Appendix 2 – Stakeholder feedback

Purpose of this document

This appendix summarises the feedback that we have received from stakeholders during the Access and Forward-Looking Charges SCR (Access SCR). Throughout this SCR we have maintained an open and transparent process, inviting stakeholder views frequently and through a range of channels. This engagement has shaped our Final Decision and Direction, which accompany this document.

The document is split into two sections summarising the responses to the questions posed in our most recent Consultations. The first section covers our June 2021 Consultation on our minded-to positions[1]. The second section covers our January 2022 Consultation on updates to our minded-to positions[2].

[1] The Consultation on our minded-to proposals is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

[2] The Consultation on updates to our minded-to proposals is available here: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

Responses to our June 2021 minded-to positions

1.1. In June 2021, we requested stakeholder feedback on our initial minded-to positions. Our consultation was comprised of three sections – the connection charging boundary, access rights and Transmission Network Use of System (TNUoS) charges for Small Distributed Generators (SDG). Below is a summary of the questions asked and the responses received. The responses have been grouped into common themes.

1.2. In Chapter 2 of the SCR Decision, 'Our Approach', we outline how the Access SCR scope has changed over time. One key change is our decision not to issue a Direction on TNUoS charging for SDG as part of the SCR. Responses on this topic have been summarised at a high level as part of this document.

Connection boundary

Consultation questions

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

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

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

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

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

Question 3f: What are your views on the recovery of the costs associated with transmission that are triggered by a distribution connection? Does this need to be considered alongside wider charging reforms or could a change be made independently?

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

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

General response

1.3. The majority of responses to our connection charging boundary proposals were supportive (62%), though a significant minority of respondents offered mixed views and raised a number of concerns (33%). A small minority of respondents did not support our proposals (5%).

1.4. The general move towards a shallower connection charging boundary received strong support. Respondents felt that the proposals represented a pragmatic set of changes in the near-term that would help to achieve net zero emissions targets. Many expressed positivity that the proposals were in alignment with a more strategic approach to distribution network reinforcement, in contrast to their perception of the current, more incremental, connections-driven approach. A recurring theme in the supportive responses were that our proposals have the potential to encourage DNOs to future-proof their networks and invest ahead of need.

1.5. Most unsupportive responses focused on isolated issues unlikely to affect or apply to most customers.

1.6. Whilst network companies were broadly supportive of our proposals, one network company expressed a view that the current system is adequate and that any changes should be considered for implementation alongside the conclusions of a wider Distribution Use of System (DUoS) charging review.

1.7. Many respondents raised potential risks to the effectiveness of the policy if the existing high-cost cap (HCC) for generation was maintained. Some stakeholders in remote areas set out a view that the proposals would not lead to significant differences from the current arrangements given the already high cost of network infrastructure in some areas. There were a small number of stakeholders who put forward a view that locational signals under the new arrangements may provide insufficient economic signals. Some responses specified that the HCC should include demand connections.

1.8. Various responses stated that the full impact of the connection charging boundary proposals is difficult to predict without further clarity on charging. Respondents also felt that the language in the proposals was too technical, which may not transfer well to those outside the energy industry and thus was not transparent.

1.9. There were also numerous calls for grandfathering of existing arrangements to be considered to minimise disruption.

1.10. Views and suggestions shared on key points and recurring topics are set out below.

Removing the contribution to reinforcement for demand connections and reducing it for generation

1.11. We asked respondents whether they agree with our proposals to remove the contribution to reinforcement for demand connections and reduce it for generation. Furthermore, we asked whether there are any arguments for going further for generation under the current DUoS arrangements.

1.12. The majority of respondents to this question (35) offered strong support for our proposals to remove the contribution to reinforcement for demand connections and to reduce it for generation. Twelve respondents expressed that any reductions in generation connection charges should be introduced alongside new DUoS arrangements and that further information on the DUoS reform was needed.

1.13. A small number of respondents (7) raised concerns that the proposal to reduce generators' contribution to reinforcement could distort generation investment decisions by reducing their locational signals and were not well justified.

1.14. Nine respondents disagreed with our proposal that the reinforcement contribution should be different for demand and generation. They felt that the proposal should go further and introduce a shallow boundary for all and remove contributions to reinforcement for generation sites as well. This was to create a level playing field across all network levels and consistency between demand and generation.

1.15. Some responses, while overall supportive, expressed the need to apply a charge to deter unrealistic applications, or suggested the use of some other form of user commitment or alternative protections to ensure stranded assets are minimised.

1.16. Four responses took the view that the proposal would help to remove barriers to the roll-out of low carbon technologies (LCTs) and would support GB's net zero targets.

1.17. There was a general theme amongst some respondents that the proposals would benefit from further clarity and detail. Due to this, some respondents felt they could not provide a sufficient response to the consultation in all areas.

1.18. A small number of respondents (2) highlighted the need for grandfathering arrangements to protect existing customers from risk of double-charging, and this view was repeated in their responses to several questions.

1.19. In terms of technology-specific comments, three respondents felt that only heat pumps and electric vehicles ('EVs') should receive exemptions from reinforcement costs to drive take-up of LCTs, rather than a blanket exception for all demand, which may include "high-carbon users".

1.20. One respondent cautioned against the treatment of storage operators similarly to generators, as storage can improve system-wide flexibility and reduce the need for network reinforcement. They reasoned that storage does not generate energy, and it therefore seemed contradictory to charge energy exported as though it was newly generated.

Effectiveness of the current connection charging arrangements in sending a signal to users

1.21. We asked respondents for evidence on the effectiveness of the current connection charging arrangements in sending a signal to users. We further asked what respondents thought would be the effect of our proposed changes and whether this would vary between demand and generation connections.

1.22. A large number of responses mentioned that current arrangements create a disincentive to connect in some areas, which could present a barrier to investment in LCTs and delay the electrification of heat and transport that is needed to achieve GB's net zero targets. Several respondents described examples of projects that had not been able to proceed under the current arrangements where connection costs were prohibitive.

1.23. One respondent described the current arrangements as part of 'an obsolete electricity network architecture' leading to a location lottery based on connection site availability. They felt our proposal would help to resolve this issue by enabling more flexibility as well as shifting certain responsibilities for economic investment from developers to DNOs, who are in a better position to manage network constraints. The respondent felt that, as a result of these proposals, DNOs would be expected and incentivised to invest in anticipation of wider network needs, rather than taking an incremental and reactive approach. In related responses, several others provided evidence showing that shallow connection charges can still deliver a reasonable signal.

1.24. One respondent summarised that the current distribution connection charging arrangements are sending such strong signals that some sites for renewable and storage projects are only economic if the grid is available without reinforcement and connection charges are low. The proposal would make the development of such sites economic, and potentially bring forward additional renewable and storage capacity.

1.25. Presenting an opposing view, five respondents supported the current connection charging boundary arrangements. They put forward the view that locational cost signals are working well and already require customers to pay the share of costs they impose on the network. These respondents saw it as beneficial that current arrangements often lead customers to seek alternative connection options, which may reduce connection charges and facilitate more efficient network development. Some respondents therefore expressed opposition to the proposals. They argued that moving to shallower charges would socialise more costs and create a risk of costly connections being subsidised for the connecting party by consumers.

1.26. One DNO expressed that the difference in acceptance rates between offers with and without reinforcement was less than 10%, however they also outlined that 75% of their customers expressed a view that the current arrangements had an impact on the capacity they requested. Another network owner respondent echoed this, stating that their engagement with customers on the costs of connection reduces the volume of connection enquiries that proceed to the offer stage in the first place. They put forward a view that our proposals will lead to flexible or curtailed connections becoming more established as temporary rather than enduring solutions for many network users.

1.27. Several respondents expressed that it was difficult to anticipate the full impact of the proposals without considering the future changes to DUoS, and that any changes for generation should be implemented alongside DUoS reform to avoid any new generation connecting in locations that increase costs for DNOs and could increase future DUoS charges for existing generators.

1.28. Some respondents also expressed a general disagreement that wider DUoS bill payers should subsidise reinforcement to a greater extent.

1.29. One respondent felt that the proposals remove some distortions but replace them with others, which could encourage projects requiring reinforcement to locate at higher voltage levels where they can maximise the benefit of not having to pay for costly reinforcement under the proposals.

1.30. Several respondents also raised that demand, generation (particularly small-scale community generators) and storage (particularly pumped) are locationally inelastic and that the methodology should not assume that customers could easily relocate. Particularly for renewables such as hydro, location is influenced by rainfall and topography.

1.31. Community generation projects are also generally unable to respond to connection pricing signals, and reduced connection costs may potentially remove this barrier. Some respondents expressed the view that community generation companies may therefore require a different set of rules from the current charging arrangements to ensure fair connection opportunities.

1.32. Locational inflexibility and unfairness were also stressed by several respondents who raised the issue of perceived unfair treatment of islands in Scotland needing to pay higher costs for an interconnector in comparison to EU/Ireland locations.

Effectiveness of the current arrangements in facilitating the efficient development and investment in distribution networks

1.33. We asked respondents about their views on the effectiveness of the current arrangements in facilitating the efficient development and investment in distribution networks and how this might change under our proposals.

1.34. Respondents were largely critical of current arrangements, with 20 responses expressing that the current system is seen to be ineffective and inefficient, does not allow DNOs to plan for increased generation or demand and thus leads to a piecemeal approach to reinforcement while not supporting the level of connections needed for net zero.

1.35. A further 16 respondents felt that the proposal would result in more efficient development of networks since DNOs will be able to plan networks in a more strategic and coordinated way. The proposal also received support as it was seen to encourage other approaches to network reinforcement, such as flexibility procurement and alternative technologies or business models which could help to enable a net zero transition at least cost.

1.36. A small number of respondents (4) felt that the current arrangements already ensured efficient and relatively timely investment overall, albeit sometimes with delays, and that they provide an effective locational cost signal. There were also concerns about if and how DNOs could fund the proposed changes.

1.37. Several responses expressed the view that the impact of the proposal on more strategic planning would be limited, and that RIIO-ED2 decision were expected to have a greater impact.

1.38. Some respondents were concerned that under the new proposals DNOs could default to building more capacity rather than exploring other options under shallower connection boundaries, or that prospective customers might submit speculative applications or applications with excessive capacity requirements that might be avoided if a financial commitment was required.

1.39. Several respondents (4) inquired how more strategic investment would be assessed and requested further information on this, while one respondent would like to see further assurances that decisions on network development are ultimately overseen by the regulator.

1.40. A small number of respondents (2) felt unable to provide feedback on the proposal but did not provide further explanation or detail as to why.

The need to provide connection customers with more certainty may reduce the potential for capacity to be provided through other means such as flexibility procurement

1.41. We asked respondents if they agreed that the need to provide customers with certainty of cost reduces the potential for capacity to be provided through other means, such as flexibility procurement, and how this might change under our proposals.

1.42. Some respondents supported this hypothesis but expressed that flexibility and certainty of price were not necessarily incompatible. Others stated that it was too early to tell whether alternatives to reinforcement would gain traction and whether a lack of guaranteed price was a significant barrier to this. Further respondents felt that the proposal risked a large increase in reinforcement and that, as a result, it could take applicants longer to secure a connection.

1.43. There was a strong sense of agreement in the responses that prices needed to be reflective of costs, however, there must also be sufficient certainty of price and revenue availability (10 responses, predominantly from developers). Price certainty was said to be critical for investment as it can reduce the cost of delivery and therefore consumer bills.

Arrangements that pose undue risk to support flexibility were seen as likely to be less effective

1.44. Some stakeholders raised that flexibility procurement arrangements were not yet sufficiently well-defined and certain for banks to provide potentially necessary loans. This was seen as a complicating factor relating to the risk of return on investment that may inhibit renewable generation.

1.45. A number of respondents expressed disagreement about uncertainty of price reducing the potential for capacity to be provided by other means such as flexibility procurement, with some stating that investors did not need price certainty but were too used to having it.

1.46. One respondent felt that flexible connections should only ever be a temporary arrangement, while another respondent viewed their principal function as being to reduce the waiting period for a connection.

High-cost cap ('HCC') - the case for reviewing its interaction with the voltage rule if customers no longer contribute to reinforcement at the voltage level above the point of connection

1.47. We asked respondents whether the HCC should be retained and whether there was a case to review its interaction with the voltage rule if customers no longer contributed to reinforcement at the voltage level above the point of connection. Responses to these questions were mixed, but a majority supported retaining the HCC (20 responses) while some responses supported the removal of the HCC (8 responses). The remaining respondents expressed no preference, but a need for its review (7 responses).

1.48. Most responses supported keeping the HCC to protect against too much of an incentive, or lack of disincentive, for generation to connect at any location regardless of cost. For example, generation connected in remote or less densely populated areas could drive very high reinforcement costs. A key argument to retain the HCC articulated by stakeholders was to protect DUoS bill payers from large cost increases and an unfair additional DUoS cost burden from connections-driven reinforcement work. Many expressed that it would be reasonable to fund more through DUoS customers if they were likely to benefit from the increased capacity created by this reinforcement, and if their contributions were not excessive.

1.49. There were several responses that did not support retaining the HCC. They suggested that spreading the cost of all connections across all network users would be fairer than continuing to require individual projects to pay for reinforcement. Some of these respondents expressed opposition to retaining the HCC for the connection voltage plus the voltage level above on the basis that this would undermine the effect of moving to shallower charges.

1.50. The removal of the HCC for generation was something that one stakeholder felt may help to increase local generation from renewables and storage projects, and that the absence of an HCC for demand may also help to support the uptake of EVs and heat pumps. One respondent outlined their view that the current HCC disincentivises investment in new large-scale projects in constrained areas, resulting in a lack of network upgrades and so hindering progress to net zero.

1.51. While some supporters of the existing generation HCC see it as a blunt tool in need of review, two responses advocated for the HCC to be applied to the voltage level above the connection level and increased for 33kV in the north of Scotland specifically, as 33kV networks in the north of Scotland were noted to be particularly constrained and frequently reinforcement is required for new connections.

1.52. Another response advocated that the HCC should apply only to the same voltage level at which customers are connected since, if triggered, the HCC is a sign of a lack of strategic planning from the DNOs. There were also views that supported retaining the HCC for generation, while proposing that a cap be introduced for demand for reinforcement up to one voltage level above the point of connection.

1.53. While several respondents did not offer a preference for or against retaining the HCC, they agreed with the need for a review of its interaction with the voltage rule and assessment of potential impacts of its removal, as any benefits of moving to a shallow connection charging boundary could be negated by an unchanged HCC. One response questioned how often the HCC is currently triggered and requested an assessment of how often it would be triggered under the changed charging boundary. If this demonstrated that the additional protection was redundant, it could potentially be removed. It was recommended to review and reassess the requirement of the HCC at a reasonable time after introducing the proposals.

1.54. Other responses expressed that the HCC should act as a trigger for assessment of the case for strategic investment and broader network optimisation options, or that more effective DUoS locational signals could replace the HCC entirely in the longer term. It was further suggested in one response that Ofgem should take account of whether projects captured by the HCC support the delivery of net zero, in which case they could contribute based on their affordability and viability, rather than a one-size-fits-all solution using a fixed £/kW threshold. This was echoed by another response which stated that the £200/kW threshold should be revisited to ensure it remains the appropriate threshold.

1.55. Stakeholder views were mixed on the specifics of calculating any HCC. Some supported the continued use of reinforcement costs at two voltage levels, however, others argued that this would undermine the move to shallower charges. A small number of respondents proposed raising the cap for specific voltages and regions, allowing for projects to avoid hitting the cap in more constrained areas. A few stakeholders suggested that reinforcement at voltages above the point of connection should trigger a strategic investment assessment by the distribution network operator (DNO) rather than an automatic cost increase for the connecting customer.

Recovery of the costs associated with transmission that are triggered by a distribution connection

1.56. We requested views on the recovery of the costs associated with transmission that are triggered by a distribution connection and whether these need to be considered alongside wider charging reforms or whether a change could be made independently.

1.57. A large number of respondents (14) felt that these costs must be part of a wider TNUoS reform and changes should not be made independently. There was a sense of general support for the ability for networks to recover costs in the responses. A further eleven views supported that these should be considered alongside wider charging reforms and that transmission reinforcement costs should be socialised.

1.58. Eight responses pointed out that the costs associated with transmission reinforcement triggered by a distribution connection should be considered a distortion that still needs to be addressed.

1.59. Others expressed that the socialisation of transmission costs where those relate to a distribution connection should be considered a priority, and that this should be progressed independently as a separate modification (2). A small number of responses suggested that these costs should be recovered through use of system charges (2).

1.60. One respondent noted that connection charges relating to transmission reinforcement may fall outside the scope of provisions set out in sections 16 to 23 of the Electricity Act 1989 ("the Act"), which relate only to costs incurred by the distributor.

1.61. Eleven respondents expressed concerns that Scottish customers may be in a disadvantaged position because of the different definition of voltage boundary between transmission and distribution when they trigger 132kV reinforcement.

1.62. There were further concerns that more information is needed to understand the extent to which distribution-level users use the transmission system and what charging methodology may be applied.

1.63. One respondent supported maintaining the current charging approach while another respondent disagreed with the premise of the question, as they felt that the SCR should relate only to price signals and not to cost recovery.

Likelihood of inefficient investment under our proposals and introduction of liabilities and securities to mitigate this risk

1.64. We asked respondents about their views on the likelihood of inefficient investment under our proposals (eg an increase in project cancellations after some investment has been made) and whether there were good arguments for further considering introducing liabilities and securities to mitigate this risk.

1.65. Seven respondents felt that the risks of inefficient investments were minimal. This was seen in the context of a growing economy and a growing demand for electricity, where alternative users will never be far away.

1.66. Some respondents (6) felt that while there was a risk of inefficient investment through our proposals, this would be outweighed by the ability of DNOs to manage investments more efficiently and expedite net zero.

1.67. Four respondents did not believe that the proposals would lead to an increase in project cancellations or stranded assets after some investment had been made, given that the current system requires developers to pay higher connection charges upfront than they would under the minded to proposals.

1.68. It was also expressed that the risk of not future proofing the network outweighed the risk of stranded assets. Even if that risk materialised, several respondents (5) believed that any stranded assets could be repurposed.

1.69. A few respondents (3) were concerned that the proposals would make inefficient investments more likely to progress, especially for demand but that a banded contribution to reinforcement could provide some certainty and signal.

1.70. Many respondents (12) expressed that liability and securities were very complex and should not be introduced to small distributed generators or that a proportionate or reduced contribution for both should be kept. There was a concern that liabilities and securities were a particularly notable issue for community generators.

1.71. On the other hand, several respondents believed that without any form of securitisation there is a significant risk of stranded reinforcement on the transmission and distribution systems. Therefore, reasonable liabilities and securities could be placed on the customer in the event that they cancel or delay their project (9 responses). Specifically, at transmission level, securities received support from two respondents.

1.72. There were also concerns that customers might oversize their capacity requests as a consequence of the proposal. A proposed mitigation for this was a capacity charge, fixed for five years.

Interactions between our connection reforms and the Electricity Connection Charges Regulations 2017 ('the ECCR')

1.73. We asked in our minded to positions consultation whether the interactions between our connection reforms and the ECCR would have to be resolved before we are able to implement our proposed reforms, and how the effects of the ECCR (if any) should be factored into decision making, given the levels of uncertainty around subsequent customer(s).

1.74. A few respondents (5) felt that the ECCR was essentially unnecessary. One stated it should be replaced by a regime whereby second and subsequent connectors pay a pro rata portion of the connection cost amortised over a long period (say 30 years) according to the amount of use on a MWh basis. Several respondents stated that the ECCR had never factored in their decision making and that the proposed connection charging changes should not be delayed by a review or reform of the ECCR. The ECCR were understood to be triggered very infrequently and applied on a case-by-case basis by these stakeholders.

1.75. A few respondents (3) stated that the ECCR will need to remain in place until a replacement solution has been set up. One respondent was concerned with the need for clarity in this area, as some developments may have expected as part of their business case that any up-front investment would be partially recovered in future via the ECCR as other network users connect. They similarly expressed a need for more clarity on how any future 'second comers' under the ECCR might contribute to prior network upgrade costs, whilst avoiding any double-counting.

1.76. A number of respondents (8) expressed that the ECCR needed to be reviewed to align with the Common Connection Charging Methodology (CCCM). Some specifically mentioned that any conflict between the charging reform and the ECCR would need to be resolved before the implementation of these reforms given the ECCR is set out in legislation.

1.77. A further eight respondents expressed that, especially for historic network extension schemes, customers should receive any reimbursement under the ECCR for a period of up to ten years or not limited by time at all under grandfathered arrangements.

1.78. A small number of respondents (2) felt that no changes were required to the provisions in the ECCR relating to sole use assets and second comers, as the treatment of extension assets is largely unaffected by the proposals.

1.79. Respondents generally regarded that the most effective way to establish how the ECCR should interact with connection reforms was through legislative changes, but it was recognised that this would have to be delivered within the implementation timescales.

1.80. Some respondents supported the proposal to explore an alternative viable solution that could be utilised either as an interim measure while legislation is changed, or until a more enduring solution emerges. Some interim solutions had already been developed with DNOs, while other organisations were also exploring interim measures. They articulated that changes should not be retrospective so as not to undermine project developments already underway.

Access Rights

Consultation questions

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

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

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

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

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

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

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

General

1.81. The majority of responses to our access rights proposals were supportive (67%), with the remainder offering mixed responses (33%). There were no responses that were wholly unsupportive of our proposals.

1.82. Those who offered broad support generally agreed that better defined access rights arrangements at distribution would provide more certainty for users and could lead to more efficient use of existing network capacity. Many respondents acknowledged that the proposals could speed up connection times, facilitate provision of flexibility, and reduce network peak loads.

1.83. However, many respondents with mixed views expressed concern at a lack of sufficient detail in our proposals, specifically around important definitions (eg non-firm, curtailment, and small users) and how our proposals might work in practice (eg how curtailment limits should be set and how they would be enforced). Hence, we worked with Delivery Group members to provide clarity on these areas in our updated minded-to position.

1.84. Key views and suggestions from respondents on specific proposals are outlined below.

Definition of non-firm access rights

1.85. The majority of respondents supported our proposal to introduce better defined non-firm access choices at distribution in principle, to protect from and provide more certainty to customers at risk of open-ended curtailment.

1.86. One respondent saw the proposal as beneficial for increased development of renewable generation projects. Others felt that robust monitoring, transparency, and data would be important for customers to make informed connection choices.

1.87. However, many respondents challenged us to provide more detail on how potential curtailment breaches would be addressed and how this would be backed up with compensation. Other feedback included the importance of limiting hours curtailed to prevent redundant network capacity, as well as the need for clear forecasting to better understand the levels of curtailment that may be required.

Time-profiled access rights

1.88. Our proposals to introduce new time-profiled access choices at distribution received broad support. Respondents perceived value on switching away from peak demand and felt that the proposal would give clarity and certainty to DNOs and developers on the impact of the new connections. However, respondents observed that some industries are unable to flex their demand so that the proposal would not be suitable for all users.

1.89. There was a general view that the proposal would allow parties to connect more quickly and provide better choice on flexible connection arrangements. However, adequate penalties and enforcement mechanisms would be required to ensure compliance.

1.90. As with non-firm access, many respondents suggested that more detail was necessary to understand how this would work in practice. Several respondents also raised potential dependencies on DUoS reform in order to give effect to our proposals.

Shared access rights

1.91. We asked respondents whether they could identify any benefits of shared access rights. The majority stated that they could not identify such benefits, and many saw shared access rights as an option unlikely to see a lot of uptake. The rationale provided by respondents was that they add complexity (eg in terms of control and metering equipment, tariffs, compliance, and billing) and risk for customers that could lead to disputes.

1.92. Some responses highlighted that potential advantages of shared access rights could instead be provided through innovation and flexibility in connection design and contracts as well as technologies, such as active network management.

1.93. Nevertheless, a number of respondents raised that shared access rights presented an opportunity to better value flexibility, particularly for mixed technology projects. In such cases, respondents argued that shared access rights could help reduce curtailment needs and potentially the need for reinforcement. One respondent argued that shared access should be available to help lower costs, increase network utilisation efficiencies and increase local balancing, collaboration, integration, and resilience.

How to value alternative access rights

1.94. We asked respondents to comment on how to reflect access rights in charges, such as connection charges or use of system charges. Respondents were evenly split on the most appropriate way to value non-firm arrangements. However, many respondents suggested that the most appropriate way to value time-profiled access was via use of system charges.

1.95. Respondents agreed that the proposed connection charging reforms would reduce or remove the extent to which alternative access arrangements could be valued through connection charges, and therefore that value to users would primarily be through a quicker connection.

De-prioritisation of transmission access reforms

1.96. Respondents largely agreed with the proposal to not prioritise the introduction of new transmission access choices as part of the SCR. Nevertheless, there was a view that a wider review of transmission access arrangements would be beneficial, especially as the transmission network will be undergoing significant change over the next decade.

TNUoS charges for SDG

Consultation questions

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

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

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

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

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

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

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

General

1.97. Questions on this proposal were answered by around 120 respondents, with more than half (around 70) disagreeing with our minded-to position. Of the respondents who did not support our position, a little under half were representatives of, or were themselves, generators, investors, or developers.

1.98. Most of the responses that were opposed to our proposal focused on the perceived implications of the introduction of TNUoS charges to SDG, not whether in principle levying them would resolve a current distortion.

1.99. We are grateful for the responses received, and the level of engagement in this complex area. The key themes from respondents on specific proposals are outlined below.

1.100. Some respondents felt that absolute charges in certain parts of the UK were too high, using terms such as, "punitive" or, "discriminatory" to describe the output of today's TNUoS charging methodology.

1.101. A number of respondents expressed concerns regarding competition between UK generators and their counterparts on mainland Europe. They felt that generators in some EU Member States do not pay or pay comparatively low transmission charges.

1.102. According to views expressed by some responses, the role of network charges ought to change, such that TNUoS enables generation deployment in areas high in relevant resources rather than being based on the physical network and/or proximity to demand.

1.103. Several respondents expressed the opinion that the current charging regime "incentivises" fossil fuel and conventional generation. Generally, this has been linked in the responses to the negative zonal TNUoS tariffs in southern areas of the UK. Following our decision to not pursue reforms regarding TNUoS charges for SDG under this SCR we issued a Call for Evidence inviting stakeholder views on wider TNUoS reform[3]. We published our next steps on TNUoS reforms alongside stakeholder responses to our Call for Evidence in February 2022[4]. We invite stakeholders to continue to engage throughout the reform package for transmission charging.

[3] Our Call for Evidence regarding TNUoS reforms can be found here: https://www.ofgem.gov.uk/publications/tnuos-reform-call-evidence
[4] Our next steps on TNUoS charges and a summary of responses are set out here: https://www.ofgem.gov.uk/publications/tnuos-call-evidence-next-steps

Responses to the January 2022 update to our minded to positions

2.1. In January 2022, we issued an update to our minded to positions and invited further stakeholder views on our policy proposals. This consultation contained specific questions on our policy positions. We provided additional detail and granularity on the proposals, as requested by stakeholders in response to our original minded to positions. Stakeholder responses have been recorded in line with the specific questions asked, reflecting this increase in granularity.

Consultation questions

Question 2a.i: Do you believe that it is necessary to introduce a High-Cost Cap (HCC) for demand, and to retain one for generation?

Q2a.ii: Do you believe that our proposals to do so represent sufficient and proportionate protection for DUoS bill payers against excessively expensive connections driven reinforcement?

Q2a.iii – What are your views on retaining the current 'voltage rule' to determine whether the HCC is breached (ie considering the cost of reinforcement at the voltage level at point of connection and the voltage level above)?

Q2a.iv – What are your views on the principles we have proposed to determine an appropriate HCC level for demand, including the potential for this to be set at a different level to generation under these principles?

Q2b – What are your views on our proposals to maintain the requirement for three phase connection requests to pay the full costs of reinforcement, in excess of Minimum Scheme (ie lowest overall capital cost)?

Q2c.i – Do you agree with our proposals to maintain the current treatment of speculative connections and is there need for further clarification on the definition of speculative connections?

Q2c.ii – Do you agree that our wider connection boundary proposals broaden the disparity between connections deemed to be speculative versus non-speculative? If so, do you believe this needs to be addressed and how?

Q2d – Do you consider that our proposed DUoS mitigations (a demand HCC, and retaining reinforcement payments for three phase and speculative contributions) present a cohesive package of protections for DUoS bill payers? Do you consider these proposals to interact in any way that could counter their effectiveness, and if so, how?

Q2e – Do our updated proposals to treat storage in line with generation for the purposes of connection charging simplify charging arrangements for these sites and better align with the broader regulatory and legislative framework?

Q2f – Do you agree with our proposals regarding the treatment of in-flight projects (ie that they should not be permitted to reset their connection agreement and retain their position in the queue), noting they retain the right to terminate and reapply from 1 April 2023 should they wish to be treated under the proposed connection charging boundary?

Q2g – Do you agree with our proposals to retain the existing arrangements for managing interactive applications? Do you agree with our proposals on the treatment of unsuccessful applicants (that the connection charges at original application date will continue to apply if queue position is retained?

Q2h – Do you agree with continuing with the definition of the Minimum Scheme as currently set out in the CCCM? Do you believe this definition requires any further clarification or amendment, and if so, why?

Q2i – Are there any risks associated with our proposals to allow current non-firm connected customers to seek a firm connection following the changes proposed by our SCR? Do you agree that existing non-firm connected customers that do seek a firm connection should be processed through existing queue management processes as determined by DNOs?

Q2j – How necessary do you consider intervention in Electricity Distribution Standard Licence Conditions 12, 15 and 15A? What duration might such measures be needed, or acceptable, following 1 April 2023? What value do you place on certainty of connection timeframes compared with time to connect?

Q3a – Do you agree with our proposal to exclude customer interruptions and transmission constraints from the definition of curtailment with respect to distribution network access arrangements?

Q3b – Do you agree that the curtailment limit should be offered by the network based on maximum network benefit and agreed with the connecting customer?

Q3c – Do you have any views on the principles that should be applied to ensure curtailment limits are set in a consistent manner?

Q3d – Do you agree with our proposal not to introduce a cap for flexibility payments made should any curtailment in excess of agreed limits be required?

Q3e – Do you agree with our proposal to introduce explicit end-dates for non-firm arrangements? Are there any mitigations for DUoS bill payers we should consider?

Q3f – Do you have views on whether the end-dates should take into account only current known or likely works, or if it should allow time for wider developments to take place?

Q3g – Do you have any comment on our proposal not to further define or standardise time-profiled access arrangements?

Q5a – Has the additional information in this consultation affected any of the views your previously submitted in response to our June 2021 consultation (if so, in what way)?

Q5b – Do you have any other information relevant to the subject matter of this consultation that we should consider in developing our proposals?

2a.i – Do you believe that it is necessary to introduce a high-cost cap (HCC) for demand, and to retain one for generation?

2.2. The majority of responses (18) were supportive of our proposals, with a number highlighting that HCCs would protect DUoS customers from high-cost connections or inefficient network investment. A small number of respondents (4) were not supportive. The remainder either had mixed views (7) or were neutral (1).

2.3. Overall, there was a broad range of comments and suggestions in relation to introducing an HCC for demand and retaining one for generation. Four respondents expressed support for an HCC for demand because these users have limited flexibility to relocate in response to network charging signals. One respondent felt that a demand HCC should only apply in relation to LCTs (e.g. EVs and heat pumps), while another was in favour of an HCC for generation but not for demand. One response noted that an HCC is an important safeguard, especially in sparse or rural networks where large new connections are not normally a feature and it would be unreasonable to ask the general body of customers to fund reinforcement. One response recognised the need for some form of protection from excessive costs and that this should be part of the DUoS reforms while another suggested that an HCC would be a way of reintroducing locational signals in network charging.

2.4. Several respondents (6) highlighted interactions between an HCC for demand and the descoped DUoS reforms. One respondent asked for clarity on whether the demand HCC would be a temporary measure pending DUoS reforms. It was also argued (2 responses) that it is difficult to assess the value of an HCC if DUoS charges became more granular. One respondent was supportive of the proposal, assuming no significant changes were made to DUoS.

2.5. There was an equal range of comments in relation to determining the level of a demand HCC and its application. One respondent suggested that this should be no less than £1,000/kVA while another would like demand and generation HCCs set in the same way. A further response requested that the HCC should be set at a high enough level that it is rarely triggered. Several (3) respondents argued the level of the HCC should be kept under review, and one respondent presented their opinion that the level of the cap should be index linked. One respondent suggested that particular focus for reviewing the HCC should be placed on its impact upon net zero enabling technologies.

2.6. In relation to how, or if, the cap is applied, two respondents acknowledged our argument that the HCC is a blunt tool and three suggested DNOs should be allowed discretion in applying it to connection offers. One response presented arguments that information should be collected and disclosed so that the impact of the HCC could be better understood. Further points raised suggested that a demand HCC may not adequately reflect the wider system benefits of network reinforcement that is undertaken for an individual connection and might disincentivise DNOs from investing strategically.

2.7. A number of respondents put forward their alternatives on when they felt an HCC should be applied or alternatives to a cap. Two respondents suggested that DNOs should be able to consider possible alternatives to reinforcement (demand-side response or flexibility procurement) before deciding that a connection cannot proceed unless costs above the HCC are paid. Another response advocated that an economic test for connections should take into account future DUoS charges which might be received as a result of the connection(s), believing this would ensure DUoS customers avoid unnecessary additional costs.

2.8. Regarding the use of an HCC, one respondent argued that it could risk maintaining the status quo of incremental network reinforcement with another stating their position that retaining the current generation HCC could hamper network investment. One response suggested the impact of the current HCC could be greater than the DNOs' estimate. One respondent raised concern that the HCC could go beyond the policy intent and have unintended consequences, such as driving a greater contribution to reinforcement than under current arrangements. How the benefit of reinforcement to customers would be measured was questioned while one respondent requested that the HCC should be reviewed with regards to 33kV connections in the North of Scotland.

Q2a.ii – Do you believe that our proposals to do so represent sufficient and proportionate protection for DUoS bill payers against excessively expensive connections driven reinforcement?

2.9. The majority of respondents (14) agreed that our proposals did represent sufficient and proportionate protection for DUoS bill payers. Four respondents disagreed and a further five offered mixed or neutral views.

2.10. Whilst there was agreement, a large number of respondents (10) noted that the level and use of an HCC should be kept under regular review, especially in relation to the expected future changes to DUoS charges. Four respondents stated that the use and/or level of the HCC should be reassessed after the outcomes of the DUoS SCR are known, with one response suggesting that the HCC should only be viewed as an interim solution until locational DUoS charges would be finalised.

2.11. One response noted that the HCC offered sufficient protection given the lack of imminent reforms to DUoS charges and the uncertainty around flexibility markets. Another respondent specifically mentioned the benefit of an HCC being straight forward to apply.

2.12. One response explained that the level of protection the proposals would provide depended on the thresholds that are applied for the HCC.

2.13. Some responses presented their positions that the use of HCCs can have disadvantages. One noted that it was hard to say whether the proposals would offer protection to DUoS customers, arguing that HCCs do not accurately consider the benefit of wider reinforcement to the network.

2.14. One respondent believed that the approach for a demand HCC was reasonable but that the level for generation should be re-examined. Another suggested that the level of the cap should be reviewed annually to ensure it is not triggered by more than 5% of connection offers. Some argued that the HCC may not constitute sufficient DUoS bill payer protections and one respondent reiterated their position from the original minded to consultation that they were not supportive of the introduction of an HCC.

2.15. On the level of the cap, three responses agreed the proposals were sufficient in theory but that that more information on the level of the cap would be helpful. Two respondents noted the importance to balance the level of the cost with wider considerations, including disincentivising electrification of industry and undermining strategic reinforcement of the network. Two respondents commented specifically on the £200/kVA and £1,400/kVA levels for generation and demand with one mentioning that

£1,400/kVA appears to be high in relation to the costs it would allow to socialise and when compared to the £200/kVA for generation. The other response understood why there was a difference in the values and expected the value for demand to reduce when only looking at reinforcement at the voltage level of connection and the one above, rather than the total cost of reinforcement that the initial £1,400/kVA was based on.

2.16. The responses received included a range of comments on practical considerations of implementing a demand HCC. The calculations used should ideally be easy to understand and present an argument that if the HCC is implemented it should only apply at the same voltage level of connection. The same response expressed concerns that basing the HCC calculation on the current voltage rule and connection charging on a different basis would create two classes of customers - those who trigger reinforcement at higher voltages and are therefore more likely to breach the HCC, and those that do not. They added that although reinforcement would only be charged in relation to the voltage level of connection, constraints at the voltage level above would still create a locational signal.

2.17. Two responses expressed a position that specific consideration should be given to connections that would trigger the HCC but could offer wider network benefits. Other responses mentioned that most distribution demand users may potentially not have the technical knowledge to understand the options presented to them without the guidance of the DNO. They added that for the DNOs to be trusted in this role there would need to be some level of independence so that users can be confident that they are acting in the best interest of the network.

2.18. While there was general agreement that the proposal would offer protection, subject to the level of the HCC, some challenges were also presented. One response argued that generators that have already connected and contributed to reinforcement could now also face higher DUoS bills and that this could potentially be viewed as leading to double charging. One respondent disagreed with the assumption that generation could move or relocate more freely than demand users in response to network charges. Another respondent argued that the question was framed too narrowly.

2.19. The frequency at which the HCC would be triggered was raised by two respondents with one presenting their position that while the HCC may only be triggered occasionally, it could represent an obstacle for new generators looking to connect. Another requested clarity on how often the HCC is currently triggered, forecasted to be triggered and whether there are commonalities in existing occurrences that may apply in the future as this information could make a more bespoke solution possible. Another respondent argued that if the HCC is triggered it could be seen as a sign of a lack of strategic planning from DNOs.

Q2a.iii – What are your views on retaining the current 'voltage rule' to determine whether the HCC is breached (ie considering the cost of reinforcement at the voltage level at point of connection and the voltage level above)?

2.20. The majority of respondents (13) were supportive of our proposal to retain the current 'voltage rule'. Five respondents were unsupportive, with six offering either mixed or neutral views.

2.21. One response noted that not including the higher voltage level would distort investment decisions and offered the example of a large load applying for multiple LV connections instead of a single HV connection. Other reasons for support included that customers would still face reduced reinforcement charges compared to the current arrangements, regardless of whether they hit the cap, and that retaining the current voltage rule would help protect consumers from excessive connection reinforcement costs. One respondent mentioned that while they opposed setting an HCC in general, they accepted that the principles were reasonable and designed so that only a small number of high-cost projects would trigger it. They added that they believe the 95th percentile of connection offers on a £/kVA basis was a reasonable threshold.

2.22. A number of respondents expressed general support with some suggestions for additional nuances. These included that the level and impact of the HCC could be assessed and reviewed periodically (4 responses). One respondent supported the principle and that a level playing field approach could also cover transmission connection works triggered by a DNO at distribution. They argued that transmission reinforcement costs should not fall wholly on users at lower voltages and that future decisions on charging should strive for consistency on this issue.

2.23. Some positions were expressed that were not as supportive of our proposals. One of the most common of these, put forward by four respondents, was that it could prevent new connections from going ahead in some areas of the network that require strategic reinforcement. One specific respondent clarified that they did not have a strong view on whether the HCC used the current voltage rule and that whatever option was selected must consider the trade-off between fairness and net zero.

2.24. One response argued that the current HCC methodology may penalise new network users and contravene Ofgem's remit to support the needs of future users on a level playing field with existing ones.

2.25. Five responses argued that the proposals would reduce the impact and potential benefits of other areas of the Access SCR. Four of these said that it could reduce the benefit of moving to a shallower connection charging boundary for generation, while one was concerned that the proposal might dampen the anticipated impact of the SCR to facilitate net zero and unlock strategic investment in the network. They added that the voltage level above a connection should be the point where the network should be required to investigate the potential for alternatives or strategic investment. One response suggested that retaining the current voltage rule would result in minimal protection for customers while another felt it could still provide distortions in instances where 132kV reinforcement was triggered, but not accounted for, by 11kV connections.

2.26. Two responses believed elements of the proposal could have been clearer. One respondent argued having different voltage rules for the HCC and the general charging boundary was confusing and that it would be better to align the HCC with the general charging boundary rules, and also give the DNOs a CBA process to decide not to undertake reinforcements in extreme cases. Another added their position that the calculation of the generation HCC in this way would mean that although reinforcement would only be paid on the connection voltage, constraints on the next voltage up would still create a locational signal. They added that following the revision of DUoS, this may mean that generators will be exposed to two, possibly conflicting, locational signals which may risk distorting locational decision making by developers.

2.27. Two responses argued that the proposal would create or increase distortions between demand and generation customers. Another suggested it may lead to perverse scenarios where the reinforcement required to provide a connection to one customer has a lower capital cost than the reinforcement to provide a second customer's connection, but the second customer would not contribute to reinforcement as the reinforcement required to facilitate their connection is at more than one voltage tier above their connection.

2.28. Another suggestion received was that any costs over an HCC should be capped at the cost such a connection would face under the pre-implementation connection charging boundary. It argued that a total cost incurred approach would be the most reasonable and therefore agreed with the DG approach of assessing reinforcement at all voltage levels. One respondent argued that in a number of areas 33kV connections now require expensive reinforcement of the 132kV network and that if the HCC still considered higher voltages, then the impact would be limited. Instead, they argued, it would in effect create a new 'ceiling' of viability that is close to the current level.

Q2a.iv – What are your views on the principles we have proposed to determine an appropriate HCC level for demand, including the potential for this to be set at a different level to generation under these principles?

2.29. On the level of the cap two respondents agreed with the proposal to base the demand HCC on a percentile calculation, while another expressed the opinions that it was more appropriate to set the cap relative to an average cost of connection. Two respondents suggested specific values, one at £500-700/kVA and another at no lower than £1,000/kVA. Rather than suggest approaches or levels one response called for Ofgem to confirm that that HCC will only be triggered by a small number of connections. Two respondents supported the proposals in principle but required further data or analysis. One of these welcomed the analysis that showed that over the past four years a very small minority of demand connections have been significantly more expensive. One further response felt that the levels for demand and generation should be set on a GB wide basis.

2.30. One response agreed that a relative threshold would protect DUoS customers against the highest cost connections but suggested that figures based on previous price control periods could cause issues when they need to be updated. They added that because of this, when the methodology to calculate the HCC level is set, it should consider how frequently the level will be revalued. Five respondents highlighted that the level(s) of the cap(s) should be regularly reviewed and assessed.

2.31. Views were split on whether the level of the HCC for demand and generation should be different or the same. Eight responses agreed that it was appropriate for demand and generation to face different HCCs. Two responses thought it was fair for demand connections to have a higher HCC because they may offer wider societal or environmental benefits. Other reasons for having different HCC levels included that for generation it was appropriate to retain a locational signal to encourage installers to target those areas that can better benefit from the exported capacity; and, given the reinforcement charging proposals for demand and generation connections are different, it was entirely appropriate that the respective HCC levels are set at different values.

2.32. Three responses argued that there should be a single HCC for both demand and generation. One response felt that the logic behind the proposed levels was unclear, and it was unsustainable to have such a large difference. Another highlighted the issue of location flexibility for both demand and generation, adding that it should be examined closely to find an appropriate figure. A further response suggested the discrepancy between demand and generation should be reviewed through the DUoS reforms.

2.33. One response sought clarity regarding which cap would apply for sites with both import and export. Another suggested that it should also be taken into account that natural increases in demand are already socialised, while the generation capacity of the grid always has to be paid for by new connections, which they argued was an unfair disparity.

2.34. A number of respondents raised other challenges to our proposals. These included calls to index the cap, noting that currently the cap is a fixed threshold (£/kW), which, in real terms, is a shrinking cap. One argued that the cap should be based on alternative costs to network upgrades as opposed to our proposed calculation. Another suggested that the approach presented could penalise demand that has no locational flexibility, such as EV charging on motorways, which the shallower connection proposals are aiming to support.

Q2b – What are your views on our proposals to maintain the requirement for three phase connection requests to pay the full costs of reinforcement, in excess of Minimum Scheme (ie lowest overall capital cost)?

2.35. The vast majority (13) of respondents supported our proposals with no responses expressing disagreement. The reasons put forward included that customers requiring three-phase supply would anticipate a financial benefit so it may therefore be reasonable for them to be exposed to the incremental cost of providing it. One response would like to see reinforcement for three-phase supply be based on a clear justifiable and efficient need and others noted that the proposals incentivised customers to only request three-phase connections when necessary, and not incentivise customers to select the more attractive (three-phase) option at the expense of the wider network users. One response noted that three-phase connections are often in excess of the Minimum Scheme and therefore it would be reasonable for these enhancements to be paid for in full by the customer.

2.36. Related to the Minimum Scheme, two responses argued that it was reasonable for a party to be liable for the incremental costs above the minimum scheme if the three-phase connection is not necessary for their upgrade. One suggested this cost should be the difference between the Minimum Scheme and the three-phase cost as opposed to the total cost of the reinforcement.

2.37. One response suggested that where electricity networks are already capable of providing three phase connections, the service or mains cable work to upgrade could be socialised within existing rules. However, where a network is not capable of providing three phase it is reasonable for reinforcement costs to fall to the requesting customer.

Another respondent supported the proposals on the assumption that where customers wish to upgrade their connection to a standard fuse size the HCC should not apply.

2.38. Two respondents felt that the decision in relation to three-phase connections may need to be reviewed in the context of an identified need for EV charging where three phase may be required, if this was not captured in current RIIO ED-2 plans, and that Ofgem should consider fairness in relation to who pays for these costs relative to who benefits from the reinforcement. Other comments received included that the case for non-domestic properties was not clear cut and that any decision made should be kept under review.

Q2c.i – Do you agree with our proposals to maintain the current treatment of speculative connections and is there need for further clarification on the definition of speculative connections?

2.39. The majority of respondents (11) were supportive of the proposals. Reasons for support included that the proposals would act as a way of deterring developers from asking for excessive capacity and a general support for proposals that discouraged speculative applications. One respondent noted that retaining existing arrangements would mitigate two risks: increased costs for DUoS bill payers and the need for additional capacity due to existing capacity being allocated cheaply and then not used. Eight of the respondents believed that further clarification was needed on the definition of speculative connections, while two responses did not believe the definition needed to be updated, but it should be kept under review whilst reforms are implemented, and new behaviours emerge.

2.40. The majority of comments that were unsupportive of the proposals related to the unfair treatment of new housing developments and the housing sector in general. Two responses argued that the current definition of a speculative development disadvantaged the housing sector in particular. Three respondents suggested that the current rules should be changed so that charging was applied retrospectively. All three suggested that housing developments could be treated as speculative to start with, as per the current definition, meaning they would be charged the full cost of any reinforcements for any offers. But, as the development progresses and became more certain, the speculative definition could be removed, and the charges then applied as if it were a normal connection. One view suggested that this could be done through a revised offer or a refund.

2.41. One respondent noted that in their experience housing developments being treated as speculative connections limits the ability of developers to build houses in areas where reinforcement is required. Therefore, they argued, the approach taken by some DNOs to apply a housing number threshold, over which a development will be considered speculative was unfair, unnecessary, and generally prohibitive to new housing developments.

2.42. Further comments received included that there was no evidence that the current regime was causing excessive risk to DUoS bill payers, and it seemed appropriate that speculative developments may have a higher cost than non-speculative, because of the uncertainty around eventual utilisation of assets. Another cautioned against discrepancies that could hinder IDNO developments. One respondent highlighted that going through the connections process may be the only way developers can get a reasonable assessment of costs and that locational DUoS charges and a simplified connection methodology may deal with this challenge better, rather than having varying charging and connection methodologies based on whether a scheme is speculative.

2.43. Specifically in relation to EIIs, one response explained that to ensure capacity increases are in place before contracts for financial support are signed, EIIs will be required to make speculative connections. They expressed concern that under the definition of speculative, the full cost falling on the EII may deter these investments, and added that if such connections remained speculative, then cost recovery through financial support (eg CCUS business models) may be considered.

Q2c.ii – Do you agree that our wider connection boundary proposals broaden the disparity between connections deemed to be speculative versus non-speculative? If so, do you believe this needs to be addressed and how?

2.44. The majority of responses received on this question agreed that the proposals would broaden the disparity between speculative and non-speculative connections. However, there was a split in views on whether this would need to be addressed.

2.45. Four responses supported a review of the definition of speculative connections. Reasons for this included ensuring the proposed arrangements were not unduly harsh in how they applied to some projects; an updated definition could address areas of particular concern; and that greater clarity in definitions should help encourage developers to consider their applications in more detail so they would not be classed as speculative.

2.46. Three respondents believed that the disparity between these types of connection was reasonable. Two of these noted that it may be unfair for DUoS customers to pick up the costs of speculative connections, with one of these noting that the treatment of speculative development, as set out in CCCM, is designed to protect DUoS customers from higher risk projects. One respondent did not believe any disparity needed to be addressed, as customers should be disincentivised to ask network operators to build assets and reinforcements that may not be used.

2.47. We received further comments related to how speculative connections should be defined, and suggestions on what could be done if these become more certain. A number of these response echoed the calls made by some housing developers for a mechanism that allowed speculative connections to recoup money should the capacity be used.

2.48. One response called for the types of connection that are deemed speculative to be narrowed so as not to include EIIs that need electricity capacity increases in place before signing support contracts for technologies such as hydrogen production or CCUS. One response called for further clarification on the applicability of the ECCR legislation to subsequent connections where initial connections were deemed speculative.

Q2d – Do you consider that our proposed DUoS mitigations (a demand HCC, and retaining reinforcement payments for three phase and speculative contributions) present a cohesive package of protections for DUoS bill payers? Do you consider these proposals to interact in any way that could counter their effectiveness, and if so, how?

2.49. The vast majority (12) of the responses received agreed that our proposals represented a cohesive package of protections for DUoS bill payers, with only two expressing disagreement. Two respondents did not think there were any negative interactions, one of these was because they did not believe the proposals interacted in any way. One response agreed that the proposals would strike a balance between costs imposed on DUoS bill payers and risking limiting adoption of LCTs.

2.50. A number of positive comments received were contingent on clarifications or caveats, including acknowledgement that within any package of reforms there are likely to be some groups that will benefit from changes. Two of these related to the HCC needing to be set at an appropriate level, but one argued that retaining an HCC would sustain existing disincentives for DNOs to invest in networks strategically. Two responses cautioned against potential unintended consequences, such as stalling the uptake of LCTs, and one of these hoped that for this reason the effectiveness of the proposals would be kept under review.

2.51. One respondent believed the proposals were suitable pending the planned DUoS reforms and another argued the proposed reforms were an improvement on the current situation but would make it harder to judge the suitability of any proposed DUoS changes. They warned there was a risk if DUoS changes attempt to address faults that are being addressed by these proposals, issues could be 'over-corrected', and incentives/disincentives made too powerful. They therefore suggested the timescales for the wider DUoS SCR should allow for the results of these proposals to be visible before more changes are implemented.

2.52. One response suggested that any situation where the HCC might apply or where speculative applications were being made could be mitigated better through the application of a flexibility solution. They therefore recommended that all such flexibility options be fully investigated prior to the implementation of the mitigations covered in the consultation. Another felt it was difficult to fully determine if the package would provide a cohesive protection or not without a full impact assessment on DUoS bill payers.

Q2e – Do our updated proposals to treat storage in line with generation for the purposes of connection charging simplify charging arrangements for these sites and better align with the broader regulatory and legislative framework?

2.53. There was broad agreement with our proposal to treat storage in line with generation, with 16 respondents expressing support for it. Three of these respondents noted that while they agreed with the proposal it was important that the decision be kept under regular review to ensure it was reflecting the benefits of storage and not preventing its deployment to any areas of the network. Two responses believed that the proposal would be an improvement to the current situation where storage has to pay for both import and export if it triggers reinforcement for either. A third respondent hoped it would encourage storage developers to weight both demand and generation connection charges when choosing locations.

2.54. One respondent agreed with the proposal, on the understanding that the HCC would be determined relative to the level of export and that it would simplify the application of the charging methodology and ensures storage is treated as generation in line with the legislative framework. Another agreed but asked for a detailed explanation of the expected impact of the decision on proposed storage connections and costs.

2.55. It was highlighted that there are many similarities between generation and storage, with one response noting that storage facilities already avoid paying a DUoS residual charge in line with other generators and to treat them differently for the purpose of connection charging may unduly distort competition in generation. One response argued that the proposals would ensure connection costs for storage are calculated more accurately and that it would ensure consistency with the treatment of storage connected to the transmission network. Another believed that assessing import and export connection charges separately for storage could lead to divergent reinforcement charges for it, depending on the characteristics of a given local network. However, they added that network charges should incentivise storage to connect in generation-constrained areas, where it can provide significant system value by importing excess electricity and alleviating constraints.

2.56. Other responses agreed that it was a logical approach rather than charging reinforcement costs based on the type of reinforcement and because storage was one of the most locationally flexible technologies. One response agreed that storage should be treated in line with generation however, noted that some generation sites also include battery storage where there may be different export and import connection constraints and additional reinforcement may be needed for firm connections.

2.57. The majority of reasons against the proposal related to the assumption that storage has the same impact on the network as other types of generation, with one response arguing this fundamentally misunderstood the system benefits of flexible capacity. Another noted that the reason storage was classified as generation was to avoid paying final consumption levies. However, they added, storage exhibits characteristics different from regular thermal, or low carbon generation, notably its ability to provide responsive flexible firm services on both the demand side and generation side. They argued this means connection and charging methodologies should evolve to recognise the uniqueness of storage assets as they can help reduce the cost of network reinforcement and reduce whole system costs. They gave the example of a storage asset looking to connect in a highly constrained area, and based on its export capacity, the planning standards may trigger additional reinforcement, despite the operational characteristics of storage in practice actually reducing the need for network reinforcement. They added that flexible connections may be able to deal with this.

2.58. Three respondents called for storage to have its own licence agreement rather than be treated as generation. One respondent argued this would take into account the differences in behaviour between storage and generation.

2.59. Two responses warned that treating storage as a subset of generation would be a barrier to the development of storage capacity. One added that in a generation dominated zone, storage could provide network benefits when acting as demand, which would not be recognised if it was charged as generation for connection purposes and further consideration should be done. Another disagreed because they felt that the assumption that storage has the same impact on the system as any other form of dispatchable generation did not reflect the operational reality of these plants. The respondent also argued that the negative generation that storage can provide can be beneficial in reducing grid constraints. All of this should be reflected in network charging.

2.60. One response expressed that assessing storage as a subset of generation might also lead to unintended consequences and risk missed opportunities to locate storage in areas of the network where it can alleviate reinforcement needs on the demand side. Another suggested the proposal would mean storage is exposed to different connection charging arrangements where it triggers import reinforcement (shallow-ish), compared to other forms of demand (fully shallow). One response was aware that the in-progress SQSS review considers the treatment of storage that might have greater repercussions on the overall treatment of storage at all levels from an access and charging perspective. They therefore welcomed a CBA on this issue, but overall expected the move to lead to cheaper connection charges for generation, storage, and collocated projects from April 2023 onwards.

2.61. A number of respondents highlighted that storage offers wider system benefits to the grid beyond those typically offered by generation. One response considered the proposal to be simplistic because it did not consider these benefits. Another response felt that network charging was a key factor to consider in the policy regime for the development of storage and the value that these flexible resources provide to the system should be appropriately reflected in charges.

2.62. The responses received also highlighted a number of other factors that they felt should be considered when deciding on the treatment of storage. Another noted that the engineering impact of storage on a network could be different depending on when it imports power (acts as demand) or exports power (acts as generation) and how this interacts with the wider use of the electricity network.

2.63. One response highlighted that there may be sites where additional demand due to storage could drive significant costs, and therefore the demand HCC should still apply to storage to protect DUoS bill payers.

2.64. Another response offered an opposite opinion, saying that storage should never pay demand reinforcement as it does not import at peak. It was argued in another response that the principles of not paying for demand reinforcement should also apply to existing generation sites where storage (or other load, such as electrolysers) is added later as the primary driver of connection (the generation site) would already be completed.

2.65. The responses also suggested the dual definition for storage could lead to perverse incentives for it to connect where import exceeds export reinforcement, meaning the Minimum Scheme would need to take both impacts into account. One called for customers to be given more bespoke choices to contractually agree to specific profiles (such as not importing at peak demand or exporting at peak generation) to avoid reinforcement costs.

2.66. Other arguments raised against the proposals included that while they aligned with the broader framework Ofgem should consult with storage developers on this issue as the proposals seem to have been developed for the benefit of DNOs rather than recognising the importance of facilitating more storage on the electricity networks. There were also some disagreements with the assumption that storage has more locational flexibility and is therefore able to better react to pricing signals. Another response saw the proposals as an improvement on current arrangements, but the issue only existed because of the variations between demand and generation, which would disappear if both were treated the same. One response could identify with storage applicants who may express frustrations if their reinforcement was chargeable as a result of this treatment in cases where the network constraint is based on the demand aspect of the storage asset.

2.67. It was suggested by one response that the consultation proposal was not clear, and that paragraph 2.128 seemed to contradict the statement that storage will be treated as generation. They asked if this were the case then why would import be considered and asked for examples to be provided for different reinforcement scenarios.

Q2f – Do you agree with our proposals regarding the treatment of in-flight projects (i.e. that they should not be permitted to reset their connection agreement and retain their position in the queue), noting they retain the right to terminate and reapply from 1 April 2023 should they wish to be treated under the proposed connection charging boundary?

2.68. A significant majority of respondents (16) were supportive of our proposals, with seven expressing disagreement or mixed views. Amongst the responses that were supportive, a range of reasons were given. One response noted that allowing projects to reset and retain their position would simply allow investors to benefit from lower reinforcement costs at the expense of DUoS bill payers without any risk to themselves. Other reasons included that the proposal was consistent with the ENA queue management policy, which is already familiar to connecting parties, and that allowing inflight projects to reapply with the same queue position would effectively be backdating the implementation date. Another suggested that accepted schemes should already have an investible business case and therefore are likely to be constructed regardless of the changing regulations.

2.69. Two respondents agreed with our proposals, but only on the basis that projects were not charged for reinforcement twice (through connection charges and through ongoing DUoS charges).

2.70. There were also a number of reasons put forward against our proposals. One response disagreed because they argued it was important that customers have the opportunity to adjust their capacity in response to high fixed TCR charges and/or for an agreed reduction in firmness without having to go to the back of the queue. Another suggested the approach would only work for sites where a queue exists. They explained that a site losing its place in a queue order to get a requote would not provide an incentive where no queue exists.

2.71. Two respondents noted there was a need for the new connection charging arrangements to recognise the wider benefits of a customer who wishes to retain their position in the queue. One of these specifically highlighted the adoption of LCTs, warning the proposal could potentially delay the deployment of EV charging points at a crucial point in the roll-out of EVs.

2.72. Another two responses highlighted the importance of making customers aware of the impacts of cancelling and reapplying. Customers should be made aware that any costs already incurred by a cancelled in-flight project would not be refunded, while the another felt that customers should be able to make an informed decision on the trade-off between lower costs from the new arrangements and a longer time to connect due to the potential influx of new connections. They added that there should be a transition process to prevent unintended negative impacts on connecting customers that seek connections for their in-flight projects.

2.73. One response highlighted that some connection offers will require reinforcement works to be undertaken in the medium to longer term. They argued for longer term works to be requoted under the new methodology.

2.74. Another argued that the end consumer would pay for the discrepancy between generators having vastly different costs but located very close to each other simply based on when they applied through wholesale costs and inefficient dispatch. They suggested that for this to be enforced then Ofgem should provide assurance that projects would not pay for the same reinforcement through connection charges pre-April 2023 and later through DUoS charges.

Q2g – Do you agree with our proposals to retain the existing arrangements for managing interactive applications? Do you agree with our proposals on the treatment of unsuccessful applicants (that the connection charges at original application date will continue to apply if queue position is retained)?

2.75. Fifteen of the responses we received expressed support for our proposals, although some support was contingent on other factors. One respondent agreed on the basis that the original details of the application did not change, arguing that allowing these changes to apply retrospectively would distort the interactive rules and give a clear advantage over later projects. Another also raised concerns that the proposed treatment of in-flight connections could distort this process. They reiterated one of their previous responses, saying the approach would only work for sites where a queue existed.

2.76. Another agreed although they did not believe the connection charge policies should be grandfathered and that if the re-offer was issued after April 2023, then the new policies should apply. They noted that it often isn't the desire of a developer to go interactive, nor is there much visibility of it, so they did not think it was something that could be gamed. One response agreed but the arrangements may need to be reviewed in future.

2.77. Two responses expressed disagreement. One noted that while a site may have the advantage of queue position, they would be at a disadvantage in that they lose on interactivity and would then be expected to require reinforcement for their connection. They added that the result of this decision would be that anyone who lost interactivity may be forced to reapply as they could be funding reinforcement under the old scheme otherwise.

Q2h – Do you agree with continuing with the definition of the Minimum Scheme as currently set out in the CCCM? Do you believe this definition requires any further clarification or amendment, and if so, why?

2.78. There was a significant amount of support for our proposal, with two thirds (12) of respondents expressing agreement. Reasons for this included that the Minimum Scheme sets an important reference against which existing and future schemes can be assessed to ensure customers are treated in a fair and consistent manner; the current definition provides a useful benchmark and has been an important component of connection charging for several years; it is still relevant and broad enough to encompass the inclusion of flexibility services and their associated costs as part of the

Minimum Scheme; it would lower reinforcement costs for DUoS bill payers while enabling low-cost connection for demand customers; and it will help DNOs deliver their wider obligations to develop an efficient network. Another respondent agreed given the nascent market for flexibility.

2.79. Other respondents agreed with the proposal but suggested some additional elements be included. One asked for more transparency on the costs used by DNOs to calculate the Minimum Scheme, particularly in relation to their reinforcement and also contestable costs that could be cheaper with a competitive provider. They added that there also needs to be reconciliation on the definition of an ANM connection providing the Minimum Scheme. Another agreed with the current definition of Minimum Scheme, but in the context of net zero and renewables, suggested a move to a regulatory framework that helped to anticipate investments rather than setting out actions only for when reinforcement is triggered. A third respondent said the Minimum Scheme should include all reinforcement costs and that the Minimum Scheme should make better use of flexible services.

2.80. One response raising potential concerns with the current definition thought that the definition of Minimum Scheme was generally okay but that there were examples of DNOs applying it in inappropriate ways to suit their own purposes.

2.81. Another respondent disagreed because they argued the reforms implied generators may be required to pay a premium to save reinforcement costs elsewhere, but demand would be shielded from this. They argued that generation connections should be charged the cheapest cost of connection.

2.82. A third respondent gave us an example of where the definition may not be appropriate. They noted that the Minimum Scheme for large-scale connections now involves a dedicated 132kV feeder back to a GSP, although the site may have been selected due to an on-site 33kV overhead line. This could be due to the 132kV infrastructure between the GSP and Bulk Supply Point (BSP) being overloaded, making it cheaper to run a dedicated feeder than upgrade existing lines. They argued that even under the new shallow charging regime, this would mean the 132kV lines would never be upgraded, and the development would not go ahead. They suggested there should be some preference given to expansion of existing networks rather than the high costs for each single connection. They explained that it was highly unlikely that the additional capacity unlocked by this would be wasted due to the large demand for low carbon generation.

Q2i – Are there any risks associated with our proposals to allow current non-firm connected customers to seek a firm connection following the changes proposed by our SCR? Do you agree that existing non-firm connected customers that do seek a firm connection should be processed through existing queue management processes as determined by DNOs?

2.83. We did not receive any comments against our proposals, The most common reason for support was that both new and existing customers should be treated in the same way and that not doing so would be discriminatory to existing non-firm customers. Another response noted that whilst non-firm customers that seek to become firm may lead to scheduling issues for DNOs, but that preventing these applications for a long time would be disproportionate. A separate response highlighted that existing customers looking to be made firm are still requesting new capacity requirements from the DNOs, and so should be treated and charged as new connections.

2.84. Some respondents expressed support but suggested additional points. One noted that they agreed and that existing customers should be able to have the connection type that best suits them but should not be given priority over new connections.

2.85. It was raised by one response that the trade-off between flexibility and a cheaper/quicker connection has been impossible to quantify under historic non-firm connection agreements. Therefore, they suggested these customers should be given the opportunity to regain their flexibility and, if they wish to offer this back to the DNO again, to be able to do so through full price discovery.

2.86. One response noted there is always a risk that a changed regime will offer benefits to certain customer groups.

2.87. The main area of concern, raised by five respondents, was that a sudden increase in connection applications as a result of these reforms in general may put a significant strain on DNOs' resources and abilities to process applications and complete reinforcement works within the required timeframes. Two of these responses noted that this could be exacerbated by also allowing existing non-firm applications to apply to be made firm but did not say this should stop them from doing so. One respondent suggested Ofgem should expect a significant decline in DNO performance for at least three months from 1st April 2023 based on the updated minded-to position, due to the influx of applications. In addition to the strain on DNOs, one respondent noted that a significant increase in applications would also put an administrative strain on the ESO's connection team.

2.88. Two responses noted there was a risk of increased burdens on DUoS bill payers as a result of the proposals.

2.89. Three responses asked for additional clarity on elements within the proposals. One asked for clarity that it was only the 'firmness' that takes a place in the queue, and that in the interim a site would contribute to maintain a non-firm connection until firmness was offered. Another argued the existing queue management policy may benefit from further clarity and for a common understanding across DNOs of what non-firm and firm connections might be, and how this might compare or align with those definitions of non-firm and firm connections already adopted at transmission. This respondent also noted that any process used to assess non-firm to firm connection applications should apply a consistent baseline.

2.90. One respondent suggested it was right for DNOs to know which non-firm schemes want to become firm in order to make appropriate strategic reinforcement decisions.

2.91. Another asked that where assets are already in the connection queue on a non-firm basis, that they are able to maintain their current position in the queue with a non-firm connection, but also able to add a request to convert to a firm connection to the back of the queue, ie not having to wait until a project is commissioned on a non-firm basis in order to apply to join the queue for conversion to a firm connection.

Q2j – How necessary do you consider intervention in Electricity Distribution Standard Licence Conditions 12, 15 and 15A? What duration might such measures be needed, or acceptable, following 1 April 2023? What value do you place on certainty of connection timeframes compared with time to connect?

2.92. There was a split in opinions on whether intervention should be made in relation to SLCs 12, 15 and 15A. Seven respondents were in favour of derogations or suspending elements of these SLCs to allow the DNOs additional time to process connection applications. All but one of the supporting responses were submitted by DNOs as they expected an increase in connection applications after the expected implementation date of 1 April 2023. However, another respondent believed that while the proposals might lead to an increase in applications after April 2023, other factors could also contribute to applications timing (eg business rates). Five respondents would like to see temporary derogations in place for at least one year, again all of which came from DNO responses. One of these said this should not cover the Connections Guaranteed Standards and that any derogations must be communicated to stakeholders so they can understand the impact on acceptance timelines.

2.93. Two of these offered specific recommendations on what should be done to the individual licence conditions. One recommended derogating against SLC15 and 15A for at least a year. The other suggested suspending SLC 12 for a year, and for SLC15, requirements 15.3(b) and 15A.2(f)should not apply in 2023/24.

2.94. Another respondent suggested that, given the timescales for SLC 12 and SLC 15A extend to three months (65 days), six months would be the minimum period from 1 April 2023 worth considering in order to provide any tangible relief.

2.95. One respondent called for Ofgem to consider delaying the start date of the ED2 targets until 2024/25 to take account of a potential surge in applications and ensure that ED2 targets take into account any enduring increase in activity volumes.

2.96. There were a number of reasons put forwarded against intervention in relation to the SLCs. Three respondents cautioned against pre-emptively intervening as the scale of the impact was not yet known, with two of these suggesting that if the surge in requests does not materialise it would represent unnecessary delays to connection timescales. One called for a more flexible approach to managing the issue.

2.97. Another respondent felt it was not clear that unilateral relaxation of these licence provisions was appropriate. They therefore proposed that the current licence requirements are maintained, but that DNOs engage bilaterally with Ofgem if they find themselves unable to meet the required standards.

2.98. Three responses highlight the potential impact of interventions on the customer experience, with one noting their current belief that times to connect are already too slow. One of these responses understood the concerns of the DNOs in relation to these conditions but believed that any intervention will have consequences for customers. They added that wherever possible timescales should be maintained and if deviation is needed this should be as time bound as possible. A number of responses argued this risk should be mitigated by DNOs through other measures. Another of these warned that an increased timeframe would slow down the roll out of renewables and instead suggested further funds should be made available to the DNO to use more resources to solve the problem. They added that if absolutely necessary a surge in applications could justify some kind of temporary grace period, but Ofgem should note the existing pressure the DNOs are under and have a more permanent resourcing solution.

2.99. One respondent also called for any relaxation of the DNOs' licence conditions to only be temporary. They argued that at the moment, DNOs tend to use the maximum time limit as a target and very rarely quote earlier than this.

Q3a – Do you agree with our proposal to exclude customer interruptions and transmission constraints from the definition of curtailment with respect to distribution network access arrangements?

2.100.Approximately three quarters (20) of respondents expressed agreement or partial agreement with our proposals. Reasons given for agreement included that interruptions are already covered by DNO incentives; both firm and non-firm customers are at risk of supply interruptions; and that issues on the transmission system are not in the control of licensees. Another respondent said that including customer interruptions and transmission constraints would reduce the control that the DNO has over the customer's constraint and would result in DNOs inaccurately estimating the number of curtailment hours a customer may be subject to. They added that this is likely to have negative implications for customers and distributors so did not believe that it was in the interest of anyone to include such events in the definition of curtailment.

2.101.A separate response noted that setting out agreed limits to the level and duration of curtailment would provide predictability for customers and set a quantified standard by which the wider distribution network can be developed, whilst still enabling the quicker connection of new demands and generation. As such, they suggested focusing on curtailment limits on actions under the control of the DNOs, which are not already incentivised. Two other responses also argued that the definition of curtailment should only include factors that are under the DNOs' control. One of these added that it should be the responsibility of the DNO to prove that curtailment was due to an event outside of their control so that these exemptions are not abused.

2.102.Three respondents agreed but raised points of consideration. These included: noting that there can be distribution curtailment as well as transmission curtailment and both of these factors are considered by developers when deciding if a project is viable; that transmission constraints are increasing significantly and impacting projects on the distribution network and that these constraints should be fully compensated in the same way as transmission connected generators are; and curtailment, regardless of cause, has a customer impact and so DNOs and the Regulator should be aware of the total picture.

2.103.Five respondents agreed subject to additional elements being factored into the proposal. Two of these flagged that the proposal would need to be monitored going forward. One said this was in relation to whether distribution connected generators are charged TNUoS, while the other mentioned it should be done to ensure interruptions and transmission constraints do not start to materially contribute to distribution connected generator curtailment.

2.104.One response suggested that for customer interruptions the new arrangements would only need to cover circumstances where known constraints lead to the need to restrict a user's access to the system and price control arrangements, such as the Interruptions Incentive Scheme and Electricity Guaranteed Standards will cover scenarios where loss if supply occurs.

2.105.Three respondents agreed that interruptions should not be included within the definition of curtailment, but that transmission constraints should be. One of these responses noted that in some cases transmission ANM forms the biggest part of a customer's ANM curtailment. Therefore, they argued, not including this transmission element would be moving away from an open and transparent way of DNOs communicating with customers. The second response reiterated the impact of transmission curtailment. They suggested that rather than excluding transmission system needs when defining curtailment at distribution, it may be beneficial to focus on identifying the actions taken to operate the transmission system, and the various drivers for these actions. The third understood that customer curtailment was covered by guaranteed standards of performance (the Guaranteed Standards of Performance (GSoP) but did not accept that transmission constraints should be similarly excluded. They suggested that it would be discriminatory to ignore the effect of transmission constraints that affect distributed generation.

2.106.Eight responses disagreed with our proposals. One argued they would mean the DNOs would not be taking responsibility to do anything about customer interruptions and generators would continue to face unjustified and unquantified risks. They also disagreed with excluding transmission constraints from the definition. They acknowledged that what happens on the transmission network may be outside the DNO control, but, in their view, this is also outside the control of the generator. Therefore, it was unclear why the generator should take the risk. Another response gave a similar view, saying this proposal would not place the risk in the right place. They said that regardless of the cause, a customer should have a right to a fixed limit of curtailed hours under our proposed better defined access rights. If this were exceeded as a result of issues further up the network, the customer should still be compensated and then it should be between the DNO and the TO to negotiate who bears this cost.

2.107.Two responses highlighted that transmission network-related constraints cause a major disruption to distribution connected generators and result in delays for projects in the connection queue. One respondent said constraints on the transmission network should be considered curtailment but would agree if it was due to a maintenance issue. They added that closer interaction was needed between DNOs and National Grid to understand these expected levels of curtailment, as for a customer the source of the curtailment is irrelevant.

2.108.One response was concerned that excluding customer interruptions would result in a significant level of uncertainty on developers. They argued that at transmission level, generators are made financially firm as a result of interruptions so there would be no level-playing field with distribution. They added that assessing the probability of future curtailment was currently very difficult for developers as DNOs do not give details on why a particular line has historically been taken out of service. On transmission constraints, they noted that a DNO can do little to prevent them, but the same went for generators. They noted that where DNOs hit generator curtailment limits, they are able to procure flexibility services from the market and then recoup costs, but generators have no route to recoup costs. Therefore, they argued, DNOs should bear this risk. They added that the simplest solution would be to introduce financially firm access rights at distribution level as at transmission.

Q3b – Do you agree that the curtailment limit should be offered by the network based on maximum network benefit and agreed with the connecting customer?

2.109.The responses to this question highlighted that some respondents were seeking further clarity regarding some of the phrases used. Two respondents were unclear of what 'maximum network benefit' meant, with one adding that the phrase 'agreed with connecting customer' implied a degree of negotiation that was not practicable. The other suggested that curtailment limits should be based on the maximum likely availability of the network for non-firm users, and that the limit should take into account the current and future connections that are causing the constraint, and the extent to which that constraint will materialise throughout a given year.

2.110.Another two responses said the definition and methodology to determine 'maximum network benefit' needed careful consideration. One warned the definition could result in non-firm customers being excessively curtailed and suggested that DNOs should look to find other flexibility solutions to tackle the bulk of the constraint and only look to use agreed curtailment afterwards. The other respondent said there was a key outstanding question of how the wider network benefit is calculated. This should include the cost of constraints to the customer and the carbon benefits if it was renewable generation, as well as considering the wider security benefits to the network of having curtailment agreements or flexibility agreements in place. The link with carbon impact was raised by another respondent, who suggested that prioritisation for which sites are curtailed should reflect network benefit, but also consider the carbon impact.

2.111.Overall, there was broad support for our proposals, with only one respondent expressing significant concerns with the DNOs determining the curtailment limits. This respondent was concerned that the development of curtailment limits was proposed to be taken forward through bilateral discussions between the DNOs and Ofgem, with no direct involvement of users. They were worried that this may mean the agreement of the connecting customer could be a take it or leave it offer from the DNO.

2.112.Reasons of support for DNOs determining the curtailment limit included that an agreed curtailment limit would help ensure the bankability of new connections and also provide an effective investment signal for DNOs when those curtailment limits have been exhausted; and that it would ensure customers get an accurate view of the expected curtailment for their connection in their offer, enabling them to make an informed decision based on their specific needs. Some called for a time limit on producing curtailment reports as they believe DNOs face delays in producing them. One response argued that curtailment limits should give the connecting customer a clear indication of the maximum level of curtailment that a connection should expect ahead of the completion of efficient network development. Another respondent agreed with our proposals, but only if the customer was requesting a firm connection offer.

2.113.Three respondents agreed with the proposals in principle but highlighted operational considerations and further questions that will need to be addressed.

2.114.Another felt that realistic curtailment limits will be heavily dependent on the presence of existing non-firm arrangements in affected network areas. They stated that existing ANM connection agreements involve curtailment on a last-in-first-off basis, meaning that any new customer connecting to an affected network will be required to be curtailed ahead of any existing customers. The third response agreed but that curtailment limits should be backed up with robust data provision and network information sharing.

2.115.One response agreed with our proposals but noted that the defined process for agreeing the curtailment limit should not be an item for prolonged debate in modification working groups. They therefore requested a position be clearly set out in the SCR Direction.

2.116.Two respondents raised concerns over measuring curtailment on a % of time in a year basis. One argued this would be unhelpful and recommended instead measuring the curtailment seasonally, (e.g. the number of hours per season). The second also expressed a desire for more granular information to be provided to generators and that the number of hours per season would be more useful than number of hours per year. They added that published DNO circuit ratings are seasonal, so there would be little additional complexity for a DNO to implement a seasonal approach, and that an indicative breakdown of the year-round contractual figure would provide significantly more value to customer. They also suggested more information be given on when in the day curtailment is likely as this is key for renewable generators such as solar PV, where curtailment at night is less material than curtailment during the middle of the day. They instead suggested defining the curtailment limit by volume (i.e. MWh/kWh limit), or to use a metric based on load factor or expected volume.

2.117.One response said that curtailment limits should be set using a deterministic process, adding that reinforcement or flexible solutions would normally be undertaken to ensure networks remained within their firm capacity when the customer connects. Another suggested that larger network users should be provided the option to choose between clearly defined interruptible access, time profiled access and financially firm access facilitated by flexibility markets and or the Balancing Mechanism.

Q3c – Do you have any views on the principles that should be applied to ensure curtailment limits are set in a consistent manner

2.118.We received a number of suggestions on the principles that should be applied to ensure curtailment limits are set in a consistent manner. Four responses noted that it was important that the methodology used could be applied in a standardised manner across all DNO regions. One of these added that it was appropriate for limits to be set under the overarching principle of maximum overall network benefit and that any baseline curtailment limits would need to be considered from a whole system perspective, it should also consider the ESO’s requirements for access to a liquid market where it can readily procure flexibility services from distribution connected parties. Another said it should be calculatable in timescales that meet connection offer timescales and should use available data. A fourth response suggested this should be defined and agreed by DNOs through Ofgem-led working group activities.

2.119.One response mentioned that an approach to set curtailment limits in a consistent way would be to use a similar approach to that used in the Common Evaluation Methodology. Another noted that the process to determine curtailment limits was being developed within the Access Rights Implementation Group and at a minimum the final SCR Decision should include the principles to set curtailment limits. They warned that if this was not very clearly defined at this stage and if it was referred for definition within the code change Working Groups the development stage could take significantly longer than currently allowed for in the implementation plan.

2.120. Another response noted that there was a fine balance between ensuring consistency and allowing innovation and bespoke offers and that each DNO may have unique conditions on their network. They argued that developers should be able to expect consistent terms and contractual arrangements between DNO areas to reduce the risk of unnecessary administrative burden, or the risk of regulatory arbitrage between DNO areas. They added that customers should know at the time they make their investment decisions when they are likely to be curtailed and it should never come as a shock.

2.121. Two responses highlighted the importance of simplicity, with one arguing that a simplistic annual number of hours/percentage of time level was not sufficient to define the curtailment allowance that a customer may face without this being defined to a more granular level by season and time of day. Two also argued that limits must be computed in a clear, transparent, and predictable manner, in order to balance the need to set a meaningful limit without limiting the efficient and strategic development of a network. One added that curtailment limits should exclude events beyond a DNO's control.

2.122. It was highlighted by two other responses that curtailment should take into account the availability behind the constraint and use load curves to determine the probability of a customer being curtailed.

2.123. One respondent suggested that the same principles should apply to both distribution and transmission constraints. Another added that the definition of curtailment should align with a typical approach to DNO/DSO operation, for example it should take into account seasons aligned with system operation and asset ratings. They added that they strongly encouraged the DNOs to review their current approach to forecasting of curtailment for new generators and, in particular, storage connections. They explained that current practice is for DNOs to assume "worst case" network conditions at all times and then provide an estimated forecast of curtailment on that basis. This, they argued, was overly conservative and likely to be completely unrealistic, particularly in the case of storage, which is likely to operate in a manner that helps management of network constraint rather than exacerbate them. They added that the current practice is hindering investment in essential new net zero assets.

2.124. A separate response also called for reform to existing DNO practices. They suggested that as part of its SCR Decision Ofgem should require DNOs to phase out and replace current ANM areas with the newly defined access rights. They argued that the continuation of ANM areas would mean that the full benefits of the proposed reform will not be realised and that ANM areas will continue to hide the true costs associated with network congestion, dull signals for network reinforcement and stunt development of flexibility markets.

2.125.One response suggested that the process to setting limits should include the input of the generation community to ensure they make an appreciable difference in terms of investors signing up to risk at the beginning of scheme development. Another expressed that curtailment limits should be negotiated with the customer as to the level that they believe their project remains financially viable. They suggested that curtailment in addition to this should be procured via wider flexibility markets. They warned that without this there was a risk of continuing the current approach, which sees one customer absorb the cost of curtailment and lack of network investment. A third response suggested that the approach to setting curtailment limits should also involve consideration of numbers of future customers to be accommodated as a lower allowance for future connections will mean lower curtailment limits and accelerated network reinforcement and vice-versa. They added that curtailment setting principles should also include consideration of existing flexible connections and the current/future potential for demand side flexibility services.

2.126.One response raised concerns that distribution network operators will be cautious in how they calculate and offer curtailment limits. They warned this may lead to some projects being considered not viable and not going ahead, slowing progress to net zero, and asked how we proposed to mitigate against this cautiousness.

Q3d – Do you agree with our proposal not to introduce a cap for flexibility payments made should any curtailment in excess of agreed limits be required?

2.127.There was a split in opinions in response to this question, with just under two thirds (17) of respondents who answered agreeing with our proposal to not introduce a cap for flexibility payments.

2.128.The most common reason given in support of not having a cap was that it would send the appropriate signals to DNOs in relation to network reinforcement, flexibility procurement and operational practices. Two of these believed that the lack of cap would incentivise the DNOs to produce more accurate forecasts, with one adding it would also incentivise the DNOs to seek out additional flexibility and to build sufficient network capacity. This respondent added that there is a balance to be struck between constraints and new capacity, and that there should be an incentive around payments made when curtailment limits are exceeded. The other added that there was a risk that the lack of cap may introduce a 'factor of safety' and inflate the curtailment limits, which may prevent developers from accepting offers.

2.129.It was also suggested that DNOs should be disincentivised from using curtailable customers as 'free flexibility' that they can use to alleviate a network problem. This respondent added that exceeding the agreed limit would be breaking the connection agreement and as such penalties should accrue. Setting a limit on those penalties may give the DNO an opportunity to take advantage of the non-firm customer should the cost of correcting the network issue be higher than the cap. They argued that this should not be an option for the DNO.

2.130.Another response argued that high flexibility charges would give the DNO an appropriate signal to reinforce, rather than continuing to make high flexibility payments. They added that putting a cap in place would give the DNO false signals as to the cost of curtailment.

2.131.Three respondents put forward comments in relation to the way prices for curtailment above the agreed level should be determined. Two believed that prices for flexibility services should be informed by the market and not impacted by caps, with one of these saying they would like to better understand how DNO costs associated with market-based curtailment are reported and allowed. The third respondent suggested that the back stop for the exceeded curtailment payments should be the cost of the reinforcement.

2.132.Four responses highlighted the impact a cap may have on the development of flexibility markets. One argued that the lack of cap was appropriate because flexibility markets are still developing, and the degree of risk to the customer associated with uncapped cost of procuring additional flexibility is not material. Other comments in support of not having a cap included that this should be part of developing a local flexibility market and DSO role; Ofgem should be looking to encourage procurement of flexibility on longer timescales and a cap on flexibility payments would distort this developing market; and it would open up flexibility markets to intermittent generation. This last respondent added that the use of cap should be kept under review to ensure that payments are providing benefit against conventional reinforcement. A separate response also suggested the use of a cap be kept under review as new flexibility markets appear, or fail to appear, as anticipated.

2.133.Another response argued the proposal seemed sensible and would ensure that the DNOs' liability for costs associated with unforeseen curtailment is not limited. They added that not applying a cap would reveal the need for additional system spend (either infrastructure investment or DNO OPEX) and would help to stimulate a growing flexibility market at low risk to the consumer too due to the early stage of those flexibility markets.

2.134.One response supported not having a cap because it would place non-firm customers on an equal footing with other customers once their curtailment limit has been reached.

2.135.A recuring argument for implementing a cap was that not doing so would expose DNOs to an uncapped level of liability, which would result in increased costs for DUoS bill payers. Two respondents warned that the price demanded by flex providers who were aware they were the only solution could far outweigh any economic assessment of the value, and one argued that prices offered should reflect the economic and efficient value of operating the distribution system. They added their belief that not having a cap would undermine the practical application of the reforms as curtailment limits may need to be set conservatively in response to the risk. The other suggested that Ofgem’s proposal could make it financially more lucrative for customers to find areas where they will be curtailed, which is not consistent with Licence Condition 32E.

2.136.One respondent was concerned that the proposal not to have a cap did not reflect the risk associated with the wider proposed arrangements and suggested it was likely to lead to unintended customer behaviour and a risk of higher costs for DUoS customers. Another noted that in certain areas flexibility may not be readily available due to a lack of a viable market or due to low liquidity in constrained areas. This could result in DNOs regularly exceeding curtailment limits, with these costs ultimately passed onto consumers through DUoS.

2.137.One response believed a backstop arrangement with the customer would be in the interests of both the customer and the DNO and could be updated to remain reflective of market conditions. They added that while they were in favour of a cap, they agreed that DNOs should procure flexibility from the market when reasonably possible to do so and suggested that DNOs could publish backstop price from time to time to ensure transparency.

2.138.Three respondents expressed mixed views. One respondent understood Ofgem’s reticence to set payment caps as this may undermine the nascent flexibility markets. However, they also called on Ofgem to ensure there are sufficient safeguards to protect the wider body of customers from extremes of prices.

2.139.Another noted that a cap is an artificial limit on the DNO being required to pay a connection customer, but this is linked to the time for which a connection will be non-firm. If the customer has a non-firm connection for longer because the reinforcement has been deferred or more strategic works are taking place, then, they argued, there should be no cap on the payments beyond the agreed limit. However, they added, if the reinforcement is undertaken at the time of the application and the customer is already getting the benefit of a quicker connection without the disbenefit of waiting for the reinforcement, then it seemed that limitless flexibility payments are providing additional benefits to the customer beyond the purpose of these changes

2.140. Another response thought the proposals were in line with how networks with firm connections are treated where load growth occurs and that higher flexibility procurement costs will accelerate the requirement for "traditional" asset reinforcement. They added that having no cap is suitable where there is a liquid demand side flexibility market but urged caution in areas where this is not the case, saying it may be appropriate to consider a cost cap in these areas.

Q3e – Do you agree with our proposal to introduce explicit end-dates for non-firm arrangements? Are there any mitigations for DUoS bill payers we should consider?

2.141. This proposal received support from the vast majority (20) of respondents. Three responses highlighted that having explicit end-dates for non-firm arrangements would help distribution network operators to plan network investment and develop the most suitable solution to make the customer firm. One of these also said explicit end-dates would provide certainty to customers on when their connection will be made firm. Another response suggested that end-dates would ensure that the DNOs undertake the reinforcement.

2.142. One response said that end-dates are needed to maintain the bankability of new connections and to preserve a signal to invest. Another respondent agreed with the proposals and suggested that not meeting end dates should trigger compensation by the DNO to the customer. They added that this cost should be for networks to manage potentially by procuring flexibility. Another response added that having end-dates would be a way to improve the process set out in DCUSA.

2.143. It was suggested by one response that explicit end-dates were a way of creating a broader approach to exiting the use of ANM to manage constraint and instead towards using fully technology-agnostic markets. Another response suggested that end-dates should not be agreed with customers, and instead should be standard from the date of energisation.

2.144. One response said that explicit end-dates for non-firm access arrangements would be an important factor for users to understand how their connection would fit their needs. They also agreed that explicit end-dates should be provided to users as part of their connection offer. Another response suggested that curtailment was likely to increase as more generators connect.

2.145.Eight responses were supportive of the proposal but raised additional points of consideration. Four of these were in relation to customer engagement when setting end-dates, with two of these highlighting that explicit end-dates should only be given if a customer has requested a firm connection. One of these added that end-dates should only apply where any shallower or costs over the HCC had been paid, and that end-dates should be designed to ensure efficient network design, as well as giving customers certainty. One respondent supported having end-dates, provided customers that were happy with a non-firm connection could keep it without being required to make it a firm connection. Another suggested that the user should be able to elect to maintain a non-firm connection until such time as an application for firmness was made. They also suggested considering DUoS reductions when a user consents to an ongoing non-firm connection.

2.146.It was suggested by one response that a customer accepting a non-firm connection may at some point want to review this decision, and that without a clear review date, customer inertia may allow this situation to persist indefinitely.

2.147.Another response highlighted the lack of clarity around what happens if a customer does not accept a non-firm connection and how long it might take to get the reinforcement completed and connected. They argued it was not reasonable to ask for a connecting customer to be curtailed indefinitely due to a constraint on the network.

2.148.One response agreed with the proposals, but questioned whether, if sufficient capacity was not provided to allow the transition from non-firm to firm, it was right that flexibility payments fully flowed through to the end consumer, or if the DNOs should bear some of this risk.

2.149. Four respondents raised concerns with the proposal. One said there may be some difficulties with how this is applied and how the DNOs may use this to dump costs. They added that curtailment should be used as a proxy signal for where network assessment is needed. They suggested a good approach would be to replicate the Network Options Assessment (NOA) process, where the DNO has the costs of curtailment, which could be balanced off with the costs of reinforcement.

2.150.Another warned that where non-firm arrangements are in place pending asset reinforcement works, explicit end dates present a risk where factors out of a DNO’s direct control affect construction timescales. They added that if explicit end-dates meant DNOs were required to procure flexibility to overcome curtailment then such time delays would result in increased costs. They suggested that making non-firm agreement end-dates contingent on specified works being completed would avoid this risk.

2.151.Two responses suggested that the challenge with setting end-dates was it is not natural to link ongoing non-firm access to one-off connection charges. They therefore suggested that an alternative approach would be for there to be a reduction in ongoing DUoS charges for as long as the non-firm arrangements are in place.

Q3f – Do you have views on whether the end-dates should take into account only current known or likely works, or if it should allow time for wider developments to take place

2.152.Nine respondents said that end-dates should only take into account current known or likely works. One of these supported the establishment of a standardised approach to agreeing non-firm access end-dates but warned that linking them to "other developments to take place, which may or may not materialise in practice" would significantly undermine the bankability of non-firm connections.

2.153.One response argued that end-dates could only logically be placed on known or likely works and should be as soon as practicable. Two responses felt that only considering known and likely events was better because the certainty would be valuable, with one adding that developers have to take the worst-case scenario and evaluate investment based on that. Another response would like to see end-dates take account of the likely timescale for the specific known reinforcement works to be designed and completed but should not allow time for DNOs to delay in their decision making.

2.154.It was highlighted by one respondent that given the amount of change underway in the industry and new approaches to energy use to achieve net zero, incorporating other potential developments was unlikely to be the most efficient method. They argued that it also risks giving rise to informal 'arrangements' for developments that have not reached the appropriate stage that prioritise them over other developments and presents a risk to transparency and fairness. They added that if relevant developments come into play, they should be assessed based on their impact to the existing network, not have the network prepared for them in advance.

2.155.Another response expressed the DNOs will have, or be able to get, a clear picture of the likely development in an area and should be proactively taking steps to ensure that reinforcement is undertaken in a timely way for all those customers. They clarified that this does not mean that they should wait for additional customers which are not reasonably foreseeable. They added that it was not in the interests of connection customers to have a predefined or set time period for wider works to be done where no such works are likely to be required and suggested that it would be important for the DNO, as part of their network planning processes and Long-Term Development Statements, to be able to understand the likelihood of additional work in their area and only to delay the connection of one customer where it is demonstrably in the interests of the wider customer base.

2.156.One respondent said 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. They added that while a pause to consider or wait for potential additional needs to be communicated may allow more efficient solutions to be delivered, we believe the risk of unnecessary delays to known connections outweighs this.

2.157.Four responses argued that end-dates should also include wider developments. One argued that if wider developments were not allowed for, there would be no benefit from these reforms, and instead there would just be a transfer of costs from new customers to existing demand customers. They added that having end-dates would act as a balance to give some time to allow wider developments but not indefinitely.

2.158.It was acknowledged by one respondent that this would be the riskier option, but it would allow greater scope for strategic investment in reinforcement and flexibility in response to projected levels of demand. Another highlighted that it was important that this process worked within development of local flexibility markets to help DNOs manage risks and reduce costs.

2.159.One response thought there was merit in allowing wider developments to be taken into account and suggested that the customer moving from a non-firm to firm connection should be compensated in some way if the end date was not met. They added that if the DNOs cannot accurately forecast these wider developments it did not bode well for anticipatory investment. However, they added, it would be better to make all distribution connected users financially firm. They believed this would mean users could continue to be curtailed according to economic merit in order to optimise the balance between network reinforcement versus the cost of ongoing congestion management.

2.160.Three other responses also put forward suggestions for alternative approaches. One suggested the DNO ought to be given scope to allow end-dates to take into account wider developments in order to protect DUoS bill payers from paying for suboptimal solutions. However, they agreed that this should be done in conjunction with the customer so that they understood the trade-off between lower DUoS charges and the risk that their firm connection might be delayed. Another believed that the calculation of end-dates should also take into account the development of flexibility markets in the area, not only timescales for reinforcement. The third respondent was supportive of the position that end-dates should be agreed between DNOs and customers and suggested that the principle should be that the connection is made firm as soon as it is practical to do so. They also suggested that there should be a standard maximum length of time that can be applied to non-firm connections that are seeking to be firm, which should be agreed between DNOs and Ofgem. They recommended this be 3-4 years.

2.161.The other comments received included: flexibility should be retained in each specific application; not all customers will need or want an end-date to their defined levels of curtailment and that dates should be adjusted to reflect things reasonably outside of the distribution network operator's control; and that end-dates should be kept under review as part of an ongoing conversation when known works that could mitigate constraints are planned, if there are none at the outset.

2.162.One response recommended that both distribution and transmission network requirements were considered. They argued that distribution connections now influence the transmission network, so the wider works should include both networks, and that improvements could be made communicating these works between the developer, DNO and NGESO to obtain accurate end-dates.

2.163.Another response agreed with the principle that the date should be negotiated between the DNOs and customers, but that they understood the dilemma and that it was difficult to be prescriptive.

Q3g – Do you have any comment on our proposal not to further define or standardise time-profiled access arrangements?

2.164.There was a significant level of support for our proposals not to further define or standardise time-profiled access arrangements. The majority (9) of responses on this related to the Access SCR final Decision being the wrong time to intervene in this area. Four respondents highlighted that this should be taken forward as part of the separate DUoS SCR, or that these potential changes should wait until after the outcomes of these reforms are known. One added that this should not explicitly prevent DNOs from connecting customers quicker whilst utilising time-profiled access arrangements with the appropriate monitoring and enforcement in place. Another noted that in specific cases where customers are able to avoid a connection charge or reduce the need for reinforcement (ie where a customer breaches HCC but is able to move their load) then it could be catered for on a bespoke basis. This view was shared by another respondent, who believed it seemed sensible to leave the definition of time profiled access to agreement between the customer and the DNO. Another response noted that DNOs are already offering these types of access arrangements.

2.165.Four additional responses highlighted that changes at this point would have little or no benefit, with one adding that it would be better for customers and DNOs to agree arrangements that fit specific circumstances. Another argued that standardising the approach may in fact limit bespoke arrangements that could work for both customers and DNOs. Another felt it may be more appropriate to revisit standardised time-profiled access arrangements when MHHS is fully established and flexibility and behavioural responsiveness at distribution level is better understood. They added that regardless of the proposal there are some DNOs which may already be utilising time-profiled access arrangements to manage their networks. Another respondent also thought it was too early to define or standardise time-profiled access arrangements, but that this may need to be revisited depending on the rate of progress made by the DNOs in this area in the future.

2.166.Two responses highlighted that standardisation may not be appropriate as the scope of time-profiled arrangements would vary locationally, with solar constraints highlighted as something that will be particularly location dependent.

2.167.One response noted that time-profiled connections could work for energy storage but on a site-by-site basis and to overcome the connection specific constraints. Another agreed that we should not prescribe a set of standardised time-bands as default options, adding that more operators should be encouraged to adopt time-profiled access rights.

2.168.Two responses raised concerns around our proposal. Another warned that without an Ofgem framework this kind of access offer may be slow to develop as network owners may approach this kind of solution with caution and not want to develop arrangements alone. They therefore suggested that all DNOs should offer the same or similar products. Two other responses also called on DNOs to collaborate to offer standardised access products. One noted that if two neighbouring DNOs' regions had significantly different options, this could create a locational signal for users wishing to connect, depending on the nature of the user. The other would welcome guidance and shared understanding across DNOs of how time profiled access could be used to ensure consistency of treatment.

2.169.Another response highlighted that time-profiled access would be a good option for solar generation which, for example, would not require network access at night.

However, they added that for plant whose output is not predictable over a longer term, such as wind, time-profiled access would not be an option.

2.170.One response warned that shoulder periods caused by timed connections operating immediately before and after the time constraint period could cause artificial peaks which would then need to be managed by DNOs. They therefore suggested that there should be a limit as to how many timed connections there could be on any given part of the network, such as a percentage of the capacity of the network. Another welcomed the proposal to enable flexibility around time-profiled access arrangements, particularly where this could be used effectively to reduce DUoS costs and potentially enable quicker connections to the network. They added that the main caveat to this was that such flexibility must not come at an additional cost to the network users that were unable to take the opportunity of time-profiled access rights because they operate continuous processes that run 24/7.

Q5a – Has the additional information in this consultation affected any of the views your previously submitted in response to our June 2021 consultation (if so, in what way)?

2.171.As part of the consultation questions, we asked respondents whether the additional information provided in the update to our minded to position had had an impact on their views of our policy proposal. We appreciated the stakeholders' responses on this question, which were largely positive. Responses indicated that the additional information had been useful and added clarity on the policy implementation approach.

Q5b – Do you have any other information relevant to the subject matter of this consultation that we should consider in developing our proposals?

2.172.A number of respondents provided additional information to us, with the main recurring areas of concern being the proposed implementation timeline (3) and changes to the ECCR (4).

2.173.A respondent warned that the proposed timeline to implementation was exceptionally fast, and it was essential that the final decision gave clear, unambiguous policy guidance and was not delayed beyond very early April in order for this to be in place by April 2023. They added that customer behaviours as a result of these reforms were very unclear and may result in a significant shorter-term 'surge' in activity as well as longer-term increases. Another response had a general concern that the timescales for implementing the changes by 1st April 2023 were challenging, particularly due to the potential impact on legislation, licences and codes, and the need to update internal systems and train internal staff. A third provided their view on key phases of the implementation timeline from April 2022 to April 2023.

2.174.Another noted that whilst the consultation made clear that BEIS was in charge of amendments to the ECCR, this was still an area of significant concern for connections which have been made on the explicit basis of recovering second comer contributions. They added that these rights must be protected in the revised ECCR legislation. Another suggested the need for ECCR reforms may not be a "showstopper" as in the worst case, some customers may get charged for ED1 reinforcement for a period until the reforms come into force. They therefore did not think this was material enough to delay the overall implementation. A third argued that the ECCR review must consider the definition of "first connection". They added that the lack of commentary on the pass-through of transmission connection asset works was a huge oversight and needed to be resolved immediately. They also welcomed the decision to not charge TNUoS to distribution connected generation and urged further action on the whole system.

2.175.One response called for Ofgem to be clear in its final direction on exactly how new mechanisms should be calculated, arguing that ambiguity will lead to delays in the code modification process. Another suggested we review the quantitative analyses performed in the Access SCR last year. They noted that when they responded to that consultation, they highlighted that the quantitative analysis assessing the option of applying TNUoS charges to SDG had significant flaws. Consequently, the proposal was based on a cost analysis that did not reflect the complexity of the energy planning network. They therefore felt there was a strong case to review the net benefit impact of the Access SCR, which may change the overall outcome of the proposals.

2.176.Concerns were raised by one respondent with the practicalities of non-firm access with respect to new housing developments. They believed that allowing non-firm access to small users would open up potential abuse or mis-selling to vulnerable customers. However, they argued that DNOs have no ability to ascertain whether a connection is for a housing estate or an industrial estate. It was unclear to them who would be responsible when the housing developer sells the house to a domestic customer. They asked if the domestic customer would inherit the non-firm access even though they should not have it or will the liability remain with the housing developer. Or in the absence of the housing developer, if the IDNO would hold responsibility. They added that flexibility providers could not solve this situation without exemption from liability.

2.177.Potential changes in behaviour caused by new rules were raised by another respondent. They gave the example of solar developers possibly focusing more on

Cornwall, which currently has significant 132kV circuit constraints, and where lots of smaller scale connections at 33kV could trigger massive 132kV reinforcement. This respondent also said that Ofgem should not wait for wider TNUoS reform to address the issue of transmission reinforcement blocking distributed generation connections; and that although BEIS is in charge of amending the ECCR, this was still an area of significant concern for connections made on the explicit basis of recovering second comer contributions.

2.178.Another response thought that for our proposals to work it would be vital that the design of uncertainty mechanisms within the RIIO ED2 process works to enable strategic investment in the network to be funded.

2.179.A recommendation was made by one respondent that the decision on the connection charging boundary for generation should be kept under review as part of the scope of the DUoS reforms. They explained that should improvements be made to generation use of system signals then it may be appropriate to move to a shallow connection charging boundary for generation in the same way as for demand.

2.180.One response highlighted that in several areas transmission network assets were becoming the constrained asset. They argued this has partially been due to ANM resulting in avoiding reinforcement, although now in many areas new curtailment reports were showing 60-90%, which is economically unviable. They added that the restrictions on both DNOs and National Grid in being allowed to reinforce ahead of need has caused significant issues. They welcome this review but urged that the cost allocation for National Grid assets getting upgraded also needed urgent consideration, as it currently falls to DNOs to charge this to new customers and the liabilities involved in this could cause projects to be cancelled. They added that if projects were cancelled, the status reverts to “no upgrade required” and no progress is made towards a lower-carbon future-proof grid.

2.181.Another response noted that while broader reform of DUoS charging had been split out into a separate SCR, it would be very useful for existing users to have certainty that they will not be double charged for the same infrastructure (i.e. pay for connection charge, then once the boundary moves, they pay through DUoS charges). They suggested that a modification similar to CMP203 could provide some assurance. They warned that without this, the changes would not improve on the key charging objective of maintaining competition as generators located very close but connecting at slightly different times could have vastly different costs. They added that ultimately end consumers would ultimately pay a higher cost for this inefficiency.

2.182.One respondent was disappointed that both the previous June 2021 consultation document and the updated minded-to consultation provided little evidence or modelling of the subsequent impact on DUoS charges. It was therefore not possible for them to determine the impact on individual sites or the scale of the distributional impacts. They felt this made it very difficult to understand what the change to DUoS bill payers might be or how any of the proposed mitigations to reduce this cost may help.

2.183.Flexibility in the subsequent code modification process was requested by one response in order to manage unexpected issues and allow users to adjust their business models. They would like to see a fixed charge per unit rather than a banding approach as more customer centric. If not, they asked for high voltage user processes to be reconsidered as they were "clearly extremely unequitable".

2.184.One respondent raised concerns in four areas. In relation to paying for reinforcements twice, they noted that in April 2005, distribution connection charges moved from "deep" to "shallowish" charges. Subsequently it was recognised that this exposed generators to a double-charge – both through a deep connection charge and subsequently through DUoS charges. This led to the introduction of a 25-year exemption period. They asked that similar transitional arrangement should be adopted here. On financially firmness they believed that failure to offer these at the distribution level maintained an uneven playing-field between transmission and distribution assets. In relation to network planning, they were not clear on how the interaction between constraints and network planning occurs and urged Ofgem to set this out and ensure that it is consistent with economically efficient delivery of net zero. Finally, on connection boundaries, they believed that the choice for a "shallower" generation connection charging boundary would continue to distort decisions regarding level of network connection given fully shallow connection charging boundary at transmission. They were also not clear that the different treatment of generation and demand connection boundaries was justified.