Consultation

Access and Forward-looking Charges Significant Code Review: Consultation on Minded to Positions

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We are consulting on minded to positions for three key areas of our Access and Forward-looking Charges Significant Code review: distribution connection charging, the definition and choice of access rights, and transmission charges for small distributed generators.

We would like views from people with an interest in these areas. We particularly welcome responses from the users of the electricity network who these proposals may affect. We would also welcome responses from other stakeholders and the public.

This document outlines the scope, purpose, and questions of the consultation and how you can get involved. Once the consultation is closed, we will consider all responses. We want to be transparent in our consultations. We will publish the non-confidential responses we receive alongside a decision on next steps on our website at **Ofgem.gov.uk/consultations**. If you want your response – in whole or in part – to be considered confidential, please tell us in your response and explain why. Please clearly mark the parts of your response that you consider to be confidential, and if possible, put the confidential material in separate appendices to your response.

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Purpose of our review

Our energy system is undergoing a radical transformation as the process of decarbonisation, digitisation and decentralisation accelerates to achieve Net Zero. We are undertaking a package of reforms to enable competition, innovation, and decarbonisation at lowest cost, and to protect consumers in the transition to a smarter, more flexible, and low carbon energy system.

These reforms include a comprehensive review of electricity network charging to identify and improve the signals users face about their impact on the networks. This is being undertaken through two closely linked reviews:

- The **Access and Forward-looking Charges Significant Code Review** (Access SCR), which is the focus of this consultation, is looking at the 'forward-looking charges' which send signals to users about the effect of their behaviour on the networks; and

- The **Targeted Charging Review** (TCR) has examined the 'residual charges' which recover the remainder of the total network charges needed to fund network expenditure.

We expect that these reforms will result in more efficient choices about where users locate on the networks and how they use them on an ongoing basis, which will support Ofgem's objective of achieving Net Zero at least cost.

Our proposals for distribution network connection charges

Customers connecting to distribution networks currently face an upfront charge made up of the cost of new assets needed to connect to the existing network, and a contribution towards the reinforcement of existing shared network assets. This approach was originally intended to provide a signal to customers to avoid constrained parts of the network where expensive reinforcement is required.

We have been reviewing whether current connection charging arrangements are continuing to work in the best interests of consumers – especially in light of increased investment needed as we electrify heat and transport. We think there are good arguments that the charging arrangements no longer provide an effective signal for network users and may actually slow down the roll-out of low carbon technologies across the energy system.

We are therefore minded to change the connection charging arrangements. We propose reducing the contribution to reinforcement within the upfront connection charge for generation and removing it completely for demand. This comes at a cost, but we think this is the right balance between maximising benefits such as removing barriers (particularly for those where we think their ability to relocate in response to a connection charge signal is limited), and doing so at least cost to consumers generally.

Our proposals for improved definition and choice of access rights

Network access rights define the nature of users' access to the network and the capacity they can use – how much they can import or export, when and for how long, and whether their access is to be interrupted and what happens if it is. For most users, this information is defined via their connection agreement. Users generally have had limited choice of access rights and, where choices have been introduced, some of them have been loosely defined and require users to potentially face undefined levels of curtailment.

We are minded to introduce the following low regret access rights choices:

- **Levels of firmness**: This would provide choices about the extent to which a user's access to the network can be restricted and their eligibility for compensation if it is restricted.
- **Time-profiled access**: This would provide choices other than continuous, year-round access rights (e.g. 'peak' or 'off-peak' access).

We are also minded not to proceed with **shared access**, which would allow users across multiple sites, in the same broad area, to obtain access to the whole network, up to a jointly agreed level. This is because there is significant uncertainty around the take-up of the option, and we have concerns about how practical it will be to implement.

Our proposals for ongoing transmission network charges

National Grid Electricity System Operator charges users for the use of the electricity transmission system to transport electricity from generators to demand customers. Currently, generators face different charges, depending on their size and where they connect to the network. Most notably, large generators face transmission network use of system (TNUoS) generator charges, while small distributed generation (SDG) faces the Embedded Export Tariff which includes the inverse demand locational charge. The Embedded Export Tariff is capped at zero (i.e. SDG may receive credits, but not charges).

We do not think the impact export has on the transmission networks differs between the size of the generator or whether they are connected at transmission and distribution and, therefore, the differences in the charging arrangements between large generation and SDG creates a distortion that can lead to inefficient network usage. To address this, we are minded to introduce a change so SDG also faces wider TNUoS generator charges, although we recognise there may be practicality and proportionality considerations that mean we need to apply a threshold to the size of generator the changes apply to.

Although we think removing the distortion will result in users making more efficient investment decisions, we are currently considering how our reforms align with our work on Full Chain Flexibility (FCF), including the role of network charges.[1] Over the course of the SCR we have also identified potential issues with TNUoS charges, which mean we think there may be benefit in undertaking a more holistic review of charges to ensure they are fit-for-purpose in the medium to long term.

This wider uncertainty means we are considering different implementation options, including delaying any decision to introduce TNUoS charges to SDG until we have greater clarity around the role of network charges, and whether grandfathering any aspects of current arrangements would be proportionate and non-distortive for a subset of generators.

[1] Full Chain Flexibility is one of the strategic change programmes identified in our Forward Work Programme 2021/22: https://www.ofgem.gov.uk/publications/forward-work-programme-202122

1. Context

Enabling a decentralised, decarbonised, and digitalised energy system

1.1. Our energy system is undergoing a radical transformation as the process of decarbonisation, digitisation and decentralisation accelerates. Across Ofgem, we are undertaking a package of reforms through our Forward Work Plan 2021/22 to enable competition and innovation, decarbonisation at lowest cost and to protect consumers in the transition to a smarter, more flexible, and low carbon energy system.

1.2. As the share of intermittent renewable generation rises, and electricity demand from heat and transport grows, the electricity system will need to become more flexible if system costs are to be minimised. The potential for energy flexibility to reduce costs as we transition to a net-zero system is widely acknowledged.

1.3. Delivering FCF in how energy is generated, used and stored is one of our five identified strategic change programmes.[2] We have established an FCF programme to deliver a secure, affordable, net zero system where all connected resources can contribute their full efficient potential to meeting system needs, by flexibly responding to available energy and network resources. This build on the work we have been doing with BEIS to deliver a smarter, more flexible energy system through the Smart Systems and Flexibility Plan. Through this programme, we will consider options and opportunities to unlock flexibility, as we decarbonise the system and protect the interests of consumers.

Fit with the wider Future Charging and Access Programme

1.4. Our Future Charging and Access programme sits alongside our FCF programme and is an important part of these wider reforms. Our programme of work aims to ensure that the arrangements for electricity network access and charging continue to support an increasingly decentralised, decarbonised, and digitalised energy system, while ensuring that the interests of consumers continue to be protected. In addition to the Access SCR and TCR, the

[2] Our full set of strategic change programmes and enduring priorities are set out in our Forward Work Programme 2021/22: https://www.ofgem.gov.uk/publications/forward-work-programme-202122

programme includes the Balancing Services Charges Task Force, which is considering who should be liable for balancing services charges and how they should be recovered.

1.5. Through the TCR, we aimed to ensure that all users pay a fair share towards the costs of the existing networks and systems, whilst supporting efficient decisions and reducing harmful distortions to the forward-looking, cost-reflective charges.

1.6. Our Access SCR is focused on improving these forward-looking signals and is an important element of our wider work to enable greater use and value of flexibility. We are aligning our Access reforms with the approach that will emerge from the FCF work and have fed our initial findings into our work with BEIS on the new joint Smart Systems and Flexibility Plan.

1.7. Our reforms have close links to RIIO-ED2 – consumers will see the benefits from a more efficient network largely through the price control and Distribution Network Operators' (DNOs) business plans. The Access reforms' interactions with RIIO-ED2 are set out in more detail in Chapter 6, and we are working with DNOs to decide the best way to manage the implications of potential changes over the course of 2021 in their final business plan.

The Access and Forward-looking Charging SCR

1.8. We launched the Access SCR in December 2018, because we thought that current access arrangements and forward-looking charges[3] will not adequately achieve the potential savings of a more dynamic and flexible system.[4]

1.9. The Access reforms will be an enabler of our strategic priorities in our 2021/22 forward work programme[5] to enable investment in low carbon infrastructure at a fair cost and deliver FCF. Making the best use of network capacity and having effective signals that reflect how users can create costs and benefits on the networks is critical to the development of a flexible

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[3] By "access arrangements" and "forward-looking charges" we mean:
Access arrangements – the nature of users' access to the electricity networks (for example, when users can import/export electricity and how much) and how these rights are allocated.
Forward-looking charges – the type of electricity network charges which signal to users how their actions can ether increase or decrease network costs in the future.
[4] More information on the background to the launch of the SCR can be found in our launch statement - https://www.ofgem.gov.uk/system/files/docs/2018/12/scr_launch_statement.pdf
[5] Ofgem's forward work programme for 2021/22 - https://www.ofgem.gov.uk/publications-and-updates/forward-work-programme-202122#Our%20focus%20for%C2%A02021/22

and dynamic future energy system, which can accommodate these new technologies and facilitate the decarbonisation of the energy system in an efficient way.

1.10. The Access reforms will also be consistent with our enduring priorities to protect the interests of consumers, support vulnerable consumers and advance decarbonisation. The objective of the SCR is to ensure that 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. There are significant potential savings from a more dynamic and flexible system. There could also be significant wider system savings through ensuring there is a level playing field for different types of energy service providers to compete on.

1.11. The scope of the SCR includes:

- A review of the definition and choice of access rights for transmission and distribution users
- A wide-ranging review of distribution network charges (Distribution Use of System (DUoS) charges)
- A review of the distribution connection charging boundary
- A focused review of transmission network charges (Transmission Network Use of System (TNUoS) charges).

1.12. Through the Energy Networks Association's Open Networks project, the Electricity System Operator and network companies are separately taking forward a review of aspects of the allocation of access rights, including improved queue management and the scope for trading. For updates on this work, please refer to the Open Networks project website.[6]

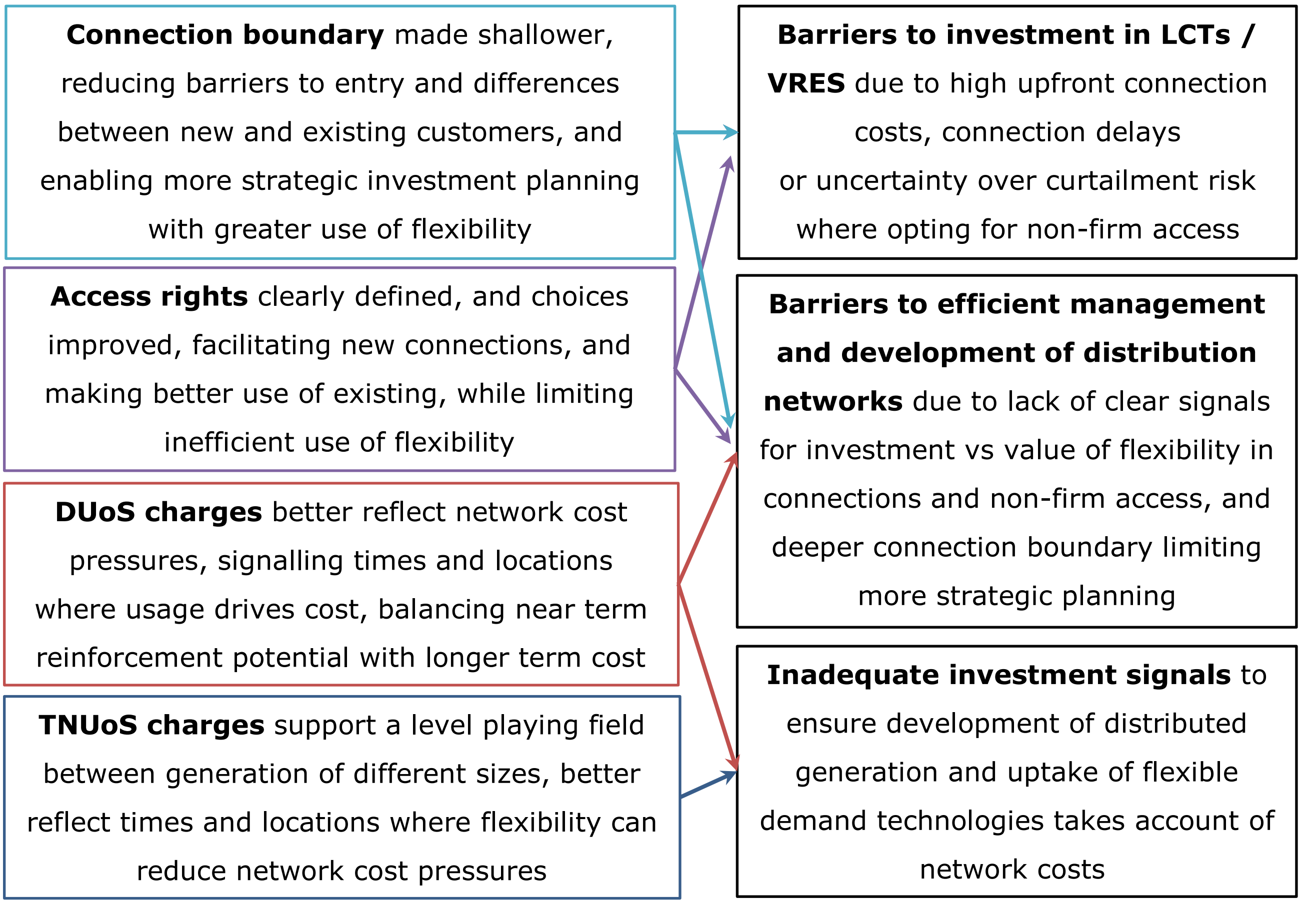
1.13. A key driver of our reforms is to make network charges more reflective of the costs that users confer on the network. We expect that more cost reflective signals could drive a range of beneficial behaviours to help reduce network costs and encourage the optimal generation mix to come forward, as well as ensuring that those driving new network costs are not cross-subsidised by other users. Along with these reforms to use of system charging, we

[6] ENA Open Networks Project: http://www.energynetworks.org/electricity/futures/open-networks-project/

are proposing to reduce the barriers for low carbon technologies' (LCTs) and variable renewable energy sources' (VRES) connection to, and use of, the network.

1.14. The reform objectives that we've focused on through the SCR and the challenges they are seeking to address are summarised in Figure 1:

Figure 1 - Reform objectives and challenges they are seeking to address



Changes to delivery of the SCR

1.15. In late 2020, we launched our FCF programme to identify all the avenues for incentivising flexible network usage and the role that each might play. Due to the strong linkages between the programme and some of our Access reforms, we decided to pause assessing our DUoS options, until we had greater clarity about the direction of the FCF work to ensure our reforms are aligned.

1.16. However, we did not think that there were the same dependencies between the FCF programme outcomes and our other reforms and, instead, they have dependencies with other projects, which meant it was important that they were not delayed:

- Changes to the **distribution connection boundary** would change the DNOs' allowances under the price control and so there is benefit in signalling any proposed changes in time for them to be reflected in business plans

- As part of our **TNUoS reforms**, we are considering applying TNUoS generation charges to SDG.[7] If we introduce this, it could have an impact on the outcomes of the next Contracts for Difference auction,[8] which is expected to happen in December 2021. Providing potential participants with some clarity regarding any proposed changes will enable them to weigh up whether to reflect them in their bids.

1.17. We also think that it would be low regret to progress now with our **access rights** reforms, as they are not mandatory, but instead provide flexibility for DNOs and users to agree more beneficial access to the network.

1.18. We are continuing to consider how we best take forward the assessment of DUoS options in light of our work on FCF and will have more to communicate on this in due course.

Purpose of this consultation

1.19. In this document we are setting out, and seeking industry consultation on, our minded to positions for distribution connection charging, definition, and choice of access rights, and TNUoS charging for SDG.

1.20. This document should be read in conjunction with:

- The draft Impact Assessment, published alongside this document

- CEPA-TNEI's Report on Quantitative analysis of options

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[7] SDG refers to distribution connected generation smaller than 100MW
[8] The Contracts for Difference scheme is the government's main mechanism for supporting low-carbon electricity generation

- CEPA-TNEI's Methodology Note
- Our open letter on shortlisted policy options[9]
- The two working papers that we published in 2019 which outlined the options in detail.[10]

In addition, we have previously shared, through the Challenge Group (CG)[11] and the Charging Futures Forum (CFF), [12] the options we have been considering and our initial views of their respective pros and cons.

1.21. During this consultation period, we will hold information events with our Delivery Group (DG),[13] CG and the CFF and engage with wider stakeholders through bilateral meetings and other targeted engagement.

1.22. Under the SCR process, we are unable to provide a final decision on some parts of the SCR in advance of others, which means we will not issue our final decision[14] and Impact Assessment for these reforms, until we are also ready to issue a decision regarding DUoS options. However, should we receive any new evidence that will materially change our minded to position with regards to access rights, connection boundary or TNUoS charges, we will provide updated views prior to our final decision.

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[9] Open letter on our shortlisted policy options - https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options
[10] Winter 2019 working paper - https://www.ofgem.gov.uk/publications-and-updates/access-and-forward-looking-charges-significant-code-review-winter-2019-working-paper
Summer 2019 working paper - https://www.ofgem.gov.uk/publications-and-updates/access-and-forward-looking-charges-significant-code-review-summer-2019-working-paper
[11] The CG provides ongoing stakeholder input into the SCR. This group provides a challenge function to the work of the Delivery Group and ensures policy development takes into account a wide range of perspectives
[12] The Charging Futures website can be found here, with further information on future meetings and how to sign up to the forum available here. The Charging Futures website also contains the materials developed by the DG and discussed at the CG here.
[13] The DG comprises of network companies, the Electricity System Operator and relevant code administrators. The DG support us in developing and assessing options, drawing on their expertise and knowledge of how the networks are planned and operated
[14] This would include a direction to industry to raise the necessary code modifications to take our decision forward

2. Our approach to option development and assessment

Section summary

This section provides information on our SCR assessment framework and how our guiding principles, supported by modelling undertaken by CEPA-TNEI, influences our assessment and decision-making. We also provide more information around the technicalities of the modelling, discussing our approach to scenarios, options packages, variants, and sensitivities.

SCR assessment framework

2.1. In considering the need for and shape of any reforms, we have a statutory duty to protect the interests of current and future consumers.[15]

2.2. The overall objective for the Access SCR 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*".

2.3. We have applied this objective to areas relevant to the SCR and chosen detailed guiding principles. These 'guiding principles' are developed from our previous 'desirable features' of network access and forward-looking charging arrangements that we set out in our November 2017 working paper.[16] These in turn were informed by our wider statutory duties, our regulatory stances[17] and relevant economic theory.[18]

2.4. We set out the guiding principles for the Access SCR in our launch statement.[19] These provide the framework for developing policy in this area and form the basis of our principles-led assessment of the options identified within each workstream. Each of our three guiding

[15] Our understanding of the consumer interest is guided by the five consumer outcomes in our corporate strategy link here
[16] Reform of electricity network access and forward-looking charges: a working paper, chapter 2, link here
[17] Ofgem's regulatory stances, link here
[18] To be clear, these guiding principles have been informed by, and are consistent with, our statutory duties and do not take precedence over our statutory duties.
[19] SCR launch statement, published on 18 December 2018, link here

principles are underpinned by a number of criteria, which we have refined over the course of the SCR to make clearer the trade-offs we are considering when assessing our reforms against the guiding principles. This includes explicitly setting out that one our considerations under guiding principle 1 is about supporting Net Zero, as suggested by a number of stakeholders and discussed at our Challenge Group:

Guiding principle	Criteria
1. Arrangements support efficient use and development of network capacity	a) Arrangements support decarbonisation and contribute to meeting net zero targets, including in relation to impacts for low carbon technologies b) Access arrangements support network capacity allocation according to users' needs and value c) Signals reflect costs and benefits of using network at different times and places d) Signals support efficient use of capacity e) Signals ensure no undue cross-subsidisation between users f) Arrangements support effective signals for justified new network capacity g) Arrangements reduce barriers to entry h) Arrangements enable new business models
2. Arrangements reflect the needs of consumers as appropriate for an essential service	a) Arrangements avoid inappropriate outcomes or unacceptable impacts for small users b) Users are able to understand arrangements c) Users have sufficient information to predict their future access and charges
3. Any changes are practical and proportionate, considering:	a) Impact on existing data collection, processing, and analysis requirements b) Impact on existing systems, assets and equipment, potential requirement for new IT/operational systems (e.g. billing systems) c) Modifications to charge calculation and settlement methodologies d) Adaptions to engineering or planning standards e) Impact on customer engagement or commercial agreements f) Ease of implementation g) Distributional impacts for network users

	h) Arrangements are appropriately future proof by being robust to uncertain future developments on the system (e.g. low regret in that they are valuable as a first step and flexible / adaptable) or set us on a clear path, where certainty is greater

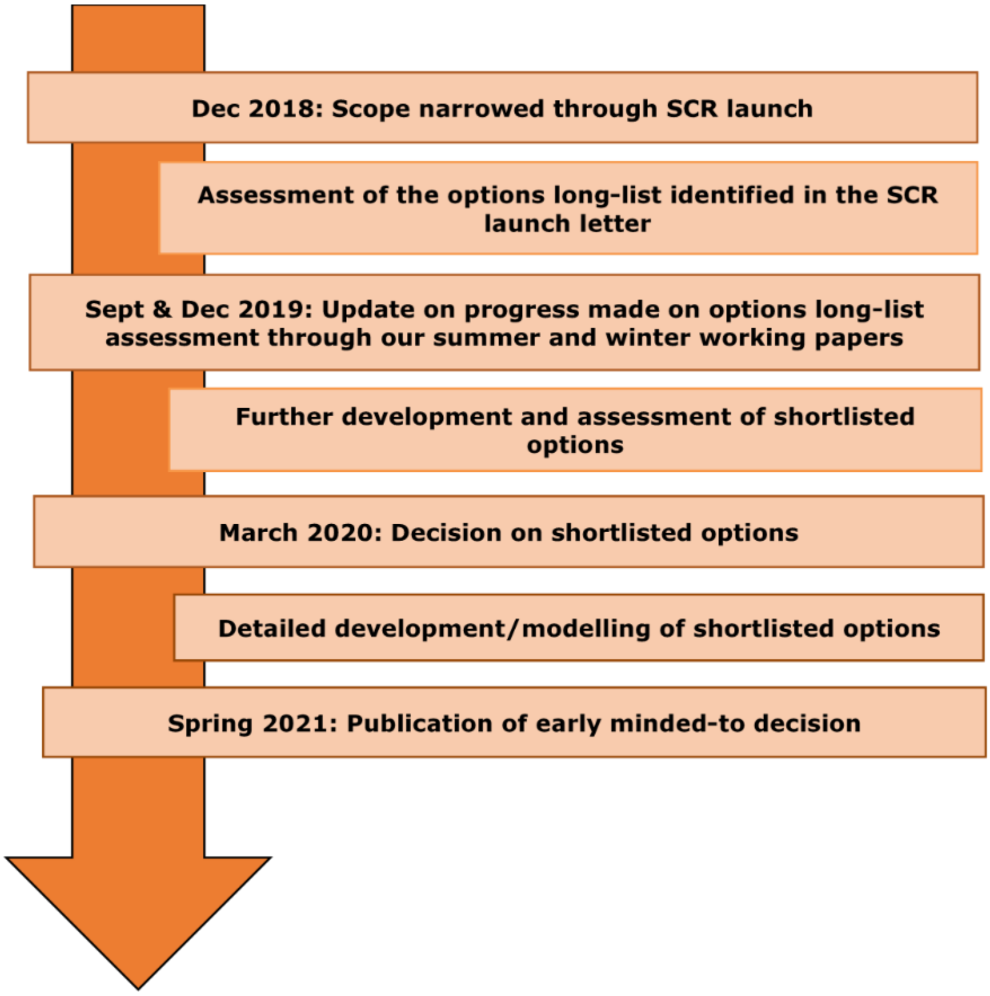
2.5. Our decisions will be supported by a quantitative assessment and we have commissioned CEPA-TNEI to undertake modelling of our options, to assess their potential distributional, behavioural and systems impact. They have undertaken a review of the literature on behavioural evidence to inform this. Given the extent of uncertainty around specific future projections, this modelling will supplement and inform our principles-led assessment rather than drive our decision-making. It will also not generate precise future charges – stakeholders should consider the indicative tariffs as **illustrative**, for the purposes of a general assessment of the options, rather than an indication of their potential individual future charges.

Qualitative options assessment

Overview of our process so far

2.6. Figure 2 provides an overview of our SCR process.

Figure 2 - Overview of our SCR process



2.7. The SCR was launched in December 2018.[20] We spent the majority of 2019 developing and undertaking a mostly principles-led qualitative assessment of a "long list" of options, which was informed by a range of activities:

[20] The SCR launch in December 2018 - https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision

- Reviewed a wide range of recent literature and case studies in other countries to identify options for improving the access and charging arrangements, including understanding differences between countries that affect their choices. We have also engaged with academics directly and through session with Ofgem's Academic Panel, where we have sought their views on our options and assessment as they developed.

- Worked with DG working groups to develop options, gather evidence and carry out analysis to identify those that best achieve the objectives.

- Engaged with other policy teams on a range of issues that would influence the development and timing of our reforms, including the Price Control, Consumer, Half Hourly Settlement, and Engineering teams.

- As described in more detail below, we undertook significant engagement with our CG and CFF where we tested our options and received challenge on a number of aspects. We also had meetings with individual stakeholders and industry bodies to help them understand our reforms and identify the potential impact on them.

2.8. In December 2019, we published our progress with assessing our long list of potential reform options, as a part of our winter working paper[21] and, in March 2020, we published our shortlisted options, which we selected, based on our principles-led assessment, giving key consideration our practical and proportionate principle.[22]

Stakeholder engagement

2.9. Since the launch of the SCR, we have been committed to delivering it in a transparent and open manner, and, as mentioned above, input from stakeholders throughout the process has been a key element of this. To support delivery of the SCR and provide stakeholders with

[21] Winter working paper with long-list of options published in December 2019 - https://www.ofgem.gov.uk/system/files/docs/2019/12/winter_2019_-_working_paper_-_exec_summary_note_publish_0.pdf
[22] Publication of shortlisted options in March 2020 - https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options

an opportunity to discuss our proposed reforms and CEPA-TNEI's approach to modelling, we established two new groups:

- **Delivery Group** – comprises network companies and code administrators and provides input to us for our consideration in developing our SCR options. Members of the DG also participate in a number of working groups to consider and report on specific workstreams.

- **Challenge Group** – comprises expert stakeholders, including suppliers, generators, trade bodies and consumer groups, who provide ongoing wider stakeholder input into the SCR, giving challenge to us and the work of the DG. This ensures policy development takes into account a wide range of perspectives and is sufficiently ambitious in considering the potential for innovation and new technologies to offer new solutions.

2.10. We have also engaged with a wider group of stakeholders through the CFF to understand their preferences and concerns, the potential impact of our reforms on their businesses and potential behavioural responses.

2.11. While we were undertaking our qualitative assessment in 2019, we engaged extensively with the CG and CFF – updating them, as our thinking developed, testing analysis done by the working groups and gathering insights in the potential impact of any changes, including:

- Charges for renewables – SDG and DUoS equal and opposite

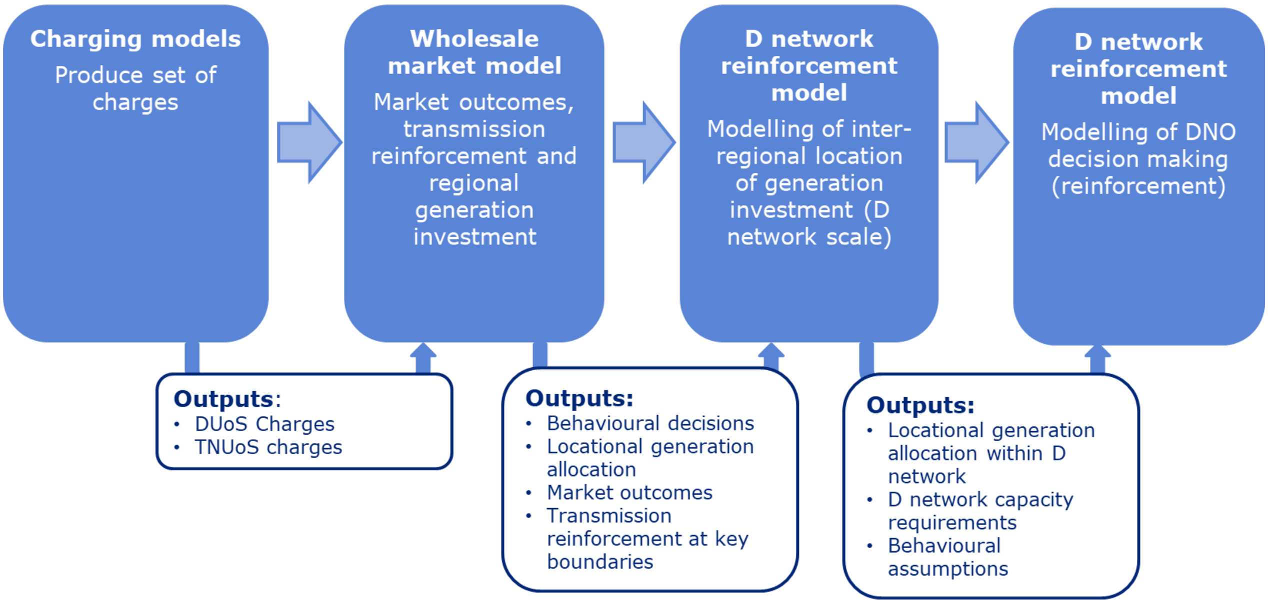
- Locational DUoS – significant increase in charging zones

- Access rights – financially firm

Impact Assessment modelling

2.12. Our proposals are based on our assessment against our SCR principles, supported by modelling. We commissioned CEPA-TNEI to undertake the modelling of our proposed reform options, to assess their potential consumer benefits and distributional and systems impact. Figure 3 provides an overview of the modelling process. Further detail is provided in the accompanying CEPA-TNEI report, published alongside this document.

Figure 3 – High-level model framework



Charging models

2.13. As shown above, a combined LV/HV and EHV network charging model was used to calculate the unit costs of using the distribution network at different locations within a DNO region. This model was designed to be flexible enough to allow for different unit costs to be calculated, depending on a number of policy choices regarding different inputs:

- The number of charging zones within each DNO region, which determines the degree that costs reflect differences in locations or are averaged across users
- Whether generation should continue to receive credits for all export, receive declining credits, based on the level of generation, or face charges where generation is driving costs
- Discounted costs for zones with spare capacity, reflecting that reinforcement is unlikely to be needed in the medium term
- The design of the charges, including the extent that costs should be recovered through capacity or consumption-based charges.

2.14. The outputs from this model were then used to calculate a set of distribution network charges for each user archetype under each option which allowed for 'static' distributional impacts to be estimated, when combined with TNUoS charges provided by the ESO.

Wholesale Market and Distribution Network Reinforcement models

2.15. CEPA-TNEI also developed behavioural response assumptions for a set of aggregated user archetypes, based on their literature review, which fed into both the distribution reinforcement cost modelling and the wholesale market modelling.

2.16. A number of inputs, such as, installed capacity in each modelled year, are taken directly from the relevant FES scenario. The market model can estimate revenues for each technology type and compare these against costs that need to be recovered. This was used to estimate changes in revenues that would need to be recovered, such as through renewable support mechanisms and the capacity market, or potentially other mechanisms. The distribution reinforcement model was then used to estimate the impacts and costs of the options on network reinforcement based on modelling of representative distribution networks.

2.17. The wholesale market model has been adapted to estimate the approximate costs of transmission reinforcement between seven key transmission zones, to measure the level of, and costs of transmission network constraints. This is a simplification to capture key transmission boundaries but does not represent the transmission network to the level of detail in the Transport model owned by the ESO.[23]

2.18. After running both sets of models (market and distribution), network and wholesale market costs are combined to calculate an NPV, combined with an estimate of implementation costs, drawing on responses to our request for information earlier this year.[24] In addition, the generation and demand behaviours observed in the market model was used to estimate the 'dynamic' distributional impacts.[25]

Selection of background scenarios

2.19. We have modelled a selection of the ESO's Future Energy Scenarios (FES) 2020 for the purposes of testing our options packages against a plausible range of potential scenarios,

[23] Transport Model owned by the ESO - https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges/transmission-network-use-system-tnuos-tariff
[24] Request for Information for SCR - https://www.ofgem.gov.uk/publications-and-updates/request-information-access-and-forward-looking-charging-review
[25] "Dynamic" distributional impacts refers to the range of charges and bill impacts for each user archetype, after taking into account the behavioural responses to the change in network charging structures, rather than impacts that change continuously over time.

combined with sensitivities to test them against key uncertainties. These scenarios vary in the level of societal change achievable and the speed of decarbonisation.[26]

2.20. We have modelled the options against the Consumer Transformation scenario and Steady Progression scenarios and carried out sensitivities against Leading the Way. The Consumer Transformation scenario delivers the Net Zero decarbonisation targets and achieves this through a significant level of societal change suggesting that consumers make greater changes to their behaviour. We expect our policy reform options could help enable a higher electrification, higher consumer flexibility scenario in a cost-effective way by contributing to the signals needed to incentivise behaviour change, in conjunction with other reform options.

2.21. We therefore consider that Consumer Transformation represents the core scenario for analysis. While Steady Progression may represent an undesirable future world, in that while it reflects substantial decarbonisation, it does not meet the net zero 2050 target, it provides an important 'stress test' of potential benefits. We have also modelled Leading the Way as a sensitivity. This is a scenario where Net Zero is met by 2048, representing the fastest credible speed of decarbonisation.

Illustrative examples of different consumer impacts

2.22. Table 1 summarises the impact our proposed reforms could have on different types of network users. We then set out in Chapters 3-5 the detail behind our policy options and the analysis we have undertaken to inform our minded to positions on the connection boundary, access rights and TNUoS charges for SDG.

[26] ESO FES 2020 - https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

Table 1 - Illustrative examples of the impact of our reforms

User type	Connection boundary	Access rights	TNUoS charges for SDG
Transmission connected onshore wind farm	• No direct impact as we are not considering changes to the transmission connection arrangements	• No direct impact as we are not considering changes to the transmission access arrangements	• Changes in charges will be incidental, due to charging SDG, rather than direct • Levels playing field by apply the same charges to all generation
Large distribution connected onshore wind farm (>100MW)	• Reduced upfront connection charge • Moves towards a more level playing field with transmission connected generation	• Could choose to install battery onsite to manage constrained periods and choose overnight access when spare capacity may be available • Reflected in reduced connection and or DUoS charges	• Already face wider TNUoS generation charges, but levels playing field by apply the same charges to all generation
Small distribution connected solar farm	• Reduced upfront connection charge • Moves towards a more level playing field with transmission connected generation	• More certainty of level of curtailment through better defined access right • Reflected in reduced connection and or DUoS charges	• Northern SDG may face charges and southern SDG may receive credits

EV charging infrastructure for fleet of delivery vehicles	• Reduced upfront connection charge • Increased ongoing network charges	• Could reduce capacity during peak periods, if not needed for charging • Reflected in reduced connection and or DUoS charges	• No direct impact
Domestic household installing a heat pump and EV charger	• Reduced upfront connection charge in some cases • Increased ongoing network charges	• No direct impact	• No direct impact

Transitional arrangements and implementation timing

2.23. In general, we do not consider the use of transitional arrangements when introducing charging reforms is typically desirable or necessary because:

- They can delay the provision of substantial reform benefits to consumers by retaining cross subsidies or distortions
- It is widely understood that charging arrangements change over time to improve cost reflectivity and better achieve the charging objectives
- With regards to these specific reforms, we have signalled for a number of years that we intended to address any undue distortions and highlighted as part of the launch of our SCR the areas we ended to focus on, which means the changes should be well understood and anticipated by stakeholders.

2.24. However, we recognise that there may be some instances where transitional arrangements could be justified. This may include:

- Where there is a possibility that the effect on market participants increases the risk of stranded expensive connections or network capacity, which were built to facilitate users who move, close, or choose not to repower
- If users have a legitimate expectation about how charging arrangements will be in the future (e.g. through enabling legislation)
- To give users time to reflect any changes in their commercial arrangements
- To mitigate the risk of double charging, where it can be clearly identified that users have already contributed to the assets that costs are associated with.

2.25. We will therefore be taking a principles-led approach to where transitional arrangements may be appropriate. This approach is key to avoiding the implementation of inappropriate transitional arrangements, as this would further delay the benefits of our reforms to consumers.

Access rights and connection boundary

2.26. Subject to feedback from this consultation and our final decision, we are proposing to implement our access rights and connection boundary reforms by **1 April 2023**:

- Access rights – we consider these changes to be low regret, as they form an additional set of flexible connection options that DNOs and users can use to facilitate connections
- Connection boundary – changes to how reinforcement is funded within a price control period would almost certainly require a reopener. While aligning with the start of RIIO-ED2 does not remove this risk, we are seeking to reduce the materiality of one should it be necessary. We will however keep this under review if further changes (e.g., to secondary legislation) are necessary. Another consideration will be how we manage applications submitted around the implementation date, further discussed in Chapter 3.

2.27. We do not think there is likely to be a case for transitional arrangements for our reforms to access rights because uptake would not be mandatory. Rather, they provide more clarity about the choices available to DNOs and both new and existing users of the network for flexible connections.

2.28. For connection boundary changes, we may have to consider transitional arrangements for generation if we do not go to a fully shallow connection boundary but do introduce generation dominated areas (GDAs) as part of any future DUoS reforms, which remain under consideration. We also recognise that there may be practical issues in identifying which parties are affected (particularly where ownership has changed and the party which paid the initial connection charge differs from the one paying ongoing network charges). At this time, we think this would therefore be better addressed as part of any future DUoS reforms than within connection charging.

TNUoS charges for SDG

2.29. When assessed against guiding principle 1, we think that removing the difference in charging arrangements between large generation and SDG will result in more efficient network usage. However, since we launched the SCR in 2018, increasing questions have been raised about whether the price signals provided by the wider TNUoS methodology will be fit-for-purpose in the future, and whether a wider review is needed. Some of the issues raised by industry that may need to be considered include:

- Tariff volatility stemming from the current transport model and approach to zoning, including the expansion constant, as highlighted by some urgent modifications raised by the ESO
- Other potential reforms to the transport model, including whether there would be benefit in signalling spare capacity on the network and if the peak and year-round backgrounds are still fit-for-purpose
- Whether the methodology produces the right signals for demand and particular technologies, such as storage
- Other longer-term network develops, which might have implications for our charging regimes, such as if we have an integrated offshore system.

2.30. Along with the current FCF work being undertaken to consider, among other things, the role of network charges in sending signals to users about their impact on the network, this means that there are likely to be further changes to the charging arrangements in the short/medium term.

2.31. We think it may not drive more efficient network usage, if we introduce a change now, which sends signals to users that may change again significantly, following any wider review of TNUoS charges. Given the potential for short term volatility, we think there may be merit in delaying implementation of this part of our reforms, until there is greater clarity about the longer-term role of TNUoS charges. We discuss this further in Chapter 5.

3. Our proposals for distribution connection charging

Section summary

We are minded to change the connection charging arrangements. We propose reducing the contribution to reinforcement within the upfront connection charge for generation, and removing it completely for demand. This comes at a cost, but we think this is the right balance between maximising benefits such as removing barriers (particularly for those where we think a behavioural response is unlikely) and doing so at least cost to consumers generally.

We are not minded to introduce the option for users to defer payment after the connection is made, or introduce new liability or security obligations on users.

Questions (please provide any further evidence to support your answers)

Question 3a: Do you agree with our proposals to remove the contribution to reinforcement for demand connections and reduce it for generation? Do you think there are any arguments for going further for generation under the current DUoS arrangements? Please explain why.

Question 3b: What evidence do you have on the effectiveness of the current connection charging arrangements in being able to send a signal to users and what do you think will be the effect of our proposed changes? How does this vary between demand and generation connections?

Question 3c: What are your views on the effectiveness of the current arrangements in facilitating the efficient development and investment in distribution networks? How might this change under our proposals where network companies are required to fund more of this work?

Question 3d: Do you agree whether the need to provide connection customers with certainty of price reduces the potential for capacity to be provided through other means such as flexibility procurement? How might this change under our proposals?

Question 3e: What are your views on whether we should retain the High Cost Cap? Is there a case for reviewing its interaction with the voltage rule if customers no longer contribute to reinforcement at the voltage level above the point of connection? Question3f: What are your views on the recovery of the costs associated with transmission that are triggered by a distribution connection? Does this need to be considered alongside wider charging reforms or could a change be made independently? Question 3g: What are your views on the likelihood of inefficient investment under our proposals (e.g., an increase in project cancellations after some investment has been made)? What are the arguments for and against further considering introducing liabilities and securities to mitigate this risk? Question 3h: What are your views on whether the interactions between our connection reforms and the ECCRs must be resolved before we are able to implement our proposed reforms? How do you factor in the effects of the ECCRs (if at all) into decision making, given the levels of uncertainty around subsequent connectee(s)? What suggestions do you have to make our policy and the ECCRs work together most efficiently?

Shortcomings in the current arrangements

3.1. When someone seeks a connection to the distribution network, the relevant DNO will consider what work will be needed to enable their connection. Generally, the connection will require the installation of new assets to extend the existing network to the customer (“extension assets”) and, in some cases, connection also requires the DNO to upgrade or expand the capacity of the existing shared network assets to facilitate the new connection (“reinforcement”). When charging connecting customers, DNOs follow the Common Connection Charging Methodology (CCCM), which has been approved by us. Independent Distribution Network Operators (IDNOs) use their own charging methodologies, which are also approved by us and largely based on the CCCM.[27]

3.2. Costs for work that facilitates a new connection are split between the connecting customer (via an upfront connection charge) and the DNO (which is recovered through a

[27] We refer to IDNOs and DNOs collectively as “DNOs” within this consultation for the sake of brevity. Where there is different treatment for either group we have made this clear.

DNO's DUoS charges). The way these costs are split is discussed in terms of the depth of the connection charging boundary. Currently, customers connecting to the distribution network are charged under what is referred to as a "shallow-ish" connection boundary. This means that in general, the connecting customer pays for:

- All of the costs for the extension assets required as part of their connection; and
- Some of the costs for any network reinforcement required to facilitate their connection.

3.3. The contribution towards reinforcement (and what is paid by the connection customer or DNO-funded) is determined through the application of a set of detailed rules set out in the relevant charging methodology. One of these is referred to as "the voltage rule". This states that the connection customer contributes to reinforcement at the same voltage level as their point of connection, plus the one above. Reinforcement undertaken at two voltage levels or more above the point of connection and higher is fully funded by the network company. This and other apportionment rules are described in more detail in Appendix 1. Extension assets, also referred to as sole use assets, are used only by the connecting customer so are paid for in full by that individual.

3.4. Charges were designed this way to share the burden of reinforcement costs between the connecting customer and the wider user base connected to the distribution system. This reflects the fact that both the connecting customer as well as other network users drive the need for, and benefit from, the additional network capacity created by reinforcement. The original intent of charging some of the cost of reinforcement to the individual triggering the work was to encourage customers to connect to the network where spare capacity already exists.

3.5. Under the Access SCR we have been reviewing whether current connection charging arrangements are continuing to work in the best interests of consumers. In particular, whether they provide an effective signal for network users and whether they may actually hinder the achievement of Net Zero at least cost. Engagement with stakeholders throughout the SCR has identified the following as the key issues that may exist. We summarise them here with more details in Chapter 2 of the draft Impact Assessments that should be read alongside this consultation:

- The current arrangements do not give an effective locational signal in many cases. Whilst some types of customer may have some geographic elasticity on where they locate (e.g. some types of generation), for most customers (typically demand) the location is driven by many factors other than the connection cost. In some cases a high connection cost signal could result in a connection not proceeding rather than the connecting customer seeking to locate elsewhere on the network, whilst in other locations users may receive no locational pricing signal at all. For example, the location of electric vehicle charging infrastructure will be largely driven by the national road networks and the points at which consumers will need to charge their vehicles prohibitively high connection costs may inhibit the investment and therefore the deployment of electric vehicle charging infrastructure in some parts of the country. Similarly, arguments apply to industrial processes that may seek to convert from gas fired to electric power and require additional distribution network capacity. These arrangements could therefore slow down our attempts to achieve Net Zero.[28]

- The current arrangements hinder the efficient development and investment in distribution networks. While other factors such as uncertainty around the ability to recover sunk investment will also have an influence, they contribute to DNOs taking an incremental and reactive approach to reinforcement as the means of facilitating new connections, rather than investing in light of anticipated wider network needs. Additionally, the current arrangements make using already connected flexible resources to offset reinforcement and facilitate new connections unattractive to customers and DNOs. If DNOs were more (or fully) responsible for funding such work, they would be better placed to consider alternative options other than reinforcement for meeting the capacity requirements of their customers. This could in turn reduce the overall requirement for traditional network investment while providing the capacity needed to facilitate new and modified connections in an efficient and timely way.[29]

- Differences between current connection charging arrangements at distribution and transmission may be creating distortions and/or impacting competition between generators connecting to the different networks. Aligning the connection charging arrangements to the extent possible may help address these issues.[30]

- In order to meet targets for the electrification of heat and transport, the use of heat pumps and EVs will play an important role. Installing this technology in new and

[28] See paragraphs 3.1.9 to 3.1.18 of our draft Impact Assessments, published alongside this document
[29] See paragraphs 3.1.19 to 3.1.24 of our draft Impact Assessments, published alongside this document
[30] See paragraphs 3.1.25 to 3.1.26 of our draft Impact Assessments, published alongside this document

existing homes will increase pressure on distribution networks. While the current arrangements mean that reinforcement triggered by a change to an existing connection is already fully funded by the DNO (subject to certain conditions), customers will face these costs if, for example, they exceed a 100A fuse size or need to move from a single to three phase connection. The cost for reinforcement also falls only on the customer whose connection directly results in the available network capacity being exceeded, despite earlier connections contributing to the need for reinforcement. Current arrangements therefore mean consumers could face significantly different costs depending on when they are able to connect.[31]

Options and our proposed position

3.6. In March 2020, we shortlisted a number of options for changing the current distribution connection charging arrangements.[32] These were:

- Reducing the extent to which reinforcement charges should be recovered from the connection charge (i.e., moving to a shallower connection boundary);

- Removing reinforcement costs from the connection charge (i.e., moving to a shallow connection boundary);

- Allowing alternative payment terms for connection charges (e.g., allowing payment over time); and,

- Introducing some form of financial commitment in the form of liabilities and securities.

3.7. We also ruled some options out at the shortlisting stage. These included capping connection charges at a ceiling, standardising connection charges and recovering the cost of extension assets through DUoS. This was because we consider that these options would introduce cross-subsidies and or negatively affect competition in connections. We considered that the shortlisted options that were retained may help achieve the Guiding Principles that we set out at the launch of the SCR and required further assessment.

[31] See paragraphs 3.1.27 to 3.1.29 of our draft Impact Assessments, published alongside this document
[32] Electricity Network Access and Forward-Looking Charging Review: Open Letter on our shortlisted policy options | Ofgem

3.8. We have now considered our shortlisted options further. While forecasts on how the energy landscape will evolve in the future rely heavily on assumptions, we have tried to quantify the impact of making a change wherever possible. As part of our assessment, we have modelled the cost of removing the locational signal from the connection charge. We have also considered the potential value of harder-to monetise benefits of making a change (e.g., by bringing forward the roll-out of renewable generation and or low carbon technologies sooner than would have otherwise been the case). This is set out in more detail in the impact assessment published alongside this consultation and supports our wider principles-based assessment of whether we should make a change.

3.9. We have previously indicated the links between connection and DUoS charging reform. Where there is reduced (or no) locational signal being provided through connection charging, it may be possible to improve the signals provided on an ongoing basis through DUoS. This could better reflect the effect consumers' actions have on the system. However, we are not yet at a stage where we have certainty over what DUoS charging will look like in the future. Our assessment of our connection charging proposals is therefore based on the assumption of either no or low change to DUoS. This gives us an indication of the cost of making a change in the absence of improved DUoS signals. We expect that these costs would be reduced if we were to make further changes to DUoS. We will therefore take this into consideration when making a final decision on the whole SCR.

Distribution connection charging boundary

3.10. We have considered two options for changing the connection boundary:

- **Reduce the contribution to reinforcement**: this would keep some contribution to reinforcement within the connection charge but less than today, with an increased contribution from DUoS customers.

- **Remove the contribution to reinforcement**; removing the contribution to reinforcement in the connection charge would result in a shallow connection boundary, with 100% of reinforcement costs funded through DUoS.

3.11. The key difference between the current arrangements and these options is the application of the voltage rule. In the first option, an amended voltage rule would apply so that connection customers contribute to reinforcement at the same voltage as the point of connection only (everything at voltage levels above would be funded by the DNO). In the second option, the voltage rule is changed such that the connection customer makes no contribution to reinforcement within the connection charge. A more detailed description of how these changes would be achieved is in Appendix 1. Under both options there would be no change to how connection charges apply for extension assets needed to connect to the existing network.

3.12. We think the case for change is strongest on the grounds that the current arrangements may be potentially holding back efforts to achieve Net Zero. That is, the energy landscape is changing and current arrangements are no longer providing an effective signal to connection customers, potentially being too strong for some (leading to delays or connections not going ahead at all), while not giving others any signal at all.

3.13. Currently, under the status quo, the contribution towards reinforcement provides a locational signal for distribution connections. Economic theory states that the most effective time to provide this signal is at the time of investment and so (in the absence of other changes to DUoS) removing it may lead to some less efficient pricing signals to those customers who have some geographic elasticity on location. This is reflected in our modelling where we see an increase in network costs under all options. However, we think the current arrangements risk creating barriers to investment or pushing users to accept non-firm connections. This is particularly the case for connection customers with less flexibility over locational decisions and where we think behavioural response (e.g., in terms of choosing a different location) is less likely or not possible.

3.14. The current arrangements also only give signals value to those who require a supply capacity over and above the spare capacity available on the network (i.e. capacity that is unutilised by or unallocated to other consumers). Connection customers who use up existing spare capacity leading receive no locational signal through the connection charge, despite contributing to the future need for reinforcement to meet the needs of other consumers. It is only once the spare capacity is utilised that a customer seeking a new or augmented connection will trigger reinforcement and therefore incur a charge towards reinforcement. Although the Electricity Connection Charge Regulations (ECCR)[33] make provision for subsequent connectees to contribute to the reinforcement, it is the connecting customer for whom the reinforcement was initially provided who bears the investment risk, and the risk that such second comers will ultimately connect. Whilst subsequent connectees may receive a

[33] The Electricity (Connection Charges) Regulations 2002 (legislation.gov.uk) and The Electricity (Connection Charges) Regulations 2017 (legislation.gov.uk)

signal (as a consequence of contributions required under the ECCRs) where they access additional capacity provided at the time of the first comer's connection, the risk is significantly less than that of the first comer who initially triggered the reinforcement. As a consequence, this could delay connections from going ahead. Also current charging arrangements only give signals on the capital cost of installing assets; it is only in exceptional circumstances that connection charges include signals on the long-run costs of maintaining the network after the connection has been made or any investment signal to users whose actions can help offset the need for future reinforcement in that area (e.g., whether to install a battery).

3.15. Stakeholders have told us that some connecting customers, particularly EV charging providers and distributed generation customers, can face prohibitively high reinforcement costs. While this is not necessarily supported by regulatory reporting by the DNOs, we are cognisant that this does not take into account those connections which do not proceed following initial discussions with the network company and which did not result in a connection offer being issued. We are also mindful that figures reported by the DNOs are, by their nature, backward looking. As more low carbon technologies connect to the system, this will lead to a significant increase in the network capacity required to meet demand. There is a risk that, under the current charging arrangements, this could act as a barrier for some users.

3.16. We think the arguments are more finely balanced in terms of efficient system development where a change will result in increased costs. Removing or reducing the strength of the locational signal contained in the connection charge, without replacing it with improved signals elsewhere, would likely result in connecting customers making connection requests in areas of the network where investment was required, and/or overstating the level of capacity that is needed. Our modelling suggests that this could be up to £380m additional network investment to 2040.[34] However, these impacts could be outweighed by other hard-to monetise benefits such as bringing forward connections of low carbon technologies and encouraging DNOs to take into account the wider needs of their customers (as opposed to responding to individual requests in an incremental fashion).

3.17. Stakeholders have suggested that applications corresponding to step increases in demand leads to inefficient piecemeal network investment, rather than looking at more holistic network-wide requirements. The piecemeal nature of connections-driven investment does not therefore enable DNOs to respond to a true picture of the need for increased

[34] See paragraph 1.2.7 of our draft Impact Assessments, published alongside this document

capacity or provide long term signals for the full value to customers and networks of flexibility or investment. While DNOs can invest ahead of need today, they risk not fully recovering their costs giving them a strong incentive to wait until they receive connection requests, rather than act in advance.

3.18. Current arrangements may also 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. Alternatively, and subject to the ECCRs, generators that can delay are able to free ride on those willing to pay for reinforcement. With shallower charges, a more efficient outcome can be achieved with the DNO managing network capacity through strategic investment based on a more holistic understanding of their network.

3.19. Furthermore, by not charging for reinforcement the DNO has more freedom to choose a cost-efficient solution to meet users' electricity requirements, which may be a range of solutions other than (or including) reinforcement. We think that making a change to the arrangements may encourage the use of existing flexible resources as means of facilitating new connections. Our Sector Specific Methodology Decision for RIIO-ED2 highlighted the potential benefits of this, reducing costly curtailment of renewables generation and the need for expensive network upgrades. 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. However, the cost of procuring flexible resources as means of supporting new connections could vary over time and so could require the customer to accept an uncertain (and uncapped) liability to be settled retrospectively. All DNOs have reported issues with using flexibility to facilitate new connections with little or no appetite from connection customers due to this risk. A shallower connection boundary could avoid this issue and allow DNOs to find the most efficient way of funding the work needed to facilitate the connection (i.e., comparing build and non-build solutions).

3.20. Government has set out an ambition of 600,000 heat pump installations per year, as well as ending the sale of petrol and diesel cars and vans by 2030.[35] We have concerns about the impact for customers seeking to install heat pumps (especially in conjunction with an EV charger) if some contribution to reinforcement is retained. Where it is necessary to install a fuse size greater than 100A or require a three-phase connection, this could represent a

[35] The ten point plan for a green industrial revolution - GOV.UK (www.gov.uk)

significant barrier to investment. It would also mean a significant disparity in the costs paid for some groups of customers, depending on when they are able to connect.

Table 2 - Assessing the relative benefits of reforms to the distribution connection charging arrangements

Option	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Reduce the contribution to reinforcement in the connection charge	• Expect benefits of reforms to outweigh these potential costs. • May not go far enough for demand users, where we think charges could be a key barrier and are less likely to have locational flexibility.	• Reduces intertemporal issue of households facing different reinforcement costs based on when they are able to connect. • Results in increased energy bills with reinforcement recovered through network charges.	• Changes to the connection charging methodology would be relatively straightforward to implement through the industry code modification process. • Further licence and legislative change may be necessary.
Remove the contribution to reinforcement in the connection charge	• Does most to remove barriers to entry and support more coordinated and strategic DNO network management. • However, may not be a positive net benefit given extent of potential costs (particularly for generation in the absence of further DUoS reform).	• Removes intertemporal issue of households facing different reinforcement costs based on when they are able to connect. • Results in increased energy bills with reinforcement recovered through network charges.	• Changes to the connection charging methodology would be relatively straightforward to implement through the industry code modification process. • Further licence and legislative change may be necessary.

3.21. On balance, we think there are good arguments for making a change to the charging arrangements. We are minded to:

- remove the contribution to reinforcement within the connection charge completely for demand connections; and
- reduce the contribution to reinforcement within the connection charge for generation connections.

3.22. We think this is the right balance between maximising benefits such as removing barriers (particularly for those where we think a behavioural response is unlikely) and doing so at least cost to consumers generally. Going further and removing the contribution to reinforcement from generation connections would, in the absence of DUoS reform, mean that these users do not face any signal about the costs they put on to the system. This is because generation currently receive DUoS credits and do not face charges, even in areas where they are driving costs. Our modelling also shows that the difference in additional network costs between the hybrid option and only partially removing the charge for both demand and generation is relatively small.[36]

3.23. We propose to reduce the contribution made by generation connections by amending the voltage rule. We do not propose any changes to the High Cost Cap (HCC) for distributed generation. Under the HCC, distributed generation fund all reinforcement above £200/kW. Where both the HCC and voltage rule apply, the voltage rule takes precedence. We discuss this in more detail in Appendix 1 of this document. We welcome views on whether further changes are needed to manage the interactions between these two aspects of the charging arrangements.

3.24. With regards to energy storage, while it is considered as generation, the import and export components are currently treated individually for the purposes of connection charging. Cost apportionment is therefore driven by whether the reinforcement is required to accommodate the import or export capacity of the connection.

3.25. Storage has significant locational flexibility and should be encouraged to locate where they do not increase costs unnecessarily. On the other hand, we have not seen any evidence

[36] Modelling provided by CEPA-TNEI suggests an additional £380m and £310m in network costs from the hybrid option and only partially removing the contribution to reinforcement for both demand and generation respectively. This is discussed further in chapter 2 of the impact assessment report published alongside this consultation, as well as the report from CEPA-TNEI.

to suggest we should treat the import component any differently from other demand connection.

3.26. We do not therefore propose any change to the approach of treating the import and export components of storage separately. This will mean that storage connections would not face any contribution to reinforcement where it is being driven by the demand capability, and a reduced contribution where driven by the generation capability.

Treatment of transmission reinforcement triggered by distribution connections

3.27. Customers seeking to connect to the transmission network currently face a shallow connection charge. Conversely, Transmission Attributable work (e.g. upgrading a Grid Supply Point) that has been triggered by a distribution connection is currently charged to the individual connection customer as part of the DNO's connection charge. This can result in an upfront cost that is prohibitively expensive, may adversely influence investment decisions, and prevent connections from going ahead for what is work that would arguably benefit many consumers.

3.28. For large distributed generation (DG), this can mean that connection customers face an upfront charge related to work at transmission as well as ongoing wider locational transmission generation charges. Furthermore, if under the proposals discussed in Chapter 5, we introduce transmission charges for small DG, these users could also face higher costs (compared to those at transmission). They would face the same ongoing network charges, but also an upfront connection charge in relation to transmission costs that a transmission connected generator would instead pay over several years. This could distort competition between transmission and distribution connected generation.

3.29. An alternative approach would be to recover these costs through ongoing use of system charges. However, there are several challenges that would need to be addressed at the same time to make such a change and avoid excessively impacting other consumers.

3.30. Under current arrangements, these costs are likely to be treated as New Transmission Capacity Costs which the DNO cannot recover through DUoS. The capital costs associated with these are instead recovered through an upfront charge to the individual (with the DNO bearing the equivalent of operation and maintenance costs during each price control period). Changes to the electricity distribution licence for RIIO-ED2 would be necessary to allow the recovery of this via DUoS. However, there is an overarching question over whether it is appropriate for transmission costs to be included within a DNO's Regulated Asset Value and allowed to be funded in such a way.

3.31. Notwithstanding the above, if these costs were to be funded by the DNO and recovered by DUoS, the subsequent question is whether this would be through a more targeted approach to DUoS than the current arrangements. More locational DUoS could allow for this to be targeted to the individual causing the work. However, in the absence of DUoS reform, this would result in all consumers funding this work with potentially significant additional costs in each distribution region.

Table 3 - Assessing the relative benefits of reforms to the recovery of costs associated with transmission works triggered by distribution connections

Option	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Transmission works triggered by distribution connections	• Reduced barriers to entry via lower upfront charges. • In absence of a change, DG could face higher costs overall beyond what is cost reflective (compared to those at transmission). This could create a distortion in favour of transmission connected generation.	• Significant additional costs for all DUoS customers, particularly in the absence of further reform	• Would require further reform of DUoS if targeting costs to individual users • Changes to the connection charging methodology would be relatively straightforward to implement through the industry code modification process. • Further licence changes would be necessary, with specific changes needed for ED2.

3.32. We think the proposal whether to change the way this work is funded is finely balanced. On one hand, recovering these costs through ongoing charges removes a significant upfront barrier for those users triggering such work. This is also consistent with the shallow boundary faced by transmission connected generation, and the arrangements being proposed for distribution. We are also mindful of the differences between the costs faced by transmission and distributed connected generation.

3.33. 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 1 April 2023. This would result in significantly higher costs being borne by all consumers.

3.34. We also note in Chapter 5 that there is increasing evidence for a wider review of TNUoS charges. It may therefore be that another approach is more appropriate and making a change now would preclude possible options in the future. For these reasons, we are not minded at this time to make any changes to the treatment of transmission work triggered by a distribution connection.

Alternative payments

3.35. Connection charges are currently paid in advance of work being completed.[37] We have considered whether to allow payment to be made after energisation over several years. This may benefit connection customers where upfront costs are a barrier. However, there are several potential consequences for DNOs, as well as consumers more generally, from introducing such arrangements.

Table 4 - Assessing the relative benefits of introducing deferred payment of distribution connection charges

Option	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Deferred payment of connection charges	• Inappropriate for DNO to provide finance where a customer has been unsuccessful elsewhere.	• Cash flow benefit for the connecting customer. • Shifts bad debt risk to DNO, and possibly consumers,	• Increased administration. • Could be difficult to manage where the connecting and enduring customer differ.

[37] Payments can be staged leading up to completion, but full payment is required in advance of energisation.

	• Could distort competition in connections.	pushing up costs for all.	• May introduce new financial obligations on the DNO (e.g., consumer credit legislation).

3.36. We do not propose introducing deferred payments. Doing so would transfer the risk of bad debt onto all customers and raises questions over whether it is appropriate for DNOs to be providing finance for users in such a way. It also raises concerns over competition in connections with IDNOs and or ICPs potentially being less able to provide what may be deemed as preferential terms.

Liabilities and securities

3.37. The cancellation of a project (or not proceeding as originally planned) can have impacts on wider system development, particularly if the network company has already made some investment. A financial obligation (referred to as User Commitment for generation and Final Sums for demand) currently exists at transmission to ultimately protect customers from additional costs should projects not go ahead. Other than in respect of speculative developments where all costs are recovered in full from the connecting customer in advance, no such arrangements are currently in place at distribution, in respect of the DNO funded investment.

3.38. If we reduce or remove the contribution to reinforcement made by the connecting customer, there is a risk of customers picking up costs should the DNO invest, but the project not reach completion for whatever reason. A new obligation on connection customers may help mitigate this risk.

Table 5 - Assessing the relative benefits of introducing new liabilities and securities for distribution connections

Option	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Liabilities and securities	• Could incentivise users to engage with DNOs early to avoid inefficient investment. • Cancellation rates suggest a greater risk at higher	• Protects wider consumer base from bad debt. • Requirement to provide security may be as much of a barrier as an upfront charge.	• Disproportionate level of administration if introduced for all users. • Could be difficult to manage where the connecting and

	voltages and for DG. • Customers are still making an upfront contribution towards any work (de-risking the DNO's investment).		enduring customer differ, especially if continuing post-energisation.

3.39. We think keeping some contribution to reinforcement for generation in the initial connection charge (in addition to fully funding extension assets) can represent a significant commitment to a project going ahead. It also mitigates the risk of a project being cancelled, resulting in inefficient investment from the DNO. This is a good argument against introducing any new obligations. There may be more of a case for demand under a shallow boundary, but it is disproportionate for all but the most expensive connections, and there may still be sufficient scope for re-use of assets. We are not minded therefore to introduce any new obligations but welcome views on the likelihood of the risk and whether we should consider this further (particularly for large or high-cost connections).

Implementation and transitional arrangements

3.40. We set out in paragraph 2.26 that if we do decide to make a change to the connection charging arrangements, this will be from 1 April 2023. We currently think the simplest approach may be to apply the new charging arrangements to all new requests submitted after that date. This may encourage some customers to delay connection requests until the new arrangements are in place (with a subsequent increase in requests after). However, it is not clear how using any other date would avoid this issue and we consider this would be a temporary issue limited by the relatively short lead time that would be involved.

3.41. The ECCRs 2017 provide for eligible persons to receive a payment if they have funded assets that are used by a subsequent connectee connecting in the ten year period after the first connection (sometimes referred to as the "second comer" regulations).[38] We will consider how our proposals interact with the ECCRs as part of our final decision.

3.42. Our current view is that the ECCRs will continue to be operable in respect of extension assets. We do not propose any changes to the payment of these so there is no impact because of our proposals.

3.43. We think a change to the ECCRs may be needed in respect of reinforcement funded by an eligible person (which could be an earlier connectee or DNO), particularly around the obligation on DNOs to demand a payment from subsequent connectees. If we do not make a change, then subsequent users connecting in the period prescribed in the ECCRs would still have to make a payment associated with reinforcement works if using assets that has been funded by an eligible person. The prescribed period set out in the ECCR is ten years after the first connection is made.

3.44. We consider that eligible persons should not expect a reimbursement payment due to the uncertainty as to whether someone would make a subsequent connection. However, we are keen to understand the impact and welcome responses to whether in practice eligible persons account for this into their business planning, and if so, how.

3.45. If a change to the ECCR is necessary, this would require legislative changes to be implemented by BEIS. Given the time needed to develop such a change, this could make implementation of our connection charging reforms by 1 April 2023 challenging. We are therefore keen to hear from stakeholders what solutions might be possible that avoid legislative change being necessary. We will continue to work with BEIS and industry to explore this, but we think any solution should achieve at least the following outcomes:

- Customers seeking to connect to distribution networks face one set of charging arrangements irrespective of whether the ECCR is triggered or not.

- Eligible persons can receive reimbursement payments that they are entitled to under the ECCR.

[38] We do not consider that changes are required in respect of the 2002 ECCRs. The 2002 regulations have a five-year prescribed period which means they will no longer have affect from 6 April 2022 which will be after when any of the Access SCR provisions take effect.

- The complexity of any solution is proportionate to the materiality of the problem and what customers can understand.

3.46. We will continue to work closely with BEIS and industry to better understand how our proposals can work alongside the regulations.

4. Our proposals for definition and choice of access rights

Section summary

We are minded to introduce better defined non-firm and new time-profiled access choices at distribution and define new non-firm arrangements in relation to the percentage of time that users are willing to be curtailed. We are also minded to continue to trial shared access arrangements via the ENA Open Networks programme.

We also confirm our position at shortlisting to not make these options available for small users[39] or to introduce new non-firm and time-profiled access choices at transmission.

Questions (please provide any further evidence to support your answers)

Question 4a: Do you agree with our proposal to introduce better defined non-firm access choices at distribution? Do you have comments on their proposed design?

Question 4b: Do you agree with our proposal to introduce new time-profiled access choices at distribution? Do you have any comments on their proposed design?

Question 4c: Can you identify any benefits to shared access rights that we have not considered, which could impact likely take-up?

Question 4d: Do you have any comment on our proposed choice about how to reflect access rights in charges (i.e. connection and/or distribution use of system charges)?

Question 4e: Do you have any comment on our proposal to not prioritise the introduction of new transmission access choices as part of this Significant Code Review?

Question 4f: Do you have views on how access rights should be standardised across DNOs?

[39] We use 'small users' to refer to households and non-domestic users that do not have an agreement for their maximum capacity usage.

Question 4g: Do you have any views on our proposed timescale of 1 April 2023 implementation?

Shortcomings in the current arrangements

4.1. Network access rights define the nature of users' access to the network and the capacity they can use – how much they can import or export, when and for how long, and whether their access is to be interrupted and what happens if it is. Network access requires a connection from the user's equipment to the wider network, and then allocated capacity on the wider network. Small users do not have a well-defined level of access.[40] For most other users, their network access is defined via their connection agreement.[41]

4.2. Traditionally users have had limited choice of access rights. Where new choices have become available, some of these choices have been loosely defined (e.g. "flexible connections" at distribution)[42] and require users to take on significant risk of curtailment. Improved choice and definition of access rights could help ensure users are able to get quicker or cheaper access to the network in line with their needs, by making better use of existing network capacity. Improved user understanding of their network access conditions will also improve their ability to provide flexibility services.

4.3. In this chapter we summarise our proposals and the rationale for our minded to positions and more detailed information can be found in Appendix 2.

Options and our proposed position

4.4. New access choices would be available to new users wanting to connect, and existing users wanting to amend their access rights over time. The three aspects of access choices that we prioritised in our launch letter were:

[40] In practice, most are only limited by their fuse size or service cable and may never have considered or 'chosen' the level of access they require.
[41] For more information about current access arrangements – please read our description of current arrangements: https://www.ofgem.gov.uk/system/files/docs/2019/12/winter_2019_-_working_paper_-_existing_arrangements_publish.pdf
[42] A "flexible connection" allows the connecting customer to be connected more quickly and avoid needing to make a contribution to reinforcement costs, in exchange for the risk of open-ended curtailment without the opportunity to agree a payment.

- **Levels of firmness**[43]: This would provide choices about circumstances where a connection capacity could be provided albeit with a lower level of security (or "firmness"), with the user's access to such access to all or part of the connection capacity being constrained in certain circumstances. Where users agreed to a lower level of firmness their eligibility for compensation in a loss of supply scenario could be restricted.

- **Time-profiled access**: This would provide choices other than continuous, year-round access rights (e.g. 'peak' or 'off-peak' access).

- **Shared access**: This would allow users across multiple sites, connected in the same broad area, to obtain access to the wider upstream network, up to a jointly agreed aggregate capacity level.

Options ruled out at shortlisting

4.5. As part of our Access SCR shortlisting decision, we ruled out the development of financially firm access at distribution (as well as determining in our launch statement that "Connect and Manage" at distribution level was out of scope of this review).[44] We acknowledge that we have received feedback from a range of stakeholders who are keen to develop this option, to mirror how it applies at transmission (accompanied with the Connect and Manage arrangements). We consider that the current distribution arrangements mean that those users with a "standard connection" have a high level of firmness and are generally only curtailed due to maintenance issues, network damage or faults. Beyond this, if a DNO wants to curtail one of these users, then the DNO would seek to agree a flexibility contract with the user. We are concerned that going further than this – particularly implementing Connect and Manage in relation to distribution network constraints – could create excessive costs for wider consumers without appropriate planning and security standards. These standards currently do not exist at distribution. It is not practical to develop and implement such standards within the implementation timeframes for these proposals (1 April 2023). This is aligned to our connection charging proposals which will encourage the DNO to consider the

43 A connection may be restricted by conditions such as a maximum export, or constraining output under certain network conditions. This is called a "non-firm" connection. Where there are no such restrictions, the offer is referred to as "firm".
[44] More information on our decision to not shortlist financially firm access at distribution can be found in Annex 1 of our March 2020 shortlisting decision: https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options

most efficient means of providing the capacity needed to facilitate a new or modified connection.

4.6. We also considered whether we should introduce a requirement for small users – or suppliers on their behalf – to nominate their access requirements, and to give them more choice over the nature of their access. However, as part of our shortlisting decision we ruled out better defining small users' access rights and giving them choice about their level of access. As set out in Annex 1 of our shortlisting decision, we did not identify significant evidence that this would support more efficient use and development of system capacity than charging focused options. We also identified practicality challenges given the number of consumers involved, and were concerned some consumers could end up with inappropriate access levels that do not meet their essential needs.[45]

Non-firm access

4.7. At distribution, we are proposing to introduce new, better defined non-firm access options. We consider that improving the definition and choice of non-firm access at distribution will help support more efficient use and development of network capacity. Improving the definition of non-firm access should significantly improve certainty for users relative to the current options for flexible connection. Our proposed reforms will also allow users to ensure that they have the level of access required to meet their needs and these reforms have received significant support from stakeholders.

4.8. We propose that these new distribution options will be defined in relation to the percentage of time that users are willing to be curtailed. Users will be able to choose what percentage of their total access rights are non-firm and will be protected from the risk of DNOs exceeding the agreed level of curtailment. More information on the proposed design of these arrangements can be found in Appendix 2.

4.9. We are not proposing to reform transmission non-firm access arrangements. These only apply where eligibility criteria for Connect and Manage are not met, and so are not as widespread as flexible connections at distribution level. In comparison to distribution arrangements, existing transmission non-firm access arrangements are relatively well-defined

[45] Further reasons for not shortlisting this option can be found here: https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options

and provide certainty to users about the level of curtailment. For example, a user's connection agreement will identify the specific element of the Security and Quality of Supply Standard (SQSS) that the user is non-firm in relation to. Most transmission users are knowledgeable about the energy system and are therefore able to understand the implications of the level of non-firm access agreed. Given this, transmission connected users have not expressed significant desire to reform current arrangements. However, we encourage NGESO to continue to consider the scope for improvements to the design of non-firm access at transmission.

Table 6 - Assessing the relative benefits of reforms to non-firm access rights at distribution and transmission

Option	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Non-firm at distribution	• New non-firm access options should support efficient network development in accordance with user requirements. • However, a conservative approach to translating physical assets into consumer experience could lead to less efficient development of the system.	• Provides new access choices with more certainty about the user's experience of curtailment. • This should facilitate users agreeing the level of access required to meet their needs. • Distribution users expressed interest in new non-firm access options.	• It will require DNOs to undertake changes to their systems and process (e.g. new data to measure curtailment rates).
Non-firm at transmission	• Moving towards a consumer outcomes approach to defining non-firm access could allow access to be allocated in accordance with user requirements. • However, a cautious approach to translating physical assets into consumer	• Existing non-firm transmission access already provides limits on the extent to which the user can be curtailed. • Reforming non-firm transmission arrangements not identified as a high priority by transmission stakeholders.	• Will require ESO to undertake changes to their systems and changes (e.g. new data to measure curtailment rates). • Significantly lower use of non-firm access at transmission.

	experience could lead to less efficient development of the system.		

Time-profiled access

4.10. Time profiled access rights may help to develop a more efficient electricity system if users profile their access rights to move away from the network peak(s).

4.11. We are proposing to introduce time-profiled access rights at distribution. However, time-profiled access will not be available for small users to choose. Users would be able to identify the percentage of their total access rights that are time profiled. Users could request to either have no access or non-firm access during the "peak" period.

4.12. We consider that new time-profiled access options at distribution could lead to more efficient use and development of system capacity. Identifying when users will have access to the network provides certainty for users and a wide range of stakeholders have repeatedly stated that this access right would be useful for them.

4.13. We are not proposing to introduce time-profiled access at transmission. Existing non-firm transmission access already provides certainty about when a transmission user will be curtailed. Unlike distribution access arrangements, we have not received significant representations that transmission access arrangements need reforming. The introduction of time-profiled access at transmission could help support more efficient use of the network, but we have not received evidence to demonstrate that there are significant benefits. However, we encourage NG ESO to continue to consider the scope for improvements to the use of flexible connections (including time-profiled options) at transmission.

Table 7 - Assessing the relative benefits of time-profiled access rights at distribution and transmission

Option	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Time-profiled access at distribution	• Should lead to more efficient use and development of system capacity by making better use of spare capacity network during off-peak periods.	• Several stakeholders have highlighted that this may be very useful. • We consider that it should allow users to agree the level of access required to meet their needs.	• It will require DNOs to undertake changes to their systems and process (e.g. new data to measure curtailment rates). • Some DNOs already offering this type of access.
Time-profiled access at transmission	• We consider it could lead to more efficient use and development of system capacity. • However, the impact could be limited because there are already existing options to facilitate temporal flexibility at transmission and NG ESO already make assumptions about when users will import/export.	• Limited support from transmission-connected users that this type of access right would be useful. • Existing non-firm transmission access already provides certainty about when a user will be curtailed.	• Will require NG ESO to undertake changes to their systems and processes. • Significantly lower use of flexible connections at transmission.

Shared access

4.14. Currently, users secure access based on the needs of an individual site. We have considered options to allow multiple sites connected locally to a network to share access to capacity on the wider network upstream of a common point up to a jointly agreed level for the relevant sites connected to the network below that connection node. These sites would coordinate their maximum demand to ensure that the aggregate demand at the relevant connection node was within the limits set out in their shared access right. As part of our shortlisting decision, we ruled out users sharing access over a wider area (i.e. users that are not in close proximity, geographically or electrically) due to concerns that it would not support more efficient use of the system, and significant practical issues and challenges.[46]

4.15. The development of shared access would require the development of clear eligibility criteria, to ensure that only those users that deliver network benefits are able to share access. The development of shared access would also require a new commercial agreement between the network operator and the users that are sharing access. This new commercial agreement would outline what roles and responsibilities remain with the individual site (e.g. compliance with technical requirements), and which sit with the party or parties responsible for sharing access (e.g. compliance with cumulative access limits).

Table 8 - Assessing the potential benefits of introducing 'shared' access options

Option	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Shared access	• Could lead to more efficient use and development of system capacity. • However, we need to identify eligibility criteria to only allow projects that deliver benefits beyond those already assumed as part of diversity assumptions.	• Some stakeholders have highlighted that this option could be useful. • However, sharing access rights will require individual users to take on risk of exceeding agreed cumulative limits on capacity. • Several stakeholders do not consider that this option would be popular.	• This option would potentially require more network monitoring and data collection, compared to non-firm/time-profiled options. • It would also require changes to commercial relationships. • We need to consider how the process for charging this type of access would work (e.g. a cumulative capacity charge).

[46] Further reasons for not shortlisting this option can be found in Annex 1 here: https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options

4.16. We are not proposing to take forward shared access as part of the Access SCR. Our industry engagement to date has emphasised the uncertainty of take-up of the option (e.g. whether sharing access with other users will be considered too risky for most users to accept). We also have concerns about the practicality of this option (e.g. how capacity/exceeded capacity charges are allocated if the users have different suppliers) and the proportionality of making these changes in the face of uncertain take-up.

4.17. We consider that further trialling and testing of shared access is useful in order to allow for further exploration of the concerns that we have identified. The ENA Open Networks have taken this forward alongside their existing work on trading access.[47]

How to charge for alternative access rights

4.18. We think that users should receive value when they obtain an access right that avoids additional network costs. We think this value can be provided through two means – allowing the user quicker access to the network than otherwise, and/or allowing them cheaper access. There are two ways in which the value of different access right choices can be signalled to users, the connection charge, or the distribution use of system (DUoS) charge. This means that the options for how they are valued are strongly linked to our decisions on connection charging and the design of future DUoS charges.

4.19. Our decision on how access rights are valued also has an impact on the design of these access right choices themselves (e.g. connection charges are more easily able to reflect bespoke access arrangements).

4.20. We are minded to reflect the value of non-firm distribution access rights via connection charges only. We explored the option of doing this via a reduced distribution use of system charge. However, it is difficult to accurately reflect the benefits of access rights choices via DUoS charges. For example, the value of alternative access rights is very location specific, whereas use of system charges tend to involve a degree of averaging and approximation. We also had concerns that inaccurately valuing access rights via use of system charges could risk over-valuing flexible access choices and introduce distortions in markets for procuring flexibility.

[47] Open Networks: developing the smart grid - Energy Networks Association

4.21. Our proposals to reduce the extent to which users pay for reinforcement costs via connection charges – fully for demand and partially for generation – will reduce or remove the extent to which connection charges reflect a financial value for opting for a non-firm or time-profiled access right. For example, this would mean that any generation users where reinforcement is not needed at their voltage of connection,[48] and all demand users, would not receive any reductions in network charges if they opted for non-firm access. However, these connection customers may still choose an alternative access choice if it helps facilitate quicker connection to the network. This could enable an earlier connection while the DNOs increase network capacity (e.g. via reinforcement or flexibility procurement), with the customers able to then have standard access from that point.

4.22. For time-profiled distribution access rights, we think there could be scope to reflect the value via connection charges and/or DUoS charges, though the latter would be dependent on our final proposals for DUoS charging reform. The charge design we are considering would provide for the costs of access during different periods to be calculated in a relatively simple and accurate way, through having capacity charges that vary at different times of day, reflecting how constrained the network is estimated to be, relative to the peak load. We will set out more detail on our thinking on this area when we outline more information on our DUoS proposals.

4.23. In this consultation document we provide broad parameters regarding the design of future network access choices (e.g. how non-firm access right choices should be valued). This provides some scope for these to be tailored to reflect the specifics of local network conditions and stakeholder preferences, whilst achieving a greater level of clarity and standardisation.

Compliance with access right choices

4.24. Compliance with new access choices is necessary to deliver the benefits of alternative access choices (e.g. avoided costs) and it reduces the risk to other users of the electricity system. We consider that improvements could be made to the current access right compliance regime to ensure that the benefits of our reforms are realised. For example,

[48] Subject to a final decision on the interaction between the HCC and voltage rule. This is discussed further in Appendix 1 on our connection charging proposals.

improving the cost reflectivity of excess capacity charges and improving the transparency of network operator actions to address instances of non-compliance.

4.25. We propose that DNOs develop a common, clear, and consistent approach to the monitoring and enforcement of access rights. The guidance should outline how network operators will ensure user compliance with agreed access right limits. More information on our proposals can be found in Appendix 2.

4.26. We are minded that our proposed access rights reforms to introduce better defined non-firm and new time-profiled access choices should be implemented for 1 April 2023.

Outages due to unexpected loads on the network impacting distribution users access to transmission

4.27. Most users connected to distribution networks do not agree explicit access rights with NGESO. Instead, they generally have implicit access (given that electricity flows do not respect regulatory boundaries) unless their connection agreement with the DNO suggests otherwise.

4.28. We have been considering whether this lack of explicit access creates any issues for smaller distributed generation as part of our thinking on whether they should pay equivalent transmission charges as larger generators. We discuss this further in Chapter 5.

5. Our proposals for TNUoS charging for Small Distributed Generation

Section summary

We consider that the current charging arrangements for generators under 100MW are no longer fit for purpose, given the growth in small distributed generation. We are minded to charge all users over 1MW TNUoS generation charges. We recognise these changes will lead to increased costs for some generators, but consider they will help to ensure the efficient development of the system and support achievement of Net Zero at least cost. However, given the potential impact, are also consulting on whether transitional arrangements, such a phased implementation of the policy, would be appropriate.

Questions (please provide any further evidence to support your answers)

Question 5a: Do you have any evidence that SDG does not contribute to flows in the same way as large generation and, therefore, should not be charged on a consistent basis?

Question 5b: Do you agree with our threshold for applying TNUoS generation charges of 1MW? If not, what would be a better threshold and why?

Question 5c: Do you have any evidence that distribution connected generation at a grid supply point has a different impact than directly connected generation?

Question 5d: Do you have a preference for one of our options for addressing the local charging distortion? If so, please indicate which option and provide your views on pros and cons. Are there any options we have missed?

Question 5e: Do you support our position that we should consider transitional arrangements? If so, do you have a preferred option and evidence to support the benefits or risks associated with each option?

Question 5f: Have we identified all the options for administering TNUoS generation charges for SDG? If not, what options have we missed, and why would they be preferable to those we have identified? Can you provide any evidence regarding the implications of the different administrative options for your business?

Question 5g: Are there any specific issues you think we need to consider, as part of our work on the future role of network charges? Why are these important to consider?

Shortcomings in the current arrangements

5.1. Currently, arrangements for setting transmission network use of system (TNUoS) charges for generators apply differently to the following broad categories of users:

- Transmission-connected generation (TG), which face wider locational transmission charges[49] and local transmission generator charges,[50] which cover the parts of the network that link user connections to the Main Interconnected Transmission System (MITS), the highly meshed central part of the transmission network

- Large distribution-connected generation (LDG), with installed capacities above 100MW),[51] which face wider locational transmission generation charges

- Small (<100MW) distribution-connected generation (SDG), which face transmission charges (via their supplier) as inverse demand for their export during Triad or the demand tariff if they import during Triad. SDG charges are negative or 'capped' at zero, so generators do not face charges for export.

- Behind the meter generation (BTMG), also known as onsite generation, which also faces transmission charges (via their supplier) as inverse demand, with their output netting off demand on their sites. When exporting from their site, BTMG faces the same signal as SDG.

5.2. We think the differences in the charging arrangements for different types of generators create a boundary distortion that can lead to inefficient decisions about where generation should locate. Figure 4 illustrates the impact of this on the charges or credits that are faced by generators in different locations, as determined by how far they are from demand.

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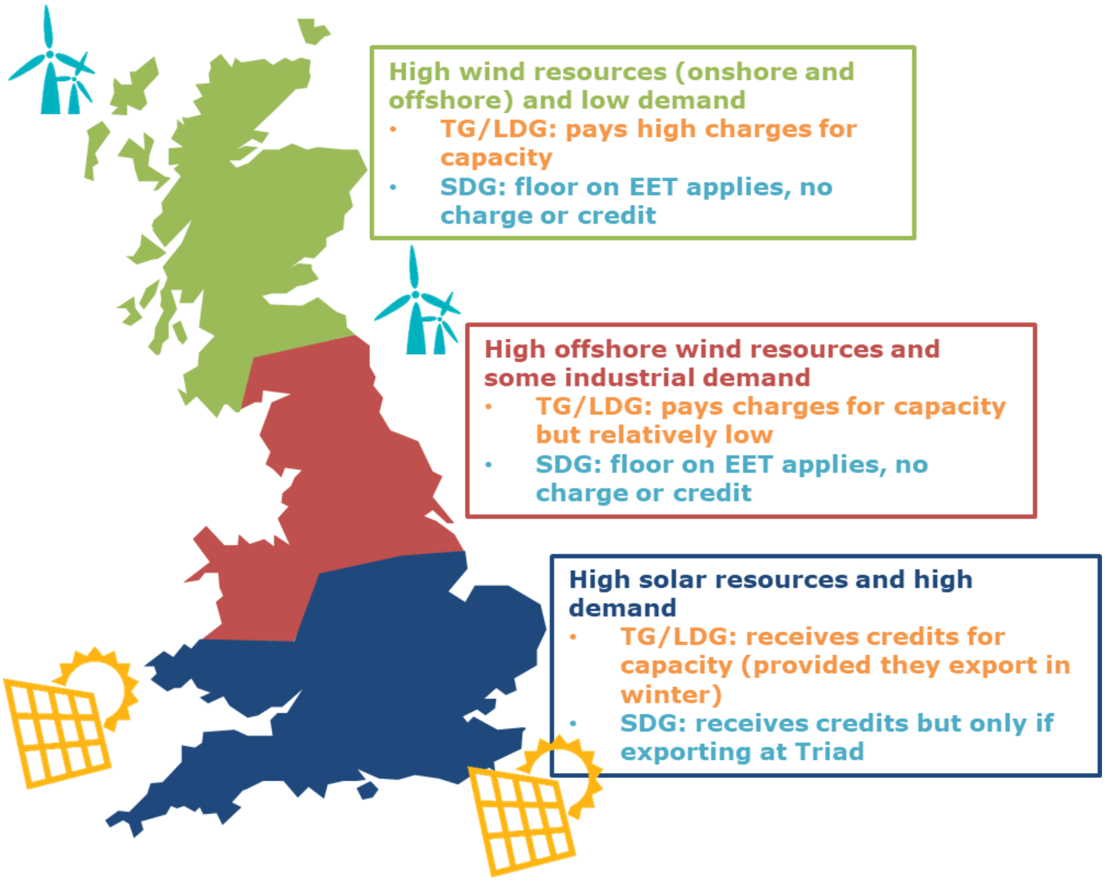
[49] Wider locational transmission charges reflect the impact of a generator on the MITS the core highly meshed part of the transmission network.
[50] Local transmission generator charges cover the parts of the network that are not part of the MITS and link individual user connections to the MITS. They can be shared, or used only by single users.
[51] Generators with installed capacity below 100MW who sign a Bilateral Embedded Generator Agreement (BEGA) will also face wider TNUoS charges

Figure 4 - Indicative locational variation in charging arrangements



5.3. As part of the Access SCR we are considering two key areas of differential treatment, explored further in this chapter:

- at the 100MW boundary, between SDG/BTMG on the one hand and TG/LDG on the other; and
- the liability for local charges, between TG and LDG/SDG.

5.4. Firstly, SDG face transmission charges that are calculated based on demand net of embedded generation (although charged to suppliers based on gross export), as they are currently assumed by the charging methodology to offset transmission system demand. However, since these arrangements were first put in place, there has been significant growth in SDG on the network, which is having an effect on the network in some places. One result of this was a change to the System Security and Quality of Supply Standards (SQSS)[52] to ensure SDG is represented in planning studies, rather than being treated as negative demand, ensuring that the transmission system is reinforced to an appropriate, economic and efficient level. This means that there is now a disconnect between the manner in which charges are calculated, and the manner in which the system is planned. We think that retaining differential treatment in our forward-looking charging arrangements results in a distortion at the 100MW boundary, which can lead to inefficient siting and operating signals.

5.5. Secondly, it is possible for SDG to utilise transmission assets which are charged for through a transmission-connected generator's Local charges (either Local Substation or Local Circuit). There is currently no process by which, in these circumstances, SDG contribute to the costs of those assets. We think this is a potential distortion that, as it relates to Local Charges, cannot be resolved by the application of Wider TNUoS charges to SDG. However, we understand that at present, there is one local substation which is a GSP but is not a MITS node (meaning that the charges for the substation are a large generator's Local Substation charge).

5.6. As links to remote islands develop, we are conscious that this scenario may become more commonplace, as embedded generators on an island may export using the cable connecting the island to the mainland, which might be another generator's Local Circuit. As part of our assessment of this issue, we have identified different options for resolving this type of distortion, but at present – given that it only relates to a single site and is theorised to become more commonplace in future years – we think that this is not a priority area for reform. That is not to say that we do not consider there to be the potential for a distortion, but in the context of the wider set of reforms and the potential for a broader review of charging arrangements, we are not convinced that SDG utilisation of local assets need be urgently addressed through this SCR. We are seeking stakeholder views on this point of prioritisation.

[52] On 24 May 2018, we approved GSR016, which amended the definitions in the SQSS of 'ACS peak demand' and 'Plant Margin, Economy Planned Transfer Conditions, Planned Transfer Conditions and Security Planned Transfer Conditions' to remove the exclusion of SDG. As a result, all generation is assumed to contribute equally under planning studies.

Options and our proposed position

Should SDG face Generation TNUoS?

5.7. For our main decision we have considered two sub-options:

1. All generation users face TNUoS generation charges.
2. SDG retain inverse demand charges (via the embedded export tariff (EET)) with the cap removed so that they may be exposed to positive charges in certain regions.

5.8. All generation make a similar contribution to system flows and growth in SDG means it is starting to have a sufficient effect on the transmission system that it is important that the ESO has visibility of it when undertaking planning studies. Given this, we do not consider there to be any justification for our forward-looking transmission charging regime to treat some generation differently to the rest and propose to charge all users TNUoS generation charges, where practical. By charging all generation TNUoS generation charges, we will be removing a significant difference in investment and operational signals between SDG and LDG/TG and creating a level playing field. Applying TNUoS generation charges is a simple and reliable way of aligning the incentives faced by SDG and other plant.

5.9. We also considered just removing the cap from the EET to enable users located far from demand to face charges, but, although it reduces the differences in charges paid, it retains some significant distortions:

- 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.

Is it proportionate for all SDG users to face Generation TNUoS charges?

5.10. For this decision we have considered two sub-options:

- All SDG users face TNUoS generation charges
- Some SDG users retain EET charges, with the cap removed.

5.11. The growth in SDG meaning that, in theory, generation of all sizes could be (or start) contributing to network costs and so should face TNUoS generation charges. However, in practice, we do not think the cost and administrative burden to identify and agree TEC with very small generation would be proportionate to the improvement in network efficiency that would arise from them facing TNUoS generation costs.

5.12. Instead, we think that SDG with export capacity below 1MW should not face TNUoS generation charges because:

- This is the boundary that existing planning studies use to ensure the flows of distribution connected generation are accounted for.
- It is also the threshold at which users can take part in the Balancing Mechanism (BM)[53] either directly or through wider access and so can access other revenue streams to offset the impact of these TNUoS generation charges.
- Finally, generators about this size are required to be included on DNO capacity registers, which came into effect following our approval of Distribution Connection and Use of System Agreement (DCUSA) change DCP350 – Creation of Embedded Capacity Registers.[54]

5.13. For these reasons, we think that 1MW represents a practical threshold for determining which SDG should face TNUoS generation charges.

5.14. Generation under 1MW will continue to face the inverse of demand charges under the EET. However, these are capped at zero, preventing SDG in areas located far from demand

[53] The Balancing Mechanism is a tool used by the ESO to balance supply and demand close to real time through acceptance of bids or offers to increase or decrease generation or consumption
[54] DCP350 decision letter: https://www.ofgem.gov.uk/system/files/docs/2020/07/dcp350d.pdf

facing charges. The cap exists to prevent dispatch distortions in areas of high transmission charges caused by the use of inverse demand charges. We think the presence of the cap is not likely lead to efficient use and development of the network, and therefore think the charging cap should be removed.

5.15. We have assessed our options against guiding principles 1 and 3 in Table 9. Guiding principle 2 is primarily about the impact of our reforms on small users and so we have not assessed TNUoS generation charges for SDG against this principle.

Table 9 - Assessment of SDG charging options against guiding principles

Options	Guiding principle 1	Guiding principle 3
Option 1a **TNUoS generation charges for all users**	• Likely to lead to more efficient use and development of the system, with all users now operating in line with LDG/TG • Charges reflect the fact that generation of all sizes could be contributing to flows and network costs	• Significant impact for some users • Very significant amount of work to identify TEC for all users, which is not likely to be outweighed by the benefit
Option 1b **TNUoS charges for all generation >1MW and uncapped EET for <1MW**	• Improved cost-reflectivity, as these users will face signals in places located a long way from demand (through uncapped TNUoS or EET) • <1MW users cannot participate in BM and so have limited avenues to mitigate impact of signals	• Significant impact for some users • >1MW users already present on DNO capacity registers • Depending on administrative arrangements, there would still be changes needed to agree export with SDG >1MW
Option 2 **Uncapped inverse demand charges – all SDG**	• Partially addresses the distortion, as SDG that drives costs would face charges • Sends a perverse signal that incentivises users to turn down during Triad to avoid charges • Retains different charging arrangements between TG/LDG and SDG	• Significant impact for some users • Simplest option to implement, as only requires cap on charges to be lifted and charges applied to export during Triad

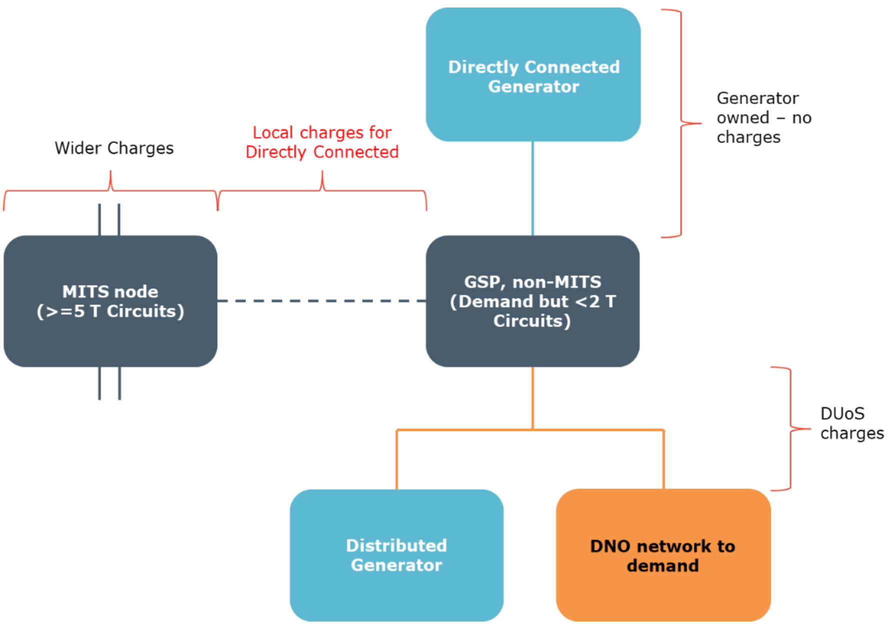
5.16. Our assessment suggests that Option 1b – applying TNUoS charges to all generators, except for <1MW SDG, which would continue to face the EET with the cap removed, would best achieve the guiding principles.

Local charges for distribution connected generation

5.17. Removing the different treatment of small and large generation with regards to wider TNUoS will address a key distortion that incentivises users to make inefficient investment decisions. However, there is still a difference in treatment between TG and all DG, as only TG faces local charges.

5.18. In almost all cases, this does not create a distortion, as DG would pay DUoS charges with respect of their "local" assets that connect them to the grid supply point (GSP) connecting them to the transmission network (i.e. the MITS node). The issue arises where a GSP is not classified as a MITS node, which is most likely to occur on remote islands, but could also occur at other GSPs. In these cases, TG would pay local charges, but DG would not face equivalent charges for local assets connecting them to the MITS node. This is illustrated in Figure 5.

Figure 5 - Example of a GSP which is not a MITS node



5.19. We have considered options for addressing this differential treatment, although as outlined at paragraph 5.6, we do not think this is a priority area for reform under this SCR. Options include:

- Amend the CUSC[55] to treat all remote island links as wider assets, which would mean the assets connecting to the MITS node would be captured under wider charges
- Maintain current classification of wider/local assets in CUSC, and levy a local charge on each embedded generator in respect of its impact on assets between the GSP to which it connects and the MITS.

5.20. If all remote island links were treated as wider assets, then they would be added to the assets being reflected through the wider charges, which are recovered from all generation in that charging zone. We recognise that, given generation on the mainland might only use the remote island links rarely, it may not be cost reflective for them to face charges that include the links and it might be necessary to consider rezoning to address the issue.

5.21. A key issue with levying local charges on embedded generation is identifying the contribution that downstream SDG has made to flows over local circuits (to the extent that it does), in order to apply charges. In some individual cases, such as with the new HVDC link to Shetland[56], our approval of some TO investment can be based on, inter alia, the build progression of a specific (new) power station, such as Viking Energy Windfarm, and we recognise that in those cases, the extent to which SDG already in situ drives such investment is unclear. Per 5.6, we do not think that this is a priority area for reform and, further consider that given the relatively high costs of some relevant assets, especially but not limited to HVDC links, further analysis and evidence-gathering is required before reaching any policy position.

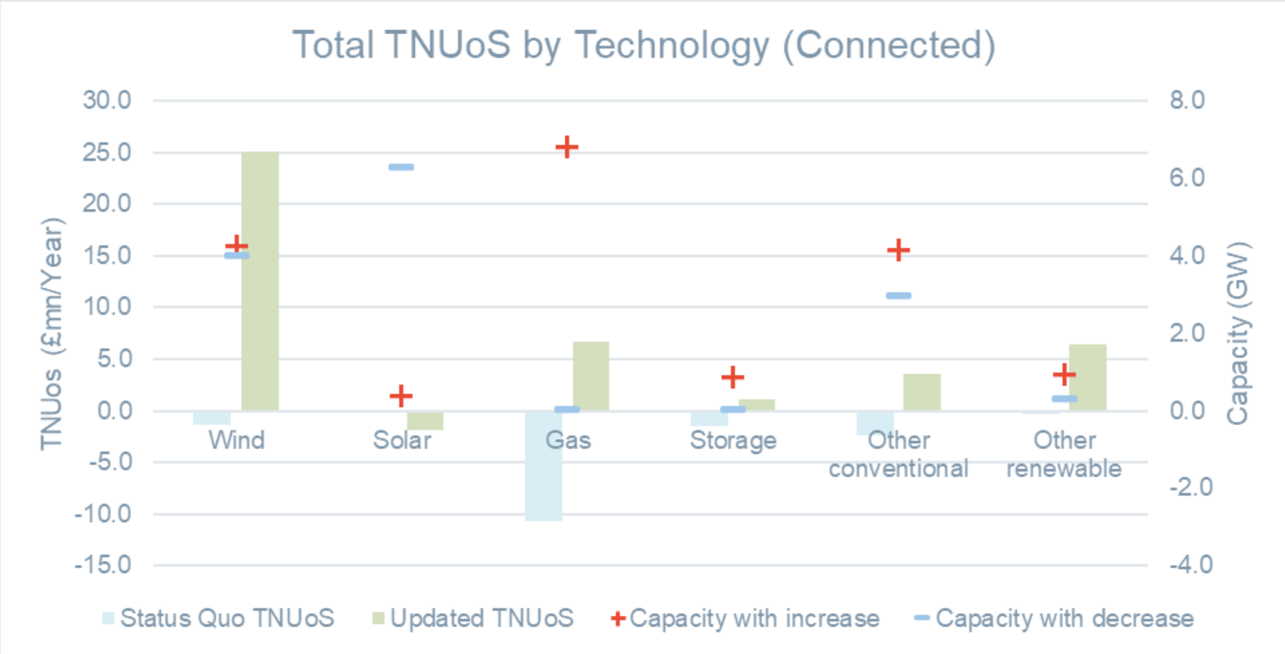
Should transitional arrangements be considered for the application of Wider TNUoS charges to SDG?

5.22. Our analysis, based on connected generators, indicates there is 5.6GW of renewables (4.3GW of wind, 0.4GW of solar, 0.3GW hydro, and 0.6GW biomass) and 0.9GW of storage which will see TNUoS costs increase under our reforms. The impact is expected to be greatest in Scotland, because SDG currently have their charges capped at zero. Conversely, in more

[55] Connection and use of system code (CUSC) is the contractual framework for connecting to and using the National Electricity Transmission System
[56] Shetland transmission project: Decision on Final Needs Case (ofgem.gov.uk)

southern regions, moving to TNUoS generation charges would lead to lower charges or even an increase in credits for approximately 10GW of renewables (largely solar).

Figure 6 - Change in charges or increased credits under TNUoS generation charges



5.23. We think it is possible that the impact of our reform will have a more significant impact on low carbon generation in areas with negative EET than users with dispatchable generation, to the extent that the latter can recoup the increased cost through higher wholesale trades and Balancing Mechanism bids/offers. However, this will only be true where trades are dispatched and, by seeking to trade at higher prices, they may simply not be dispatched in favour of cheaper southern generators.

5.24. As the purpose of the change is to facilitate more efficient use and development of the network, we are considering the following transitional arrangements, including limiting them to specific technologies focused on low carbon generation, will lead to more efficient outcomes:

- No transitional arrangements – subject to our final decision, raise the relevant code modifications immediately, in order to address the distortion most quickly
- Delay implementation – as discussed later in this chapter, there is currently significant uncertainty about the longer-term direction and role of transmission charging, and whether a wider review is required. There may be optionality value

in delaying implementation until there is greater clarity about further developments in transmission charging.

- Limited period grandfathering[57] – this could be applied as a separate implementation approach alongside the other options, with a (currently undetermined) group of generators continuing to face the capped EET for a specific period of time (e.g. 15 years from commissioning, reflecting the CfD duration).

5.25. The benefits and issues with the transitional options are summarised in Table 10.

Table 10 - Assessment of benefits and issues with transitional arrangements

Options	Benefits	Issues
No transitional arrangements	• Removes a competitive distortion, which improves cost reflectivity, in the least amount of time • Provides quickest certainty to investors about future signals, supporting more efficient siting decisions.	• Existing capacity may be incentivised to close, rather than repower, stranding expensive reinforcement • Does not provide time for users to reflect change in their commercial arrangements • Creates risk of short-term volatility if signals through TNUoS generation charges change again post-wider review of TNUoS
Implement change with delay	• Provides certainty to investors about future signals, supporting more efficient siting decisions • Gives time for users to reflect the change in their commercial arrangements	• Retains distortion for a period of time, meaning some users benefit from less cost reflective charges • May not be aligned with strategic direction of travel for network charges • Creates risk of short-term volatility if signals through

[57] "Grandfathering" refers to applying an exemption to someone or something from a new law or regulation. In this case, it would be an exemption from being charged TNUoS generation charges.

		TNUoS generation charges change again post-wider review of TNUoS
Confirm intention to address distortion but delay until greater clarity about strategic direction	• Ensures alignment with strategic direction of travel for network charges • Removes risk of short-term volatility in charges	• Retains distortion for a period of time, meaning some users benefit from the competitive distortion for longer • Continuing uncertainty about future generation charges, which may affect investment decisions, including repowering / commissioning / decommissioning
Grandfathering (can occur alongside other options)	• Mitigates impact for users who made decisions under previous regulatory arrangements	• Cost reflective outcome substantially delayed, plant that should face review now may not, and decisions on investment may be distorted. • Repowering of existing sites may be delayed to maximise revenues from existing regime • Implementation could be significantly complex and would create a boundary between those who are and are not grandfathered • Prevents any future improvements during the grandfathering period from being applied to the specific group of generators

5.26. We are currently minded to keep all options under consideration, including the option of no transitional arrangements. We are particularly interested in stakeholder evidence regarding the risk of stranded assets or cancelled repowering of existing sites and how we can mitigate this, while maximising consumer benefit from the reform.

Administrative arrangements for charging small generation

5.27. Currently, SDG users do not generally have explicit agreements with the ESO and are instead charged via their supplier for their volumes exported. This means there will need to be a change to the current arrangements to enable the ESO to recover charges for use of the transmission network. We have identified four main options for how this could be achieved:

1. All SDG enters into access agreements with the ESO to establish their capacity and then the ESO charges the supplier for TNUoS charges, similarly to how they currently charge the EET

2. All SDG enters into access agreements with the ESO to establish their capacity and the ESO charges them directly

3. Supplier agrees capacity for their portfolio of SDG in each zone for charging purposes, and are charged TNUoS by the ESO on that basis

4. DNOs agree total transmission access with the ESO on behalf of SDG embedded in their network. The ESO then charges the DNO TNUoS and the DNO bills the supplier for their combined DUoS and TNUoS.

5.28. Our initial considerations are that the first two options, where SDG enters into a direct relationship with the ESO are likely to lead to the most efficient outcomes. However, in particular with the second option, we recognise this would be an increase in administrative activities for the ESO and, unless the agreement was simplified, it could be costly for users.

5.29. We recognise similar models that are more proportionate could be possible and invite stakeholder feedback on what these might look like, particularly around whether a BEGA-light-type model could give the benefits of ESO-led arrangements without the practicality or proportionality concerns. We think, whichever model is used for DG to face the same signals and incentives as larger generators, they would need to hold dedicated capacity, or have it held for them.

5.30. We consider that a supplier led option, where suppliers hold TEC for the DG under their portfolios may provide a simple approach for charging DG, as it would not necessarily require the ESO to charge each generator separately. However, we recognise they raise a large number of implementation challenges, including the large expansion of the supplier role and increased liability they would face.

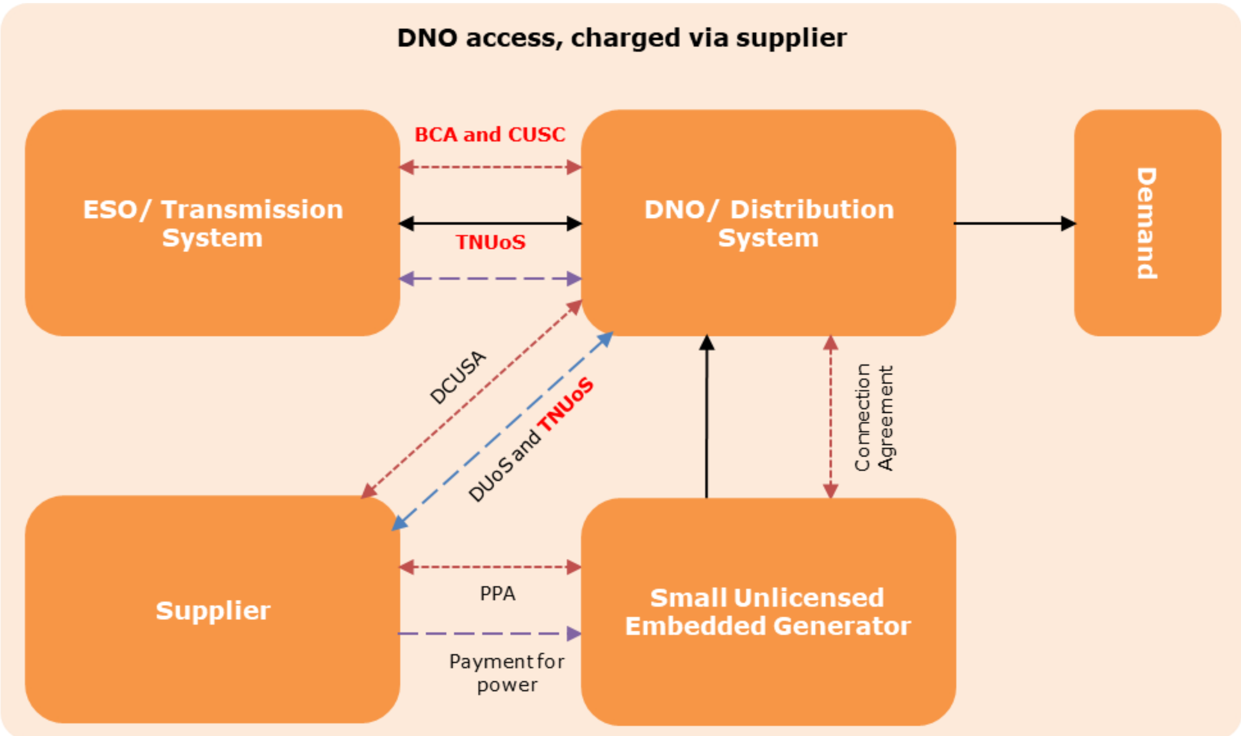
5.31. A DNO led model appears to be unnecessarily complex, when compared to an NGESO or supplier led option. Table 7 illustrates the flow of network charges, commercial agreements, and power purchases between the different participants under a DNO led model.

The red text highlights the changes that may need to be made to implement this model, with the three most significant being:

- Existing agreements between NGESO and suppliers, as established under the CUSC and to enable payment of the EET, would no longer be needed in respect of SDG
- The DNOs would need to enter into agreements with the ESO for aggregate amount of capacity the SDG on their networks would require and would be charged TNUoS by NGESO
- The DNO would then bill the supplier for TNUoS charges relating to their customers, along with the DUoS charges, which they already charge suppliers.

5.32. It is unclear to us what the benefit would be of removing the direct relationship the suppliers have with NGESO, in respect of some sites, and replacing it with an additional obligation on the DNO to pass the charges through from NGESO.

Figure 7 - DNO led model for charging TNUoS generation charges to SDG



Future developments in transmission charges

5.33. We are currently undertaking wider strategic work on approaches to delivering FCF, including the role for network charges. As described above, we are currently minded to signal that the boundary distortion should be removed, but delay implementation until there is greater clarity around the direction of travel for network charges.

5.34. As part of any further work, there is increasing evidence that we need to undertake a wider review of TNUoS charges. When we launched our Access SCR in December 2018, we included only a limited scope for TNUoS issues because we did not think issues identified with the charging arrangements were as pressing as those for distribution network charges and we had only concluded Project TransmiT in 2014. However, a number of issues have become more prominent due to continuously evolving energy landscape and the impact of some proposed code modification changes (e.g. rezoning).

5.35. We are mindful of the risk of "change fatigue" and the impact of continuing uncertainty on investor decisions, but think the benefit of ensuring charging arrangements sufficiently flexible to enable them to be applicable, regardless of the future role that charges plays, outweighs this.

5.36. We will engage further with industry on the scope of further development of TNUoS charges and the mechanism for delivery, as part of our engagement on the outcomes of our full chain flexibility work.

6. Interactions with RIIO-ED2

Section summary

This section summarises the interactions between the Access SCR and RIIO-ED2. For further details regarding RIIO-ED2 price controls, please refer to our website.[58]

Interactions with RIIO-ED2

6.1. The next electricity distribution price control (RIIO-ED2) will run from April 2023 to April 2028. The RIIO price control determines the amount of revenue that network companies can recover. The RIIO price control framework also establishes the outputs that the network operators should deliver and provides incentives for their delivery. In December 2020 we published our decision regarding the RIIO-ED2 Sector Specific Methodology.[59]

6.2. There are important interactions between the proposals set out in this minded-to consultation and the RIIO-ED2 price controls. For example, our reforms could change the amount of funding required as part of the RIIO-ED2 price control or could require the introduction of new obligations or incentives. The table below highlights the key interactions between RIIO-ED2 and this consultation.

Table 11 - Linkages between RIIO-ED2 and this consultation

Potential impact on RIIO-ED2 price control		Description
Changes in the amount of funding required	Connection boundary	Any change to the depth of connection charges would alter the costs to be recovered through the price control. A more shallow connection might also help create opportunities to consider alternatives to traditional reinforcement and might also impact user behaviour (e.g. the number of new connections) and the amount of investment required in new network capacity.

[58] Network prices controls - https://www.ofgem.gov.uk/regulating-energy-networks/2023-price-control-review-riio-ed2
[59] RIIO-ED2 Sector Specific Methodology - https://www.ofgem.gov.uk/publications-and-updates/riio-ed2-sector-specific-methodology-decision

	New costs	Some options could mean DNOs incur new costs (e.g. new network monitoring or billing systems). Should we decide the benefits outweigh the costs, there would need to be a mechanism under ED2 for the DNOs to receive funding.
	Network capacity requirements	Options for reform could impact users' behaviour. This could reduce the need for network investment. Reforms could also lead to changed approaches to network planning and development in response to capacity requirements.
Changes to obligations or incentives	Obligations or incentives to make access available	Our reforms rely on the SO and DNOs having the right incentives to make access available in an efficient manner for the system as a whole.
	Obligations or incentives to roll out new systems efficiently	Should we conclude that the DNOs need to incur new costs (e.g. new network monitoring or billing system), obligations or incentives may be required to ensure rollout.
Changes to level of risk	Expenditure risk	Reforms could alter the level of financial risk that DNOs are exposed to under the price control (e.g. risk of under/over recovery of allowed revenue).
	Output and incentive risk	Reforms could lead to risks of DNOs being unable to deliver target output levels. For example, increased volumes of connections could impact DNO connection performance (e.g. time to connect or guaranteed standards) or network utilisation levels (e.g. LIs).

RIIO-ED2 business plans

6.3. Under RIIO-ED2, Ofgem requires companies to submit well-justified business plans detailing how they intend to meet the requirements set out in the sector methodology decision. We recognise that our final decision on the Access SCR could impact RIIO-ED2 business plans and that our position on reforms could change between minded-to consultation and final decision. We expect that our changes to the distribution connection boundary and to the definition and choice of access rights will impact the RIIO-ED2 business plans due to the changes in network planning and funding that our proposals would result in. We are committed to working with network companies and wider stakeholders to manage these interactions.

6.4. In the December 2020 RIIO-ED2 Sector Specific Methodology Decision (SSMD), we acknowledged that delaying publishing our minded-to proposals and decisions to ensure they are aligned with our FCF work means that DNOs would not have sight of our minded to positions in time to reflect them in their draft business plans. For this reason, paragraph 2.27

of our RIIO-ED2 SSMD said that we expect DNOs to base their draft business plans on the current arrangements, however, they should identify the parts that are impacted by our possible decisions on the Access SCR by reference to what they do know of what is in scope, what has been shortlisted, and the steers that have been given in the working groups.

6.5. We also expect the final business plans submitted later this year to take our proposals presented within this document into account. Through the RIIO-ED2 working groups we are keen to develop common approaches to help manage the uncertainty about the impact of our Access SCR decision on user behaviour (e.g. the extent to which our decision on the connection boundary impacts the volume or types of distribution connections during RIIO-ED2). This could require the development of additional RIIO-ED2 uncertainty mechanisms or the development of common assumptions across the different DNOs.

7. Consultation questions and how to respond

Section summary

This section outlines the questions on which we are seeking stakeholder views, including a further general question in addition to those set out earlier in this document. It also outlines our intended consultation timeline and outlines how stakeholders can engage with and respond to this consultation.

Collated list of all consultation questions

3. Connection boundary

Question 3a: Do you agree with our proposals to remove the contribution to reinforcement for demand connections and reduce it for generation? Do you think there are any arguments for going further for generation under the current DUoS arrangements? Please explain why.

Question 3b: What evidence do you have on the effectiveness of the current connection charging arrangements in being able to send a signal to users and what do you think will be the effect of our proposed changes? How does this vary between demand and generation connections?

Question 3c: What are your views on the effectiveness of the current arrangements in facilitating the efficient development and investment in distribution networks? How might this change under our proposals where network companies are required to fund more of this work?

Question 3d: Do you agree whether the need to provide connection customers with certainty of price reduces the potential for capacity to be provided through other means such as flexibility procurement? How might this change under our proposals?

Question 3e: What are your views on whether we should retain the High Cost Cap? Is there a case for reviewing its interaction with the voltage rule if customers no longer contribute to reinforcement at the voltage level above the point of connection?

Question3f: What are your views on the recovery of the costs associated with transmission that are triggered by a distribution connection? Does this need to be considered alongside wider charging reforms or could a change be made independently?

Question 3g: What are your views on the likelihood of inefficient investment under our proposals (e.g., an increase in project cancellations after some investment has been made)? Are there good arguments for further considering introducing liabilities and securities to mitigate this risk?

Question 3h: What are your views on whether the interactions between our connection reforms and the ECCRs must be resolved before we are able to implement our proposed reforms? How do you factor in the effects of the ECCRs (if at all) into decision making, given the levels of uncertainty around subsequent connectee(s)? What suggestions do you have to make our policy and the ECCRs work together most efficiently?

4. Access rights

Question 4a: Do you agree with our proposal to introduce better defined non-firm access choices at distribution? Do you have comments on their proposed design?

Question 4b: Do you agree with our proposal to introduce new time-profiled access choices at distribution? Do you have any comments on their proposed design?

Question 4c: Can you identify any benefits to shared access rights, which would indicate we have underestimated the likely take-up?

Question 4d: Do you have any comment on our proposed choice about how to reflect access rights in charges (i.e. connection and/or distribution use of system charges)?

Question 4e: Do you agree with our proposal to not prioritise the introduction of new transmission access choices as part of this Significant Code Review?

Question 4f: Do you have views on how access rights should be standardised across DNOs?

Question 4g: Do you have any views on our proposed timescale of 1 April 2023 implementation?

5. TNUoS charges for SDG

Question 5a: Do you have any evidence that SDG does not contribute to flows in the same way as large generation and, therefore, should not be charged on a consistent basis?

Question 5b: Do you agree with our threshold for applying TNUoS generation charges of 1MW? If not, what would be a better threshold and why?

Question 5c: Do you have any evidence that distribution connected generation at a grid supply point has a different impact than directly connected generation?

Question 5d: Do you have a preference for one of our options for addressing the local charging distortion? If so, please indicate which option and provide your reasons. Are there any options we have missed?

Question 5e: Do you support our position that we should consider transitional arrangements? If so, do you have a preferred option and evidence to support the benefits or risks associated with each option?

Question 5f: Have we identified all the options for administering TNUoS generation charges for SDG? If not, what options have we missed, and why would they be preferable to those we have identified? Can you provide any evidence regarding the implications of the different administrative options for your business?

Question 5g: Are there any specific issues you think we need to consider, as part of our work on the future role of network charges? Why are these important to consider?

[There is no question 6]

7. General question

Question 7: Do you have any other information relevant to the subject matter of this consultation that we should consider in developing our proposals?

Timelines and next steps

7.1. We are planning towards the following milestones for concluding the SCR and implementing the outcomes:

- Access SCR Minded to Consultation closes – 25 August 2021
- Publish Final Access SCR decision – expected late 2021
- Decision on relevant code modifications – expected in 2022
- Reforms begin to take effect – from 1 April 2023

We intend to publish a webinar on the Charging Futures website, which will explain our minded to positions and answer frequently asked questions.[60]

How to respond

We want to hear from anyone interested in this consultation. Please email your responses to the questions we have asked in this consultation to FutureChargingandAccess@ofgem.gov.uk by 25th August 2021.

We will publish non-confidential responses on our website at www.ofgem.gov.uk/consultations. Further information on our approach to confidentiality and data privacy can be found in Appendix 3.

Engagement on option implementation

As set out in our launch decision,[61] the Access SCR is following the Option 1 process, [62] where we will direct licensees to raise modification proposals at the end of the SCR phase (i.e. once we have made our final decision).

We think that there is benefit to undertaking some early work on implementation, even though we recognise that it will not be required, if our final decisions are different to our minded to positions. Given this, we propose to engage with the network companies and other stakeholders to identify the information and level of detail that we should include in our final direction to licensees.

Following our final decision, we will support industry parties with raising and developing the modifications needed to implement our final reforms.

[60] Charging Futures website - http://www.chargingfutures.com/
[61] Access SCR launch - https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision
[62] SCR guidance - https://www.ofgem.gov.uk/system/files/docs/2016/06/scr_guidance.pdf

Appendices

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Appendix 1 – Detailed distribution connection charging policy proposals

This annex provides more detailed information on our proposals to reform connection charging. It should be read alongside Chapter 3 and our Impact Assessment.

Current arrangements

When a customer wants to connect to the distribution network, the relevant DNO will consider what work is needed to provide the connection. Generally, this will require the installation of new assets to connect the customer to the existing network ("extension assets") and, in some cases, increasing the capacity of the existing shared network assets ("reinforcement"). When calculating the cost to connect, DNOs follow the Common Connection Charging Methodology (CCCM), which has been approved by us. Independent Distribution Network Operators (IDNOs) use their own charging methodologies, which are also approved by us and largely based on the CCCM.

The cost of reinforcement is split between the connecting customer and the DNO (which is then recovered through ongoing network charges). The way these costs are split is discussed in terms of the depth of the "connection charging boundary". Customers facing a deep connection boundary are required to fund all of the cost of reinforcement that is required whereas, under a shallow boundary, the DNO would fully fund such work and recover it from all consumers through DUoS charges.

Currently, customers connecting to the distribution network are charged under what is referred to as a "shallow-ish" connection boundary. This means that in general, the connecting customer pays for:

- All of the costs for the extension assets required as part of their connection; and
- Some of the costs for any network reinforcement required to facilitate their connection.

The contribution towards reinforcement (and what is paid by the connection customer versus what is funded by the network company and recovered through DUoS charges) is determined a set of detailed rules which are set out in the relevant charging methodology. We have considered whether these rules should be amended to reduce or remove the contribution to reinforcement connecting customers face. These are explained below.

Where a new connection triggers reinforcement, the connection customer contributes to work at the same voltage as the point of connection, plus the one above. Any reinforcement at two voltage levels above is fully funded by the DNO. This reflects that reinforcement at these levels is likely to provide a shared benefit to a wider group of users. This is referred to as the "voltage rule".

Distributed generators that trigger reinforcement also face a High Cost Cap (HCC). The HCC states that all reinforcement above £200/kW is fully funded by the customer. Where both the voltage rule and HCC apply, the voltage rule is applied first (that is, the HCC only applies to reinforcement at the same voltage level as the connection plus one above).[63]

The apportionment of reinforcement costs between connection customers and the DNO is determined using two Cost Apportionment Factors (CAFs). The Security CAF and or the Fault Level CAF are used depending on what is driving the need for reinforcement (network or fault level capacity). This ensures that the connection customer's contribution is proportionate to their share of the new network capacity being provided.

Connection charges are paid in advance of the work being completed. These can be staged during the construction phase of a project (usually for larger customers), but if a customer does not pay in advance of energisation or agreed milestones, the work does not proceed. One possible solution could therefore be to consider what alternative payment arrangements might be appropriate. For example, connectees at transmission level currently can pay an annuitized charge over a number of years.

There is currently no standard requirement for distribution connection customers to be liable, or to provide security, in the event of a project being cancelled. This is because connecting customers pay:

- in advance of the DNO incurring the cost of doing the work; and
- a contribution to any wider reinforcement triggered by their request).

In this way, the work would be expected to go ahead as planned given the financial commitment from the connection customer, and the DNO's liability in respect of the connection charge being largely mitigated. Conversely, User Commitment does exist at transmission today to incentivise generation users to provide NGESO with notice of cancellation, closure, or reduction of capacity in a timely manner so that inefficient

[63] Ofgem's position on whether the voltage rule should take precedence over the High Cost Cap for Distributed Generation connections | Ofgem

transmission investment can be minimised. Incentivising timely provision of information aids efficient decision-making. A "Final Sums" methodology fulfils a similar role for demand users.

Reducing the contribution to reinforcement for generation

We are proposing to reduce the contribution towards the cost of reinforcement for generation connections by amending the voltage rule. We think this the most practical and proportionate means of achieving our intended reform.

We propose amending the voltage rule so that connection customers only contribute to reinforcement at the same voltage as their point of connection. Reinforcement above the voltage level of the point of connection will be fully funded by the DNO. This will reduce the upfront cost of connection (especially where work is needed at higher voltages) but keep some signal within the upfront charge. We think this is important given DUoS, in the absence of further reform, will not provide any signal of the costs these users place on the system (generation customers receive credits and do not face DUoS charges under the current DUoS charging methodology).

We think there in merit in keeping the HCC as it protects all consumers from high cost projects (particularly in less densely populated distribution areas, which may also coincide with the location of generation in parts of the network which require more reinforcement). While it is rarely triggered, our understanding is that the HCC is a useful tool in early discussions with potential connectees. However, we may want to revisit the interactions with the voltage rule as, without any further change, the HCC will only apply to costs at the same voltage level as the connection (due to the voltage rule taking precedence). This will dampen the signal to DG and results in more work being funded through DUoS.

We are considering two options:

- HCC only applies at the voltage of connection (i.e., the voltage rule takes precedence);
- HCC applies at the same voltage level as connection, plus one above (i.e., the HCC takes precedence).

We think the argument for the first option is stronger if future DUoS charges can provide an accurate signal in high cost areas. If not, we think there may be a case for the HCC taking precedence given the otherwise dampened signal that will be provided to users. Either option could be complemented by a review of the level of the HCC to ensure this is still appropriate. We are not considering whether the HCC should apply at all voltages as this would effectively be a deeper connection charge than they face today.

We do not propose changes to either CAF calculation. We consider that any changes would be arbitrary (e.g., applying a 50% reduction to either calculation) and that amending the voltage rule instead is a simpler, more transparent change for customers to understand. We also think it would be less effective in addressing some of the issues we have identified such as the ability of DNOs using flexibility to deal with constraints at the voltage above the point of connection, while still providing certainty of price for the connection customer.

Table 12 - Assessing the relative benefits of different ways of reducing the contribution to reinforcement for distribution connections

	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Voltage rule	• Connection charges can still provide signal about reinforcement to marginal user in absence of DUoS reform.	• Reduces upfront cost where work at higher voltages is required.	• Simple and transparent.
HCC	• Provides signal to generation to avoid particularly high cost areas.	• Mitigates risk of costs being borne by all consumers (especially in rural locations).	• Existing rule so well understood (but interactions with voltage rule to be resolved).
CAF	• Difficult to come up with a discount that is not arbitrary. • Does not address barriers to flexibility.	• Reduces upfront cost.	• More complex than simply amending the voltage rule.

Removing the contribution to reinforcement for demand

We propose to do this by requiring DNOs to fully fund all reinforcement for demand connections. In this case, the voltage rule and CAFs would no longer be applicable. A rule such as the HCC does not apply to demand today and we have not seen any compelling evidence that suggest a strong case for introducing one at this time.

Alternative payments

We think that the only practical option at this time would be to consider allowing connection customers to defer payment over a specific period of time after energisation (the exact mechanism for which would need to be determined). This could be introduced for demand and or generation connections – and even if we did not make any other changes to the distribution connection charging boundary. This would provide a cash flow benefit to some users and potentially help remove barriers to entry. However, we think this raises several questions and potential unintended consequences. We do not therefore propose to introduce deferred payments.

It is important to first consider whether it is appropriate for DNOs to effectively provide a source of finance to potential connectees. We think that the differences to transmission, where customers can currently pay the connection charge over a number of years, are important to note. These include, but are not limited to, size and scale of projects, customer type and volume. This activity also influences the Regulated Asset Value (RAV) at transmission, unlike distribution connections which are treated outside the price control. This could lead to a disconnect – debt increasing but the corresponding investment not being recorded in the RAV.

If the DNO is to offer deferred payments through a finance arrangement it needs to be considered whether the DNO should be considered as a provider of last resort. For example, in circumstances where a bank is unwilling to make a loan due to the commercial viability of the project or uncertainty over the creditworthiness of the company or individual, then the DNO deferred payment terms could be attractive. This would mean that only projects unable to secure finance elsewhere would take up the terms which could potentially create an increased bad debt risk. This raises further questions about whether it is appropriate that DNOs fund projects that cannot find other sources of funding and what this does to the risk of default.

In addition, potential connectees to the electricity distribution network have the option of approaching an Independent Connection Provider (ICP) as an alternative to the DNO. Networks that are built by ICPs will be adopted by either the DNO or an IDNO, who will then be responsible for the ongoing operation and maintenance of the network. The aim of introducing competition in connections is that customers connecting to the network have the opportunity of fairer prices and better service. The move to deferred payment mechanisms could have the effect of distorting this competition.

If DNOs defer payment over a future period, they will have to source capital to finance such credit arrangements. To compete with DNOs, ICPs and IDNOs would need to offer similar financing arrangements. However, some ICPs and IDNOs may not be able to do so because they cannot access finance to fund such credit arrangements, or where they can, at a much higher cost than is available to DNOs. This may also be the case in terms of competition between ICPs where some may benefit from being part of a larger group. ICPs may also be unable to recover bad debt in the absence of DUoS revenue streams, further impacting their ability to compete effectively.

Liabilities and securities

If DNOs are to fund a higher proportion of reinforcement through DUoS charges, and a user chooses to cancel their project after some investment has been made, there is a risk of these costs falling on DUoS customers. It may therefore be appropriate to consider some form of protection against this risk.

This could be introduced of all types of connection. However, we think there are strong proportionality arguments against this. Distribution connections can vary from new domestic housing up to LDG with installed capacities above 100MW, whereas transmission connected demand and generation tends to be significantly larger projects such as large industrial plants, as well as onshore and offshore wind farms, solar farms, and battery storage. The size, volume and cost of distribution connections therefore vary considerably from those at transmission where such arrangements are more established and arguably more justified. There may be a case at the highest voltage levels, but there are several important details that would need to be resolved. These include the actual level of risk, practicalities of transferring liabilities between parties and avoiding introducing new barriers.

The first consideration when thinking about introducing any new arrangements is what work this would apply to. Under all the options for connection boundary reform, extension assets will continue to be paid for by the connection customer in full and in advance of energisation. It is therefore unclear why liabilities and or securities would need to be introduced for extension assets when it does not currently exist. Where the contribution to reinforcement is reduced (but not removed completely), users will continue to contribute to network reinforcement that is needed to facilitate their connection. It will be less than it is today but might still be material enough to demonstrate sufficient commitment that a project will proceed as planned (particularly at higher voltages).

However, the risk arguably increases under a shallow boundary. Potential connectees would not face any contribution to network reinforcement, meaning the risk of a customer cancelling once some investment has been made sits with the DNO (and ultimately customers). The case for introducing something in terms of reinforcement is therefore stronger under a shallow boundary.

We have seen some evidence from DNOs that cancellation rates tend to increase as you move up through voltage tiers and are higher for generation than demand. However, the actual exposure faced by the DNO will depend on the individual case and when the cancellation occurs. DG and EHV/132kV demand connections tend to be higher cost (than lower voltage), more likely to follow a bespoke design, and or be in remote locations. The scope for re-use of an asset, or for other customers to take advantage of the new capacity made available, should the original project not go ahead, is therefore an important consideration.

There are then ongoing administration challenges post-energisation.

- It is not clear what liability the party seeking the connection could have imposed on them once the connection is made, (for example, an ICP providing a connection on behalf of a housing developer, who then sells the property).
- It is not clear how the mechanism would apply on a change of occupier. This would appear very difficult to enforce and may require changes in legislation beyond that associated primarily with electricity distribution.
- If the liability could transfer to a new occupier (through the user being required to have a connection agreement in place), this may require the customer to sign up to the agreed capacity for the connection for a defined period.
- Furthermore, it is not clear how the liability would apply post energisation if there are multiple end customers, such as in a housing or commercial estate.

Should any change be initiated the level of securitisation becomes a factor for consideration. DNOs may require up to full security to cover the liability or only part. Previous work in this area for transmission connections noted that excessive pre-commissioning generator security acts as a barrier to entry for smaller parties and so has a negative impact on competition.[64]

Taking all of this into consideration, we are therefore not minded to consider introducing new liability or security obligations for distribution connections at this time. However, we are inviting views from respondents on whether there is any evidence to suggest we should consider this further.

[64] CMP192: Arrangements for Enduring Generation User Commitment | National Grid ESO

Appendix 2 – Detailed access right proposals and assessment

Traditionally users have had limited choice of access rights. Improved choice and definition of access rights could help ensure users are able to get quicker or cheaper access to the network in line with their needs and support more efficient use of network capacity. This annex supplements Chapter 4 to provide more detailed information and justification for proposals to reform distribution access right choices.

Non-firm access rights

We are proposing to introduce new non-firm access rights for distribution connected users. However, we are not proposing to reform non-firm options at transmission. There are different ways in which non-firm access at distribution could be defined:

- **Physical conditions:** Access defined by the design of the network or source of the network constraint.
- **Consumer outcomes**: Access defined by user experience of curtailment.

Detailed option	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Physical conditions	• Linking physical network assets to specific network constraint should result in charges that directly reflect user impact. • But this approach is less supportive of access being allocated in accordance with users' needs.	• Less reflective of users' needs. • It will require more engagement with distribution users to ensure they understand the implications about when and how often they may be curtailed.	• Minimal changes required to DNOs
Consumer outcomes	• Support efficient network	• Provides more certainty to	• Will require data, collection, and

	development in accordance with consumer requirements. • Requires network operators to translate physical assets into consumer experience. If done conservatively, this may lead to less efficient use of the network.	distribution-connected users about how much they will be curtailed.	processing to measure curtailment rates. • It will also require changes to DNO systems and processes.

Due to ease of engagement and the ability to best reflect distribution-connected users' needs, we consider that defining distribution non-firm access in relation to consumer outcomes would deliver the most value. Within this option, there are also different ways in which user experience of curtailment can be measured. The options include measuring:

- The number of curtailment events
- The number of hours curtailed or percentage of time curtailed.
- The amount of energy imported/exported curtailed. This would require the DNO to forecast the amount of energy that would have been imported or exported, had the user not been curtailed.

Detailed option	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Number of curtailment events	• Unlikely to be an effective way of reflecting users' needs and therefore allocating capacity efficiently.	• Poor reflection of users' experience of access to the network.	• Requires changes to Active Network Management (ANM) systems to collect and analyse this data.
Number of hours curtailed	• Good reflection of impact on users,	• Good reflection of users' experience.	• Requires changes to ANM systems to

(could also be expressed as a %)	therefore, facilitates efficient use and development of system capacity	• Users can conduct their own forecasts to understand impact on export/import	collect and analyse this data.
Energy imported/ exported curtailed (using forecasts)	• If forecasts are accurate, it could provide the best reflection of impact on users, therefore facilitates most efficient use and development of system capacity.	• If DNO assumptions on level of import/export are accurate it could provide the best reflection of impact on users.	• More complex to implement, requires DNOs to forecast expected users' import/export and factor this into curtailment rates.

We are proposing to measure degree of curtailment based on the number of hours curtailed. This gives users a good understanding of the level of curtailment that they would be exposed to and allows the user to make their own forecasts about the amount of energy imported/exported that would be curtailed. We think that basing the level of curtailment that a user faced on DNO forecasts of what the user would have used during the curtailment period are likely to be inaccurate. This is because the DNO would have to make assumptions about whether capacity was held constant, increased, or decreased during that period, which would be individual to each user and how they operate.

We consider that users should be protected from the risk of DNOs exceeding the level of curtailment agreed. Once a user has agreed a percentage of the time that the user is willing to be flexible for, network operators will be required to comply with this threshold. Network operators should take this into account when designing and building the network. If the network operator wants to curtail the user above the threshold agreed with the user, then the network operator must procure this service. We expect this to reduce potential distortions between flexibility markets and non-firm connections.

Our proposed changes will not impact existing users' access rights. This includes existing distribution-connected users that have agreed a "flexible connection". If any existing users want to amend their access rights (e.g. to increase or decrease their level of firmness), then an application must be submitted to their relevant network operator through the standard processes.

We consider that users should be able to agree the percentage of their total access rights that are non-firm, and a percentage of their total access rights that are firm.

Time-profiled access rights

We are proposing to introduce new time-profiled access rights for distribution-connected demand and generation users. However, we are not proposing to introduce new time-profiled access rights at transmission.

Time profiled access rights may help to develop a more efficient electricity system if distribution-connected users profile their access rights to move away from the network peak. The user would therefore have to be flexible about when they export or import onto the network, to comply with their access rights (i.e. they would need to shift export or import into off-peak periods). In some limited locations, we have already seen time-profiled access rights being implemented. In these examples, the user that has agreed a time-profiled access right has benefitted from a significantly quicker and cheaper connection.

In comparison to non-firm access rights, time-profiled access rights would provide distribution-connected users with greater certainty upfront about when they will be able to import and export onto the network. If a network operator wants to curtail these users outside of the time that have been agreed with the user, then the network operator must procure this flexibility from the user.

A user with a time-profiled access right may have a reduced level of access during network peak periods. A user’s time-profiled access rights may vary across the year, to reflect seasonal changes in when the network peak period occurs. For example, for demand users, the times of peak network constraint is more likely to fall in winter when there is highest demand and less generation, while for generation users it is likely to be in summer when the inverse is true.

We understand that many users will only be able to be flexible with part of their import or export requirements. We therefore consider that users should be able to agree that only a proportion of their access rights that are time-profiled. Users may request to either have no access, reduced access, or non-firm access, during peak periods.

Shared access

At the moment, users secure access based on the needs of an individual site. We considered options to allow multiple sites to share access to the whole network, up to a jointly agreed aggregate capacity level. These sites would coordinate to ensure that they maintain their access within the limits set out in their shared access right. This may be valuable to a local energy scheme that is trying balance new generation and demand across different sites or a company managing their import/export across a portfolio of different connection sites.

With support from industry, we developed a model for how shared access could work in practice. To be eligible to share access, we consider that the sharing of access must deliver network benefits. Sharing access must therefore be approved by the network operator and reduce the cumulative level of access that the users require. Users must be connected to the same "local network"[65] and alleviate a defined network constraint. Users must also agree to sign up to a "Sharing Group Participation Agreement". The Sharing Group Participation Agreement would outline practical elements that need to be agreed (e.g. participants, start date and cumulative level of access rights).

Sharing access would also identify a "Sharing Group Manager" that is responsible for the groups' compliance with their cumulative access rights (the Sharing Group Manager could be one of the participants of the Sharing Group). As the holder of cumulative network access rights, the Sharing Group Manager would be able to trade or request additional access rights on behalf of the group. The Sharing Group Participation Agreement would outline the terms and conditions that apply to the Sharing Group Manager and the individual users participating in the sharing of access. For example, an individual user would still be responsible for compliance with relevant individual technical requirements.

We have concerns about the practicality of sharing access between multiple users. For example, at the moment industry network charges are issued to an individual user's supplier. If a Sharing Group's participants have different suppliers, then this presents challenges about

[65] At low voltage users must be connected to the same distribution substation or to substations on common circuits of the same primary substation. At high voltage, they must be connected to the same primary substation. At EHV, they must be connected to the same EHV or GSP constraint behind the same single constraint at the same voltage level on the same local network.

how capacity and exceeded capacity charges should be allocated. Solutions to overcome this issue could have significant implications for industry network charging billing systems.

Sharing access require individual network users to relinquish individual control of their access rights (e.g. a Sharing Group Manager could trade cumulative access on behalf of the sharing group) and compliance with their access rights (e.g. an individual network user may not import or export any electricity, but could still be liable for network operator enforcement action if the other Sharing Group participants exceed their cumulative access rights). Once a user joins a Sharing Group it would surrender its individual access rights. If an individual user wanted to leave a Sharing Group, it would not have "back up" individual access rights that it could rely on. For these reasons, we have concerns that the sharing access may be considered too risky for most users to accept and that the take-up of this access choice would be limited.

We consider that further trialling and testing of shared access would be useful. The ENA Open Networks has started to take this forward alongside their existing work on trading access. There are significant similarities between the sharing and trading of access - both approaches aim to facilitate interaction between network users to make more efficient use of existing system capacity. If an access right is shared, then it is jointly assigned to two or more users. If an access right is traded, then it is exchanged between two or more users. In theory, trading access may lead to the most efficient use of the network, since dynamic, market-based approaches should lead to competitive price discovery. Market based trading also allows users to respond and react dynamically to live conditions, whereas renegotiating shared access rights may take considerable time to agree with the relevant network operator.

We consider that trialling them alongside each other will allow for better assessment of the different approaches to identify whether either option is more practical or delivers more value.

Compliance with access right choices

Compliance with new access choices is necessary to deliver the benefits identified (e.g. avoided reinforcement and system operation costs). Compliance with agreed access rights also reduces the risk of security of supply issues for wider users. Better defined access rights may therefore require greater monitoring of access rights and changes to the enforcement regime. We expect that non-firm connections will require physical control equipment due to the nature of potential interruptions to network access. In contrast, there may be scope for a wider range of options for time-profiled access given the greater user certainty of their specific access periods.

We are concerned that the current approach to exceedance capacity charges does not reflect the full costs incurred by DNOs trying to maintain security of supply for wider users. Our DUoS charge design proposals (due to be published later this year) will outline our proposed approach to reforming capacity and exceedance capacity charges. This may include exposing users to the additional costs incurred by the DNO of non-compliance with access rights, in order to provide a financial incentive to encourage users to stay within their agreed access levels.

The consequences for exceeding access rights should be visible, understandable, and proportionate to the impact of overrunning agreed access right limits. We therefore propose that network operators develop a common, clear, and consistent approach to the monitoring and enforcement of access rights. The guidance should outline how network operators will ensure user compliance with agreed access rights limits (e.g. when network operators will install physical control equipment and when users face the risk of disconnection or de-energisation for breaching access rights). This guidance will improve clarity for all users (not just those that accept new access choices) about the potential consequences of exceeding their agreed access rights.

In particular, we note that the development of new access choices may lead to greater use of physical control equipment, to ensure users comply with their agreed access rights. We expect this to be required for non-firm connections, and some time-profiled connections. We consider that this is appropriate where it is proportionate to the impact of the user exceeding their access rights. However, the use of physical control equipment (or the risk of installation of physical control equipment), and any requirement to pay for its installation, should be understood by the user when accepting their alternative access rights. More information on the subgroups recommended changes to network monitoring and enforcement activities can be found here.[66]

[66] Access subgroup – monitoring and enforcement note - http://www.chargingfutures.com/media/1378/scr-access-subgroup-monitoring-and-enforcement-note.pdf

Ability of users with alternative access rights to sell services to different markets

Our proposals have been developed in the context of wider flexibility market development and tested to ensure consistency.

For many users, their ability to sell services to different markets is an important source of revenue (e.g. balancing services and DNO flexibility services). Under current arrangements, a users' access rights could negatively impact their ability to sell services to different markets. For example, some NGESO markets require users to bid in blocks of time (e.g. NGESO currently requires users to bid into the fast frequency market in four-hour block periods). These time-block periods may not align with users' time-profiled access, and may create a barrier to users choosing alternative access rights. There may similarly be a case to consider alignment in the development of DUoS charging time-bands. Equally, with an undefined non-firm connection, there is a significant risk to of non-delivery. Through our reforms, better defined access rights will enable more users to understand what flexibility markets they are available for, as well as provide network and system operators with greater confidence in their ability to deliver when required.

More information on our initial work with industry to assess how these access right choices align with wider markets can be found here.[67] We note that the markets where we identified the most significant potential barriers are currently under review or still in development. We will continue to work with government, NGESO, DNOs and the ENA to remove undue barriers for users with alternative access choices from operating in these markets. For example, through the ENA Open Network Programme, several workstreams are in progress to enable flexibility providers to stack revenues and jump between markets where possible. This includes connectees under ANM schemes.

[67] Access subgroup market participation table - http: //www.chargingfutures.com/media/1379/scr-access-subgroup-market-participation.xlsx

Appendix 3 – Consultation responses, data and confidentiality, and general feedback

Your response, data, and confidentiality

You can ask us to keep your response, or parts of your response, confidential. We'll respect this, subject to obligations to disclose information, for example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions, court orders, government regulations or where you give us explicit permission to disclose.

If you wish us to keep part of your response confidential, please clearly mark those parts of your response that you do wish to be kept confidential and those that you do not wish to be kept confidential. Please put the confidential material in a separate appendix to your response. If necessary, we'll get in touch with you to discuss which parts of the information in your response should be kept confidential, and which can be published. We may ask you to explain why you want your response, or parts of your response, to be kept confidential.

If the information you give in your response contains personal data under the General Data Protection Regulation 2016/679 (GDPR)[68] and domestic legislation on data protection, the Gas and Electricity Markets Authority will be the data controller for the purposes of GDPR. Ofgem uses the information in responses when performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. For further information, please refer to our Privacy Notice on consultations in Appendix 4.

If you wish to respond confidentially, we'll keep your response itself confidential, but we will publish the number (but not the names) of confidential responses we receive. We won't link responses to respondents if we publish a summary of responses, and we will evaluate each response on its own merits without undermining your right to confidentiality.

[68] As retained

General feedback

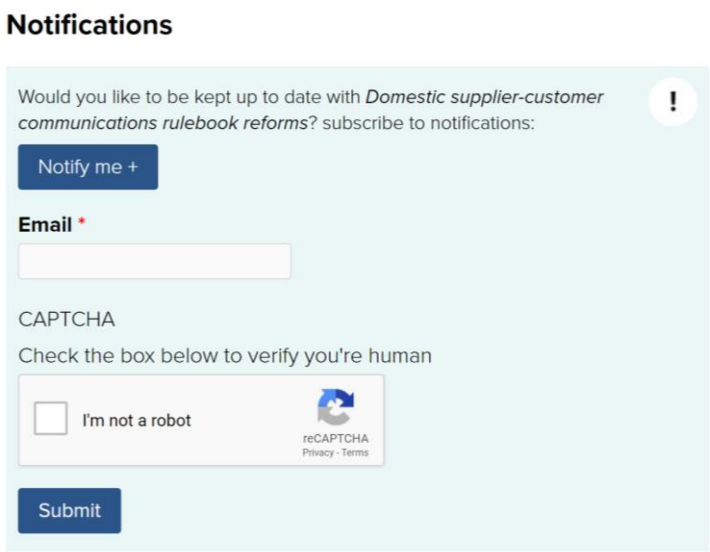
We believe that consultation is at the heart of good policy development. We welcome any comments about how we've run this consultation. We would also like to get your answers to these questions:

1. Do you have any comments about the overall process of this consultation?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Were its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

Please send any general feedback comments to stakeholders@ofgem.gov.uk

How to track the progress of the consultation

You can track the progress of a consultation from upcoming to decision status using the 'notify me' function on a consultation page when published on our website. Ofgem.gov.uk/consultations.



Once subscribed to the notifications for a particular consultation, you will receive an email to notify you when it has changed status. Our consultation stages are:

Upcoming ► Open ► Closed (awaiting decision) ► Closed (with decision)

Privacy notice on consultations

Personal data

The following explains your rights and gives you the information you are entitled to under the General Data Protection Regulation (GDPR).

Note that this section only refers to your personal data (e.g. your name, your address or anything that could be used to identify you personally) not the content of your response to the consultation.

1. The identity of the controller and contact details of our Data Protection Officer

The Gas and Electricity Markets Authority is the controller, (for ease of reference, "Ofgem"). The Data Protection Officer can be contacted at dpo@ofgem.gov.uk

2. Why we are collecting your personal data

Your personal data is being collected as an essential part of the consultation process, so that we can contact you regarding your response and for statistical purposes. We may also use it to contact you about related matters.

3. Our legal basis for processing your personal data

As a public authority, the GDPR makes provision for Ofgem to process personal data as necessary for the effective performance of a task carried out in the public interest, i.e. a consultation.

4. With whom we will be sharing your personal data

We will make your response as provided available on our website, unless you specify that your response, or parts of it, should be confidential. In which case, we will not share your response unless we are required to do so subject to obligations to disclose information, for example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions, court orders, government regulations or where you give us explicit permission to disclose.

5. For how long we will keep your personal data, or criteria used to determine the retention period.

Your personal data will be held for as long as an audit trail on decision-making relating to the questions discussed in this document should reasonably be available.

6. Your rights

The data we are collecting is your personal data, and you have considerable say over what happens to it. You have the right to:

- know how we use your personal data
- access your personal data
- have personal data corrected if it is inaccurate or incomplete
- ask us to delete personal data when we no longer need it
- ask us to restrict how we process your data
- get your data from us and re-use it across other services
- object to certain ways we use your data
- be safeguarded against risks where decisions based on your data are taken entirely automatically
- tell us if we can share your information with 3rd parties
- tell us your preferred frequency, content, and format of our communications with you
- lodge a complaint with the independent Information Commissioner (ICO) if you think we are not handling your data fairly or in accordance with the law. You can contact the ICO at https://ico.org.uk/, or telephone 0303 123 1113.

7. Your personal data will not be sent overseas.

8. Your personal data will not be used for any automated decision making.

9. Your personal data will be stored in a secure government IT system.

10. More information.

For more information on how Ofgem processes your data, click on the link to our "Ofgem privacy promise".