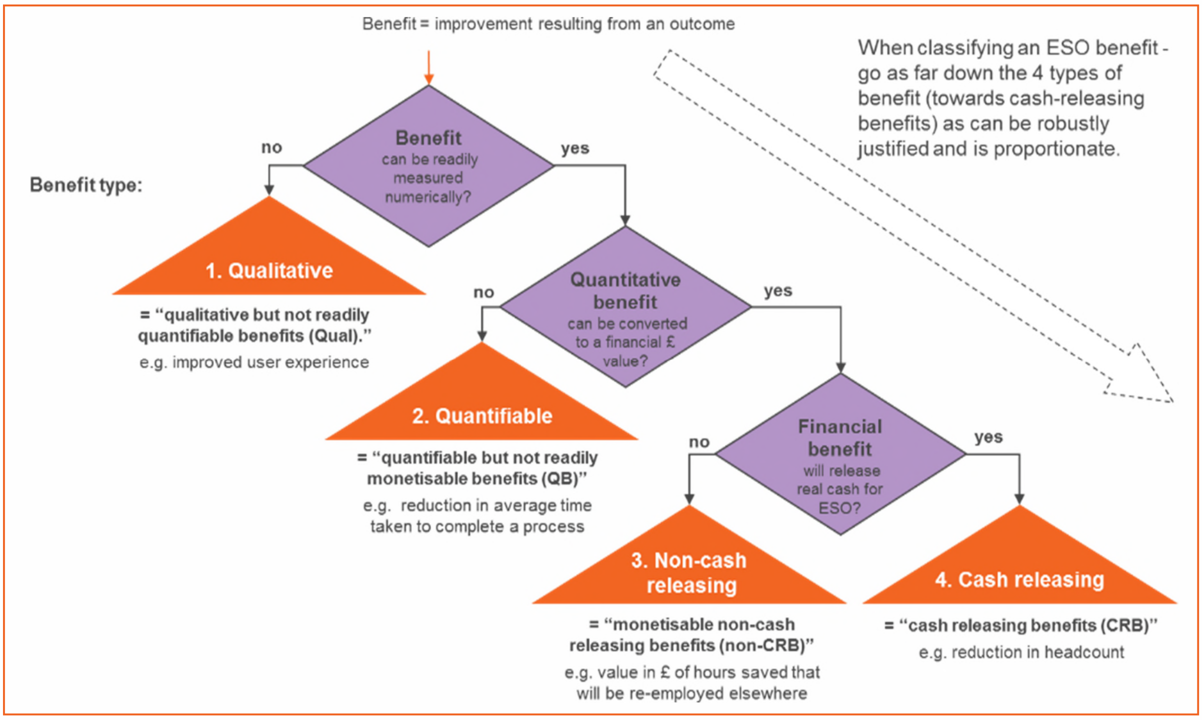
In line with Ofgem's guidance we use the following five categories of consumer benefit.

When we calculate benefits, we assign them to one of these categories:

- Improved safety and reliability
- Improved quality of service
- Lower bills than otherwise the case
- Reduced environmental damage
- Benefits for society as a whole

7.1.2. Benefit type

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



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 analysis is likely to be more conservative. If multiple activities are necessary to unlock some benefits to avoid double counting, we only attribute the benefit to one of them.

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

7.2. How we analyse consumer benefit

As discussed, we have undertaken either a cost-benefit analysis (CBA) or a break-even analysis on all our transformational proposals. The decision on approach is determined by the benefit type:

Benefit type	Approach
Quantitative and financial	Cost-benefit analysis
Quantitative and quantifiable	Break-even analysis
Qualitative	Break-even analysis

Components of a CBA

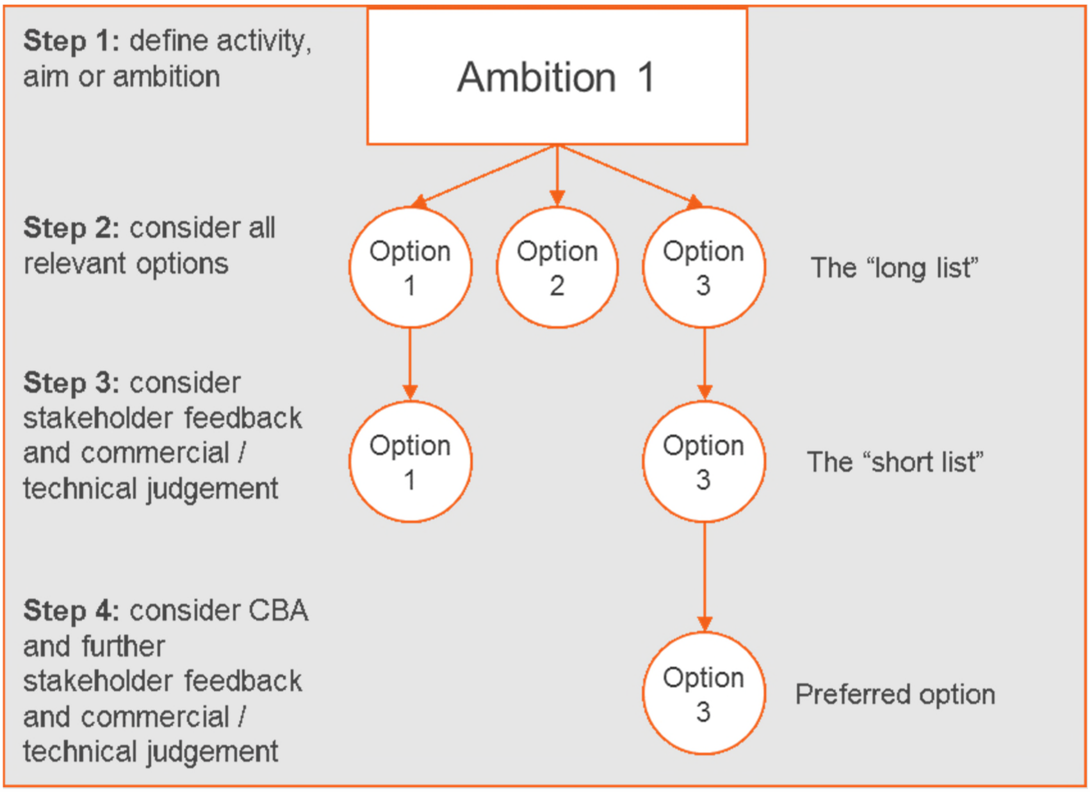
Section	Description
Changes since BP1	An explanation of changes since BP1
Counterfactual	Base case vs which other options are considered
Benefits	Estimates consumer benefit delivered
Assumptions and justifications	Assumptions and justifications related to benefits
Sensitivity analysis	Sensitivities related to benefits to understand changes in internal and/or external factors
Activity costs	Costs relating to the activity
Net present value	A financial evaluation of the costs and benefits of the activity
Dependencies, enablers and whole energy system	An evaluation of how this activity interacts with other benefits cases, defining where appropriate which benefits are mutually exclusive
Uncertainties and risks	Provides an understanding of risk which is accounted for in the benefits calculation of the activity
Other options considered	Other options considered during option process

Components of a break-even analysis

Section	Description
Changes since BP1	An explanation of changes since BP1
Why have we undertaken break-even analysis?	Explain why break-even analysis has been undertaken rather than CBA
Counterfactual	Base case vs which other options are considered
Activity costs	Costs relating to the activity
Assumptions, uncertainties and risks	Provides an understanding of risk and assumptions related to benefits
Benefits	Estimates consumer benefit delivered
Conclusions	States why even though we cannot define a financial benefit from this activity we should proceed with this activity
Other options considered	Other options considered during option process

7.3. How we have considered options

We have used the following process to consider options:



Option consideration process

We first defined our ambition, and the transformational activities needed to meet it.

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

7.4. Methodology for calculating net present value (NPV)

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

For each transformational option we:

1. Estimate the Capex and Opex costs for each year of the RIIO-2 period.
2. Calculate the financial value, where appropriate, across the five consumer benefit areas (see Benefit Type) for each year of RIIO-2. We use a range of sources, including historic data, forecasts, published analysis and our commercial and technical judgement. Our benefit assumptions are stated and justified.

   We calculate the NPV by:

   - Depreciating the Capex expenditure over the Capex depreciation period.
   - Applying the cost of capital assumption to depreciated Capex investments.
   - Calculating net benefits by the difference between costs (Opex and Capex above) and the benefits; and

- Discounting these net benefits by the discount rate (see Assumptions) and calculating NPVs over five and ten years.
- The 10-year NPV is calculated using the same method, extrapolating both the fifth year (2025/26) costs and benefits across each year to 2031.

3. 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.
4. Where appropriate, perform additional sensitivity analysis to account for any uncertainties in the assumptions.

7.5. Sensitivity analysis

The benefits presented 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 sensitivity analyses to determine a reasonable benefit range. In cases where our central estimate is marginal, a sensitivity analysis can help determine whether to proceed.

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

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

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

7.6. Interactions between benefit areas

As highlighted by the benefits dependencies map, there are many overlaps and interdependencies between our activities. It is possible that this could lead to double counting of benefits, or that undertaking an activity alters the benefit case in another.

For example, Role 1 and Role 3 both claim lower response and reserve costs. Role 3 activities use forecast cost of constraints in their benefits calculations, which proposals in Role 1 seek to reduce. We have highlighted in the relevant section where there is potential interaction.

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

- The level of double counting is likely to be small.
- We have generally adopted a conservative approach to benefit calculation, especially where we have less certainty.
- Any potential double counting will be accounted for in the relevant sensitivity analysis.

7.7. Risks and mitigations

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

Likelihood

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

Impact

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

7.8. Measuring benefit realisation

Unlike the BP1 CBA annex, this report does not contain a suite of metrics to measure our performance over the RIIO-2 period. New metrics will be determined following consultation with Ofgem as part of their draft determinations.

7.9. How we have complied with Ofgem's Guidance

In this section, we summarise Ofgem's guidance and how we have interpreted it and applied it to our BP2 CBAs. In this section we do not discuss the original Ofgem guidance for RIIO-2 CBAs[24], but the guidance issued for the BP2 submission[25]. Please refer to the BP1 CBA annex for information relating to how we have followed the original guidance.

Ofgem guidance reference 3.21

3.21. For BP2, the ESO should confirm whether the CBAs have materially changed from the original CBAs. Where they have materially changed, we require the ESO to provide justification for any material changes from the original CBAs provided in its first Business Plan.

- The ESO has stated which activities, sub-activities and deliverables have materially changed

[24] https://www.ofgem.gov.uk/sites/default/files/docs/2019/11/riio-2_eso_cba_guidance.pdf
[25] https://www.ofgem.gov.uk/publications/eso-business-plan-guidance

- The ESO has stated the impact of these materially changed activities, sub-activities, and deliverables on the CBAs
- Where the activities, sub-activities and deliverables have materially changed, and the corresponding CBA has also materially changed we have justified the changes made from the first business plan

Ofgem guidance reference 3.22

3.22. We will also require new CBAs for any new activities that the ESO plans to undertake in BP2 that have not already been subject to a CBA. Ofgem will work with the ESO to agree the scope of the new activities that require a separate CBA.

- The ESO has stated which activities are new
- The ESO has discussed these activities with Ofgem
- The ESO has agreed the scope of new activities which require a separate CBA

Ofgem guidance reference 3.23

3.23. The ESO should refer to our previous RIIO-2 Cost-benefit Analysis Guidance when developing its CBAs. For the avoidance of doubt, the CBAs should identify benefits and clearly articulate how the activities in question lead to those benefits; clearly justify any assumptions that are made; and clearly set out how anticipated costs and benefits are measured. Where financial benefits are identified, these should be either directly measurable or measurable through a proxy that has a direct cost associated with it. For benefits that cannot be easily measured, the ESO should include these in the narrative rather than the CBA financial benefits.

- The ESO has referred to the previous guidance when developing its CBAs
- The CBAs identify benefits and clearly articulate how the RIIO-2 activities generate benefits
- The CBAs justify any assumptions and changes to assumptions made since BP1
- The ESO will work with Ofgem through their draft determinations process to deliver metrics and measures to monitor the outcomes of the activities

8. Appendix B: Summary of methodology changes since BP1

Analysis Section	Benefits case	Methodology changes since BP1	Other significant updates since BP1
A1 CBA	-	-	Placeholder text provided - this CBA will be updated in our final BP2 submission
A2 CBA	Reduced Resource Costs	None	None
	Decreased Training Costs	None	1-year delay to benefits
	Improved Decision Making	None	Response and reserve costs
A3 CBA	Distributed ReStart NIC Project	None	None
	Carbon Savings	Sensitivity analysis added	Carbon price
A4 CBA	More Liquid Response and Reserve Markets	Additional justification for 5% saving assumption	Response and reserve costs
	Buying the Optimal Volume of Response	None	Response and reserve costs
A4 Break-even	-	-	Confirmation that new deliverable does not materially change the analysis
A5 CBA	Enhanced Modelling Capability	None	Clearing price of Capacity Market
	Reduced Barriers to Entry and Cost of Participation	New factor (% of companies interacting with Capacity Market) added to account for participation rates	Number of companies on Capacity Market register
A6.4 Break-even	-	-	Confirmation that the impacts of new deliverable will be considered in final BP2 submission
A6.5 CBA	Digitalised Whole System Grid Codes	None	Number of connection applications
A6.6 CBA	BSUoS Reform	The five and 10 year NPV is now estimated from analysis for CMP308 commissioned by Ofgem	BSUoS reform is assumed to start in April 2023 (12-months later than assumed at BP1)

A6.9 Break-even	-	-	New analysis for new RIIO-2 sub-activity
A20 Break-even	-	-	New analysis for new RIIO-2 activity
A21 Break-even	-	-	New analysis for new RIIO-2 activity
A7-A11 CBA	Annual NOA	New benefits case to account for inclusion of A7	-
	Facilitate Competition by Embedding Pathfinders into NOA	None	Forecasts for value from Commercial Solutions
	Extending NOA to End-of-Life Asset Replacement Decisions	None	None
	Extend NOA approach to all Connections Wider Works	None	None
	Support Decision-Making for Investment at the Distribution Level	None	None
A14 CBA	Efficiency Savings	None	Number of connection applications
	Customer Service Improvement	New benefits case to account for material changes to A14.3	-
A15 CBA	Whole System Operability NOA-type Assessment	New methodology, aligned with Stability Pathfinder findings	-
	Regional Development Programmes (RDPs)	None	Carbon price and carbon intensity
	DER Visibility Savings	New benefits case to account for new deliverables in A15.8	-
A16 CBA	Improved Network Access Planning	None	Constraint costs
A22 Break-even	-	-	New analysis for new RIIO-2 activity

Faraday House, Warwick Technology Park,
Gallows Hill, Warwick, CV346DA

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