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

Dear Patrick

Thank you for the opportunity to respond to the above consultation. This response is on behalf of UK Power Networks' three distribution licence holding companies: Eastern Power Networks plc, London Power Networks plc, and South Eastern Power Networks plc.

We support Ofgem's minded to positions and its purpose to remove barriers to investment in low carbon technologies

We are supportive of Ofgem's purpose behind the minded to positions within this consultation and believe the proposals will help accelerate achieving this purpose. As a Distribution Network Operator (DNO), we will continue to make sure our customers energy needs are met including their plans for decarbonisation.

Over recent years we have developed and trialled novel arrangements to support our customers in these areas. In developing our RIIO-ED2 Business Plan we have embedded these ideas to reach as many customers as possible. Examples of this include:

- Charge collective[1] – a collaborative project aiming to demonstrate how we can work together with Local Authorities to plan local, public charging networks in areas at risk of getting left behind in the transition to Net Zero carbon emissions.
- Green Recovery[2] – an unprecedented opportunity to support the green economy and address climate change by kick-starting shovel-ready green energy infrastructure projects
- CommuniHeat[3] – working with the community of Barcombe, East Sussex, to create a low carbon heating blueprint for off-gas grid communities. The village could hold one of the keys to helping the UK reach Net Zero carbon emissions by 2050

[1] https://innovation.ukpowernetworks.co.uk/projects/charge-collective/
[2] https://www.ukpowernetworks.co.uk/green-recovery
[3] https://innovation.ukpowernetworks.co.uk/projects/communiheat/

Our RIIO-ED2 Initial Business Plan[4] includes major plans for investment to remove barriers for our customers who are decarbonising their heating and transport:

- We will run a process to identify and address market failures with respect to the provision of on-street charging, unlocking over 3,000 public charge points in areas of market failure by the end of RIIO-ED2.
- We will ensure that 71% of off-gas grid homes in our regions have the suitable capacity to decarbonise their heating and transport by the end of RIIO-ED2.

As Ofgem acknowledge in the Impact Assessment published alongside this consultation, Ofgem's proposals will increase costs funded by DUoS customers. Our initial analysis suggests this could be in the region of an additional £325m of expenditure over the RIIO-ED2 period across our three networks; there would be a large dependence on customer response to these proposals, if implemented. We are currently evaluating the appropriate split between ex-ante funding and uncertainty mechanisms for our Final RIIO-ED2 Business Plan submission in December.

We have identified the main contributors driving this increase in expenditure and provide further details in our response to question 3a. The key drivers of the additional expenditure relate to:

- Transfer of customer-funded reinforcement, as anticipated in the draft submission, to DNO-funded;
- Loss of customer contributions to the DNO through second-comer contributions to DNO-funded reinforcement;
- Generation connection customers who would have avoided reinforcement costs through accepting curtailed flexible connections, under the proposed scheme requesting a standard connection in instances as they would not contribute to reinforcement under the proposed changes;
- Customers who have accepted connection offers which include a reinforcement payment but where construction is yet to start are likely to cancel and re-apply in order to benefit from a lower connection charge; and
- On-going customer behavioural response to lower connections prices where reinforcement and/or flexibility is needed.

At this stage there remain significant details, such as the size of any potential revenue exposure in instances where there is a period of curtailment prior to completion of any required reinforcement, to be worked through ahead of implementation. This coupled with uncertainties over both the customer behavioural response to the changes and the degree to which flexibility markets will be able to respond, strengthen our belief that appropriately calibrated Uncertainty Mechanisms will play a fundamental role in protecting customers and enabling the RIIO-ED2 price control to be agile and responsive to how customers and the market respond to Ofgem's policy changes.

Working together with Ofgem, industry and stakeholders to implement this decision and deliver the benefits efficiently

This is a significant reform of the connection charging and access framework which will result in important changes for customers, wider consumers and network operators on an enduring basis. It is important that the changes to codes, methodologies and price control frameworks put in place to implement this decision result in a set of arrangements that deliver this policy decision effectively but also efficiently. We are committed to working with Ofgem and wider industry to develop these

[4] https://ed2.ukpowernetworks.co.uk/

changes ready for implementation on 1 April 2023. We recognise this is a substantial task but it will ensure benefits are delivered whilst minimising any unintended consequences.

Appendix 1 to this letter includes our response to your consultation questions which outlines details of some of the challenges we believe will need to be addressed in the implementation phase of this SCR. Below are some of the key issues and solutions we will seek to explore further to ensure the best outcome.

Weakening of the capacity signal in connection charges

The current connection charging arrangements mean that connecting customers pay a portion of any reinforcement costs associated with providing their connection. This provides a cost signal to these customers which acts as an incentive to make use of existing capacity where possible and to only request the capacity they have high confidence they will require.

The proposal to remove the apportioned cost of reinforcement for the majority of customers means they will no longer face this signal. To illustrate this point, we provide an example of a domestic customer asking for a three-phase supply to show the cost differential:

Description		**Direct activity prime cost (excluding A&D)**			
		extension asset / non-contestable, fully chargeable (£)	customer reinforcement contribution(£)	DNO reinforcement contribution (£)	total chargeable to customer (£)
rural domestic 3 phase supply upgrade, requiring transformer upgrade from 100kVA to 200kVA	Existing charging arrangements	788	7,744	30,978	**8,532**
	Proposed charging arrangements	788		38,722	**788**

In the absence of any mitigation this could lead to inefficient expenditure on reinforcement designed to meet needs expressed by customers that do not ultimately materialise. To avoid unnecessary bill increases for the wider customer base, we believe the new arrangements must include measures to avoid this situation over and above the work that DNOs undertake today to support customers to match their connection capacity to their genuine need. For example, customers could possibly be required to commit to a longer-term connection agreement at the capacity stated in their connection offer to ensure appropriate DUoS charges are levied for the capacity they request. We believe that detailed consideration is needed on this point to avoid unrequired investment driving costs up unnecessarily for consumers.

Uncapped curtailment liability

The proposal on non-firm access rights means that DNOs may have to procure flexibility while any reinforcement required for a standard connection is constructed. The details of this arrangement will require further development through the implementation stage but there is the potential for DNOs to have to procure this flexibility at rates higher than typical market rates if the connection is in an area with low market liquidity or where large numbers of customers seek to connect in a currently constrained area.

On the basis that this flexibility will be funded through the RIIO-ED2 price control, any additional costs would cause a rise in bills for the wider customer base. To protect customers from facing bill increases that are not justified by the wider societal benefits of this decision, we suggest suitable measures should be put in place to limit such costs to an efficient level. For example, these could be:

- Limiting the aggregate cost of flexibility payments made to connecting customers while reinforcement is constructed.
- Setting or capping longer term flexibility prices based on typical market rates (these could be updated regularly) to avoid "ransom" payments in locations with little/no effective competition.

Implementation approach

The proposal to introduce the connection charging changes when RIIO-ED2 begins will act to create a distortion and hold back demand for connections in the final year of RIIO-ED1. It is anticipated that requests for connection offers would surge immediately after the changes causing challenges for DNOs to meet this demand, resulting in longer quotation and connection times. These impacts could be avoided if implementation followed immediately from a decision and in the context of collective DNO load related reinforcement underspends in RIIO-ED1, this, would seem to offer wider societal benefits sooner than the proposal to delay implementation to 1 April 2023. An alternative approach, which would also be preferential over the proposed 1 April 2023 implementation would be to consider a phased introduction of the new charging arrangements, perhaps by voltage level of by requested capacity bands every two or three months. This way, the surges in connection applications could be spread out, mitigating the impact on connecting customers and DNOs.

Grandfathering rights

Generation customers who have currently been connected or hold accepted connection offers via a curtailed flexible arrangement may stand to benefit hugely from the new charging arrangements. In many cases, a standard connection, under the new proposals could be requested and the customer would not be liable to any reinforcement cost. An alternative would be that these customers are able to carry huge influence over the price they charge the DNO for the curtailed arrangements to remain in place, given the access changes proposed. This has the effect of driving a very significant totex increase in RIIO-ED2, estimated to be in the region of £130m in UK Power Networks' areas.

A similar argument can be applied to accepted demand connections which are yet to be constructed. It can be anticipated that many of these customers would seek to re-apply and replace the existing connection offer with one under the new charging arrangements. We estimate the impact from this on RIIO-ED2 totex to be in the region of £15m across our networks. With many of these connections being driven by developers, their existing business case would become more profitable at the expense of DUoS bill-payers. We would be keen to contribute to thoughts on how 'grandfathering rights' could be developed around these changes which maintain the societal benefit of the proposals in the most cost efficient manner for our connected customers.

Alignment with the RIIO-ED2 price control

The reforms set out in this consultation will have a material impact on the costs and required mechanisms within the RIIO-ED2 price control. We have undertaken initial analysis on the financial impact we envisage from these reforms over the RIIO-ED2 period as set out above.

We will continue to update and refine our analysis of the appropriate level of ex-ante funding to include in our Final Business Plan submission as more clarity of the future arrangements is gained through the implementation phase of the SCR. Further detail on the future arrangements is also required to ensure that RIIO-ED2 price control mechanisms (such as Load Related Uncertainty Mechanisms) will be suitable to adjust allowances in line with the significant uncertainty around customer response to these reforms. To ensure this alignment between the SCR and RIIO-ED2 programmes we suggest:

- Suitable milestones in the SCR implementation programme to feed more detail on the proposed implementation into the RIIO-ED2 price control with sufficient time for companies and Ofgem to reflect this in Final Determinations;
- Further consideration from Ofgem on whether it would like DNOs to include the costs in Final Business Plans due in December 2021, or whether it makes sense to consider the range of expenditure increases associated with the minded to position first in order to then determine the best course of action (e.g. which could include further joint industry work on refining the implementation of the proposals) – noting that clarity on this matter will be required urgently to enable DNOs to respond in time for the 1 December submission deadline;
- Specific focus on uncertainty mechanisms that also incorporate the uncertainty of demand arising from these changes to enable companies to submit plans on a comparable basis to Ofgem in December 2021;
- Formal links and governance between the teams and supporting working groups delivering each programme to ensure detailed alignment.

We reiterate our support for these minded to positions and look forward to taking an active role in the implementation phase through working groups and any other support required. If you have any questions on this response, please do not hesitate to contact me in the first instance.

Yours Sincerely

James

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Appendix – Responses to 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? Please explain why.

UK Power Networks support the proposals to remove customer contribution to the cost of reinforcement for demand connections and to reduce the contribution for generation connections. We also agree with the arguments put forward in supporting a reinforcement contribution for generation connections, given the greater locational flexibility that is typical for generation connections when compared to demand connections.

Our thoughts on each of demand and generation connections is outlined below separately. Further to the analysis we have undertaken on existing connection offers and recently-accepted offers, there are a number of high-level points we wish to ensure Ofgem are aware of ahead of making a final decision. This will allow a more informed decision on the benefits versus possible costs following customer responses to these proposed changes, particularly in light of the forth-coming RIIO-ED2 submissions due in December 2021. These are set out immediately below:

- Active Network Management (ANM) schemes have been offered since October 2019, making substantial savings available to customers on connection costs for customers who are willing to accept some form of curtailment in their connection. A number of these customers will wish to convert to standard connections where they would not contribute to the cost of any reinforcement. Based on the accepted offers to date, we estimate the reinforcement cost could be in the region of £130m and is likely to be incurred in the RIIO-ED2 regulatory period. However, some of this may be mitigated or at least deferred with the application of flexibility.
- The existing cost of reinforcement borne by connecting customers, based on recent years of accepted connection offers, is in the region of £12m annually across our three networks. It is anticipated that volumes of connections will increase substantially as a result of the drive towards net zero – we are already seeing this impact on our business. This is likely to result in over £150m of additional socialised costs of reinforcement in RIIO-ED2 with a potential additional £20m of socialised costs associated with reduced ECCR income, when compared to the existing charging rules. The vast majority of this reinforcement is associated with demand connections and increasingly at low voltage and 11kV, in line with the volume of EV charging installations. Flexibility, again, may be able to offer a mitigation, but the provider of this flexibility is likely to be connected EVs, via an aggregator, a market which is also far from mature, leaving a degree of uncertainty about the impact of flexibility.
- The first bullet point above is one example of a customer response to the changes, but there will be further marginal investment cases which would be swung favourably by the proposed changes resulting in an increase in socialised reinforcement costs of approximately £10m over RIIO-ED2. Similarly, where customers have accepted a connection offer under existing charging rules, yet construction is yet to begin, we anticipate many of these customers will cancel and reapply for an identical connection, but under the revised charging arrangements. This transient effect is discussed below, but will add to the level of uncertainty and contribute to an estimated increase of £15m in RIIO-ED2 expenditure funded by DUoS.

Overall, we estimate these key points could result in an increase in socialised reinforcement expenditure in the region of £325m in UK Power Networks' distribution areas within RIIO-ED2; key variables in this include customer response to the changes, the evolution of a maturing flexibility market and the speed of EV charger roll-out.

Demand Connections

Removing customer contributions to reinforcement costs for demand connections will allow a more strategic approach to network planning and UK Power Networks supports this principle as a mechanism to support the net zero transition. The consultation document acknowledges the likelihood for inefficient investment in cases, but that this is an acceptable balance for the overall benefit of society and UK Power Networks supports this view.

There remain some specific risks of a shallow connection boundary which are discussed below, together with UK Power Networks suggested resolution of each issue:

<u>Loss of price signal to support discussions with consultants on over-estimated capacity</u>

Our experience suggests consultants or developers managing the connection on behalf of an end-connection customer(s) typically over-estimate the required usage of the development. This is a natural consequence of the scale of the downside risk of underestimating a development's power requirement. Under current arrangements, this has a cost signal provided by the contribution to reinforcement costs. Typically, where reinforcement is triggered, UK Power Networks will work with our customer to understand the nature of their development in detail and confirm whether this capacity is absolutely needed prior to providing the quotation.

Where there is no cost signal provided from the reinforcement, this dialogue is less likely to result in a reduction in requested capacity resulting in some additional cost to DUoS customers, either through reinforcement or through tendered flexibility. Some of this risk could be mitigated by a DNO taking a balanced, strategic approach towards further reinforcement. A possible forward commitment by a customer to enter into a connection agreement for a period of time after energisation of the new supply may be an alternative to securities and/or liabilities to limit the risk of inefficient investment.

<u>Forward notice of hard transition date</u>

The proposed hard transition date of 1 April 2023 is highly likely to introduce a change in customer behaviour. We expect that DNOs will see a reduction in new connection applications for several months ahead of this date, starting from when the decision on this consultation is made, until the effective date. Immediately after this date, the volume of new connection requests is likely to grow considerably, making it more challenging for DNOs to provide quotations within appropriate timescales, with potential ramifications for customer service if not handled appropriately. Through a period of engagement with customers on this issue, UK Power Networks has understood that all customers' feedback to date confirms they recognise this risk and acknowledge that sufficient advanced warning of a change would act to significantly distort the behaviour of connection applicants. To avoid this issue, there are two possible solutions:

1. Progressive introduction of new charging arrangements across the connections market, possibly by capacity or voltage level. For example, requests above 10MVA could follow the new charging arrangements for applications made one month after the decision is

published, followed by requests of more than 1MVA several months later, followed by all other requests made after a further several months.
2. Implement the new charging arrangements immediately, or as soon as practically possible after Ofgem's final decision is published. Given the net underspend in load-related reinforcement across the industry in RIIO-ED1 to date, this appears the most attractive alternative for connecting customers and DNOs.

Transition arrangements for accepted schemes yet to be constructed

The consultation is silent on any arrangements for connection offers which have been accepted, but yet to be constructed. Across UK Power Networks, this represents around one year of order-book. Within this, there is typically £12m of customer-funded load-related reinforcement. It can be anticipated that many of these projects would be cancelled by customers, particularly those where a site is not yet ready or where third-party consent is not yet in place, only for customers to re-apply after the effective date so as to benefit from the removal of reinforcement contributions. The potential impact of this is to further add to the burden and cost of re-processing connection applications, exacerbating the situation discussed in the preceding issue. We would welcome and contribute to a cross-industry dialogue to support consistency, whilst retaining a customer-focused approach, in managing this issue efficiently.

The volume of load-related reinforcement required in RIIO-ED2 will be significantly greater than during RIIO-ED1 and UK Power Networks supports the principle of managing this through RIIO-ED2 via uncertainty mechanisms. Whilst the nature of how these mechanisms are defined and operated is also to be determined, this presents a risk to both connecting customers and DNOs. It is imperative that these mechanisms are defined and managed efficiently so that appropriate decisions can be made to avoid delaying connections or presenting excessive financial risk to DNOs.

Our Initial Business Plan submission for RIIO-ED2 set out a suite of Uncertainty Mechanisms we believe are needed for RIIO-ED2 and we are reflecting the feedback received to date from both Ofgem and Ofgem's Challenge Group to ensure these mechanisms are calibrated appropriately to protect customers and enable DNOs to respond to changing customer behaviour and demand growth.

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

Generation Connections

For generation, in principle, a shallower connections charging boundary retains an appropriate location signal, and UK Power Networks supports this. The points presented above regarding risks relating to demand connections remain largely relevant to generation connections, particularly around the transition date and possible arrangements limit the surge in applications on or after a particular date.

UK Power Networks were the first DNO group to offer Active Network Management (ANM) solutions to customers across its entire network areas from October 2019, following the successful trialling of zoned flexible offerings, where customers were able to connect with the benefit of avoiding reinforcement costs whilst accepting an estimated risk of curtailment of the export capacity when network operating constraints were reached. Since the launch of ANM, this has been tremendously successful, with over 4.2GW of customer-accepted schemes to date and a significant volume of existing and new applications adding to this.

The business case for these curtailed connections is on the basis of low curtailment figures estimated in UK Power Networks' network studies. The constraints exist principally on the distribution network, but there are instances where the constraint exists on national transmission network. Where the new charging rules stipulate a customer would not contribute to reinforcement, it can be reasonably assumed that customers for schemes meeting this definition would retrospectively apply for a standard connection, triggering reinforcement. Given the minded-to position described in the consultation, this request would be triggered in cases where there are no transmission constraints ***and*** all distribution reinforcement costs are at least one voltage above the point of connection. The anticipated RIIO-ED2 impact is discussed earlier.

Whilst there were business cases which supported these connections, reinforcing to remove the low rates of estimated curtailment retrospectively would appear to represent poor value to society as a whole and it is recommended that checks are put in place which limit the reinforcement cost in RIIO-ED2 associated with moving a substantial proportion of ANM schemes to standard connections. An appropriate mitigation against this cost is to allow the High Cost Cap (HCC) rule to take precedence over the voltage rule (so the £200/kW rule would remain in place at one voltage level above the point of connection). For the recently-accepted ANM schemes, we currently estimate that this could reduce the combined reinforcement and flexibility costs in RIIO-ED2 by over 20%.

For example, a customer for a generation connection with curtailment, who accepted with a 33kV point of connection may seek to re-apply to gain a standard connection under the proposed arrangements in RIIO-ED2. Under the existing proposals, where there is 132kV reinforcement, but no 33kV or transmission network constraints to achieve a standard connection, the DNO would contribute the full cost of this reinforcement in the event there was no flexibility in the 132kV constrained zone. There are examples within our current ANM portfolio where this is the case and the 132kV reinforcement cost exceeds £200/kW. In these instances, the cost to achieve potentially very modest additional generation capacity does not appear to represent an efficient investment of customers' money – a societal cost and benefits analysis would be very unlikely to confirm the small increase in generation output would offset the additional cost. Allowing the HCC to take precedence over the voltage rule avoids this distortion by reintroducing a price signal to deter such inefficient investment.

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?

Reviewing recent UK Power Networks quotation and acceptance data, there is no appreciable difference in acceptance rates for schemes which include reinforcement to those without reinforcement. This observation is equally true where UK Power Networks undertakes the contestable work and where an ICP undertakes the contestable work. This may lead to the conclusion that the existing reinforcement charging signal is not a significant driver for altering the nature of electricity connections.

However, in the interests of delivering excellent customer service whilst driving an efficient operation, UK Power Networks consistently strives to identify, in collaboration with the connection customer, the best solution for a connection. This involves a dialogue over the likely implications, in terms of cost and timescale, associated with a connection request and can happen after an enquiry, but in a growing number of cases, through general customer engagement or through specific surgeries or Ask-the-Expert services offered by UK Power Networks. The support provided frequently leads to a change in requirements or a cancellation of the request, benefitting both the customer and UK Power Networks by avoiding unnecessary further work

This support dramatically reduces the volume of unviable connection offers, many of which would have included substantial reinforcement costs, compared to the case without constructive engagement with connection customers. This engagement should continue, although assuming the charging boundary changes are agreed as indicated in the consultation, the additional dialogue will increasingly focus on the likely usage of the connection so as to validate the identify any necessary reinforcement/flexibility requirements in a timely manner.

UK Power Networks has also worked hard with developers and public-funded bodies during RIIO-ED1 to deliver significant infrastructure investment where connection activity is evident. For example, this has involved supporting the development of nine main sub-stations in London. These mechanisms and the approaches towards facilitating connections have ensured that the existing connection charging arrangements, together with the ECCR (2017) regulations have been fit for purpose for the last few years.

However, with ever-increasing activity in the EV charging market, and to a lesser extent, heat pumps, demand connections which benefit the whole of society are becoming a much more significant component of the connections market. There is a need to ensure a wide EV charger roll-out across the whole of a distribution network, so the argument for removing reinforcement costs from connecting customers is strong. The nature of generation is different and it is certainly true that in many cases, business cases are less fixed to a particular location than is the case with demand connections, as identified in the consultation document.

The proposed changes will facilitate some connections which otherwise would not be able to proceed and connection costs will be less sensitive to whether the existing distribution networks are heavily loaded in the local area or not.

The change to a shallower connection charge boundary as described would generally push flexible or curtailed connections towards being a temporary solution for quicker connections until standard connections can be made through reinforcement. As discussed in our response to question 3a, for generation in particular, we would welcome detailed discussions with Ofgem and industry over the specific use cases which drive significant cost from changing the charging boundary such as enabling standard connections to previously-accepted ANM or flexible schemes. Taking into account potential benefit from the procurement of flexibility, the cost within RIIO-ED2 is still estimated to be high to achieve relatively small reductions in curtailed capacity.

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

As discussed in the response to question 3b, UK Power Networks has worked hard to facilitate additional capacity where demand materialises through dialogue with developers and local authorities, which has undoubtedly led to a more structured approach to investment in capacity than would have arisen with a more passive or reactive approach.

However, the scale of additional capacity required over the coming years together with the need to roll this out at all voltages and locations to allow full coverage of EV chargers changes the dynamics in the connections market. As outlined in the consultation, society as a whole will benefit from this transition and pushing reinforcement investment decisions further towards DNOs will allow for a more strategic approach to ensure overall cost efficiency in the transition towards net zero.

Typically, it is at 11kV and below that connecting customers face the broadest relative variation in reinforcement costs under current charging rules which largely depend upon the relative load on the existing network. Removing this variable from connection charges appears to be a fairer way of applying connection charges where it is known the vast majority of EV charging and heat pump uptake drives connections and reinforcement at 11kV and below.

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?

Procuring flexibility is a process which takes longer than the typical quotation turn-around timescale. Coupled with this, the flexibility market is yet to fully mature and the deployment of technologies to enable greater flexibility across the breadth of distribution networks, such as storage devices, is in relatively early stages. It is unknown how fast and fully flexibility markets will develop, particularly in the context of significant growth in overall usage of the electricity distribution networks.

Directionally, a shallower charging boundary will allow flexibility to be considered more widely as an alternative to reinforcement as DNOs are able to plan more strategically. Under the existing charging rules, there is a risk this takes longer to develop and the requirement to provide price certainty may be a barrier or would at least serve to drive more heavily caveated connection offers. The proposals will remove this issue and price certainty can be provided more easily to customers. It should be noted also that the appetite of demand customers to accept a flexible connection is limited. For example, customers managing industrial processes or those creating heating loads in restaurants are not able to respond to pricing signals or flexibility markets if their business relies on standard access to the distribution network, unless they are able to build storage devices on site. Whilst the flexibility market is still developing, the majority of demand connection offers in constrained network areas are likely to rely on reinforcement solutions until a more fluid flexibility market is realised.

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?

The High Cost Cap (HCC) rule is rarely used under current pricing rules; the threshold set is at a suitable value such that under current arrangements, the pricing signal from reinforcement charges acts as a suitable signal against inefficient investment.

However, removing the pricing signal for reinforcement at all voltages above the point of connection for generation connections will lead to a greater risk of inefficient investment or the need to procure extensive flexibility. As discussed in our response to question 3a, there are likely to be examples of the £200/kW threshold being breached with previously accepted ANM (curtailed) generation connections because of constraints at higher voltages, should there be a need to reinforce the network.

UK Power Networks is of the strong view that retaining the HCC rule and allowing this to take precedence over the voltage rule would offer a significant mitigation of the potential cost DUoS customers are exposed to following the change in charging rules.

UK Power Networks understands the history and analysis which originally set the HCC threshold at £200/kW, but as part of the implementation of the access and charging proposals, it would seem appropriate to revisit this analysis to confirm whether or not £200/kW remains the appropriate threshold.

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?

We acknowledge that removing these costs from distribution connection charges would require changes to cost recovery arrangements for transmission companies. As noted in the consultation, such a decision would also need to be evaluated in the wider context of transmission charges and any potential reform.

However, we believe there is merit to a more in-depth review of this minded-to proposal through the implementation group to ensure that it does not create material inconsistency in connection charges or drive inefficient decisions. For example, a connection that includes transmission costs for the customer might be the most efficient whole system solution but the customer could opt for a less efficient solution that involves only distribution work as they would not face the reinforcement costs.

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?

Many of the issues associated with inefficient investment are discussed in our response to question 3a. Inefficient investment will happen to a larger degree under the proposed changes than under existing charging arrangements. The key reasons and possible mitigating actions are set out below in summary:

Description of inefficient investment driver	**Impact on DUoS customers (high/medium/low) if no further control introduced**	**Possible mitigating action or control**
Demand and generation customers applying for greater capacity than needed, 'just in case'	medium	Forward commitment at point of acceptance of a connection offer of a termed connection agreement post energisation, with max import/export capacity as stated in connection offer
Retrospective application for standard connection following RIIO-ED1 time-profiled or curtailed connection or through variation of existing accepted and not-constructed connection offers	high	HCC to take precedence over voltage rule
Cancellations after investment has been made	low	DNO to apply queue management principles to the connection applicant's scope of work or development to manage risk of exposure to reinforcement costs ahead of energisation

In many cases, if a project is cancelled, another party will be able to use the capacity, but this is by no means always the case. There will inevitably be a degree of inefficient investment, even if introducing liabilities, where companies fail and/or are unable to pay a liability. Introducing securities may act to inhibit connections activity if companies are unable to access this finance cost-effectively. Owing to the complexity of administration, and the scale on which it would need to be implemented, effectively adding cost to DUoS customers which would need to be recovered. For these reasons, UK Power Networks does not support the introduction of securities and liabilities for all connections, but there may be a case to apply securities and liabilities for the largest reinforcement investments, perhaps where the value exceeds £1m. We are keen to support Ofgem in defining controls which may be effective in limiting exposure to inefficient investment.

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

Currently, the ECCRs and the connection charging methodologies are two separate reference points from which the overall distribution charging framework is constructed. It would seem sensible if these separately defined rules are combined, potentially by removing the ECCRs and codifying the forward intent into the common connection charging methodology.

Many connection customers have factored the 10-year ECCR recovery period into their investment decisions and it is critical that any revisions to the ECCR legislation (or suitable arrangements as incorporated into other charging rules) maintain this arrangement for legacy connections. One example of this active consideration of ECCRs in action is that of public bodies winning government grants to invest in new electricity infrastructure; ECCR legislation allows the subsequent recovery of this money from housing or commercial developers who benefit from this initial investment and allow the public bodies to justify the investment in light of state aid rules. Therefore, any changes to the charging arrangements should leave these arrangements for customers who have accepted connection offers in place for the entire period of effectiveness of the existing ECCRs, defined as 10 years from the point of energisation of the initial connection.

There should be a distinction drawn between the case above, where customers benefit from ECCR payments and the case where a DNO, having previously contributed to reinforcement, is the beneficiary of any ECCR payments. Where the DNO is the initial contributor, after the proposed shallower charging arrangements are implemented, customers should only be liable to make an ECCR payment where they would contribute to reinforcement in the case they were the initial connectee (e.g. for generation connections which rely on reinforcement previously built at one or more voltage level above the point of connection for a prior connecting customer).

If the ECCRs are amended only after any changes to the charging boundary are implemented, there is a risk that customers triggering reinforcement will benefit from not contributing to this reinforcement, but DNOs will be legally obliged by the ECCRs to recover some of the same reinforcement cost from subsequent customers in the same area. In effect, customers are treated differently.

We do not support the option to revise licence conditions and industry codes to effectively reverse the effects of the existing ECCRs where treatment of customers would be different under the revised charging and access arrangements according to the order they request connection. This would place licence conditions and/or industry codes in contravention with secondary legislation and places obligations on DNOs to charge connecting customers in a way which acts against the intent of the existing ECCR legislation. It is unclear what might result if this is challenged legally.

It is our view that the ECCRs need to be amended in parallel with the changes to the charging boundary. An alternative may be to repeal the ECCR legislation and write the whole charging structure, including the aspects which mimic ECCR impacts, into the revised charging licence conditions and codes.

4. Access rights

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

We agree and support better definition of access choices so as to achieve the aims of reform: enablement of LCT connections and hence progression to net zero, and efficient investment in the electricity distribution network. We note that many DNOs already offer flexible connections: we have already saved currently operational customers over £70m through use of non-firm (flexible) connections.

The arrangements offer the prospect of enabling connections ahead of the delivery of necessary reinforcement but it will be important to step through the end-to-end journey of a connecting customer of various types under the new arrangements to understand how the new arrangements will work in practice, including the extent to which customers might be willing or able to negotiate connection terms given the reduced price signal. Some customers will value an earlier connection in exchange for offering flexibility. Such flexible offers will cover the period between when the connection commences (after the construction of sole use assets) and the delivery of required network reinforcement.

In general terms, standardisation would help to ensure that all customers understand what is on offer and reduce costs for customers of researching and deciding on connection offers, especially against the alternative in which each DNO takes a different approach. However, forced standardisation might also hamper innovation.

For example, it is proposed that flexibility agreements will be defined in terms of the number of hours, or percentage of time, of curtailment. This appears simple and practical even if in some cases it might not reflect the variable impact of curtailment on customers for whom time of curtailment is important. For solar generators, 3% curtailment during morning hours would yield lower MWh curtailment on average than 3% of midday hours curtailment. We therefore expect to need to evolve more sophisticated curtailment estimation techniques and believe that standardisation should not prevent this. More generally it would be useful to explore the idea of a basic standard 'default' offer alongside the ability to tailor arrangements that suit better what customers want.

In defining exactly what standardisation entails, the following should be considered:

- how curtailment limits are to be determined. Historic averages, some form of economic or modelled approach, or simply fixed rules (akin to the 5% curtailment limit for renewable generation in the Clean Energy Package) are possibilities
- the level of granularity in applying such rules (e.g. by agreement, by DNO (or otherwise defined) region, or nationally)
- arrangements for measurement and assessment of curtailment, including its periodicity (e.g. annual) and recovery of any cost of measurement infrastructure;
- the possibility and transparency (reporting) of any non-standard arrangements.

We envisage that an industry standard methodology describing the design of these arrangements will be developed to be applied transparently by each DNO.

A further important question to be determined is exactly how any arrangements might be governed. Possibilities include specific regulation, a code subject to regulatory oversight or a self-governed industry code (e.g. initially developed by Open Networks), potentially with the ability for regulatory appeal or step-in where satisfactory agreements cannot be reached between a customer and a DNO. The approach should balance the need to provide regulatory protection against the cost and complexity of the arrangements.

We also believe it will be important to clarify the price control arrangements which will apply, particularly in relation to funding of costs associated with connections, where network conditions require additional curtailment beyond that envisaged in connection offers. The consultation suggests that such circumstances ought to be resolved by means of procuring flexibility and we would agree that this is likely to be an efficient and desirable solution because it opens the possibility of resolving such issues by procuring flexibility from other parties, compared to defaulting to some form of standardised ‘penalty’ payment. On the other hand the arrangements should have reasonable incentives to avoid such curtailment in the first place (while also avoiding incentives to adopting an overly risk averse approach to setting curtailment limits).

We note that it will not always be straightforward to determine the causes of the need for additional curtailment and hence how the costs should be borne. For example, it may arise from simple modelling error or from an unusual set of network conditions. This suggests that including an initial estimate of such costs as part of Load Related Expenditure in totex may be the simplest and fairest solution as in that case the general incentive regime on totex will apply, with additional variability catered for through appropriately calibrated Uncertainty Mechanisms. In this respect it should be noted that the actual take-up of connections (standard or flexible) will be unknown and this is a much greater uncertainty. All these matters should be considered as part of the detailed arrangements.

We fully intend to devote appropriate resources to clarifying all of such details on a collaborative basis, noting that the task is significant and should be expedited as soon as practical.

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?

We agree and support the standardisation of this offering. We, along with many other DNOs, already offer time-profiled connections. We have already saved customers £3m through their use.

Many of the comments made above in relation to Question 4a apply equally to time-profiled connections. We are likewise committed to working together to clarify matters such as:

- How standardised will the arrangements be and how will such standardisation be achieved;
- What flexibility will DNOs have to alter parameters to fit customer and network needs;
- Whether non-standard arrangements will be permitted;
- How arrangements for flexible connections and time-profiled access will work together if what is offered during ‘peak’ periods effectively a flexible connection offer; and
- How the arrangements will be governed.

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

We note the concerns raised in the consultation about the potential downsides of the arrangements, in particular barriers such as potential user lock-in through agreeing to shared access arrangements. We also agree that trading of access rights could be a more promising way of achieving the same ends as a shared access scheme. However, this would require a viable market which may not exist in every circumstance where there is a potential value in sharing access. It is very difficult to predict take up. However, we can see that community energy schemes may well be become more common as the energy system transition proceeds. We therefore believe that resources should be devoted to continuing to explore the potential for such arrangements and we will be actively involved in industry initiatives to do so.

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)?

The minded-to proposal in this consultation is that connection charges to demand connections will no longer vary because of the need for reinforcement. Nor will charges for generation if there is no need for reinforcement at the connection voltage.

Connection charges for generation will vary if reinforcement is required at the voltage level of connection. In relation to this, see our response to Questions 3a and 3e in relation to the precedence of the voltage rule and the High Cost Cap. Our comments below are not applicable to this situation.

The consultation rules out the use of DUoS charges to reflect flexibility in access rights for fear of distorting markets for flexibility. However, because any DUoS charge reform would happen after the implementation of these new arrangements, it is difficult to make an informed, overall judgement at present.

We note that it would be possible, if this were seen as desirable, to tweak the current DUoS arrangements to provide some form of signal using capacity element of the DUoS charges (i.e. apply a lower level of capacity for demand customers prepared to take up a flexible connection). We believe that this is worth exploring.

We would welcome early indication about the thinking on such reform and would be keen to work with Ofgem to develop such thinking. In the meantime it is difficult to make an informed comment. In relation to time-profiled access, the consultation is not very clear. It says (para 4.22) that there is "*scope to reflect the value via connection charges and/or DUoS charges, though the latter would be dependent on our final proposals for DUoS charging reform*." We agree that there is scope (as we suggest above) to use the capacity element of the DUoS charge to create a pricing signal in periods of peak usage. We would be keen to work together on the details of this. However, we are not immediately clear how Ofgem is envisaging the variation of connection charges for time profiled connections and would welcome further information on it.

Whatever pricing arrangements are brought in it is important that there is consistency in charging across flexible offers and time profiles to avoid potential distortions, especially if what is on offer in peak periods of a time profile is essentially a flexible connection.

Reflecting connection arrangements in DUoS charges could be seen as a temporary expedient pending wider reform, or as a more permanent feature of the arrangements. Either way, it would be desirable that the development of the arrangements and the associated instruments (codes, guidelines etc.) should trail the best way to reflect them in any future charge reform to ensure best alignment.

We can see that there are benefits to phasing implementation in this way. It may be that both the connection access arrangements and DUoS reform are required for a fully effective solution, but doing one before the other allows for a more controlled and considered implementation of what may be potentially complex DUoS changes. Having said this, expectations of what will result from a 'partial' implementation should be moderated.

A final point in relation to charging relates to the costs of non-compliance by users with conditions of access. We agree that many such costs fall on DNOs but it is an open question as to how such costs ought to be borne. It seems equitable that a failure of a user to comply ought to be borne by that user if it is an agreement freely entered into. However, if the arrangements envisage a standard offer where there is little ability of the user to negotiate curtailment levels then there may be a case for socialising some or all of those costs.

As with all other areas addressed by this consultation, we are committed to working with Ofgem, the industry and our connecting customers to resolve the details.

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

Generally, we agree with the proposal. However, we note a potential distortion where transmission constraints are leading to the use of non-firm access rights for distribution connected customers; an issue which is very material. During the past two years, we have contracted to connect 4.2GW of generation capacity via curtailed connections. 3.3GW, or over 80%, of this capacity sits behind a transmission constraint. This needs to be considered alongside the decision to continue to charge distribution customers for transmission work triggered by their connection. There seems to be no reason why such customers should not also receive the same service for the same price as those constrained by distribution constraints. Understanding the potential scale and impact of this distortion should be considered before finalising the arrangements.

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

We have discussed issues associated with standardisation at Question 4a. We believe that there is benefit to customers of consistency in approach, especially for those customers working across many DNO regions. However there could be benefit in maintaining some flexibility in the arrangements to enable offering to customers to best reflect their requirements and local network conditions and to facilitate innovation.

There are a number of ways in which these aims could be achieved in parallel. We have discussed above the possibility of a default offering. Other potential measures would be to utilise formal review periods to develop codes as experience with customers builds and/or implement codes which allow for flexibility in the adjustment of parameters based on customer needs or in the light of experience.

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

As we indicated at points earlier in our response there remains a great deal of detail to be determined in order to achieve an April 2023 implementation date. We are committed to playing a full part in this effort.

The 1 April 2023 date does make sense in that these details can be developed so that there is a coherent and consistent regulatory treatment for RIIO-ED2 and we urge that work on the regulatory arrangements is joined up with detailed work on codes. This suggests that Ofgem needs to be involved at a sufficiently detailed level in industry discussions about the detailed access arrangements.

We have outlined our concerns with a hard ‘go-live’ date in respect of the connections boundary decision earlier in our response.

5. TNUoS charges for SDG

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

It is a reasonable assumption that small generation embedded in the distribution network closer to demand is less likely to cause less power flow on the transmission network compared to generation connected directly to the transmission network (where 100% of power produced is guaranteed to flow across the transmission network). Matters other than power flows should also to be considered. For example, all generators (in the same way as all users connected to the GB electricity system) benefit from having a connection to the "National Grid" with all the services and characteristics this provides (such as consistent frequency etc.). This also suggests a reason for consistency of treatment.

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?

We agree this is a sensible threshold which aligns with other requirements for distributed generators (such as the distributed energy resource register). However, this does place requirements on some relatively small and, in some cases, less sophisticated network users and so we believe that an impact assessment of the administration requirements on these users should be carried out and justified by clear benefits. If the administration burden is found to be excessive then the option of a higher threshold should be considered.

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

The MW or MVAr contribution of a distributed generator and its respective effectiveness will vary depending where they are connected on the distribution network. In most cases, the closer the distributed generators are connected to the Grid Supply Point (GSP), the higher their contribution to the GSP power flow. Network configuration plays a factor on the effectiveness as well. This is demonstrated through our Power Potential project analysis[5] where effectiveness varies from c30% to c80%. We have seen similar variations through the constraint analysis we undertake as part of our flexible connections offering.

[5] https://www.nationalgrideso.com/document/191146/download (pg55)

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

We have no preference.

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?

We generally support the principle of transitional arrangements such as grandfathering where it can be shown that there are large incidence effects prejudicial to existing users' rights. However, as it appears that the TNUoS proposals are not to be implemented immediately, there will be a period during which the direction of future reform can be signalled to all current and prospective users. This may obviate the need for specific individual transition protection. We think that it is more important at this stage to signal the future path and timing of reform than devote resources to detailed transition arrangements.

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?

The consultation is against the involvement of DNOs in administering TNUoS generation charges, principally on the grounds of complexity. While we understand this concern, it is possible that the impacts of not involving DNOs are more detrimental or lead to missed opportunities for efficiency and joined up thinking because of the data that DNOs hold or the strength of existing customer relationships.

We think that it is important to consider a whole system approach to new arrangements for users, especially where the user is dealing with multiple system providers (e.g. ESO, TO and DNO). There are existing arrangements and lines of communication with these customers which may offer an efficient route to supporting the implementation of these arrangements. As an example, through the recent Loss of Mains change programme, the DNOs had to contact and administer protection settings changes to significant portion of all DER over 1MW. This exercise highlighted that there is a significant overhead in contacting these smaller DG customers to update their data and then maintaining this data set moving forward. DNOs have already built this capability so it would be appropriate to look at how this can be used for the purpose of TNUoS recovery.

Failing to recognise existing data and communication lines could risk inefficient implementation (and associated costs) and increased complexity for users.

We have not identified missed options and we agree complexity should be avoided, but this should be particularly from the perspective of system users. We therefore strongly suggest options where DNOs are involved could usefully be explored in more detail when it is decided to progress with these changes.

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?

See our response to Question 5f above.

7. General question

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

Please see our covering letter for the key points we think are important for Ofgem to consider when implementing this reform.