Decision

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Access and Forward-Looking Charges Significant Code Review: Final Decision

Subject	Details
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In December 2018, we launched the Access and Forward-Looking Charges Significant Code Review (Access SCR) with the objective of ensuring that electricity networks are used efficiently and flexibility, reflecting users' needs and allowing consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general.

This document sets out our Decision to make changes to how electricity distribution network connection charges are calculated and how users' access rights to the electricity distribution network are defined.

Published alongside this Decision is our Direction for the requisite change proposals to be raised to the Distribution Connection and Use of System Agreement (the 'DCUSA'). We also publish alongside a series of supporting documents which include our final Impact Assessments and a summary of stakeholder input received throughout the development of our positions. This contains a summary of responses to our January 2022 Consultation, with any individual responses not marked as confidential also made available alongside this decision.

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Executive summary

The energy system is continuing to undergo a radical transformation as the processes of decarbonisation, digitalisation, and decentralisation accelerate to achieve net zero. Since we published our initial working paper on the reform of electricity network access and forward-looking charges in November 2017, we have been undertaking a programme of reform in this area that enables competition, innovation, and decarbonisation at lowest cost.[1] This involves a package of changes to how different parties access and pay charges for the electricity network. We are pursuing this package in line with our Principal Objective of protecting the interests of existing and future consumers, particularly in the context of the transition to a low-carbon energy system.[2]

The Access and Forward-Looking Charges Significant Code Review ('Access SCR') was formally launched in December 2018[3], initiating a process of policy development, modelling, and extensive stakeholder engagement to determine changes to the existing framework. This document provides our final Access SCR Decision[4], covering two areas of the original SCR scope: (i) the distribution connection charging boundary and (ii) the definition and choice of access rights. The original SCR scope also included a review of forward-looking distribution use of system (DUoS) charges and transmission network use of system charges (TNUoS). These two areas are now being developed outside of the Access SCR, as outlined in previous publications.[5]

Our work on the distribution connection charging boundary has considered whether current arrangements continue to work in the best interests of consumers – especially considering the need for increased investment associated with the electrification of heat and transport, as well as low carbon sources of generation. We have concluded that the charging

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[1] The November 2017 Working Paper can be found here: https://www.ofgem.gov.uk/publications/reform-electricity-network-access-and-forward-looking-charges-working-paper
[2] Our statutory framework is described in detail here: https://www.ofgem.gov.uk/publications/our-powers-and-duties
[3] The Access SCR launch statement can be found here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision
[4] Also referred to as 'the Decision' throughout this document.
[5] Our Decision to launch a separate DUoS SCR is available here: https://www.ofgem.gov.uk/publications/distribution-use-system-charges-significant-code-review-launch.
Our Consultation response outlining the next steps on TNUoS charges is available here: https://www.ofgem.gov.uk/sites/default/files/2022-02/TNUoS%20Next%20Steps%20-%2025022022.pdf
See Chapter 2 sections 2.7 – 2.9 for more details on the evolution of the Access SCR scope.

arrangements no longer provide an effective signal for network users, and without change, may slow down the roll-out of low carbon technologies (LCTs) across the energy system.

Regarding the distribution connection charging boundary, we have therefore decided to:

- **Reduce the overall connection charge faced by those connecting to the distribution network.** This includes (i) removing the contribution to wider network reinforcement for demand connections, and (ii) reducing the contribution to wider network reinforcement for generation connections.

- **Retain and strengthen existing protections for bill payers.** This ensures that bill payers will be protected from cost increases associated with the most expensive types of connections. In these instances, the connecting customer will continue to be required to contribute more to the costs of reinforcement.

Our work on the Access SCR has also considered the nature of users' access rights to the network. This includes how much they can import or export, when, and for how long; whether their access can be interrupted, and what happens if it is. For larger users of the network, such as generators and heavy industry, this information is defined in their connection agreement. Under current arrangements, most users have limited choice over such arrangements. Some users have been offered a 'non-firm' connection (ie one where network access can be curtailed), typically in order to access the network more quickly or cheaply. In these cases, the arrangements may have been loosely defined or require the user to face an undefined amount of curtailment.

Regarding the definition and choice of access rights, we have decided to:

- **Ensure a standardised non-firm access option is available for larger network users**. Where there is a network benefit associated with a curtailable connection offer, distribution network operators will be required to make this option available to the connecting customer, should they wish to opt in to this kind of connection agreement.

- **Introduce clear curtailment limits and end dates for non-firm access arrangements.** Distribution network operators will have to set a curtailment limit for non-firm connection offers and include these in the offer to the connecting customer, who will have to abide by those limits. Where the customer wishes to connect initially on a non-firm basis, but ultimately be made firm, a date by which the customer should have firm access must be agreed.

Table 1 is a series of illustrative examples to support stakeholders in understanding the impact of our reforms on different types of network users.

Table 1: Illustrative examples of the impact of our reforms

User Type	Impact of distribution network connection charging reforms	Impact of distribution network access rights reforms
Small distribution connected solar farm	• Overall connection charge reduced. • Charge for wider distribution network reinforcement (above the voltage level of connection) is removed, with limited exceptions. • Connection charges will remain as they are currently for any required 'extension assets', ie for sole-use.	• Flexible access option available that may enable a quicker and cheaper connection in congested areas of the network. • Curtailment limits and end date provide more certainty about the extent to which the connection may be restricted.
Electric vehicle charging station for fleet delivery vehicles	• Overall connection charge reduced. • Charge for wider distribution network reinforcement is removed altogether, with limited exceptions. • Connection charges will remain as they are currently for any required 'extension assets', ie for sole-use.	• Flexible network access option made available based on an agreed curtailment threshold. • Charging station may be able to agree to some curtailment in exchange for a faster connection. • End date gives certainty of future capacity being made available.
Large distribution connected wind farm	• Overall connection charge reduced. • Charge for wider distribution network reinforcement (above the voltage level of connection) is removed, with limited exceptions. • Connection charges will remain as they are currently for any required 'extension assets', ie for sole-use.	• Flexible access option available that may enable quicker and cheaper connection in congested areas of the network. • Curtailment limits and end date provide more certainty about the extent to which the connection may be restricted.
Domestic household installing a heat pump and electric vehicle charger	• Overall connection charge reduced. • Charge for any wider distribution network reinforcement removed altogether, with limited exceptions. • Connection charges will remain as they are currently for any required 'extension assets', ie for sole-use.	• Flexible access arrangements are complex agreements with varying costs and benefits that must be assessed by individual connecting customers. • We do not think they are suitable for domestic consumers, and they will not be made available for this group.

The reforms we outline in this Decision are enablers for Ofgem's strategic priorities, including the enablement of investment in low carbon infrastructure at a fair cost, and the delivery of a more flexible electricity system.[6] Making efficient use of network capacity and having fair and effective signals that reflect how users create costs or savings on the network is critical to the development of a flexible, dynamic future energy system. In anticipation of continued investment in distributed energy resources and the distribution networks to achieve net zero, our decisions remove barriers to entry for network users whilst supporting more coordinated and strategic management of the distribution network.

Our Decision also supports our enduring regulatory priorities, including to protect the interests of consumers, support vulnerable consumers and support decarbonisation. It has been an objective of the Access SCR to ensure that our reforms reflect users' needs and allow consumers to benefit from new technologies and services, while avoiding unnecessary costs on energy bills in general. The potential savings associated with delivering a more flexible system that our reforms will help to enable are significant, and there is further potential for wider system savings to be realised by further enabling competition on a level playing field between energy service providers.[7]

This document is accompanied by a Direction[8] to the holders of a distribution licence to raise the requisite change proposals to the Distribution Connection and Use of System Agreement ('DCUSA') in accordance with our Decision. This Direction will begin an implementation process, to be led by industry working groups, who will consider how the requisite changes should be made to the DCUSA in line with this decision. The working groups will develop detailed proposals before submitting them back to the Authority for a decision on their implementation.

[6] Ofgem's strategy and priorities can be at the following location (based on 22/23 Forward Work Programme at time of publication): https://www.ofgem.gov.uk/our-strategy-and-priorities

[7] The Smart Systems and Flexibility Plan 2021, a joint BEIS and Ofgem publication, set out an estimate that increased flexibility could reduce cumulative system costs by £30–70bn across the period 2020 to 2050 (2012 prices, discounted): https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003778/smart-systems-and-flexibility-plan-2021.pdf

[8] This Decision should be read alongside the accompanying Direction, available alongside.

1. Introduction

Context

1.1. Our energy system is undergoing a radical transformation as the processes of decarbonisation, digitalisation, and decentralisation accelerate to achieve net zero. Since we published a working paper on the reform of electricity network access and forward-looking charges in November 2017[9] we have been undertaking a wide programme of reform to enable competition, innovation, and decarbonisation at lowest cost. We believed that a package of changes to how different parties access and pay charges for the electricity network was, and continues to be, necessary to protect consumers' interests in the transition to a smarter, more flexible, low carbon energy system.

1.2. The reforms that we have been progressing are the result of a comprehensive review of charging and access arrangements, to identify and improve the signals users face about their impact on the electricity network. These changes have principally been undertaken through two closely linked SCRs:

- **The Targeted Charging Review Significant Code Review ('TCR SCR'),** which we reached a decision on in December 2019. The TCR SCR examined 'residual charges', which recover the remainder of the total charges needed to fund network expenditure after the 'forward-looking' charge has been applied. We decided that residual charges would be levied in the form of fixed charges on final demand users and that changes to 'embedded benefits' were needed to remove distortions in the charging regime. These changes lowered overall costs to consumers.
- **The Access and Forward-Looking Charges Significant Code Review ('Access SCR')**, the subject of this Decision. The Access SCR was launched in December 2018[10] to consider the signals sent to users about the effect of their behaviour on networks. We launched this work to pursue potential cost savings for all consumers, by adapting current access and charging arrangements to facilitate and deliver a more dynamic and flexible energy system. We have now reached a final Decision which involves directing changes in two key policy areas: **the distribution connection charging boundary**

[9] The November 2017 Working Paper can be found here: https://www.ofgem.gov.uk/publications/reform-electricity-network-access-and-forward-looking-charges-working-paper
[10] The Access SCR launch statement can be found here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision

and the **definition and choice of access rights**. This concludes the Ofgem-led phase of the Access SCR.

1.3. In January 2022 we decided that we would not be directing reforms to TNUoS charges under this SCR[11]. Our reform work on TNUoS charges is continuing separately, as outlined in our response to the Call for Evidence on TNUoS charges that was published in February 2022[12]. In February 2022[13] we also decided to remove the review of DUoS charges from the Access SCR scope and create a dedicated 'DUoS SCR' to take this work forward. This work is ongoing as we continue to consider potential changes focussing on the 'forward-looking' component of distribution network charges that is designed to be reflective of the network costs and savings that users of the network can drive.

1.4. The Access SCR reforms will complement the changes that we have already introduced under the TCR. They will reduce barriers to network access, enabling users to continue to make efficient choices about where to locate on the network and how to use it, whilst also supporting the continued transition to net zero at least cost.

1.5. The changes to the distribution network charging boundary and access rights are key to removing barriers to the growing adoption of low carbon technologies and facilitating the broader decarbonisation of the GB energy system in an efficient manner. They also lay the foundations for our other ongoing reforms in this area, which are further outlined in paragraph 1.9 and in table 2 below.

1.6. We also want to realise the value of a more cost-efficient electricity network over time to reduce network costs for all consumers. We believe that our proposals will encourage network operators to take a more strategic approach to network planning and reinforcement. This includes investing ahead of need where it is efficient to do so and considering alternative approaches to reinforcement to meet the capacity needs of customers.

[11] Our Consultation on Updates to our Minded-to Positions can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions
[12] Our Consultation response outlining the next steps on TNUoS charges is available here: https://www.ofgem.gov.uk/sites/default/files/2022-02/TNUoS%20Next%20Steps%20-%2025022022.pdf
[13] Our Decision to launch a separate DUoS SCR is available here: https://www.ofgem.gov.uk/publications/distribution-use-system-charges-significant-code-review-launch

1.7. The move to reduce connection reinforcement charges for generation[14] and remove them altogether for demand[15] enables whole system cost savings in alignment with more strategic development of the network, economies of scale, better coordination/timing, use of non-build options, opportunities to optimise capacity utilisation between load and generation. As the distribution network is expected to become more constrained with the electrification of heat and transport, we consider that these changes will enable more efficient network development, including for electric vehicle and heat pump adoption.

1.8. We believe that the changes we are directing to the distribution connection boundary and network access rights are complementary. Together, they will enable more efficient use of and investment in the network, supporting the growth of LCTs required for net zero. We also believe that they are a necessary enabler for future reforms to Distribution Use of System (DUoS) charges.

Wider reforms

1.9. The Access SCR is part of a broader package of reforms to electricity network access and charging policies. Table 2 summarises a range of policy reforms which are relevant to the context of the Access SCR which are at various stages of development by Ofgem and industry.

Table 2: Summary of wider electricity network access and charging reforms

Area	Content	Impact	Timescales
Balancing Services Use of System Charges ('BSUoS') reforms: Implementing the findings of the BSUoS industry taskforce which concluded in September 2020[16].	• CMP308 – Removal of BSUoS charges from generation to final demand only	• Improved system efficiencies • Reduced distortions	Decision: Published on 25 April 2022[17] Implementation: April 2023
	• CMP361/362 – Making BSUoS a fixed charge	• Addressing BSUoS volatility • Reduced risk premia	Decision: Expected summer 2022 Implementation: April 2023

[14] Also referred to as 'shallow-ish' connection charges. In previous publications also referred to as 'shallower'.
[15] Also referred to 'shallow' connection charges.
[16] More information on the BSUoS taskforces can be found on the Electricity System Operator's Charging Futures website: https://www.chargingfutures.com/charging-reforms/task-forces/previous-task-forces/second-balancing-services-charges-task-force/what-is-the-second-balancing-services-charges-task-force/
[17] The CMP308 Decision is available here:https://www.ofgem.gov.uk/publications/cmp308-removal-bsuos-charges-generation

Targeted Charging Review ('TCR') reforms: Implementation of the TCR SCR decision made by Ofgem in December 2020 regarding the fair recovery of residual charges.[18]	• CMP343 - the application and methodology for transmission demand residual charges	• Fairer balance of charges between smaller and larger users	Decision: 10 March 2022[19] Implementation: April 2023
Distribution Use of System Charges ('DUoS') reforms: Currently under consideration by Ofgem. Originally within scope of the Access SCR, these reforms are now being taken forward under a separate DUoS SCR.	• Review of DUoS charging methodologies • Improvements to locational signals • Usage vs capacity-based charges	• Fairer and more balanced Use of System charges • Better use of existing network due to locational signals • Strategic development of the distribution network	Decision and Direction: Expected in 2023 Implementation: No sooner than 2025
Transmission Use of System Charges ('TNUoS') reforms: Currently under consideration following Ofgem's announcement of an industry taskforce to consider potential improvements to the TNUoS methodology.	• Review of TNUoS charges for Small Distributed Generation (SDG) • Consideration of the root causes of unpredictability in TNUoS charges and how this might be addressed	• Fairer distribution of transmission system costs	Taskforce recommendations: Post-2022

[18] The TCR SCR final Decision is available here: https://www.ofgem.gov.uk/publications/targeted-charging-review-decision-and-impact-assessment
[19] Our CMP343 Decision and final Impact Assessment is available here: https://www.ofgem.gov.uk/sites/default/files/2022-03/CMP343%20Decision.pdf

2. Our approach

Section summary

This chapter summarises the stakeholder engagement and assessment processes we have followed in our policy development and decision-making. It describes key policy development deliverables including changes in the scope of the Access SCR.

We describe the process and methods used to reach our final decision for the reform of the connection charging boundary and access rights. It describes our framework for principles-based assessment and the quantitative analysis undertaken to consider potential outcomes of the reforms, particularly with regards to consumer, wider societal and system benefits.

Timeline and development of SCR scope

Initial SCR scope and subsequent changes

2.1. In July 2018 we issued an initial Consultation[20] on launching an SCR as we believed the arrangements for allocating, using, and paying for capacity on the electricity network did not adequately support the deployment of new low-carbon technologies. Following feedback from stakeholders we decided in December 2018 to launch the Access SCR[21].

2.2. The initial scope of the SCR included:

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

[20] The initial Consultation document can be found here: https://www.ofgem.gov.uk/publications/getting-more-out-our-electricity-networks-through-reforming-access-and-forward-looking-charging-arrangements
[21] The Access SCR launch announcement can be found here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision

2.3. This final Decision and our accompanying Direction cover two areas of the original scope, the **distribution connection charging boundary** and the **definition and choice of access rights.**

2.4. In our June 2021 Consultation on minded-to positions[22], we did not include positions on DUoS charging reforms. In our January 2022 update[23], we confirmed that DUoS charging reforms were being de-scoped from this SCR and that we would not be directing on TNUoS reforms. A decision on these topics is not covered in this document.

SCR milestones and timeline of publications

2.5. A timeline of key milestones in the development of our proposals is listed below, with a summary of the content of each document included in Figure 1.

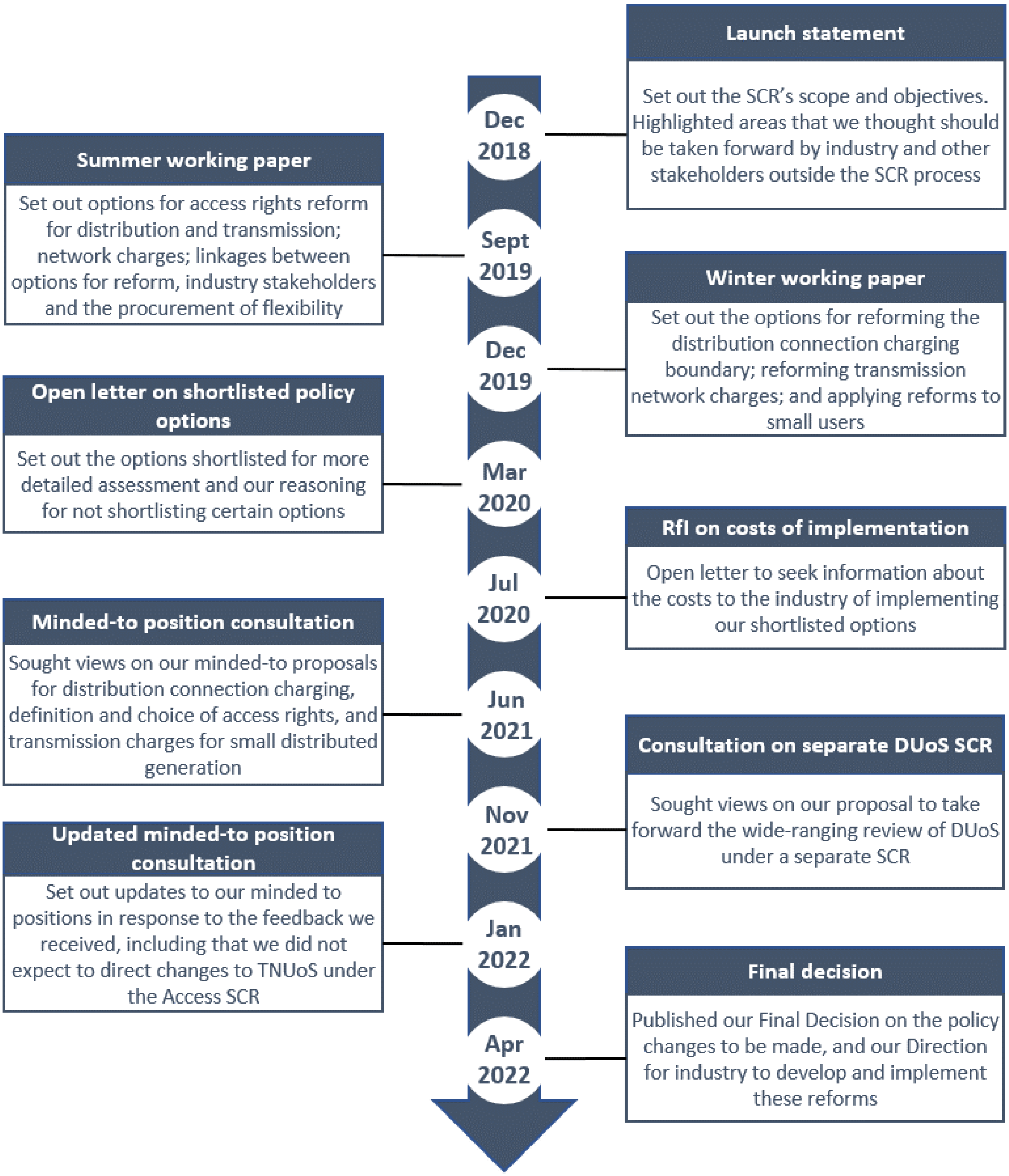
- November 2017: Working paper on reform of access and forward-looking charges[24]
- December 2018: Scope clarified in formal SCR launch[25]
- September 2019: Update on options long-list in summer working paper[26]
- December 2019: Update on options long-list in winter working paper[27]
- March 2020: Outline of shortlisted options[28]
- July 2020: Request for Information on the costs of implementing our shortlisted options[29]

[22] Our Consultation on our minded-to positions can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[23] Our Consultation on updates to our minded-to positions can be found here (paragraph 1.16 for DUoS and section 4 for TNUoS): https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions
[24] The November 2017 Working Paper can be found here: https://www.ofgem.gov.uk/publications/reform-electricity-network-access-and-forward-looking-charges-working-paper
[25] The December 2018 Access SCR launch statement can be found here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision
[26] Our Summer Working Paper can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-summer-2019-working-paper
[27] Our Winter Working Paper can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-winter-2019-working-paper
[28] Our Open Letter on our shortlisted options can be found here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options
[29] Our Request for Information can be found here: https://www.ofgem.gov.uk/publications/request-information-access-and-forward-looking-charging-review

- June 2021: Consultation on minded-to positions[30]
- November 2021: Consultation on separate DUoS SCR[31]
- January 2022: Consultation on updates to minded to positions and response to June 2021 Consultation feedback[32]
- February 2022: Decision to launch a separate DUoS SCR[33]

[30] Our Consultation on our minded-to positions can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[31] Our Consultation on launching a separate DUoS SCR can be found here: https://www.ofgem.gov.uk/sites/default/files/2021-10/Consultation%20on%20next%20steps%20for%20DUoS%20reform.pdf
[32] Our Consultation on updates to our minded-to positions can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions
[33] Our Decision to launch a separate DUoS SCR can be found here: https://www.ofgem.gov.uk/publications/distribution-use-system-charges-significant-code-review-launch

Figure 1: Timeline of Access SCR publications



2.6. We published Summer and Winter working papers, in September and December 2019 respectively, which set out a range of discussion notes and our thinking at the time. In March 2020 we published an Open Letter on our shortlisted policy options, which set out the proposals we were intending to consider further. We followed this in July 2020 with a Request for Information on the potential costs to the industry of implementing our shortlisted options.

2.7. In June 2021, following the responses to these various documents, we published a Consultation on our minded-to positions relating to the distribution connection charging boundary, the definition and choice of access rights, and TNUoS charges (which was a focused position regarding charges for SDG). This Consultation did not include minded-to proposals for wider DUoS charges.

2.8. In this Consultation we also indicated that we were not minded to further consider reforms to non-firm access arrangements for transmission[34]. In comparison to distribution arrangements, existing transmission non-firm access arrangements are relatively well-defined and provide certainty to users about the level of curtailment.

2.9. In November 2021 we consulted on whether to continue our work on wider DUoS reforms under a separate SCR[35]. We launched this separate DUoS SCR in February 2022[36]. In January 2022 we consulted on updates to our minded-to positions, including that we no longer intended to direct changes to TNUoS charges through the Access SCR. We also reaffirmed our high-level proposals in relation to the connection charging boundary and network access rights.

2.10. The following sections set out our approach to identifying and assessing options for reforms to the connection charging boundary and distribution access rights. As set out above, DUoS and TNUoS charges will be taken forward through separate work streams and are not included in the following sections.

Stakeholder engagement

2.11. Throughout the Access SCR, we sought extensive stakeholder input to shape the development of our policy options. Stakeholder responses to the publications above were considered in detail in developing our decisions. Summaries of the responses and our views were shared in subsequent publications. We have consolidated the contributions to the latest Consultation from January 2022 and key stakeholder contributions from previous

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[34] Paragraph 4.9 of our minded-to positions Consultation, which can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[35] Our Consultation on launching a separate DUoS SCR is available here: https://www.ofgem.gov.uk/sites/default/files/2021-10/Consultation%20on%20next%20steps%20for%20DUoS%20reform.pdf
[36] Our Decision to launch a separate DUoS SCR is available here: https://www.ofgem.gov.uk/publications/distribution-use-system-charges-significant-code-review-launch

publications, into the Stakeholder Feedback Appendix accompanying this document. Chapter 3 'Decision on the Distribution Connection Charging Boundary' and Chapter 4 'Decision on Access Rights' contain cross-references to this appendix as appropriate.

2.12. In addition to these written Consultations, we set up several collaborative groups to gather feedback, including a dedicated Access SCR Challenge Group and Delivery Group, and ensured that the outputs derived from these groups were appropriately incorporated into our policy considerations[37]. We also shared progress with stakeholders and sought feedback in the Charging Futures Forum[38] which was set up to enable broader engagement with the Access SCR and the TCR. These are described below.

Delivery Group

2.13. The purpose of the Delivery Group was to support the Access SCR with knowledge and experience of how the electricity distribution networks are planned and operated and to provide feedback and comments throughout the policy development process. The Delivery Group set up several specific groups which allowed for an agile and timely delivery of working papers[39] and feedback on relevant policy options.

2.14. The Delivery Group consisted of Ofgem, the Electricity System Operator (ESO), distribution and onshore transmission network owners, the ENA, relevant code administrators (eg DCUSA and CUSC), and an Independent Distribution Network Operator (IDNO) representative. A Secretariat function was provided by the Energy Networks Association (ENA). Membership of the Delivery Group was limited to these organisations to ensure we could develop and assess options in a timely manner, with access to the necessary expertise and network data.

2.15. In December 2018 we set up two detailed implementation working groups under the Delivery Group, one focused on access rights and another focused on the connection

[37] The details of our approach to Stakeholder Engagement and the groups described below were outlined in Appendix 3 to our initial SCR launch statement, available here: https://www.ofgem.gov.uk/sites/default/files/docs/2018/12/appendix_3_-_stakeholders_engagement_1.pdf
[38] Information on the Charging Futures Forum can be found here: http://www.chargingfutures.com/
[39] Delivery Group resources are available on the Charging Futures website here: https://www.chargingfutures.com/charging-reforms/access-forward-looking-charges/resources-2/scr-delivery-group/

charging boundary. Their purpose was to provide support on practicalities associated with implementation in the latter stages of the Access SCR.

Challenge Group

2.16. The Challenge Group provided input to the Access SCR from a broader group of stakeholders than the Delivery Groups. Its purpose was to ensure that our policy development considered a wide range of perspectives and was sufficiently ambitious in considering the potential for innovation and new technologies to offer new solutions. The group also provided a challenge function to the work of the Delivery Group.

2.17. Membership of the Challenge Group included nominations from academics and innovators who helped ensure that new ideas and wider perspectives were given appropriate voice within the process and increased ours and our stakeholders' understanding of specific aspects of the Access SCR, such as connection arrangements.

Charging Futures Forum

2.18. The Charging Futures Forum is an open, opt-in engagement platform (website, email distribution list and meetings), that provides a means of engaging with and updating a larger group of stakeholders on electricity network charging and access reforms.

2.19. It is an inclusive group that is open to all interested stakeholders, including network users, network operators and energy consumers and/or their representatives. The Forum enables stakeholders to provide policy input and technical expertise for policy developments, including feedback on the coordination and implementation of changes.

2.20. The Forum held a number of workshops throughout the course of the Access SCR that allowed stakeholders to discuss some of the policy proposals in more detail, as well as webinars and podcasts discussing our developing thinking. These were advertised via the Charging Futures newsletter sent out to all members of the Charging Futures distribution list.

Assessment framework

Development of policy options

2.21. Table 3 is our initial long list of policy proposals for access rights and the connection charging boundary, which was developed in 2019[40].

Table 3: Summary of our initial proposals

Area	Initial proposals
Access Rights	• Levels of firmness – This would provide choices about circumstances where a connection capacity could be provided but with a lower level of security (or "firmness"), with the user's access to all or part of the connection capacity being constrained in certain circumstances. • Time-profiled access – This would provide choices other than continuous, year-round access rights (eg '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
Connection charging boundary	• Reducing the extent to which reinforcement charges should be recovered from the connection charge (ie, moving to a 'shallow-ish' connection boundary); • Removing reinforcement from the connection charge (ie, moving to a fully shallow connection boundary); • Allowing alternative payment terms for connection charges (eg, allowing payment over time); and • Introducing some form of financial commitment in the form of liabilities and securities

2.22. In December 2019, we outlined our progress with assessing our long list of potential reform options, in our winter working paper[41]. In March 2020, we published our shortlisted

[40] Section 1 of our Options for reform of access rights for distribution and transmission – discussion note set out our longlist of options in relation to access rights and is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-summer-2019-working-paper
Section 3 of our Distribution connection boundary – discussion note set out our longlist of options in relation to the connection charging boundary and is available here: https://www.ofgem.gov.uk/sites/default/files/docs/2019/12/winter_2019_-_working_paper_-_connection_boundary_note_publish_0.pdf

[41] Our Winter Working Paper can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-winter-2019-working-paper

options[42], which we selected based on a principles-led assessment, giving key consideration to practicality and proportionality. The description of the shortlisted options and subsequent refinement of the policy options taken forward for the connection charging boundary and access rights are described in detail in Chapter 3 and Chapter 4.

Principles-based assessment approach

2.23. Under our Principal Objective, Ofgem has a statutory duty to protect the interests of current and future consumers whenever we consider the need for and shape of any reforms to regulatory arrangements[43]. In detail, this duty is to protect their interests taken as a whole, including their interests in the reduction of greenhouse gases and in the security of the supply of gas and electricity to them. As a result, in making regulatory decisions we take account of the need to contribute to the achievement of sustainable development.[44]

2.24. In our Strategic Narrative for 2019-2023 we set out our understanding of consumers' interests, in terms that provide clear guidance to reform decision-making. We established specific outcomes for consumers that are aligned to our Principal Objective and that we aim to deliver through our reforms, including (i) lower bills, (ii) reduced environmental damage, (iii) improved reliability and safety, (iv) better quality of service and (v) wider benefits for society as a whole, including support for those struggling to pay their bills.

2.25. We developed our objective and a set of guiding principles for the Access SCR that focused on delivering changes to current arrangements in line with this understanding of consumers' interests. The objective 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".

[42] Our Open Letter on our shortlisted options can be found here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options

[43] Our statutory framework is described in detail here: https://www.ofgem.gov.uk/publications-and-updates/powers-and-duties-gema

[44] For a full discussion of this interpretation, see page 9 of our Strategic Narrative, available here: https://www.ofgem.gov.uk/publications/ofgem-strategic-narrative-2019-23

2.26. We also developed three guiding principles that support this objective, outlined in our November 2017 working paper[45]. These provided the framework for developing our policy options and form the basis of our principles-led assessment of the options identified within each workstream.

2.27. Each of our three guiding 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 includes supporting decarbonisation, as suggested by a number of stakeholders, and discussed at our Challenge Group.

2.28. The guiding principles and associated criteria are set out in Table 4.[46]

Table 4: The guiding principles used throughout the SCR process

Guiding principle	Criteria for assessment
1. Arrangements support efficient use and development of network capacity	• Access arrangements support network capacity being allocated in accordance with users' needs and the value they ascribe to network usage. • Arrangements provide signals that reflect the costs and benefits of using the network at different times and places, to support efficient use of capacity, and ensure no undue cross-subsidisation between users. • Arrangements provide effective signals for where new network capacity is justified. • Arrangements reduce barriers to entry and enable new business models where these can offer value to the system. • Arrangements support decarbonisation, primarily by enabling uptake of low carbon technologies through enabling quicker connections and reducing network costs. They will also look to enable and reflect the benefits that new, innovative approaches and business models (such as local energy models) can bring to the network. However, they will not provide any undue preferential arrangements based on technology or user type.

[45] Paragraphs 2.1-2.8 of the November 2017 Working Paper, which can be found here: https://www.ofgem.gov.uk/publications/reform-electricity-network-access-and-forward-looking-charges-working-paper

[46] 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.

2. Arrangements reflect the needs of consumers as appropriate for an essential service	• Electricity provides an essential service and small users in particular need protection from arrangements which may result in harm to their welfare. This may be achieved in the access and charging arrangements themselves or through the wider policy and regulatory arrangements. • Users, or suppliers/intermediaries on their behalf, are able to understand arrangements and have sufficient information to be able to reasonably predict their future access and charges.
3. Any changes are practical and proportionate	• Changes can be implemented given the applicable legislative framework and technologies. • Costs of change are proportionate to consumer benefit.

2.29. Throughout the Access SCR process we have continued to assess all our proposed options against this set of criteria. Chapter 3 'Decision on the Distribution Connection Charging Boundary' and Chapter 4 'Decision on Access Rights' include the summary qualitative assessments of the policy options that were taken forward to this final decision. The full assessment of all shortlisted options against the criteria was included in our June 2021 Consultation on our minded-to positions[47].

Quantitative assessment approach

2.30. This section is a high-level description of the quantitative aspects of our assessment of reform options for the distribution connection charging boundary. The Impact Assessment accompanying this Decision[48] describes the modelling approach and key assumptions used in the impact assessment (IA), in further detail. The key IA results for the connection charging boundary are included in Chapter 3.

Description of overall IA approach and key assumptions

2.31. Our IA was informed by quantitative analysis developed by consultants CEPA-TNEI, which modelled packages of reform options from the original scope of the SCR across DUoS

[47] A summary of these assessments can be found in tables 2 to 9 inclusive in our minded-to positions Consultation, which can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

[48] See accompanying final Impact Assessment published alongside this document.

charging, TNUoS charging and the connection boundary. The initial draft IA was published alongside our June 2021 Consultation on minded-to positions[49].

2.32. The analysis described the impacts of the different reform options (ie positive or negative impacts on any group) and order of magnitude (eg low, medium, high). Where possible, impacts were fully quantified and monetised.

2.33. The monetised impacts were estimated over the period 2023-2040 (17 years). This period was initially chosen based on the timing of the potential changes to DUoS and TNUoS charges in the initial scope, which would take some time to become fully established and deliver benefits. Net present values (NPVs) were calculated using 2023 as the base year for discounting and in line with Treasury guidance on appraisal a 3.5% discount rate was used[50]. Costs and benefits were calculated in real 2018 prices.

2.34. There is a significant degree of uncertainty with regards to the estimated monetary impacts of the proposals, even where the costs associated with specific different outcomes are well understood. A typical economic technique to manage uncertainty is to calculate the change in a specific parameter that would achieve a breakeven point. We therefore estimated the benefit of bringing forward certain types of connections by a number of years (n). If monetary benefits are large when the number of years is small, then it is likely that the policy change is worthwhile. Conversely, if it takes a long time for sufficient benefit to outweigh cost, then there will be less confidence in its likelihood of achieving a net benefit.

2.35. CEPA-TNEI's approach combined several models to calculate the NPV impacts of our charging reform options on the wholesale market and on network reinforcement costs. The same framework was also used to estimate impacts on different network users, in different locations and at transmission and distribution voltage levels.

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[49]Our Consultation on minded-to positions and draft IA are available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

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

2.36. Outputs from the market model and distribution network model were combined in an impact assessment model to produce an NPV of the policy impacts of individual policy options.

IA model scope in relation to the connection charging boundary

2.37. At the time of modelling, our preferred option for the connection charging boundary was to adopt a hybrid approach – a shallow-ish connection boundary for generation, at one voltage level of reinforcement costs, and a fully shallow connection boundary for demand, with no reinforcement contribution. The IA therefore focused on these options, which is consistent with our final Decision.

2.38. To assess the impacts of changes to the connection charging boundary, the IA focused on potential distributional, behavioural and systems impacts.[51] It did this by assessing how alternative charging boundaries would impact (i) locational decisions and (ii) the allocation of costs between connecting customers and DUoS charges.

2.39. Due to the nature of these reforms, it was difficult to accurately quantify some of the other costs and benefits of different policy options. The model did not make assumptions about the elasticity of connection timing, because there was not sufficient evidence to support their estimation. Furthermore, the model did not quantify any benefits that different boundary depths would have on the uptake of new generation or LCTs. However, a very high-level principles-based assessment of this was undertaken, which can be found in section 3.2 of our final IA published alongside this decision.

2.40. Some of the important potential benefits of our reforms that were not modelled, include:

- It would provide opportunities for DNOs to take a stronger whole systems approach to connection planning

[51] CEPA-TNEI undertook a review of the literature on behavioural evidence to inform this. Details on the literature review can be found here: https://www.ofgem.gov.uk/sites/default/files/2021-06/%284%29%20CEPA-TNEI%20Modelling%20Methodology%20-%20Access%20SCR%20%281%29.pdf

- Reduce the risk of free riding and the incentive to avoid being the connecting customer that triggers reinforcement

- Increased optionality for DNOs to consider the most efficient means of facilitating new connections

- Address an intertemporal fairness issue that consumers face higher or lower connection charges by virtue of when they are able to connect

- Minimise distortions between transmission and distribution connected generation, therefore better facilitating competition

- Reduced greenhouse gas emissions (GHG) through facilitation of the uptake of low carbon technologies

2.41. Given that the enabling of LCT uptake, including EVs, heat-pumps and batteries is one of the major expected benefits of the reform, the absence of these benefits from the modelling needed to be explicitly taken into account when we used the results of the IA in our decision-making for the connection charging boundary. The IA was used to supplement and inform our principles-led assessment rather than drive our decision-making.

2.42. In terms of other strategic and sustainability issues, such as security of supply, we did not expect there to be a significant impact from our proposed changes to the connection regime. We also considered that there will be limited to no effects on biodiversity, landscape, land use, water, air quality or soils.

Exclusion of access rights policy options from CEPA-TNEI modelling

2.43. In the draft IA we outlined that proposed changes to access rights were not included in CEPA-TNEI's modelling[52]. We characterised our access rights proposals as 'low regrets', in part because they did not involve a significant transfer of cost between stakeholders and

[52] See section 2.1 'Access Rights' of the CEPA-TNEI document 'Quantitative Analysis of Ofgem Access Options', available at: https://www.ofgem.gov.uk/sites/default/files/2021-06/(3)%20CEPA-TNEI%20Report%20-%20Quantitative%20Analysis%20of%20Access%20SCR%20Options%20(1).pdf

were related to flexible arrangements that are opt-in in nature[53]. In the two rounds of stakeholder feedback since, and in discussions with the Delivery Group, we did not receive significant evidence or views that opposed this characterisation.

2.44. We therefore decided not to undertake further quantitative modelling of the impact of these reforms. The direct monetary impacts of these would have been difficult to quantify. One of the reasons for this, is that future uptake of flexible connection arrangements will be driven by a range of factors at the individual project level and system level that may affect the rate of opt-in customer adoption. The access rights changes we are implementing as part of this Decision are one factor which should make flexible arrangements more attractive to customers. There are other reasons, however, that flexible access arrangement may be less attractive, for example the reduced financial incentive in some instances when considered alongside our connection charging boundary changes, and the dependency how DNOs respond in their approach to network investment and connections management under ED2[54]. Our decision on access rights has instead been developed through a qualitative and principles based assessment of the options considered.

2.45. Although the access rights changes have not been explicitly modelled, we have taken into account that there are likely to be significant interactions between our changes to the connection charging boundary and access rights. These interactions are described in in chapter 4. We are satisfied that the quantitative modelling associated with the connection charging boundary is a sufficient indicator of the combined impacts of both sets of reforms.

Additional information received after undertaking the IA

2.46. Following the publication of our June 2021 minded-to positions and draft IA, the DNOs submitted their draft business plans which included views of the additional expenditure that could be associated with our Access SCR decision. These costs can be

[53] See page 10, available at: https://www.ofgem.gov.uk/sites/default/files/2021-06/(3)%20CEPA-TNEI%20Report%20-%20Quantitative%20Analysis%20of%20Access%20SCR%20Options%20(1).pdf
[54] The RIIO-ED2 price control sets the outputs that Distribution Network Operators (DNOs) need to deliver for their consumers and the associated revenues they are allowed to collect for the five-year period from 1 April 2023 to 31 March 2028.

found in the DNOs' draft business plan annexes and many DNOs have estimated large additional costs over the ED2 period.[55]

2.47. In their responses to our June 2021 Consultation on minded-to positions, stakeholders such as Citizens Advice have also put forward a view that bill payers could be exposed to higher costs than what we estimated in our IA. They encouraged us to review our decision in light of the changes in proposed ED2 expenditure, to ensure that the expected benefits still outweigh the costs.

2.48. We considered the scale of additional costs that consumers could be exposed to, based on the DNOs' updated estimates of their ED2 expenditure. These costs are highly uncertain due to difficulties in estimating the potential acceleration in connections and associated reinforcement solely attributable to our Access SCR decisions. We also note that the DNO draft business plans were submitted on the basis of our June minded-to proposals and did not include additional protections we have developed since, such as a high-cost cap (HCC) for demand connections. There was also a large variation in the assumptions used to derive the impact of the SCR on ED2 costs in the draft business cases developed by the DNOs. This is reflective of the inherent uncertainty in numbers and types of connections over ED2.

2.49. We have considered the ED2 forecasts presented in the draft business plans and their potential impact on the overall benefits case for our reforms. On balance we believe that the benefits case we have presented in the IA, and in Section 3.18 – 3.25 of this Decision, is robust and outweighs the reasonable expected costs of the changes for consumers. We are also putting in place a range of mitigations to protect the interests of consumers following implementation, including the following:

- **Data and monitoring –** Following implementation, we will monitor whether the new arrangements are working in the wider interests of consumers and support the transition to net zero, based on their ongoing costs and impacts on distribution network connections. We will review the reporting requirements through RIIO-ED2 and make to ensure that the right data is being captured.

[55] The draft business plans have been published individually by the DNOs on their respective websites.

- **Retaining and strengthening existing protections for bill payers** - This ensures that bill payers will be better protected from the cost increases associated with the transfer of network reinforcement costs associated with the most expensive connections. In these instances, the connecting customer will be required to contribute to the costs of reinforcement.

- **RIIO-ED2 mechanisms to deal with uncertain costs -** Forecasting costs for the duration of a price control with confidence is challenging. We set baseline allowances for the DNOs only where we are satisfied of the need for and certainty of the proposed work, and where there is sufficient certainty on the efficient cost of delivery. Where uncertainty remains, we will use a range of uncertainty mechanisms (UMs). UMs allow us to adjust a network company's allowance in response to changing developments during the price control period. We will publish further information on our UMs for dealing with load related expenditure in June 2022 as part of our Draft Determinations for RIIO-ED2.[56]

[56] More information and publications regarding RIIO-ED2 can be found here: https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/network-price-controls-2021-2028-riio-2/electricity-distribution-price-control-2023-2028-riio-ed2

3. Decision on Distribution Connection Charging Boundary

Section summary

This chapter provides the details of our decisions on the connection charging boundary for demand and generation distribution network connections.

We confirm our decision to introduce a 'shallow-ish' connection charging boundary for generation and a 'fully shallow' connection charging boundary for demand. This will reduce the charge associated with network reinforcement in the case of generation and remove this charge altogether in the case of demand. In both instances, connecting customers will still have to pay for new network extension assets. In addition, we confirm additional measures to ensure DUoS bill payers are protected against the potential impacts of reinforcement driven by particularly expensive connections.

The case for change

3.1. When a customer seeks a connection to the distribution network, the relevant DNO will consider what work is needed to enable the connection. Generally, the connection will require the installation of new assets to extend the existing network to the customer ("extension assets"). In some cases, the connection will also require the DNO to upgrade or expand the capacity of the existing shared network assets to facilitate the new connection ("reinforcement").

3.2. The costs of reinforcement are split between the connecting customer (via an upfront connection charge) and the wider consumer base through Distribution Use of System Charges (DUoS). The way these costs are split is discussed in terms of the "depth" of the connection charging boundary.

3.3. Under current connection charging arrangements[57], connecting customers face a "shallow-ish" connection boundary.[58] This means:

[57] Current 'shallow-ish' arrangements with cost apportionment were introduced in 2005, where before connecting customers would be required to pay for any reinforcement triggered.
[58] To set connection charges, DNOs utilize the Common Connection Charging Methodology (CCCM) set out in DCUSA Schedule 22. Independent Distribution Network Operators (IDNOs) use their own charging methodologies, which are approved by us and largely based on the CCCM. The CCCM and DCUSA are available here: https://www.dcusa.co.uk/dcusa-document/

- The connecting customer pays all of the costs for the extension assets required to connect to the existing distribution network

- If reinforcement is required to facilitate the connection, the connecting customer contributes toward the cost of that reinforcement, up to one voltage level above their point of connection.

3.4. These current "shallow-ish" connection charging arrangements share the cost burden of reinforcement between the connecting customer and wider distribution network customers. Connecting customers may receive a locational signal encouraging them to connect where there is spare capacity on the network, and the remaining cost of reinforcement, including any reinforcement two voltage levels above the voltage at the point of connection, is paid by the DNO's wider customer base.

3.5. The Access SCR set out to review whether current connection charging arrangements remain fit for purpose. In particular, we considered whether connection charges still provide an effective and fair signal to network users. We also considered the extent to which current connection charging arrangements would help or hinder progress toward a net zero electricity system at least cost. Our review of current connection charging arrangements identified the following issues: [59]

- **Ineffective signals and 'free rider' effect**. Current arrangements do not provide a consistent or fair signal to all users of the network. For example, the cost signal for network reinforcement only exists for the specific customer whose connection triggers that reinforcement, making them liable for the collective impact of previous connections. As reinforcements typically create a step-change increase in the local network capacity, there is an incentive to 'free ride', where prospective connecting customers may choose to wait until reinforcement has been triggered by another customer before requesting a connection. This may result in unnecessary delays in connections and hinder the rate of uptake of low carbon technologies.

[59] These issues are explored in greater depth in Section 3.1 of our accompanying Impact Assessment which should be read alongside this Decision.

- **Incremental reinforcement**. Current arrangements encourage DNOs to take an incremental and reactive approach to reinforcement rather than investing in anticipation of wider network needs. This is because DNOs recover much of the funding for connection-led reinforcement when users pay connection charges. The risk of not fully recovering their costs gives DNOs a strong incentive to wait until they receive connection requests, rather than act in advance.

- **Barrier to net zero**. In the context of rapid decarbonisation, we are concerned that the current reinforcement cost signals, where they exist, may be too strong for some users and risks creating barriers to investment. Stakeholders have told us that high upfront costs of connections are a significant barrier in some areas and that this could delay the deployment of the LCTs required to achieve net zero. In some cases, the cost of connection could result in a connection never proceeding, because the connecting customer is not able to locate elsewhere on the network. For example, significant expansion of electric vehicle charging infrastructure will be needed in key locations across the national road network. Similarly, industrial processes seeking to decarbonise also face locational constraints. One respondent to our Consultation on minded-to positions described current arrangements as a "location lottery" based on connection site availability, arguing that a more strategic approach to reinforcement was required to unlock capacity required to enable investment for net zero.

- **Boundary distortions between transmission and distribution** - Differences between current connection charging arrangements at distribution and transmission level[60] may be creating distortions and/or impacting competition between generators connecting to the different networks. We consider that aligning the connection charging arrangements to the extent possible and where appropriate, may help address these issues.

[60] Transmission connection charges are shallow. Transmission connected customers also face different ongoing use of system charges to those faced by distribution connected customers.

Options considered

3.6. In March 2020, we shortlisted the following options for changing the current distribution connection charging arrangements[61]:

- **Changes to the connection charging boundary:** Reducing the extent to which reinforcement charges should be recovered from the connection charge (ie, moving to a shallow-ish connection boundary); or removing reinforcement costs from the connection charge altogether (ie, moving to a fully shallow connection boundary);

- **Deferred payments:** Allowing alternative payment terms for connection charges (eg, allowing payment over time); and,

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

3.7. The development of the shortlisted options was based on the Guiding Principles that we set out at the launch of the SCR[62]. For further details on the early development of options, please refer to the following publications as well as both Consultations on our minded-to positions:

- Access SCR Winter Working Paper – Connection Charging Boundary Note[63]

- Delivery Group report on the Distribution Connection Charging Boundary[64]

- Access SCR Open Letter on Shortlisted Policy Options[65]

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[61] The shortlisted options can be found in Table 1 in our Open Letter on our shortlisted options, which can be found here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options
[62] The Guiding Principles can be found on page 8 of the Access SCR launch statement, which is available here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision
[63] The Connection Boundary note from our winter working paper is available here: https://www.ofgem.gov.uk/sites/default/files/docs/2019/12/winter_2019_-_working_paper_-_connection_boundary_note_publish_0.pdf
[64] The Delivery Group report is available here: https://www.chargingfutures.com/charging-reforms/access-forward-looking-charges/resources-2/scr-working-group-publications/
[65] Our Open Letter on shortlisted policy options is available here: https://www.ofgem.gov.uk/sites/default/files/docs/2020/03/access_scr_open_letter_march_2020_0.pdf

Options we are not taking forward

3.8. This section summarises how we considered the deferred payments and liabilities and securities options, from March 2020 until now. Neither option has been taken forward in this final decision. We have referred to previous Consultation documents for detailed assessments of these options and stakeholder feedback. The following section describes our assessment of options to change the connection charging boundary, which are part of this final decision.

Deferred payments

3.9. With respect to deferred payments, we considered whether to allow payment of connection charges to be made after energisation over several years. We assessed this option against the guiding principles of the SCR in our June 2021 minded-to decision[66]. The assessment identified several significant risks and costs associated with the option. We identified that changing to payment schedules would transfer a new, significant risk of bad debt onto all customers. It also raised concerns over competition in connections with IDNOs and or Independent Connection Providers (ICPs) potentially being less able to provide what may be deemed as preferential terms.

3.10. Based on this assessment, we indicated we did not propose introducing deferred payments. Following this publication, we did not receive significant stakeholder feedback that influenced or changed the basis of our assessment. As a result, this option was not taken further and is not part of our final decision.

Liabilities and securities

3.11. With respect to liabilities and securities, we considered whether to introduce a new financial obligation on connecting customers, to mitigate the risk of customers funding investments made for connections that end up being cancelled. We considered that such an

[66] This assessment can be found in paragraphs 3.35 and 3.36 in our minded-to positions Consultation, which can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

instrument may complement a change to a shallow-ish connection boundary, to reflect the reduction in financial contributions by the connecting customer, to connection costs.

3.12. We assessed this option against the guiding principles of the SCR in our June 2021 minded-to decision[67]. In our assessment we identified costs and risks associated with the proposal, such as the risk that it would introduce a similar overall barrier to connection, to upfront charges. On the balance of our assessment, we proposed not to introduce any obligations.

3.13. In our January 2022 response to the minded-to publication[68] we summarised stakeholder feedback that we received on this issue. A significant number of respondents provided feedback on this proposal, with the vast majority agreeing with our minded-to position and analysis that this instrument would be a significant barrier to investment[69]. Following consideration of this feedback we did not change our minded to position. As a result, this option was not taken further and is not part of our final decision.

Summary of assessment process for changes to the connection charging boundary

Options considered in our final decision on the connection charging boundary

3.14. With respect to changes to the connection charging boundary, we considered two options for changing the connection boundary against maintaining the status quo:

- **Reduce the contribution to reinforcement:** this would mean customers contribute to reinforcement at the same voltage as the point of connection only, leading to a lower customer contribution than current arrangements, with an increased contribution from DUoS bill payers (a 'shallow-ish' connection boundary').

[67] This assessment can be found in paragraphs 3.37 to 3.39 in our minded-to positions consultation, which can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[68] This summary can be found in paragraphs 2.65 to 2.73 in our updated mined-to consultation, which can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions
[69] See section 1.64 – 1.72 of the accompanying Stakeholder Feedback Appendix

- **Remove the contribution to reinforcement:** removing the contribution to reinforcement in the connection charge completely. This would result in a 'fully shallow' connection boundary, with 100% of reinforcement costs funded through DUoS charges.

3.15. We also considered a "hybrid" approach, that is, a different boundary depth for demand and generation.

Principles-based assessment of options

3.16. Table 5 is a high-level summary of our principles-based assessment of the potential changes to the connection charging boundary, which are described above. Our June 2021 Consultation[70] included this assessment, along with further details and confirmation that we were minded to proceed with the hybrid option which would:

- **Reduce** the contribution to reinforcement within the connection charge for generation connections; and

- **Remove** the contribution to reinforcement within the connection charge completely for demand connections.

[70] Table 2 in our minded-to positions Consultation, which can be found here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

Table 5: Summary of our assessment of the options against our guiding principles

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.

3.17. Our high-level proposed positions on the connection charging boundary did not change in our January 2022 Consultation on updates to our minded-to positions[71]. This publication did include updates to several details of our minded-to decision, including the use of mitigations for certain connection scenarios. These details are described in the 'Our decision' and 'Details of our decision' sections below. The following section outlines our quantitative assessments (ie our impact assessment) of these options.

[71] Our updated positions on reforms to the connection charging boundary can be found in section 2 of our updated mined-to Consultation, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

Quantitative assessment

3.18. In our quantitative IA, we considered the potential impacts of implementing the 'hybrid' connection charging boundary (reducing the contribution to reinforcement for generation connections and removing it for demand connections). Chapter 2 explained the modelling approach and the IA scope in relation to the connection charging boundary. For further detail on the underlying assumptions and methodology followed, please refer to the final Impact Assessment published alongside this decision.

Modelling results for our preferred connection charging boundary options

3.19. The impact on DUoS bill payers of moving from the current charging depth to the hybrid approach was estimated to have an NPV of £380m in additional costs over 17 years, in the central scenario.[72] We note that the robustness of estimations is predicated on the available data, and the IA itself drew upon estimates of future demand growth and technology uptake.

3.20. Other non-financial impacts estimated were positive, including the facilitation of competition between generators at transmission and distribution, reducing upfront barriers to entry which also support security of supply[73].

3.21. The IA did not consider the change in depths of charge to have significantly different effects on greenhouse gases other than helping to bring forward investment in low carbon technologies[74]. It also found no clear indication that certain types of demand or generation would be impacted more than others by such changes[75].

3.22. Table 6 sets out a summary of the potential impacts of our preferred options.

[72] This analysis and other scenarios modelled is discussed in detail in Section 2.4 of the Final Impact Assessment published alongside this document
[73] See section 3.3.3 – 3.3.9 of the IA for a detailed discussion
[74] See section 3.3.8 of the IA for a detailed discussion
[75] See section 3.4.1 – 3.4.2 of the IA for a detailed discussion

Table 6: Summary of the impacts of our connection boundary decision

Area	Connection Boundary
Monetary analysis	• A PV of £290-£530m of additional costs over 17 years. The central scenario estimates an impact of £380m.
Other system costs and benefits	• Consistent with DNOs exploring alternatives to conventional network reinforcement • Will allow users to make more efficient connection decisions between connecting at transmission or distribution where there is a choice
Competition impacts	• Would help facilitate competition between distributed generators by reducing upfront barriers to connecting to the distribution network • Seeking to align the arrangements for transmission and distribution to the extent possible should also facilitate competition • Unlikely to have a significant negative impact on competition more generally
Security of supply impacts	• Reducing barriers to entry and enabling more generation onto the system may have benefits for security of supply as demand is expected to increase in coming years
Greenhouse gas impacts	• We did not expect our proposals to have any other greenhouse gas impacts other than bringing forward the connection of LCTs
Other environmental impacts	• We considered that our proposals would not have a material impact on emissions related to losses from distribution networks • We thought our proposals may have an overall positive impact in relation to indirect visual and other amenity issues from overhead lines as DNOs consider build and non-build solutions to provide capacity for new connections
Distributional analysis	• We did not expect there to be significant differences in the impact on different types of demand and generation (eg between solar and onshore wind)

3.23. The IA also provided valuable analysis to support the choice of whether to apply the same connection charging boundary to all connecting customers, or to treat demand and generation connections differently (the hybrid option). CEPA-TNEI modelling showed that the increase in system costs is greatest for a completely shallow connection charge (£1.4bn) but is more modest under our preferred hybrid option (~£0.4bn). This shows a high incremental system cost (~£1bn) of moving to a completely shallow connection boundary for generation. This was not the case with demand. The modelled impact of moving from a shallow-ish charge for both demand and generation (where connection charges only apply at the voltage of connection) to our preferred hybrid option was comparatively smaller (~£0.1bn).[76]

3.24. Overall, we consider that the quantifiable impacts on network costs described above, will be outweighed by the broader benefits of supporting the transition to net zero and align with the broader requirement to enact changes that reduce and remove barriers to connection where they could be a barrier to the realisation of net zero.

3.25. We consider that the modelling and results of draft IA published in June 2021 continue to provide a robust estimate of impacts. Our view is that it was not necessary to update the modelling using new assumptions, based on a consideration of (i) the key inputs to our modelling, (ii) the degree of change in those inputs since the original modelling was conducted and (iii) the sensitivity of the IA results to those assumptions. This is discussed in more detail in the IA[77].

Our decision

3.26. We have decided to make the following changes to the distribution connection charging boundary:

- **Remove the contribution to reinforcement for demand connections** by introducing a 'fully shallow' connection charging boundary. This will involve connecting customers paying for extension assets only.
- **Reduce the contribution to reinforcement for generation connections** by introducing a 'shallow-ish' connection charging boundary. This will involve connecting customer paying for extension assets and a contribution towards reinforcement at the voltage level at point of connection.

[76] See section 4.2 of the CEPA-TNEI report for more information on the modelled system impacts, available here: https://www.ofgem.gov.uk/sites/default/files/2021-06/%283%29%20CEPA-TNEI%20Report%20-%20Quantitative%20Analysis%20of%20Access%20SCR%20Options%20%281%29.pdf
[77] See the Executive Summary to our accompanying IA.

- **Retain and strengthen existing protections for bill payers** to ensure they are better protected from the cost increases associated with the most expensive connections.

3.27. We consider that these reductions in connection charges will serve to bring forward investment in LCTs and allow DNOs to reinforce the network more strategically, ahead of customer need, where it is in the interests of customers to do so. These changes are summarised in Figure 2.

Figure 2: Visual illustration of changes to the distribution connection charging boundary

	Extension assets	Reinforcement assets at connection voltage	Reinforcement assets at connection voltage +1
Current arrangements	Connecting customer pays 100%	Connecting customer pays a proportion of the reinforcement costs	Connecting customer pays a proportion of the reinforcement costs
New arrangements (Demand)	Connecting customer pays 100%	Fully funded by the DNO via DUoS	Fully funded by the DNO via DUoS
New arrangements (Generation)	Connecting customer pays 100%	Connecting customer pays a proportion of the reinforcement costs	Fully funded by the DNO via DUoS

3.28. In response to our first (June 2021) Consultation, the majority of respondents (35) offered strong support for our proposals to remove the contribution to reinforcement for demand connections and to reduce it for generation. Some respondents (9) argued that we should go further and introduce a fully shallow boundary for generation as well. They argued that this would create greater parity between transmission and distribution charging arrangements.[78]

3.29. We consider that our position on the connection boundary strikes the right balance between maximising benefits, such as removing barriers (particularly for those where we think a behavioural response is unlikely) and limiting the cost impacts on wider network customers, as described in paragraph 3.23 above. In the absence of DUoS reform, going further and removing all contributions to reinforcement from generation connections would

[78] See paragraph 1.11-1.20 of the accompanying Stakeholder Feedback appendix.

mean that generators do not face any signal about the impact they drive on the network. This is because, at present, generators receive mainly DUoS credits, even in areas where they are driving costs.

3.30. We have also given consideration to the fact that in order to decarbonise the electricity network, significant network investment in the coming decade is likely to be driven by new generation connections, compared to necessary changes in demand which are more likely to result in upgrades to existing connections. We consider that new users have a degree of choice in location that existing (mainly demand) users do not. We think our decision strikes a balance between ensuring existing users who have less ability to relocate do not face an undue financial barrier in their connection charge if an upgraded connection is required to decarbonise their energy consumption.

3.31. The impact of the new distribution connection charging boundary is a transference of costs presently recovered from the individual connecting customer, to all DUoS bill payers. We think that there is a strong strategic rationale for this, as set out in our case for change, especially in the context of the UK's legally binding commitments to net zero by 2050.

3.32. A fully decarbonised power system by 2035, as set out in Government's Net Zero Strategy, is going to require widescale investment in reinforcement of the shared distribution network over the coming decade. The electrification of heat and transport is also going to place additional strain on the distribution network. It therefore becomes harder to attribute the triggering of reinforcement to any one user as opposed to the collective impact of all existing users on the network. We think that the transference of reinforcement costs to the wider DNO customer base is fairer in the context of a rapidly changing distribution grid.

Details of our decision

3.33. In this section we present additional details to our decision, to guide the implementation of the reformed distribution connection boundary. We also confirm the mitigations we will be taking forward to limit the exposure of DUoS bill payers to excessively high costs.

3.34. Our changes to the connection charging boundary will reduce the price signal sent to customers through connection charges, about the cost of connecting in certain locations. Our impact assessment suggests that this change could lead to less efficient decision-making by some customers for some locations[79]. We continue to consider that these efficiency losses are outweighed by the expected benefits, such as bringing forward connections of LCTs and encouraging DNOs to invest strategically in the wider interest of all consumers. However, we acknowledge that in the absence of DUoS reform reintroducing some locational signals, concerns remain around the risk of consumers funding inefficient system development. This is particularly pertinent for high-cost demand connections where there was lower demonstrable wider consumer benefit to the triggered reinforcement.

3.35. In order to mitigate the risk of exposing DUoS bill payers to inefficient investment and high-cost developments, our decision therefore includes the retention and introduction of a number of mitigations, wherein connecting customers will be required to pay more towards reinforcement in certain circumstances. We expand on these DUoS mitigations later in this section, in paragraphs 3.50 – 3.85.

3.36. Future DUoS reforms could impact the case for these mitigations and may come into effect midway through the RIIO-ED2 price control period. We are therefore keeping these mitigations under review in our ongoing DUoS SCR. This will allow us to monitor these mitigations whilst providing immediate protections to bill payers as the reforms to the connection charging boundary come into effect from 1 April 2023.

Definition of Demand and Generation Connections

3.37. A clear definition of what should be considered demand or generation is required to give effect to our substantive decision on the different connection charging depths (shallow for demand, shallow-ish for generation). The policy intent is that sites whose primary purpose for a connection to the network is to consume other than for the purposes of generation or export onto the electricity network should be charged under a shallow boundary. Sites that do not meet these criteria, including generation, should be charged under a shallow-ish boundary. We discuss treatment of storage in the next section.

3.38. In considering how to implement this distinction formally in the DCUSA, we reviewed the definitions that had been developed as part of the TCR. The TCR resulted in definitions for Final Demand Site and Non-Final Demand Site in order to distinguish between different

[79] See section 3.2 of our accompanying Impact Assessment Appendix which should be read alongside this decision

sites for the purposes of administering residual use of system charges.[80] We consider that these definitions, which are now part of the CUSC[81] and DCUSA[82], are a logical fit for achieving the different connection charging treatments for demand and generation that we consulted on and have decided to implement.

3.39. We have therefore decided to direct the DNOs to implement the different connection charging depths for demand and generation in alignment with the definitions of a Final Demand Site and a Non-Final Demand Site as developed as part of the TCR. These definitions are set out in Schedule 32 of the DCUSA.

3.40. Where electricity is consumed on a site for any reason other than for the purposes of generation or export, the connection will be deemed a Final Demand Site. These sites will be charged under the demand connection boundary and will not be required to contribute towards reinforcement costs. This definition also captures mixed use sites where generation and demand are co-located. Any connections deemed to be a Final Demand Site will be subject to the demand high-cost cap, discussed in paragraphs 3.50 – 3.67.

3.41. A Non-Final Demand Site is, in summary, a connection to the distribution system which only imports electricity for the purpose of exporting electricity. These customers are required to submit a signed statement to the distributor to avoid paying residual use of system charges on any metered demand. For the purposes of connection charging, any connections for sites that do not meet the definition of a Final Demand Site (ie a Non-Final Demand Site) would be (i) captured by the generation connection boundary, and therefore be subject to reinforcement costs at the same voltage of connection, and (ii) subject to the generation high-cost cap, discussed in paragraphs 3.50 – 3.67.

3.42. We think that alignment with the TCR definitions is a logical and consistent way to implement our connection charging boundary decision. These definitions have been developed over a substantial period of time in a robust, open, and deliberative process. We do not consider it a good use of industry’s time to start on a new set of definitions, when a suitable set has just been developed. However, we recognise that these definitions were

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[80] See the Annex, p. 4 of the CUSC Direction for the TCR, available here: https://www.ofgem.gov.uk/sites/default/files/docs/2019/11/cusc_direction_1.pdf
[81] These definitions are reflected in section 1 of the CUSC which is available here: https://www.nationalgrideso.com/document/91346/download
[82] These definitions are reflected in schedule 32 of DCUSA which is available here: https://www.dcusa.co.uk/dcusa-digital-document/DCUSA/DCUSA_Schedule_32/DCUSA_Schedule_32.htm

not developed for the explicit purpose of connection charging. We are therefore also directing the DNOs to develop any additional criteria to allow for clear determination of a site's use case at the time of connection application.

Treatment of storage

3.43. We confirm our position, set out in the January Consultation on updates to our minded-to positions, that storage will be treated consistently with generation for connection charging purposes[83]. This decision will require storage connections to contribute to reinforcement costs at the voltage of connection in accordance with the 'shallow-ish' connection boundary for generation, regardless of whether that reinforcement is import or export driven.

3.44. We sought stakeholder views on this position in our January Consultation on updates to our minded-to positions.[84] Our position that storage should be treated in line with generation received broad support (16 respondents). Some respondents encouraged us to keep this position under regular review to ensure that it was not preventing the benefits of storage from coming forward by disincentivising locating in areas where it could serve the purpose of alleviating network constraints.

3.45. A number of stakeholders disagreed with treating storage as generation on the basis that the 'shallow-ish' connection charging boundary would be a barrier to the development of storage capacity, compared to the fully shallow option. One stakeholder highlighted that in generation-dominated parts of the network, storage can provide benefits by alleviating constraints.[85] Another response said that network charging was a key factor to consider in the policy regime for the development of storage and the value that they provide to the system should be appropriately reflected in charges.[86]

3.46. We acknowledge the network benefits that storage can provide in responding flexibly to meet system requirements, and that storage will play an important role in the journey to net zero. However, we also recognise that the current wider market arrangements do not

[83] This position is set out in paragraph 2.128 of our Consultation on updates to our minded-to positions, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions
[84] See paragraph 2.53 of the accompanying Stakeholder Feedback appendix
[85] See paragraph 2.59 of the accompanying Stakeholder Feedback appendix
[86] See paragraph 2.61 of the accompanying Stakeholder Feedback appendix

guarantee that this will always be the case. This is especially true in instances where storage is not locating and operating specifically to alleviate a constraint, or to provide another location-specific service on the network. In such instances, it can still significantly impact network costs.

3.47. A fully shallow connection charging boundary for storage would not be consistent with our intention to retain a locational reinforcement cost signal in connection charges for certain types of users. We continue to consider that storage has more locational flexibility than most demand connections.

3.48. It is important to note that storage that is co-located with demand may not be required to contribute to reinforcement costs up to the demand high-cost cap, should it be considered a Final Demand Site per DCUSA Schedule 32 definitions. This aligns with the current treatment of other mixed sites.

3.49. We will continue to monitor whether the new arrangements are working in the wider interest of consumers and in support of our transition to net zero. We also note that DNOs have been reviewing connection queue management principles in order to allow for the storage connections to be brought forward where their flexibility can contribute to relieving network constraints[87].

DUoS mitigations: the high-cost cap

3.50. The high-cost cap (HCC), or as it is described in the CCCM, the high-cost project threshold[88], is a £/kW value above which the connecting customer is presently required to pay in full for any reinforcement costs. For generation connections, there is an existing high-cost project threshold set at £200/kW. No such threshold presently exists for demand connections.

3.51. The generation HCC limits the cost burden of an individual connection, which is shared with DUoS bill payers. The design of the HCC means the cap is based on a £/kW

[87] Further details on this can be found in section 14 of the Open Networks Project Queue Management User Guide, available here: https://www.energynetworks.org/industry-hub/resource-library/on21-ws2-p2-updated-queue-management-user-guide-(30-jul-2021).pdf
[88] The terms 'high-cost cap', 'HCC', and 'high-cost project threshold' are used interchangeably throughout this document.

threshold for reinforcement costs, rather than the absolute cost or capacity requirement of the connection. While we understand that the generation HCC is rarely triggered, its existence serves as a useful tool in early discussions between DNOs and potential connecting customers where reinforcement would be expensive. Some projects that would breach this threshold therefore decide not to proceed with their connection application at this early stage.

3.52. We have decided to retain the HCC for generation at its existing level, and to introduce an HCC for demand at a level that is triggered only for a small minority of high reinforcement cost projects. This decision is consistent with the principles we consulted on in January 2022[89], and we believe that the HCC can be an effective mechanism for protecting DUoS bill payers from excessively high reinforcement costs. The majority of respondents (18) supported and agreed with our view.[90]

3.53. In accordance with our decision to move to a 'fully shallow' connection charging boundary for demand, we consider a demand HCC to be a necessary backstop protection for DUoS bill payers against excessive costs. This will continue to ensure there is still a disincentive for connections in network areas with very high reinforcement costs. We expect it to affect only a small minority of expensive demand connections, whilst ensuring that we can achieve the benefits of reduced financial barriers to connection for the vast majority. In the absence of an HCC (and absence of other mitigations), all reinforcement costs not paid by the connecting customer would have to be funded in full by DUoS bill payers, regardless of the level of cost and nature of the connection. This could lead to inefficient decision-making and excessively high additional costs for wider DUoS bill payers as a consequence of expensive reinforcement of which the connecting customer is likely to be the principal beneficiary. Our analysis of these costs is outlined in paragraphs 3.64 – 3.66.

3.54. We have confirmed that the Schedule 32 definition of Final Demand Site and Non-Final Demand Site will be used to determine demand connections and generation connections respectively. For avoidance of doubt, this means that connections deemed to

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[89] Our position on the use of an HCC is set out in paragraphs 2.82-2.105 of our updated minded to Consultation, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions
[90] See paragraph 2.2 of the accompanying Stakeholder Feedback appendix

be a Final Demand Site will be subject to the new demand HCC, and all other connections (ie Non-Final Demand Site connections) will be subject to the generation HCC.

3.55. We have decided that to be consistent with the existing approach for generation, both HCCs should be calculated based on an assessment of the cost of reinforcement at the voltage at the point of connection plus one voltage level above the point of connection. In our June 2021 Consultation we ruled out using reinforcement at all voltages in the calculation of the HCC, as this would effectively result in a deeper connection charge than is faced today.[91] In our January Consultation we also ruled out using reinforcement costs only at voltage level at the point of connection as this removes such a high proportion of associated reinforcement costs that it would dampen the disincentive that the HCC creates, against connecting in areas where reinforcement costs were high.[92]

3.56. Where an individual connection triggers reinforcement that breaches the HCC, the connecting customer will pay 100% of the cost of reinforcement that exceeds the cap.[93] Reinforcement below the cap will be paid for according to the new connection boundary arrangements, such that generation connections will pay an apportioned contribution, and demand connections will pay no contribution (subject to applicable exceptions).

3.57. We acknowledge that developments in future DUoS charges, such as locational price signals, could affect the requirement for or effectiveness of any HCC. Therefore, as outlined in our June 2021 Consultation, we will keep the HCC and all other DUoS mitigations under review within the scope of our DUoS SCR.

The generation high-cost cap

3.58. We have decided to retain the existing generation HCC at £200/kW. We have not received sufficient evidence from stakeholders that the current level of the HCC for

[91] Page 83 of our minded to Consultation, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[92] Paragraph 2.92 of our Consultation on updates to our minded-to positions, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions
[93] The details of the current arrangements and our proposals for the voltage rule, high-cost cap and CAFs were set out in Appendix 1 of our June 2021 Consultation: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

generation is inappropriate for the requirements of distributed generators, nor have we been able to determine this from the available connections data.

3.59. Unlike the demand HCC, where none has existed before, it was not possible to conduct a detailed review into the level of the generation HCC and its effect on connections because the existing HCC distorts the historic data. We were unable to obtain from DNOs any data on customers that chose not to proceed with their connection application (nor how many of those exceeded the HCC).

The demand high-cost cap[94]

3.60. We have decided to introduce an HCC for demand connections, set at a level of £1720/kVA[95]. The level of the cap has been set on the basis of our analysis of DNOs' data on reinforcement costs arising from demand connection offers issued over the RIIO-ED1 price control period.

3.61. Under current connection charging arrangements for demand, the reinforcement costs of more expensive connections are apportioned between the connecting customer and DUoS bill payers, across the voltage at point of connection plus one above. This cost alone may be significant enough to signal to demand customers to reconsider their connection location or specification.

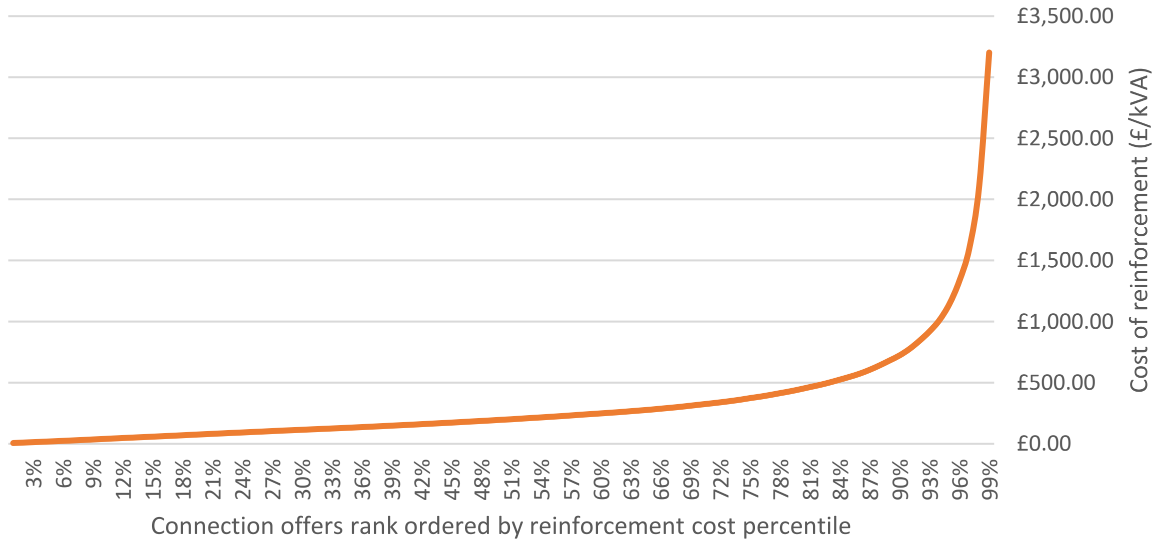
3.62. Under the new fully shallow boundary, in the absence of a demand HCC, all reinforcement costs would be charged to DUoS bill payers. This sends no signal to the connecting customer that is driving very high reinforcement costs and will not be directly reflected in their ongoing DUoS charges. The absence of any signal could lead to an increase in projects with high-cost reinforcement going ahead, while the benefits case to wider DUoS bill payers of the capacity created may be limited. On this basis, we consider it necessary to protect DUoS bill payers from demand connections with a disproportionately high associated reinforcement cost.

[94] The analysis behind this section is described in more detail in Appendix 1 - Demand HCC development methodology, published as separate document alongside this Decision.
[95] The demand high-cost cap refers to kVA rather than kW in line with how capacity is expressed in connection offers for demand customers.

3.63. In our January update, we set out the principle that the demand HCC should rarely be triggered and that it should be set at a threshold which would act as a protection only against projects with the highest cost-to-capacity ratio[96].

3.64. Figure 3 shows the reinforcement costs associated with connection offers made by all DNOs to demand customers over the first four years of the RIIO-ED1 period based on data available at time of request [97]. The plot ranks connection offers from lowest to highest reinforcement costs on the x-axis, against their costs in £/kVA on the y-axis.

Figure 3: Connection offers issued by DNOs over the course of RIIO-ED1 to date, rank ordered by reinforcement cost percentile on the x-axis and cost of reinforcement in £/kVA on the y-axis



3.65. Across the combined data for all DNOs, the cost of reinforcement for more than 90% of connection requests are below £1,000/kVA, with a small minority of connection requests driving costs that are significantly higher. The data from individual DNOs illustrates a similar profile at the level of each individual region, where a small number of projects drive disproportionately more expensive reinforcement.

[96] Paragraph 2.101 in our Consultation on updates to our minded-to positions, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

[97] Connections data was requested from DNOs in February 2022 and covered connections across all electricity distribution licence areas from the first four years of the RIIO-ED1 price control period.

3.66. Based on the above principles and this analysis of DNO data, we have calculated a demand HCC level of £1720/kVA. At this level there is no DNO region in which more than 5% of offers in the period assessed would have been affected, ensuring locational discrimination is averted. This level is also four times the average reinforcement costs of connection offers over the period.

3.67. This analysis is described in more detail in the accompanying appendix 'Demand HCC development methodology'[98].

DUoS mitigations: speculative developments

3.68. Under current arrangements, if a customer requests a connection that the DNO deems to be speculative then the connecting customer may be required to pay in full for any reinforcement costs, in addition to any ongoing operational and maintenance costs. We have decided to retain this treatment of speculative developments, which is set out in in the Common Connection Charging Methodology[99].

3.69. Although we support the current treatment of speculative developments in principle, we have identified a lack of clarity and consistency in how these arrangements are applied in practice by the DNOs. This could lead to inconsistent outcomes for network users. We are therefore directing amendments to the characteristics for projects which may be deemed to be speculative.

3.70. Under the current arrangements, developments may be considered speculative by DNOs if they have one or more of the following characteristics:

i) their detailed electrical load requirements are not known

ii) the development is phased over a period of time and the timing of the phases is unclear

iii) the capacity requested caters for future expansion rather than the immediate requirements of (an) end user(s)

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98 Published as separate document alongside this decision.

99 As defined in DCUSA version 13.7, paragraph 1.39. of Schedule 22 – Common Connection Charging Methodology, which is available here: https://www.dcusa.co.uk/dcusa-digital-document/DCUSA/DCUSA_Schedule_22/DCUSA_Schedule_22.htm

iv) the capacity requested caters for future speculative phases of a development rather than the initial phase(s) of the development

v) the infrastructure only is being provided, with no connections for end users requested

3.71. The majority of respondents to our January Consultation agreed with our proposal to retain this requirement. Respondents broadly agreed that retaining current treatment of speculative developments would deter connecting customers from over-specifying their capacity requirements, reduce the risk of stranded assets, and protect DUoS bill payers from excessive costs.[100]

3.72. Stakeholders also told us that they would like to see more clear and consistent application of the definitions and criteria set out in the CCCM by the DNOs. In particular, some stakeholders were concerned about the application of the current arrangements to new housing developments, suggesting that in some cases provisioning for and reserving capacity required for future phases of expansion may be beneficial, and that the risk of asset stranding may be exceeded by the risk of not future-proofing the network.[101]

3.73. We were asked to consider the unique characteristics and needs of multi-phased housing developments, and whether a classification as speculative on all such applications could instead lead to undesirable outcomes. We are also aware that similar arguments may apply to other needs and types of development such as public EV charging stations with firm plans to increase capacity over time.

3.74. Our expectation is that DNOs should continue to apply due discretion with respect to connection charging treatment based on their assessment of whether the connection application meets the speculative development criteria. This should include engagement with the connecting customer to seek additional information that may assist the DNO in assessing whether the project should be considered as speculative.

3.75. We understand that this classification is intended predominantly to protect DUoS bill payers where there is a significant risk of asset stranding associated with network reinforcement (should the development not materialise) and is not frequently applied by

[100] See paragraph 2.39 of the accompanying Stakeholder Feedback appendix
[101] See paragraph 2.40 of the accompanying Stakeholder Feedback appendix

DNOs. In light of the reduction or removal of the reinforcement charge as a commercial disincentive for connection applicants, the DNO's assessment of speculative developments becomes an important protection for DUoS bill payers.

3.76. We consider that the need and benefits case for capacity 'reservation' is weaker in light of the new connection charging boundaries, under which the commercial disincentive to the customer to avoid triggering of reinforcement is reduced or altogether removed. In general, we do not think it is in the best interests of network customers for connecting customers to be able to reserve capacity, especially if wider DUoS bill payers carry the risk.

3.77. We recognise, however, that in some instances it may be most efficient for the DNOs to build capacity for multiple phases of development at once rather than incrementally deliver capacity upgrades according to the phases of a project. In such instances, we think that DNOs should be able to apply reasonable discretion as to whether the evidentiary threshold required to treat future phases of development as non-speculative has been met.

3.78. If the DNO is satisfied with the evidence provided regarding timing and confidence of progression of subsequent phases, we consider that these phases should still be able to benefit from the new connection charging arrangements without being classified as speculative. Whilst this is already provisioned for in the CCCM, we think these arrangements should be clearer and more consistently applied by all DNOs.

3.79. As part of implementation, we are therefore directing the DNOs to raise a code modification(s) that will:

- Amend the description of speculative developments as currently set out in the CCCM[102]. This should include refining the characteristics in order to ensure consistent interpretation across DNOs, as well as considering more explicit treatment for connections where phased or future expansion may be the most appropriate approach for both the customer and DNO.

- Clarify that where capacity caters for future expansion rather than the immediate requirements of an end user, ie for subsequent phases of a project, it

[102] The treatment of speculative developments in Schedule 22 of DCUSA can be found in Paragraph 1.39: https://www.dcusa.co.uk/dcusa-document/digital-dcusa-document/

does not always have to be treated as a speculative development. This should be subject to DNO discretion based on an evidence-based assessment of the timing and confidence in delivery of future phases of work. We expect the working group to further develop a clearer indication of the information and criteria that may be taken into account by the DNO in determining whether the connection should be treated as speculative.

- Clarify that phased developments do not always have to be treated as speculative developments, where the customer can provide sufficient relevant evidence to support this treatment. This should include providing greater clarity on what information is required to determine what is a 'speculative phase' and an 'initial phase' and how the distinction is made.

- Consideration of introducing a methodology for connections with planned phases or future expansion which would otherwise be deemed speculative, where a case can be made for the cost efficiency and wider network benefit of not treating them as such.

DUoS mitigations: three phase connections and voltage upgrades

3.80. We have decided to retain the current treatment of three phase connections and voltage upgrades under the new connection charge boundary rules. This means that, where a phase or voltage upgrade is requested by the customer but is not necessary for the DNO to provide the required capacity, the customer will be required to pay in full for the requested upgrade. 'Required Capacity' as set out in the CCCM is the maximum capacity agreed with the customer for the connection[103].

3.81. In our January update[104], we consulted on the treatment of three phase connection requests as these can result in costly reinforcement and upgrades of the local distribution network. The majority of respondents supported retention of charges for unnecessary

[103] The treatment of three phase and voltage upgrades is set out in paragraph 1.11 of the CCCM. The definition of Required Capacity can be found in paragraph 1.24. Schedule 22 of the DCUSA – Common Connection Charging Methodology
[104] Our updated minded to positions are set out in paragraphs 2.106-2.11 of our Consultation on updates to our minded-to positions, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

upgrades were sought by the customer, with no stakeholders expressing opposition.[105] Some respondents noted that this requirement may need to be reviewed should the interpretation of 'required capacity' become a blocker to the provision of three phase connections for low carbon technologies like EV charging.[106]

3.82. We considered several options for the treatment of three phase connections under the new connection charging boundary[107]. One option was to reduce reinforcement charges for all three phase connections. We also considered requiring the DNOs to review whether an increase in phases or voltage might have a benefit to the wider customer base in the area, which might reduce their individual contribution to reinforcement costs. This method would require criteria and an evaluation process to be introduced, as well as introducing potential complications and room for challenge with regards to reasonable cost apportionment and what classifies as wider benefit. We deemed this option to be disproportionate to the scale of the issue at hand.

3.83. We understand that at present, DNOs typically determine the needs case for the requested upgrade, on the basis of the kW or kVA load requirements of the connection request. Where the load requirements can be accommodated on the existing number of phases or voltage, the customer will be asked to pay for the upgrade. An example is where a customer seeks a three phase connection to accommodate a specific device or technology, but the power requirement alone could be met with a single phase. In such a scenario, it may be best for the customer to purchase a phase converter, rather than pay the full cost of network upgrades.

3.84. We have decided to retain current arrangements for the treatment of three phase connection requests. As long as the three phase connection is determined by the DNO to be required to support the customer's capacity, the new connection charge boundary will apply. However, where the need for three phase is not clearly established, the connecting customer will still be required to fund the cost of reinforcing the local distribution system.

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[105] See paragraph 2.35 of the accompanying Stakeholder Feedback appendix
[106] See paragraph 2.38 of the accompanying Stakeholder Feedback appendix
[107] See paragraphs 2.106 – 2.111 of our Consultation on updates to our minded-to positions, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

3.85. DNOs should continue to ensure that strategic upgrades to three phase networks are principally delivered through their network development plans under the RIIO-ED2 framework. We believe this to be a more targeted and strategic approach that ensures upgrades can be prioritised according to the needs of wider network users. In contrast, a connections-led approach would be more iterative and risks greater inefficiency, with a single three phase connection request potentially triggering wide scale network investment regardless of the broader requirement for this capacity.

Treatment of transmission reinforcement triggered by distribution connections

3.86. In our June 2021 Consultation on minded-to positions, we highlighted that, even though customers seeking to connect to the transmission network face a shallow connection charge, Transmission Attributable work (eg 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.[108] While we consider that these arrangements need to be reviewed, we confirm our minded-to position not to make any changes to the current treatment of transmission work triggered by a distribution connection at this time.

3.87. We acknowledge that current arrangements could result in prohibitively expensive upfront costs that may adversely influence investment decisions, preventing connections from going ahead that could be beneficial to consumers. Large distributed generation is at particular risk of facing a high upfront charge related to work at transmission level, as well as ongoing wider locational transmission generation charges. This represents a boundary distortion between transmission and distribution systems.

3.88. In our Consultation on minded-to positions[109] we noted that an alternative could be to recover these costs through ongoing use of system charges, however such an approach would create several challenges that would need to be addressed, in order to avoid excessive impacts on consumers. For example, changes to the electricity distribution licence would be required to allow DNOs to recover these costs through DUoS, but more

[108] See paragraph 3.27 in our June Consultation on minded-to positions, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[109] See paragraphs 3.27- 3.34 in our June Consultation on minded-to positions, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

consideration needs to be given as to whether or not it is appropriate for transmission costs to be included within a DNO's regulated allowance. Further thought also needs to be given as to whether these costs, if recovered through use of system charges, can be appropriately targeted.

3.89. Whilst this Decision focuses on the distribution elements of the connection charge, we will continue to consider these arrangements in our ongoing work on DUoS and TNUoS and communicate with stakeholders on how we think this work is best taken forward.

Treatment of existing and in-flight connection applications

3.90. Our reforms should not affect the rights or reinforcement contributions required from connection applications made prior to the implementation of our reforms in April 2023. However, it is the customer's right to terminate their connection application and reapply should they wish to take advantage of a shallower connection charging boundary following implementation. In making this decision, customers should consider the impact this would have on their position in the connection queue and therefore the completion date of their connection.

3.91. A large majority of respondents to our January Consultation agreed with this position, although we received several responses that disagreed or offered other views. Responses in support of our position suggested that a consequence of allowing connecting customers to reapply and retain their existing place in the connection queue would effectively be backdating the implementation of our reforms. Some respondents suggested that since accepted schemes should already have a viable business case, they were likely to be constructed regardless of changing regulations.[110]

3.92. Disagreements tended to focus on the perceived disadvantaged position of customers who apply before the April 2023 cut off. One respondent suggested that this could cause a delay in the deployment of EV charging points at a crucial point in the rollout of EVs. One respondent also argued that it was important that connecting customers were given the opportunity to adjust their capacity in response to high fixed residual charging

[110] See paragraph 2.68 – 2.74 of the accompanying Stakeholder Feedback appendix

bands and for an agreed reduction in the level of firmness without having to lose their place in the queue.

3.93. We are of the view that the intent and direction of policy change under our reforms have been signalled for a significant period of time, since at least the December 2018 launch of our Access SCR[111] and more substantively in our June 2021 Consultation[112]. We consider that customers have been well-informed with a significant notice period for these potential changes to the arrangements for applications from 1 April 2023.

3.94. We also do not consider that connecting customers should be permitted to reset the terms of their connection agreement whilst also retaining their position in the queue in the transition to 1 April 2023 changes. We anticipate this would impose a considerable administrative burden and cost, and it could be highly complex and contentious (given the potential impact and on other connections) for what is a temporary and limited issue.

Impacts on interactivity

3.95. There are occasions where network companies receive two or more applications for connections which make use of the same part of the network, but where not all connections can be connected without reinforcement or another commercial solution. Interactivity refers to the process through which network companies determine which of these applications will be able to connect to the network using the available capacity and is a process that was developed by network companies via the ENA's Open Networks Project[113]. This process is not codified in the DCUSA.

3.96. In our Consultation we considered that under the new connection charge boundary, circumstances which lead to interactivity will still arise, and therefore will require a process to remain in place. The majority of respondents were supportive of retaining the existing arrangements for interactivity[114]. However, some of these respondents considered that if

[111] The Access SCR launch statement is available here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision
[112] Our Consultation on minded-to positions is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[113] The interactivity process is set out here: https://www.energynetworks.org/industry-hub/resource-library/open-networks-2020-ws2-p3-interactivity-process-guide.pdf
[114] See paragraph 2.75 of the accompanying Stakeholder Feedback appendix

unsuccessful interactive projects retain their queue position and are able to reapply under the new charging regime, this could be inconsistent with our treatment of in-flight projects.

3.97. We consider that an unsuccessful interactive application that reapplies should be considered a new application, albeit one that retains its queue position. We do not consider this to be inconsistent with the treatment of in-flight applications, as connecting customers have no control over whether their application will be interactive.

3.98. We confirm our expectation that DNOs should retain their established procedures for the assessment of interactive applications, accounting for any required updates to reflect the new charging boundary rules. We also expect reapplications after 1 April 2023 resulting from an unsuccessful interactive connection offer to be treated under the new connection charge boundary.

Minimum Scheme as the basis for connection charging

3.99. We confirm our position that DNOs should continue to provide connection offers based on the Minimum Scheme. The Minimum Scheme as defined in the CCCM is the scheme with the overall lowest capital costs solely to provide the required capacity. This means that connection charges, where applicable, will continue to be calculated on the basis of the Minimum Scheme.

3.100. We think that retaining the current application of the Minimum Scheme will ensure that DNOs continue to make connection offers on the basis of lowest overall network costs consistent with their obligations under the Electricity Act 1989[115] to develop, maintain and operate an efficient, coordinated, and economical electricity distribution system.

3.101. Respondents broadly agreed with this approach however some respondents asked for more transparency on the costs used by DNOs to calculate the Minimum Scheme.[116] Respondents sought more transparency on the calculation of reinforcement costs in particular, as they relate to contestable work that respondents considered could be

[115] See Section 9 Paragraph (1)(a) of the Electricity Act 1989 which sets out the general duties of licence holders.
[116] See paragraph 2.79 of the accompanying Stakeholder Feedback appendix

provided at lower cost under a competitive provider. We continue to encourage DNOs to improve transparency in their processes including the calculation of the Minimum Scheme.

Clarity on the 'point of connection'

3.102. Our proposed charging boundary reforms rely upon a definition of what is considered at, or above, the 'point of connection', with regards to where connection charges are levied. This has historically been set out in a table within the CCCM[117]. We confirm our expectation that the demarcation between voltage levels will continue to be at circuit breakers on the lower voltage side at point of transformation. As part of implementation, the proposed changes to charging boundaries will need to be reflected in the terms throughout the CCCM of the DCUSA, including worked examples.

Interactions with non-firm connections

3.103. We confirm our position that existing customers with a non-firm connection have the right to apply to 'firm up' their connection or request amended terms to their non-firm arrangements in line with our access rights decision set out in Chapter 4.

3.104. In our January 2022 update[118], we considered options to alleviate the pressure on DNOs dealing with higher volumes of applications, including whether any Ofgem intervention is required to achieve the desired prioritisation of new connection requests. The options considered included a moratorium period following 1 April 2023 for applications from non-firm connection customers seeking to firm up.

3.105. We confirm our position that there will be no moratorium period for existing non-firm connections seeking to 'firm up' or amend their arrangements. We believe that a moratorium is at odds with the improved access rights for non-firm connections proposed

[117] Paragraph 1.32 of the CCCM sets out the treatment of connections based on the voltage at their point of connection: https://www.dcusa.co.uk/dcusa-digital-document/DCUSA/DCUSA_Schedule_22/DCUSA_Schedule_22.htm
[118] See section 2.160 – 2.167 of our Consultation on updates to our minded-to positions, available here: https://www.ofgem.gov.uk/sites/default/files/2022-01/Access%20SCR%20-%20Consultation%20on%20Updates%20to%20Minded%20to%20Positions%20and%20Response%20to%20June%202021%20Consultation%20Feedback.pdf

through this SCR and would put existing customers at a significant disadvantage compared to new applicants, or even their current access rights.

3.106. We further consider that preventing applications from this customer group could be considered discriminatory and may prevent more efficient and strategic network reinforcement decision-making. Reinforcement needs may not be fully understood if applications are prevented from coming forward and triggering that investigative work.

3.107. With regards to the prioritisation of new connections over existing ones, we do not propose to introduce any specific measures to limit or specify the distinct treatment of these applications. We continue to expect that the DNOs update and standardise their queue management processes to deliver improved consistency and transparency for connecting customers to ensure that new and existing connection applications are managed to achieve the fairest customer outcomes.

DNO licence obligations on connection timescales

3.108. In the January update, we considered the possibility of a surge in connection applications following 1 April 2023 to take advantage of the new connection charging boundary[119]. We acknowledge that such an increase in volumes could impact DNOs' ability to meet their licence obligations, particularly with regards to the provision of timely connection offers[120]. We also recognised that any delays to the connections process may have negative implications for connecting customers which need confidence in the application timeframes and standards.

3.109. We sought stakeholder feedback on temporary and pre-emptive mitigations for DNOs, with respect to their licence conditions and on the potential duration of any such mitigations. We have used these insights alongside our existing policy principles to come to a position on this issue.

[119] Paragraph 2.176 of our Consultation on updates to our minded-to positions set out these comments: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

[120] Including obligations under Electricity Distribution Standard Licence Condition 12 (to quote each application within 65 working days), 15A (to issue at least 90% of connection offers within Guaranteed Standards of Performance) and 15 (to offer at least 90% of connection offers to ICPs/IDNOs).

3.110. In their responses to our January Consultation, DNOs suggested pre-emptive mitigations with respect to their licence obligations[121] on connection timescales for a period of 6 to 12 months.[122] However, other respondents thought that mitigations to address these DNO obligations would be ill-considered because the scale of the impact has yet to be established. Some respondents were concerned that, should the increased volumes not materialise, a pre-emptive consent to vary or disapply the relevant conditions would only serve to unnecessarily delay connections.[123]

3.111. We consider that we have not received sufficient evidence of the need for urgent derogation against DNOs' licence conditions ahead of our reforms going live in April 2023. In the past, we have only agreed to extensions of connection timescales on very select occasions where there has been sufficient evidence that a network company was at risk of breaching their licence conditions due to extraneous factors (for example, the late receipt of information from another party impacting the ability to meet certain obligations).

3.112. We also agree with some respondents that there are risks to pre-emptive measures, especially where the scale of the increase in volumes is unknown. We therefore consider that mitigations for these obligations should be assessed on a case-by-case basis and encourage the DNOs to engage with us should they find themselves unable to meet their obligations, or when they have evidence that they do not expect to be able to. We will assess each request on the basis of measures taken to mitigate breach of conditions.

Required changes to the Electricity (Connection Charges) Regulations 2017 (ECCR)

3.113. In our June 2021 and January 2022 Consultations, we set out how we expected our reforms to interact with the ECCR and sought stakeholder views on the possible requirement for legislative amendments to the ECCR to align with our proposed changes[124].

3.114. Stakeholder responses on this matter varied in terms of potential amendments to the current ECCR arrangements, however, the majority agreed that legislative changes

[121] The time to connect incentives are set out in Standard Licence Condition 15 of the Distribution Licence: https://epr.ofgem.gov.uk/Content/Documents/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20%20-%20Current%20Version.pdf
[122] See paragraphs 2.92-2.94 of the accompanying Stakeholder Feedback appendix
[123] See paragraph 2.96 of the accompanying Stakeholder Feedback appendix
[124] The ECCR are available here: https://www.legislation.gov.uk/uksi/2017/106/contents/made

were needed[125]. Whilst some respondents supported the idea of interim measures outside of legislative change, others outlined that the legal obligations on DNOs and other parties referred to in the ECCR would ultimately take precedent.

3.115. The ECCR currently requires electricity distributors to recover reimbursement payments from a subsequent connecting customer (the 'second comer'), in certain circumstances where prior works were paid for by a previous connecting customer (the 'first comer'). This can include costs relating to both extension and reinforcement assets associated with prior connections.

3.116. Our view continues to be that the current treatment of extension assets under the ECCR remains compatible with our proposed changes. However, we believe that the removal of reinforcement charge contributions for demand customers, and partial removal for generation customers, does require a change to second comer payment arrangements as they apply to reinforcement assets.

3.117. The original connecting customer will no longer be required to make contributions to reinforcement in the first instance, in most circumstances after our reforms have been implemented. ECCR changes may therefore be appropriate since, presently, they require the DNO to demand reimbursement from the second comer that, under the new charging arrangements, the first comer would no longer be entitled to. In considering any amendments, it may also be appropriate for legislative change to consider the treatment of historical connections that were made upon an explicit assumption that a portion of the initial connection charge could be recovered via second comer payments.

3.118. We confirm our expectation that the ECCR legislation needs to be amended, to enable our charging decision to be implemented, and that responsibility for making these amendments sits with BEIS. We understand that it is possible for any amendments to be made via statutory instrument as a matter of secondary legislation. Without legislative changes to reflect our reforms, we do not anticipate that we would be able to approve the DCUSA change proposals raised pursuant to our direction. This may result in a delay to implementation of this Decision.

[125] See paragraphs 1.73-1.80 of the accompanying Stakeholder Feedback appendix

3.119. Our changes to charging arrangements have therefore triggered an evaluation by BEIS of possible adjustments to the Electricity (Connection Charging) Regulations 2017, which currently require electricity distributors to demand reimbursement payments for prior works, including for reinforcements, from connecting customers. This exercise is scheduled to conclude in late 2022 to allow the connection charging boundary changes to be implemented from April 2023. BEIS is working in close cooperation with Ofgem and industry to deliver any necessary changes.

3.120. It is our current expectation that confirmation of enabling legislative changes will be achieved in advance of any Ofgem decisions on the change proposals relevant to our direction, enabling the Access SCR reforms to be implemented for 01 April 2023.

4. Decision on Access Rights

Section summary

This chapter outlines our decision on reforms to non-firm (curtailable) access arrangements at distribution. It presents the further work and assessment we have undertaken since our Consultation on minded-to positions and a summary of our consideration of responses received to our Consultations.

Our access rights reforms are designed to complement our decision on the connection charging boundary, enabling network capacity to be brought forward in a strategic and cost-effective manner. We consider that better-defined non-firm access arrangements at distribution will better meet users' needs, reduce risks to connecting customers, and allow DNOs to use these arrangements as a tool to effectively maximise the use of existing capacity whilst network development is undertaken.

The case for change

4.1. Network access rights define the nature of users' access to the network and the capacity they can use. This includes how much they are able to import or export; when they can access the network and for how long; and whether their access is curtailable and what happens if it is. Network access requires a connection from the user's equipment to the wider network, and capacity availability on the wider network. For most users, the level and terms of their network access is defined via their connection agreement[126].

4.2. Traditionally, distribution network users have had few access rights options, with most users having standard connection arrangements. For these connections, access to the distribution network is "firm", ie a DNO must ensure there is sufficient network capacity available such that curtailment would not ordinarily be expected to take place.

4.3. In recent years, DNOs have increasingly been offering flexible connections as an alternative to paying and/or waiting for the network reinforcement that may be required for a standard connection. Flexible connections often allow users to connect more quickly and cheaply in constrained areas of the network prior to reinforcement taking place.

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[126] For more information about current access arrangements – please read our description of current arrangements here: https://www.ofgem.gov.uk/sites/default/files/docs/2019/12/winter_2019_-_working_paper_-_existing_arrangements_publish.pdf

4.4. In exchange for quicker/cheaper access, users with flexible connections have "non-firm" or "curtailable" access to the distribution network. At present, there is no commonly defined limit on the extent to which their network access can be curtailed. Arrangements can be poorly-defined, with no standard definition of curtailment, and how they work in practice can vary across DNOs.

4.5. We have been reviewing the definition and options for distribution access rights throughout the SCR. We consider that improved definition of access options, particularly flexible connections, could increase acceptance of such options and lead to more efficient use of the network by maximising the use of existing network capacity.

4.6. We think that reforms in this area can deliver the following benefits:

- **More consistent access rights arrangements:** As the distribution network becomes more congested, flexible arrangements could become more commonplace. Better standardisation would ensure these arrangements are consistent across the market, providing transparency and a common understanding for affected parties.

- **Reduced risk and greater certainty for connecting parties:** The new arrangements would reduce risk to customers while ensuring they are able to benefit from a cheaper and quicker connection. Users on flexible arrangements would also have better certainty as to the amount of curtailment they can expect, and what happens when they are curtailed.

- **Arrangements continue to be useful to DNOs in proactively managing constraints:** Improved definition and information on how flexible connections are used could provide better information to network operators about where and when new network capacity is required. This would incentivise timely provision of network capacity and support the overall objectives of the Access SCR to enable more efficient use of and investment into the distribution network.

Options considered

4.7. Since we launched this SCR, we have been identifying and assessing a range of possible options to improve the definition and choice of distribution access rights. The options we considered fall into the following categories:

- **Firmness of rights** – the extent to which a user's access to the network can be restricted (physical firmness) and their eligibility for compensation if restricted.

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

- **Shared access arrangements -** Users across multiple sites in the same broad area could obtain access to the whole network, up to a jointly-agreed level.

4.8. For further details on the early development of options, please refer to the following publications as well as both minded-to Consultations[127]:

- Access SCR Summer Working Paper – Access Rights Note[128]

- Delivery Group report on the range of possible access options[129]

- Access SCR Open Letter on Shortlisted Policy Options[130]

Options we are not taking forward

4.9. Following the analysis set out in our working papers and undertaken subsequently, we decided not to take forward a number of the options that were initially considered, based on assessment against our guiding principles as well as our best view of their desirability and deliverability. These options, which were not taken forward to this final Decision, are described below.

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

[128] The Access Rights note can be found here: https://www.ofgem.gov.uk/sites/default/files/docs/2019/09/summer_2019_-_working_paper_-_access_right_note_final_nd.pdf

[129] The Delivery Group report can be found here: https://www.chargingfutures.com/charging-reforms/access-forward-looking-charges/resources-2/scr-working-group-publications/

[130] Our Open Letter on our shortlisted options can be found here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options

4.10. Please refer to our June 2021 Consultation for detailed assessments of the options described, including an assessment of the options against the SCR guiding principles[131]. Stakeholder feedback regarding the options can be found in the January 2022 Consultation[132] and the Stakeholder Feedback appendix accompanying this document.

Financial firmness

4.11. As part of our Access SCR shortlisting decision and set out in our June Consultation on minded-to positions, we ruled out the development of 'financially firm' access to the distribution network (as well as the application of 'Connect and Manage' at distribution level)[133]. We consider that introducing financial firmness at distribution would require the development of agreed planning and security standards and commercial mechanisms that do not currently exist at distribution, and it is not practical to develop and implement within the timeframes of the SCR (including realisation of the benefits we seek to achieve). We have also not identified clear evidence that the introduction of financially firm access would support more efficient use of the system given the high degree of physical firmness that most connections already have at distribution.

Shared access[134]

4.12. We also 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. In our shortlisting note[135], we indicated that we did not intend to take forward these options because we did not think they would support more efficient use of the system and because they presented significant practical issues and challenges.

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[131] This assessment can be found in Chapter 4 of our Consultation on minded-to positions, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

[132] We have published a summary of the feedback we received to both our Consultation on our minded-to positions and Consultation on updates to our minded-to positions alongside this Decision.

[133] This was set out in paragraph 4.5 of our Consultation on minded-to positions, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

[134] See paragraphs 1.85-1.87 of the accompanying Stakeholder Feedback appendix

[135] Annex 1 of our Open Letter on shortlisted policy options, available here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options

4.13. The development of shared access would require clear eligibility criteria to ensure that only those users that deliver network benefits are able to share access. We also have concerns about the practicality of this option (eg 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. As outlined in our June 2021 Consultation, 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[136]. The ENA Open Networks have taken this forward alongside their existing work on trading access.[137]

Small users access rights

4.14. We define small users as "households and non-domestic users that are billed on an aggregated and non-site-specific basis or who are metered directly using whole current meters". This ensures consistency with the National Terms of Connection, in particular section 2 which applies to domestic properties and smaller industrial and commercial properties[138].

4.15. Most small users[139] do not currently have well-defined access rights to the network. In practice, most consumers' level of access is only limited by their fuse size or service cable, and they may never have considered or chosen the level of access they require.

4.16. In launching our Access SCR, we recognised that energy is an essential need, noting that small users in particular may need protection where changes to arrangements may result in detriment. We also recognised that there will be differences in how readily households and small businesses are able to be flexible around how and when they need to use electricity. Some may be flexible while others will not readily be able to change their time or level of usage without risk of detriment.

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[136] Paragraph 4.16 of our Consultation on minded-to positions, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

[137] ENA open networks project – workstream 1 on flexibility and DSO transition. Details are available here: https://www.energynetworks.org/industry-hub/resource-library/open-networks-2021-ws1a-p6-market-simulations-report-v3.1-(29-apr-2021).pdf

[138] The National Terms of Connection are set out on Schedule 2B of DCUSA, available here: https://dcusa-cdn-1.s3.eu-west-2.amazonaws.com/wp-content/uploads/2022/04/01114346/SCHEDULE-2B-v14.1.pdf

[139] We define small users as "households and non-domestic users that are billed on an aggregated and non-site-specific basis or who are metered directly using whole current meters"

4.17. Given this, we considered whether our access right reforms should apply to small users, the opportunities or benefits they present and where they could lead to risks.[140] We particularly focused on any potential risks for vulnerable consumers. As a principle, we would only take forward reforms to better define access arrangements for small users if the new arrangements would reflect the needs of consumers as appropriate for an essential service, as well as supporting the efficient use of system capacity.

4.18. In our shortlisting letter and subsequent minded-to Consultations, we ruled out better-defining access arrangements for small users[141]. We have not identified 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 requirements.

Time-profiled access rights[142]

4.19. In our June Consultation on minded-to positions we proposed introducing time-profiled access rights at distribution[143]. A user with time-profiled access rights could have a reduced level of access during peak network periods and their access rights could also vary across the year, to reflect seasonal changes in when network peaks occur. We said that we thought time-profiled access options could lead to more efficient use and development of system capacity. Users would also be provided with greater certainty upfront about when they would be able to import and export from the network.

4.20. Some network operators are already utilising time-profiled access arrangements to manage the network – for example, bus garages with higher overnight capacity to facilitate charging of electric buses. In these examples, users have benefitted from a quicker and

[140] Small users annex to our Winter Working Paper, available here: https://www.ofgem.gov.uk/sites/default/files/docs/2019/12/winter_2019_-_working_paper_-_small_users_note_publish.pdf
[141] Annex 1 of our Open Letter on shortlisted policy options, available here: https://www.ofgem.gov.uk/publications/electricity-network-access-and-forward-looking-charging-review-open-letter-our-shortlisted-policy-options
[142] See paragraphs 1.82-1.84 of the accompanying Stakeholder Feedback appendix
[143] Paragraph 4.11 in our minded to Consultation, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

cheaper connection, and network operators have been able to make the most of existing network capacity whilst developing a more enduring solution.

4.21. In our January updates to our minded-to positions, we clarified that we did not intend to go further in defining time-profiled access arrangements[144]. We considered that there was insufficient evidence that introducing more standardised time-profiled access arrangements will deliver benefits beyond what network operators can already offer under current arrangements.

4.22. We consider that where there is a clear network need, network operators should continue to consider and discuss time-profiled access options with customers when making connection offers. We do not think that standardisation is necessary, however, as it could hamper the use of time profiles that are more appropriate to the site-specific needs of individual customers/groups of customers where prescribed time-bands may not always reflect local network peaks.

Summary of assessment process for changes to non-firm access rights

Options considered in our final decision on non-firm access

4.23. In our June 2021 minded-to decision document, we proposed to introduce new, better-defined, non-firm access options for distribution customers[145]. In the document we outlined several options for those access options. We indicated that we were minded to take forward the following aspects of non-firm access:

- Introducing non-firm access rights at distribution;
- Defining curtailment according to consumer outcomes (ie curtailment of the customer); and

[144] Paragraph 3.47 in our updated minded to Consultation, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

[145] Paragraph 4.7 and Appendix 2 of our Consultation on minded-to positions, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

- Measuring curtailment based on the number of hours the customer is curtailed.

Principles-based assessment of options

4.24. Table 7 is a high-level summary of our principles-based assessment of the key aspects of better-defined, non-firm access rights, which are described above. Our June 2021 Consultation included this assessment, along with further details and confirmation that we were minded-to implement the changes below[146].

Table 7: Summary of our assessment of the options against our guiding principles

Option	Guiding Principle 1	Guiding Principle 2	Guiding Principle 3
Introducing non-firm access rights at distribution	• New non-firm access options should support efficient network development in accordance with user requirements.	• 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 (eg new data to measure curtailment rates).
Defining curtailment according to consumer outcomes (ie curtailment of the customer)	• Should support efficient network development in accordance with consumer requirements. • Requires network operators to make assumptions about how a physical asset will deliver a certain consumer experience (ie level of curtailment). If done	• Provides more certainty to distribution-connected users about how much they will be curtailed.	• Will require data, collection, and processing to measure curtailment rates. • It will also require changes to DNOs' systems and processes.

[146] Paragraphs 4.7-4.9 and Appendix 2 in our Consultation on minded-to positions, which is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

	conservatively, this may lead to less efficient use of the network.		
Measuring curtailment based on number of hours curtailed (could also be expressed as a %)	• Good reflection of impact on users, therefore, facilitates efficient use and development of system capacity	• Good reflection of users' experience. • Users can conduct their own forecasts to understand impact on export/import	• Requires changes to systems to collect and analyse this data.

4.25. In our January Consultation on updates to our minded-to position[147], we re-iterated the positions above regarding non-firm access rights. In response to stakeholder feedback, we indicated we were minded to include the following clarifications to the definition and scope of non-firm access rights:

- Non-firm arrangements are not available to small users;
- A curtailment limit would be agreed between the DNO and the connecting customer; and
- There should be an explicit end date for the non-firm access.

4.26. These clarifications have been taken forward in this final decision and are described in more detail in the 'Details of our decision' section below. This section also includes further details on the development and assessment of options for defining curtailment.

Quantitative assessment

4.27. As described in Chapter 2, our quantitative assessment through the IA process focused on the potential impact of changes to the connection charging boundary. We have not undertaken quantitative modelling of the impact of our specific proposed access rights

[147] Paragraphs 3.24 – 3.39 of our Consultation on updates to our minded-to positions, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

reforms. This was based partly on our view that the options for reform had a strong basis in our SCR Principles and that the costs associated with them were minimal.

4.28. We previously described access rights reforms as 'low regrets' because they did not involve a significant transfer of cost between stakeholders and were related to flexible arrangements that are opt-in in nature. The direct monetary impacts of these would have been difficult to quantify due to uncertainty around uptake of flexible connection arrangements. Our decision on access rights has therefore been developed through a qualitative and principles-based assessment of impacts, combined with our extensive stakeholder engagement and Consultations since 2018.

4.29. In estimating and assessing the likely impacts of these changes, we have also taken into account that there are significant interactions between the impacts of our decisions on the connection charging boundary and access rights. We expect that the changes to the connection boundary will themselves be the major driver of changes to the uptake of flexible access arrangements. For example, the reduced contribution to reinforcement could drive customers on flexible connections to reapply for a physically firm connection. We believe that the quantitative modelling associated with the connection boundary is a sufficient indicator of the combined impacts of both sets of reforms.

Our decision

4.30. We have decided to introduce the following reforms to distribution network access rights:

- **Non-firm (curtailable) access arrangements** – non-firm arrangements will be available to users where there is a requirement for reinforcement and a specific network need for curtailment to manage local network constraints. Small users will not have access to these arrangements.

- **Curtailment limits for non-firm connections –** the distribution network operator will set curtailment limits and included these in the connection offer to the connecting customer, who will have to abide by those limits. If the network operator needs to curtail above this limit, then they must procure this service from the market.

- **End dates for non-firm arrangements –** non-firm arrangements will have explicit end dates, after which the connection will need to be made firm or noncurtailable. Exceptions apply where the customer has not requested a firm connection or if the HCC is triggered and the customer does not wish to contribute to reinforcement costs above the cap.

4.31. Our access rights policy positions are designed to complement the changes we are making to the distribution connection charging boundary. Together, our reforms seek to enable more efficient use and investment into the distribution network by encouraging DNOs to take a more strategic approach to network planning and reinforcement, investing ahead of need in many cases and considering alternative approaches to reinforcement for meeting capacity needs of their customers.

Details of our decision

4.32. In this section we present additional details to our decision and further explain our reasoning on key issues. These details will also help to inform the implementation of the access rights reforms.

Eligibility for new non-firm (curtailable) access arrangements

4.33. Non-firm arrangements should only be offered where the network operator has identified that there is a network benefit to doing so. Where there is no network benefit, for example, where there is sufficient capacity for a firm connection and no indication of any future connections or capacity requirement in that area, there would be limited utility or user benefit to a non-firm connection.

4.34. Non-firm access arrangements will not be available to small users, for the reasons set out in section 4.14 – 4.18, above. This means that as a principle, connection offers to small users or groups of small users will not be curtailable, and this will apply no matter where the customer is connected (including licence-exempt networks and IDNOs). Network operators should manage their networks to ensure sufficient capacity is available for small users.

The definition of curtailment

4.35. Non-firm (curtailable) access should be defined in relation to the maximum number of hours (or percentage of time) that users have agreed to be 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 or exported that would be curtailed.

4.36. In our summer working paper[148] we considered how levels of access could be defined in relation to a network user's level of firmness. The level of firmness is the extent to which a user's access may be curtailed. The higher the level of firmness, the less likely a user is to be curtailed. Under a 'standard connection' at distribution, users have a very high degree of firmness and their access to the network would generally only be restricted due to maintenance or safety issues. We considered two ways a user's level of firmness could be defined:

- **Physical conditions:** The extent to which a user's access to the network is restricted could be defined by the physical assets that connect them to the wider system, and the design of the network at the point they are connected. Access rights could also be defined such that users are only constrained for specific technical reasons (eg a thermal constraint) or linked to a specified network impact.

- **Consumer outcomes:** The extent to which a user's access to the network is restricted could also be defined by setting limits or targets for the user's maximum experience of curtailment. For example, measuring the number of curtailments, the aggregate time curtailed, the energy lost by curtailment or a combination of all of these factors. If the specified curtailment levels were to be exceeded, it could also trigger the network operator to take action (eg reinforce the network and/or pay compensation to the user).

4.37. Due to the ease of customer engagement and 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. It would be the responsibility of the network operators to translate physical constraints into user outcomes and set a curtailment limit according to the number of hours (or percentage) of time that users who have agreed to non-firm access arrangements can be curtailed to a specified threshold.

[148] Paragraph 1.16 of our Options for reform of access rights for distribution and transmission – discussion note, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-summer-2019-working-paper

4.38. In our updated minded-to positions we also put forward a definition of curtailment within the context of a non-firm access arrangement[149]. We confirm that we will be directing the code working group to define curtailment as any action taken by the network operator to restrict the conditions of a connection in response to a constraint on the distribution system.

4.39. Interruptions caused by a fault or damage to the distribution system which result in loss of supply to the user are not considered curtailment. If a customer's supply is interrupted under the definition of a customer interruption, that interruption continues to be covered under the Guaranteed Standards of Performance and thus should not be treated as curtailment.

4.40. Similarly, we have decided that curtailment as a result of constraints on the transmission network will not be treated as curtailment on the distribution network as transmission constraints are outside the control of the DNOs.

4.41. We sought stakeholders' views on our proposal to define curtailment in this manner. Approximately three quarters of respondents expressed agreement or partial agreement with our proposals[150]. Stakeholders agreed with us that supply interruptions are already covered by DNO incentives and that both firm and non-firm customers are at risk of supply interruptions. Respondents also agreed with our assessment that issues on the transmission system are not within the control of distribution licensees.

4.42. Several respondents raised that developers of distributed generation take both distribution and transmission curtailment into consideration when deciding if a project is viable. They argued that, because transmission constraints are increasingly impacting projects on the distribution network, users should be compensated for the impact of these constraints in the same way as transmission connected generators[151]. Stakeholders encouraged us to continue to monitor these arrangements to ensure that transmission constraints do not start to materially contribute to distributed generator curtailment[152].

[149] Paragraph 3.26- 3.30 of our Consultation on updates to our minded-to positions, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions
[150] See paragraph 2.100 of the accompanying Stakeholder Feedback appendix
[151] See paragraph 2.102 of the accompanying Stakeholder Feedback appendix
[152] See paragraph 2.103 of the accompanying Stakeholder Feedback appendix

4.43. We thank stakeholders for their considered responses. Our previous engagement has highlighted that clearer definition of distributed generator access arrangements to the transmission network could be valuable for some users who want to ensure that they have reliable access to potential revenues. We note that, at transmission, there is a 'Connect and Manage' regime with financially firm arrangements for curtailment, which is not the case at distribution. However, distributed energy resources can still choose to participate in the Balancing Mechanism should they wish to make themselves available for instruction and associated payments from the Electricity System Operator (ESO).

4.44. We will continue to engage with the ESO to consider how access arrangements need to evolve to support wider user and system needs, including distribution connected users' participation in wider markets.

Setting curtailment limits

4.45. We consider that curtailment limits for non-firm connections should be set by the distribution network operator and included in the connection offer. This curtailment limit should be set via a defined process on the basis of maximising network benefit, considering factors such as network availability behind the relevant distribution network constraint, the forecast time-profiled levels of demand/generation, and a probabilistic assessment of the level of curtailment may be required. We believe that distribution network operators are best-placed to define and agree how curtailment limits are set in a consistent manner across licence areas.

4.46. We expect the development of a common, repeatable process for setting curtailment limits, which will be used by DNOs to calculate the level of curtailment to be included in connection offers for non-firm arrangements. The Access Rights implementation group have made initial progress on a methodology based on the following principles that we believe should be used as the basis for further development:

- The process should be as simple as possible whilst achieving the objectives of this Decision. This may help to keep communications simple with customers, minimise complexity of calculating limits to accommodate a higher volume of connection requests, and allow for easier monitoring of curtailment outturn against the agree limit.

- The process should be common to all DNOs and be repeatable.

- The process should be based on a set risk tolerance – the probability of the limit being exceeded will be a common parameter across companies.

- Limits agreed with customers should be included in the connection agreement, and the customers who are subject to curtailment will receive regular reporting on the level of curtailment relative to their agreed limits.

4.47. In our Direction, we are instructing the DNOs to set out at standardised approach in DCUSA to the application of parameters which would apply to curtailable connections. The process and/or methodology will remain subject to industry code governance and can be kept under review as new arrangements are rolled out.

Obligations on the network operator if curtailment is required above accepted limits

4.48. We consider that users should be protected from the risk of network operators exceeding the level of curtailment agreed. Once a user has accepted an offer including the amount of time 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, and plan accordingly.

4.49. Circumstances may arise where local network constraints and system flows mean that the network operator is unable to comply with the agreed curtailment limit for a non-firm connection, while also meeting its obligations to other connected users in the area. In these circumstances, the network operator will firstly need to procure the additional service required to comply with the curtailment limit from flexibility markets where it is economic and efficient to do so, in accordance with Electricity Distribution Standard Licence Condition 31E (C31E)[153]. This ensures that procurement of flexibility is undertaken in a transparent, economic, and efficient manner using market-based mechanisms where possible. It also ensures more consistent treatment of both flexible and firm connections.

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[153]The SLCs are available here:
https://epr.ofgem.gov.uk//Content/Documents/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20%20-%20Current%20Version.pdf

Exceeded curtailment price

4.50. We have decided to introduce an "exceeded curtailment price" – a cap on the unit price of flexibility that a network operator is required to procure if circumstances arise where they need to exceed a customer's agreed curtailment limit. The exceeded curtailment price would also set the price that the connecting customer would receive from the DNO in the limited circumstance, should it arise, that their curtailment limit is breached. The DNOs should not plan for this to happen. There will be no cap on the volume of the exceedance, which will provide DNOs a strong incentive to take action to limit both the amount and duration of curtailment.

4.51. We are directing network operators to develop an approach to set this exceeded curtailment price. That methodology should incorporate the following principles:

- The exceeded curtailment price should not be used as the default curtailment remedy – that is, network operators should not aim to exceed their curtailment limits;

- The network operator must demonstrate that they have taken best endeavours to avoid the need to curtail a customer above their agreed limits;

- The cap should be set at a rate that enables competitive price discovery in flexibility markets; and

- The network operator must take steps to procure flexibility from the market in the first instance.

4.52. We will also be introducing reporting requirements through RIIO-ED2 asking network operators to report on curtailment events and how often curtailment limits are being breached – data that can be used to design future incentive/price control targets.

4.53. We believe that setting an exceeded curtailment price best aligns with the objectives of our access rights reforms. It should enable more flexible offers to be made and accepted, as DNOs would be able to offer curtailable connections with more acceptable curtailment limits.

4.54. Not setting a cap could expose network operators, and ultimately DUoS customers, to flexibility prices that do not reflect fair value. This risk exposure could also undermine the benefits of the objective of our reforms and could result in unintended behaviours from DNOs as they may choose to be more conservative in how they treat low-probability requirements in their setting of curtailment limits. This could lead to limits that are unacceptable to connecting customers and could reduce the amount of capacity that can be catered for with non-firm access arrangements.

4.55. In our updated minded-to proposals, we consulted on whether we should introduce this cap[154]. We acknowledged the risk that flexibility may not always be available in all areas where the network is constrained. In these areas of limited market liquidity, network operators could be exposed to very high costs of flexibility. This could lead to undesirable outcomes, for example, inefficient costs being passed through to DUoS bill payers or overly-conservative curtailment limits.

4.56. We also provided several reasons why a cap might not be desirable, including that the cap would not be market based and could distort nascent flexibility markets. A cap could create an incentive for network operators to exceed curtailment limits, as the most 'cost efficient' option for managing network constraints. We said that we did not think that we received sufficient evidence on the materiality of the risk of unjustified and excessive costs. We put forward the view that network operators were able to take action to mitigate these risks, for example, in the way that they manage the non-firm stack and efficiently procure flexibility ahead of need. For these reasons, we said we were minded not to introduce a cap.

4.57. Stakeholders were divided in the feedback they provided to this Consultation.[155] Some respondents that did not support a cap said that high market prices would send signals to network operators on the requirement to reinforce. They believed that the lack of a cap would incentivise network operators to produce more accurate forecasts, procure sufficient flexibility, and build sufficient network capacity. Some respondents also suggested that network operators should be disincentivised from using curtailable

[154] Paragraph 2.89 of our Consultation on updates to our minded-to positions, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

[155] See paragraph 2.128 – 2.135 of the accompanying Stakeholder Feedback appendix

customers as "free flexibility" and that the introduction of a cap would risk network operators using it as the default option to manage constraints on their networks.

4.58. DNOs, on the other hand, broadly disagreed with our proposal not to introduce a cap. They argued that a requirement to abide by curtailment limits or procure flexibility would be a new obligation and could expose them to potentially uncapped liability, with ultimately increased costs for DUoS bill payers. Whilst DNOs agreed that a cap is not market-based, they suggested that a market-based mechanism is only appropriate and efficient in instances where there is a viable market. Where the market is underdeveloped, the price demanded by flex providers with excessive market power may not reflect the economic and efficient value of operating the distribution system.

4.59. We sought additional input from the Delivery Group on the impact of this risk following our updated minded to Consultation. They told us that they were primarily concerned with "long tail" risks, for example unusual weather events such as sustained high winds that lead to an abnormal year of necessary curtailment. These could be taken into account to an extent in setting curtailment limits, but without a backstop price, DNOs may have to take an overly conservative approach to setting limits. This would lead to less useful flexible arrangements to customers and reduce the number of connections that can be accommodated through flexible arrangements.

4.60. DNOs also argued that whilst they agree with us that reinforcement is a natural backstop to the price of flexibility, in many cases, reinforcement projects would already be underway, to make curtailable customers firm. In such cases, flexibility is not being procured as an alternative to reinforcement, but merely to manage exceptional circumstances where curtailment limits cannot be complied with.

4.61. On balance, we have decided that the potential consequences arising from not setting a cap on the flexibility price outweigh the original rationale we set out for not doing so. We also believe that some of the risks raised by stakeholders – for example, the incentive for network operators to use the cap as the most cost efficient way to manage the network – can be mitigated if the cap is set at an appropriate level, and only triggered under limited conditions as set out in the principles we outlined above. We will review these arrangements, as well as the level of the cap, over the course of RIIO-ED2.

4.62. Our decisions on access rights are new arrangements. These arrangements shift risk from the connecting customer, whose exposure to curtailment may have been unlimited, to the network operator, who now has to manage their network within those limits or be exposed to additional costs. We consider that any new exposure to risk should be proportionate and protect against costs that are orders of magnitude above the value of the service provided to the network, and wider bill payers.

End dates for curtailable access

4.63. We have decided to introduce explicit end dates for non-firm arrangements, which would be agreed in advance between the network operator and the customer. We consider that time-limited, non-firm arrangements can be a useful tool for network operators to plan and optimise the timing of network investments, leading to more efficient network development over time.

4.64. End dates for non-firm arrangements would ensure that network operators invest in network capacity in a timely way and provide certainty to customers on when their connection arrangements are likely to be made firm. An open-ended arrangement provides no incentive on network operators to resolve the constraint and progress with reinforcement or procure flexibility in a timely manner.

4.65. However, explicit end dates would not apply where a customer does not explicitly request a firm connection or is unwilling to accept the costs of firming up the connection at the point at which the connection agreement is reviewed. It would also not apply where the connection request triggers the HCC and the connecting customer does not agree to contribute to reinforcement costs above the cap. In such instances, non-firm arrangements can be made on an enduring basis with no set end date.

4.66. At the end date, the connection customer on the non-firm access arrangement must be provided access to their full requested capacity. This does not mandate the DNOs to reinforce the network by this time. In line with current licence obligations, DNOs would still be able to consider if procurement of flexibility is the best way to make the required capacity available.

4.67. Respondents to our Consultation agreed with us that explicit end dates would help network operators plan network investments and develop the most suitable solutions to make a customer firm in a reasonable timeframe.[156] Some respondents asked us to ensure that the end dates are designed to drive efficient network design, whilst providing customers more certainty.

4.68. In our updated minded-to proposals, we consulted on how end dates should be set[157]. The key question was whether end dates should only consider wider known/anticipated developments or if it should allow time for other potential developments to take place, which may or may not materialise in practice.

4.69. We said that we considered there were benefits and risks to both approaches. If the former approach is taken, customers would get quicker connections but there would be a risk that less optimal solutions could be deployed leading to less efficient investment. If the latter approach were taken, a more strategic solution might emerge, but there is a risk that firm connections could be unnecessarily delayed should no further developments materialise - the solution identified at the time of the connection request might be the same as the solution that actually gets deployed, despite the delay.

4.70. Not many stakeholders provided responses to this question. Nine respondents suggested that end dates should consider only current known or anticipated works, in line with the network operators network development plans.[158] One respondent suggested that linking end dates to developments that may or may not materialise could undermine certainty and bankability of projects. Another response said that end dates should take account of the likely timescales for specific known reinforcement works but should not allow time for network operators to delay their decision making.[159]

4.71. Four responses argued that end dates should also include wider developments. One respondent argued that if wider developments were not considered, the benefits of our Access SCR reforms would be limited.[160] This respondent suggested standardising the maximum length of time that could be applied to non-firm arrangements across DNOs and that this could vary depending on the point of connection (eg three years for LV/HV, five for

[156] See paragraph 2.141 of the accompanying Stakeholder Feedback appendix
[157] Paragraphs 3.35 - 3.39 of our Consultation on updates to our minded-to positions, available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions
[158] See paragraph 2.152 of the accompanying Stakeholder Feedback appendix
[159] See paragraph 2.153 of the accompanying Stakeholder Feedback appendix
[160] See paragraph 2.157 of the accompanying Stakeholder Feedback appendix

EHV). They argued that this would allow greater scope for strategic investment in reinforcement and flexibility, in response to projected load.

4.72. On balance, we consider that end dates should only consider wider, known developments. It is unclear to us at this stage that waiting for other developments to emerge would result in a more efficient outcome. Instead, we agree with stakeholders that this could lead to uncertainty for connecting customers and a lack of transparency in terms of the work that is holding back a connection. We therefore conclude that end dates should be clearly linked to the specific work required to deliver the user’s connection and any other known or anticipated connections and wider demands in the area served by the network.

4.73. The responsibility for setting reasonable end dates should rest with the DNOs, and the planning process should do the principal approach for identifying the most strategic solution. End dates will be set on a site-specific basis and included in the connection offer to the curtailable customer, in line with today’s approach to setting energisation dates. The DNOs will be empowered to make the connection offer based on their best understanding of network needs, interactions with wider schemes, and set milestones on what is most economic/efficient for the network overall.

4.74. While we see benefits of enabling additional flexibility in timing to identify the most strategic solution, we consider that standardised end dates would be risky. A single rule applied across all connections is unlikely to always be appropriate and it would be difficult to show benefit to the customer. We note that DNOs have a range of obligations and incentives to ensure that customers are connected in a timely manner, and that will continue to be the under these new arrangements.

4.75. Our decision that end dates should be site-specific aligns with the current arrangements and connection protocol for energisation dates. It will deliver improved transparency for the connecting customer and encourage DNOs to take a more proactive approach to network planning, including developing robust long term network development plans and considering their interactions with connection offers.

Existing customers on non-firm arrangements

4.76. Our proposed changes will not impact existing users’ access rights. This includes existing distribution-connected users that have agreed a flexible connection. It is already possible for existing users of the distribution network with a flexible connection to apply for a firm connection. Should existing users wish to alter their access arrangement, then an application must be submitted to their network operator through the normal process.

5. Conclusion and next steps

5.1. This section provides a high-level summary of the conclusions of the Access SCR regarding the distribution connection charging boundary and the definition and choice of access rights, next steps to implement our Decision, and the next steps for network charging reform.

Summary of the reforms to be implemented

Distribution connection charging boundary

5.2. Our final decision on the distribution connection charging boundary is:

- **Remove the contribution to reinforcement for demand connections** by introducing a 'fully shallow' connection charging boundary. This would involve connecting customers paying for extension assets only.
- **Reduce the contribution to reinforcement for generation connections** by introducing a 'shallow-ish' connection charging boundary. This would involve connecting customer paying for extension assets and a contribution towards reinforcement at the voltage level at point of connection.
- **Retain and strengthen existing protections for bill payers** to ensure they are better protected from the cost increases associated with the most expensive connections.

Access rights

5.3. Our final decision on the definition and choice of access rights is:

- **Make 'non-firm' access available as a standard option** where there is a network benefit to issuing a curtailable connection offer. This option should not be offered to small network users (domestic and small commercial consumers).

- **Introduce clear curtailment limits and end dates for non-firm access arrangements.** Distribution network operators will have to set a curtailment limit for non-firm connection offers and include these in the offer to the connecting customer, who will have to abide by those limits. Where the customer wishes to connect initially on a non-firm basis, but ultimately be made firm, a date by which the customer should have firm access must be agreed.

Next steps

Direction and implementation

5.4. We have issued a detailed Direction alongside this document instructing the holders of an electricity distribution licence to raise modifications to the DCUSA or other industry codes as required (and to the extent that they are able to raise such modifications) to give effect to our Decision. We expect these proposed modifications to be considered through workgroups over the next few months before coming back to the DCUSA panel to be assessed and submitted to the Authority in good time to allow the reforms to be effective by 1 April 2023, in line with the start of RIIO-ED2.

5.5. We expect the relevant licensees to work together to:

- Ensure consistency of the resulting code modifications and resulting arrangements across the relevant industry codes.

- Present a detailed plan no later than 31 May 2022, or such later date with approval, to set out how they intend to work with other DNOs and other relevant industry stakeholders to ensure that the modifications are submitted to the Authority for decision no later than 31 October 2022, such later date with approval.

- Take steps to ensure potential issues which could prevent implementation along the timelines set out in these directions are raised in a timely manner with Ofgem, and a process for resolving potential issues is in place.

Changes to the Electricity Distribution Licence

In addition to changes in the DCUSA, we also intend to publish a statutory Consultation later this year to amend the Electricity Distribution Licence. Our proposed amendments will clarify new obligations on network operators with respect to our decision and ensure consistency with industry code changes being brought forward.

Network charging reform

5.6. In February 2022 we decided to descope the review of Distribution Use of System ('DUoS') charges from the Access SCR and create a dedicated 'DUoS SCR' to take this work forward.[161] This work is ongoing as we continue to consider potential changes focusing on the 'forward-looking' component of distribution network charges that is designed to be reflective of the network costs and savings that users of the network can create.

5.7. Following our call for evidence[162] on Transmission Network Use of System Charges (TNUoS), we also announced our intention to instruct the Electricity System Operator to launch and lead a taskforce[163] to consider potential improvements to current the TNUoS methodology.

5.8. We recognise the importance of ensuring that long term network price signals complement future market arrangements and remain fit for purpose as we move towards a decentralised and more flexible energy system to deliver net zero. We look forward to continuing our engagement with stakeholders in due course as we continue with these important reviews following the publication of this Decision.

[161] Our Decision to launch a separate DUoS SCR is available here: https://www.ofgem.gov.uk/publications/distribution-use-system-charges-significant-code-review-launch
[162] TNUoS reform – call for evidence is available here: https://www.ofgem.gov.uk/publications/tnuos-reform-call-evidence
[163] Statement on next steps for the review of TNUoS available here: https://www.ofgem.gov.uk/publications/tnuos-call-evidence-next-steps