Access and Forward-Looking Charges Significant Code Review: Final Impact Assessment in support of our Decision for the Distribution Connection Charging Boundary

Division:	Energy Systems Management and Security	**Type of measure:**	Decision on Significant Code Review (SCR)
Team:	Future Charging and Access	**Type of IA:**	Qualified under Section 5A UA 2000
Associated documents:	Access SCR – Decision and Direction	**Contact for enquiries:**	FutureChargingandAccess@ofgem.gov.uk
Coverage:	Partial		

Summary

This Impact Assessment (IA) outlines our analysis of the expected impacts of reforms to the distribution connection charging boundary from the Access and Forward-Looking Charges Significant Code Review (Access SCR). Our assessment of the impacts has not substantially changed since the draft IA which was published alongside our initial minded-to consultation in June 2021. We continue to consider the modelling and results of the draft IA to be robust and relevant to our final Access SCR decision. This IA should be read alongside CEPA-TNEI's modelling of the quantitative impact of our Access SCR options and the accompanying methodology note.[1]

[1] These were published alongside the June original minded-to consultation available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

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Executive Summary

This document reaffirms the results of the draft impact assessment (IA) published alongside our June 2021 minded-to positions for the Access and Forward-Looking Charges Significant Code Review (Access SCR).[2] It should be read alongside our final Decision on the Access SCR and CEPA-TNEI's quantitative assessment of Access SCR options.[3]

The draft IA assessed two elements of the initial scope of the Access SCR:

- Potential changes to the distribution connection charging boundary
- Introducing Transmission Network Use of System Charges (TNUoS) for small distributed generators (SDG)

This version of the IA covers the distribution connection charging boundary only. In our January 2022 update,[4] we confirmed that we no longer intend to direct changes to TNUoS for SDG through the Access SCR and that any future decisions on this area will be taken forward separately.[5]

Our final Decision also includes reforms to better define distribution network access rights. Our decisions on access rights were developed and assessed based on a qualitative and principles-based approach, combined with stakeholder engagement. We have not attempted to model the impact of these reforms quantitatively.

There are, however, significant interactions between the impacts of our decisions on the connection charging boundary and access rights. We expect that the changes to the connection boundary will themselves be the major driver of changes to the uptake of flexible access arrangements. For example, the reduced contribution to reinforcement could drive customers on flexible connections to reapply for a physically firm connection. We therefore

[2] June 2021 minded-to consultation available here: https://www.ofgem.gov.uk/sites/default/files/2021-06/%281%29%20Ofgem%20Access%20SCR%20-%20Consultation%20on%20Minded%20to%20Positions.pdf
Impact assessment available here: https://www.ofgem.gov.uk/sites/default/files/2021-06/%282%29%20Ofgem%20Access%20SCR%20-%20Impact%20Assessments.pdf

[3] CEPA-TNEI quantitative analysis available here: https://www.ofgem.gov.uk/sites/default/files/2021-06/%283%29%20CEPA-TNEI%20Report%20-%20Quantitative%20Analysis%20of%20Access%20SCR%20Options%20%281%29.pdf

[4] Our updated minded-to positions published in January 2022, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

[5] TNUoS reform will now be taken forward via an Electricity System Operator led taskforce as set out in our statement here: https://www.ofgem.gov.uk/publications/tnuos-call-evidence-next-steps

consider the quantitative modelling associated with the connection boundary to be a useful input to our assessment of our access rights changes, and are confident this adequately covers the impact of the package of reforms we are introducing through the Access SCR.

Impact of the distribution connection charging boundary final Decision

Our final Decision on the distribution connection charging boundary is to reduce the connection charge faced by customers connecting to the distribution network. This includes (i) removing the contribution to wider network reinforcement for demand connections, and (ii) reducing the contribution to wider network reinforcement for generation connections.

This decision was based on a qualitative assessment of options against our SCR principles, supported by quantitative modelling conducted by CEPA-TNEI which was published in June 2021 alongside our draft IA.[6]

The IA model assessed the impact of moving to the new connection charging boundary on billpayers, from 2023 to 2040. Specifically, it estimated the future cost impacts of the reduction in allocative efficiency due to the dampening of locational signals, which could lead to an increase in connections made in network locations that require expensive reinforcement. Our modelling scenarios estimated a present value ranging from £290m-£530m in additional costs under our changes, from these effects. The central scenario estimated an impact of £380m.

These figures do not represent the full monetary and non-monetary impacts of the benefits and costs that we expect to result from our reforms, based on several modelling limitations that are described in this document. We consider that our reforms will also have the following hard-to-monetise benefits:

- Provide opportunities for DNOs to accelerate the development and implementation of a whole systems approach to connection planning

[6] CEPA-TNEI's report and accompanying modelling methodology are published alongside this document. They were also published alongside the June 2021 minded-to consultation, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

- Increase optionality for DNOs to consider the most efficient means of facilitating new connections
- Address the intertemporal fairness issue that consumers face higher or lower connection charges by virtue of when they are able to connect
- Reduce the risk of free riding by connecting customers and the incentive to avoid being the connecting customer that triggers reinforcement
- Minimise distortions between transmission and distribution connected generation, therefore better facilitating competition
- Reduce greenhouse gas emissions (GHG) through facilitation of the uptake of low carbon technologies

One of the desired outcomes of our reforms is to reduce barriers to the uptake of Low Carbon Technologies (LCTs) such as electric vehicles (EVs), heat-pumps, and batteries. It will also reduce the cost of generation connections to the distribution network, bringing forward investment in new generation capacity, much of which will be low carbon.

CEPA-TNEI's modelling does not consider the impact of connections that may be pulled forward as a result of these lower connection costs. We consider that this potential acceleration in connections and associated reinforcement may result in increased costs in the initial years of implementation, compared to our modelling results. However, we believe that this is likely to be a redistribution of costs that were captured in the model (ie bringing them forward across the 17 years of the modelled timeline), not a significant additional cost in excess of our estimated impacts.

Updates to modelling inputs and assumptions

We have not undertaken further quantitative analysis since the publication of the draft IA because we consider that the modelling and results presented in the draft IA continue to provide a sufficiently robust estimate of the potential impacts of our Decision.

We note that since the modelling was undertaken, some of the input data sources and assumptions have been updated. Of these, the Future Energy Scenarios (FES), which are published annually by National Grid Electricity System Operator (NGESO), are the most significant. The modelling in this IA used data from the 2020 FES. The inputs and assumptions used in the 2021 version of the FES have been updated, however, we have not identified any major or structural changes to the FES modelling approach, from 2020.

We have also considered the degree of change in the scenario outputs of the FES from 2020 to 2021. We used three scenarios in our modelling and found that the monetised impacts were not highly sensitive to the granular technology and demand inputs to the FES scenarios. As a result, we consider the updates to the FES, between publication of our draft IA and our final decision, should not have a material impact on our understanding of the costs and benefits of the reforms. For this reason, the modelling was not updated for this final decision.

Interactions with RIIO-ED2 business plans

Draft business plans for the RIIO-ED2 period that have been submitted by DNOs have provided views of the additional, or accelerated, expenditure on networks that could be associated with our Access SCR decision. These costs can be found in the DNOs' draft business plan annexes and many DNOs have estimated large additions to costs over the ED2 period.[7]

Stakeholders such as Citizens Advice have also advised us in their response to our June 2021 minded-to consultation that bill payers could be exposed to high reinforcement costs under our changes. They encouraged us to review our decision in light of changes in proposed ED2 expenditure to ensure that the benefits of our proposals still outweighed the costs.

We have considered the ED2 forecasts presented in the draft business plans and their potential impact on the overall benefits case for our reforms. These costs are highly uncertain due to difficulties in estimating the potential acceleration in connections and associated reinforcement solely attributable to our Access SCR decisions. On balance we believe that the benefits case we have presented in this IA, and our decision, outweigh these costs.

We also note that DNO draft business plans were submitted on the basis of our June minded-to proposals and did not include the additional protections we have developed since, such as a high cost cap for demand connections. There was also significant variation in the assumptions

[7] These draft business plans are published by each DNO individually.

used to derive the impact of the SCR on ED2 costs between DNOs. This is reflective of the inherent uncertainty in numbers and types of connections over ED2.

In response to concerns that actual future costs may be higher than anticipated, we are taking the following actions in the interests of consumers:

- **Data and monitoring –** Following implementation, we will monitor whether the new arrangements are working in the wider interests of consumers and support the transition to net-zero, based on their ongoing costs and impacts on distribution network connections. We will review the reporting requirements throughout RIIO-ED2 to ensure that the right data is being captured.
- **Retaining and strengthening existing protections for billpayers** - This ensures that billpayers will be better protected from the cost increases associated with the transfer of network reinforcement costs associated with the most expensive connections. In these instances, the connecting customer will be required to contribute to the costs of reinforcement.
- **RIIO-ED2 mechanisms to deal with uncertain costs -** Forecasting costs for the duration of a price control with confidence is challenging. We set baseline allowances for the DNOs only where we are satisfied of the need for and certainty of the proposed work, and where there is sufficient certainty on the efficient cost of delivery. Where uncertainty remains, we will use a range of uncertainty mechanisms (UMs). UMs allow us to adjust a network company's allowance in response to changing developments during the price control period. We will publish further information on our UMs for dealing with load related expenditure in June 2022 as part of our Draft Determinations for RIIO-ED2.[8]

1. Introduction

1.1. Access SCR and assessment principles

1.1.1. In December 2018, we launched the Access and Forward-Looking Charges Significant Code Review (Access SCR) with the objective of ensuring that electricity

[8] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/network-price-controls-2021-2028-riio-2/electricity-distribution-price-control-2023-2028-riio-ed2

networks are used efficiently and flexibility, reflecting users' needs and allowing consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general.[9]

1.1.2. We developed this objective, and a set of guiding principles for the Access SCR that support this objective, in our November 2017 working paper.[10] These principles provided the framework for developing our policy options and form the basis of our principles-led assessment of the options identified within each workstream. The principles are:

i. That charging arrangements support efficient use and development of network capacity

ii. That arrangements reflect the needs of consumers as appropriate for an essential service

iii. That any changes are practical and proportionate.

1.2. Modelling scenarios and assumptions

1.2.1. It is important that any changes to the charging regime provide benefits to consumers over the short, medium, or long-term. However, it may be difficult to quantify these benefits accurately, especially where the benefits may accrue over a number of years and will be dependent on the uptake of LCTs such as electric vehicles, heat-pumps, grid-connected batteries, solar and wind farms. To estimate impacts across a range of plausible future uptake scenarios of these technologies, our analysis used three scenarios from National Grid's Future Energy Scenarios (FES).

1.2.2. We used the following FES scenarios:[11]

Consumer Transformation (CT): achieves net zero by 2050 and assumes electrified heating, consumers are willing to change their behaviour, there is high energy efficiency and demand side flexibility. This is treated as the central scenario as it is consistent with meeting the government's decarbonisation goals on schedule. We also think that with

[9] The Access SCR launch statement can be found here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision
[10] Paragraphs 2.1-2.8 of the November 2017 Working Paper, which can be found here: https://www.ofgem.gov.uk/publications/reform-electricity-network-access-and-forward-looking-charges-working-paper
[11] National Grid ESO's FES 2020: https://www.nationalgrideso.com/document/173821/download

the higher level of electrification and flexibility, this is the most realistic best-case scenario.

Steady Progression (SP): assumes slowest credible decarbonisation, minimal consumer behaviour change and decarbonisation of power and transport but not heat. Although this scenario does not achieve net zero by 2050, we consider it prudent to model a realistic scenario that does not do so, due to uncertainty about the future.

Leading the Way (LW): fastest level of decarbonisation that is thought plausible. It includes significant lifestyle changes by consumers and the use of hydrogen and electricity in heating. We have used the LW scenario as further background and a sensitivity test.

1.2.3. Although these only give a partial insight into the wide range of potential energy system outcomes in the 2040s (when our analysis ends) we consider that they provide a sufficiently-broad range of scenarios, to help establish that our decision is robust to different futures.

1.2.4. A fourth FES scenario, **System Transformation** (ST), also achieves net zero by 2050. However, as it relies heavily on the development of hydrogen, it has less electrification and flexibility, and is likely to provide more limited insight into the benefits of reform. For this reason, and the increased cost and complexity associated with modelling multiple backgrounds, we have excluded this particular scenario.

1.2.5. Monetised impacts have been estimated over the period 2023 to 2040 (17 years). This period has been chosen as our policy options represent a significant change to the charging regime, which may take some time to become fully established and deliver benefits. However, we acknowledge that by 2040 the energy landscape may have greatly changed. Present values are calculated using 2023 as the base year for discounting. In line with Treasury guidance on appraisal a 3.5% discount rate was used; this is also known as the social time preference rate.[12] Costs and benefits are in real 2018 prices.

[12] Treasury Green Book: appraisal and evaluation in central government available here: https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

1.3. Connection boundary context and high-level findings

1.3.1. Charges for connections to electricity networks can be expressed in terms of different depths. These depths vary in how much of a contribution to reinforcement the connectee makes, ranging from:

- **Deep**, where the customer fully funds any reinforcement of the existing network needed to facilitate the new connection; to,
- **Shallow**, where the customer pays nothing towards any reinforcement of the existing network needed to facilitate the new connection (this is fully funded by the DNO).

1.3.2. In 2005, the structure of charging for connection to electricity distribution networks was changed so that generators had to pay a "**shallow-ish**", rather than deep, connection charge. This meant that connectees made a contribution towards reinforcement (with the rest funded by the DNO).

1.3.3. The rationale for change was that the previous policy of charging full reinforcement costs to the generator that triggers reinforcement (a) exposed that generator to a disproportionate share of the costs and (b) encouraged each generator seeking a new connection to delay in the hope that another connectee will trigger expansion, on which it can then free ride.

1.3.4. An indication of the volumes and costs associated with distribution connections is set out below.

Table 1 - Accepted connection offers for all DNOs (source: RIIO-ED1 regulatory submissions)[13]

	Metered Demand			**All Generation**		
Year	17/18	18/19	19/20	17/18	18/19	19/20
Number	50,036	50,333	47,481	1,334	1,771	1,719
Element of connection that is sole use funded (£m)	478	550	595	527	457	503
Element of connection that is subject to the apportionment rule - customer funded (£m)	45	48	39	49	26	29
Element of connection that is subject to the apportionment rule - DUoS funded (£m)	157	172	114	88	56	79
Other Charges (£m)	14	24	33	5	9	20

1.3.5. We considered whether there was a case for reforming connection charges further as part of the Access SCR. At the start of the SCR we highlighted the linkages to DUoS charging, where we said changes to the connection boundary would take into account the level of locational granularity that was possible to achieve through DUoS reform, however, we have decided to progress DUoS reform through a separate SCR which will not conclude until after implementation of the Access SCR decision in April 2023.[14] We think there is still benefit in continuing with connection charging reform given the potential benefits in facilitating efforts to achieve net zero, and providing clarity on the new charging arrangements to DNOs ahead of the RIIO-ED2 price control. The case for reform is guided

[13] Excludes unmetered demand connections (<5% of metered demand connection cost)
[14] Our Decision to launch a separate DUoS SCR is available here: https://www.ofgem.gov.uk/publications/distribution-use-system-charges-significant-code-review-launch

by the SCR principles, supported by the modelling by CEPA-TNEI and our assessment of wider benefits and costs.

1.3.6. In our quantitative modelling, we considered the impacts of different options to lower the connection charging boundary depth, including our preferred 'hybrid' option (reducing the contribution to reinforcement for generation connections and removing it for demand). Chapter 2 explains the modelling approach and options we considered.

1.3.7. There are potential efficiency losses as a result of lowering the connection boundary depth. Connection charges currently provide a signal to the marginal user to avoid connecting to the network in locations which would trigger the need for reinforcement. Removing this signal means that prospective connectees are no longer encouraged to avoid such locations and leads to a loss of efficiency. CEPA-TNEI estimate this loss to be a PV of £380m over 17 years for the hybrid option under our central scenario (CT).[15]

1.3.8. Under the SP scenario, the loss would be ~£290m.[16] These losses can be compared with the various benefits that reducing boundary depth can bring. These include reducing cost barriers for connectees, allowing DNOs to respond more strategically and flexibly to connection requests, and simplification of connection charging.

1.3.9. We applied break-even analysis to test the potential benefits from quicker LCT adoption in the SP scenario. This suggested that if the growth of low carbon generation source (specifically solar or onshore wind) is brought forward by 2 months, breakeven is achieved.

2. Connection boundary IA

2.1. Problem statement and strategic case for change

2.1.1. The current charging arrangements do not support the efficient use and development of system capacity. Charges do not provide an effective signal to all users (instead, it only targets the marginal user once network capacity is reached) and, even

[15] See section 4.2, figure 4.1 of CEPA-TNEI report, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[16] See section 4.2, figure 4.3 of CEPA-TNEI report, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

where a signal is provided, behavioural change (such as choosing an alternative location) is unlikely for some users. Incentives to free ride could, amongst other things, delay or inhibit the uptake of LCTs, negatively affecting efforts to achieve net zero. For example, if in the same locality both a car hire centre was electrifying its fleet and a local postal depot was doing the same, each might delay its connection waiting for the other to connect first.

2.1.2. The current arrangements also tend to result in incremental reinforcement, without the DNO taking into consideration wider network needs. This can make flexibility unattractive as a means of facilitating new connections, as customers face an uncapped and uncertain liability. Finally, different arrangements at transmission and distribution may be distorting efficient investment decisions and competition between generators given the different uncertainties faced by developers.

2.1.3. We think changing the connection charging arrangements is therefore in the interests of future and existing consumers. This change will help reduce barriers where the contribution to reinforcement leads to prohibitive costs; remove the ability for subsequent connectees to free ride on the party who is willing to trigger reinforcement; and encourage DNOs to consider the most efficient way of providing the capacity needed to accommodate new connections (which may include build or non-build solutions). In addition, minimising distortions between transmission and distribution connected generation will benefit competition between these parties.

2.2. Policy objectives

2.2.1. Our objective is to ensure that charging arrangements:

- Support the efficient use and development of system capacity (including the removal of barriers to entry and help facilitate net zero at least cost to consumers)
- Reflect the needs of consumers as appropriate for an essential service, and
- Are practical and proportionate.

2.2.2. Our reforms will remove a locational signal from the connection charge for demand customers. We think these users have less locational flexibility than generation and will continue to receive an indication of the costs they are placing on the system through ongoing charges. Generation is different. These users do not currently face ongoing charges and we consider they have more flexibility in where they locate. We think our changes will continue to provide a signal to those generation users to avoid triggering unnecessary reinforcement, whereas it will remove barriers to electrification of heat and transport, amongst other sources of demand, where such use cases are less able to change location given. In doing so, we think that this will help facilitate the efficient roll-out of both LCTs and new generation needed to meet net zero objectives.

2.2.3. We expect that connection requests may increase as a result of our decision and that a potential negative consequence of our decision is that some of these users will seek to connect in parts of the network that are already constrained, which would increase costs for all DUoS billpayers. Through this IA we have weighed this potential increase in costs against the potential benefits of our changes, some of which are difficult to estimate on a monetary basis.

2.3. Policy options and justification for the preferred option

2.3.1. The policy options we considered are set out in the table below (and described in more detail in Chapter 3 of our June 2021 minded-to consultation[17]). We considered whether to reduce or remove the contribution to reinforcement that is included within the connection charge. We also considered a hybrid approach, that is, a different boundary depth for demand and generation.

2.3.2. As well as reviewing the depth of the connection boundary, we also considered complementary changes that could be made at the same time. These were:

- Alternative payment terms (for example, allowing payment to made over a number of years after connection was made); and/or,
- Introducing some form of liability or security obligation on connection customers.

[17] Our minded-to positions consultation can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

Table 2 - Connection boundary options and potential complements

Depth Option	Potential Complementary Adjustment	Function of complement
1. **Status Quo** ("shallow-ish" connection boundary)	• Alternative payment	• Reduce barriers to connection
2. **Reducing** the contribution to reinforcement costs that distribution users pay through connection charges (a "shallower" connection charging boundary than exists today)	• Alternative payment • Liabilities and securities arrangements	• Reduce barriers to connection • Protect existing customers from the cost of connections that do not proceed
3. **Removing** the contribution to reinforcement costs that distribution users pay through connection charges (a "shallow" connection charging boundary)	• Alternative payment • Liabilities and securities arrangements	• Reduce barriers to connection • Protect existing customers from the cost of connections that do not proceed

2.3.3. We set out the reasons why we are not minded to introduce alternative payment terms or liability and security arrangements in Chapter 3 of our consultation[18]. This was supported by stakeholder feedback[19] throughout the development of the Access SCR and in discussion with our challenge group. This IA therefore focuses on the impact of reducing or removing the contribution to reinforcement.

[18] Our minded-to positions consultation can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

[19] A summary of all of the responses to our consultations can be found in the Stakeholder Feedback annex published alongside our final Decision

Our final decision

2.3.4. Our final Decision on the distribution connection charging boundary is to reduce the connection charge faced by customers connecting to the distribution network, adopting a hybrid approach. This includes (i) removing the contribution to wider network reinforcement for demand connections, and (ii) reducing the contribution to wider network reinforcement for generation connections.

2.4. Overall monetised impacts (£m) of our final connection charging boundary decision

2.4.1. The 'cost to GB consumers' is identified in the CEPA-TNEI report for different boundary depths and basic DUoS reform[20]. The numbers quoted on the cost of connection are based on modelling work that is described in detail in section 3 of the CEPA-TNEI report.

2.4.2. Our final decision on the connection charging boundary would introduce a PV of £380m additional costs over 17 years relative to the status quo in the Consumer Transformation scenario.[21]

2.4.3. The equivalent figure for SP is £290m.[22] We estimate that it would require anticipated solar and onshore wind roll-out under SP to be brought forward by 9 months for carbon saving benefits to compensate for the cost in this scenario. We cannot bring any direct evidence to bear on the likelihood that this would be achieved, but the fact that it is in months rather than years, suggests that it could be plausible.

2.4.4. The business impact target (BIT) concerns the economic impact of regulation on businesses. The reforms we are implementing are 'non-qualifying regulatory provisions'. We rely mainly on BIT administrative exclusion D ("Deliver or replicate better competition-based outcomes in markets characterised by market power: Pro-competition").[23]

[20] This involves implementing an Ultra Long-Run Model at all voltage levels. See CEPA-TNEI report for further detail: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

[21] See section 4.2, figure 4.1 of CEPA-TNEI report, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

[22] See section 4.2, figure 4.3 of CEPA-TNEI report, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

[23] See page 33 of BEIS's Better Regulation Framework Interim Guidance, March 2020, available here: https://www.gov.uk/government/publications/better-regulation-framework

2.5. Hard to monetise impacts for the preferred option

2.5.1. The monetised results do not represent the full impact that we expect to see from this change, due to a combination of modelling limitations and wider impacts.

2.5.2. We think our reforms will have the following hard-to-monetise benefits:

- It will provide opportunities for DNOs to take a stronger whole systems approach to connection planning.
- Reduce the risk of free riding and the incentive to avoid being the connectee that triggers reinforcement.
- Increased optionality for DNOs to consider the most efficient means of facilitating new connections.
- Address an intertemporal fairness issue that consumers face higher or lower connections charges by virtue of when they are able to connect.
- Minimise distortions between transmission and distribution connected generation, thereby better facilitating competition.
- Reduced greenhouse gas emissions (GHG) through facilitation of the uptake of low carbon technologies.

2.5.3. In terms of non GHG strategic and sustainability issues, such as Security of Supply, we do not expect there to be a significant impact from change to the connection regime. We also consider that there will be limited to no effects on biodiversity, landscape, land use, water, air quality and soils.

2.6. Key assumptions/sensitivities/risks

2.6.1. The assumptions and sensitivities used in modelling the cost of making a change are set out in section 4.1 of CEPA-TNEI's report published alongside this IA together with CEPA-TNEI's methodology note.

2.6.2. We are mindful that some evidence (especially on connection offers that were not accepted) is inherently backwards looking. This also does not capture those projects which do not proceed to formal offers being issued as a result of informal discussions with DNOs early in the process. We have tried to address this by speaking to stakeholders involved in our Challenge Group although this is, by its nature, anecdotal and may not be reflective of the majority. Stakeholders may be more motivated to raise issues with the current arrangements where they have not suited them.

2.6.3. There are also risks associated with making a change, including connection customers seeking to connect in areas which drives up costs, or an increased volume of connection requests increasing the time it takes to connect.

Is this proposal in scope of the Public Sector Equality Duty?

2.6.4. Ofgem has to have regard to the specific requirements of the Public Sector Equality Duty.[24] In our overall approach to the SCR options development and assessment, we have reflected our duty of care towards these consumer groups through our guiding principle of "ensuring that the reforms reflect the needs of consumers as appropriate for an essential service".

2.6.5. We considered the impact of our reforms on groups of consumers, and in particular small users and vulnerable consumers. The modelled magnitude of the connection boundary impacts on these groups of consumers are small.

3. Evidence base for connection boundary IA

3.1. Problem statement and strategic case for change

3.1.1. Connection charges to distribution networks currently include:

- Costs of sole use assets needed to connect to the existing network; and
- Charges for a share of any reinforcement to the wider network needed to facilitate the connection.

3.1.2. This aims to provide a signal to avoid connecting in constrained parts of the network where expensive reinforcement is required.

[24] Public sector equality duty, Equality Act 2010: https://www.legislation.gov.uk/ukpga/2010/15/section/149

3.1.3. Our analysis suggests, however, that efficient signals are not being sent to all users. Only the individuals that trigger reinforcement face this cost. Previous customers who contributed to the need for reinforcement do not. Users who can delay their connection are also able to free ride on those willing to pay for reinforcement. This is arguably unfair. Both low carbon generation and demand projects tell us connection charges can be a barrier – especially where behaviour change, such as moving location, is unlikely. By requiring the DNO to fund more of the work required to accommodate new connections, a more efficient outcome can be achieved with the DNO managing network capacity based on an understanding of the needs of a wider group of customers.

3.1.4. The aim of the Access SCR is to ensure that electricity network access and forward-looking charging arrangements result in electricity networks being used efficiently and flexibly, reflect users' needs and allow consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general.

3.1.5. We are not convinced that the current connection arrangements allow this to happen for a number of reasons:

- The current arrangements are not providing an effective signal, only encouraging the customer that triggers the need for reinforcement to avoid new or increased connections in certain places, while not giving other users any signal at all. This could act as an undue barrier to some users slowing down attempts to achieve net zero.
- The current arrangements tend to result in incremental reinforcement as the means of facilitating new connections, without taking into consideration wider network needs.
- Transmission connected generators do not face reinforcement costs in the upfront connection charge. Under the current arrangements, distributed generation faces an upfront connection charge whereas a transmission connected generation can pay over several years. These differences could impact competition between distribution and transmission connected generation, particularly where parties connecting at higher distribution voltages trigger upfront transmission costs.

3.1.6. These are aligned to our 1st Guiding Principle – that arrangements support efficient use and development of system capacity. We have also identified a further issue aligned to our 2nd Guiding Principle – that arrangements reflect the needs of consumers as appropriate for an essential service.

3.1.7. On the assumption that heat pumps and EVs become mainstream and their use essential, some but not all of this work would be DNO funded. Where it is not, (e.g., where existing customers need to move to three phase connections, or above 100A), current arrangements mean users could face drastically different costs depending on when and where they are able to connect.

3.1.8. We think our 3rd Guiding Principle is less relevant for our assessment as we consider that all our proposed changes can be implemented relatively easily.

Effectiveness of the current charging signal

3.1.9. Under the status quo for distribution charges, the connection charge is the sole locational signal for most distribution connections and so (in the absence of other changes to DUoS) removing it will lead to some inefficiencies in lieu of any alternative signals. However, we are concerned that the current signal within the connection charge may be too strong for some users. It risks creating barriers to investment or pushing users to accept non-firm connections where it is not in their benefit (with the risk of being curtailed in the future). This is especially in cases where we think behaviour change (ie changing connection location) is unlikely.

3.1.10. The connection charge is a clear upfront charge known at the point of investment. However, ongoing charges can also influence investment decisions. There is also a risk that the connection charge could over-signal costs in combination with reformed, forward-looking, distribution charges. The connection charge only signals value to the marginal user of changing investment plans once network capacity is reached. Users who use up capacity before that point receive no signal but can still act to save costs. The connection charge provides no signal about long-run costs of maintaining the network and does not provide any investment signal to users whose actions can help offset need for reinforcement in that area.

3.1.11. This previously led us to reduce reinforcement costs recovered through connection charges and rely more on use of system charges instead:

- **Transmission "Plugs"** – it was argued that TNUoS charges, derived on an incremental cost basis rather than connection charges based on an actual cost basis, would provide more efficient signals.
- **Distribution** – we moved from deep to shallow-ish charges in 2005 as the benefits for competition in generation supported a change but, until or unless DUoS charges provide appropriate cost reflective signals, it remained appropriate to retain some form of locational signal within connection charges given the developments taking place in the distribution network at that time.

3.1.12. Figure 1 and Figure 2 below show how the quoted costs for metered demand projects and for generation projects were split by funding source for offers that were accepted and those that were not accepted respectively. The data is from the 2018-19 charging year, which we still consider to be broadly representative.

3.1.13. The figures show that the overall percentage of connection costs that are apportioned to connecting customers for reinforcement (ie, the component of the cost that would be reduced or removed by our change), is small compared to the percentage of costs paid for extension assets. However, the data also shows that the percentage of the costs connecting customers face for reinforcement is greater for those offers that were not accepted than for those offers that were.

Figure 1 - Percentages of quoted costs for metered demand projects and for generation projects for accepted offers split by cost category for the 2018-19 reporting year[25]

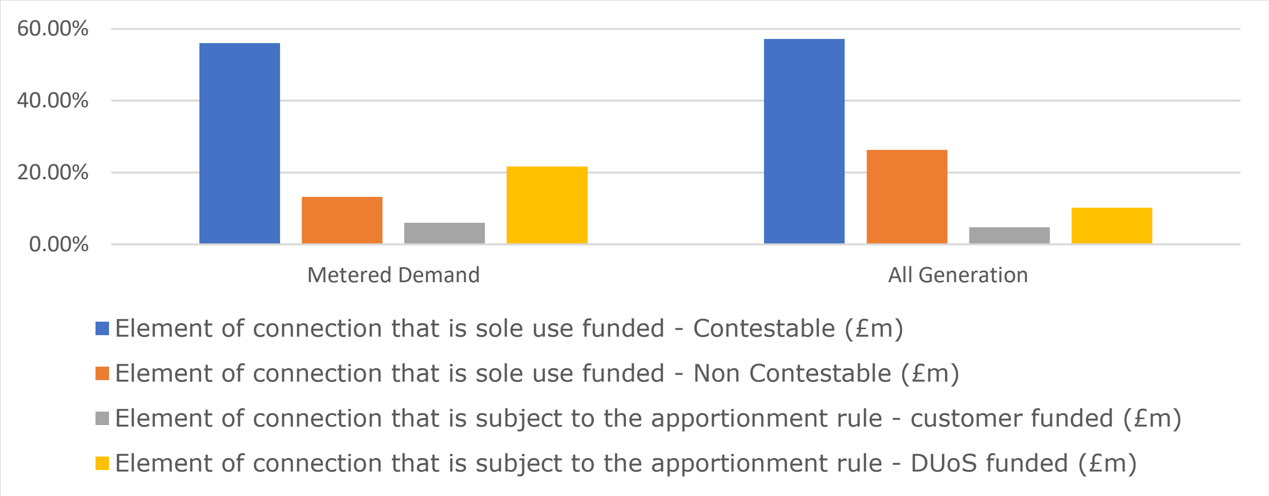
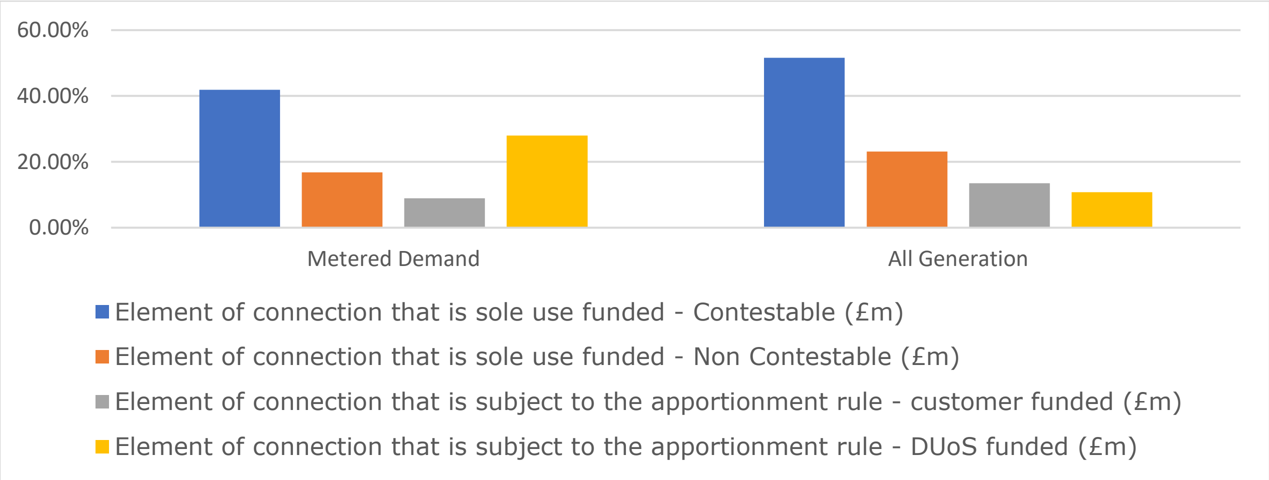


Figure 2 - Percentages of quoted costs for metered demand projects and for generation projects for not accepted offers split by cost category for the 2018-19 reporting year[26]

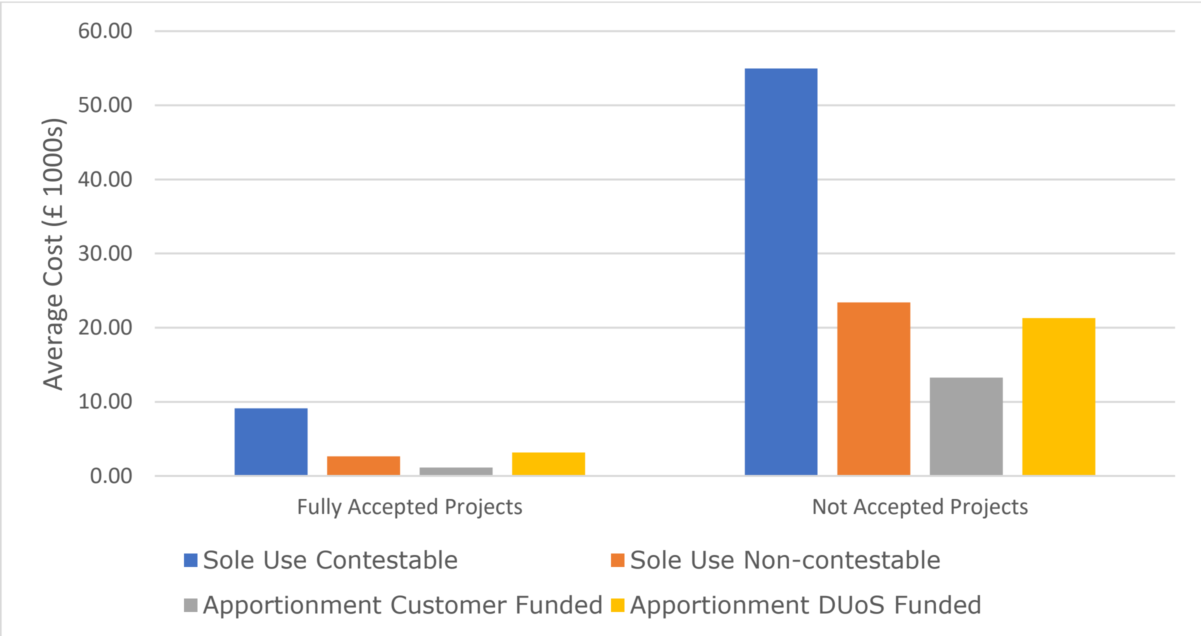


3.1.14. Figure 3 shows the average quoted costs of projects by acceptance status for the 2018-19 reporting year with the costs broken down by cost category. The grey column (apportioned customer funded) refers to those additional costs which would be funded by the DNO and recovered through DUoS if moving to a fully shallow boundary. The data

[25] Source: RIIO-ED1 regulatory submissions
[26] Source: RIIO-ED1 regulatory submissions

shows that the quoted costs of those projects that were accepted were on average lower than the quoted cost of projects that were not accepted.

Figure 3 - Average costs of for accepted and not accepted connection offers split by cost category for the 2018-19 reporting year[27]



3.1.15. It should be noted that there are a number of factors that influence connection decisions beyond the connection charging regime, many of which may be specific to the use case for an individual connection. It is therefore not possible to draw definite conclusions from these figures in isolation. However, the data suggests that high overall connection charges may be a prohibitive barrier to entry. Based on these figures, the contribution to reinforcement, while a factor in decision-making, seems unlikely to be the determining factor in whether a connection goes ahead.

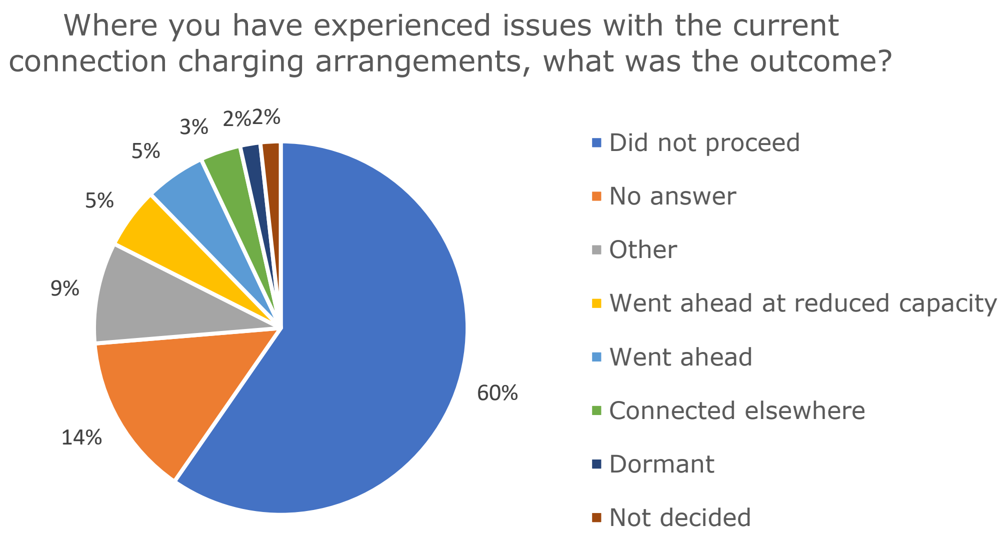
3.1.16. We are mindful that this is historic data and may not be reflective of a future where we know there will be increased pressure placed on the networks from the electrification of heat and transport, resulting in an increase in connections with less locational flexibility for demand, as well as increases in renewable generation. It also does not reflect those projects which do not proceed to a formal connection offer.

[27] Source: RIIO-ED1 regulatory submissions

3.1.17. In order to address this, we have gathered the following evidence from stakeholders about issues experienced with the current arrangements:

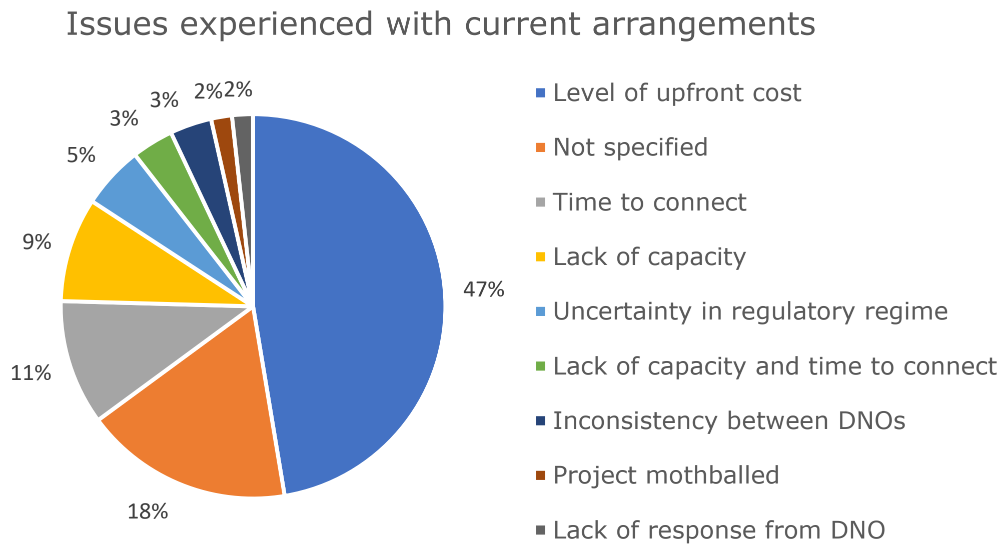
- The ENA issued a call for evidence looking for "shovel-ready" projects that will support the Green Recovery and address key Government policies such as net zero and the decarbonisation of transportation.[28] This funding is aimed at new projects that are struggling to be justified due to network infrastructure costs.
- Network infrastructure is regularly noted in discussions with stakeholders as one of the main barriers preventing people being able to meet targets around EV uptake. Network users feel it is highly unfair that the one that triggers the reinforcement bears the high cost.
- Feedback received from EV charging installers, renewable generators and other stakeholders highlighted the level of upfront cost as an issue with projects proceeding (see charts below).

Figure 4 - Stakeholder feedback on project outcomes[29]



[28]The ENA call for evidence is available here: https://www.energynetworks.org/greenrecovery
[29] Source: SCR Challenge Group, Charging Futures, BEIS OLEV stakeholder distribution list, 57 responses, 2019)

Figure 5 - Stakeholder feedback on issues experienced with connection to distribution networks[30]



3.1.18. On balance, we think this is a strong argument for making a change to the connection charging arrangements. We have concluded that there is a sufficiently compelling case that the locational signal within the connection charge is not working as intended (particularly for those customers with little locational flexibility). Costs placed onto the system by demand users can instead be signalled through ongoing charges and may be more effective in bringing down costs, while removing barriers to entry. The case for removing the contribution to reinforcement completely for generation is less compelling given the current DUoS charging arrangements. However, we think there is sufficient evidence to suggest a reduction would be beneficial to some users – while still ensuring they face a signal about the costs they place on to the system.

Efficient system development

3.1.19. The need for network investment and efficient ways of managing the system will increase as we electrify heat and transport. We think there are arguments for why the current arrangements may be leading to poor incentives on parties and will limit this from happening in the most efficient way.

[30] Source: SCR Challenge Group, Charging Futures, BEIS OLEV stakeholder distribution list, 57 responses, 2019

3.1.20. Currently, only the individual customer that triggers reinforcement faces this cost (while previous customers who contributed to the need, and subsequent customers who benefit from it, do not). This free rider effect is unfair and could act as a barrier to decarbonisation. For example, the incremental nature by which DNOs reinforce their network means that additional spare capacity is provided when connecting a new customer. Subsequent connectees can utilise this new network capacity but did not make any contribution to it in their connection charge (whereas the first connectee did). This creates an incentive to delay connecting where possible. Furthermore, current arrangements lead to a coordination failure. Generators may not be willing to pay towards reinforcement, so are left to choose a reduced capacity or non-firm connection. With shallower charges, a more efficient outcome can be achieved with the DNO managing network capacity through strategic investment based on understanding of a wider group of customers.

3.1.21. The current boundary also means that DNOs recover much of the funding for connection-led reinforcement only when users pay connection charges. DNOs can invest ahead of need but the risk of not fully recovering their costs gives them a strong incentive to wait until they receive connection requests, rather than act in advance.

3.1.22. In addition to the incentives created by the current arrangements, they may also provide a barrier to DNOs being able to use flexibility to facilitate new connections. Under the current boundary, DNOs need to recover the cost of new network capacity through charges to individual customer connections. This works for traditional reinforcement as the cost is known upfront. The cost of flexibility to facilitate new connections would vary over time and so would require the customer to accept an uncertain (and uncapped) liability to be settled retrospectively.

3.1.23. We are aware of issues reported across all DNOs associated with using flexibility to facilitate new connections, including one example where there was a significant number of potential bidders for a generation turn down/demand turn up product – but no appetite from connection customers due to the uncertain liabilities.

3.1.24. A more shallow connection boundary would place more of the onus on DNOs to find the most efficient way of funding the work needed to facilitate the connection (ie, comparing build and non-build solutions).

Differences between transmission and distribution charging arrangements

3.1.25. Transmission Attributable work (eg, upgrading a Grid Supply Point) triggered by a distribution connection is currently charged to the connection customer within the DNO's connection charge. This can be prohibitively expensive and prevent connections from going ahead (as supported by earlier comments on connection charges acting as a barrier). Reinforcement work at 132kV in Scotland is also funded by TNUoS, whereas it is included within the upfront connection charge in England and Wales. This difference could lead to a distortion between generators in different parts of GB.

3.1.26. We think there are therefore principle-based reasons for seeking to align the arrangements where possible. On the other hand, even if we were to conclude that changes could be made to allow the recovery of these costs through DUoS, we do not consider that the necessary reforms needed to better target these costs to the relevant individuals will be possible in time for our implementation date of 2023. This would result in significantly higher costs being borne by all consumers. It may also be that another approach to recovering these costs is more appropriate and making a change now would preclude possible options in the future. For these reasons, we set out in our decision document that we are not making any changes to the treatment of transmission work triggered by a distribution connection at this time.

Household impacts

3.1.27. Government has forecast a significant increase in the uptake of heat pumps from the 2030s with the Ten Point Plan setting a goal of installing 600,000 heat pumps per year by 2028.[31] The CCC's Sixth Carbon Budget forecasts a total of 5.5 million heat pumps installed in homes by 2030, of which 3.3 million are in existing homes.[32]

3.1.28. The current connection charging arrangements state that the DNO will fully fund reinforcement at an existing premises that remains connected up to 100 amps (subject to other conditions being met). We have seen analysis that suggest this is sufficient to accommodate a 10 – 12kW heat pump and a 7kW electric vehicle charger.

[31]The government's ten point plan is available here: https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution
[32]The Sixth Carbon Budget is available here: https://www.theccc.org.uk/publication/sixth-carbon-budget/

3.1.29. However, there is evidence to suggest some homes will need a heat pump larger than 12kW. This could be down to property size and other factors and is not limited to higher income deciles. Combined with an EV charger and or other appliances such as an electric shower, this could require a fuse greater than 100A – as well as potentially triggering reinforcement of the existing shared network assets in that area. These costs would then be borne by the customer triggering the work. We think therefore that there is sufficient evidence to suggest a change would benefit those customers by recovering the costs via an alternative means.

Conclusions

3.1.30. It is difficult to quantify the scale of the problem we are trying to address. This is to be expected as projects that do not proceed to formal connection offers or simply do not proceed beyond early stages are less likely to be recorded in regulatory reporting. Users' negative experiences are more likely to be motivated to highlight their concerns than those where the project has completed. However, there is sufficient anecdotal evidence to suggest many of these concerns are shared more broadly. We are also certain that the pressures placed on networks from the electrification of heat and transport will increase in coming years. Furthermore, we think there are good principle-based arguments for why the charging arrangements may no longer be sending the most effective signals and may actually incentivise the wrong behaviours if we are to achieve decarbonisation at least cost.

3.2. Monetary analysis

3.2.1. CEPA-TNEI's modelling has provided important evidence on the allocative efficiency of different boundary depths. This is set out in full in Chapter 5 of their report which is published alongside this IA.

3.2.2. For these calculations, the generation and demand backgrounds are held constant so it does not capture additional connections or connections being made earlier, which we view as a significant benefit of the reform. Instead, it captures the change in allocative efficiency as connectees connection charge depth is altered.

3.2.3. The key results are summarised below. The options that were modelled are:

- **Shallow-ish:** Under the shallow-ish counterfactual, the model reflects the existing voltage rule. This states that users contribute for reinforcement at the voltage level to which they connect, as well as the voltage level above.
- **Voltage rule:** This boundary amends the voltage rule such that customers only face connection charges for reinforcement for the voltage level to which they are connected. Contribution to higher voltage levels is no longer required.
- **D/G hybrid (our Final Decision):** This boundary removes connection charges completely for demand (ie a shallow connection boundary) and retains connection charges for generation at the voltage of connection.
- **Shallow:** This boundary introduces a shallow connection charge, removing all connection charges associated with reinforcement for both demand and generation.

3.2.4. CEPA-TNEI also modelled the impact of the above options against a notional Ultra-Long-Run (ULR) DUoS cost model, one of the options we considered as part of our forward-looking DUoS review. This model uses locationally specific estimates of network asset value and utilisation to drive locational DUoS charges, reintroducing some locational signals.[33]

3.2.5. Figure 6 shows results for the CT scenario. It shows that distribution network costs generally increase moving from the status quo option (Shallow-ish) to fully Shallow. It also highlights that total costs are less on the 132kV and EHV combined network than LV and HV combined. With the exception of the D/G Hybrid, Ultra-Long-Run costing would reduce the impact on distribution costs, but differences between the options are similar.

[33] For more information, see section 5, page 20 of CEPA-TNEI report

Figure 6 - Impacts on distribution network costs (PV, £bn); existing DUoS, Consumer Transformation[34]

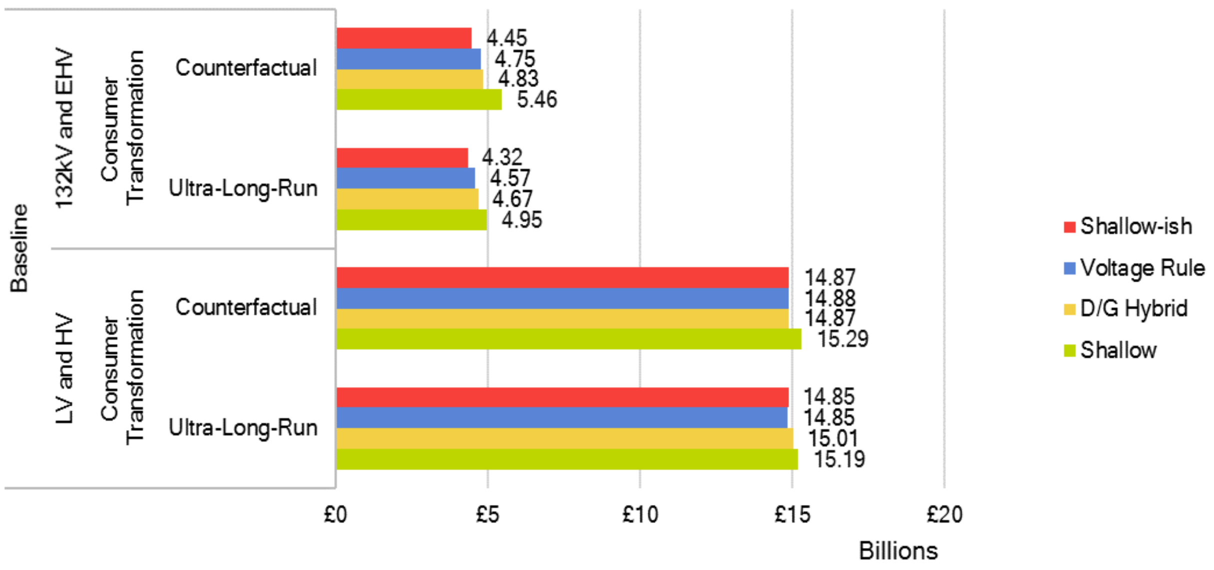


Table 3 - Impacts on distribution network costs (PV, £bn) relative to status quo; existing DUoS, by Scenario[35]

	Scenario		
Options	**CT**	**SP**	**LW**
Voltage rule	0.31	0.27	0.44
D/G Hybrid	0.38	0.29	0.53
Shallow	1.43	1.01	1.70

[34] See section 4, figure 4.1 of CEPA-TNEI report, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[35] See section 4, figures 4.1 to 4.3 of CEPA-TNEI report, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

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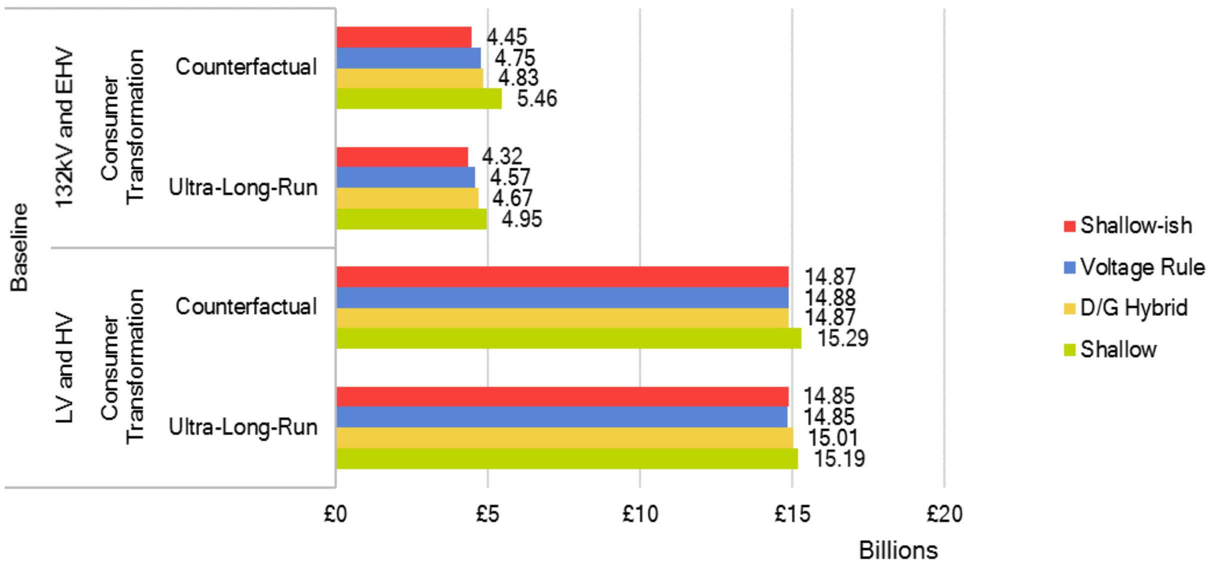

3.2.7. Table 3 summarizes the additional system costs for each of the options under different FES scenarios. It shows that additional system costs under SP are of a similar order of magnitude to CT. The ranking of options by system cost is also similar, with costs increasing moving from the status quo to shallow.

Break even analysis

3.2.8. The CEPA-TNEI modelling provides insights into the potential impacts of reforms on locational decisions. However, as highlighted earlier, it does not capture any benefits that different boundary depths would have for new generation or LCT uptake. To build in dynamic effects on top of the modelling framework was not possible, as we would have had to make assumptions about the elasticity of connection date and connection charges. We could not collect sufficient evidence to support an estimate of this parameter. This is not to say that we have ignored this impact, however. Accelerating the uptake of LCT is one of the key benefits of our reforms, which would offset the costs identified above.

3.2.9. A conventional economic technique when costs are known but monetary benefits are uncertain is to calculate the change in a specific parameter that would achieve a breakeven point. We have therefore tried to assess the possible monetary benefit of our preferred position using this simple approach. We have appraised the benefit of bringing forward certain types of connections by a number of years (n). The logic is that if monetary benefits are large when n is small then it is likely that the policy change is worthwhile. Conversely, if the number of years has to be large to generate sufficient benefit to outweigh cost, then a view might be taken on the realism or likelihood of this being achieved.

3.2.10. It is difficult to model the impact of charging changes on a diverse range of business models, so instead we are seeking to get an indication of the potential benefits by quantifying the value that would be created if the changes were able to accelerate aggregate take-up of specific technologies. We have confined attention to onshore wind generation and solar generation. While the reforms should contribute to the speed of adoption of demand connections like motorway charging stations and thereby help speed EV roll-out, we think that these impacts are too indirect and difficult to separate from the wide range of government initiatives, and our own, that support charging infrastructure.

3.2.11. Our breakeven benefit estimate is based on the FES SP scenario. This has been chosen, as LW and CT both have extremely rapid LCT rollout characteristics as a result of assumptions on technology, consumer behaviour and radical change in the energy system. Therefore, there can be limited benefit in bringing forward low carbon generation in a decarbonised system. For example, FES 2020 assumptions on installed capacity show growth rates of solar capacity of around 2GW per annum in CT and LW and 0.6GW per annum in SP from 2019 to 2050. Decentralised wind expansion over the same period is around 0.7GW per annum in CT and 0.6GW per annum in LW, in contrast only 0.03GW per annum in SP.

3.2.12. Our breakeven results depend on the value of carbon that is potentially saved from earlier decarbonisation than would otherwise occur. These values have been revised upwards since our minded-to decision. Using the current central BEIS carbon value,[36] breakeven is achieved for the preferred D/G hybrid option if all solar and onshore wind connections are made 2 months earlier than expected. In contrast, the shallow result would require connections to be brought forward by almost a year. Although this is more plausible than the equivalent minded-to value of 3 years, we still consider it less likely that going to shallow connections for generation would deliver value for money in terms of speeding connections alone compared with the D/G hybrid.

3.2.13. We are aware that this is a simple approach as whether a connection goes ahead can be influenced by several factors, many unrelated to the connection charge. However, our aim is to try and illustrate the potential benefits in comparison to the quantified costs presented in CEPA-TNEI's report.

3.3. Hard to monetise impacts

Other system costs and benefits

3.3.1. A more shallow connection boundary is consistent with DNOs exploring more options for alternatives to conventional network reinforcement, such as flexibility procurement, rather than defaulting to wider network reinforcement.

3.3.2. Our reforms will allow large users to make more efficient connection decisions between connecting at transmission or distribution where there is a choice. Connection charges can give better short-term signals (albeit limited to the marginal user triggering work), whereas ultra-long-run costs models can give better long-term signals. Our modelling does not give us specific information about choices between connecting at either but the potential benefits from removing distortions between transmission and distribution are wider than just about network costs. For example, it could be that the resulting generation is cheaper (e.g., because of better site availability/load factors).

Competition impacts

3.3.3. Our principal statutory objective is to protect the interests of consumers, wherever appropriate by promoting effective competition.[37] The DNOs have a statutory

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[36] See BEIS's carbon values here: https://www.gov.uk/government/collections/carbon-valuation--2#carbon-valuation-in-policy-appraisal

[37] As set out in Section 3A of the Electricity Act 1989, available here: https://www.legislation.gov.uk/ukpga/1989/29/contents

duty not to restrict, prevent, or distort competition in the supply and generation of electricity.[38] Ofgem considers that network charging is an important mechanism for facilitating competition and protecting the interests of consumers.

3.3.4. We think our decision will help facilitate competition between distributed generators by reducing upfront barriers to connecting to the distribution network. Seeking to align the arrangements for transmission and distribution to the extent possible should also facilitate competition between distribution and transmission-connected generators.

3.3.5. We have not seen evidence to suggest our decision would be negative for competition in the provision of connections. We have not decided to direct any changes to the treatment of extension assets. Our understanding is that the types of connections typically provided by ICPs and IDNOs would fall into this category.

3.3.6. We consider that our decision is unlikely to have a significant negative impact on competition more generally. Ofgem does not expect implementation costs to constitute a significant barrier to entry in the supply market, and in particular, the decision is not likely to impose significant new costs on developers of distributed generation.

Security of supply impacts

3.3.7. Reducing barriers to entry and enabling more generation onto the system may have benefits for security of supply as demand is expected to increase in coming years.

Other greenhouse gas impacts

3.3.8. We do not expect our decision to have any other greenhouse gas impacts other than those discussed previously (e.g., bringing forward the connection of LCTs).

Other environmental impacts

3.3.9. The operation and development of electricity distribution networks results in a number of indirect and direct impacts. The most significant effects are likely to be the emissions related to losses from distribution networks. Direct impacts include emissions of sulphur hexafluoride, a potent greenhouse gas. We consider that our decision will not have

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[38] As set out in Condition 4 of the Standard conditions of the Electricity Distribution Licence, available here: https://epr.ofgem.gov.uk//Content/Documents/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20%20-%20Current%20Version.pdf

a material impact on these characteristics. There are also indirect visual and other amenity issues – overhead wires are considered unsightly, and the sighting of wires and other installations can have effects on habitats, archaeology, and other items of natural or cultural importance. We think our decision may have an overall positive impact here as DNOs consider build and non-build solutions to providing capacity for new connections.

3.4. Distributional analysis

3.4.1. Reducing or removing the contribution to reinforcement will result in an increase in overall system costs according to CEPA-TNEI's modelling. This will be recovered from all DUoS customers, rather than being targeted (to some extent) on the individual customer(s) triggering the work. This could be higher in rural areas where there could be a higher frequency of reinforcement being required (e.g., onshore wind choosing to locate in remote parts of the network due to the availability of the natural resource) coinciding with a smaller DUoS customer base from which to recover the costs from.

3.4.2. We do not expect there to be significant differences in the impact on different types of demand and generation (e.g., between solar and onshore wind). The existing arrangements do not distinguish between technologies in terms of calculating the connection charge and we are not introducing anything that provides preferential treatment for one technology over another.

3.5. Risks and key assumptions

3.5.1. The assumptions and sensitivities used in modelling the cost of making a change are set out in section 3 of CEPA-TNEI's report published alongside this impact assessment.

3.5.2. As discussed earlier in section 2.6, we think some of the key risks and assumptions in our analysis are:

- Historical evidence is not reflective of future growth in connections.
- Anecdotal evidence submitted through our assessment is not reflective of the majority.
- Our decision could result in a slowing down of connection requests leading up to implementation and/or a sharp increase soon after.

3.6. Wider impacts

3.6.1. We think our decision will remove barriers to entry and could therefore have a positive effect on competition in the generation of electricity. Encouraging more generation on to the system may also have benefits for security of supply.

3.7. Unintended impacts

3.7.1. Some users may choose to delay connections if they perceive a particular direction of policy travel. For example, under the hybrid option that we have selected, generation might choose to delay connecting to the network if they think the connection boundary, they face is likely to be made shallow in the future. This could actually slow down the connection of more renewables. We think there are sufficient reasons why this would not happen in the majority of cases, not least the benefits to be gained from generating as soon as possible and participation in the wholesale market and or Capacity Market. Notwithstanding any of this, the expected growth in connections may reduce by economic uncertainty.

3.7.2. On the other hand, a change could result in a significant increase in number of connection requests. This could lead to extended connection queues and time to connect; however, we believe these could be mitigated by preparation and planning from DNOs.

3.8. Interactions with other Ofgem reforms

3.8.1. This change to the depth of connection charges will alter the costs to be recovered through the ED2 price control. The shallow(er) charges might also help create opportunities for DNOs to consider alternatives to traditional reinforcement. The shallow(er) charges might also impact user behaviour (e.g. the number of new connections) and the amount of investment required in new network capacity. This may reduce the need for network investment – or increase it if users site in already constrained parts of the network. Reforms may also lead to DNOs approaching, and therefore funding, network investment differently. For this reason we have decided to implement our Decision at the same time as the start of the RIIO-ED2 price control.

3.8.2. There are links between connection charging and DUoS reform. We have proceeded with this decision on the basis of no or low change to DUoS in order to provide some information to stakeholders ahead of RIIO-ED2. We will remain mindful of our Access SCR decision as we progress the DUoS SCR.