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ESO RIIO-2 Business Plan 2 Cost-Benefit Analysis

Annex 2

31 August 2022

BP2 Cost-Benefit Analysis

Contents

1. Executive summary

The opportunity for society and the wider British economy to benefit from the transition to net zero is significant – attracting inward investment, creating regional growth and jobs, improving our economic productivity and providing benefits to communities and the environment. Britain's energy system is the cornerstone of this transition and, in 2021, the UK government confirmed its ambition to fully decarbonise the electricity system by 2035. As the Electricity System Operator (ESO) for Great Britain, we hold a unique position at the heart of the energy industry. We have an unparalleled opportunity to work with government and industry to realise the benefits of the energy transition, solve the challenges that lie in our path and accelerate progress towards a net zero future.

As we step up to lead the energy transition over the longer term, we must also recognise the needs of energy consumers in the shorter term. We are submitting our second Business Plan (BP2) against the backdrop of a major cost-of-living crisis, with energy costs at an unprecedented level. It is therefore vital that we minimise the cost, and maximise the value, of our operations wherever possible and redouble our efforts to keep costs down for consumers in the near term. We must also ensure that we contribute to a "just transition", where affordability and fairness remain imperatives to a successful net zero outcome.

This cost-benefit analysis (CBA) annex accompanies BP2 and 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 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. Considering this, our BP1 plan is now being updated. We've added some new activity to our BP2 plan, and we've also updated (materially changed) activity across several 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 £2.8 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 BP2.

In total:

- Ten CBAs have been updated to reflect material changes
- Two break-even analyses have been updated to reflect material changes
- Four 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)
1,967	2,807	+840

*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 £2.8bn over the five-year RIIO-2 period (April 2021 – March 2026) and £8.5bn over 10 years (April 2021 – March 2031). All RIIO-2 activities, subject to a CBA, now have a positive five-year NPV. The total change in five-year NPV from BP1 is +£840m. 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 BP1 we will unlock more value and provide greater benefits for consumers.

Our CBAs are grouped into three Roles, in the same way as the activities are grouped in our main BP2 document.

Role 1

BP1 Role 1 5-year NPV (£m)	BP2 Role 1 5-year NPV (£m)	Change (£m)
218	288	+70

Our estimate for the NPV of our Role 1 activities has increased since BP1, mainly due to an increase in the NPV of A1 of £60m. This increase is due to changes to our assumptions within the A1 CBA methodology. The largest driver is an increase to our cost of carbon assumption (higher BEIS carbon price), which is reflected in the increase in the 'reduced CO2 emissions' benefits case.

Role 2

BP1 Role 2 5-year NPV (£m)	BP2 Role 2 5-year NPV (£m)	Change (£m)
414	198	-216

Our estimate for the NPV of our Role 2 activities has decreased since BP1, mainly due to a decrease in the NPV of A6.6 and A6.7 of £212m. There are two key drivers for this:

1. The new methodology uses refined assumptions that were unavailable at the time of our original CBA estimate.
2. Pushing back implementing BSUoS reform by 12 months to April 2023, in alignment with the recommendations of the BSUoS Task Force and industry workgroup discussions.

Role 3

BP1 Role 3 5-year NPV (£m)	BP2 Role 3 5-year NPV (£m)	Change (£m)
1,335	2,322	+987

Our estimate for the NPV of our Role 3 activities has increased significantly since BP1, mainly due to large increases in the NPVs of our A15 and A7-11 CBAs.

The NPV for A15 has increased by approximately £772m since BP1. This has mainly been driven by an increase in the benefits of the 'Whole System Operability NOA-type Assessment' benefits case. This is driven by an increase in forecast constraint costs which have been updated in the models we use. Since BP1, analysis has been undertaken on additional stability Network Services Procurement (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.

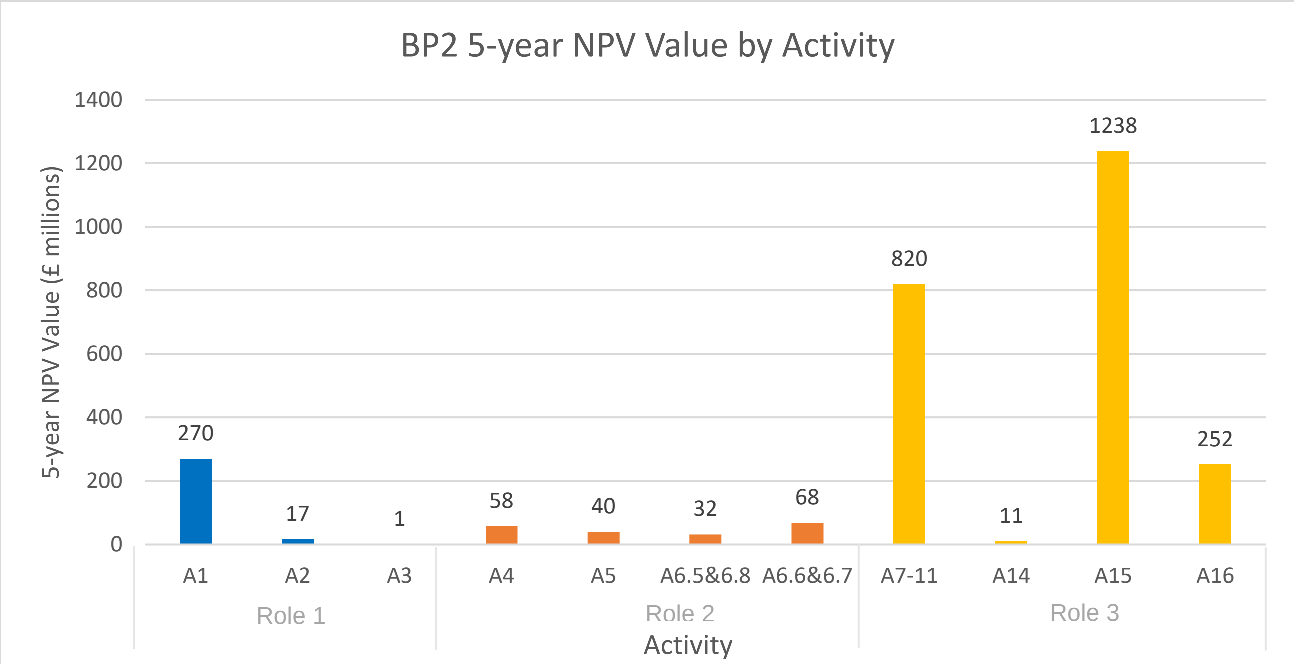
We present A7, A8, A9, A10 and A11 in a single CBA because there are very large dependencies between these activities. Creating separate CBAs may lead to double counting of benefits. The significant increase in the NPV for A7-11 of £157m is driven by increased forecasts for the value of commercial solutions to operability challenges and by including a benefits case associated with A7 for undertaking the Network

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

Options Assessment (or the process that will succeed it under the Network Planning Review). A7 is not a new activity, but its benefits were not included in this CBA at BP1.

1.2. Updated RIIO-2 activities

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



1.3. New RIIO-2 activities

BP2 sets out several 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:

- Five to ten years away from the first benefits being delivered; or
- do not have direct consumer benefits inherently (they enable existing or future activities that deliver the direct consumer benefits).

Assigning a direct financial benefit to consumers on these activities through this review would be inappropriate given their scope and respective timescales. 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 cashflow and their 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 assessment for identifying change as material is 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
Uncertainties and risks		Provides an understanding of risk which is accounted for in the benefits calculation of the activity	Updated

Section	Subsection	Description	Changes since BP1
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.

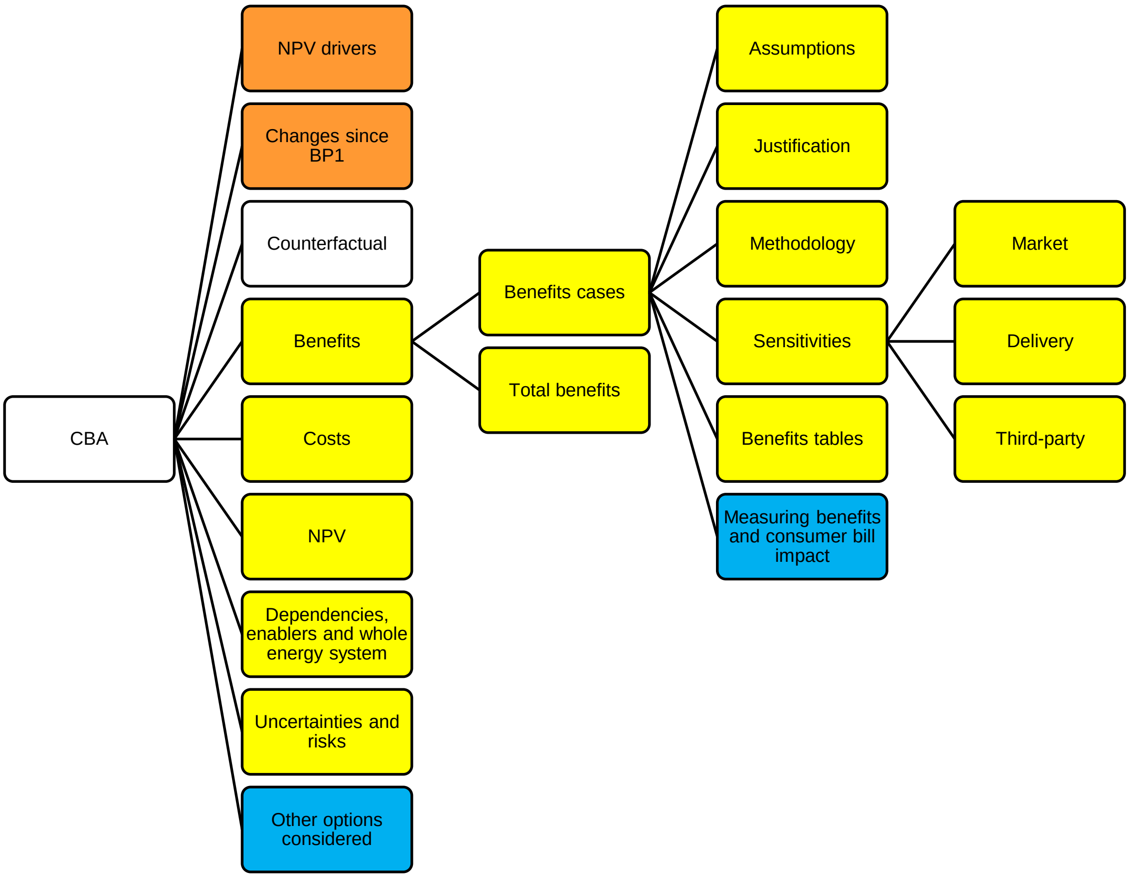


Figure 1 - CBA Sections

2.1. Assessment 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

	Scope	Timescales	Costs
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.

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:

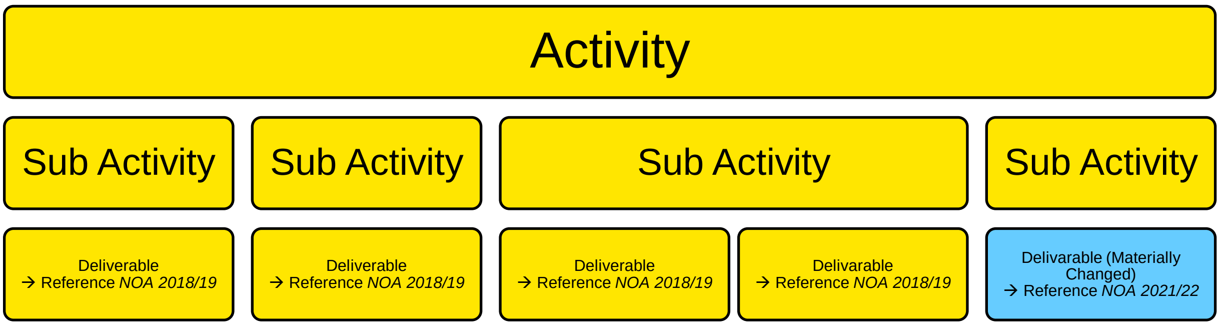


Figure 2 – CBA Reference Updates

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
- 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 £/tonneCO_2e	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
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

[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
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.

The analysis for the constraint cost (from NOA 2021/22) and the historic response and reserve costs do not take in to account the recent very high gas prices. These high gas prices have led to increased costs for the ESO in balancing and securing the system. With sustained higher gas prices, we would expect, all other things being equal, for the cost of constraint, and the cost of response and reserve to notably increase from the baseline noted here.

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.

New break-even analyses have been undertaken for:

- **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 us 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 *NOA* 2021/22
[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)	Key drivers of change
A1	Control Centre architecture and systems	210	270	+60	Cost of carbon assumption
A2	Control Centre training and simulation	16	17	+1	N/A
A3	Restoration	-8	1	+9	Cost of carbon assumption
A18	Market monitoring	Not subject to CBA			
A17	Transparency and open data	Break-even*			
A19	Data and analytics operating model	Not subject to CBA			
A4.1, A4.2 & A4.5	Lead a review of wholesale, balancing and capacity markets	Break-even			
A4.3, A4.4 & A4.6	Build the future balancing service markets	67	58	-9	Phasing of benefits
A5	Transform access to the Capacity Market and Contracts for Difference	62	40	-22	IT investment costs 1-year delay to benefits
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	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)	280	68	-212	Improved benefits methodology
A6.7	Fixed BSUoS tariff setting				
A6.9	Whole system codes reform	Break-even			

<table>
<tr><th>Activity</th><th>Name</th><th>BP1 5-year NPV (£m)</th><th>BP2 5-year NPV (£m)</th><th>5-year NPV change (£m)</th><th>Key drivers of change</th></tr>
<tr><td>A20</td><td>Net zero market reform</td><td></td><td>Break-even</td><td></td><td></td></tr>
<tr><td>A21</td><td>Role in Europe</td><td></td><td>Break-even</td><td></td><td></td></tr>
<tr><td>A7</td><td>Network Development</td><td rowspan="5">663</td><td rowspan="5">820</td><td rowspan="5">+157</td><td rowspan="5">Benefits for A7 have been included

Latest commercial solutions assumption from the Future Energy Scenarios (FES)</td></tr>
<tr><td>A8</td><td>Enable all solution types to compete to meet transmission needs</td></tr>
<tr><td>A9</td><td>Extend NOA approach to end-of-life asset replacement decisions and connections wider works</td></tr>
<tr><td>A10</td><td>Support decision making for investment at distribution level</td></tr>
<tr><td>A11</td><td>Enhance analytical capabilities</td></tr>
<tr><td>A12</td><td>SQSS review</td><td></td><td>Break-even*</td><td></td><td></td></tr>
<tr><td>A13</td><td>Leading the debate</td><td></td><td>Break-even*</td><td></td><td></td></tr>
<tr><td>A14</td><td>Take a whole electricity system approach to connections</td><td>2</td><td>11</td><td>+9</td><td>Total number of connection applications</td></tr>
<tr><td>A15</td><td>Delivering consumer benefits from improved network access planning</td><td>466</td><td>1238</td><td>+772</td><td>New deliverables providing greater consumer benefit

Constraint costs forecasts

Cost of carbon assumption</td></tr>
<tr><td>A16</td><td>Delivering consumer benefits from improved network access planning</td><td>204</td><td>252</td><td>+48</td><td>Constraint costs forecasts</td></tr>
<tr><td>A22</td><td>Offshore coordination / Network planning review</td><td></td><td>Break-even</td><td></td><td></td></tr>
<tr><td>Total</td><td></td><td>1,967</td><td>2,807</td><td>+840</td><td></td></tr>
</table>

*Not updated since BP1

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	270.00	1031.60	115.32	570.00	45.67	430.69	269.93	271.09
A2	17.24	42.48	12.08	22.40	0.75	41.07	17.24	17.24
A3	0.81	20.07	-0.91	6.54	0.81	0.81	0.81	0.81
Role 1	**288.05**	**1094.15**	**126.49**	**598.94**	**47.23**	**472.57**	**287.98**	**289.14**
A4.3, A4.4 & A4.6	57.53	138.00	38.15	72.22	-2.32	102.02	57.53	57.53
A5	39.55	81.49	22.15	56.95	-2.00	70.86	36.63	42.31
A6.5 & 6.8	32.25	138.14	27.56	36.94	9.05	32.25	14.64	49.86
A6.6 & 6.7	68.00	167.00	68.00	68.00	68.00	68.00	68.00	68.00
Role 2	**197.33**	**524.63**	**155.86**	**234.11**	**72.73**	**273.13**	**176.80**	**217.70**
A7								
A8								
A9	820.40	2,189.03	496.62	1,153.38	502.92	884.42	820.40	820.40
A10								
A11								
A14	11.52	21.24	7.89	12.70	6.12	11.70	11.52	11.52
A15	1,237.65	4,036.78	1,175.09	1,418.76	597.75	1,244.72	972.37	1237.65
A16	252.34	635.64	187.02	317.67	125.53	354.59	252.34	252.34
Role 3	**2321.91**	**6,882.69**	**1866.62**	**2,902.51**	**1232.32**	**2,495.43**	**2,056.63**	**2,321.91**
Total	**2807.29**	**8,501.47**	**2148.97**	**3,735.56**	**1352.28**	**3,241.13**	**2521.41**	**2,828.75**

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 **Annex 4 - Digital, data and technology** or in 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 – this means an activity could not fully deliver its benefits without another activity.

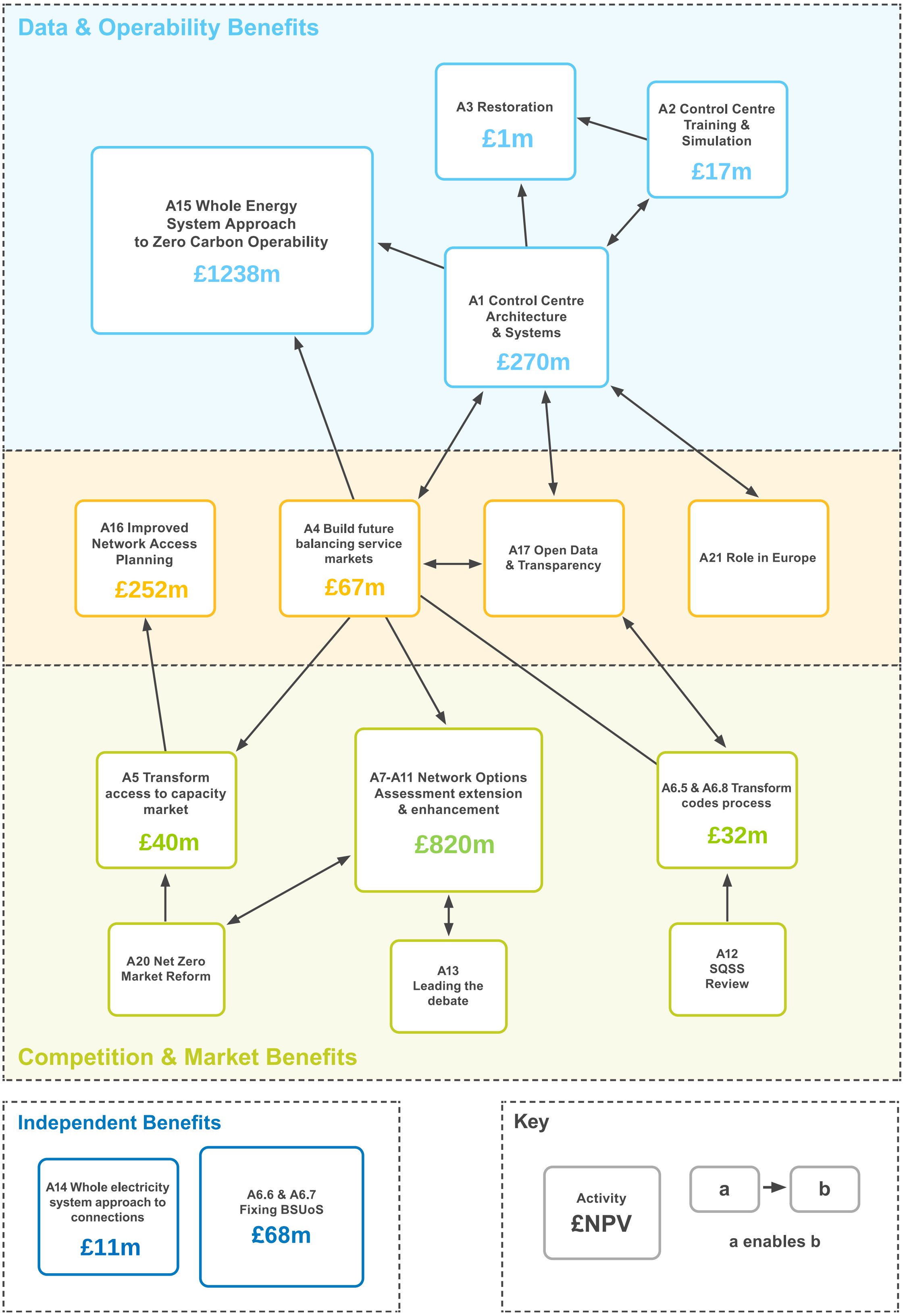


Figure 3 – Dependencies between activities

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 based on the transformational activities we have calculated benefits for. Our analysis 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 £2.18 on a consumer's annual energy bill; however, our proposed outputs will save consumers around £6.09 per year, resulting in a net reduction of around £3.90 on the consumer bill. In our BP1 analysis the net reduction was around £3.00.

Bill impact area	Consumer benefit	Percentage of total consumer benefits	Annual bill impact
BSUoS charge	£2,289m	68%	-£3.31
TNUoS charge	£928m	27%	-£2.28
Supplier charge	£174m	5%	-£0.50
Totals	**£3,391m**		**-£6.09**

We have updated our analysis by using up to date revenue, however we have kept the same parameters for Demand, Loss Scaling Factor[6] and Usage[7] as we used in our BP1 analysis to enable a like-for-like comparison over the RIIO-2 period. We recognise that these parameters will change over time and will be reflected in the latest publications by Ofgem (household demand and loss factor), and therefore the realised impact on consumer bills may differ from our analysis at the end of the RIIO-2 period.

[6] Factor to take into account energy lost as it is transported from the point of production to the end user. https://www.elexon.co.uk/operations-settlement/balancing-and-settlement/transmission-losses/

[7] Typical Domestic Consumption Value for medium Class 1 usage as published by Ofgem. https://www.ofgem.gov.uk/publications/decision-typical-domestic-consumption-values-2020

4. Role 1

Within Role 1 we have updated the existing CBAs for A1, A2 and A3. The A1 CBA has been updated for this business plan submission after the completion of the Balancing Capability Strategic Review (described in the Role 1 chapter of the main business plan document), which was being undertaken at the time our April 2022 Draft RIIO-2 Plan was published.

In Role 1 we have seen a substantial increase in our estimated NPV, this is driven by the increase to our cost of carbon assumption (higher BEIS carbon price). This has been the key driver for increases to both A1 and A3. A1 has seen an increase in the NPV of around £60m since BP1. There is also an additional £9m of benefit from A3, because of this the NPV for A3 is now positive.

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 begun during the BP1 period. This activity is not 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 • Timescales	Updated: CBA	Underlying assumption ‘Carbon Price’ has changed Underlying assumption ‘Constraint cost’ has changed
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

This subsection contains the costs and benefits of our **A1 Control centre architecture and systems (A1)** activity.

The NPV of A1 is £270 million over the RIIO-2 period, and £1,031 million over ten years. Sensitivity analysis suggests an NPV range of £46 million to £570 million over the RIIO-2 period.

4.1.1. NPV Drivers

The increase in total NPV compared with BP1 of +£60 million is mostly driven by the increase in the ‘reduced CO2 emissions’ benefits case, reflecting a higher BEIS carbon price. This highlights the importance of achieving our ambition to ensure the electricity system can operate carbon-free by 2025. Our ‘reduced carbon emissions’ benefits case has increased by £171m over the RIIO-2 period.

There has also been an increase in forecast constraint costs over the RIIO-2 period. This increases the benefit in the 'improved situational awareness' benefits case but this, and other areas, are offset by changes to the delivery schedule and an increase in costs.

Other than removing the 'better inertia forecasting' benefits case, we have not altered the methodology from BP1. We have only updated the underlying assumptions and the delivery schedule. The delivery schedules have now been split out between the Balancing and Network Control transformational IT programmes.

4.1.2. Changes from BP1

Benefits case	Changes	Description
Reduced CO2 emissions	Carbon intensity	Latest FES data used
	Expected demand	Updated carbon price
	Carbon price	Delivery schedule updated
	Delivery schedule	
Greater interconnection	Amount of interconnection	Latest FES data used
	Delivery schedule	Delivery schedule updated
Using flexible technology	Delivery schedule	Delivery schedule updated
Better inertia forecasting and needs management	Removed	Monitoring tools have not been used due to later delivery
Improved situational awareness	Constraint costs	Latest constraint cost forecasts used
	Delivery schedule	Delivery schedule updated
Reduced BM outage downtime	Delivery schedule	Delivery schedule updated

A1.5 Operational Coordination with Distributed Energy Resources (DER) and Distribution System Operators (DSO) is a new transformational sub-activity which does not generate tangible benefits within A1, it enables deliverables in Role 2 and 3 to deliver benefits. However, its costs are accounted for in the calculations of this **A1** CBA.

A1.6 Minimising Balancing Costs is not a transformational activity therefore its benefits and costs have not been included in this **A1** CBA. A1.6 is a business-as-usual activity that centres around coordinating existing work and continuous improvement.

New or materially changed sub-activity	Benefits statement
A1.5 Operational coordination with DER and DSO	The benefits for this new sub-activity are already claimed through existing benefits cases across A1. The new sub-activity acts to ensure that the deliverables from Roles 2 and 3 are fully aligned with the deliverables in Role 1 and can be integrated into the real-time operational environment. The action of alignment and coordination may accelerate benefits, but A1.5 is immature, and it would be inappropriate to model this into existing benefits cases.
A1.6 Minimising Balancing Costs	The benefits for this new sub-activity are already claimed through the existing benefits cases across a number of activities in Roles 1, 2 and 3. However, the central team and activity set up under D1.6.1, D1.6.2 and D1.6.3 should provide additional scope to speed up or increase delivery of benefits.

4.1.3. The counterfactual

If we did not undertake our transformational **A1** activity, we would use existing balancing and network control tools. These existing tools cannot enable our mission for a fully decarbonised electricity system by 2035 as they are not flexible enough to accommodate future market reforms or handle the volume and variety of market participants we expect in the future.

Our work on existing tools is described under the deliverable **D1.1.5 Maintenance and upgrades to existing systems.** This work continues in parallel to building new systems to maintain compliance with our licence obligations and enable the delivery of benefits for projects in Role 2 and 3, whilst future balancing capabilities are in development.

4.1.4. The benefits

A1 delivers benefits in five areas, which we explain in the sections below. The five areas are:

- Reduced CO2 emissions
- Greater interconnection
- Utilising flexible technology
- Improved situational awareness
- Reduced balancing mechanism outage downtime.

The benefits for ‘better inertia forecasting and needs management’ have been removed from this CBA.

4.1.4.1. Reduced CO2 emissions

Assumptions	Justification
5% of power sector carbon emissions are influenced by ESO instructions	From analysis of historic data, we have calculated that the volume of ESO activity in the balancing mechanism and trading is around 5% of national demand. As the balancing mechanism is reflective of the wider market, 5% of power sector emissions (around 2.15 million tonnes) are influenced by the ESO’s instructions.
Use of *Steady Progression* and *Leading the Way* from *FES 2021* as proxies	If we do not upgrade our balancing and control capabilities, we will be a blocker to achieving the lower carbon intensities under the *Leading the Way* scenario. Based on the *FES 2021* scenarios, our judgement is that *Steady Progression* acts as a reasonable proxy for tools not upgraded and *Leading the Way* for upgraded tools.
Levels of expected demand are taken from Leading the Way from *FES 2021*	There is little variation in expected annual demand over the five years of RIIO-2 across the *FES* scenarios.
Percentage of maximum annual benefit	ESO judgement on the delivery schedule

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

We assume our proposals unlock the lower carbon intensities of our Leading the Way scenario compared with *Steady Progression*. To account for new systems being delivered in a modular fashion we have claimed a percentage of the maximum annual benefit. This generates £226 million of consumer benefit over the RIIO-2 period.

Sensitivity analysis

We have quantified benefits in three areas:

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

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 total	Calculation
Carbon intensity Steady Progression (gCO2/kWh)	111.9	88.4	89.1	88.1	85.6		A
Carbon intensity Leading the Way gCO2/kWh	99.7	77.3	68.9	53.2	51.1		B
Reduction gCO2/kWh	12.2	11.1	20.1	35.0	34.4		C = A - B
Expected demand terawatt hours (Leading the Way)	292	285	282	282	286		D
Carbon price t/CO2e (calendar year)	248	252	256	260	264		E
Saving (£ millions)	881	800	1455	2571	2596		F = C x D x E
Attributable saving – Balancing (£ millions)	22	20	37	64	65	208	G = 50% x 5% x F
Delivery schedule – Balancing	0%	0%	10%	48%	100%		H
Benefit – Balancing (£ millions)	0	0	3.6	31	65	99	I = G x H
Attributable saving – Network Control (£ millions)	22	20	37	64	65	208	J = 50% x 5% x F
Delivery schedule – Network Control	0%	5%	25%	80%	100%		K

Benefit – Network Control (£ millions)	0	1.0	9.0	51	65	126	L = J x K
Total benefit (£ million)	0	1.0	13	82	130	226	M = I + L

Benefits £ millions	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Reduced CO2 emissions	0	1.0	13	82	130	226
Sensitivity – high market factors	0	2	25	170	292	488
Sensitivity – low market factors	0	1	6	41	65	113
Sensitivity – low delivery confidence	0	0	2	23	83	107

The above table shows the benefits associated with reduced CO_2 emissions are between £107 million and £488 million, with a central case of £226 million.

4.1.4.2. Greater interconnection

Assumptions	**Justification**
Consumer benefits delivered by interconnection	Analysis[8] undertaken by Poyry for Ofgem using the High (MA) GB consumer welfare impact, extrapolating from the three Window 2 projects. The MA (marginal additional) case provides a lower bound for benefits by assuming an interconnector is the last to be added, contrasted with the first additional (FA) case that provides an upper bound by assuming an interconnector is the first to be added. We used the High (MA) case as it provides the best central consumer welfare impact benefit proxy out of the four published MA cases.
ESO proposals unlock 2% of this benefit	Analysis of historic data comparing the volume of activity in balancing mechanism and trading activity as a proportion of national demand suggests we reprofile 5% of the market, and thus have leverage over 5% of interconnection. Allowing for the fact that we are making ongoing improvements (through IT investment reference 120 Interconnectors) and that the benefits will mainly come from our transformational investments in inertia forecasting, frequency visibility and situational awareness, we claim a conservative 2%.
Percentage of maximum annual benefit claimed	We believe our proposals ultimately unlock, at most, 2% of savings from greater interconnection. Given that we are developing new tools across the RIIO-2 period, we cannot claim the maximum benefit until the end, and so claim a reduced benefit in the preceding years.
Profile of interconnection capacity during RIIO-2	Latest figures from FES 2021 Five Year Forecast used.

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

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

We are currently required to control interconnector flow (for example by trading back imported power) for operability reasons. New balancing and control capabilities, in particular inertia monitoring, frequency visibility and situational awareness, would allow us to better understand the operating 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.

A modest assumption is that our investments contribute to unlocking around 2% of the benefits of greater interconnection. This results in an estimated consumer benefit of £5.7 million.

Sensitivity analysis

- **Market factors:** for the high sensitivity we repeated the analysis with the Base (MA) case from Poyry's findings; for the low sensitivity we used the Low (MA) case9.
- **Delivery factors:** for the high sensitivity we assume our proposals unlock 3% of the benefits; for the low sensitivity we assume our proposals unlock 1% of the benefits and are delivered one year later.
- **Third-party factors:** for the high sensitivity we have assumed a maximum of 13GW of interconnection at the end of the RIIO-2 period; for the low sensitivity this figure is 10GW.

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

Item	Value	Calculation
Total benefit per GW (2015 €m)	600	
Total benefit per GW (2018 £m)[10]	474.3	A
Total value per GW per year (£m)[11]	19.0	B = A / 25

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 total	Calculation
Total value per GW per year (£m)	19.0	19.0	19.0	19.0	19.0	94.9	B
Amount of interconnection (GW)	5.7	8.4	9.8	9.8	9.8		C

[9] When looking at consumer impact (as opposed to GB net welfare impact or total net welfare impact) the Base (MA) case provides higher consumer benefit than the High (MA) case
[10] Adjusting for inflation and exchange rates. Exchange rate is average annual 2015 EUR-GBP rate from Bank of England. Inflation is from ONS RPI All items index.
[11] 25 years is the assumed project life

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 total	Calculation
Total benefit from interconnection (£m)	107	159	186	186	186	824	D = B x C
Attributable benefit – Balancing (£ millions)	1.1	1.6	1.9	1.9	1.9	8.2	E = 50% x 2% x D
Delivery schedule – Balancing	0%	0%	0%	0%	100%		F
Benefit - Balancing (£ millions)	0	0	0	0	1.9	1.9	G = E x F
Attributable benefit – Network Control (£ millions)	1.1	1.6	1.9	1.9	1.9	8.2	H = 50% x 2% x D
Delivery schedule – Network Control	0%	5%	25%	80%	100%		I
Benefit – Network Control (£ millions)	0	0.1	0.5	1.5	1.9	3.9	J = H x I
Total benefit	0	0.1	0.5	1.5	3.7	5.7	K = G + J

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Greater interconnection	0	0.1	0.5	1.5	3.7	5.7
Sensitivity – high market factors	0	0.3	1.9	6.0	15.0	23.3
Sensitivity – low market factors	0	0.1	0.3	1.0	2.4	3.7
Sensitivity – high delivery confidence	0	0.1	0.7	2.2	5.6	8.6
Sensitivity – low delivery confidence	0	0	0.1	0.2	0.7	1.0
Sensitivity – high third-party benefits	0	0.1	0.5	1.5	5.0	7.0
Sensitivity – low third-party benefits	0	0.1	0.4	1.5	3.7	5.7

The above table shows the benefits from greater interconnection are between £1 million and £23.3 million, with a central case of £5.7 million.

4.1.4.3. Utilising flexible technology

Assumptions	Justification
£1.34 billion savings from reduced system operation costs delivered by accessing new sources of flexibility	Analysis[12] by Imperial College London suggests that there is between £0.8bn (25% of £3.2bn) and £1.88bn (40% of £4.7bn) consumer savings per year from reduced system operation costs, achievable by accessing new sources of flexibility. The midpoint is £1.34bn.
ESO proposals unlock 3% of this benefit	The report by Imperial College London (mentioned above) explains the enablers to unlock this benefit. In paragraph 2.6 one of the main requirements for future electricity systems will be "appropriate systems and interfaces to manage greater complexity in the system". In paragraph 4.1.4 the report states that system operators should be incentivised to "access all flexibility resource and be prepared to handle additional complexity in the system, by making investments and operational decisions that maximise total system benefits". We believe our transformational proposals help enable this and, consistent with our residual balancer role, unlock 3% of this giving £40.2m savings per year.
Percentage of maximum annual benefit claimed	We believe our proposals ultimately unlock, at most, 3% of savings from greater flexibility. Given that we are developing new tools across the RIIO-2 period, we cannot claim the maximum benefit until the end, and so claim a reduced benefit in the preceding years.

Based on our technical judgement, we assume our investments contribute to unlocking 3% of benefits from reduced system operation costs, leading to £80.4 million of consumer benefits over RIIO-2. To account for new systems being delivered in a modular fashion, we have claimed a percentage of the maximum annual benefit in each year.

Sensitivity analysis

Market factors: we assume the benefits of flexibility from reduced system operation costs are £0.8 billion and £1.88 billion, being the 25% and 40% cases respectively

- **Third-party factors:** we have not conducted a third-party sensitivity because the benefits case is not dependent on third-party actions that are not already accounted for under the market factors sensitivity.
- **Delivery factors:** we have assumed our proposals unlock between 2% and 4% of the benefits.

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 total	Calculation
Benefit per year from flexible technology (£ millions)	1,340	1,340	1,340	1,340	1,340	6,700	A
Attributable saving – Balancing	20.1	20.1	20.1	20.1	20.1	100.5	B = 50% x 3% x A
Delivery schedule – Balancing	0%	0%	25%	65%	100%		C

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

Benefit - Balancing (£ millions)	0	0	5.0	13.1	20.1	38.2	D = B x C
Attributable saving – Network Control	20.1	20.1	20.1	20.1	20.1	100.5	E = 50% x 3% x A
Delivery schedule – Network Control	0%	5%	25%	80%	100%		F
Benefit – Network Control (£ millions)	0	1.0	5.0	16.1	20.1	42.2	G = E x F
Total benefit (£ millions)	0	1.0	10.1	29.1	40.2	80.4	H = D + G

Benefits £ millions	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Utilising flexible technology	0	1.0	10.1	29.1	40.2	80.4
Sensitivity – high market factors	0	1.4	14.1	40.9	56.4	112.8
Sensitivity – low market factors	0	0.6	6.0	17.4	24.0	48.0
Sensitivity – high delivery confidence	0	1.3	13.4	38.9	53.6	107.2
Sensitivity – low delivery confidence	0	0	0.7	6.7	19.4	26.8

The above table shows the benefits from using flexible technology are between £26.8 million and £112.8 million, with a central case of £80.4 million.

4.1.4.4. Better inertia forecasting and needs management

The inertia monitoring tool was expected to be available from the start of the RIIO-2 period to help minimise spend on RoCoF, which is increasingly challenging to manage due ever decreasing inertia levels. We had only claimed benefits until May 2022 because that was when the Accelerated Loss of Mains Projection Programme was due to have completed and coincided with the day 1 launch of the new response products. This meant it was difficult to accurately forecast the benefits from May 2022 onwards, with respect to RoCoF spending.

We anticipate that the tool will deliver benefits by ensuring we buy the optimal levels of response to manage low frequency. However, we are not yet able to confirm the exact benefits, therefore this benefits case has been removed.

4.1.4.5. Improved situational awareness

Assumption	Justification
Constraint cost estimates	Based on modelling used in the NOA process
5% improvement in constraint spend	A network innovation allowance (NIA) project [13] demonstrated that new tools could deliver a reduction of 3% to 12% in constraint spend. Based on this, we claim a conservative 5%.
Percentage of maximum annual benefit claimed	We believe our proposals ultimately deliver a 5% saving in constraint costs. Given that we are developing new tools across the RIIO-2 period, we cannot claim the maximum benefit until the end, and so claim a reduced benefit in the preceding years.

Improved situational awareness (the ability to monitor and understand network status and evolving operational limits) allows better management of transmission. Based on the findings of a NIA project (Transmission Network Topology Optimisation), we believe our new balancing and control capabilities could ultimately reduce constraint spend by 5% per year. We taper these benefits to match the delivery of our new capabilities. This results in benefits of £108 million over RIIO-2.

To avoid any potential double counting with the benefits in section 4.2.4.3 we have not considered a reduction in reserve and response 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 lowest and highest constraint forecasts from the FES scenarios.
- **Third-party factors:** we have not conducted a third-party sensitivity because the impact of actions by third parties is accounted for in the market factors sensitivity.
- **Delivery factors:** for the upper case we assume 12% savings for constraints; for the lower case we assume 3% savings and a one-year delay.

Interaction with other benefit areas

The proposals in sections 6.1.4.1 and 6.4.4 claim to lower constraint costs. We have not accounted for these in the central benefit case here, but they would be accounted for in the market factors sensitivity analysis.

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 Total	Calculation
Constraint costs (£ millions)	975	746	660	848	1,457		A
Improvement	5%	5%	5%	5%	5%		B
Attributable saving – Balancing	2.5%	2.5%	2.5%	2.5%	2.5%		C = B / 2
Delivery schedule – Balancing	0%	0%	15%	50%	100%		D
Benefit - Balancing (£ millions)	0	0	2.5	10.6	36.4	49.5	E = A x C x D
Attributable saving – Network Control	2.5%	2.5%	2.5%	2.5%	2.5%		F = B / 2

[13] Network Innovation Allowance Closedown Report – Transmission Network Topology Optimisation https://smarter.energynetworks.org/projects/nia_nget0169/

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 Total	Calculation
Delivery schedule – Network Control	0%	5%	25%	80%	100%		G
Benefit – Network Control (£ millions)	0	0.9	4.1	17.0	36.4	58.5	H = A x F x G
Total benefit (£ millions)	0	0.9	6.6	27.6	72.9	108	I = E + H

Benefits £ millions	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Improved situational awareness	0	0.9	6.6	27.6	72.9	108
Sensitivity – high market factors	0	1.2	8.3	34.5	91.1	135
Sensitivity – low market factors	0	0.7	5.0	20.7	54.7	81
Sensitivity – high delivery confidence	0	2.2	15.8	66.2	174.9	259
Sensitivity – low delivery confidence	0	0	0.5	5.1	28.4	34

The above table shows the benefits associated with improved situational awareness are between £34 million and £259 million, with a central case of £108 million.

4.1.4.6. Reduced Balancing Mechanism outage downtime

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

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

We assume our proposals will reduce unplanned outages to one hour per year. We only claim half of this benefit during the RIIO-2 period, as we deliver new capabilities incrementally.

Financial year:	2021/22	2022/23	2023/24	2024/25	2025/26	RIIO-2 Total	Calculation

Current BM outage downtime (hours)	2.38	2.38	2.38	2.38	2.38		A
Reduced BM outage downtime (hours)	1	1	1	1	1		B
Reduction in outage downtime (hours)	1.38	1.38	1.38	1.38	1.38		C = A - B
Cost of BM outage per hour (£ millions)	0.7	0.7	0.7	0.7	0.7		D
Delivery schedule	0%	50%	50%	50%	50%		E
Benefit (£ million)	0	0.5	0.5	0.5	0.5	1.9	F = C x D x E

Sensitivity analysis

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

Benefits £ million	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Reduced balancing mechanism outage downtime	0	0.5	0.5	0.5	0.5	1.9
Sensitivity – high delivery confidence	0	0.7	0.7	0.7	0.7	2.6
Sensitivity – low delivery confidence	0.0	0.3	0.3	0.3	0.3	1.2

The table above shows the benefits from reduced balancing mechanism outage downtime are between £1.2 million and £2.6 million, with a central case of £1 million.

4.1.4.7. Total benefits case

The total benefits for **A1** are between £170 million and £760 million, with a central case of £422 million over the RIIO-2 period.

The table below provides a summary of how the benefits are allocated between the transformational aspects of the Balancing and Network Control programmes.

Benefit £ million	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Enhanced Balancing Capability (A1.2)	0	1	12	55	124	**191**

Transform Network Control (A1.3)	0	3	19	86	123	**231**
Total	**14**	**5**	**30**	**141**	**247**	**422**

4.1.5. Activity costs

Delivery of **A1** will require capex and opex spend, as summarised below:

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	29.13	46.25	46.51	46.68	33.12	**201.89**
Opex	1.24	4.12	12.76	12.75	14.08	**44.95**
Total	**30.37**	**50.37**	**59.27**	**59.43**	**47.2**	**246.84**

The total costs for **A1** are £246.84million.

4.1.6. Net Present Value

The net present value (NPV) of **A1** is estimated at £270 million over the RIIO-2 period and £1,031 million over ten years. Sensitivity analysis suggests an NPV range of:

- Market factors between £115 million and £570 million
- Delivery factors between £46 million and £431 million
- Third-party factors between £270 million and £271 million.

4.1.7. Dependencies, enablers, and whole energy system

This activity is dependent on the following transformational activities:

- **A2 Control Centre training and simulation** (Role 1) – Equipping the Control Centre with fully trained staff to operate in a zero carbon world: and
- **A17 Transparency and Open Data** (Role 1) – Ensuring the data flow between us and market participants allows them to understand system operability.

Through the most efficient operation of a complex decentralised and decarbonised electricity system **A1 Control Centre architecture and systems** enables the following transformational activities:

Activity	How it is enabled by A1 Control Centre architecture and systems
A2 Control centre training and simulation (Role 1)	Developing the tools that will be replicated in the training simulators.
A4 Build the future balancing service and wholesale markets (Role 2)	A4 will ensure markets are open to all technology and service types and increase the number of participants. Our current systems cannot handle these, hence the need for A1.
A15 Taking a whole electricity system approach to promote zero-carbon operability (Role 3)	The Network Services Procurement (Pathfinder) projects are allowing new technologies and services to provide solutions to operability issues. Our current systems are not easily configurable to handle non-traditional uses of the system and need to be upgraded
A17 Transparency and Open Data (Role 1)	Providing additional data from real world system operation. Greater transparency is also delivered by the Data and Analytics platform.

Activity	How it is enabled by A1 Control Centre architecture and systems
A21 Role in Europe (Role 2)	Ensuring alignment with European energy systems will likely require functionality that our existing systems cannot handle.

To ensure that we are in the best position possible to leverage the opportunities that the DSO transition will bring, it is vital that all the deliverables from Roles 2 and 3 are coordinated with Role 1 deliverables and activities, including **A1. A1** will also assist in ensuring the exchange of data between ourselves, DERs and DSO.

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

4.1.8. Uncertainties and risks

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

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

Risk	Mitigation	Likelihood	Impact
We develop short-lived tools due to difficulty in predicting how modelling tools will need to evolve by the end of RIIO-2 given the pace of changing market needs and/or implications from Future System operator direction	• Ensure continued review of requirements throughout remaining RIIO-2 period. • Deploy proof of concept tools where possible to gain understanding of requirements • Continue to use the product delivery principles and flexible, modular applications.	3	1
Full integration to NGESO Future Balancing system may not be aligned to the NCMS delivery plan	• Maintain Engagement with internal ESO product delivery teams • Periodic review of dependencies & programme interlocks • Review, impact assess and maintain fallback options	2	1
Full integration with new NGET SCADA system may not be aligned to NGESO NCMS Delivery plan and may require the implementation of additional components (e.g., Interfaces) to facilitate IEMS migration	• Maintain engagement via formal 'Technical Working Group' forum • Periodic joint review and alignment of delivery schedules and dependent activities, including contingency options • Planning and alignment on cutover dates and pre-requisites to migrate away from the IEMS	2	2
Key internal SME/system user resource availability may impact the testing and implementation of the new system and toolset	• Ensure early forecasting of resource requirements to business units	3	1

	• Timely recruitment for appropriately skilled resources where not already available		
Adverse change in Cyber threat, including geo-political landscape may impact security posture and result in scope creep.	• Maintain regular dialogue with security representatives ensuring alignment with industry standards	3	2
Feedback from the TAC via their assurance function may result in amendments to programme delivery approach	• Maintain continuous improvement approach with TAC and ensure change control is adhered to on any proposed amendments	3	2
Delay to the delivery of hardware and networking infrastructure required to successfully test and operate the new tool set	• Maintain continuous dialogue with Data Centre Enablement team and key suppliers such as Vodafone	3	1

4.2. A2 Control Centre training and simulation

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

The net present value (NPV) of A2 is £17.24 million over the RIIO-2 period, and £42.48 million over ten years. Sensitivity analysis suggests an NPV range of -£0.75 million to £42.48 million over the RIIO-2 period.

4.2.1. NPV drivers

The NPV has not changed significantly since BP1. There is a small increase of £1m.

Costs have decreased overall by approximately £4m 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.

4.1.2. 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 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 our 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,

Assumption	Justification
	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 4GW 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 2.7GW of resource is better utilised. This gives a 2.7GW/65GW = 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	0.03	0.15	1.16	2.33	2.33	**6.01**
Opex	1.73	1.64	2.11	2.92	3.46	**11.86**
Total	**1.76**	**1.79**	**3.27**	**5.25**	**5.79**	**17.87**

The total cost for our A2 activities is £17.87 million.

4.2.6. Net present value

The net present value of these activities is estimated at £17.24 million over the RIIO-2 period and £42.48 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 £12.08 million and £22.40 million.
- Considering delivery scenarios, between £0.75 million and £41.07 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 provide real world experience for training and simulation. 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 **A1** by providing the skills needed for zero carbon system operation.

Delivery of **A2** 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 Annex 4 – Digital, data and technology.

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

4.2. A3 Restoration

This subsection contains the costs and benefits of our **A3 Restoration (A3)** activity. The NPV of our A3 activities is £0.81 million over the RIIO-2 period and £20.07 million over ten years.

4.3.1. NPV drivers

The increase in total NPV compared with BP1 of +£9 million is driven by one factor: the increase in our Cost of Carbon assumption. As a result, the overall five-year NPV for this activity is now positive, even without considering the other benefits this activity unlocks by 2050.

We have not altered the benefits methodology from BP1 and 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** 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[14]

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 in restoration services 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 because the benefit case is based on benefit figures previously published by us.

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 CO2 to 2050	Findings from Distributed ReStart NIC Project

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

[14] 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

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	2.21	7.21	7.48	5.7	**22.6**
Opex	0	0.6	0.91	1.54	1.33	**4.39**
Total	**0**	**2.81**	**8.12**	**9.02**	**7.03**	**26.99**

The total cost for our **A3 Restoration** activities is £26.99 million.

4.3.6. Net present value

The NPV of A3 is estimated at £0.81 million over the RIIO-2 period and £20.07 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 Annex 4 – Digital, data and technology

Risk	Mitigations	Likelihood	Impact
A restoration standard is not established, and implementation frameworks are not used	We 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
Market mechanisms across different parties (ESO/DSO/DERs) are too complex and may be susceptible to distortion	Market mechanisms are still being trialled for balancing services and will be developed with this risk in mind	2	1

Risk	Mitigations	Likelihood	Impact
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	270.00	1031.60	115.32	570.00	45.67	430.69	269.93	271.09
A2	17.24	42.48	12.08	22.40	0.75	41.07	17.24	17.24
A3	0.81	20.07	-0.91	6.54	0.81	0.81	0.81	0.81
A17	Break-even analysis							
A18	Not subject to CBA							
A19	Not subject to CBA							
Role 1	**288.05**	**1094.15**	**126.49**	**598.94**	**47.23**	**472.57**	**287.98**	**289.14**

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 systems and architecture	Capex	29.13	46.25	46.51	46.68	33.12	**201.89**
		Opex	1.24	4.12	12.76	12.75	14.08	**44.95**
		Total	**30.37**	**50.37**	**59.27**	**59.43**	**47.20**	**246.84**
A2	Control Centre training and simulation	Capex	0.03	0.15	1.16	2.33	2.33	**6.01**
		Opex	1.73	1.64	2.11	2.92	3.46	**11.86**
		Total	**1.76**	**1.79**	**3.27**	**5.25**	**5.79**	**17.87**
A3	Restoration	Capex	0	2.21	7.21	7.48	5.70	**22.60**
		Opex	0	0.60	0.91	1.54	1.33	**4.39**
		Total	**0**	**2.81**	**8.12**	**9.02**	**7.03**	**26.99**
A18	Market monitoring	Not subject to revised analysis						

A17 Transparency and open data							
A19 Data and analytics operating model							
Role 1	**Capex**	**29.16**	**48.61**	**54.88**	**56.49**	**41.15**	**230.5**
	Opex	**2.97**	**6.36**	**15.78**	**17.21**	**18.87**	**61.2**
	Total	**32.13**	**54.97**	**70.66**	**73.7**	**60.02**	**291.7**

5. Role 2

Within Role 2 we have updated the existing CBAs and break-even analyses 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. There is a CBA for sub-activities A4.3, A4.4 and A4.6, and a break-even analysis for A4.1, A4.2 and A4.5. The overall NPV of the A4 CBA has reduced by approximately £9m since BP1. This is due to an increase in costs from BP1 related to delays in delivery for sub-activities A4.3 and A4.4, and new deliverables in A4.6.

We have seen a £22 million reduction in the five-year NPV for A5. This reduction in NPV is driven by an increase in costs from BP1, as well as the delays to realisation of benefits for sub-activity A5.2. The delays are due to the postponement of the deployment of the EMR portal to external users until 2023/24. This one-year postponement has been made in response to stakeholder feedback that external users would prefer to use the platform after all features are developed.

For A6 we present four separate pieces of analysis, which is consistent with our approach in BP1. The A6.5 and A6.8 CBA has seen an NPV increase of £28 million, this is driven by the increase in total benefits, which are directly proportional to the total number of connection applications. At BP1 we used a figure of 400 connection applications per year which continues for FY 2022/23 and 2023/24 while at BP2 we are forecasting approximately 1,400 connection applications per year beginning in FY 2024/25. We are observing a rising and sustained number of connection applications and therefore any benefit associated with improving efficiency during grid connections will also increase.

The NPV for A6.6 and A6.7 has reduced significantly, by £212 million since BP1. There are two key drivers for this, firstly the new methodology uses refined assumptions that were unavailable at the time of our original CBA estimate. Secondly, pushing back implementing BSUoS reform by 12 months to April 2023, in alignment with the recommendations of the BSUoS Task Force and industry workgroup discussions.

Activity	Activity name	Material changes in activity since BP1	Analysis status	Changes in analysis since BP1
A4.3, A4.4 & A4.6	Build the future balancing service markets	Scope	Updated: CBA	Minimal change
A4.1, A4.2 & A4.5	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 and Contracts for Difference	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 & A6.8	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 & A6.7	Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS)	New sub-activity	Updated: CBA	Five-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 (A4)** which includes the sub-activities A4.3, A4.4 and A4.6.

The NPV of these activities is £57.53 million over the RIIO-2 period and £138 million over ten years. Sensitivity analysis suggests an NPV range of £-2.32 million to £102.02 million over the BP2 period.

5.1.1. NPV drivers

The overall NPV of the A4 CBA has reduced by approximately £9m since BP1, this is due to an increase in costs from BP1 related to delays in delivery for sub-activities A4.3 and A4.4, and new deliverables in A4.6. The delays and new deliverables mean that we will realise less benefits within the RIIO-2 period, however the activities within A4 are key to facilitating the single market platform and enabling participants of 1 MW size.

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 an efficient frequency 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 an efficient frequency 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. This is not a forecast of future response and reserve spend, it is the value of the response and response market today used for estimation of consumer benefits
Our actions deliver a 5% saving in the response and reserve markets	Evidence from early trials (as identified in the *2019-21 Forward Plan*[15]) 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 launched 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.

In BP2, there are several planned initiatives that target further increases in market liquidity. These include:

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

- 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 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.

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. This is not a forecast of future response spend. It 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*[16]) and from subsequent market changes
Benefits delivered from year three of RIIO-2	This allows two years for implementation of the activity

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

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. By managing the daily variation closer to real time and reducing use of mandatory services, we will buy considerably less volume than if we did 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.

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	5.05	7.87	6.68	6.68	6.4	**32.62**
Opex	1.44	4.16	6.27	5.58	5.63	**23.08**
Total	**6.49**	**12.03**	**12.95**	**12.26**	**12.03**	**55.7**

The total costs for **A4** are £55.7 million.

5.1.6. Net present value

The NPV of **A4 Build the future balancing service and wholesale markets** is estimated at £57.53 million over the RIIO-2 period and £138 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 £38.15 million and £72.22 million.
- Considering delivery factors, between £-2.32 million and £102.02 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 Transparency 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 and Contracts for Difference** (Role 2)
- **A7 – A11 *NOA* enhancements** (Role 3)
- **A17 Transparency and Open Data** (Role 1) – by providing additional data from competitive markets

Delivering **A4.3, A4.4** and **A4.6** 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 these 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 Annex 4 – Digital, data and technology.

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 us. 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 **A4 Lead a review of wholesale, balancing and capacity markets**, which comprises of the RIIO-2 sub-activities A4.1, A4.2 and A4.5.

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.

5.2.1. Why have we undertaken break-even analysis?

This analysis provides details of the benefits 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. The implementation of their recommendations provides the consumer benefit and we do not know at this stage what those benefits will be.

5.2.2. The counterfactual

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

5.2.3. Activity costs

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	0	0	0	0	0	**0**
Opex	2.97	3.57	3.84	3.80	3.77	**17.95**
Total	**2.97**	**3.57**	**3.84**	**3.80**	**3.77**	**17.95**

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

5.2.4. 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, e.g., 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 we have resource and 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	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

5.2.5. 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. 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 enable zero carbon operation and will therefore result in reduced environmental damage.

5.2.6. Conclusion

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

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

This subsection contains the costs and benefits of our activity **A5 Transform access to the Capacity Market and Contracts for Difference (A5)**.

The NPV of A5 is estimated at £41.64 million over the RIIO-2 period, and £83.57 million over ten years. Sensitivity analysis suggests an NPV range of £0.01 million to £72.94 million over the RIIO-2 period.

5.3.1. NPV drivers

We have seen a £20m and £89m reduction in the five-year and 10-year NPV for A5. This reduction in NPV is driven by an increase in costs from BP1 of £18m.

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. We have also updated the benefits methodology for the 'DER Visibility Savings' benefits case. A one-year delay to the realisation of the benefits has led to a reduction in benefits of around £2m. 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
Barriers to Entry	Postponement of benefits to 2023/24	Updated to reflect stakeholder feedback on complete platform access.

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. 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 carry out 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[17]
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 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[18] 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 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 auctions 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.

[17] 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

[18] 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

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.

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 Capacity Market companies' FTE requirements mirror our own
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.

In response to stakeholder feedback and to ensure availability of a critical winter security product, the use of the new EMR portal was moved to the 2023 prequalification process. This means that the realisation of the benefits of Reduced Barriers to Entry and Cost of Participation has been postponed by a year. This will enable greater opportunities for customers to access and familiarise themselves with the new platform prior to using it for prequalification in 2023.

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
We apply a new factor for the proportion of companies registered on the EMR portal that interact with the Capacity Market. This factor is 50%.	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
Postponement of access to the platform to 2023/24	Stakeholder feedback requested access to the complete platform rather than iterative access

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 2024/25.
- **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	0.0	2.2	2.2	2.2	**6.6**

Sensitivity – high market	0.0	0.0	2.7	2.7	2.7	**8.1**
Sensitivity – low market	0.0	0.0	1.6	1.6	1.6	**4.8**
Sensitivity – low delivery	0.0	0.0	0.0	2.2	2.2	**4.4**
Sensitivity – high third-party	0.0	0.0	3.2	3.2	3.2	**9.6**
Sensitivity – low third-party	0.0	0.0	1.1	1.1	1.1	**3.3**

The above table shows the benefits from this activity are between £3.3 million and £9.6 million, with a central case of £6.6 million over the RIIO-2 period.

5.3.4.3. Total benefits case

The total benefits for A5 are between £29.88 million and £108.74 million, with a central case of £74.65 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	5.59	5.21	4.08	3.07	3.07	**21.03**
Opex	3.74	5.21	4.14	4.08	4.69	**22.59**
Total*	**9.33**	**10.42**	**8.22**	**7.15**	**7.76**	**43.62**

**Totals may appear incorrect due to rounding*

The total cost for A5 is £43.62 million.

5.3.6. Net present value

The NPV of A5 is estimated at £39.55 million over the RIIO-2 period and £81.49 million over ten years and will start to deliver positive returns from 2023/24. Sensitivity analysis suggests an NPV range of:

- Considering market factors, between £22.15 million and £56.95 million.
- Considering delivery factors, between £-2.00 million and £70.86 million.
- Considering third-party factors, between £36.63 million and £42.31 million.

5.3.7. Dependencies, enablers and whole energy system

A5 is dependent on the following transformational activities:

- **A17 Transparency and open data** (Role 1) – this activity delivers the Digital Engagement platform.
- **A20 Net Zero Market Reform** (Role 2) – successful delivery of A5.4 is dependent on the outcomes of A20.

Delivering **A5** 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 these 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 Annex 4 – Digital, data and technology.

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 we have 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 (A6.4).**

5.4.1. Changes from BP1

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

5.4.2. Why have we undertaken break-even analysis?

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 that we do 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	0.27	0.27	0.27	**0.80**
Total	0	0	0.27	0.27	0.27	**0.80**

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 our *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 we 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
There is a key dependency on the necessary legislation changes that will give us the powers to transform code processes.	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 are:

- To contribute to safe and reliable operation of the system in future by making sure codes remain appropriate for emerging markets and business models.
- The modification process is more efficient and reduces the time that customers are required to be involved. Code changes with the greatest expected benefit will be prioritised and 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. This will 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 us 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 code modifications which we facilitate each year[19]. 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 and 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 (A6.5)** and **A6.8 Digitalisation of codes (A6.8).**

The NPV of A6.5 and A6.8 is estimated at £32.25 million over the RIIO-2 period and £138.14 million over ten years, which will start to deliver positive returns from 2025/26.

5.5.1. NPV drivers

The five and 10-year NPV has increased by £28m and £121m respectively since BP1.

The reason for this large change is 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 which continues for FY 2022/23 and 2023/24 while at BP2 we are forecasting an average of 1,381 connection applications per year beginning in FY 2024/25. 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.

Although split into two sub-activities A6.5 and A6.8 benefits are accounted for in a combined CBA because it is difficult to demonstrate distinct benefits for each sub-activity. It is anticipated that ongoing work will continue to gather data from across industry to identify and inform the benefits associated with individual workstreams, in turn informing separate cost benefit analysis for A6.5 and A6.8 in BP3.

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 and accounts for approximately 80% of the total benefits case. For simplicity there is a single benefits case, Reduced Barriers to Entry.

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

5.5.3. The counterfactual

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

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 experience tailored to 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 one 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 one 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 through Digitalising the Grid Code (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	0.11	1.09	0.46	0	**1.66**
Opex	0.29	0.45	0.78	0.75	0.41	**2.69**
Total	**0.29**	**0.56**	**1.87**	**1.21**	**0.41**	**4.35**

The total cost for A6.5 and A6.8 is £4.35 million.

5.5.6. Net present value

The NPV of A6.5 and A6.8 is estimated at £32.25 million over the RIIO-2 period and £138.14 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 £27.56 million and £36.94 million.
- Considering delivery factors, between £9.05 million and £32.25 million.
- Considering third-party factors, between £14.64 million and £49.86 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 us 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 us 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 Annex 4 – Digital, data and technology.

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 applying our expertise and driving benefits across markets	3	2
There is a key dependency on primary legislation changes that will give us the powers to transform code processes.	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	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 we 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) (A6.6)** and **A6.7 Fixed BSUoS tariff setting (A6.7)**.

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

5.6.1. NPV drivers and changes from BP1

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

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

- CMP361/362 – 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.

It should be noted that at the time of writing (in August 2022), a decision is still outstanding from Ofgem regarding CMP361/362. A minded-to decision is due July to include a further industry consultation and a final decision is expected during August, the decision may impact the NPV for BP3.

Our estimate of the five-year NPV for A6.6 and A6.7 has reduced significantly since BP1, by £212m. This is due to:

- The use of an improved benefits methodology for BP2 - our BP1 CBA was created in 2019, before the final report of the Second Balancing Services Task Force 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 five-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 balancing actions are taken.

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 us 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 code modification proposals for BSUoS reform. The analysis included an 18-year NPV for

CMP308[20] and CMP361[21]. 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 five-year RIIO-2 period and £167 million over 10-years. Therefore, our estimate of the five-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 our 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.	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.	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 (A6.9).**

[20] 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)
[21] 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)

5.7.1. Why have we undertaken break-even analysis?

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 us 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 that we do 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., Network Services Procurement projects (Pathfinders) and Onshore Competition	Early alignment and engagement across the business. 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 we are resourced appropriately to undertake engagement	2	2
Risks to time, quality, and cost in delivery of the project and managing its scope	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:

- We 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 us, 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

Options	Reasons for not choosing them
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 that we provide
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 us
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?

We have undertaken this analysis because this activity does not deliver consumer benefit by itself. The implementation of its recommendations provides the consumer benefit and we do not know at this stage what those benefits will be.

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	0.44	0.44	0.43	**1.31**

Costs £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total	**0**	**0**	0.44	0.44	0.43	**1.31**

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 we are 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 we are 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.	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.
- 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 that we provide

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 us

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?

We have undertaken this analysis 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 centred conversations	Engage early with Government to highlight the needs to appropriately manage European stakeholders Engage early and continuously with our European counterparts	3	3

Risk	Mitigations	Likelihood	Impact
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.	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:

- The 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
  - ensures that information is shared between the EU and UK
  - influences the EU to ensure developments in the EU are compatible with the UK and vice versa
  - mitigates the risk of divergence between the EU and UK energy policy
  - 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 for us 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 we act 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	57.53	138.00	38.15	72.22	-2.32	102.02	57.53	57.53
A4	Break-even analysis							
A5	39.55	81.49	22.15	56.95	-2.00	70.86	36.63	42.31
A6.4	Break-even analysis							
A6.5 & 6.8	32.25	138.14	27.56	36.94	9.05	32.25	14.64	49.86
A6.6 & 6.7	68.00	167.00	68.00	68.00	68.00	68.00	68.00	68.00
A6.9	Break-even analysis							
A20	Break-even analysis							
A21	Break-even analysis							
Role 2	**197.33**	**524.63**	**155.86**	**234.11**	**72.73**	**273.13**	**176.80**	**217.70**

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	2.97	3.57	3.84	3.80	3.77	**17.95**
		Total	2.97	3.57	3.84	3.80	3.77	**17.95**
A4	Build the future balancing service markets	Capex	5.05	7.87	6.68	6.68	6.40	**32.62**
		Opex	1.44	4.16	6.27	5.58	5.63	**23.08**
		Total	**6.49**	**12.03**	**12.95**	**12.26**	**12.03**	**55.7**
A5	Transform access to the Capacity Market and Contracts for Difference	Capex	5.59	5.21	4.08	3.07	3.07	**21.03**
		Opex	3.74	5.21	4.14	4.08	4.69	**22.59**
		Total	**9.33**	**10.42**	**8.22**	**7.15**	**7.76**	**43.62**
A6.4	Transform the process to amend our codes	Capex	0	0	0	0	0	**0**
		Opex	0	0	0.27	0.27	0.27	**0.80**
		Total	0	0	0.27	0.27	0.27	**0.80**

			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	Capex	0	0.11	1.09	0.46	0	**1.66**
		Opex	0.29	0.45	0.78	0.75	0.41	**2.69**
		Total	**0.29**	**0.56**	**1.87**	**1.21**	**0.41**	**4.35**
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	0.4	0.4	0.4	**1.2**
		Total	**0**	**0**	**0.4**	**0.4**	**0.4**	**1.2**
A20	Net zero Market Reform	Capex	0	0	0	0	0	**0**
		Opex	0	0	0.44	0.44	0.43	**1.31**
		Total	**0**	**0**	**0.44**	**0.44**	**0.43**	**1.31**
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.

We present A7, A8, A9, A10 and A11 in a single CBA because there are very large dependencies between these activities. Creating separate CBAs may lead to double counting of benefits. The significant increase in the NPV for A7-11 of £157m is driven by including a benefits case associated with A7 for undertaking the Network Options Assessment (and the process that this changes into under the Network Planning Review (A22)). A7 is not a new activity, but its benefits were not included in this CBA at BP1. The benefits from 'Facilitate competition by embedding pathfinding projects into the NOA' benefits case, which is linked to A8, will now materialise in FY24 due to extended timescales for delivering these services following Network Services Procurement (Pathfinders). However, the total benefit is now approximately £130m larger than at BP1, this increase is driven by using the latest commercial solution assumptions from the Future Energy Scenarios in our CBA methodology

Break-even analyses were presented for A12 and A13 in our BP1 submission. These analyses were not updated for BP2 as A12 has not materially changed since BP1, and the changes to A13 do not materially impact its existing break-even analysis.

A14 has undergone minor change, with the NPV increasing by approximately £9m since BP1. The key drivers of this are increased benefits from efficiency savings, which are directly proportional to the total number of connection applications. As well as a new benefits case for Customer Service Improvement, which accounts for the material changes in sub-activity A14.3.

The NPV for A15 has increased by approximately £772m since BP1. This has mainly been driven by an increase in the benefits in 'Whole System Operability NOA-type Assessment' benefits case, due to increased forecast constraint costs and a new methodology. The increase in A15's NPV is further driven by the addition of a new benefits case for DER visibility savings to account for the new deliverables in sub-activity A15.8.

A16 NPV has increased by approximately £48m over five years. This increase in NPV is driven by the increase in forecast constraint costs as the benefits in this CBA are directly proportional to them.

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	None	Updated: CBA	'Connection Applications' assumption has changed

Activity	Activity name	Material changes in activity since BP1	Analysis status	Description of changes from BP1 in analysis
	approach to connections			
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
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 (A7-11)** activities.

The NPV of our A7 - A11 activities is £820.40 million over the RIIO-2 period and £2,189.03 million over ten years. Sensitivity analysis suggests an NPV range of £496.62 million to £1,153.38 million over the RIIO-2 period.

6.1.1. NPV drivers

The NPV has increased by approximately £157m and £868m over five and 10 years respectively.

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

- **Network Options Assessment (or the process that will succeed it under the Network Planning Review):** A new benefits case for undertaking a *NOA* 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 Network Services Procurement (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*).

Except for the new *Network Options Assessment* 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
Network Options Assessment	New benefit case	Activity A7 is now included in this CBA
Facilitate Competition by Embedding Network Services Procurement (Pathfinder) projects 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: Network Options Assessment
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 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:

- Network Options Assessment
- Facilitate competition by embedding Network Services Procurement (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. Network Options Assessment

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 Network Options Assessment (or the process that will succeed it under the Network Planning Review) it is possible to accelerate the identification and delivery of these benefits.

To calculate the benefits of a Network Options Assessment 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. Use the *NOA 2021/22* capability for new boundaries.
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 we 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 that Network Options Assessments deliver £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 isn't needed
- **Third-party factors:** we haven't 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 A1 and A16 also claim to lower constraint costs. By taking a conservative view of the benefits of Network Options Assessments (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 a Network Options Assessment (and the process that this changes in to under the Network Planning Review (A22)) are between £35 million and £137 million, with a central case of £69 million.

6.1.4.2. Facilitate Competition by Embedding Network Services Procurement (Pathfinder) projects 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 by *NOA* 2018/19.

This activity takes learnings and processes from our *2019-21 Forward Plan* and embeds them into network investments. The Network Services Procurement (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 stability Network Services Procurement (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
Facilitate Competition by Embedding Network Services Procurement (Pathfinder) projects into the NOA (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

Assumption	Justification
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 we do. We believe that by reviewing TO decisions, we 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 we do 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

Only 25% of schemes submitted to *NOA 2018/19*[22] 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% (five years 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**

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

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.

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 us 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**

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

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

We have also considered if it is viable for us 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 132kV networks in England and Wales is around £40 million per year, as noted in our *2018/19 Forward Plan*. We believe there is value in us 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. This leads to delivering £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.

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

- **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 £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capex	-0.06	1.77	3.20	1.60	1.20	**7.83**
Opex	2.71	4.60	3.62	2.78	2.77	**16.48**
Total*	**2.65**	**6.37**	**6.82**	**4.38**	**3.97**	**24.31**

**Totals may appear incorrect due to rounding*

The total cost for our A7 - A11 activities is £24.31 million.

6.1.6. Net present value

The NPV of A7 - A11 is estimated at £820.40 million over the RIIO-2 period and £2,189.03 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 £496.62 million and £1153.38 million.
- Considering delivery factors, between £502.92 million and £884.42 million.

6.1.7. Dependencies, enablers and whole energy system

Facilitating competition by embedding Network Services Procurement (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 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 Annex 4 – Digital, data and technology.

Facilitate competition by embedding Network Services Procurement (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
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
Our 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 our assessment complement this	3	3
We 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 (A14)**.

The NPV of A14 is £11.52 million over the RIIO-2 period and £21.24 million over ten years. Sensitivity analysis suggests an NPV range of £6.12 million to £12.70 million over the RIIO-2 period.

6.2.1. NPV drivers

For A14 there is a £9m and £6m increase in five 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 more than doubled since BP1, but due to the large increase in benefits from 'efficiency savings' the five-year NPV has increased by £9 million since BP1.

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

The Connections Reform is a review of existing processes and development of a new approach to connections. We will establish fit for purpose processes that allow us and other organisations, such as TOs and DNOs, to manage new connections alongside complexity of the growing diverse contracted background, the evolving nature of the energy system demographics and the introduction of new technologies and mixed connection profiles.

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 two 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 we have received since 2017 plus central, lower, and upper sensitivities. In the last two 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.

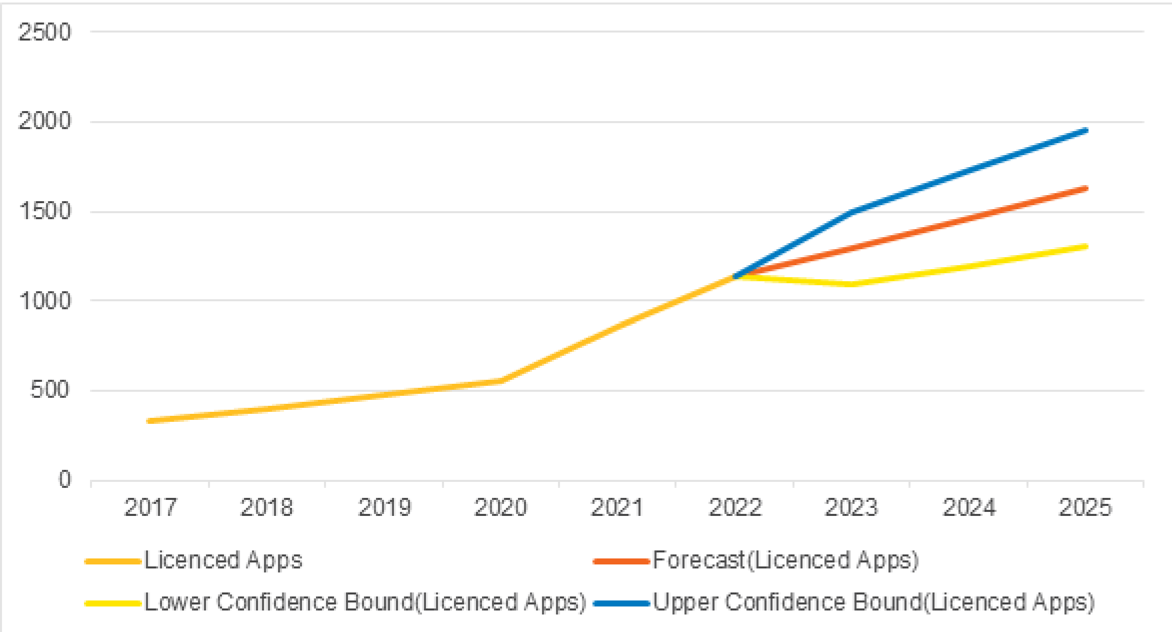


Figure 4 - Connection Applications

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	4.1	4.7	5.2	5.3	**22.6**
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 £23 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 as 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 is focused on ensuring that we perform against BP1 deliverables and 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 and 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 we have 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**
Customer Service Improvement (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	0.90	1.32	1.41	1.41	1.41	**6.44**
Opex	0.10	0.42	3.07	3.28	2.40	**9.27**

Total	1	1.74	4.48	4.69	3.81	15.71

The total costs for A14 are £15.71 million.

6.2.6. Net present value

The NPV 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 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.

Connections enabling Regional Development Programmes

As part of delivering A14 we are also identifying opportunities to engage with the whole electricity system team to develop alternative strategies to enable connection of DER ahead and instead of enabling works (transmission network reinforcements). We have seen growth in the number of Transmission Connections and in the number of new and moving to contracted stage for Transmission and Distribution. This has resulted in a growth in the number of schemes with dependencies on reinforcement and build of new sections of Transmission network. This is translating into both delays and increase of costs to consumers.

Therefore, we have decided to focus on enabling the work of the Regional Development Programmes (RPDs) via the whole electricity system team. We will look at options to connect DER earlier which will support net zero goals and reduce or remove the need for network reinforcements. The savings associated with RDPs have been included in A15.

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 Annex 4 – Digital, data and technology.

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)	2	1

Risk	Mitigations	Likelihood	Impact
	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		
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 so 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
Lack of engagement and attendance from organisations, customers, and stakeholders to Connections Reform Working Groups	Creation of new roles within the team to create new engagement strategy ahead of the start of the Reform	2	1
Inability to agree improvement to timescales and processes for change in legislation, codes and regulation	Provide a business case to BEIS and Ofgem to support request for non-standard approach to change management as support to Connections Reform programme	3	2
Inability to align data platforms between DNOs, DSO, ESO and TOs	Customer Portal team to look into how this platform can be used as central hub	3	2

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 NPV of A15 is estimated at £1,237.65 million over the RIIO-2 period and £4,036.78million over ten years. Sensitivity analysis suggests an NPV range of £597.75 million to £1,418.76 million over the RIIO-2 period.

6.3.1. NPV drivers

The NPV for A15 has increased by approximately £772m and £3,093m over five 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**.[24] The delivery of these benefits is also supported by new deliverables in **A15.6 Transform our capability in modelling and data management**.[25] The benefits of these new deliverables total £73m; however, they are not the largest driver for the change of NPV.

The largest driver for the increase in NPV from BP1 comes from the Whole System NOA Type Assessment benefits case at £1.3bn in benefits. 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 Network Services Procurement (Pathfinder) projects (described in A8) to identify system operability needs.

The methodology for the third benefits case, RDPs, 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
RDPs – Carbon savings	Carbon intensity	Latest *FES* data used
RDPs – 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 Network Services Procurement (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.
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.

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

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 RDPs, embed enhanced frequency control capability, deliver necessary potential innovation projects or 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
- RDPs
- 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 Network Services Procurement project (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 Network Services Procurement (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 Network Services Procurement 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 Network Services Procurement (Pathfinders) projects	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, we 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.

We 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.

Stakeholder feedback received on our draft BP2 submission suggested that we might be overestimating the size of the benefits. We have reflected on this feedback and concluded that we retain the benefit as calculated. The counterfactual that we have used is appropriate as it represents our best forecast of the costs we would have to incur to remedy the stability issue in the coming years, as we are not aware of any other projects or schemes that will address the issue being proposed elsewhere. The proposed activity then represents the saving from adopting a Whole System Operability NOA-type Assessment, based on our experience of the Stability Pathfinder.

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[26].

The table below shows the forecast annual cost (£m) of satisfying the SCL requirement[27].

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

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

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

Market factors	No change	No change
Delivery factors	No change	TO Options delivered earlier
Third-party factors	No change	No change

Benefits £ million	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Total**
Whole system operability *NOA*-type assessment (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 development, note this is a net value with costs accounted for
Additional renewable capacity unlocked by each RDP is 278 MW	Based on previous RDP development
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 RDPs 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. 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 developed. We use the value of our completed RDPs to forecast future RDP benefits[28].

To date RDPs have provided different benefits:

- Avoided asset build; some RDPs remove the requirement for asset build, for example one RDP produced a saving of £13 million in required asset build.
- Earlier connection of renewable generation; some RDPs facilitate early connection of renewable generation (i.e., ahead of required transmission investment works) which supports the transition to net zero. For example, one RDP provided network access for an extra 278 MW of renewable generation across four grid supply points (GSPs). We have assumed a carbon offset of 974-gigawatt hours (GWh)5 of carbon-free generation per year. We have assumed a similar carbon saving for future RDPs and one year to realise the benefits.

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

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	High Carbon price MW Avoided asset build: £25.8m Additional renewable capacity: 556 MW	Low Carbon price Avoided asset build: £25.8m Additional renewable capacity: 556 MW
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	487	487	487	487	487	

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Sensitivity – low market						
	=	=	=	=	=	
Thousand tonnes of carbon saved	109	86	86	86	83	
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	
	=	=	=	=	=	
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 £28 million and £277 million, with a central case of £104.7 million over the RIIO-2 period. Going forwards we will work, where possible, with relevant TOs and DNOs to develop future RDP CBAs. This will ensure alignment with DSO CBAs and clarity regarding overall benefits.

6.3.4.3. DER Visibility Savings

Assumptions	Justification
Forecast operability costs of £1,484 million per year	DER Visibility Benefits Assessment Master
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*[29] 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

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

Third-party factors	No change	No change

Benefits £ million	2021/22	2022/23	2023/24	2024/25	2025/26	Total
DER Visibility 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 are between £779 million and £1,631 million, with a central case of £1,431 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	1.94	6.75	13.52	11.93	7.89	**42.02**
Opex	1.50	3.27	5.35	6.19	7.16	**23.47**
Total	**3.44**	**10.02**	**18.87**	**18.12**	**15.05**	**65.49**

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

The total costs for A15 are £65.49 million.

6.3.6. Net present value

The NPV of A15 is estimated at £1,237.65 million over the RIIO-2 period and £4,036.78 million over ten years, and it will start to deliver positive returns from 2023/24. Sensitivity analysis suggests an NPV range of:

- Considering market factors, between £1,175.09 million and £1,418.76 million.
- Considering delivery factors, between £597.75 million and £1,244.72 million.

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 Network Services Procurement (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 Annex 4 – Digital, data and technology.

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'[30]	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 on 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 NPV of this activity is £252.34 million over the RIIO-2 period and £635.64 million over ten years. Sensitivity analysis suggests an NPV range of £125.53million to £354.59 million over the RIIO-2 period.

[30] 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 £48m and £216m over five 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. The tangible financial benefits will be generated post 2025 following completion of the proof-of-concept activities and training activities.

This sub-activity does not create additional financial benefit within A16 in the BP2 period. It does realistically mitigate the risks of wider system changes if automation programmes are completed ahead of schedule. Existing benefits cases cover the benefits created by this sub-activity.

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 DER. This supports the quantifiable benefit delivered through rolling out the STC cost recovery mechanism process across Great Britain. 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 England and Wales with a 11.5% reduction (central case)	40	53	37	52	101	**284**

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	2.04	1.15	1.20	1.40	1.40	**7.19**
Opex	0.62	0.97	1.74	1.84	1.88	**7.06**
Total	**2.66**	**2.12**	**2.94**	**3.24**	**3.28**	**14.25**

The total costs for A16 are £14.25 million.

6.4.6. Net present value

The NPV of A16 is estimated at £252.34 million over the RIIO-2 period and £635.64 million over ten years and it will start to deliver positive returns from 2021/22. Sensitivity analysis suggests an NPV range of:

- Considering delivery factors, between £125.53 million and £354.59 million.
- Considering market factors, between £187.02 million and £317.67 million.

6.4.7. Dependencies, enablers and whole energy system

A16 depends on the following transformational activities:

- **A5 Transform access to the Capacity Market and Contracts for Difference** (Role 2) - through the RDPs
- 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 Annex 4 – Digital, data and technology.

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

Risk	Mitigations	Likelihood	Impact
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?

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 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 government 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

Risk	Mitigations	Likelihood	Impact
Early stage of whole energy system transition means potential opportunities and pathways are unclear	Use design by doing ethos initially through targeted innovation projects to inform transition and aid timely progression	1	1
Stakeholder buy-in to planning processes is 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[31] in reduced capital and operational costs between 2030 and 2035.
  - 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 using 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.
- Improved security of electricity supply.

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 us 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 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.
- 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:

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

- 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 that we provide

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 DNOs to understand the wider system
  - Upskill the DNOs 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	820.40	2,189.03	496.62	1,153.38	502.92	884.42	820.40	820.40
A10								
A11								
A12	Break-even analysis							
A13	Break-even analysis							
A14	11.52	21.24	7.89	12.70	6.12	11.70	11.52	11.52
A15	1,237.65	4,036.78	1,175.09	1,418.76	597.75	1,244.72	972.37	1237.65
A16	252.34	635.64	187.02	317.67	125.53	354.59	252.34	252.34
A22	Break-even analysis							
Role 3	**2321.91**	**6,882.69**	**1866.62**	**2,902.51**	**1232.32**	**2,495.43**	**2,056.63**	**2,321.91**

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	1.77	3.2	1.6	1.2	**7.83**
		Opex	2.71	4.6	3.62	2.78	2.77	**16.48**
		Total	**2.65**	**6.37**	**6.82**	**4.38**	**3.97**	**24.31**
A12	SQSS review	Not included in BP2 CBA annex						
A13	Leading the debate							
A14	Take a whole electricity system approach to connections	Capex	0.9	1.32	1.41	1.41	1.41	**6.44**
		Opex	0.1	0.42	3.07	3.28	2.4	**9.27**
		Total	**1**	**1.74**	**4.48**	**4.69**	**3.81**	**15.71**
A15	Taking a whole energy system approach to promote zero carbon operability	Capex	1.94	6.75	13.52	11.93	7.89	**42.02**
		Opex	1.5	3.27	5.35	6.19	7.16	**23.47**
		Total	**3.44**	**10.02**	**18.87**	**18.12**	**15.05**	**65.49**
A16	Delivering consumer benefits from improved network access planning	Capex	2.04	1.15	1.2	1.4	1.4	**7.19**
		Opex	0.62	0.97	1.74	1.84	1.88	**7.06**
		Total	**2.66**	**2.12**	**2.94**	**3.24**	**3.28**	**14.25**
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**	**4.82**	**10.99**	**19.33**	**16.34**	**11.9**	**63.48**
		Opex	**7.69**	**13.42**	**17**	**17.51**	**17.63**	**73.26**
		Total	**12.51**	**24.41**	**36.33**	**33.85**	**29.53**	**136.74**

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

7.1. How we deliver consumer benefit

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

7.1.1. Benefit categories

In line with Ofgem's guidance, when we calculate benefits, we assign them to one of these five 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:

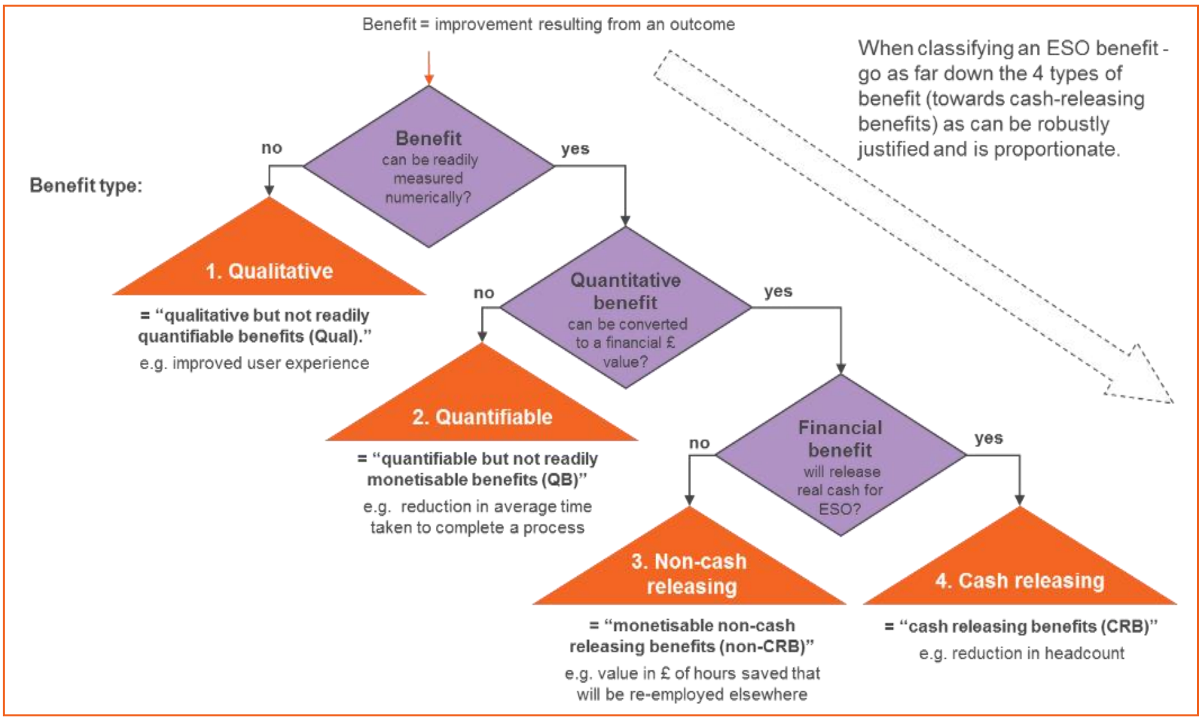

Figure 5 – Benefit Type

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:

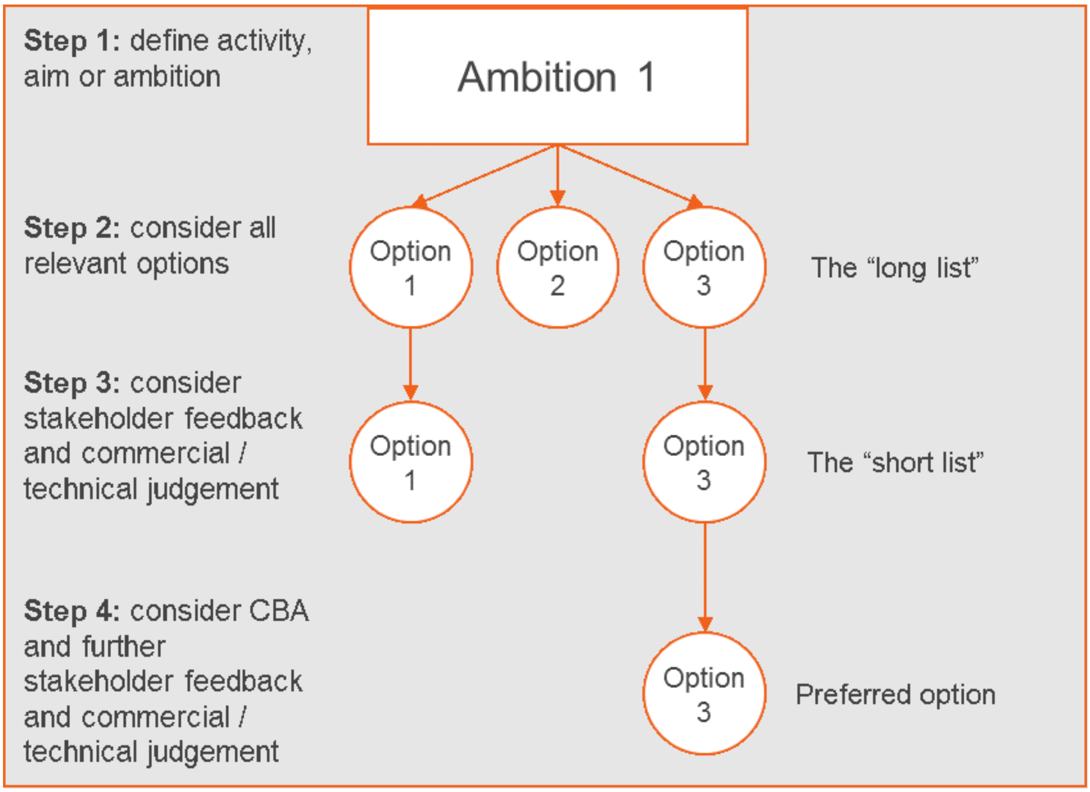

Figure 6 – Option consideration

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. We have 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[32], but the guidance issued for the BP2 submission[33]. 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
- 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

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

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	Reduced CO2 Emissions	None	Carbon Price Delivery Schedule
	Greater Interconnection	None	Delivery Schedule
	Using Flexible Technology	None	Delivery Schedule
	Better Inertia Forecasting and Needs Management	Benefits case removed	-
	Improved Situaltional Awareness	None	Constraint costs Delivery Schedule
	Reduced BM Outage Downtime	None	Delivery Schedule
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	None	Response and reserve costs Additional justification for 5% saving assumption
	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)	Number of companies on Capacity Market register

Analysis Section	Benefits case	Methodology changes since BP1	Other significant updates since BP1
		added to account for participation rates	1-year delay to benefits
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 5 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	-

Analysis Section	Benefits case	Methodology changes since BP1	Other significant updates since BP1
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

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