ofgem

Making a positive difference
for energy consumers

Access and Forward-Looking Charges Significant Code Review: Draft Impact Assessments in support of Minded to Positions for a) Distribution Connection Charging and b) Charging SDG TNUoS

Division:	Systems and Networks	**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:	Consultation on Minded to Positions	**Contact for enquiries:**	FutureChargingandAccess@ofgem.gov.uk
Coverage:	Partial		

Summary

These are Ofgem's draft impact assessments (IAs) supporting our minded-to positions on two elements of the Access SCR: distribution connection charging and TNUoS charges for Small Distributed Generation (SDG). The impact assessments support our main consultation on our minded to positions, published alongside this document. The impact assessments should also be read alongside the CEPA-TNEI report 'Quantitative analysis of Ofgem Access Options: TNUoS SDG and Connections' and the supporting methodology note, also published alongside. This document should be seen as integrating consideration of specific Access SCR objectives, a high-level summary of CEPA-TNEI findings and an explanation of additional factors that we have taken into account in our thinking.

Our conclusions for the connection charging boundary are based on Access SCR principles, CEPA-TNEI modelling, and stakeholder engagement. We have concluded that the connection boundary for demand users should be reduced to the shallow level. That is, these connectees should not pay for anything other than their direct asset costs (meaning any and all reinforcement would be funded by the DNO). For generators, we consider that the depth of connection should be made shallower than it is today, but not fully shallow (so that such connectees pay for their direct asset costs and reinforcements at the same voltage level as their connection). Reinforcement at voltage levels above the point of connection would be funded by the DNO.

We have considered whether Small Distributed Generation (SDG) should pay TNUoS charges. On a principled based assessment, and with the benefit of CEPA-TNEI's modelling of the impact on consumers, we think that there are strong arguments to support this change.

In developing its decision, Ofgem will take into account respondents' views on its initial proposals, including any comments on these draft impact assessments. An updated impact assessment will be published together with the final proposals.

Contents

1. Introduction 5
   1.1. Access SCR and assessment principles 5
   1.2. Connection boundary context and high-level findings 7
   1.3. Charging SDG TNUoS context and high-level findings 10
2. Connection boundary IA 11
   2.1. Problem statement and strategic case for change 11
   2.2. Policy objectives 12
   2.3. Policy options and justification for the preferred option 12
   2.4. Overall monetised impacts (£m) for the preferred option 14
   2.5. Hard to monetise impacts for the preferred option 15
   2.6. Key assumptions/sensitivities/risks 15
3. Evidence base for connection boundary IA 16
   3.1. Problem statement and strategic case for change 16
   3.2. Monetary analysis 26
   3.3. Hard to monetise impacts 29
   3.8. Wider impacts 32
   3.9. Unintended impacts 32
   3.10. Interactions with other Ofgem reforms 33
4. TNUoS charging for SDG IA 33
   4.1. Problem statement and strategic case for change 33
   4.2. Objectives of reform to TNUoS charges for SDG 34
   4.3. Policy options that have been considered and justification for the preferred option 35
   4.4. Overall monetised impacts (£m) for preferred option 36
   4.5. Hard to monetise impacts for preferred option 37
   4.6. Key assumptions/sensitivities/risks 38
5. Evidence base for TNUoS SDG IA 39

Making a positive difference for energy consumers

5.1. Problem under consideration 39

5.2. Description of options assessed 40

5.3. Monetary analysis 40

5.4. Hard to monetise impacts 43

5.5. Distributional Analysis 45

5.6. Risks and key assumptions 49

5.7. Wider impacts 50

5.8. Unintended impacts 50

5.9. Interactions with other Ofgem reforms 51

5.10. High level description of monitoring and evaluation plan. 52

1. Introduction

1.1. Access SCR and assessment principles

1.1.1. A strategic Government aim is to achieve 'net zero' greenhouse gas emissions by 2050, an increase in the level of ambition from government's previous emissions reduction target. Considerable investment is required to further investment in renewable electricity generation, as well as in the electrification of transport and heat. One of Ofgem's key aims is to assist decarbonisation at least cost to the consumer. The Access and Forward Looking Charges Significant Code Review ("the Access SCR") aims to help this process by identifying charging structures that will work for industry, network operators, and consumers.

1.1.2. The Access SCR principles are that:

i. Charging arrangements support efficient use and development of network capacity;

ii. Arrangements reflect the needs of consumers as appropriate for an essential service;

iii. Any changes are practical and proportionate.

1.1.3. 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 Low Carbon Technologies (LCTs) such as electric vehicles, heat-pumps, grid level batteries, solar and wind farms. The main scenarios used throughout this analysis are three of the four National Grid's Future Energy Scenarios(FES)[1]:

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

[1] National Grid ESO's FES 2020: https://www.nationalgrideso.com/document/173821/download

the higher level of electrification and flexibility, it is might be considered as a 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.

1.1.4. 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 help establish that our proposals are robust to different futures.

1.1.5. For both the IAs the future generation mix will be important in determining impacts. We have used the **Leading the Way** (LW) FES 2020 scenario, as further background and a sensitivity test. This is the fastest level of decarbonisation that is thought plausible. It includes significant lifestyle changes by consumers and the use of hydrogen and electricity in heating.

1.1.6. **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. We welcome views on the choices of scenario that we have made.

1.1.7. Ofgem also takes a proportionate approach to carrying out and documenting in these Impact Assessments (IAs). We consider who will be affected by the proposals and this is tailored to the nature of the decision being taken. At a minimum, we include a description of the impacts (i.e. positive or negative impacts on any group) and order of magnitude (e.g. low, medium, high). However, where possible we quantify the effects with the ambition to monetise as many costs and benefits as possible, using the insights from modelling by CEPA-TNEI.

1.1.8. As these are draft IAs for the Connection Boundary and TNUoS SDG[2] charging, we welcome comments from interested parties on the cost, benefit and risk estimates

[2] SDG is generation under 100MW that is connected to the electricity distribution network.

associated with the options considered in these IAs, which we will consider through the consultation process.

1.1.9. Monetised impacts have been estimated over the period 2023 to 2040 (17 years). This period has been chosen as our proposals 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. Costs and benefits are in real 2018 prices.

1.1.10. Views are also invited on the form and structure of this assessment. An updated impact assessment will be published together with the final proposals document.

1.2. Connection boundary context and high-level findings

1.2.1. The key problem that we seek to address is that charges for connection can create free riding behaviours and lead to unfair outcomes, particularly in the context of growth in demand and generation as we strive to achieve net zero.

1.2.2. In charging for connections to electricity networks, charges 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).

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

1.2.4. 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. We stated that until or unless DUoS (Distribution Use of System) charges provide appropriate cost reflective signals, it remained appropriate to retain some form of locational signal within connection charges. Demand connections, already shallowish at the time, remained unchanged. That these arrangements were successful is evident (see 1.3.2 below).

1.2.5. 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)[3]

	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

[3] Excludes unmetered demand connections (<5% of metered demand connection cost)

1.2.6. We are now considering whether there is 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 are continuing to consider how we best take forward the assessment of DUoS options. We think there is still benefit in continuing with connection charging reform however given the potential benefits in facilitating efforts to achieve net zero, and providing clarity on our proposals to DNOs ahead of the RIIO-ED2 price control. The case for reform is guided by the SCR principles, supported by the modelling by CEPA-TNEI and our assessment of wider benefits and costs.

1.2.7. There are potential efficiency losses as a result of lowering 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 our preferred hybrid option (Demand connections shallow, Generation connections shallowish).[4]

1.2.8. In the case of SP, the loss would be ~£290m.[5] 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. Analytically, we apply break even analysis to test the potential benefits from quicker LCT adoption in the SP scenario. This suggests that if the growth of low carbon generation sources (specifically solar or onshore wind) is brought forward by 9 months, break even is achieved. We welcome views on whether this is likely, or provides useful insight.

1.2.9. The final IA will integrate consideration of the minded-to position on the connection boundary within the wider Access SCR preferred package and this will test the sensitivity of this result.

[4] See section 4.2, figure 4.1 of CEPA-TNEI report
[5] See section 4.2, figure 4.3 of CEPA-TNEI report

1.3. Charging SDG TNUoS context and high-level findings

1.3.1. The key problem we seek to address is that the existing signals for SDG from charging are no longer appropriate. As SDG exports are increasing, we think it should face signals about the cost of using the network. This would help avoid inefficient decisions on scale and location on the network.

1.3.2. Over the past two decades small generators[6] (<100MW) have grown dramatically from circa 1.5GW to 24GW. The number of small onshore wind farms in GB has grown ten-fold from 50 in 2001 to 660 in early 2021[7]. Similarly, the first ground mounted solar farm was operational in 2011 and now there are over a thousand such installations with a total capacity of 8.3GW. At present, all solar farms connect to the distribution system and almost half of onshore wind farms do so. Depending on location, many of these generators utilises the transmission network to reach centres of demand.

1.3.3. Transmission connected generators and distribution connected generators with export capacity greater than 100MW[8] (collectively, large generators (LG)) pay transmission network use of system (TNUoS) charges, which are based on their agreed access to the transmission network ("Transmission Entry Capacity" (TEC)).

1.3.4. In contrast, SDG face transmission charges (via their supplier) that are based on inverse demand for their export during Triad, on the assumption that their output nets off demand in their region. These charges are also capped at zero, which means that, although SDG can earn credits for offsetting demand, they do not face charges, even if they are located in an area where generation exceeds demand, causing generation-driven flows on the transmission network.

1.3.5. The difference in charges faced by different types of generators creates a distortion that incentivises generation to connect in locations and at voltage levels that may not be the most efficient. Therefore, the main concern is with principle (i), in that currently the use that is made of the transmission network by SDG is not reflected in charges.

[6] Distribution connected generators with output of less than 100MW
[7] Source: Renewable Energy Planning Database, March 2021
[8] Generation with export capacity less than 100MW that enters into a Bilateral Embedded Generator Agreement (BEGA) would also face TNUoS charges

1.3.6. Our IAs largely draw on quantitative modelling undertaken by CEPA-TNEI[9] which indicates a potential benefit of £544m[10] from charging SDG TNUoS and removing the boundary distortion between SDG and LG. This supports our principles-based assessment that it is more cost reflective to charge all generation under the same methodology, reflecting the fact they drive the same costs on the transmission system. On this basis, we think the change should be made.

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 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 low carbon technologies, 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. A 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).

[9] See section 5 of CEPA-TNEI report
[10] See section 5.4.1, figure 5.15 of CEPA-TNEI report

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 where service is needed to meet net zero. 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 proposals. A potential negative consequence of our proposals is that some of these users will seek to connect in parts of the network that are already constrained. This will increase costs for all but is balanced against the benefits we expect a change to bring.

2.3. Policy options and justification for the preferred option

2.3.1. The high-level policy options are set out in the table below (and described in more detail in Chapter 3 of the consultation published alongside this impact assessment). We are considering whether to reduce or remove the contribution to reinforcement that is included within the connection charge. It would also be possible to have a different boundary depth for demand and generation (e.g., a 'hybrid' approach).

2.3.2. As well as reviewing the depth of the connection boundary, other complementary changes could be made at the same time. For avoidance of doubt, these could also be made even if leaving the boundary at its current depth. These are:

- 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.

Table 2 - Connection boundary options and potential complements

Depth Option	Potential Complementary Adjustment	Function of complement
1. **Status Quo** ("shallowish" 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. This has supported by stakeholder feedback throughout the development of the Access SCR and in discussion with our challenge group. This impact assessment therefore focuses on the impact of reducing or removing the contribution to reinforcement.

Our preferred option

2.3.4. Our preferred option is to adopt a hybrid approach. This would fully remove the contribution to reinforcement for demand and reduce it for generation. We think this option provides the best balance between removing barriers, encouraging more efficient system development and supporting net zero at least cost.

2.4. Overall monetised impacts (£m) for the preferred option

2.4.1. The 'cost to GB consumers' is identified in the CEPA-TNEI report for basic DUoS reform and different boundary depths. The numbers quoted on the cost of connection are based on modelling work that has been carefully undertaken. However, there are limitations to the precision of these, as outlined in section 3 of the CEPA-TNEI report.

2.4.2. For the preferred option the reforms would introduce a PV of £380m additional costs over 17 years relative to the status quo in the Consumer Transformation scenario.[11]

2.4.3. The equivalent figure for SP is £290m.[12] 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 under consideration 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").[13]

[11] See section 4.2, figure 4.1 of CEPA-TNEI report
[12] See section 4.2, figure 4.3 of CEPA-TNEI report
[13] See page 33 of BEIS's Better Regulation Framework Interim Guidance, March 2020

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 impacts:

- 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, therefore better facilitating competition.
- Reduced greenhouse gas emissions (GHG) through facilitation of the uptake of low carbon technologies.
- 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 impact assessment 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.

Will the policy be reviewed?

2.6.4. This will be considered in reaching an overall decision on the Access SCR.

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

2.6.5. Ofgem has to have regard to the specific requirements of the Public Sector Equality Duty.[14]

2.6.6. The CEPA-TNEI report presents distributional results for TNUoS charging which highlight very small consumer impacts. Our belief is that as connection boundary impacts are of a similar magnitude that there is no practical impact in this respect.

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 constrained parts of the network where expensive reinforcement is required.

[14] 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 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 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 generator 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 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. We are concerned that the current signal within the connection may be too strong for some users. 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 an alternative signals. However, it risks creating barriers to investment or pushing users to accept non-firm connections (with the risk of being curtailed in the future). This is especially in cases where we think behaviour change is unlikely.

3.1.10. On one hand, the connection charge is a clear upfront charge known at the point of investment. However, ongoing charges can also influence investment decision. There is also a risk that it 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. It 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:

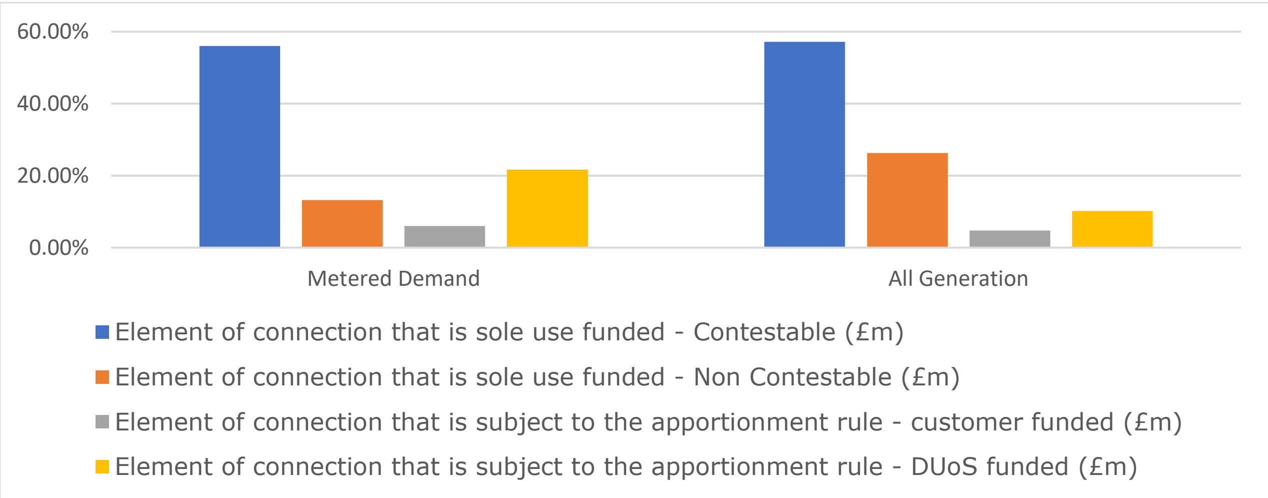
- **Transmission "Plugs"** – it was argued that TNUoS charges, derived on an incremental cost basis rather than connection charges based on an actual cost basis, would provide more efficient signals.

- **Distribution** – we moved from deep to shallowish charges in 2005 as the benefits for competition in generation supported a change but, until or unless DUoS 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 believe to be broadly representative.

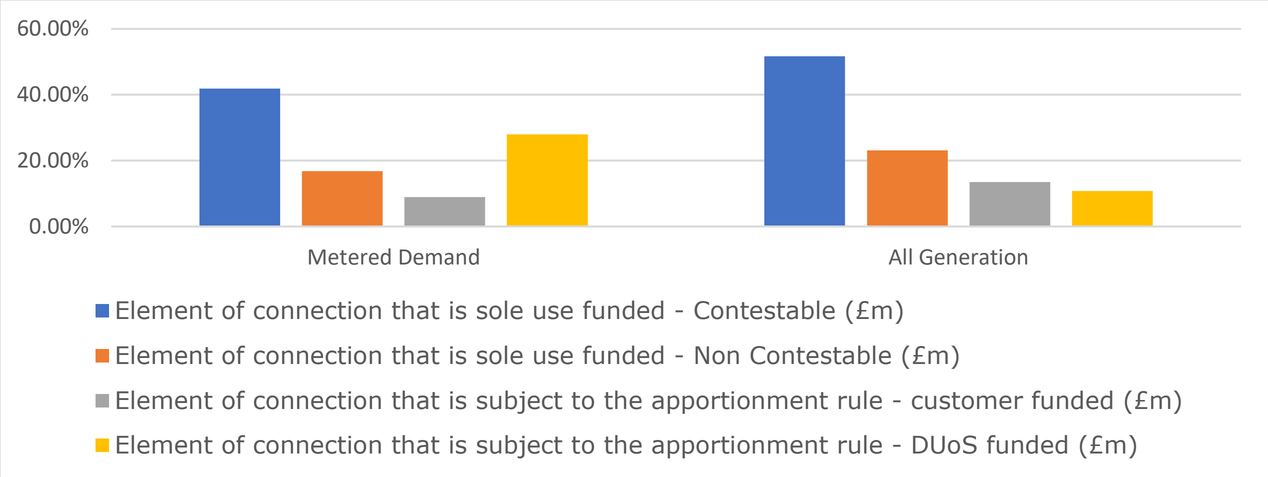
3.1.13. The figures show that the overall percentage of connection costs that are apportioned to connecting customers for reinforcement (i.e., the component of the cost that would be reduced or removed by our change), is small compared to the percentage of costs paid for extension assets. However, the 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[15]



[15] Source: RIIO-ED1 regulatory submissions

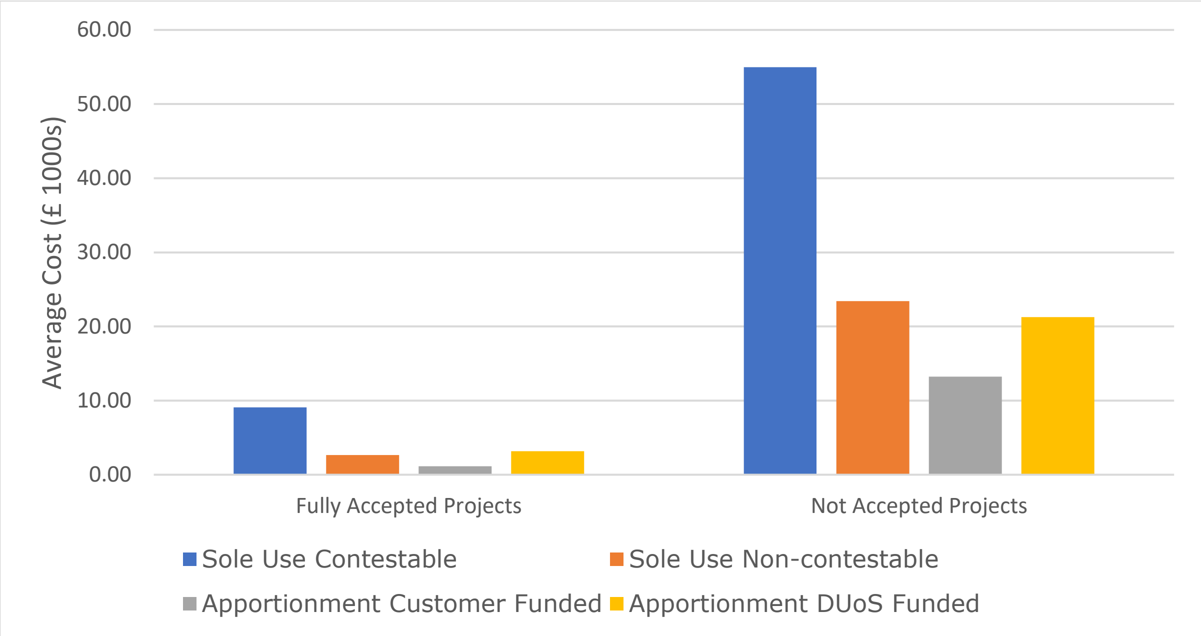
Figure 2 - Percentages of quoted costs for metered demand projects and for generation projects for not accepted offers split by cost category for the 2018-19 reporting year[16]



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 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.

[16] Source: RIIO-ED1 regulatory submissions

Figure 3 - Average costs of for accepted and not accepted connection offers split by cost category for the 2018-19 reporting year[17]



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 conclusion 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.

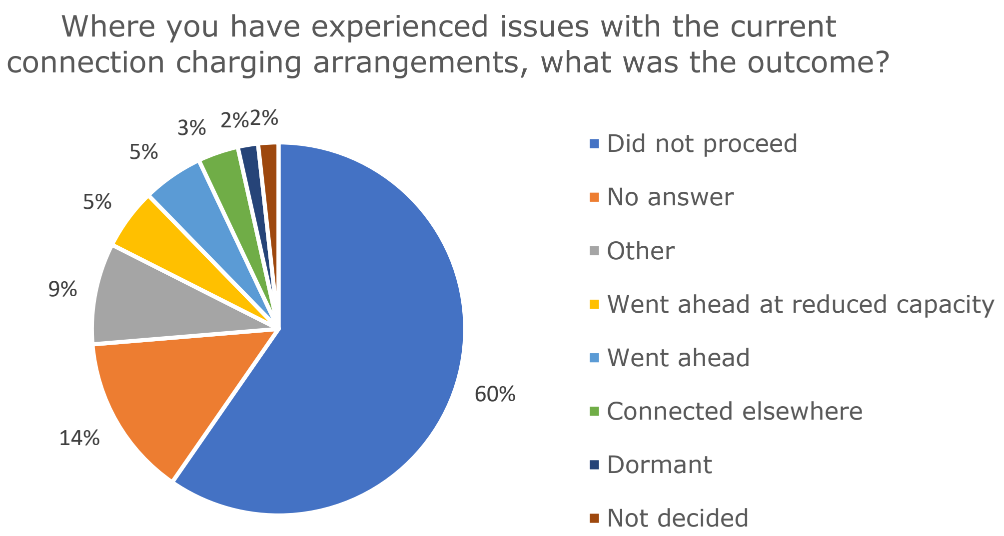
3.1.16. We are mindful though that this is historic data and may not be reflective of a future where we know there will be increased pressure placed on the networks from the electrification of heat and transport, resulting in an increase in connections with less choice as to where for demand, as well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

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

[17] Source: RIIO-ED1 regulatory submissions

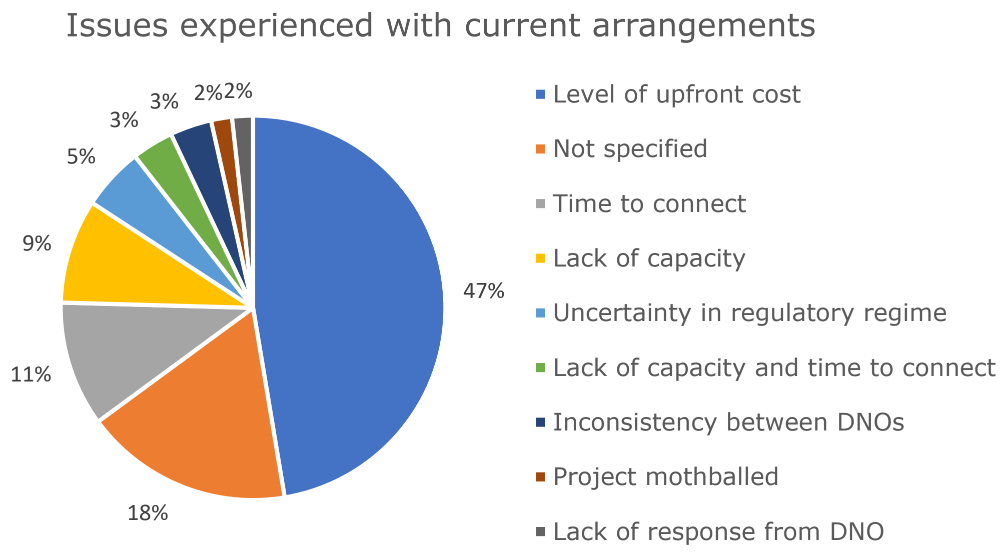
- The ENA issued a call for evidence looking for "shovel-ready" projects that will support the Green Recovery and address key Government policies such as net zero and the decarbonisation of transportation.[18] This funding is aimed at new projects that are struggling to be justified due to network infrastructure 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[19]



[18] [Green Recovery - Energy Networks Association]
[19] 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[20]



3.1.18. On balance, we think this is a strong argument for making a change to the connection charging arrangements at this time. 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.

[20] 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 are generally unwilling 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 (i.e., comparing build and non-build solutions).

Differences between transmission and distribution charging arrangements

3.1.25. Transmission Attributable work (e.g., 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 in Scotland, 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 Chapter 3 of our consultation that we are not minded at this time to make any changes to the treatment of transmission work triggered by a distribution connection.

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. 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.[21]

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.

3.1.29. However, there is evidence to suggest some homes will need a heat pump larger than 10kW. 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

[21] Sixth Carbon Budget - Climate Change Committee (theccc.org.uk)

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.

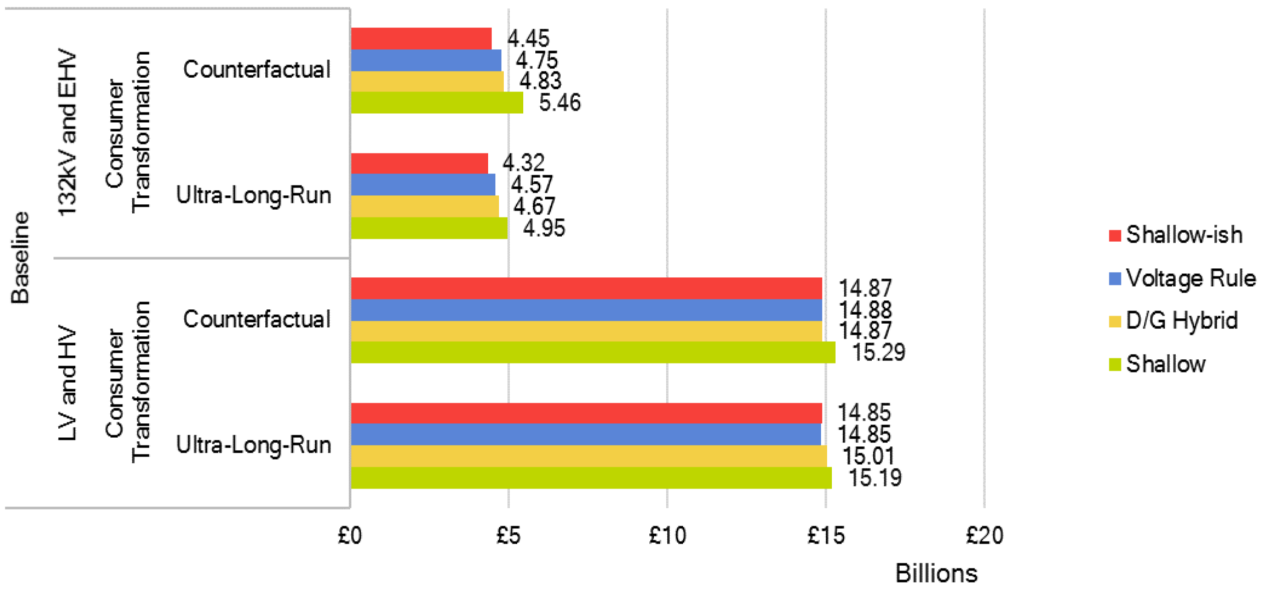
Conclusions

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 which 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 can also say with reasonable confidence 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 relative cost of different boundary depths. This is set out in full in Chapter 5 of their report which is published alongside these IAs. The key results are summarised below:

Figure 6 - Impacts on distribution network costs (PV, £bn); existing DUoS, Consumer Transformation[22]



3.2.2. Figure 6 shows results for CT. It shows that distribution network costs generally increase moving from the status quo option (Shallow-ish) to 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.

Table 3 - Impacts on distribution network costs (PV, £bn) relative to status quo; existing DUoS, by Scenario[23]

	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

22 See section 4, figure 4.1 of CEPA-TNEI report
23 See section 4, figures 4.1 to 4.3 of CEPA-TNEI report

Break even analysis

3.2.3. The CEPA-TNEI modelling is sophisticated and answers questions on locational dimensions of reform. However, 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 this framework is not possible as we would be forced to make assumptions about the elasticity of connection date and connection charges. There is not sufficient evidence to support an estimate of this parameter. Yet, the ability of reforms to speed the uptake of LCT is one of the key factors potentially off-setting costs identified above.

3.2.4. 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 proposals 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 number of years has to be large to generate sufficient benefit to outweigh cost, then a view might be taken on its realism or likelihood.

3.2.5. 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 achieved 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.

3.2.6. 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, FES2020 assumptions on installed capacity show growth rates of solar capacity of around 2GW per annum in CT and LW and 0.60 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.

3.2.7. As shown in Figure 6 shows results for CT. It shows that distribution network costs generally increase moving from the status quo option (Shallow-ish) to 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.

3.2.8. Table 3, the additional system costs under SP are of a similar order of magnitude to CT. The ranking of options by system cost is also similar.

3.2.9. Our results depend on the value of carbon that is potentially saved from earlier decarbonisation than would otherwise occur. Using the central BEIS traded carbon value[24], breakeven is achieved for the preferred D/G hybrid option if all solar and onshore wind connections are made 9 months earlier than expected. Using the BEIS high values, the breakeven point reduces to 6 months (values for the voltage rule are identical). In contrast, the shallow result would require connections to be brought forward by 2 years (high carbon values) or 3 years (central carbon values). These high values seem unrealistic and suggest the it is unlikely that going to shallow connections for generation would deliver value for money in terms of speeding connections alone.

3.2.10. We are aware that this is a simple approach as whether a connection goes ahead can be influenced by a number of 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. We welcome views from stakeholders on how this might be improved for our final decision.

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.

---

[24] See Table 3 in Data tables 1-19: supporting the toolkit and the guidance: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

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[25]. The DNOs have a statutory duty not to restrict, prevent, or distort competition in the supply and generation of electricity[26]. Ofgem considers that network charging is an important mechanism for facilitating competition and protecting the interests of consumers.

3.3.4. We think our proposals 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 proposals would be negative for competition in the provision of connections. We are not proposing 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 proposals are unlikely to have a significant negative impact on competition more generally. Ofgem would not expect implementation costs to constitute a significant barrier to entry in the supply market, and in particular, the proposals are not likely to impose significant new costs on developers of distributed generation.

---

[25] As set out in Section 3A of the Electricity Act 1989

[26] As set out in Condition 4 of the Standard conditions of the Electricity Distribution Licence

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 proposals to have any other greenhouse gas impacts other than those discussed previously (e.g., bringing forward the connection of low carbon technologies).

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 proposals will not have 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 proposals 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 proposals could result in a slowing down of connection requests leading up to implementation and/or a sharp increase soon after.

3.8. Wider impacts

3.8.1. We think our proposals 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.

3.9. Unintended impacts

3.9.1. Some users may choose to delay connections if they perceive a particular direction of policy travel. For example, under the hybrid option, 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 and or capacity market. Notwithstanding any of this, the expected growth in connections may reduce by economic uncertainty (or increased if other interventions incentivise economic recovery following Covid-19).

3.9.2. 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.

3.10. Interactions with other Ofgem reforms

3.10.1. Any change to the depth of connection charges would alter the costs to be recovered through the price control. A shallow(er) charge might also help create opportunities to consider alternatives to traditional reinforcement. A shallow(er) charge might also impact user behaviour (e.g. the number of new connections) and the amount of investment required in new network capacity. Options for reform could impact users' behaviour. This could reduce the need for network investment – or increase it if users site in already constrained parts of the network. Reforms could also lead to a DNOs approaching, and therefore funding, network investment differently. We therefore think there is a strong case for implementing any changes at the same time as the start of the RIIO-ED2 price control. Setting out a minded-to position at this stage allows DNOs to factor this into their final business plans to be submitted in December 2021. Not doing this would almost guarantee the need for a complex and resource-intensive reopener within RIIO-ED2.

3.10.2. There are links between connection charging and DUoS reform. We have proceeded on the basis of no or low change to DUoS in order to provide some information to stakeholders ahead of RIIO-ED2. However, depending on gaining more clarity on DUoS, it may be possible to go further for generation. We will keep this under review as the SCR progresses.

4. TNUoS charging for SDG IA

4.1. Problem statement and strategic case for change

4.1.1. Differences in the charging arrangements for LG and SDG means they face different investment and operational signals. However, the growth in SDG since these arrangements were put in place means that export from SDG can be contributing to costs by exacerbating network constraints. This change in the potential impact SDG has on the transmission network resulted in a recent change[27] to the SQSS[28] to ensure all generation is included in the transport model so that the ESO has visibility of it. We think

[27] GSR016 "Small and Medium Embedded Generation Assumptions": https://www.nationalgrideso.com/industry-information/codes/security-and-quality-supply-standards-old/modifications/gsr016-small-and

[28] The Security and Quality of Supply Standard (SQSS) sets out the criteria transmission licensees must use in the planning operation of the transmission system

the increase in SDG means that it should face signals about the cost of their use of the network. Retaining the differential treatment creates a boundary distortion that leads to inefficient decisions about the size of new generation connections and where to locate on the network.

4.1.2. Our principles based expectation is that removing the distortion will lead to:

- Better locational decisions, as generation responds to signals and locates in zones that are closer to demand and less generation dominated.
- A greater incentive to generation located in southern zones (i.e. closer to demand) to run at periods of high wholesale and balancing mechanism prices, rather than at times when there is a high likelihood of TNUoS credits
- An increase in larger, more efficient, plant – specifically a move from small onshore wind to large onshore or offshore wind.

4.1.3. In turn, this should lead to less transmission network investment, lower constraint management costs, reduced curtailment of renewables and lower carbon emissions (due to decrease in dispatch of conventional tech for constraint management).

4.1.4. We think a decision regarding the future treatment of SDG should be made now, in order to provide some clarity about our view of treatment of distortions, in advance of the next Contracts for Difference round that is expected to occur in December this year. However, as discussed later in this chapter, and in chapter 5 of the main consultation on our minded to positions published alongside this document, we are considering delaying implementation until we have greater clarity on the future role of network charges.

4.2. Objectives of reform to TNUoS charges for SDG

4.2.1. Our review of electricity network access rights and forward-looking charges aims to improve signals to users and to unlock consumer savings, both by encouraging more efficient use of existing network capacity and ensuring an efficient system develops in the future.

4.2.2. We have reviewed the options we are considering in light of our strategic programme on full-chain flexibility, which is seeking to identify the different mechanisms available for incentivising efficient network usage and the role they could play. We have identified those options we consider to be highest priority because they address known distortions and lowest regret. We have continued to assess these in advance of the DUoS reforms, which we have paused so we can consider them in the context of full-chain flexibility.

4.2.3. The option of charging SDG TNUoS charges is one of our highest priorities, as it addresses an ongoing distortion and ensures customers can benefit from reduced system costs, due to a more efficient generation mix in the future.

4.3. Policy options that have been considered and justification for the preferred option

Status Quo

4.3.1. Under the status quo, LG faces TNUoS generation charges, which vary between the 27 generation zones. SDG face charges for export during Triad that are based on the inverse of forward-looking demand TNUoS charges (which vary between the 14 distribution zones). Where the SDG would face charges, this is capped at zero. These charges are applied under the embedded export tariff (EET).

Remove cap from the EET

4.3.2. The option most similar to current arrangements would be to remove the cap from the EET, which prevents SDG facing charges in zones where the forward-looking charge is negative. However, as highlighted in paragraph 5.9

- TNUoS generation charges are based on power flow modelling to determine the cost of the network they use to meet demand, while the EET is calculated as the inverse of demand charges adjusted by the Avoided Grid Supply Point (GSP) Infrastructure Credit.

- The EET only applies to export during Triad, while TNUoS generation charges apply to a generator's transmission entry capacity (TEC), which does not vary by volume

- SDG would receive a perverse signal to reduce export during winter system peak, in order to avoid charges.

Therefore, this would leave a distortion between the treatment of SDG and LG, as they would still be charged under different methodologies and send a perverse signal to generation in locations a long way from demand to reduce their output during Triad in order to avoid charges. Given these significant remaining issues, we decided that, where practical, we should not keep charges under the EET.

Apply TNUoS generation charges to all generation

4.3.3. The alternative, and our preferred option, is to apply TNUoS generation charges to all generation. As described previously, this will remove the difference in charging arrangements between SDG and LG, resulting in more efficient network usage.

4.4. Overall monetised impacts (£m) for preferred option

4.4.1. Although the change to SQSS took place in 2018, a code modification has not yet been raised to reflect it in the Transport Model,[29] which means using the status quo as the baseline for our IA modelling will overstate the impact that charging SDG TNUoS generation charges would have on users. To make sure our IA is measuring the right costs and benefits, CEPA-TNEI have undertaken a two-step process, where they first calculate the impact of adding SDG into the Transport Model and then use this as the baseline for assessing the impact of our reforms.

4.4.2. It should be noted that this does not pre-empt our decision on any modification to reflect the SQSS change in the Transport Model, which may be raised by industry, but is a simplifying assumption applied to our modelling to isolate the impact of our policy change.

[29] The Transport Model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point on the transmission system, based on a study of peak demand conditions

4.4.3. CEPA-TNEI's modelling shows consumer welfare is positive under the Consumer Transformation FES scenario.[30]

Table 4 - Consumer Welfare impact of preferred option

	£m, NPV
Consumer Welfare impact of Preferred Option	544*

**See footnote for breakdown*[31]

3.5.3. SP has a modelled benefit of £643m NPV, and LW a modelled benefit of £311m NPV.[32]

4.5. Hard to monetise impacts for preferred option

4.5.1. 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. We think our reforms will have the following hard-to-monetise impacts:

- Movement of generation capacity between the distribution and transmission networks (compared to a counterfactual without the reforms), as the incentive to connect smaller DG, rather than larger, more efficient, transmission connected generation is removed;
- The cost of implementing the changes, including amendments to commercial arrangements, which will depend on the implementation approach;
- Any potential impact of a change in the generation mix (e.g. an increase in solar instead of onshore wind), including on Security of Supply, although we do not expect there to be a significant impact;
- Increase in distributed generation seeking to connect via private wires;

[30] See section 5.4, figure 5.15 of CEPA-TNEI report
[31] Wholesale price -375, Tariff, 93, Transmission Network 42, Constraint Management 22, RES Support -329, Non-RES missing Money 264, Monetised C02 33, Change in tariff residual 700, Distribution Capacity 95
[32] See section 5.5, figures 5.23 and 5.24 of CEPA-TNEI report

- More participation from distributed energy resources providing balancing services, associated with improved definition of transmission access

4.5.2. We consider that our reforms will have limited impact to no effects on other non-monetary factors, such as potential risk of extreme energy prices and volatility, and should help meet the UK's legally binding energy targets. We also consider that there will be limited to no effects on biodiversity, landscape, land use, water, air quality and soils.

4.6. Key assumptions/sensitivities/risks

4.6.1. The assumptions and sensitivities used in modelling our options are set out in CEPA-TNEI's report published alongside this IA.[33] Some of the key assumptions and sensitivities are:

- The change in TNUoS charges is sufficient to outweigh other factors relevant to decision making, such as availability of renewable resources (e.g. wind).
- The FES are a robust reflection of potential future developments, including changes in planning permissions, in order to support achievement of net zero.
- More cost reflective signals will improve efficiency of siting decisions and dispatch.
- The extent to which charging SDG wider TNUoS generation charges will impact on repowering decisions for existing SDG.
- That we have identified a realistic level of current response to Triad in the counterfactual, which would be replaced with capacity based TNUoS charges.

Will the policy be reviewed?

4.6.2. This is to be addressed as part of the overall minded-to decision.

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

[33] See section 3.5 and appendix A of CEPA-TNEI report

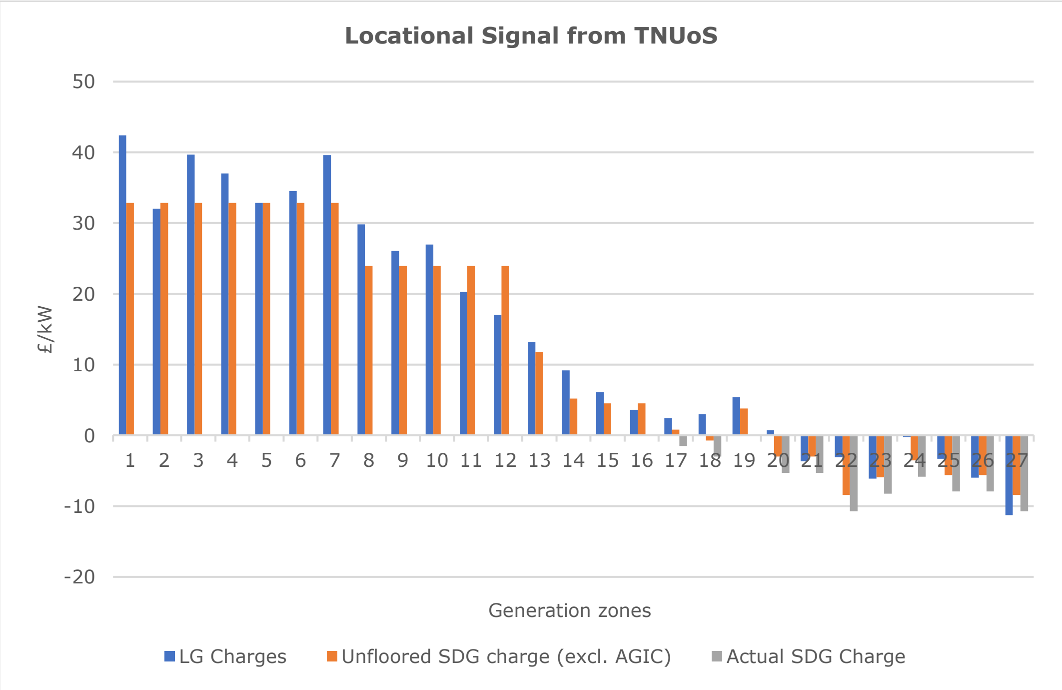
4.6.3. This reform impacts directly on commercial entities and it should not have any directly disparate impact on groups with protected characteristics[34].

5. Evidence base for TNUoS SDG IA

5.1. Problem under consideration

5.1.1. The different charging arrangements faced by LG compared to SDG creates a boundary distortion that incentivises new generation to be classified as SDG, in order to avoid paying charges for the use of the transmission system. This is illustrated in Figure 7, which shows that the difference in charges can be as much as £42/kW in north Scotland.

Figure 7 - Locational signals under TNUoS methodologies



5.1.2. One option we have considered would be to remove the cap on charges that means generation in zone 1-16 do not face actual SDG charges, but this retains unjustified differences in the method used to calculated charges and introduces a perverse signal for generation to turn down during Triad to avoid facing charges.

[34] As set out in the Equality Act 2010

5.1.3. We think removing this distortion is consistent with our wider strategic objective, which is to ensure electricity networks are used efficiently and flexibly, reflecting users' needs and allowing consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general. We also think this is consistent with our work on full-chain flexibility, as it would result in more efficient network usage, reducing the additional flexibility needed to manage constraints.

5.2. Description of options assessed

5.2.1. As described above, in 4.3.2, only two options were taken forward for modelling:

1. **Status Quo** – retain different charging arrangements that charge LG, based on their TEC, but treats SDG as inverse demand during Triad.

2. **Introduce TNUoS charges for SDG** – charge all generation above 1MW on the same basis, removing the boundary distortion. The same charging structure for embedded producers with capacity of below 1 MW would apply but the floor on the charge at zero would be removed.

5.3. Monetary analysis

5.3.1. We have assessed the change against three of National Grid ESO's FES scenarios and summarise the impact below.[35] The cost categories that we assessed under the IA are:

- **Wholesale price** – impact on day ahead prices of a scenario with SDG exposed to TNUoS compared to the EET. Broadly speaking, the EET supresses wholesale power prices at times of peak demand by incentivising small generators to dispatch over and above the wholesale price alone. This combined with the impact on generation mix impacts the wholesale power price. In general, wholesale power prices increase across the scenarios, primarily due to the removal of the EET.

[35] For further detail, see CEPA-TNEI report section 5.

- **Tariffs** – TNUoS charges faced by demand customers which reduce when SDG is charged TNUoS as overall revenue from generators increases, resulting in lower demand residuals.

- **Transmission network** – impact on the cost of transmission network reinforcement. The improved locational signal faced by SDG results in some plant connecting further south and so reducing the need for transmission network reinforcement at key constraint boundaries.

- **Constraint management** – impact on the costs of changing the output of generators through the Balancing Mechanism to resolve transmission constraints. Under scenarios with high renewables and demand (e.g. Consumer Transformation) these costs reduce significantly when SDG is exposed to TNUoS due to the impact on locational decision; while under scenarios with less renewables and demand (e.g. SP) these costs are much lower and increase slightly when SDG is exposed to TNUoS.

- **RES support** – policy costs (e.g. CfD payments).[36] These costs increase across the scenarios, reflecting the higher costs faced by renewable SDG when exposed to TNUoS costs.

- **Non-RES 'missing money'** – security of supply support costs (e.g. Capacity Market payments).[37] These costs decrease in all scenarios as the increase in wholesale power prices increases the revenues which generators can achieve in the wholesale market and so decrease the support required.

- **Monetised CO_2** – costs paid by carbon intensive generators historically under the EU Emissions Trading System (ETS) and now under the UK ETS, and UK Carbon Price Support. These costs decrease across the scenarios due to demand changes and because dispatch is more efficient, requiring less carbon emitting generators.

- **Change in tariff residuals** – refers to any over or under recovery of revenue, which are assumed to be ultimately passed through to customer energy bills in the modelling.

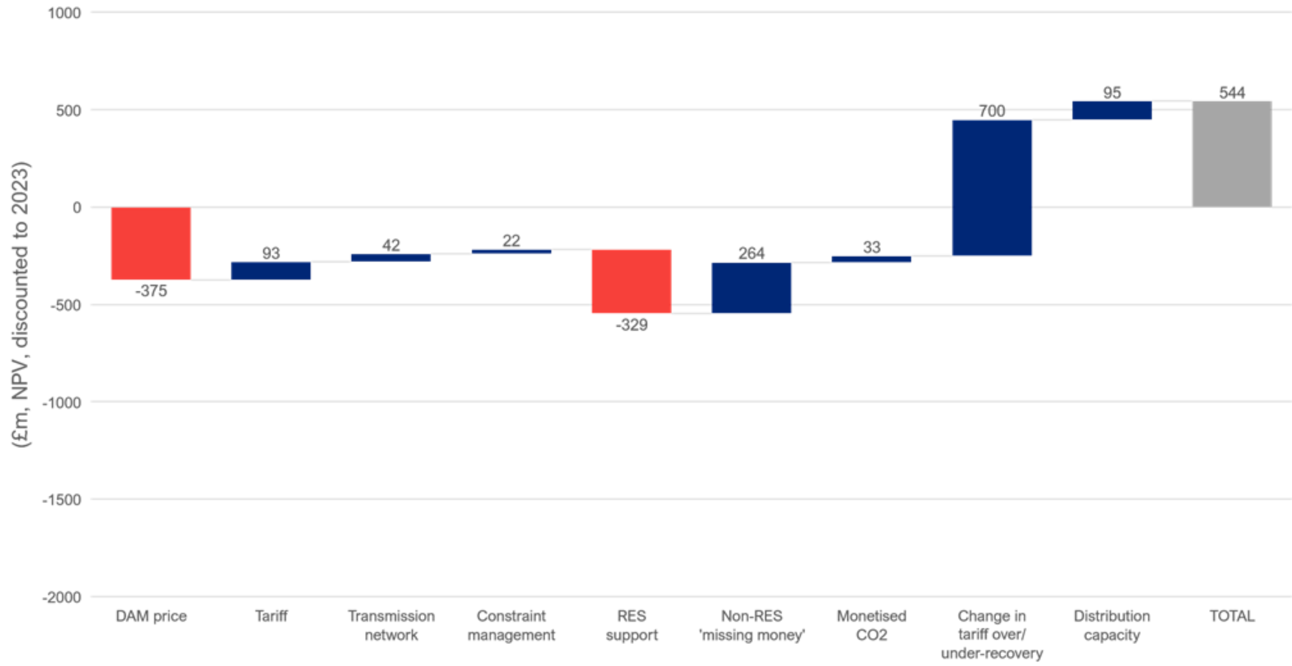
[36] These are calculated based on the difference between the revenues which RES are able to achieve and the level of investment required to reach the desired level of renewable roll-out.
[37] These are calculated based on the difference between the revenues which non-RES are able to achieve and their fixed operational costs plus annuitised capex costs (for new capacity), or going forward fixed costs (for existing capacity).

Consumer transformation

5.3.2. Under the CT scenario, we expect our reforms to have a positive NPV of £544M for consumers. The key contributors to the NPV are:

- **Impact on TNUoS tariffs** – exposing SDG to TNUoS results in a larger contribution to TO and ESO allowed revenue from generation, and so reduces demand residual charges for consumers; *(PV +£700m)* and
- **Reduced capacity support costs** ("Non-RES Missing Money") driven by higher wholesale prices reducing the extent to which support is needed to incentivise development of new generation capacity; *(PV +£264 m*) offset by
- **Increase wholesale power prices**, driven by incentives for producers to dispatch during expected Triad periods;(*PV -£375m*) and
- **Increased RES support costs** driven by the need for additional RES support to offset the increase in TNUoS charges for SDG. While the increase in TNUoS for SDG drives an increase in total RES support costs, it will also ensure that they are more appropriately targeted as there will no longer be a TNUoS distortion between LG and SDG when competing for RES support (*PV -£329*).

Figure 8 - Consumer welfare impacts under CT (figure 5.15 in the TNEI-CEPA report)



5.3.3. SP has a higher NPV of £643m and LW has a lower NPV of £311m. These are illustrated graphically in section 5.5 of the CEPA-TNEI report, figure 5.23 and 5.24

5.4. Hard to monetise impacts

Other system costs and benefits

5.4.1. The monetised results do not represent the full impact that we expect to see from this change. Because the modelling includes a fixed exogenous rollout of renewables, it does not capture the benefit of any movement between the distribution and transmission networks, as the incentive to connect as SDG is removed. This should result in an increase in more efficient transmission connected projects, leading to a further reduction in costs.

5.4.2. Our reforms should lead to changes in the generation mix, with an increase in larger onshore and offshore wind in Scotland and solar and wind projects in southern zones. However, our modelling does not capture any potential impact of changes to the generation mix and whether it has any implications on Security of Supply, though we would expect any such impact to be limited.

Competition impacts

5.4.3. We think our reforms will have a positive impact on competition by removing an undue distortion between different types and location of generation. For example, a 10MW onshore windfarm in the North of Scotland will currently pay TNUoS if connected to the Transmission system. A similar windfarm may be in close proximity and pay none as it is connected to the distribution system.

Security of supply impacts

5.4.4. We consider that our reforms will have limited impact on other non-monetary factors, such as potential risk of extreme energy prices and volatility.

Other greenhouse gas impacts

5.4.5. We do not expect our proposals to have any other greenhouse gas impacts other than those quantified.

Other environmental impacts

5.4.6. The policy will have limited to no effects on biodiversity, landscape, land use, water, air quality and soils.

Implementation costs

5.4.7. The ESO does not currently have a contractual relationship with SDG[38] which means there will need to be changes to the current arrangements to enable SDG to be charged TNUoS. We have identified several options for how the new arrangements could operate, summarised below and described in detail in our consultation on our minded to position. The ESO could contract with:

- SDG to establish the TEC required by each generator. Charges could be levied by the supplier it respect of their SDG customers, who already receive EET benefits in respect of contracted generation, where applicable.

[38] The exception to this is where SDG has entered into a Bilateral Embedded Licence Exemptible Large Power Station Agreement (BELLA). Note that, where SDG has entered into a Bilateral Embedded Generator Agreement (BEGA), they already face TNUoS charges and so would not be impacted by our reforms.

- Each DNO for the total level of capacity that DNO needs for their directly connected generation, with the ESO charging the DNO and the DNO responsible for charging the supplier for their customers' share of TNUoS charges.

- Each supplier who would agree the total level of capacity required for their customers, with charges levied on suppliers by ESO and passed on to generators, based on commercial agreements with their supplier.

5.4.8. Although our initial view is that the most straightforward and transparent option is for the ESO to enter into simplified contractual arrangements with each small generator, we recognise this would increase administrative complexity for SDG. We are seeking respondents' views on each option, including any significant challenges with them.[39]

5.4.9. Because of the uncertainty regarding the preferred option and how it would operate in practice, we have not been able to quantify the impact of the changes as part of our IA. However, we do not expect the costs incurred to be significant for individual generators or occur on an ongoing basis.

5.5. Distributional Analysis

Changes in TNUoS charges

5.5.1. Introducing TNUoS charges for SDG will result in SDG located in northern zones a long way from demand facing charges while those in southern zones are likely to see an increase in their credits. Table 5.1 of the CEPA-TNEI report shows the change in tariffs as a result of removing the floor on the EET for users with export capacity below 1MW. Tables 5.2 and 5.3 show the impact on 2024 and 2040 tariffs for SDG moving from EET to TNUoS generation charges, with generation in northern Scotland facing charges of up to £54/kW by 2040.

[39] See question 5f in the main consultation on our minded-to proposals, published alongside this document

Changes in producer revenues

5.5.2. Our IA modelling also identifies the distributional impact of the change on producer revenues across transmission and distribution charging zones under both the CT and SP scenarios. The impact is similar under both scenarios:

- A slight increase in revenue for transmission connected generation in Scotland, and a decrease in revenue for distribution connected generation in Scotland.
- A significant reduction in revenue for distribution connected Scottish renewables, which are commonly SDG.
- A small negative impact on some distribution connected generation in southern zones, due to the removal of the EET benefit.

5.5.3. Table 5.9 of the CEPA-TNEI report shows the change in producer revenues over the modelled period (CT). In brief, at the transmission level, there are relatively high increases net revenues in the North of Scotland, the most marked being positive NPV impacts of circa £16.7m for offshore wind and £12.7m for onshore wind. In T2 (the rest of Scotland), there is a positive NPV impact of circa £11.1m for offshore wind and £16.2m for onshore wind.

5.5.4. At the transmission level, in total, there are most significant overall benefits to offshore wind and onshore wind. The most marked effects are in T2 (for onshore wind) and T4 for offshore wind (circa £18.4m positive NPV).

5.5.5. The nature of the reforms means that, at the distribution level, Scottish RES is most adversely impacted overall, with the largest negative impact for distributed onshore wind. When individual distribution zones are considered, all technologies sited in D7 benefit (with particularly high positive impacts for onshore wind and solar). D12 stands out as a zone in which 6 technologies experience small adverse effects.

Figure 9 - Total impact on net revenues of transmission and distribution connected producers (2024 - 2040, CT)

	T1	T2	T3	T4	T5	T6	T7
Offshore_wind	16.73	11.14	17.72	18.41	6.62	20.51	1.82
CCGT_existing	1.45	0.07	0.08	-1.60	11.83	-0.99	2.43
CCGT_new	-	-	-	4.41	-0.20	-	0.07
OCGT_existing	-0.02	-	-	0.08	0.17	-	0.14
OCGT_new	-	-	-	0.11	0.27	-0.09	0.02
H2_CCGT	-	-1.80	-5.39	-1.79	-1.81	-	-
Onshore_wind	12.69	16.24	-	0.71	-0.01	-	-
Solar	-0.32	-0.22	-	0.01	-1.48	-0.18	0.28
Nuclear	-	9.32	6.58	-2.59	-1.13	5.55	-0.54
Biomass	-1.52	0.43	-3.84	12.14	1.04	0.13	-
Hydro	-0.59	-0.14	-	-0.00	-6.79	-	-0.01
Pumped_storage	-7.82	-2.73	-	-7.42	-	-	-
Battery	-0.42	-0.83	-0.86	-0.62	-5.15	-0.63	-5.27
TOTAL	**20.19**	**31.48**	**14.28**	**21.85**	**3.36**	**24.29**	**-1.07**

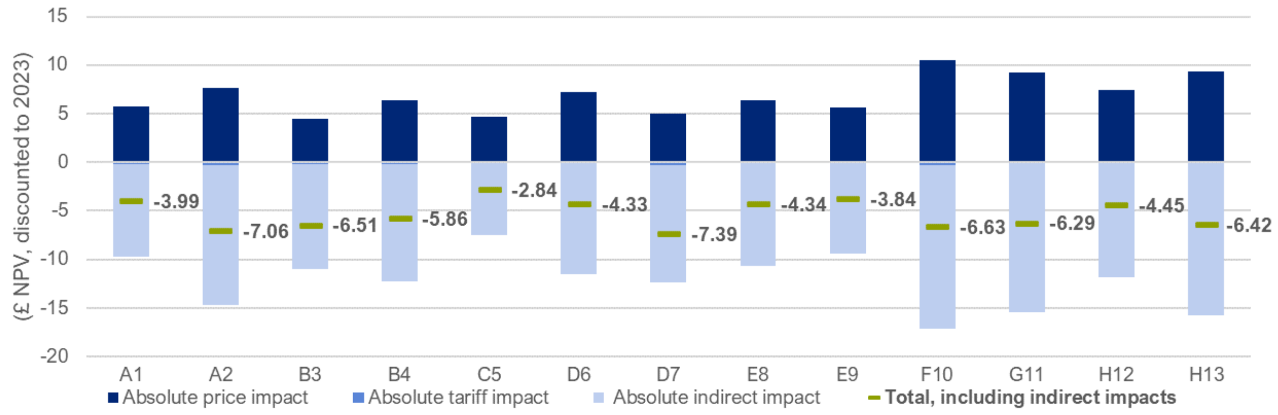
	D1	D2	D3	D4	D5	D6	D7	D8	D9	D10	D11	D12	D13	D14
CCGT_existing	0.86	2.05	3.32	5.39	7.09	8.91	15.79	-	2.74	6.77	-0.39	-	-2.05	0.88
CCGT_new	-	-	0.16	0.07	19.34	1.66	1.56	1.74	-	-	-0.04	-0.47	-	0.17
OCGT_existing	0.29	-	0.82	1.40	-	1.00	0.79	0.61	-0.13	-	0.10	-	1.73	3.20
OCGT_new	-	-	2.18	0.92	1.39	0.01	6.30	0.43	0.91	1.73	-0.12	-2.30	-0.37	1.02
GT	2.03	0.39	1.52	22.02	29.43	15.69	41.02	15.06	7.18	22.42	1.63	-0.63	7.58	4.96
H2_CCGT	-0.25	-0.24	0.04	0.86	1.93	1.39	2.43	1.12	0.77	1.47	0.26	0.03	0.64	0.45
Onshore_wind	-976.51	-881.88	69.47	75.79	150.77	42.58	174.08	5.76	-4.86	6.70	-7.40	-0.44	4.19	-4.42
Solar	-63.89	-49.01	-3.60	-73.70	62.93	31.36	203.06	118.38	178.32	76.77	72.62	9.85	223.32	186.29
Biomass	-38.03	-39.50	-22.38	14.74	70.92	23.15	37.00	73.94	33.13	15.65	14.91	-2.80	9.77	17.08
Hydro	-489.19	-46.83	-0.22	0.59	0.56	5.89	0.54	22.00	0.19	57.80	0.11	0.07	0.42	1.80
Battery	0.29	-0.23	0.05	0.08	0.10	0.39	0.09	0.12	-0.11	-0.02	-0.48	-0.06	-0.16	0.14
TOTAL	**-1,564.40**	**-1,015.25**	**51.37**	**48.17**	**344.47**	**132.03**	**482.66**	**239.16**	**218.15**	**189.29**	**81.20**	**3.25**	**245.07**	**211.58**

Changes in consumer bills

5.5.6. For distributional analysis the Centre for Sustainable Energy developed a series of archetypes for us.[40] Figure 10 shows the absolute impact on bills (NPV) over the full appraisal period resulting from the combination of welfare effects. This figure shows that consumers face an increase in bills due to the impact of TNUoS reform on the DAM price but face an overall decrease in bills as a result of the combination of welfare impacts. The highest NPV saving of £7.39 for the D7 archetype equated to 60p per annum.

[40] Ofgem energy consumer archetypes: https://www.ofgem.gov.uk/system/files/docs/2020/05/ofgem_energy_consumer_archetypes_-_final_report_0.pdf

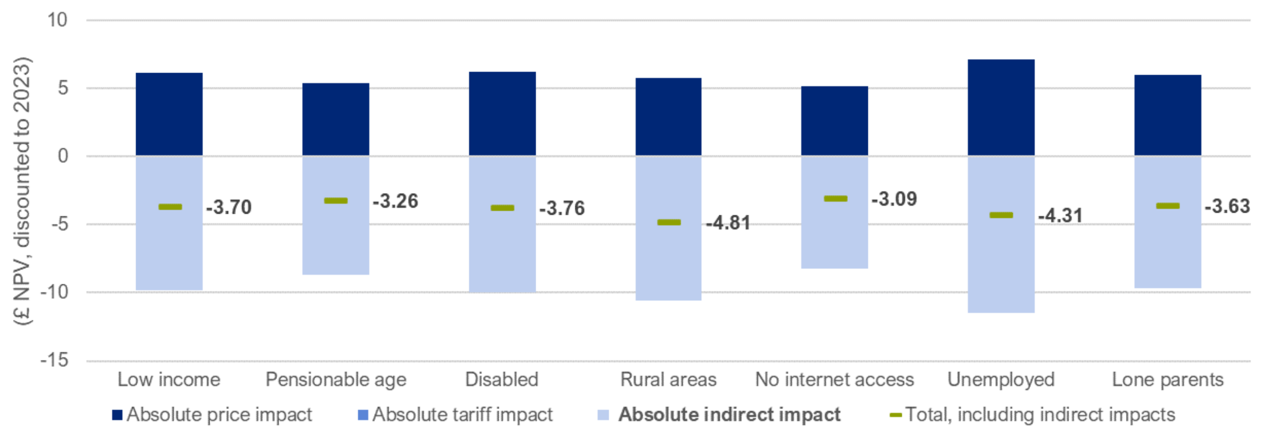
Figure 10 - Total impact on bills for Ofgem's domestic consumer archetypes (NPV, discounted to 2023)



Statutory archetypes

5.5.7. CEPA-TNEI highlight that our statutory archetypes are generally later adopters of EVs and heat pumps and therefore are less responsive to higher price periods in the modelling. This means that they face bill impacts which are generally in proportion to the average total electricity consumption for that archetype. The highest total saving is in Rural Areas, where almost £5 NPV could be saved (40p per annum).

Figure 11 - Total impact on bills for Ofgem's statutory consumer archetypes (NPV, discounted to 2023)



5.5.8. Our distributional framework allows for the identification of Equity-weighted domestic bill impacts and impacts as a percentage of income. The CEPA-NEI presents results for price and tariff effects only and also including indirect bill impacts.

5.5.9. Impacts on commercial non-domestic archetype consumer bills and large industrial and commercial non-domestic archetype consumer bills are also considered.

5.6. Risks and key assumptions

Key assumptions

5.6.1. CEPA-TNEI's report provided alongside this IA set out the assumptions that underpin the modelling results.[41] However, the ones that have a significant influence on the results are:

- Owing to the structure of the model CEPA-TNEI are using, some of the nuances of the variation in TNUoS tariffs may not be drawn out (i.e. there are 27 generation, and 14 demand zones for charging – CEPA-TNEI are using 7 broad geographical regions).
- Overall installed capacities per technology type are exogenous and actual volumes generated and location of plant are endogenous (within bounds that limit the extent that generation can move between zones).
- The FES are assumed to be a robust reflection of potential future developments, including changes in planning permissions, that will be needed in order to support achievement of net zero.
- Our modelling of how users respond to the current charging arrangements (e.g. Triad signals), in order to understand the impact of our reforms.

Key risks

5.6.2. We think there are two key risks associated with our reforms, with the first being that assumptions underpinning the FES that achieve net zero do not materialise, undermining our benefits case. In particular, if there are not changes to planning permissions in England, then generation may not be able to move zones in response to

[41] See section 3.5 of CEPA-TNEI report

TNUoS. Therefore, benefits associated with lower constraint costs or reduced transmission investment may not materialise.

5.6.3. The other key risk is that our modelling has not sufficiently identified the impact of our reforms on repowering decisions, due to the fact it is based on generic generation assumptions, rather than the impact on different renewables located around GB. We think there is a risk that, if existing generators facing significant increases in TNUoS charges (up to £30/kW) choose not to repower and alternative generators are not able to internalise the impact, then some network assets built to provide capacity will become stranded.

5.7. Wider impacts

5.7.1. We think our reforms will have a positive impact on competition by removing an undue distortion between different types of generation. However, we recognise that some stakeholders believe that, because of its role in supporting net zero, SDG should not face charges for locating in areas far from demand. Our view is that:

- Removing the distortion will enable other renewable projects to be developed, including at transmission level, where there is scope for more efficiently sized generation

- The role of network charges is to send cost reflective signals to incentivise efficient network usage, rather than to apply distortions or cross-subsidisation to achieve government goals. Instead, these should be supported through direct subsidies or other policy interventions.

5.7.2. With regards to our Public Sector Equality Duty, which focuses on eliminating discrimination and advancing equality of opportunity, we do not think our reforms have an impact on or achievement of this duty. This is particularly the case for vulnerable consumers (e.g. disability and age).

5.8. Unintended impacts

5.8.1. We have considered the risk of our reforms having unintended impacts and have not identified any material consequences at this stage.

5.9. Interactions with other Ofgem reforms

5.9.1. Although we believe it is the role an economic regulator to address known distortions, we are mindful of the interaction with several other reforms, which mean there may be merit in delaying implementation:

- The change will have a significant impact on small generators in northern areas, including existing generators
- There is increasing evidence of problems with the overall transmission charging methodology that make it uncertain whether this change should be made in isolation
- We need to consider the role transmission charges will play in incentivising more flexible network usage, which is being considered as part of the full-chain flexibility strategy.

5.9.2. Given the uncertainty about the impact of future changes on TNUoS charges over the short/medium term, we are considering whether we need to mitigate the impact in the short term, options for which are summarised in Table 5. We are consulting on these options as part of our minded to consultation[42], in order to ensure we have identified all the implications of each option.

5.9.3. In addition to these options, we are considering whether to apply time limited grandfathering, which would retain the current arrangements for a group of small generators. We recognise there are several challenges with this, including setting parameters for determining who the grandfathering applies to and the fact that grandfathering means any future improvements to the charging arrangements would not apply either.

Table 5 - Implementation options

Option	Assessment
Immediate	• Removes the distortion most quickly

[42] See question 5e in the main consultation on our minded-to proposals, published alongside this document

	• Does not allow users time to reflect changes in commercial arrangements • Small generators may face further significant change in charges following wider transmission charging review
Phase over several years	• Would start to address the distortion and clearly signals future impacts • Gives generators time to manage their commercials before facing the full impact
Delay until a wider review has happened	• There are a number of other issues with the transmission charging methodology, which mean a wider review of charges is merited • Retains the distortion for several years but would remove risk of increased cost of capital/disruption caused by multiple changes in a short time

5.10. High level description of monitoring and evaluation plan.

5.10.1. Our decision to charge SDG TNUoS charges is largely a principle-led decision, as we think as an economic regulator, it is right that we should remove a boundary distortion to increase efficient use of the network. However, as described above, we also recognise the significant uncertainty around the future of network charges, which means it may not be efficient to send a signal now that may change in a few years.

5.10.2. Given these factors, we have not identified a monitoring programme to assess the impact on the change on future network efficiency and repowering decisions for existing generators. Depending on the further clarity we have about our wider program of work at the time we make our final decision, we will address this as part of our final IA.