7. We will enable the ongoing transition to the energy system of the future

What this stakeholder priority is about

This priority is about how we help the UK achieve net-zero targets by innovating to advance the decarbonisation of electricity supply, transport and heat at the lowest cost to consumers.

What you have told us so far

We welcome the Government's decision to legislate for net zero by 2050 and the ambitious goals this entails. To make these goals a reality will require a collaborative approach across industry to accelerate decarbonisation and ensure the transition is fair for the consumer. You have told us that you want us to play a more proactive role in enabling the transition.

What we will deliver

Provide ***a* network that enables the transition to net zero by 2050**, reducing future system operation costs by between £20bn and £120bn depending on future energy scenario.

Enable **competition and new business models** to further minimise cost to consumers.

Deliver **electricity whole system solutions** by optimising across all network companies.

Enable **all energy whole system solutions** through a proposed approach to anticipatory investment and options for overcoming decarbonisation challenges, such as ultra-fast vehicle charging to overcome range anxiety and an integrated network for connecting offshore wind faster, cheaper and with less disruption. The activities required to deliver against these proposals are dependent on how the energy market and industry framework changes over time. We will ensure we are ready to deliver whatever our customers require of us, but have built the detail of our plans for this priority on the minimum values/low end of the Common Energy Scenario, as required by Ofgem. This scenario was put together with input from our stakeholders and in collaboration with other networks.

What you can find in this chapter

1. What this stakeholder priority is about
2. Track record and implications for T2
3. What our stakeholders are telling us
4. Our proposals for the T2 period
5. The justification of our proposals
6. Our proposed costs for the T2 period
7. How we will manage risk and uncertainty

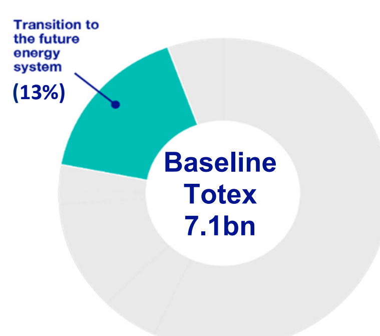
We are proposing a plan that can flex to deliver net-zero targets and is robust to future uncertainty through a suite of mechanisms that automatically adjust our allowances, ensuring consumers pay a fair amount however the energy system develops. Over 75% of expenditure for this priority is subject to such mechanisms and no uncertain spend is included.

To enable competition, we have not included £1.5bn of projects that meet Ofgem's contestability criteria and, through taking a whole system approach with Distribution Network Operators and developing a unit cost allowance mechanism for reactors, our baseline is £184m less than it would have been for this priority.

All past engineering and asset management innovations and stretching commitments to future efficiency are built into the total cost of £936m for delivering these baseline proposals. This represents 13% of the overall business plan as reflected in figure 7.1.

Over 70% of the investment proposed for this priority has been subject to economic assessment through the Electricity System Operator's (ESO) Network Option Assessment process and all areas of expenditure are supported by an investment decision pack justifying the need, scope and cost of our proposals.

Figure 7.1 Proportion of expenditure



1. What this stakeholder priority is about

As owner of the electricity transmission network in England and Wales, we enable decarbonisation and maintain security of supply at lowest cost to the consumer. We do this by:

- innovating **reinforcement** of the electricity transmission network
- enabling **competition in networks** and non-network solutions
- collaborating across organisational boundaries to enable **whole system solutions**
- proposing options that enable the decarbonisation of power, transport and heat
- developing **uncertainty mechanisms** that ensure our plan can flex to deliver net zero.

Consumer value proposition (CVP)

The CVP looks at the value we are providing above Ofgem's minimum requirements that we can robustly monetise. This chapter contains the following CVP items:

- CVP1: Optimisation of harmonic filtering (value of £18.82m)
- CVP2: Whole-system alternatives to reactor investments (value of £16.62m)
- CVP8: Optimisation with ESO to reduce whole-system costs (value of £84.88m)

For more detail, please see chapter 5.4 and the CVP annexes ET.07 to ET.07C.

Energy scenarios

The customer driven investments in this chapter depend on the changing needs of customers. We have built the detail of our draft plan using an England and Wales energy scenario based on our own market intelligence and specific stakeholder engagement. This scenario has been constructed to stay within the minimum values in the Energy Networks Association (ENA)'s Common Energy Scenario, as required by Ofgem. As this common scenario is not consistent with delivering net zero by 2050 and the industry code framework is inherently uncertain, our proposed uncertainty mechanisms are a critical enabler of the transition to legislated targets, at least cost to consumers, alongside our baseline totex plan. These mechanisms are set out and evidenced in Section 7 of this chapter, with more detail available in annex NGET_ET.12 Uncertainty mechanisms.

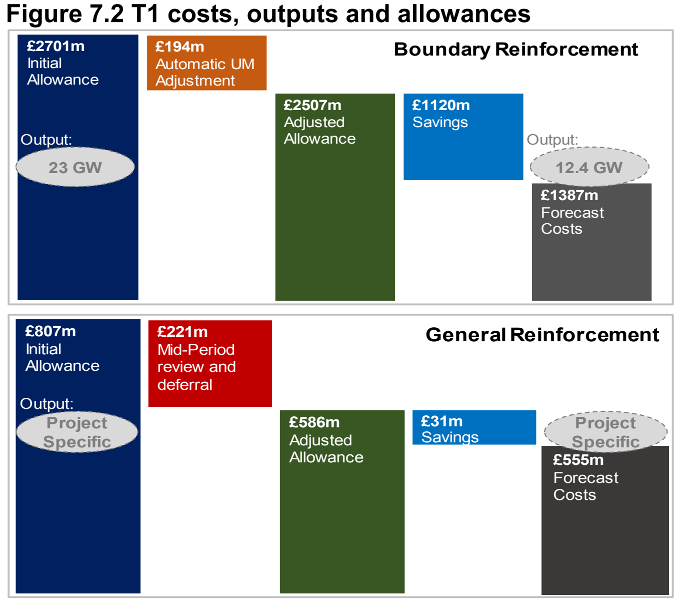
The costs to deliver this priority are primarily from network reinforcement to facilitate the flow of electricity between regions. Whilst our proposals are consistent with the Common Energy Scenario, they have been tested by the ESO against a range of future outcomes through the annual Network Options Assessment (NOA) process. We have also undertaken extensive analysis and stakeholder engagement, confirming the ongoing need for electricity transmission in even the most highly decentralised futures.

2. Track record and implications for T2

2.1 Costs, outputs and allowances in T1

This priority can be split into costs and outputs related to **boundary reinforcements**, such as new/uprated circuits or network reconfigurations, and **general reinforcements**, such as certain voltage control equipment and site separation works. Initial forecasts included in the T1 period are shown alongside allowance adjustments and current forecasts for the 8-year period in figure 7.2.

Figure 7.2 T1 costs, outputs and allowances



Volume changes due to changing customer needs

The way energy is generated, transported and consumed is changing rapidly. Not all this change was anticipated when preparing our business plans for the T1 period. Whilst the level of decarbonisation has been broadly in line with expectations, the extent of decentralisation was not foreseen. This trend has reduced transmission reinforcement anticipated at the start of the T1 period.

Automatic adjustment of allowances

Ofgem developed a suite of mechanisms as part of the approach to dealing with risk and uncertainty at the start of the T1 period. These mechanisms adjust our allowances to ensure consumers only pay for what our customers need us to deliver. A mechanism for network reinforcements providing a unit cost allowance for each additional MW of boundary capability was put in place. Unit cost allowances for network reinforcement have adjusted our allowances down by £194m.

Cost changes through efficiency

Given considerable changes in the projects delivered versus those that were expected, it is not possible to define a baseline against which to specifically measure efficiency for customer driven work. Some examples are provided below.

T1 benefits are embedded into our T2 plans

In the T1 period, we took risks by innovating to reduce costs for consumers. This was achieved through a combination of cheaper solutions, reducing network costs, as well as through solutions that delivered network capacity more quickly, thereby reducing ESO system operation costs more quickly. We did this by:

- Deploying the first series compensation devices in Great Britain on the circuits from Scotland to England & Wales – *providing more capacity on these existing circuits and delivering system operation cost savings more quickly.*
- Working with a start-up company based in California to develop power flow controller technology (Smartwires). A world first at transmission voltage – *providing additional capacity at a lower cost (estimated saving of £387m in T1) and delivering system operation cost savings more quickly (not yet deployed).*
- Developing an approach that uses the correlation between the need for capacity and extra circuit cooling offered by the wind – *providing additional capacity at a lower cost (not yet deployed).*
- Installing the first offshore HVDC link to be run in parallel with the AC transmission network in Great Britain as a joint venture with Scottish Power Transmission – *delivering system operation cost savings more quickly.*
- Through smaller innovative solutions, lean asset design, asset reuse and improvements to industry codes – *providing additional capacity and security of supply at a lower cost.*

This innovation has not come without risk. We have experienced difficulties in the commissioning and reliable operation of all the new technologies we have deployed to date, delaying the benefits of these network enhancements. Challenges of this nature are to be expected when innovating, but do not undermine the significant, net consumer benefits delivered. We have therefore included these innovations in our T2 plan.

Whole system approach

Increasing levels of decentralisation and flexibility are offering new solutions to network issues and a greater imperative to optimise across organisational boundaries. Nevertheless, the concept of whole system planning is not a new one. Network companies and the ESO have traditionally worked together to coordinate business plans and identify the most economic solutions available. We are embracing potential whole system solutions in the T2 period by removing £184m of investment identified as required from our baseline plans and proposing new uncertainty mechanisms.

Our participation in the ESO's NOA, ongoing involvement in the Energy Networks Association's Open Networks Project and bilateral collaboration with Distribution Network Operators (DNOs) through Joint Technical Planning Meetings and, more recently, Regional Development Plans are just some of the examples of where we have developed whole system solutions in the T1 period. The accompanying annex NGET_A7-8.03 Whole Systems provides further detail and specific examples.

Price control effects

Costs and allowances can also vary through price control mechanisms, such as costs incurred for outputs delivered beyond the second year of RIIO-T2.

2.2 Learning for the T2 period

The following key learnings from our experience in the T1 period have influenced our T2 proposals:

i) Baseline plans built on the extreme of an energy scenario envelope (i.e. Gone Green) are likely to lead to significant revenue adjustments through uncertainty mechanisms. We have engaged stakeholders and other networks to agree a Common Energy Scenario, reducing this risk in the T2 period.

ii) Volume driver uncertainty mechanisms are essential to deal with energy uncertainty, but output definitions have been inadequate in areas. We propose evolving these to enhance cost-reflectivity and remove the need for voluntary deferrals of allowances by working with Ofgem and other network companies on:
    - refining the output definition for wider works so that it is more resilient to changes in the generation and demand background and the dynamic nature of boundaries
    - introducing new output categories for embedded generation, system operability and preconstruction work
    - better alignment of funding and expenditure for outputs delivered beyond the end of the period (e.g. T2 period + 3 years).

iii) Innovations in how we deliver projects and in new technologies have reduced costs for consumers in the T1 period. These efficiencies are included in both the costs of our baseline plan and in the unit cost allowance calculations of our proposed uncertainty mechanisms described in Section 7 of this chapter and highlights the consumer benefits of setting unit cost allowances in advance to continue to incentivise innovation.

iv) Despite risks, innovation delivers benefits for consumers. However, when investments are delivered late, consumer benefits are also delayed. We propose to address this by ensuring **we do not benefit from these delays** through the regulatory framework and that the proceeds of any contractual compensation events are passed back to consumers, as set out in Section 5.2.i later in this chapter.

v) With hindsight, we could have put forward a more compelling whole system solution to emerging voltage issues in the T1 period. As the system continues to decentralise, managing voltage and inertia on the transmission network is more challenging. We are addressing this by working closely with DNOs and the ESO. The expansion of the NOA process to cover voltage investments and development of a system operability unit cost allowance uncertainty mechanism, as described in Section 7 of this chapter, will also ensure that the optimal consumer outcome is delivered.

vi) We have developed 10 projects under the current planning act with an average duration of 5-8 years to obtain consent. We are looking to use our experience from these projects to deliver the required pre-application consultation and engagement more effectively, better targeting resources at key aspects, considering the timing of high resource commitment activities in the process, and being more proportionate in the information we produce. By taking this approach we think we can reduce the time to achieve consents, the duration and extent of uncertainty for communities, and improve the cost profile of the process for the benefit of consumers.

3. What our stakeholders are telling us

The proposals put forward for how we enable the ongoing transition towards the energy system of the future are a combination of:

i. licence obligations, annual processes and ongoing stakeholder engagement, and
ii. bespoke engagements undertaken in building our T2 business plan.

i. Licence obligations, annual processes and ongoing stakeholder engagement

Most of our proposals are either heavily or exclusively influenced by our licence obligations, evolving annual processes run by the ESO and together with DNOs, as well as ongoing stakeholder engagement, as detailed in figure 7.3.

Our licence obligations and the industry code framework set out how we must plan the network and interface with other parties. We must design the network to maintain compliance with the *Security and Quality of Supply Standards*, adhere to the procedures and requirements across the ESO/TO interface in the *SO-TO Code* and work with the DNOs as set out in the *Grid Code*.

We gather considerable insights through ongoing domestic and international engagement with customers about their future plans, other transmission owners, our leadership role in groups like the ENA, CIGRE, the Institute of Asset Management, the IET, and the Women's Engineering Society, amongst others. We also rely on publications by others operating in this field and the work we commission with expert consultants.

ii. Bespoke engagements undertaken in building our T2 business plan

We have logged the detailed information on our engagement for this priority and how we have responded to the challenges of the Independent Stakeholder Group which can be found in annexes NGET_A7-8.01 Engagement Log (Whole system – DNO&ESO), NGET_A7-8.02 Engagement Log (Future of Transmission & Managing Uncertainty) and NGET_ A7.01 Engagement Log (Whole system – non-network company). A summary of our approach, key trade-offs and how this bespoke engagement has influenced our proposals is provided in table 7.4 below. This is split into three strands: (a) future role of transmission and managing uncertainty, (b) whole system engagement with network companies and (c) whole system engagement with non-network companies.

Figure 7.3 Key obligations, processes and ongoing engagement influencing our proposals for this priority

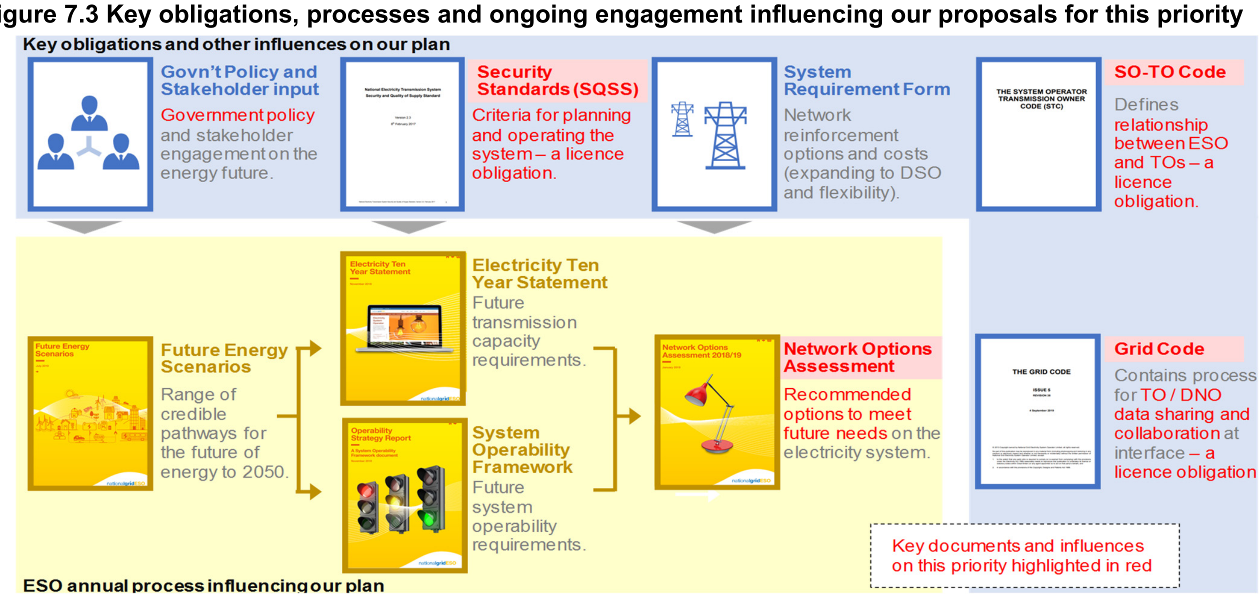


Table 7.4 Summary of our engagement

<table>
<tr><th rowspan="2"></th><th colspan="2">a) Engagement on the role of electricity transmission in the long term and managing uncertainty in the short to medium term</th></tr>
<tr><th>Future role of transmission</th><th>Managing uncertainty in the T2 period</th></tr>
<tr><td>Purpose and approach</td><td>We published a discussion document in July 2018 supported by an online survey, social media, a webinar and bespoke sessions to cover all relevant stakeholders to:
a) inform in an area with limited analysis and debate in the public domain
b) gather views on priorities and the future role of transmission to shape our engagement
c) consult on the need for the transmission network in the long-term to allow for more effective development of the RIIO-T2 price control framework and our business plans.</td><td>We published a consultation document in February 2019 supported by a webinar to:
a) playback the outcomes of our engagement on the future of transmission
b) inform about our current approach to business planning and uncertainty
c) consult stakeholders on how scenarios should be used for the T2 period
d) involve stakeholders in where we should propose a baseline allowance
e) shape our input into the Common Energy Scenario work.</td></tr>
<tr><td>What stakeholders told us</td><td>Stakeholders told us that:
• decentralisation and decarbonisation are trends most likely to impact transmission in the long term
• despite uncertainty, there is a need for electricity transmission in the long term
• decarbonisation, reliability and lower costs for consumers are top priorities; facilitating flexible energy services and enabling customer solutions are also important to certain segments
• we should play an active role in enabling the energy transition and ensure electricity transmission is not a blocker to EV uptake
• delivering whole system solutions is important
• we should undertake timely reinforcement where required.</td><td>Stakeholders told us that:
• FES with additional regional insights are a suitable range for planning our business
• our approach to setting an England & Wales scenario is reasonable
• there is majority support for setting a baseline allowance that is least likely to change over the T2 period
• it is appropriate to review existing uncertainty mechanisms and consider the introduction of new ones, particularly where these facilitate potential whole system solutions
• there is merit in the development of an anticipatory investment mechanism.</td></tr>
<tr><td>What consumers told us</td><td colspan="2">Quantitative acceptability testing showed strong support for investments needed to support future changes in electricity supply and demand (91% support for proposals). Planning the energy system of the future was ranked 3rd after only reliability and protecting the network. This relative level of support remained when consumers were asked to also consider the impact on bills. Further qualitative testing, through focus groups, confirmed these results. Whilst results differed across domestic and non-domestic consumers, both showed a strong willingness to pay for investments to accommodate renewable energy. Combined, the results from our consumer engagement suggest that these types of investments should be near the top of our priorities.</td></tr>
<tr><td>Examples of key trade-offs and how engagement influenced our plans</td><td colspan="2">This strand of engagement confirmed stakeholders' priorities we had compiled from prior engagements (set out in our 'Listen Report'). The insights we gained gave us confidence in the long-term role of electricity transmission and, therefore, in extending the current approach to managing medium-term uncertainty in the price control using 'unit cost allowances'. It also shaped our input to the Common Energy Scenario work and the England and Wales scenario upon which our plan is based, changing our assumptions on regional demand variations and solar PV capacity.
A key trade-off was whether we should play a passive role (responding to network issues), or a more proactive role (highlighting whole system issues and potential solutions) in enabling the energy transition. DNOs and, on some topics, the ESO, thought we should play a more passive role, whilst most other stakeholders wanted us to be proactive. This trade-off was debated twice in the Independent Stakeholder Group. Based on the views of most stakeholders, we decided that an active role is appropriate and are putting forward proposals for an anticipatory investment process, consideration of non-network solutions and our thinking on how to resolve some of the key challenges in this plan.</td></tr>
<tr><td>How we've responded to the Independent Stakeholder Group/ Challenge Group</td><td colspan="2">The Independent Stakeholder Group challenged our approach to uncertainty mechanisms and whether we are doing enough to ensure the price control is sufficiently flexible to allow net-zero 2050 targets to be met. In response to this challenge, we have broadened our suite of mechanisms and have undertaken extensive statistical analysis and probabilistic modelling of uncertainty to develop the detail.
The RIIO-2 Challenge Group has influenced our plans by stipulating a requirement to work with other networks to create a Common Energy Scenario and to submit a baseline plan that is consistent with this scenario. They also challenged us to ensure our plan can flex to support the pathways to net zero. The broader suite of mechanisms we are proposing in response to the Independent Stakeholder Group, and set out in Section 7 of this chapter, address this.</td></tr>
</table>

	b) Engagement to build a whole system plan with electricity network companies	
	DNO engagement	*ESO and other TO engagement*
Purpose	As a key stakeholder, we engaged extensively with all the DNOs through a series of all-day workshops and conversations. This working level interaction was supplemented with bilateral and senior level conversations as well as meetings through the ENA to: a) share assumptions around future demand and generation growth b) understand DNOs future capacity requirements at grid supply points c) collaborate on proposed investment plans. d) collaborate on whole system options and processes e) collaborate on asset replacement plans.	As a key stakeholder, we engaged extensively with the ESO in an iterative process through bilateral discussions, with other TOs and through their System Operability and NOA processes to: a) understand the network reinforcement that delivers boundary capability in the most economic way for consumers b) understand what services the ESO require to operate the network in the T2 period c) explore the potential of an incentive to minimise costs at the network owner/system operator interface. d) collaborate on potential new services that could help reduce the cost of system operation.
What stakeholders told us	Through these various channels, the DNOs: • indicated there is an ongoing need for transmission infrastructure at the distribution interface • agreed a national view of timing of electric vehicle growth and electrification of domestic heating • indicated that DNO data submissions, rather than a national scenario, should be used for identifying specific investment requirements at the interface • stated a preference for a strong ESO role in whole systems, particularly through NOA expansion, and agreed interim approach to building T2 plans • supported the introduction of a reactive, unit cost allowance based, uncertainty mechanism	Through these various channels, the ESO have indicated that they: • support our intention to help facilitate the energy transition and further develop an approach to anticipatory investment that mitigates consumer risk • are keen to ensure that any network options recommended through the expanded NOA process or other ESO needs are appropriately funded and they support progressing our proposed uncertainty mechanisms with Ofgem • believe our proposals to develop an economic modelling capability to better inform our NOA submissions and explore options with flexibility providers may cause confusion with stakeholders on the role of the TO versus the ESO.
What consumers told us	Delivering efficiency savings showed very strong consumer support in both the quantitative and qualitative acceptability testing (92% positive). Nevertheless, when asked to rank priorities, consumers positioned efficiency savings in 4th place after reliability, protecting the network and planning the energy system of the future. Delivering whole system solutions benefits all these areas and we have strongly pursued it as a result.	
Key trade-offs and how engagement influenced our plans	The ESO's requirements and recommendations have a huge influence on the proposals in this plan. Our investments in network reinforcements to increase boundary capability, innovation in new technologies and investment in system monitoring, together representing over 70% of costs in this priority, are all directly recommended by the ESO. A **key trade-off** for this strand of engagement was whether to include costs in our baseline to maintain compliance with security standards against the Common Energy Scenario where whole system alternatives could exist, or to exclude these costs from our baseline and develop an uncertainty mechanism that would provide funding where transmission investment is found to be the best solution for consumers. Based on the insights gathered through this engagement, we have decided not to put full reactor investment costs into our baseline to fully embrace the potential of whole system solutions to reduce costs for consumers, thereby **reducing our baseline proposals by £184m** (i.e. the cost difference between 5 and 35 reactors). Uncertainty on roles in the whole system planning process was highlighted by some **DNOs** and there were different views on the role of the TO. Some DNOs were keen to work exclusively with the ESO, whilst the ESO and other DNOs indicated a preference for full collaborative working. Most preferred the collaborative approach and, on balance, we think this is likely to lead to better consumer outcomes. As such, our proposals are based on this approach.	
How we've responded to the Independent Stakeholder Group/ Challenge Group	The **Independent Stakeholder Group** has challenged whether our plans are doing enough to support system operability into the future – this feedback was later echoed by both the **RIIO-2 Challenge Group** ("we are particularly interested in your plans to support the ESO in its goal of carbon-free operation by 2025…") and in the **ESO's direct feedback** on our July draft plan ("keen to see you thinking more broadly around stability issues and what solutions you could provide there.") – as a result we developed a system operability uncertainty mechanism as set out in Section 7 of this chapter and in annex NGET_ET.12 Uncertainty mechanisms.	

	c) Engagement to build a whole system plan with non-network companies	
	Flexibility provider engagement	*Customers and cross-sector engagement*
Purpose	Through attending conferences, bilateral conversations and hosting workshops, we engaged flexibility providers and storage developers to: a) seek to understand their current and future capabilities b) inform them of the potential opportunities in providing network capacity services (as opposed to ancillary services) c) understand if we can play a role in helping them come to market.	Through workshops, bilateral conversations, industry round tables and conferences we have been engaging customers, stakeholders across sectors, experts and policy makers on facilitating more renewable energy and the decarbonisation of transport to: a) listen to fully understand their challenges in decarbonising the economy at lowest cost to consumers b) ensure transmission is not a blocker c) involve stakeholders in the development of potential solutions. d) empower stakeholders to decide on a way forward.
What stakeholders told us	Flexibility providers and storage developers told us: • the potential for flexibility is sometimes underestimated – especially for portfolios • there are technical challenges for both flexibility and network companies to overcome to realise the potential • greater visibility of network issues and their characteristics is needed • greater acceptance of the services that can be provided is needed • considerable uncertainty over future opportunities and revenue streams exists • flexibility solutions can add consider consumer value by supplementing network solutions; opportunity to replace network capacity altogether limited in the short to medium term.	Experts and customers told us that: • an aggregated approach, where the regulated network owner invests in harmonic filtering equipment, could reduce the overall requirement for filters and lower costs for consumers • a change in approach to the charging methodology may be required to accommodate this development • a strategic/anticipatory approach to connecting large volumes of offshore wind on the east coast could accelerate their connection, lower costs for consumers and minimise disruption for those communities affected. Stakeholders in other sectors and policy makers have told us that: • range anxiety is a challenge to the Government's ambitions to decarbonise transport • existing vehicle charging market structures at motorway services are complex and participants do not have enough certainty of affordable infrastructure or utilisation • solutions must be robust to adapt to future uncertainty; a whole system approach is required that optimises between transmission and distribution.
What consumers told us	As set out in the strands of engagement, above, consumers showed strong support for investments that enabled decarbonisation. Through all strands of our consumer engagement, we also sought to test the appetite for investment ahead of clear need. Our proposed solution to overcome range anxiety had 85% support for the principle through our acceptability testing, with 51% also supportive of the potential bill impact. This result was discussed and corroborated through the focus groups. Willingness to pay for investment ahead of need was the highest across all of our plan categories with domestic consumers at over £11 (per consumer per year) and was middle of the pack with non-domestic consumers at over £30. When asked what approach we should take to decarbonising energy, 58% of respondents using our slider tool indicated that we should invest now to meet potential demand or once the general direction is known.	
Key trade-offs and how engagement influenced our plans	As highlighted in engagement strand (a), we have opted to play a proactive role in enabling the energy transition as a result of our engagement. We have worked closely with non-network companies and undertaken our own detailed analysis to jointly develop solutions to decarbonisation challenges. Flexibility providers thought it was worth continuing to explore a potential role for TOs in helping them come to market, whilst the ESO pointed out that they also had this role, and expressed some concerns about TOs doing so. Our proposal has evolved to commit to continue to seek opportunities to work with flexibility providers as well as working closer with the ESO should opportunities arise. Due to a lack of stakeholder support, we have removed the proposal to invest £2m to develop an economic modelling capability to better inform our NOA submissions.	
How we've responded to the Independent Stakeholder Group/ Challenge Group	The **Independent Stakeholder Group** challenged the breadth of our thinking on decarbonisation challenges, initially focused on ensuring transmission is not a blocker to a rapid EV roll-out and providing solutions to overcome range anxiety. As a result, we have also considered the challenges of connecting increasing amounts of wind generation; putting forward proposals for harmonic filtering and a strategic approach to connecting offshore wind on the east coast. The **RIIO-2 Challenge Group** challenged us to consider non-network solutions and expand our whole system thinking beyond network companies. This strand of engagement and the proposals we are putting forward in this chapter and annex NGET_A7-8.03 Whole System address that challenge.	

4. Our proposals for the T2 period

The table below outlines how what stakeholders are telling us links to our proposals, costs and consumer benefits.

Table 7.5 Proposals for the T2 period

Main proposals for enabling the ongoing transition to the energy system of the future				
Stakeholder feedback	**Proposals**	**Output type**	**T2 baseline (£m)**	**Consumer benefit**
1) Provide a network that enables the transition to net zero by 2050 at lowest cost to consumers	Innovate and invest in the network reinforcement to facilitate a changing energy market and keep costs down	PCD	507.1	Decarbonised economy Lower system operation costs
	Invest in protection and control coordination studies, changes required to maintain security of supply and identify future requirements for zero-carbon operation by 2025	PCD	31.1	Decarbonised economy Reliable supply
	Invest to facilitate closure of conventional generation and secure easements to maintain access and minimise costs	PCD	134.7	Decarbonised economy Lower network costs
2) Facilitate competition and new business models to minimise costs	Facilitate competition by highlighting projects meeting contestability criteria, consenting contestable projects and protecting consumers in incumbent delivery	PCD	181.5	Lower network costs Lower system operation costs
	Innovate by facilitating non-network solutions	Commitment	0	
3) Deliver electricity whole system solutions across network companies	Optimise with the ESO through a new mechanism to reduce whole system costs and installation of system monitoring to allow for zero- carbon operation by 2025	LO	48.0	Decarbonised economy Lower network costs
	Optimise with DNOs by identifying whole system opportunities, establishing an ongoing process and investing in [redacted] reactor units	ODI PCD	30.7	
Anticipatory/strategic investment for enabling the ongoing transition to the energy system of the future				
What stakeholders are telling us	**Proposals**	**Output type**	**T2 baseline (£m)**	**Consumer benefit**
4) Enable all energy whole system solutions	Seek to implement a suitable anticipatory investment mechanism that allows solutions to unlock rapid decarbonisation to net zero 2050.	Commitment	0	Decarbonised economy Lower network costs and barriers to entry Clean air
	Provide strategic network options that have the potential to help overcome some of the challenges of decarbonising at lowest cost to consumers.	N/A	0	

5. The justification of our proposals

Delivery of this priority predominately relates to enhancing the capacity and operability of the wider network to reduce wholesale, system operation and network costs for consumers.

All investments in our baseline proposals are underpinned by an investment decision pack and have been assessed as being the most efficient way to deliver outputs. Over 70% of proposals have been tested by the ESO and shown to deliver net consumer benefit.

5.1 Our proposal to provide a network that enables the transition to net zero at lowest cost to consumers

i. Innovate and invest in network reinforcement to facilitate a changing market and keep costs down

Key driver – Investment of £507m provides increased capacity of 22.5 GW on the transmission network. This investment, made in response to the ESO's NOA recommendations, is estimated to save consumers at least £250m/annum in avoided future constraint costs (based on analysis of the latest NOA outputs).

Options considered – When assessing future SQSS compliance, we may find that a *key system boundary* is at risk of insufficient capability. In response, we develop and assess a range of options for increasing capability by upgrading existing assets, innovative use of new technologies, whole system options, and construction of new transmission assets.

When preparing our submission to the NOA process, we identify and submit multiple reinforcement options for a given boundary. The ESO undertakes econometric modelling and recommends the best option for consumers. In the 2019/20 NOA process we have submitted 154 reinforcement options for 25 boundaries.

Whole system alternatives – The outcome of our engagement with flexibility providers is that they are well placed to add value by complementing transmission investments on boundaries, but their ability to provide an alternative is currently limited by size and duration.

We continue to seek opportunities with flexibility providers (detailed in Section 5.2.ii of this chapter), but note that the ESO is expanding the NOA in 2019 and that they are best placed to identify these alternatives.

We engaged DNOs on how we arrived at our proposals and whether they might offer better alternatives. Whilst all said they would participate in the expanded NOA, no alternatives were put forward. Similarly, no concerns were raised with how we arrived at our baseline plan.

Funding for preconstruction will need to cater for efficiently incurred abortive costs if requirements change through a whole system approach (e.g. through the ESO Connection Infrastructure Options Note).

Business as usual innovation – We continue our innovative work with suppliers to develop the world's first transmission level power flow controller technology (Smartwires), ensuring this T1 innovation continues to reduce costs for consumers in the T2 period. Discussions with the ESO are ongoing to agree how many devices can be safely and reliably integrated into the system. Further justification is provided in annex NGET_A7.02 Incremental Wider Works.

We also continue development of an innovative approach to circuit capacity that uses correlation between the cooling effect of wind with increased power flows from wind generation on a given circuit. Statistical analysis of historic weather data and testing are required for full implementation.

A summary of innovations included in our baseline plan is shown in table 7.6.

Table 7.6 BAU innovation (£m)

NOA code	Description	T2 cost	Project cost
CBEU	Establish **enhanced thermal ratings** on the Creyke Beck to Keadby 400kV route.	[redacted]	[redacted]
HSS2	Install **Smartwire device** along Fourstones to Harker to Stella West 275kV route.	[redacted]	[redacted]
MHPC	Install **Smartwire device** along Harker to Gretna & Harker to Moffat 400kV route.	[redacted]	[redacted]
	Total (rounded):	**22**	**34**

Competition – Tables 7.6 and 7.7 are a list of our proposed baseline investments. Some of these projects meet Ofgem's value threshold for early (>£50m) or late (>£100m) competition and have been highlighted. In Section 5.2.i of this chapter, we explain why we do not think these meet all the criteria for competition. **Construction costs for projects assessed as meeting competition criteria have not been included in our baseline plan.**

Cost justification – We have embedded innovation developed through the T1 period into our T2 plans. We are also making stretching commitments to future efficiencies by moving our benchmarked capex unit costs to be at or below the TNEI industry mean equating to an **£11.4m reduction** in this stakeholder priority. We have also applied a **£5.6m productivity commitment** to improve the productivity of our people by 1.1% year on year. Further detail is provided in Chapter 14 – *Our total costs and how we provide value for money.*

Uncertainty approach – We propose incremental improvements to the T1 mechanism, to ensure adjustments to our allowances more closely reflect the cost of delivering an output and ensure consumers only pay for what our customers require. Further information is set out in Section 7 of this chapter and in annex NGET_ET.12 Uncertainty mechanisms.

Table 7.7 Proposed investments for additional boundary capability in the T2 period (£m)

NOA code	Description of investment	T2 cost	Project cost
Note: projects highlighted are above Ofgem's project value threshold for early (>£50m) or late (>£100m) competition, but have been assessed as not meeting all criteria (including re-packaging), as detailed in Section 5.2.i of this chapter			
BMM2	Two new 225MVAr switched capacitors (MSCs) at Burwell Main providing voltage support to the East Anglia area as future system flows increase.	[redacted]	[redacted]
BMM3	One new 225MVAr switched capacitor (MSC) at Burwell Main providing voltage support to the East Anglia area as future system flows increase.	[redacted]	[redacted]
BNRC	Additional dynamic reactive compensation equipment (STATCOMs) at Bolney and Ninfield substations to maintain voltages within acceptable operational limits.	[redacted]	[redacted]
BRRE	Replace conductors in parts of the existing Bramford to Braintree to Rayleigh overhead line that have not already been reconductored, with higher-rated conductors, to increase the circuit's thermal rating.	[redacted]	[redacted]
BTNO	Construct a new 400kV double circuit between Bramford substation and Twinstead tee point to create double circuits between Bramford to Pelham and Bramford to Braintree to Rayleigh Main. Increase power export capability from East Anglia into the rest of the transmission system.	[redacted]	[redacted]
CDRE	Replace conductors on the existing double circuit from Cellarhead to Drakelow with higher-rated conductors to increase their thermal rating.	[redacted]	[redacted]
FMHW	Upgrade of Feckenham to Minety single circuit to allow it to operate at higher temperatures, and therefore increase its thermal rating.	[redacted]	[redacted]
HAE2	Replace an existing transformer at Harker substation with one of higher rating to prevent overloading following transmission system faults.	[redacted]	[redacted]
HAEU	Replace an existing transformer at Harker substation with one of higher rating to prevent overloading following transmission system faults.	[redacted]	[redacted]
HSNO	Uprating of Hinkley Point to Bridgwater 275kV circuits to 400kV*.	[redacted]	[redacted]
HWUP	Uprate Hackney, Tottenham and Waltham Cross substations and interconnecting double circuits from 275kV to 400kV, strengthening power flow into London, via Rye House, down to Hackney.	[redacted]	[redacted]
IFHW	Upgrade of Feckenham to Ironbridge circuits to allow them to operate at higher temperatures, and increase their thermal rating.	[redacted]	[redacted]
KLRE	Reconductor 400kV circuits running from Kemsley via Longfield tee to Littlebrook with higher-rated conductors.	[redacted]	[redacted]
KWHW	Upgrade of Keadby to West Burton circuits to allow them to operate at higher temperatures, and increase their thermal rating.	[redacted]	[redacted]
MBRE	Replace conductors in the Bramley to Melksham circuits with higher-rated conductors to increase their thermal ratings.	[redacted]	[redacted]
NEMS	Three new 225MVAr switched capacitors (MSCs) at Norton, Osbaldwick and Stella West 400kV substations providing voltage support to the east side of the transmission network as future system flows increase.	[redacted]	[redacted]
NOR1	Replace some of the conductors in the Norton to Osbaldwick double circuit with higher-rated conductors to increase thermal ratings.	[redacted]	[redacted]
RTRE	Replace conductors on the remaining sections of the Rayleigh to Tilbury circuit not recently reconductored, with higher-rated conductors, increasing the thermal rating.	[redacted]	[redacted]
SEEU	Provide new communications system and other equipment to allow existing reactive equipment to be switched in or out of service very quickly following transmission system faults. Providing better control of system voltages following faults.	[redacted]	[redacted]
SER1	Replace the conductors from Elstree to Sundon circuit 1 with higher-rated conductors to increase their thermal rating.	[redacted]	[redacted]
THRE	Replace the conductors in the Hinkley Point to Taunton circuits with higher-rated conductors to increase thermal ratings.	[redacted]	[redacted]
THS1	Install series reactors at Thornton substation to connect parts of the site currently being operated disconnected from one another to limit fault levels. This allows flow sharing between the different parts of the site and reduces thermal overloads on connected circuits.	[redacted]	[redacted]
WHTI	Turn-in the West Boldon to Hartlepool circuit, to connect to the Hawthorn Pit site it currently passes. This creates new West Boldon to Hawthorn Pit and Hawthorn Pit to Hartlepool circuits and ensure better load flow sharing and increased connectivity in the north east 275kV ring.	[redacted]	[redacted]
WYQB	Install a pair of quad boosters on the double circuits running from Wymondley to Pelham at Wymondley 400kV substation, improving capability to control power flows across North London.	[redacted]	[redacted]
WYTI	Modify the existing circuit that runs from Pelham to Sundon with a turn-in at Wymondley to create two separate circuits that run from Pelham to Wymondley and from Wymondley to Sundon. This improves the balance of power flows.	[redacted]	[redacted]
	Sub-total:	[redacted]	[redacted]
N/A	Early uprating of small cable section of Melksham – Bramley circuit in advance of NOA proceed signal for MBRE whilst completing undergrounding for Visual Impact Provision work.	[redacted]	[redacted]
	Total:	**485**	**1007**
*part of suite of works required to deliver Hinkley – Seabank circuit	**Average PV of constraint savings across FES:**		**56,600**

Our plan proposes investment to up-rate a short section of cable as part of the North Wessex Downs Visual Impact Provision (VIP) scheme in anticipation of the future NOA requirement to deliver the MBRE project. The VIP project is currently scheduled for 2024 delivery, ahead of the need to upgrade the capability of the overall Melksham to Bramley route (currently 2027 in NOA). Simply installing a cable section that matches the existing rating would very likely mean a costly upgrade of a cable section that was installed only 3-4 years before, when NOA indicates proceed for MBRE. As well as a significant cost impact, this would also involve major construction works in an area specifically identified for its visual and environmental sensitivity.

Subject to proceeding with the North Wessex Downs VIP scheme, we propose to include the additional cost required to deliver VIP underground cable mitigation works that provide capability equal to that proposed in the MBRE upgrade project as part of our plan. As NOA indicates a requirement for MBRE in both net-zero FES scenarios, the risk of demand not materialising is low.

The cost of a like-for-like cable installation, funded through the VIP scheme, is [redacted] whilst the cost of the increased capability proposed in anticipation of the future NOA requirement is [redacted]. Our plan includes the difference of £15m, the consumer benefits of which are evidenced in annex NGET_A7.02 the Incremental Wider Works and accompanying CBA.

ii) Invest in protection and control coordination studies, changes required to maintain security of supply and identify future requirements for zero-carbon operation by 2025

Key driver – To enable the ESO's goal of operating a zero-carbon network by 2025. The System Operability Framework indicates increasing amounts of renewable generation leading to declines in system inertia and short-circuit levels that could cause transmission protection not to operate as expected, posing a risk to network safety and reliability. Consumers face the risk of more frequent demand disconnection if this risk is not better understood and appropriately mitigated.

Options considered and cost certainty – Investment in modelling, software and analysis is required to undertake coordination studies and make setting changes to ensure our protection and control systems are robust enough to withstand changes on the network. This type of detailed analysis has not been required to date, but must be undertaken in the T2 period due to the levels of renewable generation in all scenarios; particularly those consistent with net zero by 2050. We appointed independent experts, Quanta Technology, to estimate the scale, potential issues, work required to model and mitigate them as well as cost. The cost of modelling and changes to settings in the T2 period is £31.1m. Quanta's work also indicates the likely need to upgrade equipment across England & Wales to mitigate risks.

Further justification for these costs is provided in annex NGET_A7.03 Protect and Control Coordination.

Whole system alternatives – We collaborate internationally with other network owners on this issue and modelling will need to be done at a 'whole system' level to fully assess impacts.

Uncertainty approach – The volume of upgrades is subject to the outcome of the studies and effectiveness of setting changes. Given this uncertainty, investments have not been included in our baseline proposals to protect consumers, as shown in table 7.8. We propose a targeted within-period determination uncertainty mechanism (UM) to fund upgrades identified through the studies, as detailed in section 7 of this chapter.

Table 7.8 Proposed investments for changes to protection and control in the T2 period

Category	Cost (£m)
Application software and modelling of protection system	[redacted]
Coordination study, testing and implementation of setting changes	[redacted]
Upgrade of non-unit and overcurrent P&C equipment	Subject to UM
Total:	**31.1**

iii) Invest to facilitate closure of conventional generation and secure easements to maintain access and minimise costs

These activities ensure we can access our assets and continue to operate our sites. They are a continuation of programmes started prior to the T1 period.

Securing easements

Key driver – As part of our operations, we require access to privately owned land to access our assets. This has historically been managed purely through wayleaves, but these wayleaves come with risks of termination (e.g. when land owners sell or assets pass to an executor) and potential negative network reliability and legal cost implications for consumers.

Options considered – To avoid becoming a distressed buyer of access rights or subject to litigation that requires us to move our assets, we have been undertaking a programme of renegotiating wayleaves as permanent easements with land owners for several years. Other organisations with similar challenges also take this approach. To protect consumers from this risk, we plan to continue this programme into the T2 period.

Cost certainty – Whilst the numbers and timing of easement claims are impacted by the property market cycle and other factors, there is a clear trend over time. Forecast costs for this programme in the T2 period, at £18.7m per annum, are therefore based on historic spend and recent trends. Further justification for the total cost of £93.3m is in annex NGET_A7.05 Easements.

Site separation to facilitate the closure of conventional generation

Key driver – As the electricity system continues to decarbonise, many ageing conventional power stations are closing. In parallel, many of Britain's fleet of nuclear power stations are coming to the end of their lives. This work ensures we can continue to operate our substations at sites where power stations are closing. Most of the power stations were established when the transmission network and power stations were jointly owned, and the symbiotic nature of essential site services from that period has persisted.

Options considered – Past experience, where site separation was undertaken in a reactive rather than proactive manner, the short notice of closure provided by power stations has shown not to be sufficient to negotiate the necessary wayleaves and secure LV supplies, often leading to an additional cost of temporary supplies. Where this occurs, the costs tend to be at least 35% (~£1.5m per site) higher than when a proactive approach is taken. As a result, we are proposing a proactive approach in the T2 period.

Cost certainty – The work required to ensure that we can continue to operate these sites can include ensuring each substation has an independent 415V electricity supply, water supply, sewage and drainage, water disposal, telephone line, security fencing and tunnel security, earthing, firefighting and removal of assets from power station land where relevant.

The forecast cost of £41.4m in the T2 period to continue with this programme of work is informed by a site-specific assessment of the components of work required and the cost of those components from work undertaken in T1 (which is forecast to be a total of £75m across the period). A breakdown is shown in table 7.9 and further detail provided in annex NGET_A7.04 Site Separation.

Table 7.9 Cost of site separation work in T2 period

Site	Cost £m	Site	Cost £m
Cowes	[redacted]	West Burton	[redacted]
Hartlepool	[redacted]	Ratcliffe	[redacted]
Grain	[redacted]	Uskmouth	[redacted]
Hinkley B	[redacted]	Wylfa	[redacted]
Fawley	[redacted]		
		Total:	41.4

5.2 Our proposal to facilitate competition and new business models to minimise cost

We are driven to further minimise the cost of the energy transition for consumers. We continue to engage Ofgem and stakeholders to progress key policy areas (i.e. approach to CATO and the replacement for Strategic Wider Works, referred to as SWW in the T1 period).

i) Facilitate competition by highlighting projects meeting contestability criteria, consenting contestable projects and protecting consumers in incumbent delivery

Incentives at the heart of the RIIO price control mimic competitive pressures and drive innovation and efficiency for consumers. For certain large capital projects, the introduction of a competitively appointed transmission owner **(CATO) model in the T2 period has the potential to add further consumer value and <u>we are strong advocates of this approach</u>.**

We continue to proactively engage to progress the CATO approach so that consumers can benefit from it as soon as possible. Where a CATO approach is not possible, we will ensure robust native competition to identify and reveal efficient costs. We also propose an approach to mitigate the consumer impact of late project delivery for large projects. These various components of our proposal are set out in figure 7.10 and explained in more detail, below.

Figure 7.10 Facilitate competition components

Facilitate competition in third party delivery
- a) Early competition – projects >£50m
- b) Late competition – projects >£100m
- c) Consented projects ready for competition

Facilitate competition and protect consumers in incumbent delivery
- d) Native competition
- e) Mitigate impact of late delivery

Key assumptions we have made

We have identified projects in our plan for the T2 period that are likely to be suitable for third party competition. In doing so, we have applied Ofgem's "re-packaging" criteria, highlighted all projects meeting the £50m threshold for early and £100m for late competition and assessed these projects against contestability criteria. There are complex interactions between the process and funding arrangements for competition and the rest of our business plan. Some key policy decisions are also outstanding. We have made the following assumptions in putting together our final proposals:

- The ESO publishes future network capability needs in the Electricity Ten Year Statement (ETYS) and the NOA – *these sources are best for less defined "system needs" that could be competed; our early competition assessment is focused on the specific projects in our plan.*
- Ofgem has proposed a Large Onshore Transmission Investment (LOTI) mechanism for projects >£100m, replacing SWW, that works on similar principles and would be central to the CATO process. The detail of how such a mechanism would work has not yet been decided – *we have assumed the mechanism applies to all contestable and uncertain projects >£100m. Projects >£100m that do not meet these criteria have been included in our baseline plan.*

a) Early competition – projects >£50m

The early competition model, whereby Ofgem runs a tender before planning consent is sought, has the greatest potential for consumer benefit through innovation. We recognise there are challenges to implementation, but have put considerable thought into helping overcome these for consumers, including in our response to Ofgem's Sector Specific Methodology consultation.

We have "flagged" all relevant projects >£50m across our entire business plan and assessed these primarily against the opportunity for innovation as directed by Ofgem. As secondary considerations, we have also factored in time criticality and certainty of need in our assessment. Table 7.11 sets out how we have defined and applied these criteria and table 7.12 shows our assessment of projects within this priority. Similar assessments are shown for customer connection and asset health projects in chapter 8 *We will make it easier for you to connect to and use the network* and chapter 9 *We will provide a safe and reliable network.*

Table 7.11 Criteria for contestability assessment and how these have been applied to projects

Criteria	How we have applied to projects to assess suitability
Is the requirement new and separable?	We have assessed whether projects are new and could be separable to allow for clear ownership boundaries, safety requirements and segregation of obligations/liabilities. **New** = involving the implementation of completely new assets or the complete replacement of an existing asset; **Separable** = assets can be clearly delineated from other (existing) assets. *[note: only used in assessing suitability for late competition]*
How time critical is the requirement?	We have considered **the current NOA recommendation** (chapter 7), the **customer's contracted connection date** (chapter 8) or **asset health indicator** (chapter 9) to assess whether time to run a competition could delay constraint cost savings, customer requirements or impact reliability.
Certainty of need	We have considered the **number of FES scenarios** in which a network requirement is deemed as beneficial for consumers, the estimated **level of consumer benefit** indicated by NOA (i.e. PV of future constraint savings), our **project health score** for customer connections and the **NARMS risk output** to assess certainty of need.
Opportunity for innovation	We have considered the level of opportunity for innovation in project design, delivery or operation for each project. Primarily, **whether another solution to the requirement is likely/possible.** *[note: only used in assessing suitability for early competition]*

Table 7.12 Competition suitability assessment for all projects >£50m within this priority

Project Name (NOA ref)	Project Cost (£m)	NOA Rec.	New and Sep.	Time criticality	Certainty of need	Scope to innovate	Suitability assessment (Suitability for competition against our criteria: Limited suitability ○ ◔ ◑ ◕ ● High suitability)
HVDC: Peterhead to Drax (E4D3)	[redacted]	Proceed	●	◑	●	◑	Time criticality risks delay of benefits; scope to innovate reduced due to project maturity and multiple TO interface
HVDC: Torness to Hawthorn Pit (E2DC)	[redacted]	Proceed	●	○	●	◔	Time criticality risks delay of consumer benefits; scope to innovate low due to project maturity
South London to South East Coast (SCN1)	[redacted]	Proceed	●	◔	●	●	Considerable consenting challenges and challenging earliest in service date (EISD from NOA).
Bramford-Twinstead (BTNO)	[redacted]	Proceed	○	◑	●	◑	Maturity of project severely limits scope to innovate
Hackney-Tottenham-Waltham X (HWUP)	[redacted]	Hold	○	●	◕	◑	Uprating of existing assets; scope to innovate limited by network requirement
Central Yorkshire (OENO)	[redacted]	Proceed	●	◕	◕	●	Time to run competition and considerable scope to innovate
Bramley – Melksham Reconductoring (MBRE)	[redacted]	Hold	○	◕	◕	○	Capability enhancement through reconductoring provides minimal scope to innovate + NOA already tests alternatives
Bolney and Ninfield Reactive comp. (BNRC)	[redacted]	Proceed	◑	○	●	◔	Time criticality risks delay of constraint cost benefits; scope to innovate low due to project maturity
Hinkley Point to Taunton Reconductoring (THRE)	[redacted]	Hold	○	◕	◕	○	Capability enhancement through reconductoring provides minimal scope to innovate + NOA already tests alternatives

b) Late competition – projects >£100m

To assist the ESO in identifying projects that meet Ofgem's late competition criteria (high value >£100m, new and separable), we provide details of all network reinforcement projects under development on an annual basis through the NOA process. All our projects were assessed by the ESO against Ofgem's contestability criteria in the latest NOA iteration. The following projects were highlighted by the ESO as meeting the criteria: OENO – Central Yorkshire reinforcement, SCN1 – New 400kV transmission line between south London and the south coast, E2DC – Eastern Scotland to England; Torness to Hawthorn Pit offshore HVDC, E4D3 Eastern Scotland to England; Peterhead to Drax offshore HVDC. We are highlighting all our projects >£100m in table 7.13, even if already assessed by the ESO as not meeting the contestability criteria. Our suitability assessment for late competition uses the criteria set out in table 7.11, as with early competition, but the scope for innovation is replaced with Ofgem's new and separable criteria. Our assessment shows that 4 projects meet Ofgem's criteria, one of which (E2DC) may not be suitable due to the urgency of delivering the associated consumer benefits.

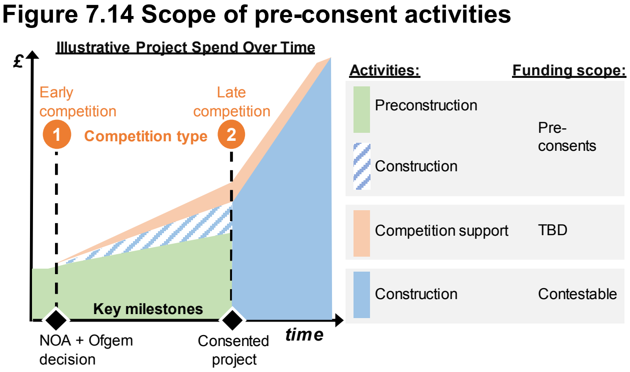
Table 7.13 Competition suitability assessment for all projects >£100m in our customer driven plan

Project Name (NOA ref)	Project Cost (£m)	NOA Rec.	ESO indicate contestable	New and Sep.	Time criticality	Certainty of need	Scope to innovate	Suitability assessment (Suitability for competition against our criteria: Limited suitability – High suitability)
HVDC: Peterhead to Drax (E4D3)	[redacted]	Proceed	Y					More time to contest than E2DC and higher project value
HVDC: Torness to Hawthorn Pit (E2DC)	[redacted]	Proceed	Y					Time criticality risks unnecessary consumer exposure to additional constraint costs
South London to South East Coast (SCN1)	[redacted]	Proceed	Y					Considerable consenting challenges and challenging earliest in service date (EISD from NOA).
Bramford-Twinstead (BTNO)	[redacted]	Proceed	N					Does not meet Ofgem new and separable criteria
Hackney-Tottenham-Waltham X (HWUP)	[redacted]	Hold	N					Does not meet Ofgem new and separable criteria
Central Yorkshire (OENO)	[redacted]	Proceed	Y					Time to run competition and considerable scope to innovate

c) Consented projects ready for competition

To enable competition, we have not included any post-consenting costs for projects that meet the early or late competition criteria in our baseline plan. The total value of these projects is estimated at over £4bn, with over half this cost likely to be incurred within the T2 period. For those projects that have a NOA proceed signal and are contestable, we propose to define a new output of a ***contested project***, which we would deliver, ready for a late CATO competition. To deliver this output, we propose a baseline allowance of £182m across all four projects to undertake the necessary activities to consent a project that is subsequently contestable and does not duplicate any costs, as shown in figure 7.14, below.

Figure 7.14 Scope of pre-consent activities



Funding for efficient activities to achieve consent includes normal pre-construction activities such as detailed project development, surveys and consenting, as well as costs traditionally considered to be construction, such as full surveys suitable for construction. We assume that any competition support costs would be covered by a separate mechanism.

A detailed breakdown of costs and benefits is included in annex NGET_A7.06 Facilitate Competition (pre-consents). Costs per project are shown in table 7.15.

Table 7.15 Estimated costs for potentially contestable projects (£m)

Project (NOA ref)	T1 cost	T2 cost to consent	Estimated total project cost^
SCN1	6.0	71	[redacted]
OENO	4.8	35	[redacted]
E4D3	1.5*	45*	[redacted]
E2DC	5.1*	31*	[redacted]
Totals:	**17.4***	**182***	**5,067**

*excludes costs to consent in Scotland
^total estimated project cost across Scotland and England

We have not included any pre-consenting costs for future projects that meet the criteria for late competition (i.e. those that do not yet feature in NOA or have not yet been given a *proceed* signal), but have instead developed an uncertainty mechanism that would automatically adjust funding for delivery of the output.

This mechanism, detailed in Section 7 of this chapter and annex NGET_ET.12 Uncertainty mechanisms, provides the funding certainty that allows us to respond promptly to NOA proceed signals and protect consumers from the potential late delivery of projects. It can be implemented in a manner that works with CATO and/or LOTI policy as this emerges and integrated into a milestone based approach to mitigating the impact of late delivery.

d) Native competition

We utilise competitive processes in all procurement, except where the potential benefits of doing so are outweighed by the costs. Our plan for native competition is set out in Chapter 14 *Our total costs and how we provide value for money* and annex NGET_A14.06 Delivering competitive value through procurement.

e) Mitigate impact of late delivery

Innovation carries risk of failure, but consumers still benefit overall in the long term. As we set out to meet the challenge of net zero by 2050 it is important that networks continue to have incentives to innovate, but that they do not benefit when innovations fail. In considering how to minimise consumer detriment, we balanced benefits of additional protection against the cost of providing such protection.

Our proposal is that a mechanism is put in place for large capital projects to recover the time value of money over any delay period from network companies. In addition, any contractual payment for damages with suppliers would be used to offset consumer detriment. We propose that the delivery date is set at a milestone after consents have been obtained and a contract is put in place with suppliers. The detail of this approach should be finalised alongside LOTI and the approach to CATO.

ii) Innovate by facilitating non-network solutions

Key driver – The decentralisation and digitalisation of energy is leading to new opportunities to resolve network issues using storage technology (e.g. batteries) and demand side response (where electricity consumption is shifted as a service to the network operator). DNOs have started procuring flexibility to resolve issues on their networks and the ESO also procures flexibility services through ancillary services contracts and the balancing mechanism. To date, the focus has been on ancillary services and short-term balancing mechanism actions, rather than on providing a longer-term network capacity type service.

Options considered – At transmission level, it is primarily the role of the ESO to establish markets and procure services. The NOA process is expanding and evolving through the Network Development Roadmap to include the assessment of non-network solutions and the ESO is proposing to enhance its ability to enter into long-term contracts with flexibility providers in the T2 period.

As a Transmission Owner, we are keen to understand the role we can play in helping to bring these technologies to market for the benefit of consumers. The way we are funded through the RIIO framework may present opportunities in this area for developers of storage assets and demand side response portfolios to work with us to deliver combined solutions that lower costs for consumers. Our engagement in this area with the ESO, DNOs and flexibility providers continues as part of our ongoing engagement activities.

Whole system alternatives – Stakeholders have told us that the potential of storage and demand side response is often underestimated, there are technical challenges to overcome and developers face uncertainty over future opportunities and revenue streams. We sought to better understand and align on the potential for flexibility against various network opportunities in the T2 period as part of our engagement.

Opportunities for flexibility will continue and likely grow to provide services within regional distribution networks and ancillary services for the ESO. In relation to our business plan, we understand that there are opportunities for flexibility to provide consumer value in delaying network investment at the interface between transmission and distribution. This has been part of our engagement with DNOs and is reflected in our plans at the transmission/distribution interface. In addition, there are opportunities to complement network investment on the wider electricity transmission network, particularly as flexibility solutions can often be deployed faster than most traditional network reinforcements.

From our engagement with stakeholders to date, we understand that the opportunity for flexibility solutions to provide an enduring alternative to network capacity is currently limited due to scale and duration. This is reflected in our conclusions in figure 7.16.

Figure 7.16 Flexibility network services potential

		not a TO cost		
Consumer value:	Delay network investment at Tx / Dx interface	Reduce cost of secure system operation	Compliment network investment on wider network	Alternative to network investment on wider network
Type of flexibility suitable:	Small, short-duration storage and small to medium aggregated portfolios of domestic + I&C DSR	Medium, short-duration storage and large aggregated portfolios domestic + I&C DSR	Large, aggregated and diversified portfolios of storage and DSR assets or single large storage assets	Large, aggregated and diversified portfolios of storage and DSR assets or single large storage assets
Relative T2 opportunity (2021—2026):				

Detailed engagement with energy storage developers and Ofgem is ongoing to investigate the use of battery technology to supplement incremental transmission network upgrades and provide additional transmission boundary capacity within the T1 period. The potential for a long-term contract between the Transmission Owner and storage developer could allow for storage solutions to come online and deliver consumer benefits more quickly. Despite challenges, these engagements point to a potential role for network owners.

We commit to continue to work with the broader flexibility community and the ESO to enable flexibility solutions that address the ESO's market requirements. This will be measured through regular updates to the Independent Stakeholder Group.

Cost certainty – We do not propose additional funding to work towards this commitment.

5.3 Our proposal to deliver electricity whole system solutions across network companies

As we rapidly transition towards a low carbon future, the consideration of whole system solutions across network companies is important to minimise costs for

consumers. Many emerging whole system options are not yet well defined and, whilst the ESO is expanding the NOA process and Regional Development Plans, no formal framework for carrying out whole system assessments currently exists. Many of the network issues that could most benefit from whole system solutions, such as system operability issues, are also difficult to define precisely ahead of time.
We have taken an approach to building our plan that involves identifying known issues and working with the ESO, DNOs and other TOs to investigate whole system options.

i) Optimise with the ESO through a new mechanism to reduce whole system costs and installation of system monitoring to allow for zero-carbon operation by 2025

These proposals have been informed by the ESO's Operability Strategy document, requirements set out in the STC and engagements with the ESO and TOs.

a. Interface optimisation mechanism

Key driver – Decarbonisation has led to increased costs of operating the system (reported by the ESO as £449m in the 12 months to May 2019) and the ESO needs as many tools as possible to minimise the cost of operating a zero-carbon system by 2025.

Options considered – Whilst TOs can provide flexible services to the ESO, the existing Network Access Procedure (NAP – covered in Chapter 8 *We will make it easier for you to connect to and use the network*) delivers a fraction of the potential consumer benefit because it only allows for the recovery of costs incurred and therefore does not compensate for additional risk in providing services and the strong incentive to minimise network owner costs in the regulatory framework.

We propose that TOs will be able to offer the ESO a range of flexible services, including rescheduling or accelerating timescales for delivery, providing alternative contracting, maintenance and construction activities, and working practices which would otherwise not be available to deliver whole system solutions. The ESO would market test the suitability of these services against a range of alternative options and select the most economic one for solving the system's balancing and/or operability need.

The opportunity for TOs to earn a market rate for the extra cost and risk of delivering these services would provide a strong incentive to discover whole system solutions to reduce consumer costs, rather than minimise network owner costs in isolation.

This approach could be implemented in parallel with the existing NAP at no additional cost to consumers. Our proposal adds another tool into the ESO's toolkit for operating a zero-carbon system by 2025 and managing system constraint costs at no additional cost to consumers.

Competition – The introduction of this TO flexibility approach would lead to a larger market for services, increased competition and ultimately lower costs to consumers of operating the network. Depending on scope (i.e. how much of the network it covers), our analysis of published constraint costs estimates a reduction of up to £188m per annum. A more in-depth analysis of the potential on the top ten constraint causing outages in 2018, estimated at £156m, has shown that TO flexibility options had the potential to reduce this by a net £76m when the cost of delivery is considered.

Installation of system monitoring

Key driver – Our proposed investments in this category involve the installation of system monitoring equipment across the network to help deal with the system implications of the energy transition. A national roll-out of system monitoring is required through the SO-TO code procedure STC-P 27-1, which specifies the provision of synchronised data from all grid supply points to the ESO by 31 March 2026. These investments will enhance security of supply and reduce the cost of system operation.

Options considered – Provision of this data is a licence obligation and requires some investment in monitoring. Both a *full system* and more targeted *wide area* option were considered. The more targeted solution, providing wide area observability, delivers our obligation at lowest cost to the consumer and allows the ESO to operate a zero-carbon system by 2025. To deliver against this requirement we propose to invest in:

- system monitoring devices on all circuits at all grid supply points (approx. 1,200 services)
- data collection and archiving
- a system visualisation tool
- analytics to support modelling, validation and system dynamics.

Cost certainty – We propose to invest £48m to carry out this work. These costs are based on recent tender return costs from competent installers and schemes (VISOR, EFCC and SEWAMS schemes). Additional justification for these costs is available in the annex NGET_A7.07 System Monitoring.

b. Providing solutions to stability challenges

Key driver – The ESO's System Operability Framework highlights system stability as a key challenge in maintaining an operable system. Stability is the ability of the system to quickly return to acceptable operation following a disturbance. Conventional (synchronous) generation supports the stability of the system. Without intervention, the system will become less stable through the energy transition as less synchronous generation runs.

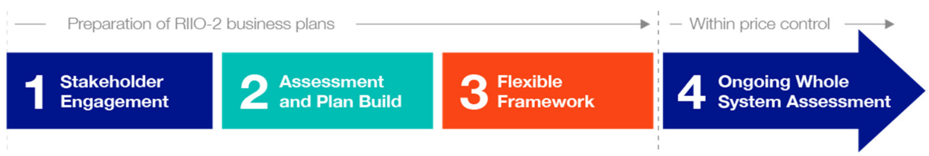
Options considered – The ESO is developing new approaches to maintaining a stable system through a variety of routes, including developing a better understanding of the issues and where and when they are likely to occur. The strategy sets out that new technology requiring capital investment is likely to form a significant part of the solution and indicates that synchronous compensators are one option that could be in consumers' interests.

Uncertainty approach – We will ensure that we are ready to deliver these solutions when they are required and if they are deemed to be in consumers' interests. To allow for the ESO's whole system assessment, no costs are included in our baseline plan for this requirement and we have developed a system operability uncertainty mechanism to deal with potential funding requirements. This is described in Section 7 of this chapter and in annex NGET_ET.12 Uncertainty mechanisms.

ii) Optimise with DNOs by identifying whole system opportunities, establishing an ongoing process and investing in 5 reactor units

We worked closely with the DNOs in building our plans to ensure their needs are met and all whole system solutions were considered. As many of the network issues anticipated during planning are uncertain, an ongoing process for identifying and assessing whole system solutions was required. Work to develop a process is ongoing through the Energy Networks Association's (ENA) Open Networks Project but has not concluded in time for our T2 business plan. We have developed and agreed an approach to preparing our business plan with DNOs, as shown in figure 7.17.

Figure 7.17 Whole system approach to developing our business plan



The approach developed is iterative and comprises:

1. Engagement with the DNOs to understand their requirements and potential alternative solutions.
2. Assessing future requirements and building our business plan.
3. Development of a robust suite of uncertainty mechanisms that adjust allowances.
4. An ongoing process of whole system assessment throughout the T2 period; delivered through formal activities such as the expanded NOA or through region specific joint planning activities such as Regional Development Plans.

This is how we have developed our business plan.

Whole system assessment of network reinforcement

In line with the work of the ENA's Open Networks Project, the ESO is expanding their NOA process to allow DNOs and other third parties to provide solutions to network issues. This process has not yet been completely defined but is likely to be fully implemented in the early part of the T2 period.
To investigate whether DNOs could offer whole system alternatives to our plans, we discussed our boundary capability investment proposals (as set out in Section 5.1.i of this chapter) with them. Where additional capacity requirements are in the order of 1 GW, there was consensus that transmission investment is highly likely to be most cost effective as the distribution networks would require major upgrades to provide equivalent capacity, electrical losses would be higher and any flexibility services from regional distributed energy resources would be insufficient to resolve issues on that scale.

Where new capacity requirements are lower, in the order of 100s of MWs, some DNOs indicated they may offer alternatives into the future NOA process, potentially in the form of parallel 132kV circuits. Other DNOs believed their networks did not have capacity to resolve these issues and that no alternative whole system options could be identified at this stage.

Whole system assessment of system operability (management of high volts)

Whole system options to managing high voltage issues were also discussed with DNOs.

Key driver – Reactive power is required for voltage control. As we transition to a decentralised and decarbonised electricity system, the ESO has indicated in its Operability Strategy document that it needs access to new sources of reactive power.

Options considered & whole system alternatives – Our analysis of SQSS requirements against the Common Energy Scenario indicates a potential need for 35 reactors across the network in England and Wales. The ESO will eventually test regulated network solutions for reactive power against other network and commercial options. The first of these is already underway through its high voltage pathfinding projects in the Mersey and Pennines regions.

We have agreed with the DNOs and the ESO that we will only include the costs of the most certain reactive investments in our baseline plan. We have used the study on short-term need undertaken through the ENA pathfinder to select these projects.

Cost certainty – The cost of our baseline proposal is £30.7m for the installation of reactors at [redacted], as shown in table 7.18, below. These costs are based on similar projects delivered in T1. annex NGET_A7.08 System Operability (Voltage) provides further detail.

Table 7.18 Reactor requirements

Scope and reactive requirement	Transmission solution and cost	Proposed T2 approach
Short-term need based on ENA study, DNO engagement and initial results of ESO pathfinder	[redacted]	Baseline funding
0.9GVar	£30.7m	
Remainder of Common Energy Scenario requirement across T2 period	[redacted]	Unit cost allowance when transmission solution identified through whole system process
5.3 GVar	~£184m	

Uncertainty approach – We propose a new automatic uncertainty mechanism, which would provide a unit cost allowance when a transmission solution is identified through the whole system process. Further information is set out in Section 7 of this chapter and in annex NGET_ET.12 Uncertainty mechanisms.

Taking this approach to reactor requirements has allowed us to reduce our baseline proposals by £184m (i.e. a reduction from [redacted]) so that optimal whole system solutions can be identified and delivered in the T2 period for the benefit of consumers.

5.4 Our proposal to enable all energy whole system solutions

i. Seek to implement a suitable anticipatory investment mechanism that allows solutions to unlock rapid decarbonisation to net zero 2050

Achieving net zero by 2050 requires the decarbonisation of our whole energy system at an accelerated rate. A different, more agile and coordinated approach is required to resolve the associated network challenges and minimise cost. Despite T1 improvements, building the necessary network infrastructure can often take longer than our customers need to deliver their projects. The resulting risk is that energy networks become a blocker to meeting societal decarbonisation ambitions. This more agile approach also needs to ensure it does not place too high a cost and risk on consumers.

We are proposing a mechanism, involving a cross sector group of key stakeholders, policy makers and regulators, that would consider the following factors for key strategic infrastructure solutions to net zero challenges:

- **Criteria:** define when anticipatory investment is in consumers' interest.
- **Need case:** establish what circumstances trigger a pre-agreed investment approach.
- **Whole system outcomes:** stakeholder collaboration to ensure optimal, whole system outcomes are delivered.
- **Funding:** how companies can recover their efficient costs.
- **Risk sharing:** appropriate customer user commitment, consumer protection and reward for value created.
- **Monitoring:** provisions to provide regulatory and stakeholder oversight of projects.

We will continue to engage with stakeholders to further shape how an ongoing anticipatory investment process could work. Initial results from consumer and stakeholder engagement indicate support for acting early to enable decarbonisation, even if certain solutions are later not fully utilised.

ii. Provide strategic network options that have the potential to help overcome some of the challenges of decarbonising at lowest cost to consumers

Most stakeholders want us to take a proactive role in enabling the energy system of the future and have challenged us to provide whole system options to address the challenges of net zero.
We've worked extensively with stakeholders to develop the following whole system options:

a. East coast offshore wind coordination.
b. Aggregated harmonic filtering infrastructure.
c. Accelerating EV uptake through ultra-rapid. vehicle charging at motorway service areas.

Some of these options could be well suited to an anticipatory investment mechanism whilst others, such as harmonic filtering, could be funded through an uncertainty mechanism in the core RIIO price control. Further detail on each is provided below.

a. East coast offshore wind coordination

To deliver net zero by 2050, we may need to safely integrate a further ~30GW of renewables by 2025. The cost reductions achieved in both onshore and offshore wind point to a significant role for these technologies in achieving this target. Strike prices as low as £39.65 £/MWh for offshore wind in the recent Contract for Difference round are a strong proof point.

The focus on wind development in the UK has resulted in 18 GW of installed capacity over the last 10 years, with an average annual rate of installation of 1.7 GW per annum. This rate is dwarfed by the Climate Change Committee's (CCC) stated need for 6-8 GW of deployment per annum. Current offshore wind capacity of ~8 GW is connected via 32 connections. The same approach to deliver the CCC's target of 75 GW by 2050 would require an additional 268 connections.

A coordinated approach to connecting offshore wind, supported by anticipatory investment, has the potential to accelerate connections, reduce costs and minimise disruption and visual impact. A report by Redpoint Energy for Ofgem in 2011 indicated that coordinated investment could reduce costs to consumers by 15%.

A coordinated approach

The Crown Estate has granted rights to extend existing offshore wind farms by 5.5 GW and has proposed around 7 GW of Round 4 offshore wind leasing. Most Round 4 sites, approximately 5 GW, are likely to connect to the east coast.

There is potential for a further 37 GW of offshore wind and interconnectors to be developed off the east coast of England in the next 10 to 15 years. These connections imply a high number of cable route corridors, onshore substations, converter stations, and reinforcements to the existing onshore network. To address this challenge, the onshore transmission network could be built around the east coast, reducing the number of circuits required.

This approach, as shown in figure 7.19, would expand the existing transmission network on the east coast by building a loop of circuits to shore, providing connection sites for currently contracted offshore wind, interconnectors and anticipated (Round 4) projects.

Figure 7.19 Offshore wind topologies

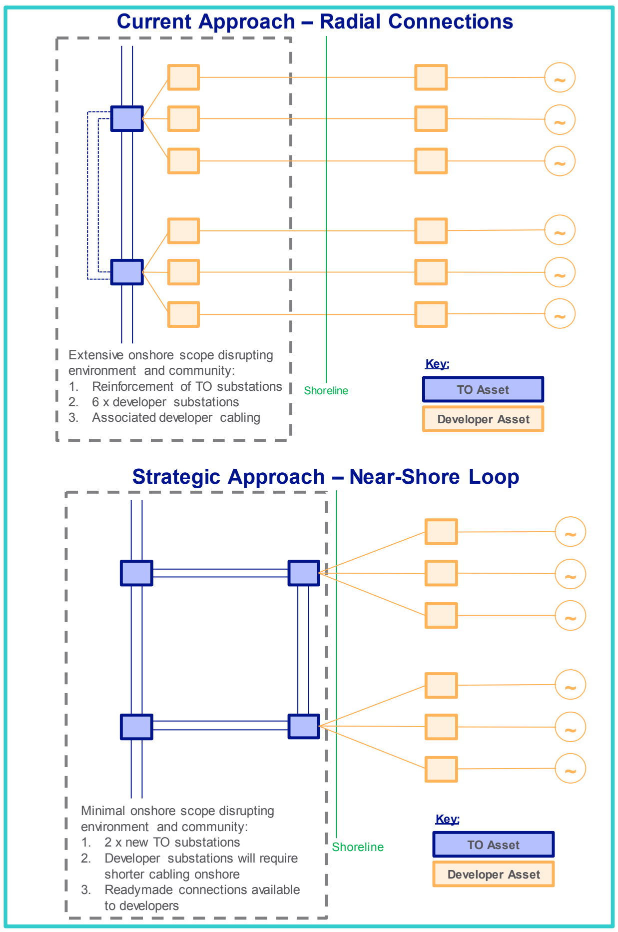


Figure 7.19 contrasts the current radial approach with a coordinated one that would require less onshore construction, minimising cost and disruption. In current costs, we anticipate that this solution would cost between £3bn and £5bn and deliver considerable net benefits for consumers.

Preconstruction work would be required over the T2 period to maximise the benefits of this approach and we propose that any allowances would be allocated as part of the anticipatory process.

b. Aggregated harmonic filtering

All future energy scenarios show an increasing amount of wind, solar, storage and interconnectors. Connecting these technologies to the system introduces distortions that can be damaging to customer's equipment at certain frequencies, known as harmonics. Limits on harmonic distortion levels are placed on developers of these technologies, often requiring them to invest in harmonic filtering equipment.

Together with experts, and alongside other network companies, we have been investigating the potential consumer benefits of aggregating filtering requirements to reduce the total number of filters required. This approach would involve the regulated network company responding to customer connection applications through the ESO and building any filtering requirements in lieu of developers alongside other reinforcements required to connect. The modular nature and relatively short delivery lead time would allow for aggregation without stranding risk.

We estimate that, if undertaken centrally, the total cost of harmonic filtering up to 2030, for the connection of 16 windfarms, could be up to £119m. Working with independent experts, Atkins, we found that an aggregated approach reduced the number of harmonic filtering units required from 56 to 37, reducing the cost by 20% compared to a disaggregated approach.

We have had positive views from stakeholders on the potential of this approach, which would lower the cost of decarbonisation for consumers, and believe that it could be implemented with minimal changes to the industry framework. We propose that this option would be suitable for funding through a within-period determination as set out in Section 7 of this chapter and annex NGET_ET.12 Uncertainty mechanisms.

c. Accelerating EV uptake through ultra-rapid vehicle charging at motorway services

The decarbonisation of transport is a huge opportunity for the UK to reduce emissions, as transport became the largest single contributor to the UK's carbon emissions (27%) in 2016. The CCC, net-zero report recommended a phase out of fossil fuel powered vehicles by 2035 at the latest.

Electric vehicles (EVs) will play a large part in meeting these aims. They will be charged in many different locations: at home, at work or even when parked on the street. However, EV drivers will still require charging along the strategic road network to fuel during long journeys. A key barrier to EV purchasing is consumers' perception of 'range anxiety'.

To enable EV uptake for mass market customers, a network of ultra-rapid EV charge points will need to be delivered by 2025 – the time at which vehicle cost parity is anticipated. This will ensure that a lack of charging infrastructure is eliminated as a barrier to EV uptake. Infrastructure must allow EV drivers to make long-distance journeys, delivering charging times like those experienced for refuelling existing internal combustion engine vehicles. Today, drivers are used to being able to take any journey in the UK with the ability to quickly refuel en route in the time it takes to buy a cup of coffee.

While initially these chargers will be under-utilised due to the small number of EV users, the most economic infrastructure solution is to plan for a future where there is no liquid fuel. The alternative scenario is to deploy infrastructure after the number of EV users rises, creating an environment of disruptive and costly construction work to modify the network. An inadequate number of charge points may cause queues, leading to a stalled market – reinforcing consumers' perception of range anxiety. Ensuring that there is enough capacity to enable more ultra-rapid chargers to be added as and when necessary to meet the future demand, ahead of current need, avoids this future expense and disruption to customers.

While some investment has been made into UK charging infrastructure, and approximately 90% of existing motorway service areas (MSAs) have chargers on site, they are usually 50kW chargers which can take over an hour to charge a vehicle. To leverage private investment, the market needs certainty in both affordable cost of infrastructure and EV utilisation rates.

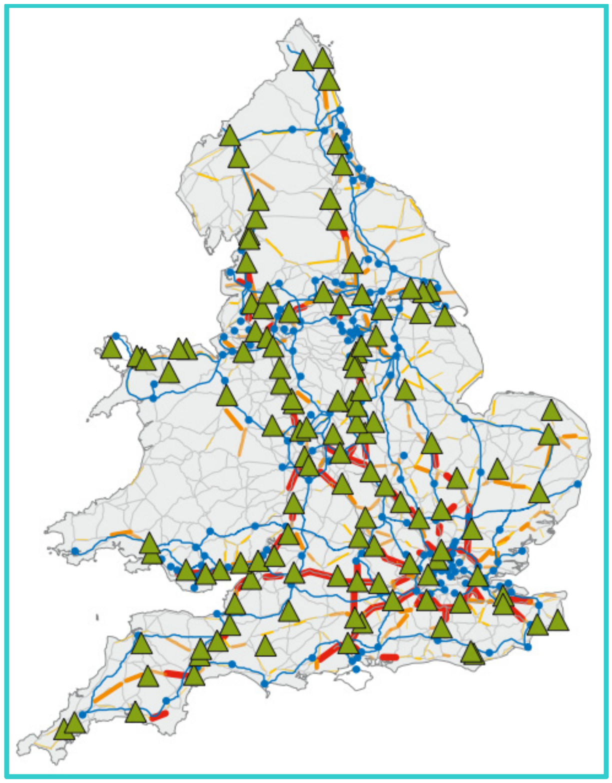
We know from talking to prospective market participants that they do not currently have certainty on either, with many struggling to make the case for the costs of the electricity network infrastructure, especially ahead of full utilisation. It is evident that under any likely scenario of EV uptake, due to existing power constraints, most MSAs will require a reinforced power connection before 2030 to meet demand for additional charging points.

Developing an electricity network solution

Transmission Owners and Distribution Network Operators, together, can enable a smooth and efficient consumer transition to EVs. We have examined the links between the strategic road network and the electricity transmission network in England and Wales to understand the minimal viable infrastructure requirement to overcome consumer range anxiety. We have studied the power capacity of the MSA sites, across the strategic road network, the journeys EV drivers are likely to take, and how close they would need to be to an ultra-rapid charger to overcome range anxiety. We also assessed the infrastructure required to support enough ultra-rapid charge points to provide EV drivers confidence and avoid peak-time queues.

As shown in figure 7.20, we have identified over 50 ultra-rapid EV charging sites along the strategic road network, where an upgraded electricity network connection would allow 95% of EV drivers in England and Wales to be within 50 miles of an ultra-rapid charging station. This would provide drivers with the ability to charge their vehicle in the time it takes to buy a cup of coffee.

Figure 7.20 Strategic motorway service areas



We have identified a cost-efficient solution for the sites, which could include a combination of distribution and direct transmission network connections. Of the MSA sites which prove most economical for a direct transmission connection, 90% could be supplied from existing substations, reducing reinforcement works and minimising the delivery cost.

Policy makers are still considering funding sources for this infrastructure. Anticipatory investment of between £500m and £1,000m in a network of charging infrastructure ahead of full market demand, as described in this section, can ensure networks help overcome range anxiety and decarbonise transport in a cost-effective manner.

6. Our proposed costs for the T2 period

Our proposed costs for delivering against our proposals for the T2 period on this priority are detailed within table 7.21.

We have embedded innovation developed through the T1 period into our T2 plans. We are also making stretching commitments to future efficiencies by moving our benchmarked capex unit costs to be at or below the TNEI industry mean equating to an **£11.4m reduction** in this stakeholder priority. We have also applied a **£5.6m productivity commitment** to improve the productivity of our people by 1.1% year on year. Further detail is provided in Chapter 14 – *Our total costs and how we provide value for money.*

Table 7.21 Proposed baseline costs for the T2 period*

Baseline costs (£m 2018/19)	21/22	22/23	23/24	24/25	25/26	Total T2	Annual T1	Annual T2	Subject to native competition	Internal historic benchmarks	External benchmarks	Subject to UM
Innovate and invest in network reinforcement	94.1	138.9	65.6	71.3	137.2	507.1	77^	101.4	✓	✓	✓	✓
Protection and control coordination studies	7	6	6	6	6	31.1	N/A	6.2	✓	✓	✓	✓
Generation closure and secure easements	34.7	34.8	27.6	18.9	18.7	134.7	26	26.9	✓	✓	×	×
Facilitate competition and new business models	106	72.4	3.1	0	0	181.5	12^^	36.3	✓	✓	×	✓
Optimise across the network owner and ESO	9.8	9.4	9.3	9.7	9.8	48.0	3	9.6	✓	✓	×	×
Optimise across transmission and DNO	4.9	24.7	1.1	0	0	30.7	16	6.1	✓	✓	✓	✓
Total:	256.6	286.2	112.7	105.9	171.7	933.1	134	186.6	Cost certainty status: High confidence			
Pension allocation						3.1						

*Business Plan Data Table reference: Load related expenditure worksheets contained in section B (B0.7, B4.2a, B4.2c, B4.4b, B4.5, B4.5a, B4.6, B4.8, B4.9, B4.10) ^excluding Western HVDC link ^^only for pre-construction activities and only for projects >£500m

Figure 7.22 Expenditure profile across the T1 and T2 period (excluding SWW projects)

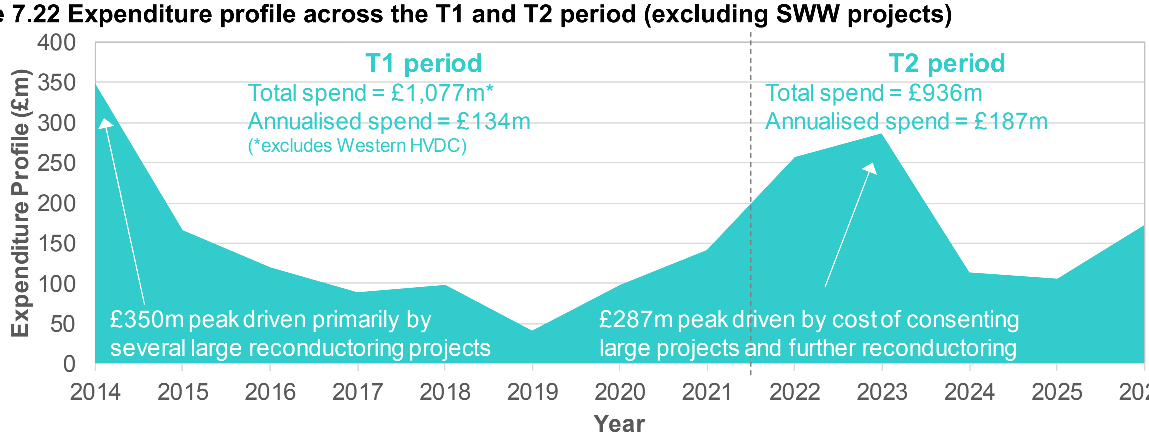


Figure 7.22 illustrates the expenditure profile for this priority over the T1 and T2 periods, excluding SWW Projects in the T1 period, but including the cost of taking similar projects to consent ready for competition in the T2 period. A simple comparison shows proposed annualised expenditure is 40% greater in the T2 period than in the T1 period (£187m vs. £134m). Comparing on a like-for-like basis, by excluding the cost of consenting 4 contestable projects, would bring annualised spend between the two to a difference of just over 10% (£151m vs. £134m). Peak to trough variability of T2 baseline expenditure is just 40% of that in the T1 period.

Table 7.23 Costs for projects that meet contestability criteria – not included in our baseline plan

Contestable projects not included in baseline plans to facilitate competition	Estimated cost (£m)
Construction and consenting costs in Scotland (where relevant) for Eastern HVDC link 1 and 2 (E2DC and E4D3), new South Coast route (SCN1) and central Yorkshire circuit (OENO)	4,885

7. How we will manage risk and uncertainty

We have built our plan with a focus on protecting consumers from risks in both the longer term (beyond the T2 period) and the medium term (within the T2 period).

Longer term risk: under-utilisation of assets
In the longer term, the main risk is potential under-utilisation of assets on our network. We have mitigated this through extensive analysis and stakeholder engagement, confirming the ongoing need for electricity transmission in the most highly decentralised futures.

We also minimise the risk of under-utilisation of assets by ensuring each investment is accompanied by a strong need case. The signals we receive from our customers about their future requirements through the commercial arrangements (i.e. the Connection and Use of System Code) and the ESO's economic assessment of future constraint cost savings across all Future Energy Scenarios underline that need. The consumer payback period for many investments, in reduced system operation costs, will often be a period much shorter than the life of the asset (e.g. 5 – 10 years).

Medium term risk: cost and volume uncertainty in an ex-ante price control
In the medium term, one of the main risks is uncertainty over cost and volumes of work in an ex-ante price control. We mitigate this by only including the most certain costs in our baseline plan and proposing uncertainty mechanisms that allocate risk to whomever is best placed to manage it.
Our plan is consistent with the minimum values in the Energy Networks Association (ENA)'s Common Energy Scenario and therefore relies on uncertainty mechanisms to deliver for customers and enable net zero by 2050.

Consumers can best manage uncertainty about the route to Net Zero emissions because the route will reflect changes in their behaviour. We are best placed to manage uncertainty over the costs of achieving the outputs consumers want because we can efficiently control our costs.

With the market continuing to rapidly evolve, the ongoing development of whole system solutions, growing system operability requirements and network competition, a more complex uncertainty landscape exists in the T2 period, requiring an evolution of the T1 approach.

In developing our proposals, we have ensured mechanisms:

i. change our allowances if consumers' needs change during the T2 period so that we can invest in the outputs they need,
ii. allow whole system solutions to be identified and delivered during the T2 period,
iii. retain the incentive for us to reduce our costs and share the cost savings with consumers.

We have worked with external experts to develop an enhanced suite of uncertainty mechanisms, building on the existing T1 approach of unit cost allowances and the experience of the operation of these mechanisms.

To manage uncertainty for this priority, we propose:

- A re-designed boundary capacity (IWW) mechanism to be more cost reflective and resilient to change
- A new volume driver for system operability investments required by the ESO
- A new volume driver for delivery of a consented project to facilitate competition
- A targeted within-period determination to fund protection and control upgrades indicated through planned coordination studies.
- A targeted within-period determination to fund investments in harmonic filtering

A rigorous and comprehensive econometric approach was used to develop our proposals, as shown in figure 7.24 below, which are a critical component of our overall business plan and are evidenced against Ofgem's business plan guidance criteria in table 7.25, below.

The detail of our analysis and proposals to manage energy supply and demand uncertainty is set out in annex NGET_ET.12 Uncertainty mechanisms and accompanying workbooks showing the detail of our development and statistical analysis.

Figure 7.24 Econometric approach used to develop proposals

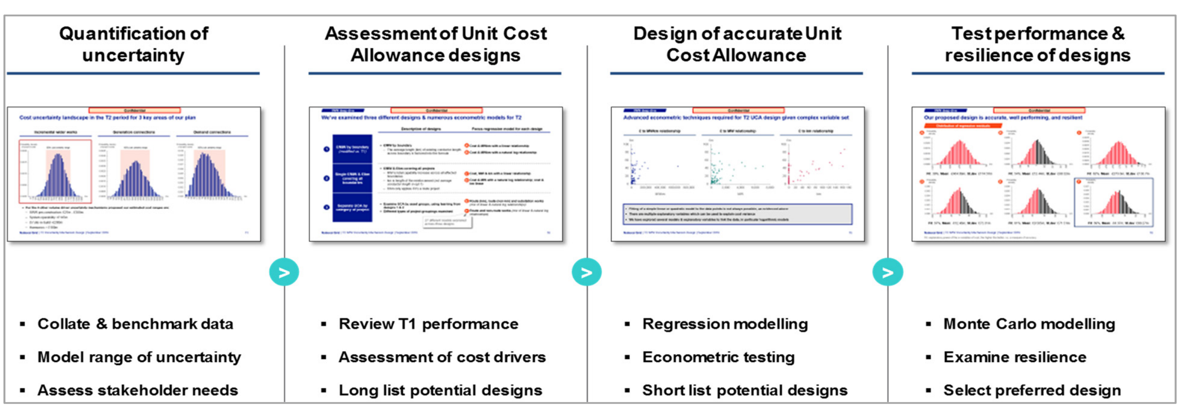


Table 7.25 Proposed uncertainty mechanisms and justification

Incremental Wider Works (Boundary Capacity) – Unit Cost Allowance (UCA)

Key stats:	
Models considered	7
Input data points (projects)	77

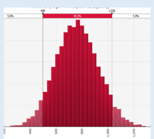
Uncertainty characteristics

i) Risk and ownership

- System need and best whole system solution uncertain
- Requirements driven by annual ESO NOA process
- Network company manages cost risk, whilst consumer best to manage volume risk

ii) Materiality

- Range of uncertainty is £541m *(90% of Monte Carlo simulations have a total cost between £497m and £1,038m)*



T2 CAPEX probability distribution

(output of Monte Carlo analysis)

iii) Frequency and probability

- Annually as part of the ESO NOA process
- Near 100% probability of some change in future requirements

T1 experience and learning

i) T1 experience

- Per boundary UCA reduced allowances by >£190m as system needs changed
- Output based UCA maintained ability to innovate (e.g. Smartwires); leading to considerable consumer benefit
- Mechanism not sufficiently cost-reflective / overly sensitive to energy scenario changes
- No ability to add new boundaries indicated by the ESO through NOA

ii) Learnings for T2

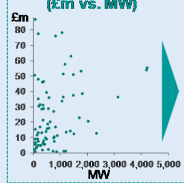
- More rigorous, analytical approach to developing and testing UCAs, not limited to data on single boundary, required
- More cost-reflective, output based, UCA would better protect both consumers and companies
- Approach must work with annual NOA process and allow for new boundaries to be added
- Revenue calculation based on latest forecast of outputs can smooth customer charges

T2 proposals

i) Proposed mechanism and benefits

- Combined pre-construction and construction mechanism
- Separate UCAs for route and non-route projects, using average boundary length to enhance cost reflectivity
- Expansion factors applied to length in order to reflect increased cost of cabling to simplify mechanism
- Established regression techniques to design and Monte Carlo simulations to test for the most accurate and resilient UCA

Inputs (£m vs. MW)

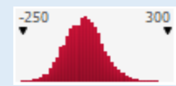


Proposed Design

Route reinforcements:
0.7284 £m/ln(MWkm) + 0.4102 £m/km

Non-route reinforcements:
- 3.7397 £m/ln(MW)

Testing (cost vs. allowance)



Mean: -£9.48m
Std. Dev.: £64.2m

- Roll-forward T1 efficiencies into T2 dataset for calculating UCAs
- Revenue calculated based on latest 5-year RRP forecast of outputs in order to minimise customer charging volatility

ii) Drawbacks and mitigations

- Minor increase in complexity of mechanism outweighed by significant increase in cost-reflectivity and mitigated through simplifications in other areas, such as approach to cables

System Operability (Voltage) – Unit Cost Allowance (UCA)

Key stats:	
Models considered	4
Input data points (projects)	36

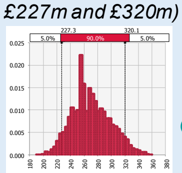
Uncertainty characteristics

i) Risk and ownership

- System need and best whole system solution uncertain
- Requirements driven by expanded annual ESO NOA process and System Operability Framework
- Network company manages cost risk, whilst consumer best to manage volume risk

ii) Materiality

- Volume uncertainty due to supply & demand changes is £92.9m *(90% of Monte Carlo with total cost between £227m and £320m)*



T2 CAPEX probability distribution

(output of Monte Carlo analysis)

- Additional whole system uncertainty down to £30.7m baseline = *£290m uncertainty range*

iii) Frequency and probability

- Possibly annually, at least biennial
- 100% probability of some change in future requirements

T1 experience and learning

i) T1 experience

- Requirement to deliver both static & dynamic reactive compensation on the system increasing as more distributed and renewable generation connect
  - Increasing system voltage and negative reactive power demand
  - Reducing inertia and short circuit level
- T1 funding through a fixed ex-ante allowance not subject to UCA
- Significant uncertainty around volume and location of reactors and STATCOMS
- Approach to whole system assessment under development

ii) Learnings for T2

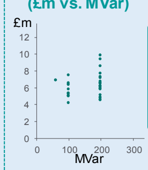
- Need for reactive equipment will be determined by ESO expanded NOA or DNO whole system collaboration
- New UCA required to adjust allowances and allow work to commence when transmission solution chosen

T2 proposals

i) Proposed mechanism and benefits

- Need triggered either when ESO has provided delivery signal or whole system process with DNOs has completed
- Static - ordinary least squares regression and average unit costs modelled for (i) all schemes, (ii) by voltage and (iii) by size
- Dynamic – average unit costs modelled for all projects due to input data sample size
- Preferred model for static based on average unit cost by size & dynamic based on average unit cost for all projects

Inputs (£m vs. MVar)

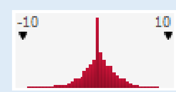


Proposed Design

Static capability
60MVAr: [redacted] £m/MVAr
100MVAr: [redacted] £m/MVAr
200MVAr: [redacted] £m/MVAr

Dynamic capability
All MVAr: [redacted] £m/MVAr

Testing (cost vs. allowance)



Mean: £0.6m
Std. Dev.: £1.9m

- Revenue calculated based on latest 5 year RRP forecast of outputs in order to minimise customer charging volatility

ii) Drawbacks and mitigations

- UCA restricted to set unit sizes may restrict type of solution
- All system operability solutions are market tested by the ESO, or compared through the expanded NOA process, which mitigates any reduction in scope for innovation

Harmonic Filtering – within period determination

Uncertainty characteristics

i) Risk and ownership

- Customer need and timing of implementation uncertain
- Requirements driven by volume of generation connected through power electronics (predominately renewables)
- Cost and volume risk too high to set ex-ante allowances in order to protect consumers

ii) Materiality

- A total uncertainty of up to between £60m and £100m is estimated based on our work with Atkins

iii) Frequency and probability

- Low frequency over T2 period (2 or 3 maximum anticipated)
- High probability of usage, subject to any necessary code changes being implemented

T1 experience and learning

i) T1 experience

- Uncontrolled harmonics on the system can have negative effects such as overheating of equipment and maloperation of protection
- Customers currently required to install harmonic filters to comply with levels set in the Grid Code
- Separate analysis undertaken by different TOs demonstrates that an aggregated approach could lower the overall cost of controlling harmonics for consumers

ii) Learnings for T2

- There is an opportunity in the T2 period to implement an aggregated approach and reduce the cost of the energy transition
- Broad stakeholder support for this approach
- An ability to provide suitable allowances is needed in the regulatory framework for the T2 period

T2 proposals

i) Proposed mechanism and benefits

- No baseline allowance
- We propose the cost of aggregating harmonic filtering would be subject to a targeted in period determination upon a Bilateral Connection Agreement being in place between the customer(s) and the ESO

ii) Drawbacks and mitigations

- Additional regulatory burden of in period determination outweighed by the consumer benefits
- Further mitigated by grouping of relevant customer projects informed by outcome of CfD rounds

Facilitate competition (pre-consents) – Unit Cost Allowance (UCA)

Key stats:

Models considered	3
Input data points (projects)	9

Uncertainty characteristics

i) Risk and ownership

- System need and approach to delivery of projects post-consents uncertain
- Requirement driven by ESO NOA process and approach to CATO competition / Large Onshore Transmission Investment (LOTI)
- Network company manages cost risk, whilst consumer best to manage volume risk

ii) Materiality

- Estimated range of uncertainty >£300m based on inspection of potential projects in NOA

iii) Frequency and probability

- More than once in T2 period; linked to the ESO NOA process
- High probability of change in future requirements, given T1 experience

T1 experience and learning

i) T1 experience

- Project development costs split into pre-construction and construction activities
- Projects <£500m - fixed pre-construction allowance of 1%-4% total project cost
- Projects >£500m - fixed £46m (09/10) allowance for pre-construction of 2 projects with potential to substitute to other projects
- Significant churn in projects >£500m; mechanism not sufficiently flexible to reflect requirements, resulting in ~£33m overspend (18/19)

ii) Learnings for T2

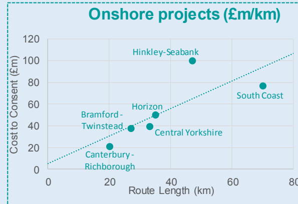
- Desire to facilitate competition in transmission for projects >£100m that have a NOA proceed signal
- Completing pre-con. activities only would result in re-work and less effective competition; consents achieved milestone more appropriate
- Cost-reflective, automatic uncertainty mechanism would let allowances flex to meet requirements
- Approach must fit with NOA, any successor to Strategic Wider Works and *Late CATO* competition

T2 proposals

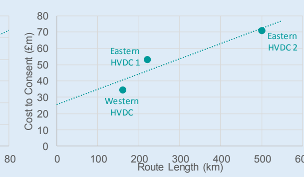
i) Proposed mechanism and benefits

- Propose new output of a consented project ready for *Late CATO* and/or LOTI mechanism
- Remove activities based differentiation between pre-construction and construction; include all efficient costs to achieve consents
- Baseline funding of £182m for projects that have a NOA proceed signal and meet criteria for late competition
- Separate unit cost allowances for onshore and offshore (sub-sea) projects so allowances can flex to meet future NOA signals

Onshore projects (£m/km)



Offshore projects (£m/km)



Proposals: £1.4m/km £0.2m/km

ii) Drawbacks and mitigations

- Proposed approach flexible and robust to current understanding of approach to Late CATO and LOTI, but these have not yet been finalised leaving a minor risk of inconsistency
- This risk can be mitigated through continued engagement in CATO and LOTI design

Protection and Control – within period determination

Uncertainty characteristics

i) Risk and ownership

- System need and the specific mitigating investment required uncertain
- Requirements driven by detailed study of system requirements, from modelling activity included in baseline plan
- Cost and volume risk too high to set ex-ante allowances in order to protect consumers

ii) Materiality

- A total uncertainty of £90.2m is estimated based on independent review by Quanta Technology

iii) Frequency and probability

- Low frequency – upon outcome of coordination study
- 100% probability of coordination studies identifying some additional future requirements

T1 experience and learning

i) T1 experience

- ESO & international studies consistently forecast a significant reduction of system inertia and short circuit level as capacity of synchronous generation reduces
- We employed an independent party (Quanta Technology) to estimate the scale and scope of the challenges and lay out a plan for further development to ensure effective operation and coordination of our protection and control systems
- We continue to engage extensively with experts and other network companies

ii) Learnings for T2

- To identify the details of protection and control issues and most efficient mitigating actions, it is necessary to develop comprehensive models and perform "wide area" protection coordination studies across the transmission network
- Changes to settings are also required and included in our plans, but subsequent investments will be required to enhance system operability and maintain security of supply

T2 proposals

i) Proposed mechanism and benefits

- Baseline allowance proposed in T2 period to deliver the coordination study and consequential changes to protection settings
- Subject to the outcome of the co-ordination study, further investment estimated at £90m for protection equipment replacement or other equipment installation may also be necessary to maintain protection performance within T2 period and beyond
- We propose the cost of protection upgrades would be subject to a targeted in period determination upon sufficient progress of the coordination studies

ii) Drawbacks and mitigations

- A within period determination with a fixed date or window could delay funding to undertake the work required to operate a net-zero system by 2025 and mitigate the issues highlighted by the ESO in the System Operability Framework
- We propose that the determination could take place at any point during the T2 period when coordination studies have provided sufficient clarity on scope

System Operability (other ESO requirements) – within period determination

Uncertainty characteristics

i) Risk and ownership

- Volume of TO solutions to future operability challenges unclear prior to ESO whole system assessment
- Risk too high to set ex-ante allowances

ii) Materiality

- Robust estimate of materiality challenging; likely range of between £10m to £50m

iii) Frequency and probability

- High frequency for small requirements (e.g. intertrips)
- Low frequency for large requirements (e.g. synch. comp.)
- Very high probability of usage (based on System Operability Framework)

T1 experience and learning

i) T1 experience

- Experience indicates that the ESO can sometimes benefit from equipment beyond the minimum cost TO design to reduce overall costs (e.g. inter-trips, additional circuit breakers, etc.)
- The ESO's System Operability Framework points to a need to address falling inertia and a NOA stability 'pathfinder' project has been launched to find solutions, but no funding mechanism is in place to allow TOs to deliver solutions

ii) Learnings for T2

- Once the ESO has undertaken a whole system assessment of solutions that meet their operability requirements, a mechanism is required to provide funding where a TO is deemed the most economic solution

T2 proposals

i) Proposed mechanism and benefits

- No baseline funding proposed
- For small ESO requirements we propose a logging up mechanism is used to fund these with a cap of £20m across the T2 period
- For larger ESO requirements, or once the £20m cap is reached, we propose that funding would be subject to a targeted in period determination upon completion of an ESO whole system assessment
- A mechanism that provides funding for TO solutions when they are deemed most economic is crucial for minimising the cost of energy transition

ii) Drawbacks and mitigations

- Depending on how ESO requirements evolve over the T2 period, the frequency of usage for this mechanism could be quite high
- We propose to mitigate this through the introduction of a logging up mechanism for smaller requirements that the ESO has tested as economic